Appendix A_1:

Ohio's July 16, 2014 Request for a Comment Period Extensions

John R. Kasich, Governor
Mary Taylor, Lt. Governor
Craig W. Butler, Director

July 16, 2014

Ms. Gina McCarthy
U.S. EPA Administrator
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Ms. McCarthy,

On June 18, 2014, U.S. EPA published proposed rules to reduce the amount of carbon dioxide from fossil fuel-fired power plants under 111(d) of the Clean Air Act.

Ohio is reviewing this proposal and has quickly recognized that the proposed rules need input and coordination from other State regulatory agencies including Public Utility Commission of Ohio, the Ohio Department of Development Services, the Ohio Office of Energy Efficiency, Ohio Department of Health and others to attempt to understand and respond to your proposal by the October 16, 2014 date.

Although we recognize that U.S. EPA has allowed for a 120-day comment period, due to the complexity of this proposal and the needed interaction with the various state agencies to prepare comments, we are requesting an additional 90 days to submit comments.

Please contact me if you have any questions.

Sincerely,

Craig W. Butler
Director

50 West Town Street • Suite 700 • P.O. Box 1049 • Columbus, OH 43216-1049
www.epa.ohio.gov • (614) 644-3020 • (614) 644-3184 (fax)

Appendix A_2:

U.S. EPA's July 25, 2014 Denial of Ohio EPA's Comment Extension Request

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 25 2014

OFFICE OF
AIR AND RADIATION

Mr. Craig W. Butler
Interim Director
Ohio Environmental Protection Agency
P.O. Box 1049
Columbus, Ohio 43216-1049

Dear Mr. Butler:

Thank you for your letter of May 8, 2014, to U.S. Environmental Protection Agency Administrator Gina McCarthy on the Clean Power Plan for Existing Power Plants that was signed on June 2, 2014 and published in the *Federal Register* on June 18, 2014. The Administrator asked that I respond on her behalf.

Climate change is one of the greatest challenges of our time. It already threatens human health and welfare and our economic well-being, and if left unchecked, it will have devastating impact on the United States and the planet. Power plants are the largest source of carbon dioxide emissions in the United States, accounting for roughly one-third of all domestic greenhouse gas emissions.

The Clean Power Plan aims to cut energy waste and leverage cleaner energy sources by doing two things. First, it uses a national framework to set achievable state-specific goals to cut carbon pollution per megawatt hour of electricity generated. Second, it empowers the states to chart their own paths to meet their goals. The proposal builds on what states, cities and businesses around the country are already doing to reduce carbon pollution, and when fully implemented in 2030, carbon emissions will be reduced by approximately 30 percent from the power sector across the United States when compared with 2005 levels. In addition, we estimate the proposal will cut the pollution that causes smog and soot by 25 percent, avoiding up to 100,000 asthma attacks and 2,100 heart attacks by 2020.

Before issuing this proposal, the EPA heard from more than 300 stakeholder groups from around the country, including several from Ohio, to learn more about what programs are already working to reduce carbon pollution. These meetings, with states, utilities, labor unions, nongovernmental organizations, consumer groups, industry, and others, reaffirmed that states are leading the way. The Clean Air Act provides the tools to build on these state actions in ways that will achieve meaningful reductions and recognizes that the way we generate power in this country is diverse, complex and interconnected.

We appreciate your providing your views about the effects of the proposal. As you know, we are currently seeking public comment on the proposal, and we encourage you and all interested parties to provide us with detailed comments on all aspects of the proposed rule. The public comment period will remain open for 120 days, until October 16, 2014. We have submitted your letter to the rulemaking docket, but you can submit additional comments via any one of these methods:

- Federal eRulemaking portal: http://www.regulations.gov. Follow the online instructions for submitting comments.
- E-mail: A-and-R-Docket@epa.gov. Include docket ID number HQ-OAR-2013-0602 in the subject line of the message.
- Fax: Fax your comments to: 202-566-9744. Include docket ID number HQ-OAR-2013-0602 on the cover page.
- Mail: Environmental Protection Agency, EPA Docket Center (EPA/DC), Mailcode 28221T, Attention Docket ID No. OAR–2013-0602, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.
- Hand Delivery or Courier: Deliver your comments to: EPA Docket Center, Room 3334, 1301 Constitution Ave., NW, Washington, DC, 20460. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Again, thank you for your letter. I appreciate the opportunity to be of service and will look for opportunities to work with our partners in Ohio as we move forward with our plans to finalize the Clean Power Plan for Existing Power Plants next year.

Sincerely,

Janet G. McCabe
Acting Assistant Administrator

Appendix A_3:

September 11, 2014 Extension Request Letter from 53 Senators

United States Senate
WASHINGTON, DC 20510

September 11, 2014

The Honorable Gina McCarthy
Administrator
Environmental Protection Agency
U.S. EPA Headquarters – William J. Clinton Building
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Dear Administrator McCarthy,

We are writing to request that the Environmental Protection Agency (EPA) provide a 60 day extension of the comment period for the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units." While we appreciate EPA granting an initial 120 day comment period, the complexity and magnitude of the proposed rule necessitates an extension. This extension is critical to ensure that state regulatory agencies and other stakeholders have adequate time to fully analyze and comment on the proposal. It is also important to note that the challenge is not only one of commenting on the complexity and sweeping scope of the rule, but also providing an opportunity to digest more than 600 supporting documents released by EPA in support of this proposal.

The proposed rule regulates or affects the generation, transmission, and use of electricity in every corner of this country. States and stakeholders must have time to fully analyze and assess the sweeping impacts that the proposal will have on our nation's energy system, including dispatch of generation and end-use energy efficiency. In light of the broad energy impacts of the proposed rule, state environmental agencies must coordinate their comments across multiple state agencies and stakeholders, including public utility commissions, regional transmission organizations, and transmission and reliability experts, just to name a few. The proposed rule requires a thorough evaluation of intra- and inter-state, regional, and in some cases international energy generation and transmission so that states and utilities can provide the most detailed assessments on how to meet the targets while maintaining reliability in the grid. This level of coordination to comment on an EPA rule is unprecedented, extraordinary, and extremely time consuming.

It is also important to note that the proposed rule imposes a heavy burden on the states during the rulemaking process. If the states want to adjust their statewide emission rate target assigned to them by EPA, they must provide their supporting documentation for the adjustment during the comment period. The EPA proposal provides no mechanism for adjusting the state emission rate targets once they are adopted based on the four building blocks. So the states need enough time to digest the rule, fully understand it, and then collect the data and justification on why their specific target may need to be adjusted, and why the assumptions of the building blocks may not apply to their states. This cannot be adequately accomplished in only 120 days.

Thank you for your consideration of this request.

Sincerely,

Deb Fischer

Heidi Heitkamp

[illegible]	Mary L. Landrieu
Mitch McConnell	[illegible]
David Vitter	Mark R Warner
Joe Donnelly	[illegible]
[illegible]	[illegible] Manchin
[illegible]	Chuck Grassley
[illegible]	Orrin Hatch
Pat Roberts	[illegible]
John Cornyn	Ron Johnson
John Boozman	[illegible]
[illegible]	Lamar Alexander
[illegible]	Mike Crapo
[illegible]	Dan Coats

Jim E Risch

Mike Johanns

Saxby Chambliss

Michael B. Enzi

Jerry Moran

[illegible]

[illegible]

[illegible]

[illegible]

[illegible]

Tom Coburn

Mark Begich

[illegible]

Rob Portman

John Barrasso

[illegible]

[illegible]

John Hoeven

Richard Shelby

[illegible]

Roy Blunt

Rand Paul

[illegible]

[illegible]

Pat Toomey

Appendix B:

Issue Paper: Building Block #1 Heat Rate Improvements for Coal-Fired Power Plants

Issue Paper: Building Block #1

Heat Rate Improvements for Coal-Fired Power Plants

What is Efficiency and Heat Rate?

EPA's Clean Power Plan proposes to use a number of different "building blocks" to gauge the adequacy of state plans to reduce CO_2 emissions from the existing fossil-fueled fleet of electric generating units. This paper discusses the first "building block," improvements in the heat rate (or efficiency) of the existing coal-fired generating units.

The First Law of Thermodynamics, also known as the Conservation of Energy states that for any system, the energy out is equal to the energy put in. The energy that is produced can come in various forms (heat, sound, light, etc.). What is most important is the amount of "useful energy" produced from the process to meet a given objective. The amount of useful energy output from a given energy input determines a system's efficiency. Take, for example an automobile engine. The First Law states that 100% of the energy from the gasoline will be released in the engine when the fuel is burned. However, only about 20% of the energy produced in the vehicle's engine is useful in meeting the objective (moving the car from point A to point B). If so, then that engine is 20% efficient. The remaining 80% is lost through heat loss and friction in other parts of the engine and drivetrain system (e.g. pistons, valves, transmission, lubrication systems, fans, belts, etc.). There is no piece of equipment or system that is 100% efficient.

In the case of a fossil fuel-fired power plant, energy enters the plant in the form of fuel (e.g. coal, natural gas, etc.). The fuel is burned to release energy in the form of heat, which is then converted to mechanical energy by various means to turn a generator to produce electricity. In a coal-fired steam generating power plant, the energy from burning coal is used to heat water to steam. That steam then powers a turbine, which turns a generator to produce electricity. As with the car example above, not all of the energy produced by the combustion of coal is used to actually produce electricity. Much of that energy is lost in the form of waste heat, friction, sound, and other means by various parts of the process. All of these losses impact the overall efficiency of the plant. Technological innovations along with the ability to more closely monitor and reliably control processes have effectively improved the efficiency of fossil fuel fired power plants.

A measure of efficiency in a power plant is heat rate, which is how much fuel energy is used to make electricity. Lower heat rate values mean that the same amount of electricity is produced with less fuel, which means the system is more efficient. Power plant operators are motivated to optimize and lower heat rate (improve efficiency) because it lowers the cost of producing electricity. Technically, heat rate is the energy required (expressed in British Thermal Units or Btu) to generate 1 kilowatt of electricity, for 1 hour (also known as a kilowatt-hour or kWh). Assuming zero energy losses, it would take 3,412 Btu to produce 1 kWh. A theoretical power plant that is 100% efficient would then have a heat rate of 3,412 Btu/kWh. As discussed in more detail below, the efficiency of most existing fossil power plants is in the 30 to 40% range.

How is Heat Rate Measured?

Heat rate is periodically calculated for coal-fired power plants based on measurements of coal consumption, laboratory analyses of coal samples to determine an average Btu content in the coal consumed, and the total kilowatt-hours generated during the time period. The calculation follows below:

$$\text{Heat Rate (Btu / kwh)} = \frac{\text{lbs coal consumed x heat content of coal (Btu/lb)}}{\text{total kilowatt-hours generated}}$$

Existing monitoring techniques do not provide accurate instantaneous or continuous measurements of heat rate. In particular, the variability of fuel energy content and thermal fluctuations like ramping up/down on load can produce significant swings in instantaneous heat rate. In addition, the current methods used to estimate and report fuel heat input to EPA are not sufficiently precise to consistently detect a heat rate improvement rate of 6% or less.

Power plant heat rates can be expressed as a gross value or a net value. Gross unit heat rate is represented by the total energy input from the fuel divided by the gross kilowatt-hours generated by the generator. Net heat rate subtracts out the generated electricity that is used by the plant to run the fuel handling equipment, water treatment systems, emissions control systems, lighting and various other systems and components (collectively termed auxiliary load) that make up the complete power plant. Auxiliary load for a coal-fired plant is typically on the order of 5-10% of the total generator output. Typical practice in the industry is to report net unit heat rate, so as heat rate is discussed in the remainder of the paper, it is assumed to mean net heat rate. Below is a table from the U.S. Energy Information Administration that shows the 2012 average net unit heat rates for various power generating technologies using various fuels. The actual range of heat rate values within each category varies significantly due to a number of unit-specific design, fuel, and operational differences that are discussed in the sections that follow below.

	2012 Average Heat Rate (Btu/kWh)			
Technology/Fuel	Coal	Petroleum	Natural Gas	Nuclear
Steam Generator	10,107	10,359	10,385	10,479
Gas Turbine	--	13,622	11,499	--
Internal Combustion	--	10,416	9,991	--
Combined Cycle	--	10,195	7,615	--

Heat Rate Source: U.S. Energy Information Administration, These average heat rate values above can be expressed as efficiencies in the following manner:

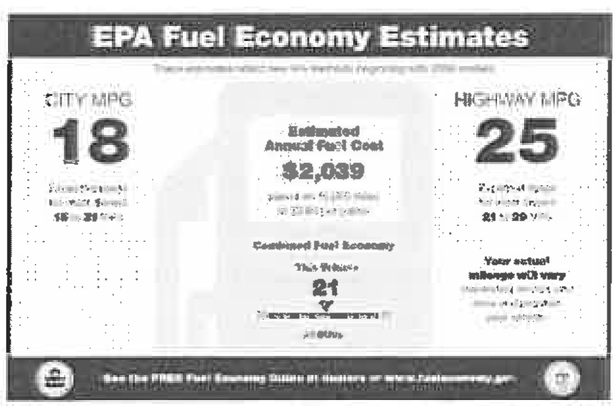
(3,412 Btu/kWh / Average Net Unit Heat Rate) x 100 = % Efficiency

	2012 Average Unit Cycle Efficiency (%)			
Technology/Fuel	Coal	Petroleum	Natural Gas	Nuclear
Steam Generator	34%	33%	33%	33%
Gas Turbine	--	25%	30%	--
Internal Combustion	--	33%	34%	--
Combined Cycle	--	33%	45%	--

Existing U.S. coal-fired power plants had an average net unit heat rate of 10,107 Btu/kWh and were approximately 34% efficient in 2012. Note that **higher efficiency translates to a lower heat rate.** This makes sense when considering that higher efficiency means that it takes less fuel to generate the same kilowatt-hour output. Less fuel means fewer Btu, so in turn, a lower heat rate. Reducing the heat rate of the existing coal fleet by 6% (per Building Block #1 of USEPA's proposed 111(d) rule) would lower the average net unit heat rate of every unit by roughly 600 Btu/kWh, and increase the average cycle efficiency of every unit by roughly 2%.

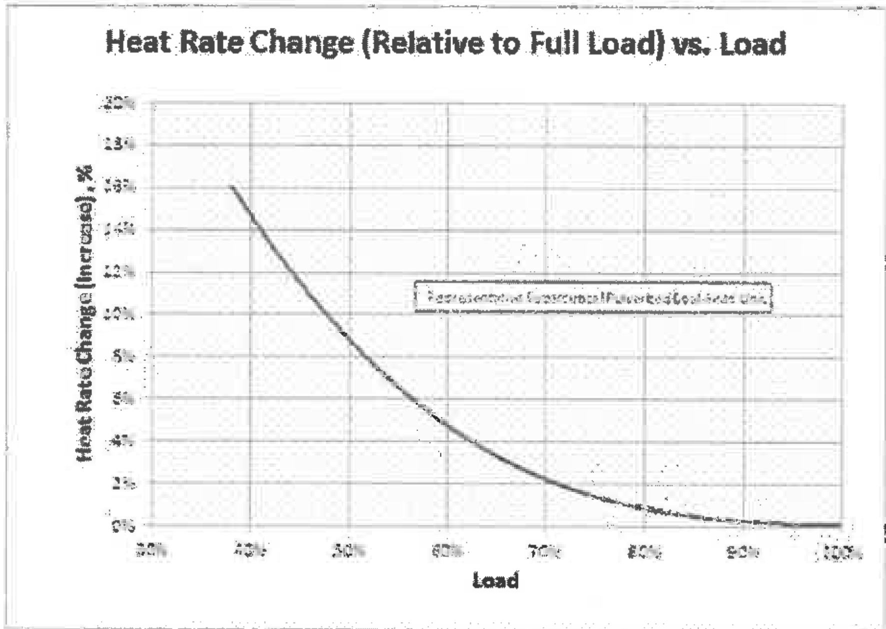
Is a Unit's Heat Rate Constant, and If Not, What Impacts Heat Rate?

It is extremely important to point out that the heat rate of a unit is **NOT** a constant value and varies significantly due to numerous factors which can have both positive and negative effects. Everything from basic unit design, fuel characteristics, operating load conditions, age/condition of equipment, maintenance and cleanliness of components, can all impact the heat rate. A good analogy is that of automobile fuel efficiency. Fuel efficiency of an automobile (typically expressed in miles per gallon or MPG) is most notably impacted by "city" versus "highway" driving. The frequent stops, starts and speed changes associated with city driving result in worse gas mileage than when driving on a highway at a constant rate of speed with fewer changing conditions.



www.fueleconomy.gov

A fossil fuel fired power plant's heat rate is no different. Operating in a full-load steady-state condition versus cycling loads up and down, or running at minimum loads for which the unit was not optimally designed have a negative impact on heat rate, reducing the kilowatt-hours out for every Btu that goes in. The relationship of unit load to heat rate is shown for a typical unit in the graph below.



City and highway driving is not the only variable that impacts an automobile's fuel efficiency. Things like the basic aerodynamic design of the car, the condition of the road (smooth or rough), the air pressure in the tires, the cleanliness of the engine's air and fuel filtration systems, the fuel type and even the outside air temperature and humidity can all impact the fuel efficiency of an automobile. A power plant's heat rate can be similarly impacted by process and equipment design, maintenance and cleanliness of critical components, changes in weather conditions, changes in fuel energy content or fuel delivery, changes in process water and cooling water temperatures, etc.

The balance of this paper focuses on coal-fired power plants and discusses how achieving and sustaining heat improvement is extremely challenging – not just to accomplish, but also to measure.

Is Every Coal Fired Steam Generating Unit Designed with the Same Heat Rate?

The answer to this question is **absolutely not.** The diversity of the existing coal-fired generating fleet is not unlike the diversity of automobiles on the highway. The existing coal fleet is comprised of units of various ages, which were designed by different manufacturers to burn different types of coal. For example, the John W. Turk, Jr. Plant in Arkansas began operation in 2012. Turk utilizes a state-of-the-art ultra-supercritical steam cycle that allows for a greater transfer of heat energy from the combustion of coal to the steam circulating through the system. This design produces higher temperature and pressure steam than is typical in most units, which results in a higher overall efficiency for the Turk Plant (on the order of 38%) over conventional coal-fired steam generators. Turk's average net unit heat rate as a result of its state-of-the-art design is approximately 9,000 Btu/kWh. It has only been in the last decade, with advances in steam piping materials that designs like the Turk Plant have become feasible to build and operate. Currently, Turk is unique as it is the only operating ultra-supercritical unit in the U.S.

It is important to differentiate between a unit's average heat rate and its "design heat rate." Design heat rate is a theoretical target that represents an optimal, full-load, steady-state condition and is considered the best a unit could potentially achieve under its original design conditions. Units may achieve their design heat rate when new with all components in their best condition, but it is well-understood that the unit will not, and should not be expected to achieve its design unit heat rate under all operating conditions or throughout the life of the unit. The age of the unit, historic operations and maintenance over its life, as well as the retrofit of any auxiliary equipment like emissions controls will all negatively impact the heat rate over the life of the unit resulting in an average unit heat rate that is higher than the unit's original design heat rate. While there are similarities between units, and often even identically designed units at the same plant site, the heat rates of each unit are as unique as fingerprints, because each unit has been operated and maintained differently.

What Can Be Done to Improve Heat Rate?

Improving the heat rate of a unit usually means targeting one or more of the systems or components that make up the power plant for a specific improvement. The 2009 Sargent & Lundy (S&L) study on heat rate improvements, which EPA referenced in Building Block #1 of its proposed Clean Power Plan evaluated a series of potential heat rate improvements opportunities, and estimated potential ranges of heat rate reduction. S&L then applied their findings to two case studies to estimate potential improvements. The approach S&L used to determine potential heat rate improvements in the study was reasonable and practical. However, S&L's study was not intended to address the many variables that impact the measurability, feasibility and sustainability of the improvement opportunities which were identified. Since the study does not contain any evidence that the recommendations from the case studies were actually implemented and heat rate improvements measured, there is no empirical data demonstrating that the estimated improvements were actually achieved or could be maintained.

EPA inappropriately used the study to assume that the types of improvements estimated by S&L are equally applicable and achievable at each and every coal-fired power plant in the country. This is simply **not** the case. For ADEQ's information and use, we have summarized the heat rate improvement strategies identified in the S&L report, and noted how these strategies are applicable (or not) to units in Texas in the table below.

HR Improvement Strategy	Sargent & Lundy Description	Applicability to AEP Units
Boiler Island – Materials Handling	VFDs provide no substantial reduction in plant heat rate. Pulverizer upgrades warranted only if facility is switching fuels. Ash handling is not considered a prime area of investment for plant heat rate reduction.	VFDs provide very limited benefit to units dispatched at high net output factors (i.e, essentially run near or at full load when in service)
Boiler Overhaul	Major changes to a furnace are not undertaken due to regulations currently in place (NSR enforcement). Economizer replacements do occur during some SCR retrofit projects.	Limited to maintenance activities.
Neural Network	Used to optimize plant performance during load changes.	Neural Networks "tested" on several units. No substantial benefit could be derived. Biggest heat rate benefit derived by minimizing excess air levels (set by limits). This was no better than operator ability. Further, could drive the unit to slag up upon fuel switch. Company has Generation Fleet Monitoring and Diagnostics with intelligent software that identifies/flags pattern changes in operation.
Intelligent Sootblowers	Applicable to units burning PRB and lignite fuels - engages DCS with system controls for the sootblowers.	

HR Improvement Strategy	Sargent & Lundy Description	Applicability to AEP Units
Air Heaters	Replace seals to reduce leakage and examine during emissions controls retrofits. Control acid dew point, particularly in connection with SCR retrofits.	Flue gas O_2 monitoring in place at many facilities to identify seal and air in-leakage issues.
Turbine Overhaul	Degradation and improved designs can be addressed, but greatest reductions are associated with changes in design, and performance will degrade over time.	Turbine overhauls conducted on a regular schedule. Rubs/high vibration events are somewhat random. Generally seals wear uniformly over time.
Feedwater Heaters	Cost of increasing heat transfer surfaces is prohibitive due to small incremental reductions in heat rate.	No feasible measures identified.
Condensers	Regular cleaning schedule has varying impacts on heat rate depending on location and cooling water characteristics.	Back pressures routinely monitored. Issues are addressed as soon as reasonably possible. Tubes cleaned as necessary.
Boiler Feed Pumps	Ordinary wear and tear degrades performance and is addressed during overhauls or upgrades.	BFP rotors are swapped out on routine schedules to maintain high feedpump efficiency.
Fans and VFDs	Installation of upgrades usually made in connection with emissions controls.	Many units have high efficiency axial vane ID fans.
Emission Control Technologies	Discussion of potential improvements associated with older emission control system designs.	Limited power management savings benefit available for vast majority of units. Many units will be retrofitted with new controls.

HR Improvement Strategy	Sargent & Lundy Description	Applicability to AEP Units
Boiler Water Treatment	Most power plants already have advanced water treatment systems installed.	AEP maintains very tight control over boiler water chemistry standards. Well defined corporate oversight program in place.
Cooling Water Treatment	Proper maintenance of water quality in the cooling system maintains efficiency that could be lost through fouling.	Proper maintenance procedures are in place for cooling water treatment. Cells taken out service during part load and cool periods (auxiliary power management).
Advanced Cooling Tower Packing	Optimization of cooling water temperatures and fan requirements must be conducted to investigate effectiveness of upgrading fill or implementing VFDs for older fans.	High efficiency fills have proven to be problematic and susceptible to fouling thereby driving up heat rate. High efficiency fills have actually been replaced on many cooling tower units. Fans (cells) taken out of service to reduce auxiliary loads during part load and cool periods.
Other Improvements	Motor replacement programs can yield minor heat rate improvements.	

In addition, there are several distinct caveats to the report's findings must be considered that are imperative for understanding the realistic applicability and opportunity that any potential heat rate improvement project might afford. These include:

- improvements are not uniform and what may work for one unit, may not for another;
- the heat rate benefit of multiple improvement projects is not necessarily cumulative meaning that improvements in one area can be masked by operations or conditions in another thus diminishing any significant overall heat rate improvement;
- outside influences beyond the control of the unit operators and outside the optimized equipment design performance can alter or erase heat rate improvements as these plants are dispatched based upon electricity demand, which is driven by external forces (e.g. customers, regional transmission operators, etc.);
- improvements must be cost effective and measurable to justify their implementation;

- space constraints may exist on a particular unit that prohibit the addition of equipment or re-routing of ductwork/piping to implement a heat rate improvement project;

- the benefit derived from many of the suggested heat rate improvement technologies is finite, and will diminish over time due to the age and operation of the unit;

- for some heat rate improvement projects the potential benefits will only be apparent at full load operations, but offer no measurable improvements for cyclic or minimum load operations;

- conversely, some base load units would show no benefit to heat rate if the improvement was obtained only at lower loading of the unit;

- EPA's 111(d) proposal suggests that future coal power plants will be dispatched and operated much differently than in the past, which means that the feasibility and benefits of any potential heat rate improvement must be evaluated more in context with future operations that may not afford the same magnitude of improvement potential.

It is evident that potential heat rate improvements are impacted by many variables that are both within and beyond the control of unit owners and operators. An analogy to simplify this point is the decision to replace the air filter in your car, which is known to improve fuel efficiency, typically at higher vehicle speeds. However, if the highway by which you commute to work is suddenly closed and you are rerouted through busy city streets, any fuel efficiency improvement from new air filter might go unseen. Similarly, if improvements are made to components or systems within the power plant, and then the unit adds emissions controls to meet a new regulation or is cycled more frequently to balance intermittent loads from new wind and solar generation, the heat rate improvements may never be fully realized. In fact, depending upon the situation, the unit's average heat rate might actually deteriorate.

Heat Rate Improvement Opportunities Are Limited for New and Well-Maintained Plants

It should not be misinterpreted that heat rate improvements are not valuable or can never be implemented. Most power plant owners and operators have historically made heat rate improvements and overall efficiency of their generating units a high priority because of its positive impacts on operating costs and equipment performance. Remember, better heat rate means less fuel, which lowers the cost of generating electricity and creates an economic driver to improve efficiency. Many of the units in the existing coal generating fleet have proactively pursued and actively performed projects to improve heat rate, all while utilizing preventative maintenance and routine cleaning practices that promote and sustain efficient operations. Yet, no credit for proactive efforts like these is available in the EPA's Clean Power Plan and the amount of heat rate improvement contemplated by EPA is very aggressive and overly ambitious for units that have historically been well maintained and operated. For recently constructed coal units that were built with more advanced and more efficient technologies, many of the potential heat rate improvement opportunities listed above have already been incorporated into their designs. Any potential improvement opportunity will be minimal and certainly far from the level that EPA has considered in the proposed Clean Power Plan.

Appendix C:

Sargent & Lundy Coal Fired Power Plant Heat Rate Reduction Letter

Sargent & Lundy LLC

Raj Gaikwad, Ph.D.
Vice President
Advanced Fossil Technologies
Ph: (312) 269-3830
Fax: (312) 269-2690
Email: rajendra.gaikwad@sargentlundy.com

October 15, 2014

Coal Fired Power Plant Heat Rate Reduction

Mr. Rae Cronmiller
Sr. Principal Environmental Counsel
National Rural Electric Cooperative Association
Generation and Fuels
4301 Wilson Boulevard
Arlington, Virginia 22203

Dear Mr. Cronmiller,

Sargent & Lundy, L.L.C. (S&L) is pleased to submit the conclusions of the study titled "Coal Fired Power Plant Heat Rate Reduction – NRECA" performed for NRECA. The key conclusions are as follows:

- Sargent & Lundy's 2009 Report does not conclude that any individual coal-fired EGU or any aggregation of coal-fired EGUs can achieve 6% HRI or any broad target, as estimated by the EPA.

- The results in the 2009 Report were mostly based on publicly available data, data from original equipment manufacturers, and Sargent & Lundy's power plant experience. Furthermore, the case studies showed that not all of the examined alternatives were feasible to apply to an individual generating unit due to a number of factors, including plant design, previous equipment upgrades, and each plant's operational restrictions.

- Various limitations exist for applying each heat rate improvement strategy, and these limitations depend on the unit type, fuel type, and many other site-specific conditions. Therefore, the ability to apply each strategy and the amount of heat rate reduction that can be achieved by each strategy is site-specific and must be evaluated on a case-by-case basis.

- It appears as though the EPA assumed that heat rate improvements cited in our 2009 Report were additive and applicable to all coal-fired units. Heat rate improvement ranges described in the 2009 Report case studies were estimated at a conceptual level, and were not based on detailed site-specific analyses. Verification of actual heat rate improvements was not made to determine whether any of the strategies were implemented and what actual heat rate improvements were realized based on site-specific design.

- Combinations of strategies to achieve heat rate improvements do not always provide heat rate improvement reductions equal to the sum of each individual strategy's heat rate improvement because many of the technologies affect, or are dependent upon, plant operating variables that are inter-related. Therefore, case-by-case analyses should be conducted to determine whether the incremental heat rate improvement through the application of multiple strategies is economically justified.

- The performance of some of the evaluated heat rate improvement strategies degrades over time, even with best maintenance practices. Therefore, depending on the strategy employed or the technology installed to reduce heat rate at an existing coal-fired EGU, the unit heat rate initially obtained may increase over time.

- Heat rate is increased when plants operate at lower loads, and the benefit of a heat rate improvement strategy is reduced at lower loads. Therefore, if an existing EGU is currently base-loaded and shifts to a load-cycling operating profile in the future, that unit's annual average heat rate will increase, and the heat rate reduction strategy (or strategies) implemented will not lower the annual average heat rate as much as compared to base-load operation. In some cases any HRI improvements achieved by undertaking the relevant options described in S&L's 2009 Report could, in some cases, be negated by HRI losses associated with load-cycling.

- The installation of additional pollution controls such as that required by regulations including BART, MATS, etc. will decrease the heat rate efficiency of any unit as compared to its heat rate efficiency before the installation.

- Many of the options for HRI listed in our 2009 Report have triggered New Source Review actions by EPA and others.

- Based on the case studies performed by S&L, it appears that most of the utilities are employing best operational and maintenance practices. In light of this observation, it appears that significant further reduction in heat rate, such as that assumed by the EPA, may not be feasible.

Sargent & Lundy concludes that the only technically appropriate method to properly evaluate potential HRI is to conduct a unit-by-unit evaluation. Please contact me if you have any questions or need any further information.

Very truly yours

Raj Gaikwad

Raj Gaikwad, Ph.D.
Vice President
Advanced Fossil Technologies

Appendix D:

Ohio EPA: Ohio Coal-Fired Gross Heat Rate

Ohio Coal Fired EGUs Gross Heat Rate: 1997-2013. Clean Air Markets Database

Category	State	Plant Name	Generator ID	Fuel type	Prime mover type	Nameplate Capacity (MW)	1997 Heat Rate (Btu/kwh)	1998 Heat Rate (Btu/kwh)	1999 Heat Rate (Btu/kwh)	2000 Heat Rate (Btu/kwh)
COALST	OH	Avon Lake	7 (10)	BIT	ST	86.0	-	-	-	-
COALST	OH	Avon Lake	9 (12)	BIT	ST	680.0	9394.063959	10540.19693	10199.30425	9298.671552
COALST	OH	Cardinal	1	BIT	ST	615.2	9711.643902	9979.581507	8946.176327	8775.941359
COALST	OH	Cardinal	2	BIT	ST	615.2	9371.557902	9093.400963	9185.868099	8937.041748
COALST	OH	Cardinal	3	BIT	ST	650.0	9600.799077	9131.86926	9381.876051	8899.334862
COALST	OH	Conesville	3	BIT	ST	161.5	9806.406869	9486.051778	9195.225089	8374.315794
COALST	OH	Conesville	4	BIT	ST	841.5	10136.62571	10599.35578	10317.40723	9011.860924
COALST	OH	Conesville	5	BIT	ST	443.9	10040.57565	10107.09164	9614.866341	9733.709037
COALST	OH	Conesville	6	BIT	ST	443.9	9980.321692	10099.11938	9648.551944	9745.502659
COALST	OH	FirstEnergy Ashtabula	5	BIT	ST	256.0	9836.705691	10492.06767	10074.53033	10964.94298
COALST	OH	FirstEnergy Bay Shore	1	PC	ST	140.6	9490.460537	8812.376862	8903.31562	9150.638808
COALST	OH	FirstEnergy Bay Shore	2	SUB	ST	140.6	9502.853193	8776.767114	8867.912871	10109.46471
COALST	OH	FirstEnergy Bay Shore	3	SUB	ST	140.6	9509.03423	8726.223024	8893.722247	10064.46524
COALST	OH	FirstEnergy Bay Shore	4	SUB	ST	217.6	9470.557407	8894.015693	8909.582585	10132.51671
COALST	OH	FirstEnergy Eastlake	1	BIT	ST	123.0	10482.18088	10319.83919	10314.37129	10375.67932
COALST	OH	FirstEnergy Eastlake	2	BIT	ST	123.0	10481.61891	10245.35137	10545.80834	9955.851242
COALST	OH	FirstEnergy Eastlake	3	BIT	ST	123.0	10188.9505	11166.93937	10674.51139	9722.056738
COALST	OH	FirstEnergy Eastlake	4	BIT	ST	208.0	9381.181564	9336.439174	9352.983219	9940.430257
COALST	OH	FirstEnergy Eastlake	5	BIT	ST	680.0	9562.359345	10469.06061	9509.640584	9706.426257
COALST	OH	FirstEnergy Lake Shore	18	SUB	ST	256.0	13507.81693	11964.10157	11735.51338	12754.2547
COALST	OH	FirstEnergy R E Burger	3	BIT	ST	103.4	-	-	-	-
COALST	OH	FirstEnergy W H Sammis	1	BIT	ST	190.4	10185.69025	10425.1817	10311.46798	9595.626257
COALST	OH	FirstEnergy W H Sammis	2	BIT	ST	190.4	10290.49217	10335.26873	10404.47855	9593.373775
COALST	OH	FirstEnergy W H Sammis	3	BIT	ST	190.4	10408.62058	10238.06554	9894.629309	9870.339716
COALST	OH	FirstEnergy W H Sammis	4	BIT	ST	190.4	10413.05754	10248.28376	9891.647174	9721.797945
COALST	OH	FirstEnergy W H Sammis	5	BIT	ST	334.0	10386.13888	10028.52373	9832.240476	9667.659902
COALST	OH	FirstEnergy W H Sammis	6	BIT	ST	680.0	9762.003864	10008.08476	10028.55734	9623.241985
COALST	OH	FirstEnergy W H Sammis	7	BIT	ST	680.0	9759.032129	9689.131745	9847.095762	9665.877074
COALST	OH	General James M Gavin	1	BIT	ST	1300.0	10198.50737	9986.446389	9996.139645	9668.053811
COALST	OH	General James M Gavin	2	BIT	ST	1300.0	9866.655299	9758.983873	9884.509839	10272.2647
COALST	OH	Hamilton	8	BIT	ST	25.0	-	-	-	-
COALST	OH	Hamilton	9	BIT	ST	50.6	13592.89299	12241.4153	12877.11318	12666.0088
COALST	OH	J M Stuart	1	BIT	ST	610.2	9982.637244	9984.419333	9732.468469	9700.338338
COALST	OH	J M Stuart	2	BIT	ST	610.2	9597.105332	9431.081239	9380.876616	9518.784234
COALST	OH	J M Stuart	3	BIT	ST	610.2	9498.20933	9089.578862	9143.518909	9071.912154
COALST	OH	J M Stuart	4	BIT	ST	610.2	9683.879757	9735.348063	9778.356131	9446.885583
COALST	OH	Killen Station	2	BIT	ST	660.6	10943.67592	10880.79797	10869.41564	9536.752515
COALST	OH	Kyger Creek	1	BIT	ST	217.3	9016.225222	9016.036651	8617.411686	8831.987039
COALST	OH	Kyger Creek	2	BIT	ST	217.3	8967.857223	9037.487163	8626.320768	8857.062385
COALST	OH	Kyger Creek	3	BIT	ST	217.3	8950.035904	9020.98689	8627.789276	8830.475237
COALST	OH	Kyger Creek	4	BIT	ST	217.3	8911.142197	9036.209837	8630.41542	8850.481484
COALST	OH	Kyger Creek	5	BIT	ST	217.3	8968.371061	9003.611582	8615.729528	8853.232087
COALST	OH	Miami Fort	6	BIT	ST	163.2	10677.91232	10621.31776	10911.20969	10478.7977
COALST	OH	Miami Fort	7	BIT	ST	557.1	9798.254548	10540.83115	10867.73791	9880.952938
COALST	OH	Miami Fort	8	BIT	ST	557.7	10377.24786	11088.96655	10601.53937	9687.478079
COALST	OH	Muskingum River	1	BIT	ST	219.6	9179.033496	9310.687839	9441.540925	8927.167991
COALST	OH	Muskingum River	2	BIT	ST	219.6	9246.040236	9358.845785	9204.097639	8901.691245
COALST	OH	Muskingum River	3	BIT	ST	237.5	9142.738829	9366.818114	9067.598632	8942.271647
COALST	OH	Muskingum River	4	BIT	ST	237.5	9171.06024	9315.746713	9207.16282	8935.659329
COALST	OH	Muskingum River	5	BIT	ST	615.2	9554.205591	8938.861394	8876.559877	8897.405064
COALST	OH	Niles	1	BIT	ST	132.8	13764.62829	10063.60178		
COALST	OH	Niles	2	BIT	ST	132.8	6401.531201	8555.467633		
COALST	OH	O H Hutchings	1	BIT	ST	69.0	11342.08552	8572.832322	13287.44957	13489.14602
COALST	OH	O H Hutchings	2	BIT	ST	69.0	10857.80432	14156.0359	15306.42744	10303.84314
COALST	OH	O H Hutchings	3	BIT	ST	69.0	11063.92831	10791.74143	10391.55503	10170.96759
COALST	OH	O H Hutchings	4	BIT	ST	69.0	11072.47976	10693.78262	10727.77379	11693.24927
COALST	OH	O H Hutchings	5	BIT	ST	69.0	11220.01752	10668.20931	10065.41149	10852.67809
COALST	OH	O H Hutchings	6	BIT	ST	69.0	11676.15052	10757.97019	12254.56254	10891.11905
COALST	OH	Orrville	10	BIT	ST	25.0	-	-	-	-
COALST	OH	Orrville	11	BIT	ST	25.0	-	-	-	-
COALST	OH	Picway	5	BIT	ST	106.2	12819.97867	12241.29844	11466.48257	10251.65201
COALST	OH	W H Zimmer	ST1	BIT	ST	1425.6	9832.282496	9113.828584	10499.48711	9516.605194
COALST	OH	Walter C Beckjord	1	BIT	ST	115.0	10325.7013	10739.98833	11762.15872	10250.00475
COALST	OH	Walter C Beckjord	2	BIT	ST	112.5	10379.99142	10679.01869	11096.07685	11074.64135
COALST	OH	Walter C Beckjord	3	BIT	ST	125.0	10144.75567	10386.45278	9545.975663	10975.86204
COALST	OH	Walter C Beckjord	4	BIT	ST	163.2	9932.547698	10124.50076	10284.86859	9734.259091
COALST	OH	Walter C Beckjord	5	BIT	ST	244.8	9893.386454	10095.45375	10638.29727	9392.718519
COALST	OH	Walter C Beckjord	6	BIT	ST	460.8	10772.03594	10903.60901	11617.09474	10522.25574

Plant Name	Generator ID	2001 Heat Rate (Btu/kwh)	2002 Heat Rate (Btu/kwh)	2003 Heat Rate (Btu/kwh)	2004 Heat Rate (Btu/kwh)	2005 Heat Rate (Btu/kwh)	2006 Heat Rate (Btu/kwh)	2007 Heat Rate (Btu/kwh)
Avon Lake	7 (10)	-	-	-	-	-	-	-
Avon Lake	9 (12)	10027.05675	9955.127305	8634.028886	8251.160914	8901.151701	9027.725366	8930.781031
Cardinal	1	8528.521485	8453.500916	8321.609224	8396.482146	8497.608109	8625.65116	8832.431752
Cardinal	2	9066.196508	9211.994938	8575.320027	8580.551545	8785.434962	8733.221585	9161.315888
Cardinal	3	9089.485016	9661.603828	9333.808021	9410.803604	9383.030251	9330.864194	9521.07039
Conesville	3	8930.108791	9447.234742	9311.863164	9364.71173	9548.60494	9729.237413	10127.97918
Conesville	4	8431.18543	9034.823734	9067.024523	9131.765778	9350.762005	9416.05889	9756.687551
Conesville	5	9728.088235	9177.219635	9176.570612	9362.193333	9264.510244	9399.124996	9618.573483
Conesville	6	9698.69666	9198.918203	9100.576102	9343.584918	9235.483448	9443.947084	9587.089726
FirstEnergy Ashtabula	5	10592.86341	11082.72064	11028.33532	11165.58471	9683.754396	10682.68333	10563.01105
FirstEnergy Bay Shore	1		-	-	-	-	-	-
FirstEnergy Bay Shore	2	9740.983488	9710.262271	9883.712648	9923.405053	9761.508498	10143.96473	9835.606468
FirstEnergy Bay Shore	3	9723.41149	9704.131748	9859.116191	9839.35455	9741.575219	10132.45613	9844.998626
FirstEnergy Bay Shore	4	9770.273401	9649.625832	9814.029874	9724.309124	9769.052061	10132.44995	9847.512434
FirstEnergy Eastlake	1	10266.98849	10122.6394	10139.94066	10818.49993	10397.37043	9724.344826	9730.038838
FirstEnergy Eastlake	2	9924.052664	10112.33747	10766.18393	10467.58651	10180.2285	9862.035821	9681.679128
FirstEnergy Eastlake	3	9882.840847	9675.024942	9594.579164	9819.78077	9728.874976	9594.94294	9755.987479
FirstEnergy Eastlake	4	9448.739844	9436.416927	10374.61527	10004.17594	9924.380084	10102.88166	9599.654612
FirstEnergy Eastlake	5	8379.461684	8722.313091	10042.51089	8841.040285	8403.322962	8369.987917	8220.810655
FirstEnergy Lake Shore	18	11611.80978	12127.18302	12023.78337	11212.79942	11131.28323	10868.64997	10669.96826
FirstEnergy R E Burger	3		-	-	-	-	-	-
FirstEnergy W H Sammis	1	10045.36925	9491.134209	9915.435007	10297.85717	10436.40885	10257.19974	10432.1209
FirstEnergy W H Sammis	2	9819.680332	9634.403269	9904.39614	10301.71931	10461.84979	10261.76709	10255.84229
FirstEnergy W H Sammis	3	9784.500972	9419.072575	9041.213096	9075.586822	8833.113918	8860.913011	8857.876328
FirstEnergy W H Sammis	4	9771.91343	9406.438099	9176.990526	9081.595711	8862.306323	8862.183658	8862.91288
FirstEnergy W H Sammis	5	9698.355966	9775.622936	9440.013842	9886.051382	9489.492786	9448.860083	9406.657946
FirstEnergy W H Sammis	6	9667.876507	9364.298489	9300.621811	9414.646363	9468.592989	9188.048209	9278.209022
FirstEnergy W H Sammis	7	9373.184834	9318.639944	9071.099404	9487.087774	9840.202213	9188.403109	9258.065945
General James M Gavin	1	9569.534305	8569.02157	9015.893596	9350.744308	8666.885848	9156.766081	8842.110845
General James M Gavin	2	10386.87672	9204.279304	10150.65704	9166.496849	9157.535845	9341.021998	9588.240942
Hamilton	8			13808.51647	14244.59691	13944.07705	13909.89636	13138.7355
Hamilton	9	12382.25795	12135.0689	12277.31929	12370.13711	12477.98959	12672.49302	12691.34117
J M Stuart	1	9324.410905	9560.215033	9257.495306	8790.227481	9064.73949	8945.510667	8560.053567
J M Stuart	2	8942.006962	9261.826524	9157.448049	8336.445882	8742.684663	8487.402237	8294.219776
J M Stuart	3	8920.051288	9189.024289	9195.897121	8465.744448	8523.000245	8482.078522	9069.400061
J M Stuart	4	9694.587587	9617.518628	9428.46268	8760.325462	8976.838528	8799.390693	8657.655361
Killen Station	2	9420.94085	9447.68588	9825.523316	8957.927687	7420.411121	9411.609504	9618.182366
Kyger Creek	1	8940.076857	8615.95202	8915.941984	9103.451989	8757.531096	8854.094778	9057.44718
Kyger Creek	2	8940.318844	8689.922875	8931.308298	9084.977409	8751.868675	8852.540771	9077.36607
Kyger Creek	3	8912.924245	8723.229007	8870.821043	9067.544692	8724.500999	8842.932139	9050.753419
Kyger Creek	4	8935.527815	8742.350303	9015.888677	9069.402322	8783.324502	8841.25914	9089.603707
Kyger Creek	5	8904.432107	8731.023803	8955.095329	9069.127099	8762.461401	8870.622428	9075.211257
Miami Fort	6	9976.238542	9681.616914	9287.648373	8516.848136	9487.033653	9232.642215	9540.637444
Miami Fort	7	8085.800209	8699.615369	8807.683463	9174.871087	8918.387048	9362.224041	9556.498339
Miami Fort	8	9087.906451	9325.965552	8919.748325	9422.085792	9262.889935	8941.743993	9292.846306
Muskingum River	1	9325.244487	9046.814531	9024.979425	9166.764051	9169.232218	9112.140528	9065.81551
Muskingum River	2	9252.928209	9021.486999	9020.682955	9057.761332	9011.81197	9014.081489	9020.461517
Muskingum River	3	9359.753552	9048.758294	9054.743547	9159.655349	9092.960043	9071.597349	8991.024504
Muskingum River	4	9212.37357	9021.806771	9038.448698	9191.26017	9047.687949	9001.613488	9072.268377
Muskingum River	5	8663.847481	8903.971424	8411.72761	8186.682783	8726.789461	8394.716887	8517.488217
Niles	1		-	-	-	-	***11601.42***	11132.58686
Niles	2		-	-	-	-	***11594.82***	8583.29015
O H Hutchings	1	11505.5887	10689.11909	12373.28544	11439.23615	12658.7224	11786.99333	9983.812761
O H Hutchings	2	10732.21626	10648.78854	12565.47481	11900.87956	11760.8714	11165.37154	10160.21997
O H Hutchings	3	11078.92299	11253.00358	11961.59783	12298.48394	11339.05454	10151.80434	10569.20672
O H Hutchings	4	11279.18703	11126.10934	12068.31261	12365.84663	11132.5287	10219.43185	10431.333
O H Hutchings	5	10957.70806	11581.57459	12335.76275	13236.98941	12635.1395	10815.59477	11416.59745
O H Hutchings	6	10923.89323	11261.24919	12206.59208	12681.99163	12583.49181	10573.01503	11064.95379
Orrville	10		-	-	-	-	-	-
Orrville	11		-	-	-	-	-	
Picway	5	9951.839037	11984.93858	10979.16801	10614.93565	11693.44225	12867.21269	12727.40634
W H Zimmer	ST1	8358.732201	8405.842005	8302.464969	8312.213717	7832.370132	8011.471311	7943.802586
Walter C Beckjord	1	10270.67263	10308.71169	10359.27736	10137.02184	9835.768744	9433.392419	9736.50841
Walter C Beckjord	2	10862.95277	10205.29386	10344.60107	10339.88117	10072.54912	9840.906762	9640.041143
Walter C Beckjord	3	10557.93687	9718.008258	9672.938244	9905.769337	9877.213257	10124.75161	10383.0116
Walter C Beckjord	4	9112.217425	8702.921384	9183.62225	9575.158263	9084.132868	9045.474338	9175.997106
Walter C Beckjord	5	9712.371554	9517.916493	9335.87303	8887.383133	8749.781364	8853.936738	9196.375142
Walter C Beckjord	6	9751.008626	10174.45227	9864.500113	9702.240322	9183.801987	9324.827654	9938.230402

Plant Name	Generator ID	2008 Heat Rate (Btu/kwh)	2009 Heat Rate (Btu/kwh)	2010 Heat Rate (Btu/kwh)	2011 Heat Rate (Btu/kwh)	2012 Heat Rate (Btu/kwh)	2013 Heat Rate (Btu/kwh)
Avon Lake	7 (10)	-	-	-	-	-	
Avon Lake	9 (12)	9581.596405	8829.025792	8529.845012	8263.274573	8474.523092	8752.423131
Cardinal	1	8727.442717	8862.057449	8794.055445	8764.179334	8744.535578	8692.674349
Cardinal	2	8734.917761	8801.479632	9051.870103	8669.550977	8835.817623	9033.338072
Cardinal	3	9229.986645	9169.480601	9097.836764	9107.409515	11763.57847	8489.836186
Conesville	3	9597.513669	10119.96213	9768.706803	9893.600594	11351.55563	
Conesville	4	9352.646326	10720.50952	9516.853564	10256.19058	9651.696199	9322.669457
Conesville	5	10403.88795	9475.796398	9574.932989	10050.57333	10367.0138	10624.48772
Conesville	6	10459.25694	9401.256165	9509.425592	10082.88788	10700.78229	10613.66456
FirstEnergy Ashtabula	5	10627.81849	10174.10082	10984.79979	12109.33142	11035.88628	11476.38402
FirstEnergy Bay Shore	1	-	-	-	-	-	
FirstEnergy Bay Shore	2	9912.463951	10480.4792	9447.260949	9563.528716	10853.68177	
FirstEnergy Bay Shore	3	9905.689169	9857.477482	9460.197237	9586.400237	11654.82751	
FirstEnergy Bay Shore	4	9895.426903	10150.67488	9478.606926	9605.028641	11721.96646	
FirstEnergy Eastlake	1	9613.865258	9325.208314	9481.574447	9576.098966	9068.803426	9355.386183
FirstEnergy Eastlake	2	9604.858914	9209.251591	9458.047328	9509.652263	9032.315875	9481.611018
FirstEnergy Eastlake	3	9747.456047	9368.691535	9324.043181	9148.957842	8703.540451	9005.816974
FirstEnergy Eastlake	4	10231.98343	9319.832553	9631.558552	9821.839648	9363.559639	
FirstEnergy Eastlake	5	7856.377601	7850.538098	8317.723565	9039.270009	8960.09015	
FirstEnergy Lake Shore	18	9592.658769	10295.7471	9673.35129	8495.555195	11991.66019	12008.73509
FirstEnergy R E Burger	3	-	-	-	-	-	
FirstEnergy W H Sammis	1	9972.762043	9693.203992	9211.690607	8924.005206	9070.171911	9017.254174
FirstEnergy W H Sammis	2	9991.420869	9744.601604	9209.101162	8945.262521	8915.511073	8992.466162
FirstEnergy W H Sammis	3	8295.602935	8457.221581	8896.003671	8885.300738	8780.774607	9005.325388
FirstEnergy W H Sammis	4	8253.340741	8189.803708	9108.078687	8564.656341	8826.239961	8982.295449
FirstEnergy W H Sammis	5	9183.754334	9493.337906	9154.964108	9240.071135	9411.974552	8557.258652
FirstEnergy W H Sammis	6	8759.985154	8577.490364	9316.122895	9036.12209	9191.068343	8502.655604
FirstEnergy W H Sammis	7	9058.391957	8910.362616	9212.259396	9062.417512	9161.903041	8512.925786
General James M Gavin	1	8408.041533	9200.151263	8835.414615	9300.425775	9467.728426	8882.052571
General James M Gavin	2	8272.386029	9360.906568	8492.767644	9511.575223	9182.096055	8874.591002
Hamilton	8	12180.88323	-	-	-	-	
Hamilton	9	12259.40251	11048.38279	10399.78865	10552.8576	10181.75275	10705.57285
J M Stuart	1	10107.72891	9507.59745	9778.100986	9365.698315	9734.542158	9302.44909
J M Stuart	2	9764.715945	9339.300859	9773.529455	9435.057184	9292.238136	9266.51757
J M Stuart	3	9899.211537	9531.728539	9503.390658	9358.431851	9112.370075	8781.002017
J M Stuart	4	10101.8137	9383.333714	9177.766561	9773.463753	10031.63753	9503.286774
Killen Station	2	9844.544043	9497.595242	9408.711072	8841.944861	8679.63635	9650.530389
Kyger Creek	1	9113.653869	8731.781702	8936.059948	9181.801552	9961.413922	9196.553433
Kyger Creek	2	9126.698516	8769.202366	8994.352609	9180.116419	12190.38043	9183.614424
Kyger Creek	3	9057.556275	8740.158161	9045.664317	10964.60333	10058.87723	9565.442103
Kyger Creek	4	9127.101823	8793.784472	9006.565036	9163.823843	10009.34873	9594.646191
Kyger Creek	5	9124.032788	8765.66864	9000.833706	11012.0088	9982.664687	9452.832148
Miami Fort	6	8876.19216	8916.538274	9105.693593	8804.8343	9276.730687	9171.557636
Miami Fort	7	9892.934214	9508.174863	9519.285865	9531.389176	9465.150911	9223.00425
Miami Fort	8	9398.572082	8637.993252	8698.539879	8934.524184	8356.367519	8188.327759
Muskingum River	1	9015.265488	8964.969444	8932.442299	9258.120598	9217.516633	
Muskingum River	2	8963.877573	8890.712908	9052.989319	9316.436289	9458.912712	
Muskingum River	3	8992.319266	8982.189727	8896.539224	9116.00202	10630.1737	11550.04723
Muskingum River	4	9000.778578	8954.329842	8834.736889	9287.53495	9756.227316	10836.78396
Muskingum River	5	8481.708996	8579.444147	8758.62345	8763.64167	8791.075629	8805.255718
Niles	1	9729.869891	10074.15913	10366.82666	10664.04365	10626.61801	
Niles	2	9722.404155	10128.59013	10187.22712	11109.44795	-	
O H Hutchings	1	11457.95395	13193.42758	13018.93704	12804.74253	15375.05821	
O H Hutchings	2	12122.14739	11099.15589	11955.83608	13441.21669	11799.65157	
O H Hutchings	3	11465.74422	11241.21107	11719.89437	11968.80945	11913.21057	
O H Hutchings	4	11627.35923	12767.65925	10591.87354	-	-	
O H Hutchings	5	11935.48435	11102.18614	11405.76821	11374.26481	11928.56624	
O H Hutchings	6	12004.68964	10590.1254	11134.48189	11413.4806	11555.05083	
Orrville	10	-	-	-	-	-	
Orrville	11	-	-	-	-	-	
Picway	5	11698.01237	11263.60312	11557.84232	13773.85703	12972.45066	12083.55671
W H Zimmer	ST1	8615.652699	8475.380855	8402.184069	9004.076261	8625.544047	8838.691354
Walter C Beckjord	1	10027.69822	9870.947941	-	-	-	
Walter C Beckjord	2	9658.334084	9339.574535	-	10574.32624	-	
Walter C Beckjord	3	10815.84097	9905.801148	-	9758.108462	13665.4093	
Walter C Beckjord	4	9099.335828	9736.474897	10142.52953	10552.44252	10219.66917	9921.548137
Walter C Beckjord	5	***9679.489005***	9273.49752	9033.139193	8602.380963	8793.994447	8704.194918
Walter C Beckjord	6	10202.06136	9534.301267	10794.14032	10278.74249	9491.425851	9252.377636
		Niles information updated by plant representative on July 7, 2014.					
				Original CAMD Values for 2008:			
				Niles	***1***	***46392.63531***	***Btu/kw-h***
				Niles	***2***	***44184.88822***	***Btu/kw-h***
		Beckjord information updated by Duke Energy, on July 8, 2014.					
				Original CAMD Values for 2008			
				Beckjord	***5***	***65940.0389***	***Btu/kw-h***

Appendix E:

Comments on this Proposal from EPRI

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

COMMENTS OF THE ELECTRIC POWER RESEARCH INSTITUTE ON

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA-HQ-OAR-2013-0602; FRL-9911-86-OAR]

Carbon Pollution Emission Guidelines for Existing Stationary Sources:

Electric Utility Generating Units

October 20, 2014

The Electric Power Research Institute, Inc. (EPRI) respectfully submits the enclosed comments[1] on the U.S. Environmental Protection Agency's (EPA's) proposed rule titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units. EPRI thanks the EPA for the opportunity to comment on this proposed rule.

EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1986, as amended, and acts in furtherance of its public benefit mission. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment. EPRI also provides technology, policy and economic analyses to inform long-range research and development planning, as well as supports research in emerging technologies.

More specifically related to this proposed rule, EPRI has been involved in global climate change-related research for more than 20 years, with economic and integrated assessment analyses and expertise related to emission projections, mitigation technologies, and climate economics. Technology assessment and technology innovation have been central to EPRI's activities since its inception. EPRI work spans nearly every area of electricity generation, delivery and use; management; and environmental responsibility. In assembling these comments, EPRI draws upon decades of experience and expertise in wide ranging research efforts associated with heat rate improvements, natural gas generation, and nuclear and renewable technologies as well as energy utilization across the electric sector.

These comments on the proposed rule reflect EPRI's research background in that they are technical rather than legal in nature. They are based upon EPRI's research and development experience over the last 40 years related to technology innovation, planning, and analysis of the electric power sector. EPRI comments focus principally on three areas of assessment: (i) technical engineering assessment; (ii)

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[1] This document is an EPRI Report # 3002004658.

economic assessment and analyses; and (iii) power sector system assessment. All comments contained in this letter reflect only EPRI's opinion and expertise and do not necessarily reflect the opinions of those supporting and working with EPRI to conduct collaborative research and development.

EPRI comments are organized into five areas that parallel the proposed rule's structure.

1. Definition of Best System of Emissions Reduction (BSER) and the building blocks;
2. State Goals;
3. State Plans;
4. Impacts of proposed rule, including a technical assessment of the Regulatory Impact Analysis (RIA); and
5. Benefits of the proposed rule.

Summary comments for each of these areas are provided followed by more detailed comments. In addition, EPRI provided a variety of references and technical documents as appendices to the main body of comments.

EPRI hopes its comments and technical feedback will be valuable to EPA.

Sincerely,

Anda Ray

Anda Ray
Vice President, Environment
And Chief Sustainability Officer

SUMMARY OF EPRI COMMENTS

This section summarizes EPRI's comments. The next section provides more detailed comments followed by various reference materials and technical documents in appendices. The abstracts and, in many cases, full copies of the referenced EPRI reports are available at EPRI.com.

BUILDING BLOCKS AND THE BEST SYSTEM OF EMISSIONS REDUCTION

Based on its technical research and evaluation of the proposed rule, EPRI suggests that U.S. Environmental Protection Agency (EPA) consider establishing the Best System of Emissions Reduction (BSER) centered on the following considerations:

- Utilize latest available technical knowledge so that the BSER accurately reflects the cost-effective mitigation potential of electric generating units (EGUs).
- Reduce uncertainty for EGU owners to provide clearer understanding of necessary operating conditions and investment planning needed to maintain reliable, affordable, and environmentally responsible electric generation and delivery.
- Better account for the heterogeneous nature of the existing electric system operating within differing state or regional characteristics.
- Consider the system dynamics of the power sector as building blocks are not necessarily additive and maintain varying degrees of interdependency.

Building Block 1: Heat Rate Improvements

- Estimates of heat rate improvements at existing coal EGUs are very dependent on individual unit characteristics (age, design, maintenance history, type of coal, etc.) and are difficult to apply a national fleet-wide heat rate goal. In estimating mitigation potentials, EPRI recommends that the estimates should be based on current studies and data that take into account recent EPA environmental control regulations. Regional or state-specific research and data should be used as the basis for estimating potential heat rate improvements rather than use of a national average for all. States differ widely in the characteristics and operating performances of their respective generating fleets.
- While EPRI studies indicate there may be opportunities to achieve a variety of heat rate improvements at an EGU in the range of 0.5% – 5% on a net generation basis, these values may not be additive and their applicability and realized savings are highly dependent on the characteristics of an individual unit.
- Increased penetration of renewable power and greater use of natural gas combined-cycle (NGCC) units, as called for in the proposed rule, will lead to potential heat rate increases in coal units associated with lower utilization of these units, and the need for these units to engage more often in

flexible operations (e.g., load following, extended low output generation, cycling), rather than "baseload" operations. In addition, there are potential wastewater-related impacts that should be recognized as flue gas desulfurization (FGD) wastewater treatment may be negatively impacted with large swings in FGD water chemistry resulting from increasing flexible operations.

- EPA's use of gross heat rate data for estimating heat rate improvement-related carbon dioxide (CO_2) mitigation for building block 1 is inconsistent with the use of the net emission accounting used in the state goals computation. This leads to inconsistencies, confusion, and possible overestimation of the heat rate improvement-related mitigation potential. EPRI recommends that EPA use a consistent approach for net heat rate estimation and accounting through the proposed rule.

Building Block 2: Dispatch Changes

- EPRI comments focus on the critical question of whether there will be sufficient capability to handle flexible operations duties that are now principally handled by NGCCs. That is, flexibility and reliability could become primary concerns as many NGCCs may move to baseload while coal generation capacity is reduced and variable generation from renewable energy substantially increases.
- EPA proposes to increase capacity factors for NGCC units to 70% based on the premise that "...changes in generation patterns have been driven largely by changes over time in the relative prices of natural gas and coal." While EPRI sees no technical issue with individual NGCC units physically operating at a 70% capacity factor, there is little long-term operating experience with widespread and sustained operation of a majority of NGCC units at that level. In addition, the capacity factor of NGCC units has been highly influenced in the past by volatility in the price of natural gas and is therefore, likely to have a significant impact on capacity factors in the future. EPRI notes that achieving technically feasible capacity factor of 70% does not include other significant daily operating impacts on capacity factors, such as the market price of natural gas, availability of pipeline infrastructure, and firm pipeline capacity. Reinforcing the dependency of gas price to capacity factor; natural gas prices are currently forecasted to be relatively low, history has demonstrated the price of natural gas to be highly volatile, and multi-year forecasts have consistently been inaccurate. Establishing a mitigation goal based on an assumption of persistent low natural gas prices is not a reliable or dependable approach to estimating capacity factors for NGCC plants over a long period.
- Establishing a dispatch-based mitigation goal that impacts other existing generation types without thorough consideration of the impacts to resource adequacy may significantly degrade reliability. For example, during the extreme cold temperatures across most of the Southern and Eastern United States from January 6 to 8, 2014, natural gas fired generating plants did not perform as expected due to both plant outages and natural gas delivery system inadequacies.
- The changes in the utilization of the various generating plants driven by this proposal could have a significant impact on transmission reliability due to potential large changes in power flows across the system and retirement of generation that contributes to transmission system voltage and frequency performance. The change in generation will almost certainly require development of new transmission to ensure operational reliability, but scheduling outages of existing facilities will be difficult if simultaneous upgrades across many systems are needed such that time lines for

commissioning of new transmission facilities may be delayed. To understand the full reliability, economic, and financial impacts of the proposed rule, detailed transmission reliability evaluations should be conducted.

Building Block 3a: Renewable Generation

- EPA's "best practices" scenario for developing state-specific renewable energy targets assumes state equivalency for regional calculations of resource potential. This assumption is problematic when regions are large and encompass states with appreciably different renewable energy resources.
- Based on EPRI research, a more effective and comprehensive basis for state aggregation would be informed by the region-specific potentials for renewable energy development, which would include technology costs, fuel costs, network effects, and regulatory requirements. Investor response, regional competition for other resources, learning-by-doing and network effects, regulatory limitations, and public acceptance also should be considered.

Building Block 3b: Nuclear Generation

- In reviewing how EPA used this building block for state goal setting and in the Regulatory Impact Analysis (RIA), EPRI urges EPA to consider the lifetime of existing nuclear units where many units will reach their 60-year license limit by 2029. Three units with licenses scheduled to expire prior to 2030 are already in their extended period of operation and would need to obtain additional license extension to extend their operating lives to 80 years (known as subsequent license renewal). Though it is expected that many reactors will apply for and receive license extensions out to 80 years, there is no level of certainty at this time.
- There is significant uncertainty as to whether the Nuclear Regulatory Commission (NRC) will extend the operating licenses for each nuclear unit as assumed. License renewal is a long and multifaceted process which is based on submittals of complex studies to the NRC and its detailed review. EPRI encourages EPA to consider evaluating a lower bound case and develop a sensitivity analysis on the potential future of nuclear power generation capacity.
- EPRI has no specific technical comments to add on Building Block 3b.

Building Block 4: Demand Side Energy Efficiency

- The level of energy efficiency performance in this proposed rulemaking –1.5% annual incremental electricity savings as a percentage of retail sales– is greater than EPRI's assessment of energy efficiency program potential. EPRI research indicates that achieving this level of energy efficiency will required the addition of measures beyond energy efficiency programs and will occur over a longer period and at a higher cost than suggested in the proposed rule and accompanying RIA. While efficiency improvements in end-use devices and advances in controls technology can lead to energy savings; economic, market, and perceptual barriers can inhibit or curb customer adoption. The assumptions used to determine the economic viability of the proposed levels of energy efficiency should be reviewed to ensure that adverse economic impacts are avoided. Furthermore, evidence indicates that the adoption of financial mechanisms that encourage electric utility investment in energy efficiency, similar to those underway in several states, can facilitate the achievement of incremental energy efficiency.

- EPRI agrees with EPA that the link between energy efficiency and CO_2 intensity reduction is present. However, in quantifying the link between energy savings and CO_2 reductions, EPA would benefit from a modeling approach that considers the economic optimization of future generation fleet resources over time, as EPRI does. In addition, EPRI urges EPA to consider both the spatial effects of regional variation in the electric power generation mix, and temporal effects of changes in electric system load shapes resulting from changes in energy efficiency, and their associated impacts on marginal CO_2 emissions.

STATE GOALS

- EPA's definition and use of the BSER to set state goals, while granting flexibility in implementation, proposes a system of compliance that is intrinsically inflexible. The dynamics of compliance, under circumstances of any unplanned shortfall in the non-emitting resources required for compliance, force an additional curtailment of covered fossil output, creating a further reduction in supply and forcing states to increase imports or reduce exports. This creates the risk of multi-state compliance failures that could disrupt interstate power flows.
- Language on constructing mass-based greenhouse gas (GHG) emissions reduction targets is ambiguous. The proposed rule and supporting documents contain language that leave open a variety of possible interpretations on how to construct mass-based targets from the established rate-based targets. As part of its analysis of the proposed rule, EPRI examined three possible interpretations resulting in three different mass targets which can differ by as much as 30% from one another implying dramatically different CO_2 mitigation paths.
- The proposed rule considers only the resource adequacy perspective with regard to potential electric system reliability impacts and does not address the potential thermal, voltage, and frequency impacts. Nor does the proposed rule consider the associated potential transmission economic implications of additional facilities required to ensure operational reliability or financial implications of stranded transmission investments that become underutilized. EPRI encourages EPA to conduct detailed transmission reliability evaluations to understand the full reliability, economic, and financial impacts of the proposed rule.

STATE PLANS

- Establishing workable evaluation, measurement and verification (EM&V) requirements for energy end-use efficiency efforts will be critical to incorporating these efforts in state compliance plans and actions. EPRI suggests that the states consider establishing a set of generalized, process-oriented EM&V requirements that would apply to all energy efficiency programs and measures, while providing flexibility to customize EM&V approaches, as appropriate for different types of programs and measures, provided that EM&V meets the minimum standards established by EPA.

- While transmission and distribution (T&D) efficiency options do not have the benefit of widely accepted EM&V approaches that exist for end-use energy efficiency options, EPRI encourages the states to develop standards to measure and verify savings from T&D programs using the concepts, approaches, and terminology in practice today related to end-use energy efficiency efforts.
- As the electric sector decarbonizes and generates electricity with a lower carbon emissions intensity, electrification of more carbon-intensive sectors has the potential to cost-effectively reduce GHGs across the U.S. economy. Electrification has been long recognized in the energy-economics literature, technology studies, and the climate policy area as a cost-effective approach to mitigate GHGs. For example, while the implementation of an electrification strategy could cost-effectively reduce GHG across multiple sectors, the CO_2 emissions from the power sector could remain flat or even slightly increase. While it is understood that compliance for out-of-sector reductions is challenging, they should not be excluded if appropriate rigor and durability can be demonstrated. EPRI recommends that care should be exercised so that state plans do not to eliminate or dis-incentivize clean electrification.

IMPACTS OF THE PROPOSED RULE

Regulatory Impact Analysis

- EPA provided estimates of energy efficiency potential and cost by state as part of the calculations for Building Block 4 in computing the target rate. However, in the analysis with the Integrated Planning Model (IPM) energy efficiency is not adequately modeled as a resource in competition with other mitigation options which could lead to underestimating the associated costs.
- A related limitation of IPM is that this model does not represent unit commitment and electric power plant hourly dispatch in a detailed manner. EPRI research shows that important insights can be gained when electric sector models capture positive and negative correlations between load, renewable energy resource variability, and uncertainty across adjacent regions given that renewable resources are non-uniformly distributed in space and time. EPRI encourages EPA to consider enhancing the treatment of renewable energy in IPM and to complement the IPM analyses with more detailed, unit commitment modeling.
- While EPA recognizes "...that biomass-derived fuels can play an important role in CO_2 emission reduction strategies..." biomass as a renewable fuel is not treated as a non-emitting resource in the proposal's RIA. Biomass is therefore disadvantaged as a potential compliance option. EPRI encourages EPA to apply the latest peer-reviewed scientific research to develop with the states an appropriate GHG accounting framework for biomass as a renewable resource in state compliance plans.

BENEFITS OF THE PROPOSED RULE

Estimated Air Quality Reduction Benefits

- The limitations of the Environmental Benefits Mapping and Analysis Program (BenMAP) used to calculate benefits in the proposed rule should be recognized. These limitations include: (i) embedded options in the tool that are limited and inconsistent with the scientific literature; (ii) no simple way to consider uncertainty within its framework; and (iii) no provision for considering different species or components of fine particulate matter ($PM_{2.5}$) despite increasing evidence that some components of $PM_{2.5}$ may be more highly associated with health effects than others.
- EPRI also encourages EPA to address the appropriateness of calculating benefits associated with the additional air pollutant reductions in populations living in geographic regions that already meet the National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$ and ozone. The RIA estimates benefits of further reducing $PM_{2.5}$ levels from the proposed rule in the same populations even when the initial exposure is at or below the NAAQS. Given that the NAAQS are set at levels that will "protect the public health" with an "adequate margin of safety," there appears to be an inconsistency related to calculating benefits associated with reducing air pollutions below these levels.

Estimated Climate Benefits (USG Social Cost of Carbon)

- From a detailed EPRI technical assessment of the U.S. Government's Social Cost of Carbon (USG SCC) estimation approach, EPRI identified a set of fundamental issues and related concerns that suggest the need for EPA to revisit the estimation approach to develop scientifically sound results.
- The USG SCC estimates are the result of significant aggregation and therefore are vague and difficult to interpret, discuss, and evaluate. Greater technical clarity on what underlies and drives the estimates is needed to better understand the USG SCC estimates.
- EPRI suggests EPA revisit the overall USG SCC estimation approach because (i) the USG approach does not provide consistent, comparable, and robust analytic results; and (ii) the approach would benefit substantially from an external scientific peer review, similar to the peer review of other EPA regulatory models such as IPM. Given the importance of the SCC for regulatory benefits analysis, peer review would be appropriate to ensure the development and use of scientifically sound estimates and to ensure the public confidence in these estimates.
- There also are methodological issues related to the application of the USG SCC values in the proposed rule's benefit-cost assessment. For example, EPA applies the SCC values to estimated CO_2 reductions from the electric power sector when SCC values should only be applied to estimated net changes in global emissions.
- Lastly, the RIA compares levelized (or annualized) compliance costs to annual CO_2 benefits (in a particular year). This is an inconsistent comparison with an uncertain meaning. EPRI suggests that EPA's comparison of economic benefits and costs be based on the comparison between the net present value of compliance costs and estimated CO_2 benefits over time.

DETAILED EPRI COMMENTS

This section provides detailed comments and is followed by various reference materials and technical documents in the appendix.

1. DEFINITION OF BEST SYSTEM OF EMISSIONS REDUCTION AND THE BUILDING BLOCKS

1.1 Detailed Comments Building Block 1: Heat Rate Improvements

EPRI's research neither proves nor disproves that a 6% heat rate improvement could be attained in any given operating power plant. However, EPRI's research[2] does show that (i) heat rate improvements are not necessarily additive, (ii) they are very sensitive to operational issues - cycling, fuel type, etc., and (iii) they are very dependent on the type of equipment installed such as emissions controls. EPRI research has not yet developed data on the sustainability of most of the heat rate improvements discussed in these comments.

EPRI research identified potential unit-specific, heat rate improvements in the range of 0.5 – 5% on a net basis. However, the numerical values for separate heat rate improvements may not be additive. They also may not be achievable or justifiable at every coal-fired plant. In many cases, staff at many well-performing plants have been proactive and already implemented some of the possible improvements (e.g., steam turbine upgrades, remote monitoring centers, etc.), thus reducing the potential for further maximum heat-rate improvement. Estimates of heat rate improvements at existing coal EGUs are very dependent on the individual unit characteristics (age, design, maintenance history, type of coal, etc.) and are difficult to apply a national fleet-wide heat rate goal.

In the last several years, older power plants with higher heat rates and no longer considered economically viable have been retired by plant owners. These retirements typically remove units with the most potential heat rate improvement from the fleet. Those units where investments have already been made to improve operations are less apt to be retired, but have less additional potential heat rate improvement.

More detailed discussion and the feasibility of achieving high, fleet-wide average heat rate improvements is addressed below for the following areas:

- Net heat rate is significantly affected by increased plant auxiliary power consumption due to the addition of environmental controls;
- Diverse individual unit designs lead to differences in potential heat rate improvement opportunities;

[2] See EPRI Report 3002003457, "Range and Applicability of Heat Rate Improvements", 2014 for a summary of recent research.

- Potential economic disincentive to implement heat improvements due to concerns about incurring costs resulting from the age of the unit or, potentially, New Source Review requirements; and
- Adverse impacts on unit efficiency when engaging in flexible operations (e.g. load following, cycling, prolonged low output operations).

Net Heat Rate Sensitivity to Additional Plant Auxiliary Power Consumption

Historically each set of emissions control regulation increases auxiliary power consumption by about 1% of gross generation.[3] If the trend (observed over 20 years) continues, additional air emissions control technologies will likely be required and as a consequence, additional auxiliary power consumption will result. All EPRI and other referenced estimates of heat rate improvements are reported on a net basis. Net heat rate reflects the cost of generating electricity including the cost of auxiliary power consumed as part of the process and thus net heat rates are affected by the addition of emissions controls. The use of gross heat rate data for determination of heat rate improvement-related CO_2 mitigation potential in Building Block 1 is inconsistent with the use of the net emission accounting used in the state goals computation. This may lead to inconsistencies, confusion, and possible overestimation of the mitigation potential. EPRI recommends that EPA use a consistent approach for net heat rate estimation and accounting through the proposed rule.

With respect to the effect of air emissions requirements, the Mercury and Air Toxics Standards (MATS) Rule[4] requires coal plant operators to pay more attention to tuning and improving combustion performance, thus potentially improving plant heat rate. But if the installation and operation of additional emission mechanical controls are required, net heat rate – not gross heat rate – will typically suffer. Since those controls increase the consumption of auxiliary power, less efficient plants may be required to operate to make up the difference consumed by the new controls. The incremental increase in those plants' operation will increase the average heat rate of the affected fleets.

Uniqueness of Unit Designs and Options for Heat Rate Improvement

Power plants are designed for an optimal heat rate. While that heat rate may not be the lowest achievable at any given point in time, trade-offs occur with respect to capital and operations and maintenance (O&M) costs, siting, and fuel. The average age of operating coal-fired power plants is 40 years. Over the course of the past four decades, these plants have been subject to physical modifications and repairs and

[3] EPRI report 1024651 "Program on Technology Innovation: Electricity Use in the Electric Sector", 2011.
[4] The MATS includes the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Electric Utility Steam Generating Units and the revised New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units. www.epa.gov/mats and ww.epa.gov/ttn/atw/nsps/boilernsps/boilernsps.html

suffered age-related degradation. Many of the modifications have been the addition of emissions controls, which typically have an adverse effect on heat rate. Since initial startup, many units have changed fuel supply and reduced staffing size, increasing operational challenges which create additional potential adverse heat rate effects.

The actual heat rate improvement achievable at any site is unit-specific, as shown in EPRI studies. The maximum potential improvement depends on the condition and operation of the unit. For example, those units where major modifications or replacements of the turbine have been recently completed will have much smaller potential for heat rate improvements, while those units that have not upgraded equipment or have been less well maintained will have a larger potential for heat rate improvement. The costs to improve heat rate are also unit-specific; factors that may affect the costs include the age of the unit, its location, its condition, and whether asbestos removal is required. Economy of scale also plays a role, as the expenditures are more easily justified for larger units with higher capacity factors.

A 2014 National Coal Council[5] report includes a review of various options for improving the heat rate of existing coal power plants including coal switching, coal drying, steam turbine upgrades, condenser cleaning, instrumentation and controls improvements, low temperature heat recovery, auxiliary power use reduction, and cooling tower improvements. This report states:

> "In some cases the benefits are cumulative – such as those derived from minimizing auxiliary power, fuel drying, and improving heat rejection. Other actions that increase heat removal from the boiler – economizer modifications, improved air heater performance and low temperature heat recovery – do not provide cumulative benefits. All efficiency improving measures are unit and site-specific and will not always be technically and/or economically feasible. A detailed analysis would be required to assess the benefits of this set of measures, as well as its compatibility with new source review regulations. It is possible that a thermal efficiency improvement of up to 3-4 percentage points could be derived, if these actions can be proven to work together and do not compromise plant reliability."

The report also has a detailed list of reasons why cited heat rate improvements might not be applicable at a specific power plant. It also includes a list of factors which could lead to an increase in coal power plant heat rates including more operation at part-load, adding more environmental control equipment, switching from once-through to evaporative or air cooling, and switching from bituminous to lower sub-bituminous coal.

In 2014, EPRI completed a report "Range and Applicability of Heat Rate Improvements"[6] summarizing the results of recent EPRI projects focused on improving the heat rate of operating coal-fired power

[5] "Reliable &Resilient: The Value of Our Existing Coal Fleet ", May 2014, National Coal Council, http://www.nationalcoalcouncil.org/NEWS/NCCValueExistingCoalFleet.pdf. The National Coal Council is A Federal Advisory Committee to the U.S. Secretary of Energy.

[6] EPRI Report 3002003457, "Range and Applicability of Heat Rate Improvements", 2014.

plants. The study identified examples—both demonstrated/realized and projected—of methods to improve heat rate or recover efficiency losses. Examples include:

- Production Cost Optimization (PCO). In EPRI's project, the units evaluated realized 3-5% net heat rate improvements through various means.[7]
- Sliding Pressure. By employing sliding pressure over a several-month period, a 2% net heat rate improvement was realized at part load.[8]
- Remote Monitoring. The use of remote monitoring centers was documented to improve net heat rate 2.5 to 4%.[9]
- Steam Turbine Steam Path Modifications. EPRI members reported steam turbine steam path modifications were worth 2% to 4% net heat rate improvements.[10]
- Cycle Alignment. Implementing a cycle alignment (isolation) program was documented to be worth at least 0.5% improvement in net heat rate.[11]
- Capital and Maintenance Projects. A list of 57 potential actions and modifications to improve efficiency was made and evaluated in detail. While the amount of gains would be unit specific, the projected net heat rate improvements ranged from less than 0.1% to more than 2% for the various actions and modifications. One utility applied the methodology and analyzed a number of these potential projects for its own specific fleet, resulting in a projected 5% improvement in net heat rates.[12]

Economic Barriers to Heat Rate Improvement: New Source Review, Limited Remaining Life, High Costs for Additional Heat Rate Improvement

Owners of many coal-fired plants may refrain from making improvements based on the financial risk associated with potentially triggering a New Source Review, which may result in the requirement to invest in additional emissions controls. EPRI does not take a position on New Source Review

[7] EPRI report 1015734, "Production Cost Optimization Assessments", 2008; EPRI Report 1019704, "Production Cost Optimization Project 2010"; and EPRI report 3002002772, "Production Cost Optimization Project", 2014.
[8] EPRI report 1023912, "Methods to Mitigate the Effect of Increased Cycling and Load Following on Heat Rate", 2012.
[9] EPRI report 1023075, "Evaluation of Remote Monitoring Heat Rate Improvement", 2011.
[10] EPRI report 1018346, "Compilation of Results and Feedback Regarding Turbine Upgrades at Nuclear and Fossil Power Plants", 2008.
[11] EPRI report 1024640, "Cost Benefit Assessment of Cycle Alignment", 2011.
[12] EPRI report 1019002, "Capital and Maintenance Projects for Efficiency Improvements", 2009 and report #1021206 , Methodology for Fleetwide Energy Efficiency Analysis", 2010.

requirements; rather, EPRI notes that the requirements could increase costs of potential heat rate improvements and therefore are a potential impediment which should be recognized in the rule's calculations.

In July 2009, the National Energy Technology Laboratory (NETL) conducted a workshop [13] which reported that the largest barriers to heat rate improvement projects are the New Source Review provisions of the Clean Air Act and the lack of economic incentives exacerbated by the fuel adjustment clauses in utilities electrical rates permitting them to pass-through changes (increases) in fuel costs directly to consumers.

These conclusions are supported by the National Coal Council report previously cited which states the following about the potential impact of New Source Review

> "The New Source Review (NSR) permitting program unintentionally limits investments in efficiency. Some actions to improve efficiency at an existing power plant could lead to a designation of the change as a "major modification" subjecting the unit to NSR permitting requirements. These requirements usually entail additional environmental expenditures (that can reduce efficiency), as well as delays associated with processing the permit. In general, if a plant owner expects that an efficiency improvement would lead to such a designation, the efficiency project will not be pursued as the resulting permitting process would be extensive and the compliance requirements would be onerous and likely too stringent to be practicable."

The finances of power generating companies, both regulated and independent power producers (IPPs), require that any large expenditure must be justified, create a return on investment, or both. Often, smaller and/or older units operate less frequently, making a reasonable return on investment difficult to achieve for expensive modifications. In many cases, these units are old and may have a limited remaining life. Some heat rate improvement modifications and actions are costly and require a long period of operation to realize a return on investment. Thus some of these modifications may not be economically attractive for units with a few or unknown years of remaining projected lifetime.

In 2010, in collaboration with one of its member utilities, EPRI issued the results of a year-long study titled "Methodology for Fleetwide Energy Efficiency Analysis."[14] The focus of the research was the evaluation of power plant projects that would reduce CO_2 emissions by improving plant efficiency. A team of experts, including assistance from EPRI, developed a list of potential projects to improve power plant efficiency. The team developed estimates for each project including the cost to implement and the potential heat rate improvement. Next they determined which projects were applicable to each of their operating units. Those 174 capital projects were studied in detail to determine accurate, unit-specific

[13] "Opportunities to Improve the Efficiency of Existing Coal-fired Power Plants Workshop Report", 2009, National Energy Technology Laboratory.
[14] EPRI Report 1021206, "Methodology for Fleetwide Energy Efficiency Analysis", 2010.

costs and heat rate improvement values. Of those 174 projects, 58 "top priority" projects were deemed as "no cost," since fuel savings would eventually offset capital costs after 30 years. The initial cost to implement the 58 projects across this fleet was $61 million and the expected improvement in the heat rate of those plants was 2.5%. The remainder of the identified projects were estimated to cost $740 million to achieve an additional heat rate improvement of 2.5%.

Adverse Impacts due to Flexible Operations

Current operating conditions call on older coal plants for flexible operation, requiring load following and significant time at part load, again reducing plant efficiency. With the increased use of natural gas for electrical power generation and the proposal to increase it further, those coal-fired plants still in operation will be required to engage in flexible operations more frequently. These large coal plants were designed to be baseload and the near continuous variations in power level decreases both efficiency and reliability. EPRI completed a study in 2011 titled "Cycling and Load Following Effects on Heat Rate"[15] to determine the extent of the efficiency losses associated with increased load following. The report confirmed a substantial loss and identified the areas in the plant that suffered with the decreased load stability. Based on those results, both hardware and control systems were unable to maintain design operating values during portions of transient operation / non-steady state operation, (e.g. lower steam temperatures). Thus, the time that a unit spends operating at off-design conditions causes poorer heat rates.

In addition, there are potential wastewater-related impacts that should be recognized as FGD wastewater treatment –both biological as well as physical/chemical treatment approaches– may be negatively impacted with large swings in FGD water chemistry resulting from increasing flexible operations. For example, biological treatment is one of the proposed options under the effluent limitations guideline Best Available Technology (BAT) for FGD wastewater for selenium and nitrates. Initial EPRI research,[16] focused on FGD chemistry namely oxidation reduction potential, shows that FGD water chemistry can swing from high to low load.

1.2 Detailed Comments Building Block 2: Dispatch Changes

Technical assessment of NGCC 70% Capacity Factors

Based on EPRI and other known research, there are no technical reasons why individual NGCC units cannot maintain 70% capacity factors over the long term. Useful references for this technical assessment include:

[15] EPRI Report 1022061, "Cycling and Load Following Effects on Heat Rate", 2011.
[16] EPRI Report 1022160, "Selenium Speciation and Management in Wet FGD Systems", 2011.

- ASME paper GT2010-23182 "A Historical and Current Perspective of the Availability and Reliability Performance of Heavy Duty Gas Turbines: Benchmarks and Expectations"[17] which shows NERC GADS data for 2004-2008 timeframe. Average availability ranged from 86.9% to 90.2% depending on the unit size.
- Article in *Combined Cycle Journal*, 2nd Quarter, 2011,[18] showing combined cycle plants in the United States with F-class natural gas turbines achieved an average of 90.5% availability and 92.4% median availability based on NERC GADS data for 2005-2009 timeframe.
- Currently available NERC GADS Generating Availability Report shows average Availability Factor for 2010 and 2011 at about 87.7% (and an Equivalent Availability between 84.8%-85.8%).

It should be noted that capacity factors and availability factors are not the same thing. Availability factor indicates how often a power plant is capable of running (i.e., when it is not undergoing maintenance), while capacity factor indicates how often a power plant actually runs. Availability factor sets the upper bound on capacity factor. How often a power plant is dispatched when it is "available" will dictate its capacity factor. While EPRI sees no technical issue with individual NGCC units physically operating at a 70% capacity factor, there is little long-term operating experience with widespread and sustained operation of a majority of NGCC units at 70% capacity factor. Because maximum NGCC output is a function of weather conditions, assumptions regarding nameplate capacity should be re-examined to determine an appropriate assumption reflective of widespread NGCC operations at potentially high capacity factors across a wide range of weather conditions.

Based on maintenance guidance from natural gas turbine suppliers, EPRI concludes that increased capacity factors are not likely to cause decreased availability. Natural gas turbine suppliers recommend tracking both the number of starts experienced by a turbine and the number of operating hours. General Electric, for example, recommends natural gas turbines be taken out for inspection after 24,000 operating hours or 1200 starts, whichever comes first.[19] Consequently, a turbine which starts up and runs for only two hours every day would be taken off-line for inspection after 1,200 days (about three years and three months) while a turbine which operated 70% of the year (6,132 hours) and had one start per week would be taken off-line for inspection after three years and 10 months of service.

More critical questions than whether NGCCs can operate with higher capacity factors is whether there will be sufficient units to handle load-following duties that are currently handled by NGCCs if (i) most existing NGCCs move to baseload operation, or (ii) if economics drive reduced operation of the NGCCs

[17] ASME paper GT2010-23182 "A Historical and Current Perspective of the Availability and Reliability Performance of Heavy Duty Gas Turbines: Benchmarks and Expectations", ASME Turbo Expo 2010: Power for Land, Sea, and Air Volume 1: Aircraft Engine; Ceramics; Coal, Biomass and Alternative Fuels; Education; Electric Power; Manufacturing Materials and Metallurgy, ISBN: 978-0-7918-4396-3 | eISBN: 978-0-7918-3872-3

[18] See http://www.ccj-online.com/archives/2q-2011/commentary-ram-analysis/

[19] Balevic, David, Steven Hartman, and Ross Youmans, "Heavy-Duty Gas Turbine Operating and Maintenance Considerations", GER- 3620L, GE Power Systems, Atlanta, GA, 2010.

(for example if natural gas prices are higher than expected by EPA). EPRI is concerned that today's coal fleet may not be able to provide adequate flexible operations capabilities for the overall fleet as most existing coal plants were not originally designed for such duty.

In the public inspection version of the preamble to the proposed rule, pages 186-7, it states: "We also conclude from our analyses that the extent of re-dispatch estimated in this building block can be achieved without causing significant economic impacts. ...delivered natural gas prices were projected to increase by an average of no more than ten percent...." In its evaluation of this section, EPRI found it difficult to identify EPA's modeling assumptions on the magnitude of exports of liquefied natural gas (LNG) from 2020 to 2029. The combination of increased LNG exports and increased consumption by the power industry could boost natural gas prices by more than EPA is anticipating, potentially leading to higher costs than estimated by EPA.

Further in that same section, Page 194, it states: "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." Given the approach in Building Block 3 to increase the amount of power generated from non-emitting sources, a capacity factor greater than 70% seems difficult to achieve. EPRI recognizes that 70% capacity factor may be incompatible with the desire to increase the contribution from renewable sources in certain regions of the country while at the same time noting that this is not related to the technical limitations of NGCCs. It is important to note that EPRI's assessment regarding technical feasibility of 70% NGCC capacity factor does not consider potential fuel availability or natural gas supply infrastructure issues.

Dispatch and system reliability

Establishing a dispatch-based mitigation goal that impacts other existing generation types without thorough consideration of the impacts to resource adequacy may significantly degrade reliability. During the extreme cold temperatures across most of the Southern and Eastern United States from January 6-8, 2014, natural gas fired generating plants did not perform as expected due to both plant outages and natural gas delivery system inadequacies. As an example, in the PJM footprint 9,700 MW of gas generation capacity was unavailable due to forced plant outages and another 9,300 MW unavailable due to natural gas supply constraints, such that approximately 36% of the natural gas generation capacity was effectively forced out.[20]

Sensitivity of NGCC unit capacity factors to natural gas prices

EPA used recent history to support the idea that NGCC units can increase capacity factors to 70% by stating in the proposed rule that "...changes in generation patterns have been driven largely by changes

[20] PJM Interconnection, "Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events," May 8, 2014.

over time in *the relative prices of natural gas and coal"* (emphasis added, p. 175). However, history suggests that NGCC capacity factor is a sensitive function of natural gas prices; therefore, the assumption of high future NGCC capacity factors could be invalid if significant natural gas price volatility and increases were to be experienced in the future. This historical relationship is illustrated in Figure 1 by showing the trends in both the price of natural gas and resulting NGCC capacity factors from 2008 to 2013 from the most current U.S. Energy Information Administration (EIA) Electric Power Monthly.[21]

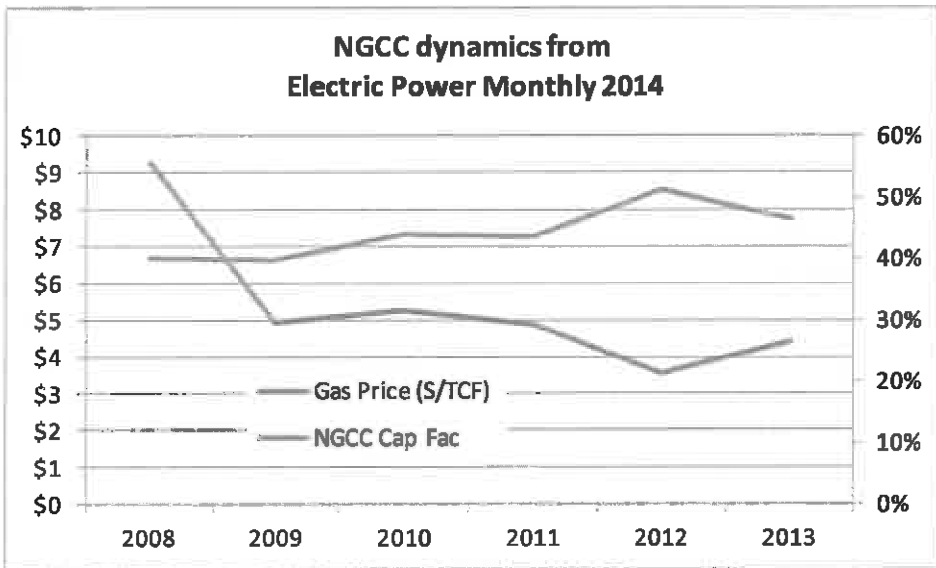

Figure 1: Natural gas price relationship to NGCC unit capacity factors

Specific Comments on Technical Support Document, "GHG Abatement Measures"

The following comments relate to specific sections and pages of the Technical Support Document (TSD), "GHG Abatement Measures" Chapter 3:

On page 3-5 under the heading "Historical Context" the CO_2 emission rate of U.S. coal power plants is stated to be 2,200 lb/MWhr and that of NGCCs is 907 lb/MWhr. Footnote 42 says this information comes from the "2012 eGrid data" file provided in the docket. On page 3-10, footnote 53 says the $15/ton CO_2 "price signal" is based on CO_2 emission rates of 2,354 lb/MWhr for coal and 926 lb/MWhr for NGCC and also cites the 2012 eGrid data file. EPRI recommends EPA clarify or correct this discrepancy in the two sets of numbers cited as coming from the same data file.

The final sentence on page 3-10 cites an expected increase in natural gas production of 20% between 2012 and 2020 as a reason the United States can accommodate an increase in the average NGCC capacity

[21] http://www.eia.gov/electricity/monthly/

factor to 70%. EPRI suggests that it is important to evaluate what is expected to be consumed by the LNG export facilities which have recently been approved. For example, EPRI estimates 3.6 trillion cubic feet (TCF) per year have already been approved and another 3.6 TCF is under review by DOE.[22] EPRI recommends EPA clarify its assumptions for the potential magnitude of LNG exports to the potential price of natural gas.

Page 3-11: "Adding in the existing sources that were not yet online in 2012 (under construction) increases total NGCC generation calculated in the goal setting to 1,444TWh." This would represent a 50% increase over what was produced in 2012, which was a record year; however, in the "Building Blocks" memo TSD, EPA predicts NGCC power production in 2030 will be 1,743TWh, which is 178% of the 2012 value. That implies a significant increase in natural gas consumption versus today. For 2020 EPA predicts NGCC power production will be 1,369TWh, which shows a mismatch between what is in this reference document and what is in the cost-benefit calculation memo.

Page 3-12: "For comparison, NGCC generation growth of 450TWh (calculated in goal setting) would result in increased gas consumption of roughly 3.5 TCF for the electricity sector." There is a miscalculation here based on what is stated in Footnote 69 where the heat rate of an NGCC is assumed to be 10,000 Btu/kWhr – EPRI believes this is too high. To get 3.5 TCF from 450TWh of electricity one has to assume a heat rate of 7,964 Btu/kWhr. However, EIA estimates the electric power sector consumed 9.1 TCF of natural gas in 2012.[23] Consuming an additional 3.5 TCF of natural gas would mean an increase of 38.5%, but that does not seem to match with the statement on page 3-11 that NGCC generation would increase by 50%. Although the amount of power produced by simple cycles might be large enough to account for this discrepancy, the modeling results in the cost-benefits memo show only a very small amount of power being generated by simple cycles.

The discussion on page 3-14 regarding the availability of NGCCs is confusing and seems to suggest that the availability of "advanced" NGCCs is higher than that of lower firing temperature NGCCs. EPRI recommends EPA clarify the discussion on page 3-14.

Page 3-20: In the discussion of the assumptions that went into EPA's IPM predictions they say they assigned a CO_2 charge to units that produced CO_2 at a rate greater than 1,100 lb/MWhr. Additional rationale for this charge and at this particular level would be useful.

Table 3-6: The base case has an NGCC capacity factor of 52% which is significantly higher than the value in 2012. It is uncertain whether this is due to the assumed impact of planned coal unit retirements and NGCCs taking up the slack or another reason.

[22] See table of proposed LNG export projects in N. Powell and S. Sullivan, "How LNG export projects could slot into DOE's reshuffled queue", SNL Data Dispatch, June 2, 2014.
[23] http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

Page 3-26: At the top of the page it is stated: "This is because only 29 state goals are premised on the existing NGCC fleet achieving an average capacity factor of 70 percent. Consequently, a 70 % utilization rate target for the existing NGCC fleet requires an average national capacity factor of 63 percent." This second sentence is confusing and should be clarified.

1.3 Detailed Comments Building Block 3a: Renewable Generation

Proposed Quantification

The EPA proposes primary and alternative approaches for quantifying target renewable energy generation levels for each state. The primary method divides contiguous states into six regions to define a "best practices" scenario. This approach begins by calculating a baseline renewable energy level for each region by summing 2012 levels of non-hydro renewable generation. Then, an aggregate renewable generation target for each region is calculated by averaging the existing Renewable Portfolio Standard (RPS) requirements currently adopted by states in the region. Finally, state-specific renewable energy targets are determined by applying a regional annual growth factor to the state's initial renewable energy level subject to the maximum generation target.

Adequately accounting for the spatial and temporal distributions of renewable resources and their associated costs is an essential consideration in regulatory design. However, the primary approach for calculating state-specific renewable energy targets assumes state equivalency for regional calculations of resource potential. This assumption is problematic when regions are large and encompass states with drastically different renewable resources. Given the sizeable areas spanned by the six EPA regions, there is evidence of differing levels of renewable energy resource adequacy and availability across these proposed regions. Additionally, the EPA assumption that existing RPS targets are feasible across all states within a defined region does not adequately consider the varying definitions of 'renewable' across the states. Renewable resources physically located in one state are often used to satisfy RPS requirements in other states. Since these benefits are not allocated to the buyer's state, this raises questions regarding treatment of the environmental attributes of the renewable resource.

The primary approach assumes that RPSs are a reasonable proxy for quantifying renewable generation potential because: (i) states with RPSs "…have already had the opportunity to assess those requirements against a range of policy objectives including both feasibility and costs;" and (ii) "RPS requirements developed by the states necessarily reflect consideration of the states' own respective regional contexts." As shown in recent literature[24, 25, 26] however, motivations for RPS implementation and stringency are

[24] Lyon, T. P., & Yin, H. (2010). Why do states adopt renewable portfolio standards?: An empirical investigation. Energy Journal, 31(3), 133-157.
[25] Delmas, M. A., & Montes-Sancho, M. J. (2011). US state policies for renewable energy: Context and effectiveness. Energy Policy, 39(5), 2273-2288.

multi-faceted and include many state-specific factors that cannot be generalized to other contexts or assumed to be indicative of best practices over a multi-decadal horizon.

Section 4 of the GHG Abatement Measures TSD assumes that all states in each region can achieve by 2030 the average of the 2020 requirements of RPS states in that region. To accomplish this, the TSD assumes that states within each region exhibit similar levels of renewable resources, an inference made from state-level technical resource potential projections reported in a NREL GIS-based analysis. In fact, a review of this NREL report reveals a rather wide variation in renewable technical potential for specific regions and by renewable resource. For example, the technical potential for biomass varies significantly across virtually all regions. Additionally, in the NREL study, all biomass feedstock land resources were considered available for biopower use. Competing uses of available land and biomass resource, such as for biofuel production, were not considered. This could further affect the technical resource potential for biopower within a region. The variation of renewable resource technical potential is perhaps the most pronounced for the West region. Significant variability in renewable technical resource is indicated for hydrothermal, urban photovoltaic (PV), rooftop PV, concentrated solar power (CSP), and hydropower.

Even if renewable resources across states in a region had similar technical potentials, the primary renewable energy approach does not consider how these profiles may have dissimilar market potentials. Accounting for heterogeneous abatement cost functions for renewable resources across states is an important element in reaching specified emissions targets while minimizing abatement costs (or conversely in reducing more emissions for a given expenditure level). Identical standards for groups of states clustered by their technical potentials are not necessarily indicative of relative compliance burdens, especially in the presence of grid integration costs, siting concerns, and the provision of balancing flexibility from existing assets. Inadequately accounting for this cost information may overlook opportunities for lower-cost reductions in other states or building blocks, which would be exploited in an approach with broader coverage and greater flexibility.

A more appropriate and comprehensive basis for state clustering would be informed by the market potential for renewable energy development, which would include technology costs, fuel costs (e.g., for biomass), investor response, regional competition for other resources, learning-by-doing and network effects, regulatory limitations, and public acceptance. These externalities will influence regional renewable energy costs. EPRI assessed and reported the regional costs for deployment of renewable generation in two key reports.[27,28]

For a state where renewable generation (based on 2012 levels) already meets or exceeds the regional renewable energy target proposed under this quantification in Building Block 3, its obligation under the

[26] Carley, S., & Miller, C. J. (2012). Regulatory stringency and policy drivers: A reassessment of renewable portfolio standards. Policy Studies Journal, 40(4), 730-756.
[27] EPRI Report 1023993, "Renewable Energy Technology Guide: 2012".
[28] EPRI Report 1026656, "Program on Technology Innovation: Integrated Generation Technology Options 2012", 2013.

target is capped at its share of the regional renewable energy target. Similarly, once a state meets its share of the regional renewable energy target from 2017–2030, its obligation is capped. One alternative approach would be to incentivize states that have already met the renewable energy target to continue promoting renewable development and consider this 'added' renewable generation as an overall contribution to the regional renewable energy target. Such an approach could better account for the economic and market externalities that will impact individual state renewable energy deployment within a region.

Alternative Approaches to Quantifying Renewables

In addition to its primary approach for quantifying state-specific renewable energy targets, EPA proposes an alternate approach that determines available resources using a bottom-up methodology described in a TSD. This alternative approach relies on a metric that compares a state's renewable energy technical potential to its current renewable energy generation for different technology types and on IPM-projected market potentials at cost reductions of up to $30/MWh. For a given renewable technology, a state's target is defined as the lesser of the benchmark rate (based on the development renewable energy rate of the top 16 U.S. states) multiplied by state-specific technical potential (measured by NREL) or the IPM-generated development level.

In contrast to the primary approach, this metric attempts to incorporate information about technical and market potential simultaneously to inform renewable energy targets. Information on renewable energy technical potential is taken from the NREL GIS-based study. IPM modeling offers at least the possibility that development costs, grid limitations, and other considerations described above are taken into account.

However, the documentation associated with the alternative renewable energy approach does not present compelling justifications for many of its primary assumptions, including:

- Selection of the top one-third of states (16) in defining the average development rate;
- Selection of $30/MWh as a cost reduction target for IPM-projected market potential;
- Performing minimization of two metrics rather than maximization; and
- Selection and granularity of the technology choice set.

The TSD also does not illustrate robustness of targets to alternate specifications and does not provide a sense for how reasonable alternatives could bias flexibility and cost estimates.

EPA describes a different alternative method in the TSD that uses state-by-state assessments of technical and economic potential for different renewable energy technologies. The method compares the "...estimated cost of new renewable energy to the avoided cost of energy from implementing clean energy generation, by comparing the total cost of generation for each renewable energy technology by region to the estimated fuel, operating, and capital costs avoided by adding that generation." Since this approach uses detailed supply curve information from many locations, it broadly seems more consistent with cost-effective compliance than the primary and alternative methods. However, there is insufficient evidence about the precise methodology or its results to make definitive assertions about the relative merits and transparency of this approach.

1.4 Detailed Comments Building Block 3b: Nuclear Generation

EPRI has no specific technical comments on EPA's development of Building Block 3b on nuclear power generation. However, in reviewing how EPA used this building block for state goal setting and in the RIA, it's not clear if the Agency took into account the lifetime of nuclear units and that many units will hit the 60 year mark by 2029.

The current U.S. fleet of operating nuclear reactors stands at 100 units. These reactors were originally licensed for 40 years. License extension (for an additional 20 years) has been applied for and granted in many cases, although a number of plants have shut down prior to the end of their licensed lifetime.

The license expiration for each unit in the current fleet is shown in Table 1. There are 28 units that have licenses scheduled to expire before 2030. Of these, 18 units have pending applications submitted to extend their license from 40 to 60 years. Three units with licenses scheduled to expire prior to 2030 are already in their extended period of operation and would need to obtain additional license extension to extend their operating lives to 80 years (known as subsequent license renewal). Though it is expected that many reactors will apply for and receive license extensions out to 80 years, there is no level of certainty at this time.

Due to on-going economic pressures and the need for many plants to obtain license extensions, there is significant uncertainty as to the number of reactors that will be operating in 2030. Several nuclear plants have already shut down prior to their license end date. Looking beyond 2030, an additional 50 units have licenses expiring between 2030 and 2040.

There also is uncertainty that either companies will decide not to seek license extensions due to economic considerations, or that the Nuclear Regulatory Commission may not approve further extending the lifetimes of these units. As a consequence, the estimate EPA developed of available non-emitting nuclear power may be an overestimate. EPRI recommends that EPA consider a lower bound case and a sensitivity analysis on the potential nuclear power capacity.

Table 1: License expiration dates for current nuclear fleet

Plant Name, Unit Number	Operating License Expires
Indian Point Nuclear Generating, Unit 2	9/28/2013
Indian Point Nuclear Generating, Unit 3	12/12/2015
Davis-Besse Nuclear Power Station, Unit 1	4/22/2017

Plant Name, Unit Number	Operating License Expires
Sequoyah Nuclear Plant, Unit 1	9/17/2020
Sequoyah Nuclear Plant, Unit 2	9/15/2021
LaSalle County Station, Unit 1	4/17/2022
LaSalle County Station, Unit 2	12/16/2023
Callaway Plant	10/18/2024
Limerick Generating Station, Unit 1	10/26/2024
Byron Station, Unit 1	10/31/2024
Grand Gulf Nuclear Station, Unit 1	11/1/2024
Diablo Canyon Nuclear Power Plant, Unit 1	11/2/2024
Waterford Steam Electric Station, Unit 3	12/18/2024
Fermi, Unit 2	3/20/2025
Diablo Canyon Nuclear Power Plant, Unit 2	8/26/2025
River Bend Station, Unit 1	8/29/2025
Perry Nuclear Power Plant, Unit 1	3/18/2026
Clinton Power Station, Unit 1	9/29/2026
Braidwood Station, Unit 1	10/17/2026
Byron Station, Unit 2	11/6/2026
South Texas Project, Unit 1	8/20/2027
Braidwood Station, Unit 2	12/18/2027
South Texas Project, Unit 2	12/15/2028
Oyster Creek Nuclear Generating Station, Unit 1	4/9/2029
Limerick Generating Station, Unit 2	6/22/2029
Nine Mile Point Nuclear Station, Unit 1	8/22/2029
R.E. Ginna Nuclear Power Plant	9/18/2029
Dresden Nuclear Power Station, Unit 2	12/22/2029
Comanche Peak Steam Electric Station, Unit 1	2/8/2030
Seabrook Station, Unit 1	3/15/2030
H. B. Robinson Steam Electric Plant, Unit 2	7/31/2030
Monticello Nuclear Generating Plant, Unit 1	9/8/2030
Point Beach Nuclear Plant, Unit 1	10/5/2030
Dresden Nuclear Power Station, Unit 3	1/12/2031
Palisades Nuclear Plant	3/24/2031
Vermont Yankee Nuclear Power Plant, Unit 1	3/21/2032
Surry Nuclear Power Station, Unit 1	5/25/2032
Pilgrim Nuclear Power Station	6/8/2032
Turkey Point Nuclear Generating, Unit 3	7/19/2032
Quad Cities Nuclear Power Station, Unit 1	12/14/2032

EPRI Report 3002004658, October 2014.

Plant Name, Unit Number	Operating License Expires
Quad Cities Nuclear Power Station, Unit 2	12/14/2032
Surry Nuclear Power Station, Unit 2	1/29/2033
Comanche Peak Steam Electric Station, Unit 2	2/2/2033
Oconee Nuclear Station, Unit 1	2/6/2033
Point Beach Nuclear Plant, Unit 2	3/8/2033
Turkey Point Nuclear Generating, Unit 4	4/10/2033
Peach Bottom Atomic Power Station, Unit 2	8/8/2033
Fort Calhoun Station, Unit 1	8/9/2033
Prairie Island Nuclear Generating Plant, Unit 1	8/9/2033
Oconee Nuclear Station, Unit 2	10/6/2033
Browns Ferry Nuclear Plant, Unit 1	12/20/2033
Cooper Nuclear Station	1/18/2034
Duane Arnold Energy Center	2/21/2034
Three Mile Island Nuclear Station, Unit 1	4/19/2034
Arkansas Nuclear One, Unit 1	5/20/2034
Browns Ferry Nuclear Plant, Unit 2	6/28/2034
Peach Bottom Atomic Power Station, Unit 3	7/2/2034
Oconee Nuclear Station, Unit 3	7/19/2034
Calvert Cliffs Nuclear Power Plant, Unit 1	7/31/2034
Edwin I. Hatch Nuclear Plant, Unit 1	8/6/2034
James A. FitzPatrick Nuclear Power Plant	10/17/2034
Donald C. Cook Nuclear Power Plant, Unit 1	10/25/2034
Prairie Island Nuclear Generating Plant, Unit 2	10/29/2034
Brunswick Steam Electric Plant, Unit 2	12/27/2034
Millstone Power Station, Unit 2	7/31/2035
Watts Bar Nuclear Plant, Unit 1	11/9/2035
Beaver Valley Power Station, Unit 1	1/29/2036
St. Lucie Plant, Unit 1	3/1/2036
Browns Ferry Nuclear Plant, Unit 3	7/2/2036
Calvert Cliffs Nuclear Power Plant, Unit 2	8/13/2036
Salem Nuclear Generating Station, Unit 1	8/13/2036
Brunswick Steam Electric Plant, Unit 1	9/8/2036
Joseph M. Farley Nuclear Plant, Unit 1	6/25/2037
Donald C. Cook Nuclear Power Plant, Unit 2	12/23/2037
North Anna Power Station, Unit 1	4/1/2038
Edwin I. Hatch Nuclear Plant, Unit 2	6/13/2038
Arkansas Nuclear One, Unit 2	7/17/2038
Salem Nuclear Generating Station, Unit 2	4/18/2040

EPRI Report 3002004658, October 2014.

Plant Name, Unit Number	Operating License Expires
North Anna Power Station, Unit 2	8/21/2040
Joseph M. Farley Nuclear Plant, Unit 2	3/31/2041
McGuire Nuclear Station, Unit 1	6/12/2041
Susquehanna Steam Electric Station, Unit 1	7/17/2042
Virgil C. Summer Nuclear Station, Unit 1	8/6/2042
McGuire Nuclear Station, Unit 2	3/3/2043
St. Lucie Plant, Unit 2	4/6/2043
Catawba Nuclear Station, Unit 1	12/5/2043
Catawba Nuclear Station, Unit 2	12/5/2043
Columbia Generating Station, Unit 2	12/20/2043
Susquehanna Steam Electric Station, Unit 2	3/23/2044
Wolf Creek Generating Station, Unit 1	3/11/2045
Palo Verde Nuclear Generating Station, Unit 1	6/1/2045
Millstone Power Station, Unit 3	11/25/2045
Hope Creek Generating Station, Unit 1	4/11/2046
Palo Verde Nuclear Generating Station, Unit 2	4/24/2046
Shearon Harris Nuclear Power Plant, Unit 1	10/24/2046
Nine Mile Point Nuclear Station, Unit 2	10/31/2046
Vogtle Electric Generating Plant, Unit 1	1/16/2047
Beaver Valley Power Station, Unit 2	5/27/2047
Palo Verde Nuclear Generating Station, Unit 3	11/25/2047
Vogtle Electric Generating Plant, Unit 2	2/9/2049

Source: http://www.nrc.gov/reading-rm/doc-collections/nuregs/staff/sr1350/

1.5 Detailed Comments Building Block 4: Demand Side Energy Efficiency

The level of energy efficiency performance in this proposed rulemaking –1.5% annual incremental electricity savings as a percentage of retail sales– is greater than EPRI's assessment of energy efficiency program potential. EPRI research indicates that achieving this level of energy efficiency will required the addition of measures beyond energy efficiency programs and will occur over a longer period and at a higher cost than suggested in the proposed rule and accompanying RIA.

EPRI's recently published study "U.S. Energy Efficiency Potential Through 2035"[29] indicates an achievable range of energy efficiency potential from programs equivalent to an annual incremental electricity savings of 0.5% to 0.7% of retail sales through 2035. Moreover, EPRI estimates the economic potential of energy efficiency – characterized by 100% adoption of all cost-effective energy efficiency

[29] EPRI Report 1025477, "U.S. Energy Efficiency Potential Through 2035", 2014.

measures as customers phase them in over time – as equivalent to 0.9% of annual retail sales through 2035. By these benchmarks, the goal of 1.5% annual incremental savings represents a target that may be beyond the scope of cost-effective energy efficiency measures in the context of energy efficiency programs. In EPRI's view, other mechanisms complementary to energy efficiency programs, including federal, state, and local energy efficiency building codes and energy efficiency product standards, would be needed to attain the target levels.

EPRI's Energy Efficiency Potential Model[30] uses an appliance stock turnover approach to estimate the potential for energy efficiency by sector, by region, and by end-use. The model utilizes base data on national and regional electricity consumption from the EIA Annual Energy Outlook (AEO)[31,32] and detailed information on the performance and costs of technologies and measures from multiple sources, including regional measure databases, engineering models, and EPRI's staff of technical experts. The results are adjusted to reflect market barriers and best practices for energy efficiency programs as seen today. This well-established approach provides an accurate and useful estimate of the potential for energy efficiency that has been used to inform electric utilities and other entities in developing and augmenting energy efficiency programs.

The levels of energy efficiency in the proposed rulemaking represent a realization of best-in-class performance as achieved or mandated by a select few states. While EPRI agrees that efficiency improvements in end-use devices and advances in controls technology can make the realization of electricity savings equivalent to 1.5% of retail sales technically possible, economic, market, and perceptual barriers can inhibit or curb customer adoption. These barriers can be overcome with federal, state, and local energy efficiency building codes and energy efficiency product standards. EPRI's energy efficiency potential study indicates it will be necessary to use these methods to achieve the levels EPA assumes as energy efficiency programs alone will not reach these levels. However, these methods can take longer to implement and produce results less than utility best-in-class programs. Moreover, there is a 'learning curve' associated with effective implementation of energy efficiency programs. States with more experience implementing energy efficiency programs are likely to have a higher proficiency at launching new energy efficiency programs, whereas, states with less experience may require more time bring their programs to market. In addition, while a small number of states are achieving electricity savings at level commensurate with the 1.5% incremental annual target, maintaining that level over decades has not been proven. These factors lead EPRI to question whether a level of 1.5% incremental energy efficiency can be achieved as quickly as EPA assumes.

Additionally, there are market considerations that can inhibit or curb the realization of energy efficiency measures, even when they are economically beneficial to consumers. For example, dislocations in

[30] EPRI Report 3002001417, "User Guide to the Utility Energy Efficiency Potential Calculator Version 2.0", 2013.
[31] Latest available version: U.S. Energy Information Administration (EIA). "Annual Energy Outlook 2014 with Projections to 2040". U.S. DOE EIA, Washington DC, DOE/EIA-0383(2014). April 2014.
[32] EPRI's most recent analysis for national and regional energy efficiency potential referenced: "Annual Energy Outlook 2012 with Projections to 2035," U.S. DOE EIA, Washington DC, DOE/EIA-0383(2012), June 2012.

customer awareness of energy efficiency measures or the market availability of energy efficiency measures can hamper adoption. While such market considerations can be, and have been, overcome with federal, state, and local energy efficiency building codes and energy efficiency product standards, these methods will increase the customer's cost of energy efficiency implementation. This is because the consumer cost of energy efficiency measures implemented through codes and standards is not offset by energy efficiency program incentives. This introduces another risk of decreased or slower adoption rates than EPA's assumptions.

In addressing customer economics, EPA determines its proposed levels of energy efficiency to be economic based on estimates for levelized cost of saved energy (LCOSE). EPA's estimates for LCOSE that would be incurred by achieving the 1.5% incremental savings goal are based on available electric utility program costs and the historical relationship between program costs and participant costs. While EPA has taken a conservative approach by applying program costs at the higher end of the range of reasonable values, the assumption that the ratio of participant costs to program costs will remain fixed at historical levels in the future may understate participant costs and therefore understate LCOSE and thereby overstate energy efficiency potential.

EPA estimates the LCOSE for participants to be between $85/MWh and $90/MWh. This estimate is difficult to assess since EPA does not specify the composition and relative contributions of end-use measures towards the overall energy savings target. Each end-use has a unique load shape, and specific technologies within an end-use category may have distinct load shapes. Load shapes can have a significant bearing on the costs of energy efficiency. For instance, energy savings distributed over nighttime hours, such as from residential lighting technologies, may not be as cost effective as energy savings distributed primarily over summer on-peak hours, such as from energy-efficient air conditioning. Therefore, the LCOSE is difficult to estimate without some assumptions of the underlying load shapes of energy savings

EPA compares its estimated LCOSE of $85/MWh to $95/MWh to American Council for an Energy-Efficient Economy's (ACEEE's) LCOSE value of $54/MWh.[33] The ACEEE value is reduced by its assumed level of incentives of 20% of participant costs which were derived from the assumption of equal program costs and participant costs. The incentives are removed from these LCOSE estimates. These estimates are so tightly bound by the assumptions that any error or changes in the future may produce much higher cost and much less available efficiency. This could mean that achieving a level of 1.5% incremental energy efficiency will cost more than EPA assumes.

In looking further at the economics of energy efficiency, the use of an assumed level of incentives, 20% of estimated first participant costs, may produce distributional or subsidization effects between participants and non-participants if the impacts are not limited by the avoided cost savings. This is a consequence of the use of the Standard Practice Economic Tests for energy efficiency. The total resource

[33] ACEEE. "The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. U1402. March 2014.

cost (TRC) test, used by EPA and standard in the industry, is not affected by incentive levels which are a transfer payment between constituent groups. EPRI cautions that if the use of the TRC in choosing and designing energy efficiency measures is not tempered with examination of appropriate incentive levels through the use of ratepayer impact measures or participant cost tests, then uneconomic cross-subsidies may result depending upon the load shape of the energy efficiency implemented.

Finally, in addition to using federal, state, and local energy efficiency building codes and energy efficiency product standards, evidence indicates that the adoption of financial mechanisms that encourage electric utility investment in energy efficiency, similar to those underway in several states, can facilitate the achievement of incremental energy efficiency. Such measures include allowance for recovery of energy efficiency program and administrative costs, the recovery of the lost contribution to fixed costs, and an incentive for shareholders or ratepayers to produce the desired "best practice" efforts.

Assumptions/basis for converting energy efficiency savings to CO_2 emissions reductions

EPA contends that there is a link between electrical energy efficiency and reductions in CO_2 emissions. The EPA's GHG Abatement document[34] refers to projected average 2020 Emissions Intensity across the U.S. Power Systems of 1,127 lbs/MWh saved. EPA describes this calculation as an average of the emissions reduced using IPM and from its base case.

EPRI research supports the assertion that the implementation of energy efficiency produced measurable, verifiable, and permanent emission reductions. EPRI has developed an emissions calculator based on its environmental analyses using the US Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN)[35]. As part of this analysis, EPRI estimates marginal emissions impacts of changes in load as a function of the characteristic load shapes of individual end-use measures.

EPRI and EPA models recognize that CO_2 emission impacts depend upon the spatial and temporal effects of changes in the load. EPRI agrees that using a model that captures the timing of energy efficiency implementation in relation to the generation dispatch stack allows for an energy efficiency portfolio to be optimized for CO_2 reduction.

EPRI research supports the link between energy efficiency and CO_2 intensity reduction and finds that EPA's approach for determining CO_2 intensity reductions of current energy efficiency measures is reasonable. However, EPA's approach and method may not be appropriate for long term forecasting; it does not account for evolution of the generation fleet over time. As the mix of generation in a given region changes, so does the average and marginal intensity of CO_2 emissions, which will in-turn impact the emissions reduction impact of specific types of energy efficiency interventions.

[34] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: GHG Abatement, U.S. Environmental Protection Agency, Office of Air and Radiation, June 2014.
[35] EPRI Report 3002001410, "EPRI Energy Efficiency CO_2 Intensity Calculator, 2013 Edition".

2. DETAILED COMMENTS ON STATE GOALS

2.1 Form of the Goals, BSER Structure, and Compliance

The EPA proposed BSER, while granting broad flexibility in implementation, proposes a system of compliance that is intrinsically inflexible. The dynamics of compliance, under circumstances of any unexpected shortfall in the non-emitting resources required for compliance, creates the risk of multi-state compliance failures that would disrupt interstate power flows. To the extent levels of renewable energy, nuclear credits, and energy efficiency posited in EPA's target setting are not realized (i.e., the sum of Building Blocks 3 and 4 [BB3+4]), covered fossil generation will need to be curtailed below 2012 levels to satisfy compliance. While the specifics vary from state to state, at the national level, under delivery of a certain amount (X) of MWh from energy efficiency or renewable energy will require a 2.5 X MWh reduction in covered fossil generation for compliance. This dynamic will force states to seek increased imports, cut exports, or construct redundant new generation outside the jurisdiction of 111(d). If the shortfall occurs unexpectedly (i.e., within the lead time for securing new renewable energy, energy efficiency, or new NGCC capacity) the curtailed supply may force a choice between compliance and reliability. States that cut electricity exports (or ramp up imports) transfer the problem to neighboring states, forcing them to seek the power elsewhere; however, the BSER design cuts the short term response capability of the existing fleet to a minimum across all the states.

The BSER Building Blocks cover coal unit heat rate improvements (BB1), redispatch from coal[36] units to existing NGCCs[37] (BB2) and credit for non-emitting generation. The non-emitting generation includes an allowance for nuclear output[38] and renewable output (BB3) and certified load reductions from energy efficiency (BB4). The building blocks are combined into a CO_2 emission rate:

$$Rate^* = \frac{(Minimized\ Covered\ Fossil\ CO2\ per\ BB1\ and\ BB2)}{(2012\ Fossil\ MWh)\ +\ (EPA\ target\ BB3\ and\ BB4\ MWh)}$$

The proposal sets an annual target rate (*Rate**) for each state, starting with an interim target in 2020 that becomes tighter (lower) by 2029 and is constant thereafter. Compliance requires meeting the target rate over a three-year rolling average. EPA proposes target rates tailored to each state, mostly based on 2012 data. The resulting targets make near-maximum use of the opportunities for redispatching NGCCs for coal, and seek substantial increases in deployment of renewable energy and energy efficiency that may be unrealistically high (see comments above on renewable energy and energy efficiency). Nationally, the implied expectations in the state goals for nuclear credits renewable energy and energy efficiency sum to

[36] Also includes redispatch of oil and gas steam generation.
[37] Available redispatch MWH is NGCC output at a 70% capacity factor, minus 2012 generation.
[38] 6% of nuclear generating capacity as of May 2014 at a 90% capacity factor.

almost 1,000TWh in 2030, approximately 25% of current generation.[39] By comparison, total covered fossil generation in 2012 was about 2,50TWH (~60% of total generation).

States have flexibility in how they meet the target rate through varying mixes of non-emitting generation (nuclear, renewable energy, and energy efficiency) and different mixes and levels of fossil generation (coal and natural gas).

By the nature of the compliance equation, a shortfall in BB3+4 requires a reduction in covered fossil emissions. The two options for cutting covered CO_2 emissions are to redispatch more NGCC MWh for coal (which cuts the numerator), or by cutting the covered fossil output (which cuts both the numerator and the denominator).[40] Most states will have limited opportunity for additional redispatch beyond what was subsumed in the target setting. This is because the targets were set so that (i) either the existing NGCCs are at a 70% capacity factor, which leaves little room for additional output, or (ii) the coal generation has been fully displaced and is already at zero. As a consequence, for most states the bulk of any adjustment to maintain compliance in the face of a shortfall in renewable energy or energy efficiency deliveries will be made up by reducing the output of the covered fossil generation. However, the algebra of the compliance equation dictates a multiplier effect called the "Fossil Leverage Factor" (FLF). This factor dictates the reductions in fossil MWh induced per MWh of lower deliveries of BB3 or BB4. Roughly speaking, a 10% shortfall in displacing generation will require a 10% reduction in covered fossil generation. Given the 2.5:1[41] ratio between these two resources at the national level, this means that a 100TWh shortfall BB3+4 will require an additional 250TWh curtailment of covered fossil generation to maintain compliance. The total deficit becomes 350TWh.[42]

Each state has its own FLF and as can be seen in the Table 2 below; they vary widely. At the state level the FLF can be calculated as:

$$FLF = Rate^*/(r - Rate^*)$$

where Rate* is the state's target emission rate and r is the marginal emission rate for that state's fossil generation (i.e., the coal emission rate if coal has not been redispatched to zero, or if so the NGCC rate).

For 20 states, a one MWh shortfall in the sum of BB3 and BB4 deliveries must be made up by more than two MWh. As can be seen in the "Gen as a % of Sales" column, many of the high leverage states export large fractions of their generation (e.g., West Virginia, North Dakota, and Arizona). If they cut back exports to achieve compliance, trading partners will then be forced to find replacement power. Options

[39] Whether these goals are attainable at reasonable cost is not pertinent to this comment.
[40] The converse also applies; greater levels of displacing generation allow fossil sources to increase their output and their emissions while still meeting the target compliance rate.
[41] The ratio follows from the 2,500TWh of covered fossil generation to the 1,000 of Nuc, RE, and EE, summed across all the state in the EPA spreadsheet setting the rate targets.
[42] Note that for shortfalls in output from existing nuclear units would have a smaller multiplier, reflecting that only 6% of existing nuclear output is input to BB3, though shortfalls in output from new nuclear that is included in the target calculations would be similar to the 3.5 for RE and EE.

for making up the lower generation include increased output from new generation (NGCCs) or importing more power from out-of-state (or cutting exports to other states). This transfers the pressure to other states which will need to increase their generation, but their covered fossil generation is similarly tied to deliveries of BB3+4 displacing generation. The result risks creating a multi-state shortage of covered generation, forcing a choice between reliability and compliance.

Table 2: State Fossil Leverage Factors

Rank	State	2020 Fossil Leverage Factor	2030 Fossil Leverage Factor	Gen as % of Sales
1	Alabama	1.37	0.99	151%
2	Alaska	0*	6.87	96%
3	Arizona	6.37	3.55	143%
4	Arkansas	0.93	0.74	114%
5	California	2.13	1.63	71%
6	Colorado	1.47	1.13	89%
7	Connecticut	4.44	2	106%
8	Delaware	0.94	0.72	45%
9	Florida	0.67	0.54	90%
10	Georgia	0.81	0.63	88%
11	Hawaii	2.95	2.02	96%
12	Idaho	0.45	0.36	47%
13	Illinois	2.09	1.38	127%
14	Indiana	5.15	3.08	103%
15	Iowa	1.95	1.59	113%
16	Kansas	3.31	2.07	110%
17	Kentucky	18.9	6.45	97%
18	Louisiana	0.87	0.68	90%
19	Maine	0.96	0.8	133%
20	Maryland	3.18	1.41	61%
21	Massachusetts	0.61	1.85	75%
22	Michigan	1.62	1.21	104%
23	Minnesota	0.8	0.67	83%
24	Mississippi	12.07	4.42	99%
25	Missouri	6.71	3.72	99%
26	Montana	7.08	3.4	208%
27	Nebraska	5.28	2.59	113%
28	Nevada	5.86	2.75	97%

Rank	State	2020 Fossil Leverage Factor	2030 Fossil Leverage Factor	Gen as % of Sales
29	New Hampshire	2.65	1.24	195%
30	New Jersey	5.85	1.48	76%
31	New Mexico	1.19	0.91	150%
32	New York	0.54	0.36	93%
33	North Carolina	1.6	1.07	86%
34	North Dakota	4.96	4.03	259%
35	Ohio	3.66	2.03	86%
36	Oklahoma	0.85	0.7	114%
37	Oregon	1.24	0.78	111%
38	Pennsylvania	1.89	1.13	142%
39	Rhode Island	17	5.77	98%
40	South Carolina	0.83	0.61	115%
41	South Dakota	0.69	0.53	82%
42	Tennessee	1.79	1.23	72%
43	Texas	0.79	0.6	98%
44	Utah	2.89	2.12	127%
45	Virginia	0.87	0.61	58%
46	Washington	0.68	0.35	108%
47	West Virginia	23.35	5.17	233%
48	Wisconsin	1.63	1.18	84%
49	Wyoming	6.52	3.6	256%
*Mix of fuels makes calculation of Leverage Factor for 2020 ambiguous for Alaska.				

For states that have rate targets with zero coal output assumed (e.g., AZ, CA, NY, MS, MA), the only source of covered emissions is NGCC output. If state compliance planners believe that availability/deliverability of renewable energy and/or energy efficiency is below the expectations used by EPA to set state rate targets, then the only in-state option for compliance is adding *new* NGCCs to back-off existing NGCCs, clearly an inefficient solution.

Even if a state has abundant renewable energy and energy efficiency opportunities, there is still an operational issue due to multi-year delivery lead times. The displacing generation options have substantial lead times. For renewable energy, the lead time is taken up by integration studies, siting, permitting, construction, and possible transmission enhancements. Energy efficiency programs have lead times to set up, and the measurement and certification of results will likely mean that participation in the compliance accounting will lag substantially. The nuclear credits are even less flexible and face only downside uncertainty. This means that within the year, or even within a three year rolling average compliance period, the only flexible compliance option is redispatching NGCCs for coal, and as observed above, the state targets were set at levels that essentially fully utilize that option.

It is worth noting that these near-term dynamic issues will not show up in simulation models such as IPM that have perfect foresight. The models deliver the displacing generation by assumption or otherwise make up deficits by adding new generation. It is when resources do not become available as planned that the near-term operational issues identified here become important.

The basic challenge is that the BSER couples slow-moving long-lead time compliance options (e.g., nuclear, renewable energy, energy efficiency) to short-lead-time options (i.e., redispatch from coal to natural gas). The only "fast moving" option, redispatch, has by the BSER's design been largely maxed out. In the short term, any deficits will be transferred to other states through the power market. In the longer term, adding new NGCCs to back down existing NGCCs, though wasteful, can satisfy compliance obligations.

In consideration of the above challenges, EPRI offers the following alternatives to address them:

- Assure that the renewable energy and energy efficiency assumptions used to set state targets are realistic with little uncertainty in their attainment. This would help avoid shortfalls with multiplier effects, but would still be subject to risk from non-delivery in the short term. Allowing states to bank "over generation" of energy efficiency and renewable energy would help avoid future shortfalls and their negative consequences.

- Including safety values to limit the reductions in covered fossil output if/when there are shortfalls in BB3 + BB4 output could help keep compliance problems in one state from propagating to other states through the power market.

Longer averaging periods for compliance provide only limited value under most circumstances. Deficits in BB3+BB4 deliveries must be fully covered by subsequent "over deliveries" to comply with the target over the averaging period. Given the lead times for adding more renewable energy or energy efficiency, this is unlikely to be possible with a three-year averaging period, and in any case requires over investment creating an eventual surplus of energy efficiency or renewable energy in the long term.

2.2 Calculation Issues with Individual Building Block and State Goals

This section highlights a common point of confusion in analyzing the relative contribution of the individual Building Blocks used to create the EPA target rate by state. Because the EPA target rate is a fraction (i.e., lbs/MWh) the contribution of each Building Block to making up the target rate *depends crucially on the order in which the Building Blocks are added.* As a result, if the computation is performed by first removing heat rate improvement (BB1), then natural gas re-dispatch (BB2), renewables and nuclear (BB3), and energy efficiency (BB4) in that order, the results will be different than if the computation were performed by first removing BB4, then BB3, BB2, and BB1. Below is an example of this issue for the state of Pennsylvania.

For this reason, EPRI provides its own assessment of the impact of each Building Block by state that provides data that is comparable across Building Blocks and does not depend upon the ordering. This is done by removing one Building Block at a time from EPA's computation, calculating the new target rate (and hence the difference), then adding that Building Block back in, before removing the next. In this way, the impact of each Building Block on the target rate is computed from the same baseline (the EPA target rate), and are thus directly comparable. Any progressive one-by-one approach does not have this property and will tend to exaggerate the impact of the Building Blocks removed last in the calculations.

Example of How Building Block Ordering Affects Contributions to the Target Rate

From the EPA provided spreadsheet '20140602tsd-state-goal-data-computation.xlsx' the following can be computed for 2030 that make up the calculation for the target rate in Pennsylvania.

CO_2 emissions: 210,942.6 million lbs

Covered fossil generation (BB1&2): 142.52TWh

Expected renewables generation for Pennsylvania (BB3): 35.33TWh

Existing nuclear generation (at 6% credit – BB3): 4.48TWh

Energy efficiency (BB4): 18.19TWh

EPA's target rate can then be written down as

$$\text{Target rate} = \frac{210942.6}{142.52 + 35.33 + 4.48 + 18.19} = 1052 \text{ lb/MWh.}$$

Suppose you consecutively remove BB1, BB2, BB3, and BB4 in that order. As you remove each building block, the target rate changes as shown below

$$\text{Rate} - \text{BB1} = \frac{220849.4}{142.52 + 35.33 + 4.48 + 18.19} = 1101 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB1} - \text{BB2} = \frac{231891.6}{142.52 + 35.33 + 4.48 + 18.19} = 1156 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB1} - \text{BB2} - \text{BB3} = \frac{231891.6}{142.52 + 18.19} = 1443 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB1} - \text{BB2} - \text{BB3} - \text{BB4} = \frac{231891.6}{142.52} = 1627 \text{ lb/MWh.}$$

Now suppose you instead consecutively remove BB4, BB3, BB2, and BB1 in that order. As you remove each building block, the target rate changes as shown below

$$\text{Rate} - \text{BB4} = \frac{210942.6}{142.52 + 35.33 + 4.48} = 1157 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB4} - \text{BB3} = \frac{210942.6}{142.52} = 1480 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB4} - \text{BB3} - \text{BB2} = \frac{220881.4}{142.52} = 1550 \text{ lb/MWh.}$$

$$\text{Rate} - \text{BB4} - \text{BB3} - \text{BB2} - \text{BB1} = \frac{231891.6}{142.52} = 1627 \text{ lb/MWh.}$$

Now compare the incremental contribution of each building block to the target rate using the two methods.

Ordering	BB1	BB2	BB3	BB4
BB1-2-3-4	49	55	287	184
BB4-3-2-1	77	70	323	105
EPRI (single impact)	49	50	261	105

This example demonstrates that ordering is important. A change in ordering can change the impact of a single building block by more than 50%. Furthermore, calculating the numbers by removing Building Blocks in order like this creates a bias towards those Building Blocks removed last. The EPRI calculations are all computed off a common base – the EPA target rate – and are thus comparable.

2.3 Equivalency of State Rate and Mass-Based Targets

The EPA proposal and supporting documents contain language that leave open three possible interpretations on how to construct a mass-based target from the rate-based targets set by the EPA. The various interpretations imply significantly different CO_2 paths with one interpretation shown to be considerably more stringent than the 'equivalent' rate-based target. EPRI recommends EPA clarify the construction of mass-based targets, and clearly define the meaning of 'equivalence' between a mass-based and rate-based target.

The first interpretation is based upon the following paragraphs found in the '20140602tsd-projecting-egu-co2emission-performance.pdf' Technical Support Document.

> "A mass-based CO_2 emission performance goal is calculated by projecting the tons of CO_2 that would be emitted during a state plan performance period (e.g., 2020-2029, 2030-2032) by affected EGUs in the state if they hypothetically were meeting the state rate-based CO_2 emission performance goal for affected EGUs established in the emission guidelines. The translation of a rate-based goal (expressed in lb CO_2/MWh of useful energy output from affected EGUs) to tons (expressed as total tons of CO_2 emissions from affected EGUs over a specified time period) is based on a projection of affected EGU utilization and dispatch mix." (p13)
>
> "*A Mass-Based CO2 Emission Goal Policy Scenario*. This projection scenario is used to translate a rate-based goal to a mass-based goal. The scenario applies a rate-based CO_2 emission limit to affected EGUs that is equivalent to the state-specific rate-based lb CO_2/MWh emission goal in the EPA emission guidelines. The CO_2 emissions from affected EGUs projected during the specified plan performance period in this scenario represents the translated mass-based CO_2 emission performance goal for the state plan. To construct this scenario, this emission limit is added to the underlying reference case scenario described above." (p15-16)

Given this language, it appears that the mass-based target should be constructed by creating a model of the future which projects capacity and generation mix subject to the constraint that covered units meet the EPA rate-based target by state. From this model, the CO_2 emissions from covered units can be calculated, and this would form the mass-based target by state.

This first interpretation has the property of 'equivalence of CO_2 emissions from covered units', so that covered CO_2 emissions (as modeled) would be the same if the state were using rate-based compliance or mass-based compliance. (This does not imply that total CO_2 emissions, including emissions from new units, would be the same). However, the language of the proposal itself seems to imply more support for a second, more stringent interpretation.

The second interpretation can be inferred from §60.5770(3) of the proposal itself.

> "The conversion must represent the tons of CO_2 emissions that are projected to be emitted by affected EGUs, in the absence of emission standards contained in the plan, if the affected EGUs were to perform at an average lb CO_2/MWh rate equal to the rate-based goal for the state identified in Table 1 of this Subpart." (Federal Register, Vol. 79(117) p34953)

Given this language, and from the example constructed in page 16 of the '20140602tsd-projecting-egu-co2emission-performance.pdf' Technical Support Document, the construction of the mass-based target can be interpreted as constructing a reference case, extracting generation from covered units, and simply multiplying that generation by the EPA target rate to get mass-based target emissions for covered units.

The second interpretation implies, for most states, a mass-based target that is strictly lower than the first interpretation. This is because the second interpretation applies the EPA target rate (which is the average of emissions from covered units + renewables + some nuclear + energy efficiency) only to generation from covered units (and *not* renewables, nuclear, or energy efficiency). The mathematics of this calculation imply that the resulting emissions target must be lower than if the target were achieved by running a model with the rate as a constraint (in which case capacity and dispatch from covered units *and* renewables *and* nuclear *and* energy efficiency could be modified to meet the constraint). The only exceptions would be for states for whom the economics are such that they would not build additional renewables or energy efficiency under a rate-based target.

Consider the hypothetical example of State Z. Assume State Z has been set a target of 334 lb/MWh by 2030. Now suppose that the state is projected in the reference case to generate 1,000MWh of NGCC generation at 500lb/MWh, and 500MWh of renewables in 2030, due to local RPS policies already on the books. The 2030 average emissions rate would then be:

$$(1000*500 / (1000 + 500)) = 333 \text{ lb/MWh}$$

which meets the target rate, so State Z is already in compliance with the Clean Power Plan. Note that emissions from covered units are 500,000 lbs. Under the second interpretation, however, the mass-based target for this state would be 1,000MWh * 0.334 = 334,000 lbs. In other words, the state meets the rate-based target in the reference case but would have to do more to reach compliance with the 'equivalent' mass-based target. It is unlikely that any state with significant potential for renewables, nuclear, or energy efficiency would consider a mass-based target under this interpretation.

The differences between mass-based and rate-based compliance are such that EPA's use of the word 'equivalent' seems incongruous. It may be that the second interpretation is incorrect due to the definition of 'covered units', and a third interpretation is in order.

The third interpretation is identical to the second, except that the term 'covered units' includes both existing fossil *and* renewables *and* covered nuclear *and* energy efficiency. In this interpretation, the mass-based target would be calculated by taking reference generation from covered existing fossil units, renewables, covered nuclear, and energy efficiency, and multiplying that by the target rate. This interpretation would resolve the paradox arising in the hypothetical example above, as State Z would now be compliant under both rate-based and mass-based targets. This third interpretation would have a stronger claim to equivalence, as the target rate is applied to the same set of units as was used to calculate the target rate in the first place.

EPRI has used data from the IPM reference case and Option 1 – State scenarios provided by the EPA to illustrate how these three interpretations lead to very different mass-based targets by state. Table 3 below illustrates the three interpretations' mass targets as calculated from IPM results. The first column is the first interpretation, in which the emissions target is simply the emissions from covered units in the IPM Option 1 – State scenario. The second column is the second interpretation, in which the emissions target is calculated by taking generation from covered units in the IPM Reference Case, and multiplying that by the EPA target rate. Note that the U.S. wide emissions from covered units in the second interpretation is 22% lower. The third column is the third interpretation, in which the emissions target is calculated by taking generation from covered units, renewables, and covered nuclear in the IPM Reference Case, and multiplying that by the EPA target rate.

Table 3: Hypothetical state mass targets (million short tons) in 2030

State	Interpretation One	Interpretation Two	Interpretation Three
Alabama	53.1	45.5	51.0
Arkansas	21.4	29.0	31.2
Arizona	14.4	15.3	19.5
California	57.7	31.5	58.6
Colorado	30.4	21.8	27.9
Connecticut	4.7	4.1	4.5
Delaware	0.8	1.8	1.9
Florida	47.9	56.3	58.0
Georgia	45.1	42.8	47.2
Iowa	31.4	19.5	28.7
Idaho	0.7	0.4	1.9
Illinois	80.5	56.2	71.3
Indiana	97.4	75.6	91.3
Kansas	38.2	27.0	34.6
Kentucky	95.4	71.0	74.0
Louisiana	29.2	21.6	22.6
Massachusetts	8.4	8.1	8.9
Maryland	16.1	10.1	13.0
Maine	2.0	1.5	3.1
Michigan	61.4	44.7	51.5
Minnesota	15.8	13.6	18.5
Missouri	88.2	67.8	74.0
Mississippi	10.3	13.1	13.4
Montana	19.8	15.3	26.1

State	Interpretation One	Interpretation Two	Interpretation Three
North Carolina	45.3	40.2	47.9
North Dakota	34.5	26.0	33.3
Nebraska	31.5	22.4	24.1
New Hampshire	2.0	2.2	3.1
New Jersey	6.4	5.8	6.6
New Mexico	12.5	8.0	10.5
Nevada	9.2	5.1	7.5
New York	19.4	10.1	19.2
Ohio	101.4	69.1	76.1
Oklahoma	31.8	29.5	35.4
Oregon	5.5	2.4	11.5
Pennsylvania	86.9	61.5	68.8
Rhode Island	5.2	2.6	2.8
South Carolina	20.8	10.3	13.1
South Dakota	3.3	2.0	4.8
Tennessee	35.5	27.7	33.4
Texas	126.7	116.7	131.3
Utah	24.7	24.2	25.9
Virginia	17.3	10.3	14.1
Washington	3.4	1.5	10.8
Wisconsin	32.5	30.1	33.7
West Virginia	69.8	69.9	72.5
Wyoming	37.7	36.2	40.5
US TOTAL	1667.9	1307.5	1559.3

Given the differences between these three sets of mass-targets and given the uncertainty around the context and use of the word 'equivalence' in the proposal, EPRI recommends that EPA define a consistent way to calculate 'equivalence' of the rate-based target and mass-based target.

2.4 Transmission Reliability Considerations

Power system reliability encompasses both adequacy of supply to meet demand and operational reliability of the transmission system. Power systems must be operated to ensure that supply and demand are balanced and that this balance is maintained respecting thermal, voltage, and frequency criteria for not only the present operating state but also for any single contingency and other credible contingencies beyond a single contingency. The proposed EPA rule considers only the adequacy perspective of the reliability impact of the rule and does not address the potential thermal, voltage, or frequency impacts. Nor does the rule consider the associated potential transmission economic implications of additional facilities required to ensure operational reliability or financial implications of stranded transmission investments that become underutilized as a result of the change in system power flows. To understand the full reliability, economic, and financial impacts of the proposed rule, detailed transmission reliability evaluations should be conducted.

Detailed reliability studies are conducted when any new generation plant interconnects to the bulk transmission system to ensure the deliverability of energy in a reliable and economic manner. If new transmission facilities are required, those facilities are planned and constructed. Constructing these new facilities will require outages on existing facilities, which are increasingly difficult to schedule. Coordinating outages across many systems that are attempting to simultaneously develop new transmission facilities to accommodate mandated generation changes will be challenging at best and likely result in increased congestion costs and longer lead times to commission the new facilities as sequencing of outages will be required.

Retirements of existing, conventional generation will require replacement generation to ensure continued supply to the loads. In situations where retiring conventional generation plant sites can be used to build new generation, the existing transmission infrastructure may potentially be utilized as is or with some minor upgrades. However, if new sites are needed for replacement generation new transmission infrastructure may be required to interconnect these generation resources with load pockets. For example, the retirement of an existing coal plant located near a load center and installation of replacement generation at a different, more remote location can change the power flow on the transmission lines leading into the load center and can lead to significant transmission congestion. Detailed transmission planning studies would be required to determine the extent of thermal impacts for a given large-scale generation replacement scenario, but significant investments in new transmission infrastructure may be required to ensure transmission reliability. Further, it is unlikely that sufficient lead times exist for actually building new transmission facilities that might be required to support the change in generation mix to meet the rules interim goals in 2020, especially considering the challenges scheduling outages of existing facilities noted above.

In addition to economic impacts associated with relieving congestion resulting from new generation, the retirement of a large number of conventional thermal generation plants may also impact transmission system voltage and frequency stability. Conventional thermal plants are traditional resources providing voltage and frequency support to the system. With respect to voltage performance, these plants provide dynamic reactive power to the system to control steady-state voltage levels and to ensure transient voltage stability of the transmission system. While most central station replacement generation technologies would likely have reactive support capabilities, some resources such as distributed solar PV and demand response may not be able to support transmission system reactive power and voltage control needs. Even for replacement technologies that do have reactive capabilities, the locational aspect of the replacement generation is critical in that reactive support is a local need. Replacing a large number of existing thermal generators with an equivalent capacity of generation or demand resources located elsewhere would not ensure voltage stability such that other transmission investments may be required.

Similarly, conventional thermal plants also provide frequency support to the transmission system through inertial and primary frequency response to oppose and arrest disturbance-driven frequency excursions. In fact, coal units have one of the highest inertia constant (H) among all synchronous units. As with reactive support, replacement resources may or may not have frequency support capabilities.

For example, under the proposed rule, many conventional thermal plants may be replaced by bulk or distributed connected variable generation (wind and solar). On-going and recently concluded EPRI research has shown potential frequency and voltage impacts of changing generation mix due to retirement of conventional thermal plants and increasing penetration of renewable generation. In terms of frequency performance, the report titled "Frequency Response Adequacy and Assessment"[43] showed that replacing conventional thermal units with transmission interconnected wind generation may adversely impact frequency performance if the replacement wind generation is not controlled to contribute to frequency response. Wind plants can certainly be equipped with these capabilities, but other replacement resources may not be as capable. In terms of voltage performance, the report titled "Evaluation of Potential Bulk System Reliability Impacts of Distributed Resources Frequency Response Adequacy and Assessment"[44] showed that high levels of distributed variable generation can impact system transient voltage performance.

Most of the transmission reliability considerations noted can be mitigated with additional investments in transmission infrastructure, but the impact of these costs and timing of these facility upgrades on reliability during transitional periods should be considered as part of the proposed rule.

[43] EPRI Report 1024275, "Frequency Response Adequacy and Assessment: Global Industry Practices and Potential Impact of Changing Generation Mix", 2012.
[44] EPRI Report 1021977, "Evaluation of Potential Bulk System Reliability Impacts of Distributed Resources", 2011.

3. DETAILED COMMENTS ON STATE PLANS

3.1 Evaluation, Measurement, and Verification for Energy Efficiency

EPA proposes three options to guide incorporating Demand Side Energy Efficiency in State Plans:

1. Establishing specific EM&V requirements with a level of defined rigor such as a required minimum level of precision and accuracy for all energy efficiency programs and measures

2. Establishing specific EM&V requirements for certain types of widely used energy efficiency programs and measures – such as those addressed by the U.S. Department of Energy 's (DOE's) Uniform Methods Project (UMP) – while establishing a generalized EM&V approach that states can apply to programs that are relatively new, innovative, or untested

3. Establishing a set of generalized, process-oriented EM&V requirements that apply to all energy efficiency programs and measures, while providing flexibility to customize EM&V approaches, as appropriate for different types of programs and measures, provided that EM&V meets these minimum requirements

EPA also suggests any of these options could be supplemented with a prescription of who can conduct EM&V activities and prepare energy savings documentation, and to specify their needed qualifications.

EPA thoroughly outlines the considerations necessary for a state to develop EM&V plans for consideration by EPA. However, the potential variation in methods and trade-off between cost and rigor identified by EPA are such that a state could invest considerable time and resources in developing a plan that may not be acceptable to EPA. Additionally, EPA also correctly identifies that EM&V protocols for many potential energy efficiency measures such as building codes and behavioral based approaches are not as advanced and widely implemented as other more common measures. EPRI suggests EPA outline minimum requirements for EM&V to ensure uniformity and provide guidance for EM&V plan development. However, these minimum standards should not be prescriptive. Flexibility is important to allow for customization to address state specific needs and incorporation of new efficiency measures as they are developed. EPRI believes EPA's third option could provide both minimum guidance and adequate flexibility to meet states' current and future needs.

EPA suggests that one option for guiding state plans is to limit the types of energy efficiency to pre-defined, well understood measures with straight forward evaluation methods. EPRI believes this would unduly limit the amount of energy efficiency available for implementation in a state plan and while in the short term this may not result in diminished energy efficiency levels, in the longer term as programs mature and energy efficiency implementation becomes more advanced, it may be difficult to find additional savings opportunities that fit within these defined measures. Further, limiting to well-recognized measures does not allow for innovation in the energy efficiency field that could further expand its effectiveness and impacts.

EPRI encourages EPA to adopt an adjustment of CO_2 emission rate based on avoided CO_2 emissions. EPA should consider a requirement for reporting of hourly energy efficiency savings to improve the estimation of avoided CO_2. EPRI encourages this approach while acknowledging that this is not currently practiced in most states. As EPA outlines, an average emission rate approach assumes that the dispatch of all EGUs will be reduced uniformly with the implementation of energy efficiency. However, this is not what actually happens. EGU's are dispatched on an economic basis, and marginal units will not have the same emission rates as the fleet average. If a calculation of avoided CO_2 is to be used in the determination of state compliance, then identification of savings on an hourly and unit specific basis is critical to accurately calculating avoided CO_2 emissions from energy efficiency.

3.2 Evaluation, Measurement, and Verification for Transmission and Distribution Energy-Efficiency

Energy losses across T&D networks typically represent around seven to nine percent of all electricity produced (approximately 284 million MWh of annual energy losses from 4,058 million MWh of total generation produced in the United States in 2013. That is roughly equivalent to the electricity needed to power 26 million homes, considering that the annual consumption of the average U.S. residential customer is approximately 11,000kWh.[45] If T&D systems were more efficient (i.e., reduced energy losses), the rate of CO_2 emissions per delivered MWh would be reduced. The amount of reduced energy losses represents an equivalent reduction in the amount of generation needed, and thus reduce CO_2 emissions equivalent to the system average CO_2 emissions rate.

Improving efficiency of T&D systems is one potential option to lower the total electricity sector emission rate while still ensuring the high reliability standards required by electric utilities and expected by customers. Contributions from distribution and transmission systems can be achieved through aggressive deployment of measures that directly reduce network losses, as well as measures that reduce CO_2 emissions via increased transmission system utilization. This allows greater throughput on existing transmission corridors and enables integration of higher levels of renewables such as wind and solar, as well as other less-carbon intensive generation resources.

EPRI has conducted extensive research on T&D efficiency. From 2008 to 2012, EPRI performed research to provide electric utilities and industry participants with tools to help assess energy efficiency opportunities to reduce losses and improve utilization of T&D systems, to choose and implement the most effective options, and to measure and verify results and ascertain the causes of possible deviations.

The effort was structured and implemented in two interdependent activities: (i) a suite of demonstration projects and case studies to understand efficiency improvements through real-life examples, and (ii) base research to set the basis for the demonstrations, including a comprehensive evaluation methodology for

[45] EIA http://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3

quantifying the improvements as well as guidelines for project development and implementation. EPRI established collaborative research activities on energy efficiency for both distribution and transmission systems.

A total of 22 electric utilities participated in the distribution efficiency system collaborative. To evaluate distribution efficiency improvements, 66 circuit case studies were modeled and fine-tuned, based on field data. The options evaluated to reduce losses and energy consumption included voltage optimization, conservation voltage reduction, highly-efficient distribution transformers, low loss conductors, voltage upgrade, phase balancing, and reactive power compensation and control. Field trials of voltage optimization were implemented on nine circuits. Detailed advanced metering infrastructure (AMI) data from two circuits also provided information on transformers and secondaries.[46]

A similar number of electric utilities participated in the transmission efficiency collaborative. Seventeen transmission efficiency projects and case studies were conducted within this initiative.[47] The options studied to reduce transmission losses included voltage upgrade of transmission circuits, volt/var optimization, reduction of substation auxiliary power, low loss conductors, highly-efficient substation transformers, and reduction of shield wire losses and corona and insulator losses. EPRI also assessed options to reduce emissions through enhanced transmission capacity and system utilization, which included dynamic rating of transmission lines; use of high-temperature, low-sag (HTLS) conductors in congested corridors; power routers; and energy storage. In addition to these options, new technologies such as smart controls, wide-area monitoring, and high-performance computation clusters have the capability to dynamically mitigate conditions that may overload transmission infrastructure or imperil the security of system operation. This may enable transmission systems to operate safely close to the limits of the installed grid infrastructure and thereby improve system utilization and reduce emissions.

The outcomes of the various activities conducted throughout the EPRI T&D efficiency effort confirm that T&D systems can effectively contribute to reducing carbon emissions through aggressive deployment of measures to reduce losses and increase utilization. However, projects that improve T&D efficiency are seldom economically justified solely on the basis of reduced energy losses. Moreover, options that improve system efficiency can be economically sound in the context of projects undertaken for the purpose of system expansions, system upgrade, or component replacement and modernization. Hence, efficiency considerations should be included as part of a comprehensive energy-delivery resource plan.

One of the main challenges for T&D efficiency as a contributor of emission reduction is the measurement and verification (M&V) of the savings. Certainly as compared to end-use efficiency projects for which certain established measures have well-understood energy savings, efficiency projects in T&D systems do not have the benefit of widely accepted energy savings guidelines. Currently there is no industry-wide standard method to account for either electrical losses on the T&D system or the loss-reduction

[46] EPRI Report 1023518, "Green Circuits: Distribution Efficiency Case Studies", 2011.
[47] EPRI Report 1024345, "Transmission System Efficiency and Utilization Improvement: Summary of R&D Activity and Demonstration Projects", 2012.

opportunities for T&D upgrade projects. Further, there is no standard method for converting the energy savings to emissions reductions.

As part of its research, EPRI developed a framework to consistently assess benefits, cost, and performance of technologies to improve transmission efficiency and utilization, which it applied uniformly to the transmission efficiency demonstration projects to quantify impacts in a standardized manner. EPRI evaluated various tools and approaches for assessing energy and emission savings from measures to reduce losses as well as from measures to increase transmission capacity leading to higher integration of renewable generation.[48,49]

This body of EPRI research can serve as a foundation for continued efforts to develop a consolidated and widely accepted M&V methodology for T&D energy efficiency. Such an endeavor may be best undertaken under the auspices of a coordinated collaborative that brings together industry stakeholders including electric utilities, system operators, regulatory bodies, academic institutions, and research organizations.

As above for energy efficiency end-use options, EPRI also suggests that avoided T&D losses from energy efficiency measures be included in the inventory of possible options states may implement in their plans.

3.3 Electrification Strategies and State Goals

In the proposed rule, EPA has stated a nationwide goal, by 2030, of reducing CO_2 emissions from the power sector approximately 30% from 2005 levels. However, EPRI is concerned that the proposed rule would establish a mitigation approach that does not adequately recognize alternative methods of reducing emissions in an efficient and cost-effective manner across the U.S. economy. In the proposed rule, EPA cites the 2009 Endangerment Finding,[50] the recent Intergovernmental Panel on Climate Change report,[51] and the recently released National Climate Assessment[52] to establish impacts from GHGs and the reason for regulatory action on CO_2. According to EPA, all GHGs "cause and contribute" to the EPA identified impacts -- not only CO_2. Further, CO_2 is emitted from various sectors of the economy—not only from the electric sector. In terms of U.S. GHG emissions, the electric sector comprises 32% of total anthropogenic

[48] EPRI Report 1020142, "The Power to Reduce CO_2 Emissions: Transmission System Efficiency".
[49] A .Del Rosso and C. Clark, "Methods and Tools to Estimate Carbon Emission Savings from Integration of Renewable and T&D Efficiency Improvement", IEEE Power & Energy Society Meeting, July 2011 Detroit, MI.
[50] "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act," 74 Fed. Reg. 66,496; Dec. 15, 2009.
[51] Intergovernmental Panel on Climate Change (IPCC) report, "Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change," 2007.
[52] U.S. Global Change Research Program, Climate Change Impacts in the United States: The Third National Climate Assessment, May 2014.

emissions (excluding land use); the transport sector about 28%; and the combination of the commercial, industrial, and residential sectors comprises about 30%.[53]

A strategy that decarbonizes the power sector and increases the share of electricity used by energy end-use consumers has been long recognized in the energy-economics literature, technology studies, and the climate policy area as a cost-effective approach to mitigate GHGs and other air emissions; that is, as the electric sector decarbonizes and produces cleaner energy, electrification of more carbon-intensive sectors is an effective and economic action to reduce all GHGs.

A recently published study by Stanford University's Energy Modeling Forum[54] focused on the development and cross-model comparison of results from a new generation of comprehensive U.S. climate policy intervention scenarios focusing on technology strategies for achieving climate policy objectives. A robust finding from the study that a cost-minimizing approach to reducing GHGs across the economy is one that "increases electricity production as low carbon electricity substitutes for liquid, solid, and gaseous fuels in end-uses." This further confirms key conclusions and recommendations on near-term emissions reductions and technology choices in the U.S. National Academies most current multi-volume report titled *America's Climate Choices.*[55] Specifically, the report on *Limiting the Magnitude of Future Climate Change,*[56] Chapter 3 states:

"We conclude that the most substantial opportunities for near-term GHG reductions, using technology that is deployable now or is likely to be deployable soon, include the following:

- Improved efficiency in the use of electricity and fuels, especially in the buildings sector, but also in industry and transport vehicles.
- Substitution of low-GHG emitting electricity production processes, which may include renewable energy sources, fuel switching to natural gas, nuclear power, and electric power plants equipped to capture and sequester CO_2.
- Displacement of petroleum fuels for transportation with fuels with low- or zero- (net) GHG emissions."

EPRI defines this approach as an "Electrification Strategy for Emissions Reductions." This well-recognized, cost-effective strategy to mitigate GHG, that is, *Electrification*, requires consideration for flexibility in state plans. Moreover, strategies that employ an electrification approach should not be disadvantaged by too narrow an interpretation of compliance under the proposed rule. While it is

[53] "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2012", Report EPA 430-R-14-003, United States, Environmental Protection Agency, April 15, 2014.
[54] Fawcett, A., Clarke, L., and Weyant, John. 2014. EMF24 Study on U.S. Technology and Climate Policy Strategies. The Energy Journal, Volume 35 (Special Issue 1).
[55] America's Climate Choices - Committee on America's Climate Choices. National Research Council of The National Academies, The National Academies Press, 2010. ISBN 13: 978-0-309-14585-5. www.nap.edu
[56] Chapter 3: Opportunities for Limiting Future Climate Change, In Limiting the Magnitude of Future Climate Change, Committee for America's Climate Choices, National Academies of Sciences. ISBN 978-0-309-14597-8.

understood that compliance for out-of-sector reductions is difficult, they should not be excluded if appropriate rigor and durability can be demonstrated; care should be taken not to eliminate or dis-incentivize clean electrification. For example, while the implementation of an electrification strategy could cost-effectively reduce GHG across multiple sectors, the CO_2 emissions from the power sector could remain flat or even slightly increase. Existing literature cited above, including EPRI analyses and reports,[57] has substantiated this. Therefore, EPRI recommends that care should be exercised so that state plans do not to eliminate or dis-incentivize clean electrification.

[57] EPRI Report 1020389, "The Power to Reduce CO_2 Emissions: The Full Portfolio", 2009 and Blanford, Merrick, and Young (2014). "A Clean Energy Standard Analysis with the US-REGEN Model," The Energy Journal, 35(1), pp. 137–164.

4. IMPACTS OF THE PROPOSED RULE

4.1 Energy Impacts in Regulatory Impact Analysis

Table 5, in the RIA, shows that in EPA's model for the "State" scenario in 2030 power production from natural gas will increase by 24.5% or 351TWh. The vast majority of the natural gas power would come from combined cycles rather than simple cycles (1743TWh vs 40TWh). Power production from coal would drop by 21% or 347TWh in the same scenario. The amount of power generation from combustion turbines (CTs) as opposed to combined cycles is quite low in the modeling results shown in Table 5 when compared to current experience. The results for the base case in 2020 show only 19TWh from CTs compared to 1,088TWh from combined cycles. The GHG Abatement Measures TSD, Table 3-3 says NGCCs in 2012 produced 981TWh in the United States. EIA's website states that 3% of the electricity produced in the United States in 2012 came from NGCCs.[58] Three percent would be 110TWh or about 11% of the output from NGCCs compared to about 2% in EPA's modeling results. Since CTs handle short-term load following and peak needs, it is unclear if EPA's model took into account for those duties. Given the relatively high heat rates of CTs compared to combined cycles, if EPA's model predicted that CTs produced on the order of 100TWh instead of 20, the percent reduction in CO_2 emissions from fuel switching would not be as great as the model currently shows. Alternatively, if CTs are going to operate less frequently than they do today, this implies that the coal power fleet will have to accommodate load following duties. That will increase the CO_2 emission rates of coal power plants.

The amount of power produced by coal in 2020 is estimated to be 1,395TWh; however, in EPA's state goal computation spreadsheet (20140602tsd_state_goal_data_computation.xlsx), the total amount of power produced from coal plants is 1,098TWh or 21% less than what was used in the cost-benefit analysis. This is an inconsistency which could impact the outcome of the cost-benefit analysis.

Table 6 shows that EPA's model predicts there will be 211GW of installed coal-based generation capacity nationwide in 2020. In 2012 there were 323GW of coal-fired capacity, which could be interpreted as a projection that approximately 35% of the existing coal fleet will be retired by 2020. The base case for 2020 calls for 244GW of coal capacity, which seems to indicated 33GW of retirements from the proposed rule. It is unclear if EPA has previously estimated the other 79GW of retirements occurring due to other current or pending regulations or additional factors. If 112GW of coal generating capacity is retired, it is unclear what capacity will replace it to ensure adequate reserve margins. Table 6 predicts there will be a total of 251GW of NGCC in 2020 which is only 4GW more than existed in 2012. Additional details from EPA on this issue would be useful.

Table 7 shows EPA's model is predicting an average capacity factor of 57% from the NGCC fleet in 2030. This is significantly less than the 70% capacity factor premised in the proposed rule preamble (line three of page 179), and less than the 64% used as the basis of the proposed state targets (page 190,

[58] http://www.eia.gov/todayinenergy/detail.cfm?id=13191 "Natural Gas-fired Combustion Turbines Are Generally Used to Meet Peak Electricity Load", October 1, 2013.

sentence before footnote 144). Table 15 shows EPA's model predicts natural gas prices will increase by 10.3% (or \$0.66/MMBtu) in 2030 compared to the base case. This price prediction has an impact on the overall cost of implementing the fuel switching strategy of Building Block 2. EPRI suggests that EPA consider that prices may increase beyond 10% if, as predicted, the power sector's increase of natural gas increases by 25%.

4.2 Regulatory Impact Analysis and Use of the Integrated Planning Model

Modeling the Economics and Dispatch of Renewable Energy Resources

The spatial and temporal distributions of renewable energy resources are integral considerations in regulatory design. Adequately representing these factors in the modeling efforts to inform renewable energy targets is a challenging but necessary task in understanding the dynamics of investment and dispatch over time. In particular, selecting and weighting representative hours in piecewise approximations of load and resource duration curves can influence the economic attractiveness of renewable energy investments. Models must capture positive and negative correlations between load, renewable resource variability, and uncertainty across adjacent regions given that renewable resources are non-uniformly distributed in space and time. Representing periods of resource extremes is especially important in understanding capacity and generation needs across regions. EPRI research illustrates how incorporating these feedbacks can materially influence recommendations from modeling exercises (Blanford, Merrick, and Young 2014[59]).

EPA's applications of IPM use seasonal load duration curves with six segments for the summer and winter seasons (i.e., 12 segments per year) between 2016 and 2030. The model output only maintain eight representative annual segments for later model years. This assumption is especially problematic given that detailed dispatch becomes increasingly important as renewable energy deployment increases, which typically occurs in later decades of the time horizon. In contrast, standard US-REGEN runs require 87-segment load and resource duration curves to adequately sample the corners of the joint distribution.

A related limitation of IPM is that it does not represent unit commitment and dispatch in a detailed manner. Dispatch is based on variable generation costs alone and does not include operational constraints (e.g., ramp rates, startup and shutdown costs, minimum load limits). These omissions impact IPM's ability to offer insights about questions related to the operation of a fixed portfolio of capacity or to investment decisions related to capacity expansion. Consequently, the resource adequacy and reliability analysis TSD does not sufficiently demonstrate potential operational challenges associated with the

[59] Blanford, Merrick, and Young. 2014. A Clean Energy Standard Analysis with the US-REGEN Model. The Energy Journal, 35(1), pp. 137–164.

capacity mixes resulting from the proposed rules. The TSD states that "…the implementation of this rule can be achieved without undermining resource adequacy or reliability…," and IPM runs are used as supporting evidence for this claim. Detailed unit commitment modeling would be a prerequisite to a thorough assessment of the resource adequacy and flexibility needs induced by the proposed rule. Additionally, the IPM analysis focuses only on operational challenges in 2020 and does not examine how resource adequacy issues may change toward the end of the interim compliance period nearly a decade later.

Energy Efficiency Assumptions are not Resource-Based

EPA provided estimates of energy efficiency resource and cost by state, as part of the calculations for Building Block 4 in computing the target rate. In particular, EPA assumed that the first year energy efficiency improvements cost $550/MWh, if in total they reduce demand by 0.5% of sales or less, $660/MWh if in total they reduce demand 0.5% – 1.0% of sales, and $770/MWh if in total they reduce demand by more than 1.0% of sales.

This assumption leads to a contradiction. If a state invests in energy efficiency improvements that lead to .4999% reduction in sales year on year, then the cost is $550/MWh. If a state invests a little extra, so that total energy efficiency improvements lead to a .50001% reduction in sales, all the improvements now cost $660/MWh. Furthermore, there is no consideration of an upper limit in energy efficiency resource. A state is assumed to be able to add 1.5% or more of energy efficiency per year into the foreseeable future, regardless of the current state of the end-use capital stock and the state of technology.

This analytical contradiction points to a core issue with EPA's treatment of energy efficiency, that is, it is not modeled as a resource. EPRI suggests that EPA examine its model to take into account the cost and quantity assumptions used are based upon recent historical experience, and do not consider the quantity of end-use capital stocks in a state, do not consider the technical potential for technological improvements (and costs thereof) in the end-use capital stocks, and do not consider the different compositions of end-use capital stocks between states.

EPRI recommends that energy efficiency be treated as a resource, in the same fashion that renewable resources are computed by state in the Alternate Renewable Energy approach. This involves an estimate of end-use capital stocks by state, an explicit assessment of the available resource based upon those estimates, and a forecast of how technological improvements into the future could increase that resource.

Model Energy Efficiency Endogenously in Integrated Planning Model for Regulatory Impact Analysis

The IPM scenarios created in support of the RIA all assume that a fixed quantity of energy efficiency is deployed in all Clean Power Plan scenarios, at EPA assumed costs. Modeling energy efficiency in this way can lead to biased cost estimates, and would be much improved by an endogenous representation that allows the model to weigh energy efficiency against alternative technologies to meet load. This is relatively easy to do in a model such as IPM, and EPRI makes a suggestion as to one such implementation.

The current IPM modeling structure incorporates energy efficiency by subtracting it from demand and accounting for the costs of incorporating the energy efficiency ex-post (after the model has solved). This structure effectively forces the same amount of energy efficiency into the model in all scenarios – except the base scenario in which no energy efficiency is included (outside what is already included in the Annual Energy Outlook 2013 load forecasts).

In using this structure to model energy efficiency, EPA made three implicit assumptions:

1. Energy efficiency is so cheap that all available energy efficiency (at EPA limits) will be built in any scenario in which the Clean Power Plan is implemented.
2. Energy efficiency is so expensive that none will be built in the base scenario.
3. Energy efficiency is not the marginal technology for compliance with the Clean Power Plan (e.g., it is cheaper than new renewables or cheaper than coal-to-gas re-dispatching).

It seems implausible that all three of these assumptions could hold simultaneously. That would imply that energy efficiency is too expensive in the base case to deploy at all, and that the implicit subsidy granted to energy efficiency by the Clean Power Plan is enough to make it one of the cheapest compliance technologies. But there are several states, which, in the IPM scenarios have little or no compliance cost and therefore offer no subsidy to energy efficiency. Rhode Island is a case in point. In the Option 1 – States scenario, the shadow price to meet the EPA target rate is $0. This means that Rhode Island needs to do nothing to comply with the EPA target rate, and therefore offers no additional incentive to energy efficiency (or renewables). Yet under the IPM modeling of this scenario, energy efficiency appears in Rhode Island under the Clean Power Plan, but not under the Base Scenario. This is inconsistent with IPM's principle of meeting load at least cost and causes bias in the cost estimates.

As noted, it is unlikely all of the above implicit assumptions hold simultaneously. If any one of these assumptions is not true, then the method of forcing in energy efficiency exogenously leads to a bias in cost estimates.

1. If energy efficiency were expensive enough that cheaper compliance options existed, then the EPA technique of forcing energy efficiency in at EPA defined limits will overstate the total costs of compliance. In this case, compliance costs are biased upwards.
2. If energy efficiency is so cheap that it would be built in the reference case, then EPA's assumption that energy efficiency is not in the reference case biases compliance costs downwards. Because the benefits of energy efficiency outweigh the costs even in the reference case, adding exogenous energy efficiency to the model results in a net reduction in system costs. If the energy efficiency is only added to the scenario case, and not to the reference case, these net benefits are incorrectly counted as part of the compliance costs for the proposed rule, and will

reduce the reported compliance costs accordingly. In this case, the failure to include energy efficiency in the reference case biases compliance costs downwards.

3. If energy efficiency is the most expensive (utilized) compliance option, then the cost of the energy efficiency should drive the marginal price of CO_2. But the technique of forcing energy efficiency in exogenously implies the model treats energy efficiency costs as fixed – so the marginal cost is then computed by the next most expensive compliance option. This biases the compliance costs downwards.

It is not possible to gauge the scale of the potential bias without modeling energy efficiency endogenously. For the purpose of these comments, EPRI has utilized US-REGEN[60] to assess how energy efficiency, at EPA assumed quantities and costs, compares with other technologies. The US-REGEN model has many similarities to the EPA/IPM model. It is an inter-temporal regional model of the United States electric sector, focusing on the contiguous 48 states. For this analysis, EPRI added energy efficiency as an explicit technology that competed with other generation technologies to meet load. This was done as follows:

1. Create a new technology 'energy efficiency', and assume that 1MW of energy efficiency constructed in 2020 provides savings of 1MWh for every hour in 2020, 0.95MWh for every hour in 2021, 0.9MWh for every hour in 2022, and so forth until 2040 when the energy efficiency measure would expire. Then apply symmetric assumptions to other model years. This 20 year linearly decline in energy efficiency realized is taken directly from the 'GHG Abatement Measures' TSD. The assumption that the energy efficiency applies in every hour of the year was made by EPRI, and designed to maximize the value of energy efficiency while maintaining other EPA assumptions; thus weighting the model in favor of energy efficiency.)
2. Assign a cost to the energy efficiency. The paradox of EPA's energy efficiency costs assumption highlighted in Comment 2 above implies that energy efficiency cost is a non-linear function of quantity. For the purposes of this analysis, EPRI considered two boundary cases. One where all energy efficiency cost \$550/MWh in the first year, and one where all energy efficiency cost \$770/MWh in the first year. Using the assumptions stated above, this equated to \$4641/kW for the \$550/MWh cost, or \$6497/kW for the \$770/MWh. Energy efficiency deployment was limited to EPA assumed limits by year and state.

Using US-REGEN, EPRI created four scenarios (see Appendix A for more details). A reference case with energy efficiency priced at \$550/MWh (Ref-EE550), a reference case with energy efficiency priced at \$770/MWh (Ref-EE770), then the same cases with the constraint that average emissions rate meet the EPA target rate, in other words, an implementation of the Clean Power Plan. Denote these cases as CPP-EE550 and CPP-EE770 respectively.

[60] EPRI Report 3002000128, "US-REGEN Model Documentation", 2013.

Result 1: At $550/MWh, energy efficiency is competitive with other technologies even in the reference case. At $770/MWh, almost no energy efficiency is built in the reference case.

In the Ref-EE550 case, 6.41GWh of energy efficiency 'capacity' (equating to 56TWh in load reductions) was built in 2020 alone. This implies that 6.41GW of new energy efficiency was the least cost option amongst all the other technologies provided for in US-REGEN (such as new renewables, new NGCC, nuclear etc.) In the Ref-EE770 case, no energy efficiency was built until 2045, and then only 1GW of 'capacity' (8.7TWh). This suggests EPA's proposed costs span the range between energy efficiency being competitive with other technologies, and being uncompetitive with other technologies.

A significant portion of EPA assumed energy efficiency was priced at $550/MWh in IPM. This, combined with Result 1, suggests that EPA's estimated costs suffer from a downward bias due to energy efficiency not being modeled in the reference case.

Result 2: At $770/MWh, very little energy efficiency was built under the Clean Power Plan policy after 2020.

In the Clean Power Plan-EE770 case, a little under 2GW of energy efficiency capacity was built in 2020, and no more until 2040. This is well under the EPA proposed quantity of energy efficiency. A significant portion of EPA energy efficiency was priced at $770/MWh in IPM. If this result were replicated in IPM, it would imply total costs were likely overstated, but marginal costs understated for the Clean Power Plan scenarios.

To summarize, EPRI believes that the current modeling of energy efficiency as an exogenous input in IPM causes identifiable biases in the costs. EPRI recommends that energy efficiency be modeled as a technology option that competes against other technologies to meet load, both in the Clean Power Plan scenarios and the reference scenario. EPRI's own implementation may serve as a guide to how this can be done in a capacity investment model. By doing this, EPA would avoid three sources of potential bias in costs as outlined above.

Treatment of Biomass

While EPA recognizes "...that biomass-derived fuels can play an important role in CO_2 emission reduction strategies..." biomass as a renewable fuel is not treated as a non-emitting resource in the proposal's RIA and is therefore disadvantaged as a potential compliance option. This may be because EPA is revising its biogenic emissions GHG accounting framework in response to EPA Science Advisory Board comments (Khanna et al., 2012[61]). This exclusion of biomass-derived fuels as a low- or non-emitting CO_2 resource is inconsistent with the current scientific literature that suggests climate beneficial

[61] Khanna, Madhu, Robert Abt, Morton Barlaz, Richard Birdsey, Marilyn Buford, Mark Harmon, Jason Hill, Stephen Kelley, Richard Nelson, Lydia Olander, John Reilly, Charles Rice, Steven Rose, Daniel Schrag, Roger Sedjo, Ken Skog, Tristram West, Peter Woodbury, 2012. SAB Review of EPA's Accounting Framework for Biogenic CO_2 Emissions from Stationary Sources, September 28, 2012.

U.S. biopower is possible (e.g., Miner et al., 2014,[62] Latta et al., 2013,[63] Daigenault et al., 2012,[64] Sedjo and Tian 2012[65]). EPRI encourages EPA to apply the latest science to develop, with the states, an appropriate GHG accounting framework for biomass as a renewable resource in state compliance plans.

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[62] Miner, Reid A., Robert C. Abt, Jim L. Bowyer, Marilyn A. Buford, Robert W. Malmsheimer, Jay O'Laughlin, Elaine E. Oneil, Roger A. Sedjo, and Kenneth E. Skog, 2014. Forest Carbon Accounting Considerations in US Bioenergy Policy 112.
[63] Latta, G.S., J.S Baker, R.H. Beach, S.K. Rose, B.A McCarl, 2013. "A multi-sector intertemporal optimization approach to assess the GHG implications of U.S. forest and agricultural biomass electricity expansion," Journal of Forest Economics 19(4): 361-383.
[64] Daigneault A, Sohngen B, Sedjo R 2012. Economic approach to assess the forest carbon Implications of biomass energy. Environmental Science & Technology 46(11): 5664–5671. http://dx.doi.org/10.1021/es2030142
[65] Sedjo, R. and X. Tian, 2012. Does wood bioenergy increase carbon stocks in forests? Journal of Forestry110:304 –311.

5. BENEFITS OF THE PROPOSED RULE

5.1 Detailed Comments on Estimated Air Pollution Reduction Benefits

The RIA for the propose rule describes the estimated human health co-benefits associated with reductions in SO_2 and NOx (ambient $PM_{2.5}$ precursors), directly emitted fine particles, and NOx as a precursor of ozone. The RIA quantifies the benefits of reductions in $PM_{2.5}$ and ozone using EPA's BenMAP. The RIA also contains a qualitative discussion of the potential benefits of direct reductions in exposure to NOx, SO_2, mercury, and CO.

EPRI's comments focus on two major topics: (i) limitations of BenMAP; and (ii) appropriateness of calculating benefits of pollutant reductions in populations already meeting the NAAQS for $PM_{2.5}$ and ozone.

Limitations of BenMAP

BenMAP is a complex tool used to evaluate many policy options and air quality planning scenarios in the United States and elsewhere. While it consists of a number of elements, or steps, to estimate benefits from changes in air quality, the focus of EPRI's comments is on the so-called "concentration-response function," or the function that statistically relates health outcomes to an incremental change in pollutant concentration. Specifically, EPRI identified three concerns with BenMAP, which extend to the use of BenMAP in the RIA benefits calculations for the proposed rule.

First, some of the embedded options are limited and inconsistent with the literature. For example, BenMAP includes three PM-mortality concentration-response functions: one each from Krewski et al.[66] and Lepeule et al.[67] for adult mortality, and one from Woodruff et al.[68] for infant mortality. These are taken from the literature, but they do not reflect the totality of the literature. For example, a recent analysis by Smith and Gans[69] surveyed the literature and identified 22 studies containing valid concentration-response functions and identified 59 appropriate risk estimates from these studies. A given study may have multiple valid risk estimates; for example, one can identify four different risk coefficients from Krewski et al. ranging from negative to 0.01. However, BenMAP includes only one of these coefficients (0.0058), which gives the impression of much more precise conclusions from that study than is the case. Overall, the estimates identified by Smith and Gans range from −0.0155 to 0.0255, as shown

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[66] Krewski, D., Jerrett, M., Burnett, R., Ma, E., Hughes, E., Shi, Y., et al. 2009. Extended follow-up and spatial analysis of the American Cancer Society study linking particulate air pollution and mortality. HEI Research Report, 140, Health Effects Institute, Boston, MA.

[67] Lepeule, J., Laden, F., Dockery, D., Schwartz, J. 2012. Chronic exposure to fine particles and mortality: an extended follow-up of the Harvard Six Cities Study from 1974 to 2009. Environ. Health Perspective. 120:965-970.

[68] Woodruff, T.J., Grillo, J., Schoendorf, K.C. 1997. The relationship between postneonatal infant mortality and particulate air pollution in the United States. Environ. Health Perspective. 105:608-612.

[69] Smith, A.E., Gans, W. 2014. Enhancing the characterization of epistemic uncertainties in PM2.5 risk analyses. Risk Analysis., online advance publication; doi: 10.1111/risa.12236.

below in Table 1 extracted from that publication. The impact of choice of risk estimate on resultant calculated benefits is illustrated by reference to a study that used BenMAP to estimate the premature mortality in the United States due to 2005 $PM_{2.5}$ concentrations (Fann et al[70]). This paper estimated an annual 130,000–320,000 premature deaths based on the lowest and highest of the BenMAP risk coefficients. If the range of risk coefficients identified by Smith and Gans is used, the same analysis produces risk estimates ranging from 0 to 516,000 deaths. This is not only much wider but also reveals a chance there is no risk at all.

Table 1. Ranges of Epidemiologically-Based Mortality Risk Coefficients for Long-Term Exposure to $PM_{2.5}$: Our Literature Review Versus Contents of BenMAP's Main Library

Summary	Our Review	BenMAP
Year range	1993–2012	2002–2009
Number of estimates	59	3
Min	−0.0155	0.0058
Max	0.0255	0.0148
Mean	0.0068	0.0088

Note: Risk coefficients are stated as fractional change in annual risk of death per $\mu g/m^3$ of increase in annual average ambient $PM_{2.5}$ concentration.

Second, BenMAP has no simple way to consider uncertainty within its framework. While it does report ranges of benefits, these ranges reflect only the range of the two concentration-response functions used and does not consider any other sources of uncertainty. Sensitivity analyses are one way to address this issue, but they are limited for two reasons. First, alternatives not embedded within BenMAP are not easily considered as part of this analysis. Second, there is no clear way to consider the impacts of simultaneously varying more than one input or assumption into BenMAP at a time. The result of these two issues is that BenMAP can give a misleading impression about the uncertainty associated with a given analysis. In the existing applications, the limited sensitivity analyses give uncertainty ranges that are biased toward suggesting less uncertainty than there probably is. EPRI is currently supporting research to develop an integrated uncertainty analysis that is expected to illustrate the greater policy insights that can be obtained using this approach rather than a set of deterministic calculations as currently exists within BenMAP.

Third, BenMAP offers no provision for considering different species or components of $PM_{2.5}$ despite increasing evidence that some fractions of components of $PM_{2.5}$ may be more highly associated with

[70] Fann, N., Lamson, A.D., Anenberg, S.C., Wesson, K., Risley, D., Hubbell, B.J. 2012. Estimating the national public health burden associated with exposure to ambient PM2.5 and ozone. Risk Analysis. 32:81–95.

health effects than others. For example, Rohr and Wyzga[71] reviewed the epidemiological and toxicological evidence regarding PM composition and health effects and concluded that more scrutiny needs to be given to carbon-containing PM components (elemental and organic carbon), as growing evidence suggests these are most strongly associated with adverse health outcomes.

Benefits Calculated in Areas Meeting NAAQS

Figures 4-4 and 4-5 in the RIA depict, in different ways, the proportion of the U.S. population exposed to $PM_{2.5}$ at various concentrations in the modeling baseline. Both suggest that approximately 95% of the population experiences $PM_{2.5}$ levels that are already at or below the NAAQS of 12 $\mu g/m^3$ before implementation of the proposed rule. Nevertheless, these same populations are included in the benefits calculations, even when the initial exposure is at or below the NAAQS. It is not appropriate for health benefits to accrue at levels of PM that are already deemed to be protective of human health. NAAQS are set at levels that will "protect the public health" with an "adequate margin of safety." The increased use of epidemiological evidence in the NAAQS-setting process has made the determination of the preceding quoted concepts more difficult, since such evidence has not yet clearly identified a threshold below which the risk per concentration unit diminishes and thus could be assumed to be "safe." Thus, uncertainty about the association is the only consideration available for setting a standard above zero. In essence, the NAAQS is set at a level below which the uncertainty in the association becomes too large. However, in RIAs for a variety of regulations, including those which target $PM_{2.5}$ indirectly (such as this proposed rule), the same weights have been given to risks calculated for population exposures below the NAAQS as they do for exposures above this level. An inconsistency therefore exists, with RIAs assuming elevated risk with 100% certainty for all ambient pollutant exposure concentrations below the NAAQS, which is directly at odds with the rationale used to set the standard. Recent EPRI-supported research discusses this inconsistency in more detail (Smith, 2014[72]). Smith's paper provides several quantitative examples that show that, due to inclusion of risks calculated in areas in attainment with the NAAQS, the benefits estimates in RIAs are biased upward from the expected value that can be inferred from the rationale for the NAAQS. This upward bias is even larger for $PM_{2.5}$ co-benefits in RIAs for non-$PM_{2.5}$ regulations. Though not analyzed by Smith (2014), the proposed rule would be one such example.

5.2 Greenhouse Gas Reduction Benefits

This section addresses the development of the USG SCC[73] values and the application of those values in the RIA to estimate the benefits of reducing CO_2 emissions related to the proposed rule. The comments below are based on a recent EPRI report titled "Understanding the Social Cost of Carbon: A Technical

[71] Rohr, A.C., Wyzga, R.E. 2012. Attributing health effects to individual particulate matter constituents. Atmos. Environ. 62:130-152.
[72] Smith, A.E. Inconsistencies in risk analysis for ambient air pollutant regulations. Forthcoming in ***Risk Analysis***, Fall 2014 with a pre-publication copy included in Appendix B.
[73] Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (November 1, 2013). http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.

Assessment."[74] EPRI believes that its comments and recommendations on the USG SCC should be submitted related to this proposed rule because: (i) its research identifies fundamental issues with the USG SCC values, as well as how EPA applied those values, (ii) while USG SCC values already have been used in various federal regulatory proposals, this proposed rule is more significant in terms of estimated GHG reduction benefits, and (iii) EPRI hopes these comments can help improve the understanding of the SCC and transparency in its application.

Assessment of the USG SCC Development

The SCC estimates the monetary value of future incremental climate change impacts. The SCC is complex to compute, and the USG SCC estimates are the result of significant aggregation. Specifically, the USG SCC estimates are the culmination of global socioeconomic, climate, and damage modeling over 300 years and aggregation of results across three models (DICE, FUND, PAGE), over time, across scenarios, and across impact categories and regions. As such, the USG SCC estimates are difficult to interpret and evaluate. Making sense of the USG SCC estimates requires an understanding of these details. The EPRI study sets out to elucidate and assesses the modeling and raw detailed results underlying USG SCC estimation.

The EPRI study models and assess the raw SCC modeling and results—undiscounted and disaggregated to the underlying modeling elements. It evaluates each component of the SCC modeling causal chain — socioeconomics and emissions, climate modeling, and climate damage modeling —characterizing and assessing what was done with diagnostic modeling analysis, comparison, and consideration of alternatives. It also considers the overall USG SCC experimental design. The work aims to improve understanding of SCC modeling and estimates to inform public discussion and facilitate improved SCC analyses and climate change research broadly.

From the assessment, EPRI finds significant variation across models in underlying model structure, behavior and results, and identify fundamental issues and opportunities for improvements. Specifically, EPRI finds a number of issues with the current methodology that suggest the need to revisit the approach and estimates.

Consideration of uncertainty: Uncertainty is paramount when modeling global biophysical and socioeconomic systems for 300 years as is done in the USG SCC approach. Uncertainty is included in the USG SCC modeling via three elements: (i) uncertainties standardized across models (socioeconomics & emissions, climate sensitivity); (ii) model structure uncertainty via the use of multiple models; and (iii) model specific parametric uncertainties. EPRI's assessment suggests that the current approach for each should be re-considered. For the standardized uncertainties, the assessment identifies implementation issues and alternative specifications to consider. For model structure uncertainty, EPRI finds significant differences in responses across models (e.g., climate change, climate damages, and response sensitivity)

[74] EPRI Report 3002004657, "Understanding the Social Cost of Carbon: A Technical Assessment", 2014.

that need to be further evaluated to establish that they are legitimate reflections of uncertainty and, as such, useful information, and not arbitrary differences, or another dimension of uncertainty to formally model. For instance, observed modeling differences, such as sea-level rise formulation, temperature lag, climate feedback, non-CO_2 forcing, and damages included and formulations need to be reviewed to resolve or justify differences, and/or develop a new standardized uncertainty. For model specific parametric uncertainties, EPRI finds substantial inconsistency in the climate change and damage uncertainties considered across models. The models explore very different parametric uncertainty in both components and therefore represent different uncertainty spaces. The USG modeling uses the means from these uncertainties, yet these means do not appear to come from the same statistical population, which is required for averaging. Finally, EPRI finds that there are additional categories of uncertainty to consider in the modeling (e.g., socioeconomic structure, alternative climate modeling, alternative specifications for 2013 revisions, and alternative 2300 extrapolations).

Comparability of results across models: From a diagnostic analysis, EPRI finds significant variation in climate change and climate damage responses across the three models used in the USG SCC approach. Variation that is due to implementation inconsistencies, structural modeling differences, and differences in the uncertainties considered within each model. The substantial differences raise questions about the statistical comparability of the results across models, which is an issue for averaging results across models as is done in the USG SCC approach. Further assessment of the specifications and uncertainties and reconciliation or justification of differences is an essential future activity to insure comparable estimates in the USG's multi-model approach.

Robustness of the USG SCC estimates: Robustness of the USG SCC estimates is potentially an issue given the sensitivity of the models that EPRI observes in its assessment, and that EPRI identifies reasonable alternatives to the current modeling. Robustness was not evaluated in the USG SCC exercise, but would be a useful exercise to provide the public with greater confidence in final SCC estimates. Such an evaluation would test the sensitivity of results to alternatives and develop an experimental design that produces results that are robust to alternatives.

Multi-model approach: From its assessment, EPRI identifies a number of experimental design issues. One in particular is related to the multi-model approach. Averaging results across models requires that the differences in the models be equally legitimate, and results from the different models comparable and independent. However, EPRI's observations regarding differences in modeling, implementation, specification, and application suggest that the models may not be meeting these requirements. For instance, EPRI found a variety of issues that raise questions about the statistical comparability of the results across models. Also, the models are likely not independent given their use of the same climate impacts studies as inputs. Ensuring legitimately different, comparable, independent results across models could be challenging.

Application of USG SCC in the Regulatory Impact Analysis

EPRI also identified methodological issues regarding how the SCC is used within the proposed rule.

CO_2 reductions: The RIA estimates CO_2 benefits by multiplying the USG SCC values by estimated CO_2 reductions. The emission reduction benefits are estimates for CO_2 emissions changes within the power sector only. This is problematic because the SCC should only be applied to estimated net changes in global CO_2 emissions. The SCC is the marginal value of an incremental change in global CO_2 emissions. Therefore, regulatory analysis applications should be sure to estimate changes in net global emissions associated with a proposed rule, or justify why it is unnecessary. The proposed rule may have emissions implications beyond the boundaries of the power sector (i.e., "leakage"), and those effects should be accounted for to properly estimate CO_2 benefits.

Inconsistency in CO_2 benefit and cost calculations: EPRI notes two fundamental inconsistencies in the RIA's cost-benefit comparisons of estimated CO_2 benefits and compliance costs. These inconsistencies need to be corrected for proper comparison of benefits and costs.

- Levelized costs vs. annual CO_2 benefits – The RIA compares levelized (or annualized) compliance costs to annual CO_2 benefits. This is an inconsistent comparison with no practical meaning. The proper comparison is a comparison of the net present value streams of fixed and variable compliance costs and estimated benefits (both for CO_2 and air pollution reductions).
- Reference scenario assumption inconsistency – The proposed rule's base case is inconsistent with the socioeconomic/emissions scenarios used in the SCC calculations. Specifically, the U.S. CO_2 emissions, energy system, and economic condition underlying the estimated CO_2 reductions and compliance costs are inconsistent with the socioeconomic and emissions futures underlying the USG SCC estimates used to value the proposed rules CO_2 reduction benefits. The SCC estimates are computed using five alternative global socioeconomic and GHG emissions futures designed to span a range of possible global futures, with each future considered equally likely. Compliance costs and CO_2 reductions in the RIA, on the other hand, assume a single, U.S. power sector projection (based on the AEO 2013 Reference Case). This is an issue because the underlying USG modeling shows that SCC values vary across socioeconomic and emissions assumptions (USG, 2014). Therefore, one would want the same reference case assumptions for the SCC, CO_2 reductions, and compliance costs, or an argument for why it is unnecessary. Comparing the USG SCC and AEO2013 Reference Case socioeconomic and emissions projections, EPRI finds that the AEO2013 projections do not compare well with any of the USG SCC input scenarios, with lower projected U.S. energy sector CO_2 emissions and higher GDP that are based on much lower assumptions regarding the emissions and energy intensity of output (CO_2/GDP and Btu/GDP respectively). This is just for the U.S., so it is difficult to speculate on the implications of using consistent reference assumptions without a global context.

Guidance on use of the different SCC values: The USG SCC technical documentation recommends using all four of the USG time profiles of SCC values. The four have meaningful differences in discounting and what they represent probabilistically. However, there is no USG guidance on how agencies should apply the different SCC values jointly and consistently in rulemaking.

Recommendations regarding the USG SCC and CO_2 benefits estimates

Based on EPRI's technical assessment of the USG SCC modeling and estimates and evaluation of the application of the SCC in the proposed rule CO_2 benefits estimates, EPRI finds that there are a number of opportunities for improving the proposed rule's CO_2 benefit and overall cost-benefit analyses and offer the following recommendations:

SCC estimation

- Internal review of modeling – A detailed review of modeling differences, alternatives, and uncertainties represented would be beneficial to resolve or justify differences, improve comparability and uncertainties represented, and enhance robustness.

- Revisit experimental design – EPRI finds a number of experimental design improvement opportunities related to implementation inconsistencies, standardized uncertainties, model specific uncertainties, and multi-model application. Given the challenges associated with a multi-model approach, including inconsistencies, comparability, and independence, a new framework would also be a practical consideration.

- Peer review of application and models – The USG SCC approach to estimating SCC values is novel. The approach utilizes estimates from three models with specific specifications for standardized and model specific uncertainties and a results aggregation scheme. External peer review of the modeling framework (models, runs, aggregation); uncertainties (standardized, model specific, and specifications); and other elements would lead to improved methods and provide the public with greater confidence in the resulting estimates. Explicit peer review of the individual models would also be practical as is commonly done for other models used for regulatory processes, for example IPM used in the proposed rule's RIA.

- Evaluate robustness – It would be useful to evaluate the robustness of the USG SCC estimates to alternatives to establish confidence in the final estimates. In particular, a fuller characterization and discussion of uncertainty, and a subsequent analysis of robustness, would provide the analysts, and the public, with greater confidence in the estimates produced and the stability of those estimates.

SCC application in the proposed rule

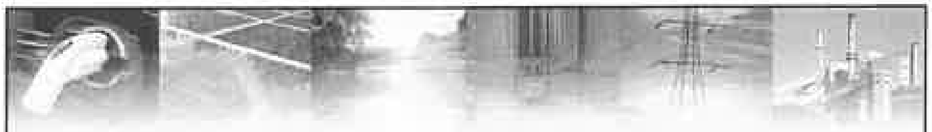
- Calculate global CO_2 changes – Estimates of global CO_2 changes associated with the rule are required for proper use of the SCC for CO_2 reduction benefits calculations.

- Resolve inconsistencies in cost and CO_2 benefit comparison – Inconsistencies in the estimated compliance costs and CO_2 benefits need to be resolved for proper comparison.

- Provide application guidance – Guidance regarding use of the four USG SCC estimates is needed.

APPENDIX A

Example analysis of endogenous energy efficiency with the US-REGEN Model.



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Modeling Endogenous Energy Efficiency in US-REGEN

David Young & Victor Niemeyer
Energy and Environmental Analysis Group
September 30, 2014

Introduction

- Goal of this slide deck is to demonstrate how the modeling endogenous energy efficiency impacts the potential deployment of energy efficiency under a reference scenario, and under a scenario that approximately mimics the Clean Power Plan – Option 1
- EPA assumes no energy efficiency appears in the reference scenario versus a 1.5% per annum penetration after 2020 in the CPP scenario
- US-REGEN modeling results suggest this is not a cost minimizing outcome at the range of costs assumed by EPA, when energy efficiency is modeled endogenously

EPRI

Reference Assumptions

- Starting point for this analysis is EEA 2014 reference case, which includes
  - AEO2014 demand and fuel prices
  - No forced retirements for existing coal units
  - Limitations on new transmission and nuclear builds
  - Technology costs per EPRI Generation Options report
  - Includes state RPS, MATS, CWA § 316(b), RCRA CCR, and CAA § 111 (b) CO_2 performance standards for *new fossil units* but not for modified and reconstructed units
  - CA AB32, RGGI, WA/OR state CO_2 policies

Energy Efficiency Assumptions

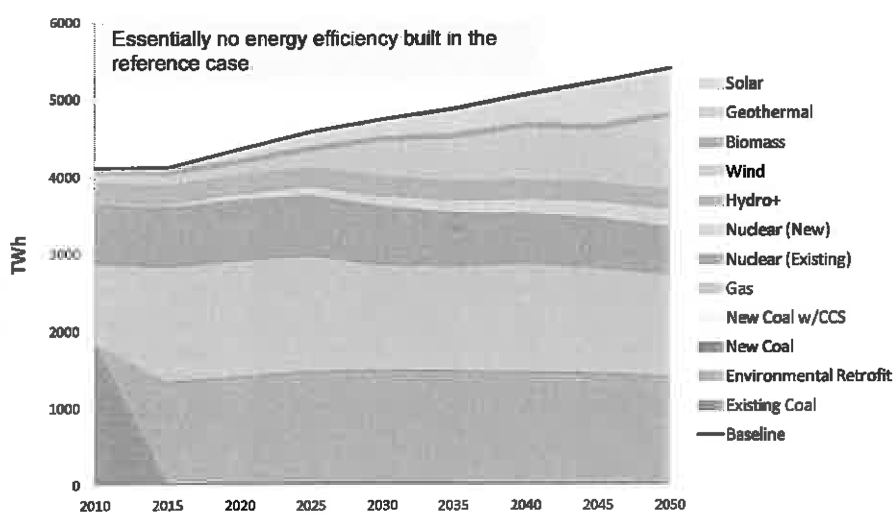
- EPA target rates assume a certain level of EE by state, at a first-year cost of between $550-$770/MWh
  - EE investment made in one year will endure for 20 years, with associated annual MWh reductions linearly declining to zero over that time

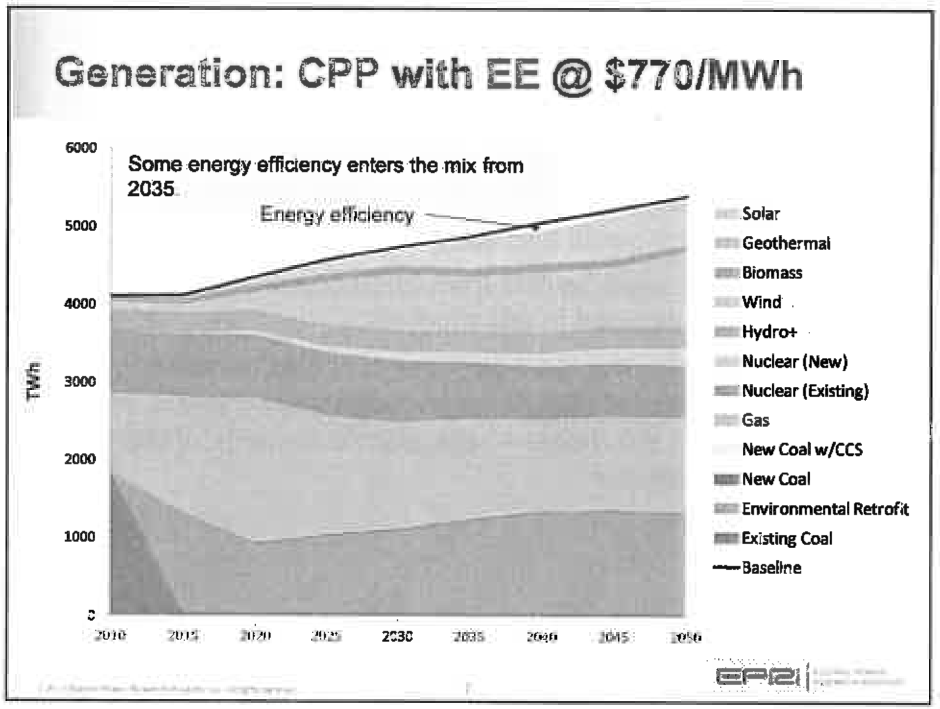
- We assume EE costs either all $550/MWh or all $770/MWh and let the model choose whether to use it, or to use other technologies
  - Also fix maximum quantity of EE by year at EPA target setting assumptions

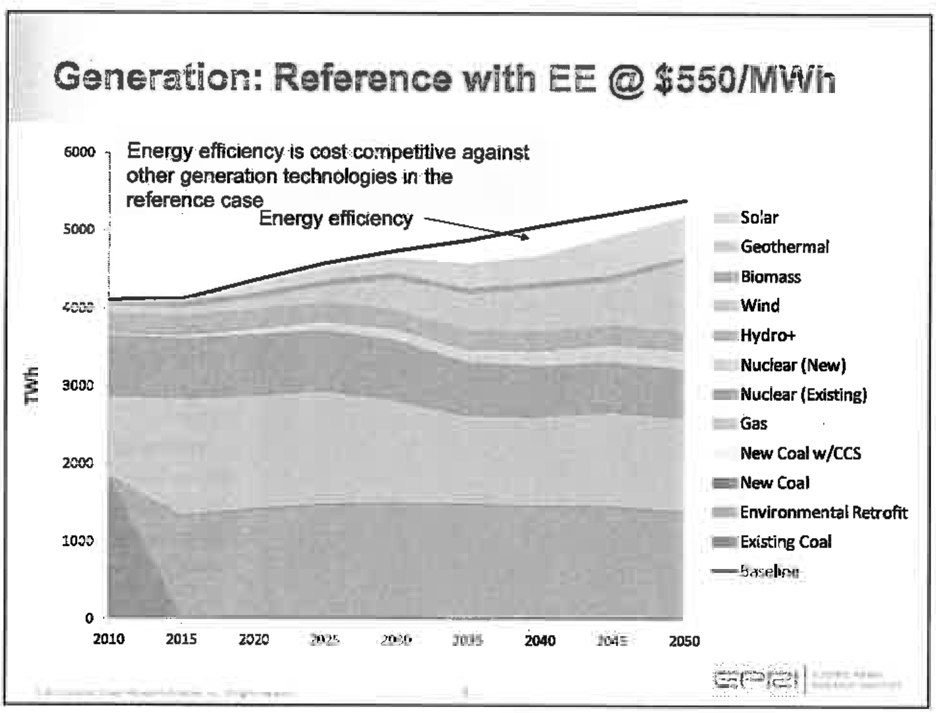
CPP Assumptions

- Rate-based targets by US-REGEN region
  - EPA state targets recalculated for US-REGEN regions using EPA's formula and data
  - Target rates must be met from 2020 onwards – no averaging assumed in this analysis
- Analysis looks for the least cost path to meet the EPA BSER emissions rate target given technology options implemented in the model – actual state implementation may be very different

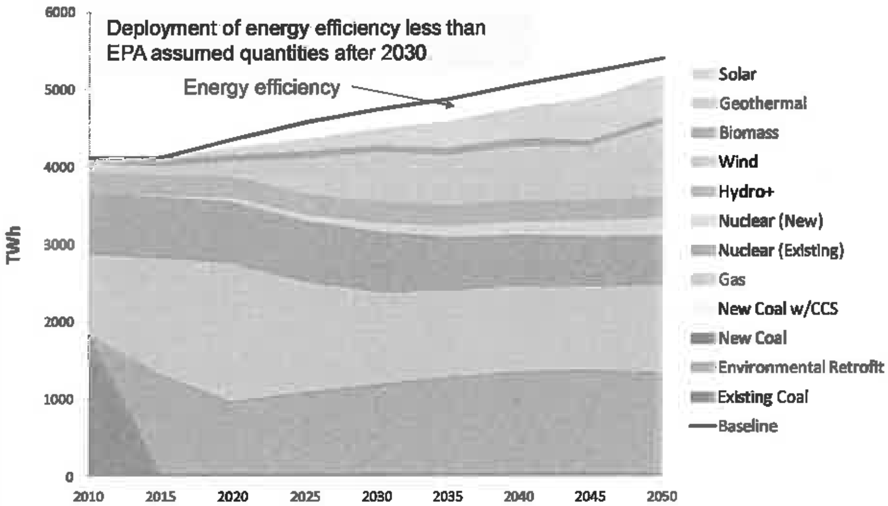
Generation: Reference with EE @ $770/MWh




Generation: CPP with EE @ $770/MWh
Some energy efficiency enters the mix from 2035
Energy efficiency
6000
5000
4000
3000
2000
1000
TWh
2010
2015
2020
2025
2030
2035
2040
2045
2050
Solar
Geothermal
Biomass
Wind
Hydro+
Nuclear (New)
Nuclear (Existing)
Gas
New Coal w/CCS
New Coal
Environmental Retrofit
Existing Coal
Baseline
EPRI


Generation: Reference with EE @ $550/MWh
Energy efficiency is cost competitive against other generation technologies in the reference case
Energy efficiency
6000
5000
4000
3000
2000
1000
0
TWh
2010
2015
2020
2025
2030
2035
2040
2045
2050
Solar
Geothermal
Biomass
Wind
Hydro+
Nuclear (New)
Nuclear (Existing)
Gas
New Coal w/CCS
New Coal
Environmental Retrofit
Existing Coal
Baseline
EPRI

Generation: CPP with EE @ $550/MWh



Observations

- Little deployment of energy efficiency at the $770/MWh cost mark in either the reference or CPP scenarios
- Greater penetration of energy efficiency at the $550/MWh cost mark, both in the CPP scenario and the reference scenario
- Results suggest that an assumption of no energy efficiency in the reference and large scale deployment of EE in the policy case are not cost-minimizing outcomes at either cost point

Further Reading

- US-REGEN Homepage
  http://eea.epri.com/models.html
- US-REGEN Documentation
  http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000128

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APPENDIX B

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INCONSISTENCIES IN RISK ANALYSES FOR AMBIENT AIR POLLUTANT REGULATIONS

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INCONSISTENCIES IN RISK ANALYSES FOR AMBIENT AIR POLLUTANT REGULATIONS

ABSTRACT

This paper explores a conceptual issue fundamental to the risk analyses that the U.S. Environmental Protection Agency (EPA) uses to support its decisions on revisions to primary National Ambient Air Quality Standards (NAAQS). Quantitative risk estimates are prepared as part of the NAAQS-setting deliberations, using inputs derived from epidemiological studies of statistical associations between criteria pollutant concentrations and health effects incidences. These quantitative risk estimates are not directly used to set a NAAQS, but are incorporated into a broader risk-based rationale for the standard that is intended to conform to the legal requirement that a primary NAAQS "protect the public health" with "an adequate margin of safety." In a separate process, EPA staff relies on the same epidemiologically-based risk calculations to prepare its estimates of the benefits of the rulemaking that are provided in its Regulatory Impact Analyses (RIAs) for the NAAQS standard. This paper describes a logical inconsistency between the risk-based rationale used to set each primary NAAQS and the estimates of the benefits from that NAAQS that appear in the RIAs for that rulemaking. The paper provides quantitative examples based on the 2012 revision of the fine particulate matter ($PM_{2.5}$) primary NAAQS, and the 2011 Mercury and Air Toxics Standards. The examples show that, due to inclusion of risks calculated in areas that are already in attainment of the $PM_{2.5}$ NAAQS, RIAs' benefits estimates are biased upward from the expected value that can be inferred from the rationale for the NAAQS. The upward bias is even larger for $PM_{2.5}$ co-benefits in RIAs for non-$PM_{2.5}$ regulations.

Keywords: Risk Analysis, $PM_{2.5}$, Epidemiology, Co-benefits

1. BACKGROUND

When the first $PM_{2.5}$ NAAQS was established in 1997, the principal basis for it was epidemiological evidence and quantitative risk analyses based on that evidence. Quantitative risk analyses based on epidemiological evidence have continued to be a central feature of the review process for revisions of the $PM_{2.5}$ NAAQS since then, and have also been incorporated into revisions of NAAQS for ozone, nitrogen dioxide (NO_2) and sulfur dioxide (SO_2). This paper focuses on a logical inconsistency between the rationale that EPA Administrators use for setting a NAAQS when relying primarily on epidemiologically-based risk evidence, and the estimates of benefits from those rules that EPA staff produces in its RIAs.[1]

2. THE RATIONALE FOR SETTING A PRIMARY NAAQS

The Clean Air Act requires EPA[2] to set a primary NAAQS for each criteria pollutant at levels that will "protect the public health" with an "adequate margin of safety."(1) This determination must be made without regard to cost of meeting the standard.(2) Prior to the 1997 $PM_{2.5}$ NAAQS rules, the rationale for choosing the NAAQS involved a balanced consideration of size of affected population, severity of effect, and certainty of effect. However, the evolution since 1997 to greater use of epidemiological evidence in setting a NAAQS forced a change in how the rationale could be constructed. This was because the available epidemiological evidence for several clearly adverse types of health effects due to $PM_{2.5}$ (such as premature death) did not identify any level of pollutant concentration where the risk per increment of concentration

[1] A separate point of discussion regarding the quantitative risk estimates is whether the full body of scientific evidence is sufficient to give confidence that these epidemiological associations reflect a causal relationship between the pollutant and health endpoint studied. This article notes but does not attempt to add to that discussion.

[2] Formally under the Clean Air Act, the responsibility for deciding where to set a NAAQS is vested in the Administrator. In this article, I use "EPA" to refer to the EPA Administrator, and "EPA staff" to refer to actions or analyses of the agency staff.

appears to diminish – colloquially called an effects "threshold."[3] This situation eliminated two of the three considerations that had typically been incorporated into NAAQS-setting rationales: the severity of effect is unchanging and the entire U.S. population is implicated as at-risk as the potential NAAQS level is lowered.

As a result, uncertainty about the reliability of the association became the only consideration available for setting a primary NAAQS anywhere above zero that can be argued to be adequately protective of the public health as required by the statute. Although the evidence developed for the NAAQS review includes quantitative estimates of health effects that continue without diminution down to zero concentration levels, EPA makes a case that expanding scientific uncertainty about the quantitative assumptions employed in those risk calculations ultimately becomes so large that one can consider the public health to be adequately protected, albeit not "risk-free," at a non-zero level. That non-zero level is then set as the NAAQS. This rationale for dealing with the no-threshold situation was deemed legally valid by the Supreme Court in 2001.[(2)]

Thus, the rationale for the $PM_{2.5}$ primary NAAQS decision (and for several other criteria pollutants set since 1997) has been *ad hoc* reasoning about where within the range of observed exposure levels the continued existence of the statistical association becomes too uncertain to represent a public health concern. Although the written rationale does not use the terminology of probability or expected values, it is readily interpreted as the expression of a subjective judgment

[3] Even if one is confident that the association is causal over some part of the range of data studied, the types of epidemiological studies in use have very limited ability to reliably discern the shape of a potential concentration-response relationship, and thus to inform the question of where or whether the association may end. Indeed, it is theoretically established that unavoidable inaccuracies in measurement of the explanatory factor variable (i.e., the pollutant) will make it difficult to statistically detect a threshold or other non-linearity at low concentrations that may actually exist (see Ref. 3).

regarding the probability that the apparent mortality relationship ceases to exist at different levels of ambient pollutant concentrations. Given that the size of the affected population and the severity of the effect are maximal in the case of all-cause mortality risk, the implied subjective probability that the relationship exists at the selected NAAQS level must, logically, be essentially zero. Indeed, the probability that the health effects association is present must fall to nearly zero at an ambient concentration somewhere above the selected NAAQS level, because that level needs to include a margin of safety below the point of no further expected risk to the public health.

3. THE RESULTING LOGICAL INCONSISTENCY IN BENEFITS ESTIMATES FOR A NAAQS

Thus, in setting a NAAQS using epidemiological evidence, quantitative estimates of health risks for concentrations below the NAAQS are deemed far less reliable and more inaccurate than the numerical precision with which they are reported. In essence, the quantitative risk estimates at levels below the selected NAAQS are given zero weight in EPA's judgment. However, this lack of confidence in such risk estimates has not made its way into the RIAs that accompany the release of the rule.

RIAs are documents that report on the benefits and costs of each major new regulation, such as a revised NAAQS. Federal regulatory agencies are required to prepare RIAs;[4,5] however, they have no connection to the legal requirements of the statute that motivates the regulation, such as the Clean Air Act in the case of air pollutant regulations. Nevertheless, as the NAAQS review process shifted towards use of quantitative risk analyses, the same epidemiologically-based method of quantifying health risks from ambient $PM_{2.5}$ to produce benefits estimates was adopted in $PM_{2.5}$ RIAs.[4] However, at the same time that EPA was setting NAAQS at levels where there is minimal confidence that the public health is affected at lower concentrations, the RIAs have been giving the same weight to risks calculated for population exposures below the NAAQS level as they do to risks calculated for population exposures above the NAAQS level. That is, RIAs assume elevated hazards exist with 100% certainty for all ambient pollutant exposure levels down to a zero concentration, inconsistent with the judgments formed in regulating those pollutants.

The fact that RIAs calculate risk reductions below the NAAQS, and effectively down to zero, is widely known. Using quantitative examples, this paper illustrates the extent to which this practice results in upward-biased risk and benefits estimates relative to the logic on which the various NAAQSs are set. This author recommends that that EPA staff more clearly communicate uncertainty in its risk estimates, and report central benefits estimates that are consistent with the subjective judgments of the standard setting process.

4. OVERSTATEMENT OF EXPECTED BENEFITS OF THE 2012 $PM_{2.5}$ PRIMARY NAAQS REVISION

The implications of this inconsistency are illustrated using as an example the RIA for the 2012 PM NAAQS rulemaking.[(6)] In this rulemaking the annual primary standard for $PM_{2.5}$ was tightened from an annual average of 15 $\mu g/m^3$ to 12 $\mu g/m^3$. In the associated RIA, a range of 460 to 1000 fewer premature deaths per year was estimated from tightening the standard to 12 $\mu g/m^3$ by applying two different concentration-response functions to the Agency's standard risk calculation formula. The concentration-response coefficient for the lower end of the range was

[4] While the "benefits" in an RIA are stated as a monetary value to be compared to the regulation's costs, they are directly derived from quantitative estimates of physical health effects.

derived using a coefficient from Krewski *et al.* (2009),[7] and the upper end of the range was derived using a coefficient from Lepeule *et al.* (2012).[8] A wider range of uncertainty than this range in potential mortality risk reductions exists,[9] but the following discussion addressed only how the Agency's selected range changes when the assumptions of the RIA's risk analysis are reconciled with the logic for the setting of the standard.

Calculations were performed using the BenMAP model.[10] We obtained from Agency staff the air quality input files that had been used for the RIA's calculations. Using those data, we confirmed that BenMAP does indeed produce the RIA mortality reduction estimates. We then used the data to assess the portion and location of the RIA's premature mortality estimates that are associated with reductions in baseline $PM_{2.5}$ below the selected NAAQS. We found that 70% of the benefits for the standard of 12 $\mu g/m^3$ were due to reductions in $PM_{2.5}$ from baseline levels that were already below the selected NAAQS level.

Given that the choice of a NAAQS level of 12 $\mu g/m^3$ meant that EPA assigned too little confidence in the continuation of health effects below 12 $\mu g/m^3$ to warrant setting the NAAQS at a lower level, standard risk analysis would assign negligible probability to calculations of benefits from reductions that would be occurring from levels below that NAAQS. That is, the *expected* values for 70% of the Agency's risk calculations should be approximately zero. When reductions from $PM_{2.5}$ levels already below 12 $\mu g/m^3$ are given zero weight in the expected benefits calculation, BenMAP calculates that the expected benefits of that NAAQS would be 138 to 313 reduced premature deaths per year, considerably lower than the 460 to 1000 deaths reported in the RIA.

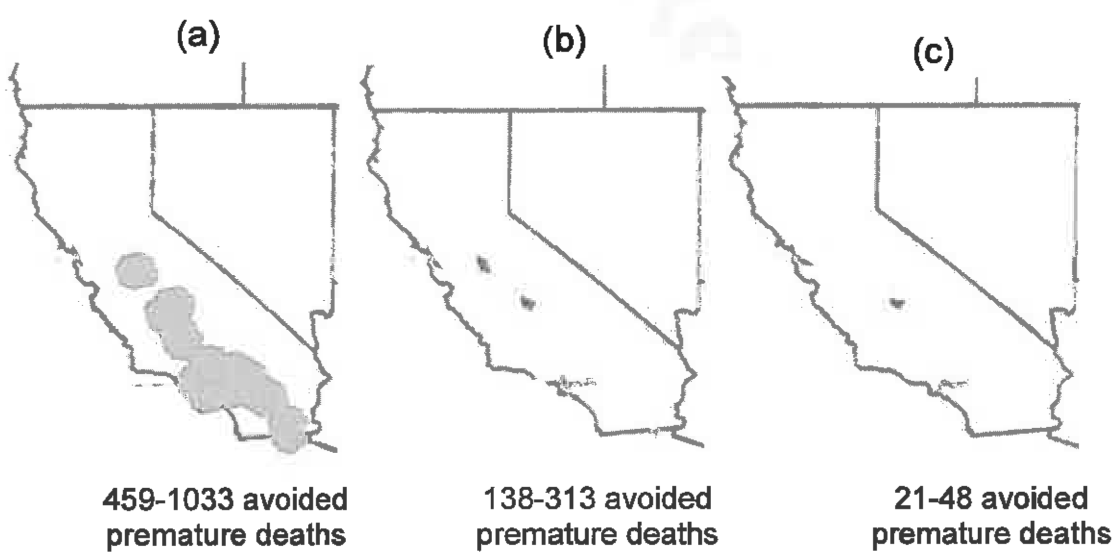
As noted above, the rationale for the NAAQS arguably implies that some of the benefits derived from areas with concentrations just above 12 $\mu g/m^3$ also should be given less than 100% weight, taking into account EPA's assurance that exposures to annual average concentrations of 12 $\mu g/m^3$ are protective *with an adequate margin of safety*. If, for example, the margin of safety is taken to be about 1 $\mu g/m^3$, and risks calculated for pollutant reductions occurring in areas below 13 $\mu g/m^3$ are also given zero weight, BenMAP calculates the expected benefits associated with the selected NAAQS of 12 $\mu g/m^3$ are only 21 to 48 deaths, less than 5% of the RIA's estimate of benefits from that standard.

Whether the particular probability weights used in this analysis are correct, or should be refined, the point of this analysis is that the RIA's benefits estimates are extremely sensitive in the downward direction to any such weighting.

Geographical representation of where these health benefits are expected to occur is also interesting to explore. The reductions in premature mortality were calculated only for areas that were within 50 km of a monitor that the RIA's air quality analysis projected would not attain each alternative standard under baseline conditions in the year 2020. Figure 1 shows the areas in which the RIA's estimate of 460-1000 avoided premature deaths occur. It is notable that all of those benefits occur in California, a point discussed later. Figure 2 zooms in on California to show: (a) the areas in Figure 1 where benefits are attributed to reductions in $PM_{2.5}$ at any level; (b) the more limited areas projected to experience a health benefit when only reductions in $PM_{2.5}$ that start above the 12 $\mu g/m^3$ NAAQS are considered; and (c) the even more limited areas if a 1 $\mu g/m^3$ margin of safety is assumed to be associated with the selected standard of 12 $\mu g/m^3$. That is, Figure 2(c) only gives weight to risks below 13 $\mu g/m^3$.

Figure 1. Areas Projected to Experience Health Benefits under the Selected NAAQS of 12 $\mu g/m^3$ in the $PM_{2.5}$ NAAQS RIA (459-1033 avoided premature deaths, rounded to nearest death)

Figure 2. Sensitivity Analysis of Areas Projected to Experience Health Benefits under the 12 $\mu g/m^3$ NAAQS: (a) Assuming benefits for all baseline $PM_{2.5}$ levels; (b) Assuming risks exist only if baseline $PM_{2.5}$ is above 12 $\mu g/m^3$; (c) Assuming risks exist only if baseline $PM_{2.5}$ exceeds the selected standard by more than 1 $\mu g/m^3$.



This example from the $PM_{2.5}$ NAAQS RIA brings to light another important uncertainty in its mortality benefits. All of the benefits estimates for the NAAQS of 12 $\mu g/m^3$ are based on $PM_{2.5}$ changes in California. The risk calculations for changes in $PM_{2.5}$ in California are performed using relative risk estimates derived from the entire U.S., yet the epidemiological evidence that an association between $PM_{2.5}$ and all-cause mortality risk association exists in California is tenuous.[5] Hence all of the risk estimates above, even if one does not wish to discount risks in areas already below the NAAQS, might actually be zero. The new $PM_{2.5}$ NAAQS was set on the basis of projected mortality reductions that occur only in a part of the U.S. where the evidence of heightened mortality risk from $PM_{2.5}$ appears to be weaker than for associations in other parts of the U.S.

5. OVERSTATEMENT OF $PM_{2.5}$ CO-BENEFITS IN NON-$PM_{2.5}$ RULEMAKINGS

Epidemiologically-based estimates of co-benefits from coincidental reductions of ambient $PM_{2.5}$ have also driven statements about regulatory benefits for a majority of non-$PM_{2.5}$ air rulemakings in recent years.(11) The upward bias in RIA benefits estimates becomes even more pronounced when co-benefits are calculated from coincidental $PM_{2.5}$ reductions from regulations that do not relate to the PM NAAQS or regulations to help attain that NAAQS. A prominent example is the Mercury and Air Toxics Standards (MATS) for electricity generating units.(12)

[5] The $PM_{2.5}$ RIA (6) cites seven California-specific $PM_{2.5}$ cohort studies with all-cause risk estimates and notes that four have insignificant associations while three have larger coefficients (at p. 5.A-13). However, one of the three positive findings cited (i.e., Ostro, et al, 2010) was erroneous, according to an erratum published the following year (Ostro et al., 2011), and the corrected estimate of association was found to be insignificant. The remaining two positive findings cited were from the same cohort, but with an updated analysis. Thus, the evidence for an all-cause mortality association in California alone consists of four null findings and one cohort with a positive finding.

Promulgated in December 2011, the MATS RIA projected $PM_{2.5}$ co-benefits in the hundreds of billions of dollars per year, based almost entirely on estimates of reduced premature mortality from reductions in $PM_{2.5}$: 4,200 to 11,000 deaths per year. The reductions in $PM_{2.5}$ in the MATS RIA are projected to occur when generating units are forced to install controls to reduce acid gas emissions, which will also reduce SO_2 emissions, a precursor to ambient $PM_{2.5}$ formation. A figure in the MATS RIA reveals that over 99% of those projected benefits are projected to occur in areas where the $PM_{2.5}$ levels will already be below the $PM_{2.5}$ NAAQS of 12 $\mu g/m^3$ (Figure 5-15 on p. 5-105 of Ref. 12). If the MATS rule's co-benefits are calculated probabilistically, accounting for the very low subjective probability that EPA assigned to the existence of the $PM_{2.5}$-health effects relationships at levels below the NAAQS, the resulting estimate of expected benefits from the MATS rule becomes nearly zero.

It is notable that the fraction of $PM_{2.5}$ co-benefits calculated below the NAAQS is much higher than the already-high level of 70% that we have found for the benefits calculated for the NAAQS rule itself. This is due to the fact that benefits in the RIA for the NAAQS rule were calculated only in areas within 50 km of a monitor that was projected to be out of attainment. By letting projected non-attainment constrain the geographical area over which benefits will be calculated, one ensures that a larger fraction of the resulting benefits will indeed be from areas above the NAAQS. However, when co-benefits of some other rule are assessed using $PM_{2.5}$ risk relationships, no such constraint is applied. In the MATS rule, co-benefits were calculated across the entire nation, and furthermore, the units where acid gas controls were incremental to baseline controls were more likely to be in areas already attaining the NAAQS. As a result, nearly all of the $PM_{2.5}$ co-benefits are projected in NAAQS-attaining areas. For these reasons, the bias in $PM_{2.5}$ co-benefits estimates in RIAs for non-$PM_{2.5}$ rulemakings will tend to be much greater than the bias in the direct benefits estimates in RIAs for $PM_{2.5}$ regulations.

6. CONCLUSION

In conclusion, we find that a large majority of the Agency's estimated health benefit from the 2012 $PM_{2.5}$ NAAQS are attributable to reductions of $PM_{2.5}$ in areas that are already in attainment of the $PM_{2.5}$ NAAQS. RIA calculations of risk reduction in areas already attaining the new NAAQS are given the same weight (i.e., implicit subjective confidence level) as projected benefits from areas that would be exceeding the NAAQS. This RIA calculation is based on assumptions that are inconsistent with the rationale for that NAAQS. The above sensitivity analyses show that the upward bias in RIAs' benefits estimates is large compared to estimates of expected benefits. The upward bias is even larger for co-benefits from $PM_{2.5}$ in RIAs for non-$PM_{2.5}$ regulations.

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Appendix F:

FERC House of Representatives Subcommittee Transcript

This is a preliminary, unedited transcript. The statements within may be inaccurate, incomplete, or misattributed to the speaker. A link to the final, official transcript will be posted on the Committee's website as soon as it is available.

RPTS ZAMORA

DCMN HUMKE

FERC PERSPECTIVES: QUESTIONS CONCERNING EPA'S PROPOSED CLEAN POWER PLAN AND OTHER GRID RELIABILITY CHALLENGES

TUESDAY, JULY 29, 2014

House of Representatives,

Subcommittee on Energy and Power,

Committee on Energy and Commerce,

Washington, D.C.

The subcommittee met, pursuant to call, at 10:01 a.m., in Room 2123, Rayburn House Office Building, Hon. Ed Whitfield [chairman of the subcommittee] presiding.

Present: Representatives Whitfield, Shimkus,Pitts, Burgess, Latta, Olson, Gardner, Kinzinger, Griffith, Barton, Upton (ex officio), Rush, McNerney, Tonko, Yarmuth, Green Capps, Doyle, Barrow, Matsui, and Waxman (ex officio).

Staff Present: Nick Abraham, Legislative Clerk; Gary Andres, Deputy Staff Director; Charlotte Baker, Deputy Communications Director; Sean Bonyun, Communications Director; Matt Bravo, Professional Staff Member; Leighton Brown, Press Assistant; Allison Busbee, Policy Coordinator, Energy and Power; Annie Caputo, Professional Staff Member; Patrick Currier, Counsel, Energy and Power; Tom Hassenboehler, Chief Counsel, Energy and Power; Brandon Mooney, Professional Staff Member; Mary Neumayr, Senior Energy Counsel; Chris Sarley, Policy Coordinator, Environment and Economy; Jeff Baran, Staff Director for Energy and Environment; Phil Barnett, Staff Director; Caitlin Haberman, Policy Analyst; and Alexandra Teitz, Chief Counsel for Energy and Environment.

Mr. Whitfield. I would like to call the hearing to order this morning.

And certainly want to thank all of the FERC commissioners for joining us at this morning's hearing in which we are going to get your perspectives on questions relating to EPA's proposed Clean Power Plan and its impact on reliability, as well as other challenges. I know that you all have a very busy schedule, and we do appreciate very much your being with us this morning to explore this very important issue.

At this point, I would like to recognize myself for 5 minutes for an opening statement. As I said, this is our second hearing on EPA's proposed Clean Power Plan, which would change the way electricity is generated, transmitted and consumed in each State.

Our first hearing focused on the EPA itself, and I must say that it was obvious from that hearing that EPA does not have the expertise on the intricacies of electric markets and reliability implications of this radical transformation that they are proposing for electrical generation, the electric generation sector.

As I noted before, we are also seriously concerned with this proposed rule; for one thing, EPA's unprecedented use of the Clean Air Act is questionable on legal grounds. Legal experts, and we always know there is conflicting legal experts, but many legal experts see nothing in the Clean Air Act that empowers EPA to commandeer State decisionmaking authority over how each State produces, delivers and uses electricity.

The EPA is also embarking on a comprehensive effort to Federalize electric generation, even though the Agency, as I said, has absolutely no energy policy setting authority or expertise. That is why it is important today to hear from the Federal body that actually does have that authority and expertise. Although, I might add that the top-down command and control efforts of EPA go far beyond even FERC's jurisdiction.

As a preliminary matter, I would like to better understand FERC's level of participation in this proposed rule. Is FERC an equal partner with EPA, a junior partner or hardly a partner at all in promulgating this rule? And what would be FERC's role in implementing this rule? We are also interested in tapping into FERC's considerable expertise on electric reliability. As I suspect, many reliability concerns with this proposed rule that have not been considered by EPA.

As it is, the Agency has already promulgated a number of different rules that have contributed to coal-fired power plant shut downs. This proposed rule would lead to more of the same. So we are interested in learning from FERC whether it believes coal-using states can abruptly and quickly move away from this base-load source without raising significant reliability concerns.

I am also worried by many of the assumptions of EPA that they make as to how States can meet electricity demand while complying with the rule. For example, the Agency suggests that States can easily ramp up natural gas-fired generation to help meet the target goals, but we know from the experience of last winter that several regions of the country have natural gas pipeline capacity constraints.

Similar questions about EPA's optimistic assumptions regarding the ability of renewables to help fill the void, especially given the many challenges that come with integrating intermitted resources into the grid. And the limitations of renewables will be exacerbated, if affordable and reliable base loads supplies, like coal and nuclear and even natural gas, face a constrained future as they do under the Obama Administration.

Overall, we see great risk in EPA trying to overrule the State's choices as to the best electricity mix as well as risk in constraining a State's ability to change its generation portfolio and as you know, at a certain timeframe within this proposed rule, States can't change, even if they might want to. So EPA's proposed efforts dictating electricity use is quite troubling. This is an area where the reach of the Federal Government has been limited, and for good reason, since these local resources decisions are best left to States.

So we look forward to your testimony today. I know we have a lot of questions for you, and certainly, as I said, you all have the expertise and we look forward to your opening statements.

And with that, I would at this time recognize the gentleman from Chicago, Mr. Rush, for his 5-minute opening statement.

[The prepared statement of Mr. Whitfield follows:]

******** COMMITTEE INSERT ********

Mr. Rush. I want to thank you, Mr. Chairman, for holding this important hearing on FERC perspectives, questions concerning EPA's proposed Clean Power Plan and other grid reliability challenges.

Mr. Chairman, as the title suggests, we are here today to hear from the FERC commissioners on the impact that we can expect President Obama's Clean Power Plan to have on a variety of issues related to fuel diversity, the integration of variable energy resources, natural gas, electricity generation and grid reliability, among many other topics.

Mr. Chairman, last month, this subcommittee heard testimony from Acting Assistant Administrator of the Office of Air and Radiation, Janet McCabe, that in developing the Administration's Clean Power Plan, EPA consulted on reliability-related issues with DOE, FERC, State, public utility commissioners as well as the Independent System Operators Regional Transmission Organization Council.

In fact, when determining the best system of emission reduction, or BSER, reliability was one of the key factors that EPA considered and the Agency made sure to allow flexibility for States to design and implement their own programs in order to ease pressure on the system reliability.

Additionally, Mr. Chairman, the EPA proposed to give States a 10-year period to achieve their final goals, which allows for measures to be phased in to ways that protect reliability. But why is it so important that we act at all? Well, Mr. Chairman, a series of assessment reports have come out recently, including the third national climate assessment, the fifth intergovernmental panel on climate change assessment, the EPA's climate change indicators in the U.S. 2014, and the bipartisan risky business, the economic risk of climate change in the U.S.

Each of these reports highlights the devastating consequences of climate change on both public health and the environment, and each urging policymakers, you and I, Mr. Chairman, to act. And what have we learned from all of these telling studies, Mr. Chairman? We have learned that 7 of the 10 top warmest years on record have occurred since 1998 and dangerous heat waves have become more and more frequent.

We have learned that extreme storms threaten to flood coastal communities, risking lives and that cyclone intensity has increased over the past 20 years, were 6 of the 10 most acting years since the 1950s occurring during that period. We have learned that dangerous wild fires continue to intensify, reducing air quality, threatening forests, threatening property and risking the lives of firefighters. We have learned that the area of land burned by wild fires annually has increased since the 1980s and that 9 of the 10 years was the most land burned have occurred since 2000.

We have learned that by mid-century, farmers in the midwest will face crop year decline of up to 19 percent and by the end of the century, States like Oregon, Washington and Idaho could experience as many hot days over a 95 degrees Fahrenheit as currently expected in the State of Texas. We have learned that as climate warmed, labor productivity in key sections including construction, agriculture and utilities would likely be reduced and that these reductions and labor productivity may be the greatest in the southeast.

So Mr. Chairman, it is for all of these reasons that President Obama has decided to act and fill the void left by this very same Congress in hopes of mitigating some of the most devastating effects on climate change due in large part to emissions from some of the nation's oldest and dirtiest power plants.

Mr. Chairman, I look forward to this hearing on the FERC commissioners' responses to questions and on the FERC commissioners to the President's plan, their response to the President's plan. And with that, Mr. Chairman, I want to yield back all the time that I might have.

Mr. Whitfield. Gentleman's time is expired.

Mr. Rush. Right on time.

[The prepared statement of Mr. Rush follows:]

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Mr. Whitfield. At this time, I would like to recognize the gentleman from Michigan, Mr. Upton, chairman of the full committee for a 5 minute opening statement.

The Chairman. Well thank you, Mr. Chairman.

A couple weeks ago, EPA's Acting Assistant Administrator Janet McCabe told this subcommittee that the Agency's proposed rule for existing electricity generation is not an energy plan but rather it is a pollution control rule. Then last week, Administrator Gina McCarthy made the exact opposite argument during her testimony before the Senate that the proposal is not about pollution control but, in fact, it is about energy and spurring investments in the EPA's preferred energy choices.

This comparison of exchanges by the two top officials at EPA demonstrates the Agency's current dilemma. After failing to push comprehensive cap and trade legislation through a Democratic Senate because of legitimate fears that it would hamstring our economy and make energy more expensive, the Administration is now pursuing a plan B approach by stretching the Clean Air Act to accomplish the exact same goals.

Assistant Administrator McCabe's answer is the one that the agency will likely stick to when the rule gets challenged in court, as EPA has no explicit energy policy setting authority under the law. But Administrator McCarthy had the more candid response, as this rule clearly is an effort by EPA to assert control in new regulatory authorities over States' electricity decisionmaking.

EPA's Clean Power Plan requires States to submit for approval individual or regional energy plans to achieve the agency's carbon dioxide emission targets. EPA is systemically Federalizing under the Clean Air Act what was once in the clear purview of the States or the markets. If the States are truly the labs of democracy, then why assert the Federal Government over their energy planning?

FERC is the agency charged by Congress with regulating electricity in interstate commerce, which is why it is so important to gain FERC's perspective today. Even this Agency, with explicit authority over electricity matters, does not have the expansive reach and vision by EPA's Clean Power Plan. I am particularly concerned about the Clean Power Plan's impact on energy diversity. Maintaining a diverse energy portfolio is a core component of this committee's vision for America's energy future, a vision that we call the architecture of abundance.

Consumers and businesses are best served by an electricity supply that can be generated from a variety of sources: Coal, nuclear, natural gas, obviously, as well as renewables, and in the proportion that each State deems best to suit its unique circumstances.

Maintaining diversity, both diversity in our electricity generation portfolio as well as the diversity of strategies for meeting a State's electricity needs is critical to affordable and reliable energy, but EPA's top-down Clean Power Plan will give us less of both kinds of diversity.

I thank the FERC commissioners today and certainly welcome Mr. Bay for his first appearance before us. And I yield the balance of my time to Mr. Shimkus.

[The prepared statement of The Chairman follows:]

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Mr. Shimkus. Thank you, Mr. Chairman.

Reliable low-cost energy is a critical and key asset to this country and for job creation. We appreciate what you do to help maintain that.

In my sole region this winter, we came very close to the demand meeting supply, and I think that is a thing that hopefully you will help focus on. Base load is a key component of that, and as these rules drive some generating facilities out of the market closure, then we are going to have these concerns, and woe be it to the member of Congress that has brownouts during the hottest time of the summer or the coldest time in the winter.

There is also the big debate, you guys are involved with it on the transmission grid. As we pick and choose winners and losers and electricity generation, we have to move electricity larger distances and that stirs up the public. I think there is a credible debate about localizing generation and then not having these transmission fights.

As you have heard me before numerous times, I am also concerned about the physical security aspects. As a former Army officer on the, you know, during the Cold War, we worried about the Soviets doing electromagnetic pulses that would knock out transmissions and I know that is not the focus of this hearing, but security aspects of that, and maybe it is not a terrorist attack, maybe it is just a solar flare that really causes great concerns, and I am going to be watching that and involved with that in this year and the next couple years.

The last thing I would like to, with this time, is just, Chairman LaFleur, and I will follow up with my questions, when you last appeared for us, you said you would keep your fellow commissioners in consultation with you. I think some of the testimony kind of questions that, based upon meetings with the EPA, and I hope we get clarification on that.

Thank you, Mr. Chairman. I yield back my time.

Mr. Whitfield. The gentleman yields back.

[The prepared statement of Mr. Shimkus follows:]

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Mr. Whitfield. At this time, we will recognize the gentleman from California, Mr. Waxman, for a 5-minute opening statement.

Mr. Waxman. Thank you very much, Mr. Chairman. I would like to thank each of the commissioners for being here today, and I especially want to congratulate and welcome Mr. Bay who has just been confirmed to the commission.

The Federal Energy Regulatory Commission plays a key role in maintaining the reliability of electric grid and protecting electricity consumers. That is what makes your job so important. The Republican members of this committee deny the existence of climate change or pretend it doesn't exist. They see the EPA's Clean Power Plan for the power sector as a threat to grid reliability, and that is why they have called you here this morning. They hope you will say something that will give them ammunition.

But those of us who are listening to the overwhelming scientific consensus see carbon emissions from power plants, not EPA regulations, as the real threat to the grid. The facts are sobering. Last year the levels of heat-trapping carbon pollution in the atmosphere exceeded 400 parts per million for the first time in millions of years. Last year was the fourth hottest year on record, 7 of the 10 hottest years on record occurred in the last decade, and all 10 occurred since 1998.

Wild fires in the west have gotten much worse. Droughts are setting records and devastating harvest. Sea-level rise and fierce storms are threatening our coast. These, and many other indicators, tell us that global warming is harming us now, and it is going to get much worse. The power sector will feel these impacts. Intense storms will disrupt power delivery. Droughts and rising temperatures will force plant shut downs. Transmission systems will lose capacity at high temperatures.

And that is why the Clean Power Plan is so important for the grid and for our future. It was issued by EPA, but I am sure it went through an interagency review, because it is important to get FERC's perspective. A significant transition is under way in the power sector. Market forces and public policies are driving a shift to renewables, demand side efficiency and natural gas fire generation. We have doubled our capacity to generate renewable electricity from wind and solar in just 5 years.

Wind power is already cost competitive with fossil fuel generation in parts of the country and the cost of solar power is plummeting. Natural gas costs less than coal and even coal boosters acknowledge that it is not cost effective to build new coal plants today because of the competition from natural gas, not because of any regulations by any government agency.

These changes in the electricity sector are bringing Americans cleaner air, new jobs, lower bills and more choices. The Clean Power Plan will advance these positive developments. FERC, too, should make its own contribution. The statutory standards that FERC administers, gives the agency many tools to help combat climate change and create the clean energy economy of the future.

And I want to bring to the members' attention, the University of California Berkeley Center for Law, Energy and the Environment report that was recently issued on this subject, authored by Steven Weissman and Romany Webb, which I ask unanimous consent to insert in the record.

Mr. Whitfield. Without objection.

[The information follows:]

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Mr. Waxman. I hope all the commissioners will give these ideas serious consideration. As this new report shows, we don't have to choose between protecting the environment and reliable electricity. FERC grid operators, State public utility commissions and power plants, even progressive power companies are already planning for the changes that are under way.

Our nation has a proven track record of adapting to new environmental requirements without adverse impacts on reliability. We don't have to cling to the past, and we don't need to be afraid of the future. We can protect our environment, strengthen the grid and leave our world a better place for our children.

Thank you, Mr. Chairman. I yield back my time.

Mr. Whitfield. Gentleman yields back.

[The prepared statement of Mr. Waxman follows:]

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Mr. Whitfield. At this time, we look forward to the opening statements of the commissioners of the FERC. And we have with us this morning, the Honorable Cheryl LaFleur, who is the acting chairman; we have the Honorable Phillip Moeller, who is a commissioner; we have the Honorable John Norris and Tony Clark; and our newest member, Mr. Norman Bay of New Mexico.

So at this time, Chairman LaFleur, we will recognize you for 5 minutes for your opening statement. Make sure your microphone is on, and we look forward to your testimony.

STATEMENTS OF THE HON. CHERYL A. LAFLEUR, ACTING CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION; THE HON. PHILIP D. MOELLER, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION; THE HON. JOHN R. NORRIS, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION; THE HON. TONY CLARK, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION; AND THE HON. NORMAN C. BAY, COMMISSIONER, FEDERAL ENERGY REGULATORY COMMISSION

STATEMENT OF THE HON. CHERYL A. LAFLEUR

Ms. LaFleur. Well, thank you very much, Chairman Whitfield, Ranking Member Rush and members of the subcommittee.

I am honored to serve as the acting chairman of the Federal Energy

Regulatory Commission, and I appreciate the opportunity to be with you this morning.

As this subcommittee is well aware, the Nation's resource mix is changing in response to a number of factors, including the increased availability of domestic natural gas, growing use of renewable generation in response to State and Federal policies, and new environmental regulations. Although these drivers of power supply changes are themselves outside the commission's jurisdiction, we must be aware of and adapt to them to carry out our responsibilities to promote reliability and ensure just and reasonable rates for customers.

Our work supports reliability in three primary ways: First, FERC supports the timely development of needed energy infrastructure. The commission has permitting authority over natural gas pipelines, LNG terminals and non-Federal hydropower. We also support new infrastructure through our rate authority over those facilities and over electric transmission.

Second, FERC oversees wholesale power markets that support reliability. We work to ensure that centralized capacity, energy and ancillary services markets send correct signals to support the procurement and retention of resources needed for reliability.

Finally, FERC directly oversees the reliability of the grid by establishing mandatory standards for the bulk power system under Section 215 of the Federal Power Act. It has been almost 10 years since Congress enacted Section 215, and I believe the commission has established a solid track record not just on day-to-day reliability, but on emerging issues, like cybersecurity, physical security and geomagnetic disturbances.

As I mentioned, one of the key drivers of changes in our resource mix are new EPA regulations regarding air, water and solid waste pollution. EPA is, of course, responsible for promulgating environmental regulations under the statutes it implements. We, in turn, are responsible for helping ensure that reliability is sustained as new environmental regulations are carried out. Our work in this area is not limited to interactions with EPA but includes collaborations with states, industry and other stakeholders.

One recent example is our work on the mercury and air toxic standards where we issued a policy statement outlining how we would advise EPA on when additional time might be needed to comply with the mercury and air toxics in order to avoid a reliability violation. We also established a regularly-scheduled public forum with NARUC, co-led by my colleague, Commissioner Moeller and myself and our State colleagues, to regularly collaborate with EPA and other stakeholders on how the MATS rule and other rules were being implemented.

I have closely followed the development of the Clean Power Plan because I believe it will have implications for the operation of the grid and require FERC engagement to ensure that reliability is sustained. FERC staff commented on the proposal through the OMB interagency review process from a reliability perspective. Among other recommendations, FERC staff emphasized the need for the development of natural gas pipeline and electric transmission infrastructure to enable compliance with State compliance plans. FERC staff also emphasize the importance of regional cooperation to promote efficient compliance with the Clean Power Plan.

I appreciate that the plan gives considerable flexibility to the States to use the different building blocks it outlines, but I believe FERC will have at least three important roles: First, to support the development of pipelines and transmission that will be needed to attain the goals of the plan; second, to consider how market structures need to adapt to support the research choices that states make under the plan; and finally, to continue to be closely engaged with EPA and the states and others to identify any problems and help to make sure they are addressed.

Reliability has been my top priority in my time at FERC, and I believe it is job one for anyone involved in electricity. I have seen many changes to the Nation's resource mix in the past 30 years, but the central importance of reliability is unchanged, even as new technologies and new environmental challenges and aspirations emerge. As FERC chairman and as a commissioner, I will continue to champion these issues.

I thank the subcommittee for giving me the opportunity to appear, and I welcome your questions.

Mr. Whitfield. Thank you, Ms. LaFleur.

[The prepared statement of Ms. LaFleur follows:]

******** INSERT 1-1 ********

Mr. Whitfield. At this time, recognize Mr. Moeller for his 5-minute opening statement.

STATEMENT OF THE HON. PHILIP D. MOELLER

Mr. Moeller. Thank you, Chairman Whitfield, Ranking Member Rush and members of the committee.

I am Phil Moeller. I have been on the commission since 2006. Thank you for holding this hearing on a very important subject, the EPA's Clean Power Plan. As its name indicates, this is essentially power or electricity policy, so it is very relevant that we are here talking about it because we have the job under Section 215 of the Federal Power Act to assure the reliability of the Nation's bulk power grid.

And reliability should not be, and I don't think it is, a partisan issue, but it has to be our job, number one, so we have to look skeptically at these kinds of proposals to make sure that we can keep the lights and more importantly the heating and the cooling on when consumers need it.

The biggest challenge, I think, in this rule is that it treats states individually in terms of compliance, but electricity markets are fundamentally interstate in nature and that just creates some challenges that may not be insurmountable but need to be looked at very closely. In my written testimony, I have noted a few examples of states that certainly have concerns about how they will be treated.

Idaho, for instance, consumes coal power but doesn't generate it, so what does that mean for its baseline now in going forward? We have states like Wisconsin and New Jersey that spend significant amount of money, billions of dollars to clean up their fleet, but they don't get credit under the Clean Power Plan. And then there are stranded assets, such as the one I note in Mississippi, where $1 billion of scrubbers is essentially not counted under the plan. So those are issues you will hear about as the comments come in on the rule.

The rule is based on compliances on four building blocks. You have probably gone into them. I will point out one that has a little bit of concern to me, which is essentially getting the gas fleet up to 70 percent dispatch. Now, the challenge there is that we have traditionally gone under something called economic dispatch where the cheapest power plants are called in the merit order of dispatch. This would change it to environmental dispatch. You can do that with a carbon fee and mesh the two, but obviously the prices go up. It is a fundamental change, not only with how we regulate power but actually how the system is operated, and it needs to be examined very closely.

The related issue that concerns me has to do with the example we have in New England. Almost everybody in the country, not universally, but almost everyone believes that we need more pipeline into New England because of the pipeline constraints. The challenge is financing it, because pipelines have traditionally been financed under long-term contracts with local distribution companies, but the new customer class for pipelines is basically power plants that may or may not be called on a daily basis based on the market they are in.

So with that, the challenge is how do you get long-term financing with power plants that aren't going to sound essentially long-term contracts. Now, these are not insurmountable problems, but it is a real issue in New England. We haven't been able to solve it and I am concerned that if we move to a system where there is a lot more gas generation to be dispatched, are we going to have the pipeline capacity? Can we finance the pipeline capacity to meet that need? It is a real conundrum, one that we need to take a look at more closely.

Essentially, what I have been calling for is a more formal role for our commission as we deal with EPA on these issues, kind of an open and transparent role, so that basically we can get the engineers together to discuss the challenges involved because it really comes down to a very granular level with reliability. The laws of physics will trump regulations. There are always unintended consequences when we shut down power plants because, although they may not produce a lot of power, they may be producing other products, ancillary services that maintain reliability in the grid. And the location of those plants is key, and sometimes you can't replicate a plant in that location.

So the granular level of analysis is very important, and I think it should be open and transparent because, engineers can disagree, but we need kind of an open forum for them to do it. I am also not here to say that we shouldn't do anything. I think we can do a lot of good by essentially improving and modernizing the pricing of electricity. Under the leadership of Acting Chair LaFleur, the FERC has opened up a proceeding on price formation in the wholesale markets. This is overdue, it is a good effort. I am kind of impatient. I want this to move forward, because we have some inefficient pricing right now.

Similarly, at the retail level, I urge my colleagues at the State level to consider more realtime and dynamic pricing at the retail level because that will send more accurate pricing to consumers, and hence, they should use their power more efficiently.

Again, thank you for having us, and I look forward to any questions you have.

Mr. Whitfield. Thank you, Mr. Moeller.

[The prepared statement of Mr. Moeller follows:]

******** INSERT 1-2 ********

Mr. Whitfield. Mr. Norris, you are recognized for 5 minutes.

STATEMENT OF THE HON. JOHN R. NORRIS

Mr. Norris. Chairman Whitfield, Ranking Member Rush and members of the subcommittee, thank you for the opportunity to share with you my thoughts on how EPA's proposed Clean Power Plan will work. The fact that we are here today having this discussion on reducing carbon emissions, to some degree, tells me it is already working.

As you may have read in my written testimony, I believe the EPA's proposed Rule 111(d) can work. The flexibility provided in the rule, along with the continuous communication and cooperation between EPA, FERC, NERC the states, RTOs, industry and others to make appropriate adjustments along the way to ensure reliability lead me to the conclusion that we can reduce carbon emissions and keep the lights on. If the question is, is this the most efficient way to reduce carbon emissions in our electric sector? I would give you a firm no, it is not.

I applaud the EPA for this action but recognize that this was the only option available to curtail harmful greenhouse gas emissions because Congress has failed to act. Placing a cost or a value on carbon consistent across the country would, I believe, be a far and away more efficient and fair way to address carbon emissions. While the EPA's proposal does provide more certainty on energy investment than before an industry struggling with uncertainty, it is nowhere near the clarity and direction legislation establishing a national energy policy on carbon would provide.

Let me share with you an excerpt from an interview from a former Republican colleague of yours. He tells of a conversation he had with an elderly gentleman about the need for a carbon policy, and I quote: I was talking to him about, "What about your grandkids?" And he said, "I think they can get by on their own." I don't think that caring fellow really meant it quite that bluntly. I think what he meant was somebody will figure something out.

And, of course, my response to him is, "Well, technological innovation will sure work better if we set the economics right, because what we believe as conservatives and people who believe in free enterprise is if you get the economics right, somebody chasing the dollar would deliver to me a better product. They will make money and they will serve my needs. That is what makes our system go around.

"But if you can't get to that next step of getting the price on carbon, because if you attach that price, the external hitting cost of the product, it changes economics and all kinds of exciting things happening for the enterprise system." But he wants to stick at that point of saying it is not a cost, that CO2 is not a cost; it is not a negative. If it is a negative externality, it is a value of zero. If you attach a zero to it, there is no change in the pricing structure.

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So for him, it is very important to continue to deny the science because he wants to assign a zero to the cost of carbon.

That was former Congressman Bob Inglis, who is providing a strong, conservative economic voice on this issue, a voice worth listening to. I, too, believe the best way to address climate change is to first recognize the overwhelming evidence provided by scientists throughout the world that our planet faces severe consequences if we do not take action. The U.S. can and should help lead a worldwide effort to reduce carbon emissions, and that our innovative and entrepreneurial spirit will seize the opportunities to tackle this problem.

If we are here today to debate whether the EPA's proposal will work or not, I fear Congress is missing the point, again. A rule that is not yet finalized but empowers 50 states with significant flexibility to address the proposed regulations and then grid operators to work to incorporate those State decisions into their operations, it will nearly be impossible to be proved today that it will or will not work.

But if the EPA and every other entity involved commits to making it work, I am confident it is achievable. But for the sake of our consumers, our utility businesses and America's entrepreneurs and innovators, we as a Nation could take a better course of action and enact a national energy policy to begin the transition to a low-carbon economy.

Reliability will always be one of my highest priorities as a commissioner. It is my responsibility, and I will not hesitate to step forward and take appropriate action if grid security is threatened by this proposed rule or any other threat or reaction. But this rule is a very gradual transition, and I believe a very necessary transition, for I believe my responsibility as a citizen and public servant is to also speak up for my children, the children of America and the world. We are talking about action that threatens their future.

Much talk, I think, is spent on addressing the financial debt we are leaving our children, and I commend all of you here today who are addressing that issue. But I hope you will also consider the atmospheric debt we are not adequately addressing. This is a debt I believe even more devastating but also deadly.

Thank you. That concludes my testimony. I look forward to your questions.

Mr. Whitfield. Thank you, Mr. Norris.

[The prepared statement of Mr. Norris follows:]

******** INSERT 1-3 ********

Mr. Whitfield. Mr. Clark, you are recognized for 5 minutes.

STATEMENT OF THE HON. TONY CLARK

Mr. Clark. Thank you, Chairman Whitfield, Ranking Member Rush and members of the committee.

I hope you will allow me a point of personal privilege for an introduction that I have today which is, in probably the half a dozen or so times that I have testified in front of Congress, I have never had my boys be able to join me. They have always been in school or back home in North Dakota, but today they are here. So Alex and Thomas.

Mr. Whitfield. We will have some questions for Alex and Thomas.

Mr. Clark. I am sure he looks forward to them. They can now look 30 years into the future being able to look back into a Congressional record and see their names are in there.

Out of respect for your time, I won't repeat the testimony that I submitted, but instead will probably just extend a little bit upon it. It is quite clear from the questions that we received from all of you, the pre-hearing questions that preeminent in the minds of the committee are, can FERC answer questions related to the EPA rule and whether they will be a concern about either cost or reliability.

I think, hopefully, what you gathered from my responses were that it is probably too early to know with specificity exactly what those impacts will be and the primary driver for is that is that we simply don't know what the potential State implementation plans, compliance plans might look like, and we also don't have a sense for what a Federal implementation plan or a Federal compliance plan would look like.

Typically, as the EPA has proposed rules, there would be a marker for what a Federal plan might look like; in this case, we don't have that. So it is a little tougher for us, I think, as a commission, to model it. But I think we can make some general comments about the trendline that we might at least wish to keep in mind especially as a commission as we work through some of these issues.

And what really got me thinking about it was an article that I read in the Washington Post last Friday, actually, after I had submitted my written testimony, which was about the challenges that a community in Colorado was having with regard to changing over their fleet in a relatively short amount of time, and there were some costs concerns that were taking place in that community. It happened to be Pueblo. And it got me thinking about the EPA proposed rule and what might be pathways to it.

It is quite clear, although the EPA has said that they will offer flexibility to states, a pathway that they have offered up as a potential one that might be compliance, relies in some part on a combination of perhaps cap and trade, like a regional gas house initiative like they have in the northeast, some sort of reliance on energy efficiency and demand response resources, a shuttering of coal plants and, at the same time, pivoting towards heavier reliance on natural gas, perhaps some sort of renewable portfolio standard in the State.

So you put all these things together, and it actually looks very much like what one of the regions has already been going through, which is the one that Commissioner Moeller mentioned, which is New England. I think one of the things that FERC and Congress will need to keep its eye on as we potentially move forward in these rules is, at least from my perspective, if someone were to ask me which area of the country do you have the most concern about both as a matter of cost and reliability, I would probably point to New England, not solely because of some of the things that have happened already with regard to carbon regulation, but certainly some of those things do play into it.

So should the EPA rule come to pass? I would think that FERC would need to ensure that as it moves forward, we would want to make sure that some of the concerns that we have seen already happen in New England with the pipeline constraints and the rapid conversion to gas and the very tight reliability system and sometimes very high cost for electricity aren't exported to other regions of the country, and overcoming that could be, indeed, a challenge.

With that, I will end my testimony, yield back the remainder of our time and look forward to your questions.

Mr. Whitfield. Thank you very much, Mr. Clark.

[The prepared statement of Mr. Clark follows:]

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******** INSERT 1-4 ********

Mr. Whitfield. At this time, we will recognize the gentleman from New Mexico, Mr. Bay, for a 5-minute opening statement.

STATEMENT OF THE HON. NORMAN C. BAY

Mr. Bay. Chairman Whitfield, Ranking Member Rush and members of the subcommittee, my name is Norman Bay, and I currently serve as the Director of the Office of Enforcement at FERC.

On July 15, it was my honor to have been confirmed by the Senate to serve as a member of the commission. I anticipate being sworn in once all the necessary arrangements have been completed. Thank you for inviting me to testify at this hearing regarding EPA's proposed Clean Power Plan and other grid reliability challenges. I look forward to working with this committee in my tenure on the commission.

One of FERC's critical responsibilities is the regulation of electric reliability. As the Director of the Office of Enforcement, I have been involved in investigations of potential reliability violations and inquiries into major reliability events, but I have not been involved in the EPA rulemaking.

While the EPA has responsibilities under the Clean Air Act and other legislation, the commission has similar and no less important responsibility to promote the reliability of the bulk power system.

One way that I believe the commission can help to ensure reliability is through open communication and a strong working relationship with the EPA; the Department of Energy; the States and NARUC; the North American Electric Reliability Corporation, or NERC; regional transmission organizations; independent system operators; and industry. It is my understanding that FERC staff, EPA and DOE have communicated at various times regarding the EPA's power sector regulations. The agencies should continue this effort to ensure that the EPA is aware of any potential impacts its regulations may have on the reliability of the bulk power system.

To the extent necessary and appropriate, commission staff should continue its communications with EPA and industry participants subject to FERC's regulation, including RTOs and ISOs and public utilities. Once I am sworn in, I look forward to meeting with my colleagues to discuss in greater depth these issues and to examine how we can work collaboratively within the commission's authority to promote the reliability of the bulk power system.

Thank you for inviting me to testify here today. I look forward to remaining engaged with the committee and the EPA, DOE, NERC, the states and industry on these important issues.

Mr. Whitfield. Thank you, Mr. Bay, and thank all of you for your testimony.

[The prepared statement of Mr. Bay follows:]

******** INSERT 1-5 ********

Mr. Whitfield. At this time, we will recognize the panel for questions, and I will recognize myself to start off for 5 minutes of questioning.

It is quite clear that anyone who has examined the Clean Power Plan views it as a fundamental change and President Obama frequently talks about Congress being an obstructionist, and Mr. Norris made the comment this is necessary because Congress has failed to act. And I would point out that Congress did act by deciding not to act. When Mr. Waxman was the chairman of this committee, the Cap and Trade Bill was reported out of the House of Representatives. It went to the Senate, and the Senate did not adopt it. So Congress did act in the sense that it did not adopt the cap and trade.

One of the frustrating -- and I am sure that President Obama is frustrated, and it is great that we have hearings like this to bring all of this out into the open, to have a discussion for the American people. Because one of the frustrating parts for the American people is when they see decisions affecting basic services like electricity and the impact that that has on our economy being made by the courts and by regulators, and they view that as not really being transparent.

So we in Congress, we do not intend to just lay down and let the President do whatever he wants to on climate change or any other issue without having a public discussion about it. And so CO_2 emissions, by the way, today are the lowest from energy sources that they have been in 20 years. Lisa Jackson even made the comment that even if we move vigorously forward as we are attempting to do here on CO2 emissions, it would make no difference unless other countries do the same.

And we see in Europe today, they are mothballing natural gas plants because natural gas prices are so high coming out of Russia that they are building coal plants today. And we, under this plan, would not have the flexibility to build a new coal plant if natural gas prices go up because the technology is not available to be able to do it in a economic way that would make it possible to do it. We don't have enough money to build Kemper plants all over America the way they are attempting to do in Mississippi, and it is not being done without Federal dollars.

So this kind of discussion, I think, is invaluable. Mr. Rush had made the comment about the drought and the impact on farmers, and I would tell you, the price of corn has fallen from $8.10 a bushel down to $4 a bushel because corn is so abundant right now. So there are lots of different perspectives on this.

But Ms. LaFleur, everyone is concerned about reliability, and we have asked the EPA about this and we ask this question of you in our written questions: Did the EPA request a written document from FERC relating to reliability? Do you have a written report that was given to EPA on reliability issues?

Ms. LaFleur. Thank you for that question, Congressman

Whitfield.

No, they did not request written comments. My understanding, this is the first time I have been through the interagency review, but there were a number of staff meetings and then a, kind of a formal debrief where we made our comments over at the OMB with a number of EPA people there. And we kept a memo, but we did not turn them in in writing because that has not been the practice.

Mr. Whitfield. I personally think that is disappointing because reliability is such a key issue.

Mr. Moeller, I don't have a lot of time left, but would you just comment briefly on this economic dispatch versus environmental dispatch and how that might get to a cap and trade system?

Mr. Moeller. Well, that is one of the four building blocks, and the building block is an aspiration to get the gas fleet up to 70 percent dispatch, which has been very rarely done in this country, only in very limited circumstances. So there are some operational questions.

But essentially, the only way, I mean, if you have to hit your target by increasing your gas fleet production, that is going to trump what is normally economic dispatch of the cheapest plant. Now, the only way you can reconcile that is then put a fee on the other sources, and it is talked about in the rule, you put a fee on the other carbon emitters so that they are less competitive to gas. So that is how it would be done.

Mr. Whitfield. Well, thank you. My time is expired.

At this time, I recognize Mr. Rush for 5 minutes of questions.

Mr. Rush. Thank you, Mr. Chairman.

Mr. Chairman, the American people are tired of the finger pointing, they are tired of the excuse after excuse, the blame that goes from one to another. They are really, really tired of the inaction and the inertia that seems to be the standard of this Congress.

There is no question, Mr. Chairman, that we need to reduce our carbon pollution if we are going to avoid the worst impacts of climate change. No question about it and the power sector is the largest source of carbon pollution in the U.S. There is no question about this. Mr. Chairman, I believe that the EPA's Clean Power Plan is a reasonable approach to reducing emissions from power plants in light of the unending excuses, in light of this Congress' failure to act.

Commissioner Norris, do you agree that a Clean Power Plan is a reasonable approach since this very Congress has failed to act?

Mr. Norris. I think the EPA plan is, as I mentioned, the most feasible, reasonable one that they can do out of their authority, that it is workable. It would be more efficient if we would remove the uncertainty around carbon and enact a policy that would provide more certainty and more efficient in this transition.

Mr. Rush. Again, commissioner, how will EPA's proposed rule affect investment in renewable energy and energy efficiency resources?

Mr. Norris. It is a much-needed signal to both renewable energy and other technologies that can provide demand side management energy efficiency and new technologies for generation, that, I think, there is a great hunger, an appetite for investing in new clean air energy technologies. This will help spur more investment which will create more technology opportunities for us to make this an efficient transition.

Mr. Rush. What about nuclear power? With the low price of natural gas, some nuclear power plants are struggling financially. How could the proposed rule help keep those nuclear plants running?

Mr. Norris. Well, again, I think it provides a much-needed signal to the value of nuclear plants because they are noncarbon emitting. It has been a real concern of mine that we maintain our nuclear fleet because it is noncarbon emitting and a solid base load source of generation. So I think the EPA rule will assist in providing a better market, if you will, for nuclear resources.

Mr. Rush. Yeah. Again, commissioner, what do you think about whether industry and regulators can rise to the challenge and achieve the carbon reduction set out in the Clean Power Plan without sacrificing electric reliability?

Mr. Norris. I am sorry?

Mr. Rush. Without sacrificing electric reliability.

Mr. Norris. Without jeopardizing electric reliability?

Mr. Rush. Sacrificing.

Mr. Norris. Yeah, I think, as I said, you are not going to prove it is or isn't going to work because it is still in development. The key thing is going forward is the communication and cooperation between the EPA, FERC, NERC and all the other entities that we -- everyone wants to keep the lights on, including the EPA. And so what it is going to take is just a continuous effort going toward to make sure reliability needs are addressed if and when they occur.

Mr. Rush. Chairman LaFleur, do you agree?

Ms. LaFleur. I certainly agree that it is going to take a ongoing effort of communication to identify issues that specific states or regions might be having. As with all, I believe, and I testified on MATS before this committee, I said the two things you need for change are flexibility and coordination and that is even more true in this rule. We need coordination to make sure the State plans work and protect reliability.

Mr. Rush. Commissioner Bay, what are your thoughts? Do you agree?

Mr. Bay. I think that there could be challenges.

Mr. Rush. Turn your mike on, please.

Mr. Bay. I am sorry.

I think that there could be challenges, but I think that the challenges are manageable. I would note, for example, that with the 2005 baseline that the EPA used, there has already been a 15 percent reduction in carbon emissions from generators so that an additional 15 percent needs to be achieved over the next 16 years.

And even under the EPA proposal, it estimates that in 2030, gas-fired generation will constitute more than 30 percent of generation and coal will be more than 30 percent, as well. And with the regulatory certainty provided by the rule, I agree with Commissioner Norris that it will incent innovation. And industry is amazing when they know that there is something to be improved upon and that can result in better or more profits.

Mr. Rush. Thank you, Mr. Chairman.

Mr. Whitfield. At this time, recognize the gentleman from Texas, Mr. Barton for 5 minutes.

Mr. Barton. Well, thank you, Mr. Chairman.

And I want to thank the commission for being here. We rarely have all the commissioners, so that is an honor to have each of you. I was really going to rip Mr. Clark today, but since his two boys are in the audience, I am going to have to give him a pass on that. But no, not really.

I have a general question that I would like each of the commissioners to have the opportunity to answer. You don't all have to, if you don't wish to. With this new EPA carbon rule, would seem to me to be at variance with the FERC's stated responsibility to provide electricity at a reasonable cost. I don't buy the argument that you can close all these power plants and you are going to miraculously replace them with either natural gas, nuclear power or this clean coal technology which really only exists in the laboratory. It hasn't been proven in a commercial scaled-up facility yet.

So, you know, my general question is, can the FERC have any impact to guarantee that we continue to provide electricity at a reasonable cost to the consumer if this rule goes forward?

Ms. LaFleur. Well, thank you, Mr. Congressman.

I do not think the rule itself is inconsistent with FERC's responsibilities. As I see it, the EPA makes environmental rules and those become the baseline within which the system is planned, and we have to make certain that within those rules the rates are done in a just and reasonable way and that we will be paying attention to that as well as paying attention to reliability.

I think all transitions cost money and so the transition to a new resource mix, whether it is because of the environment or because of anything else, to build pipelines, to build transmission is going to cost money. The long run costs are really unknown. They depend on the relative cost of the fuel, and we also don't know the long run cost of leaving climate change, you know, unattended to, which is not free. So, but we will be working to make sure that the transition costs of the pipelines, the transmission, the things we regulate are done in a reasonable way.

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[11:02 a.m.]

Mr. Moeller. Congressman Barton, I agree with Acting Chair LaFleur about we have to react to an environmental rule. I suppose that there is a possibility that EPA could put some kind of a safety valve in from an economics perspective. That is not in the rule right now, but that is a potential. Even they admit that this is going to cost consumers money and raise rates.

The question is how do we transition? And my concern is do we have the right market signals to actually allow for these types of investments, particularly in pipelines, if we are going to expand the gas fleet so much.

Mr. Norris. Thank you, Congressman. First of all I agree with you, there are no miracles here, but we are talking about accounting for all the costs including the external costs. I do have great faith in America's technology innovation. The costs for renewable energy are coming down dramatically in this country. Technologies for a demand site management and energy efficiency are going up dramatically in terms of their capability.

And finally, the fuel costs for renewable energy is zero. We know that is a constant going forward. That gives me great hope that we can make this transition in a very manageable way for the economy. In fact, a very positive way for the economy because of the world wide market that is out there for clean energy technologies.

Mr. Clark. Congressman, as I indicated in my testimony, FERC has allowed costs that are legally incurred by a business to be bid into the markets themselves. So to the degree that it is just bidding in costs that are otherwise legally incurred, that may not directly implicate FERC markets from a jurisdiction standpoint.

There is potentially though one, what I referred to as a potential jurisdictional train wreck between EPA and FERC, and it would be this; if EPA through the Clean Air Act required utilities to go down the path of environmental dispatches, we've talked about, and depart from economic dispatch, that could potentially be challenging for FERC in this way.

Our authority comes not through the Clean Air Act, but through the Federal Power Act, which requires just and reasonable rates and non-discriminatory rates. We have always judged that by economic dispatch. So to depart from economic dispatch and move to something else could potentially be challenging for the commission, I think.

Mr. Bay. Congressman Barton, I think you raised an important issue, and certainly FERC under the Federal Power Act has to do its best to help ensure that rates remain just and reasonable. I think the commission has taken some actions to examine price formation in the energy markets as well as in the capacity markets that could be very helpful in addressing the issue that you raise.

Mr. Barton. My time is expired, Mr. Chairman.

I want to just make a statement real quickly. In 2005 the then chairman of the FERC, Chairman Keliher, complained to me that FERC didn't have the authority to enforce some of its rules, and we gave the FERC some additional authority. We changed the penalty structure.

That authority has been used in a way that many people think has not been normal due process, so I hope to work with the subcommittee in the next Congress to put in a reform package to provide more transparency and more of a balanced playing field on some of the things that, some of these investigations that FERC has been engaged in, in the last four or five years.

With that I yield back.

Mr. Whitfield. At this time I recognize the gentleman from California, Mr. Waxman, for five minutes.

Mr. Waxman. Thank you, Mr. Chairman.

The world's leading scientists have repeatedly confirmed that climate change is already happening. It is caused by human carbon pollution and will get much worse if we do not act. So, this is a question for all the commissioners. Do any of you believe that there is no need to act on climate change? If any of you believe there is no need to act on climate changes, raise your hand, and I will call on you. Otherwise, I have other questions.

So seeing no one jumping to that bait, it sounds like, all of you believe that there is some need to deal with climate change. Just this morning the President's Council of Economic Advisors released a new report on the cost of inaction on climate change. They estimate that just one degree celsius additional warming could cost the U.S. economy $150 billion per year. It is getting harder and harder to deny the imperative of action, and we cannot make meaningful progress on climate change without controlling carbon pollution from our largest source, power plants. Several of you discuss of your written testimony the ongoing transition in the power sector as natural gas, renewables and energy efficiency are playing larger roles in meeting our power needs.

Chairman LaFleur, what is driving this shift?

Ms. LaFleur. Thank you for the question, Congressman Waxman. I actually think the biggest driver of change is the abundance of domestic natural gas. Up in New England where we have heard about the challenges of pipelines, there are coal plants that have been under attack by the environmental community for 20 years.

Mr. Waxman. Natural gas is a driving force.

Ms. LaFleur. And second is as has been mentioned, the new renewable technologies and the technological improvements and policy support.

Mr. Waxman. The new renewable portfolio standards, and how about improvements in renewable technologies?

Ms. LaFleur. Yes.

Mr. Waxman. And new environmental regulations?

Ms. LaFleur. Yes, that is the third.

Mr. Waxman. So environmental standards play a role, but we would be facing a shift in the power sector even without these regulations that EPA is proposing.

Commissioner Norris, how do FERC and other involved entities such as regional transmission organizations and State public utilities commissions work to ensure reliability in our power system? Do you try to ensure that generation and transmission infrastructure remain frozen in time, or do you work to ensure that as inevitable changes occur, the impacts on reliability are addressed?

Mr. Norris. The states and RTOs are empowered with that responsibility now and no reason why they would not continue to be empowered with that responsibility, to choose their means, set the reserve margin and choose their means for meeting the adequate resources in the way that best fits their State and their economy. I see no reason that it change.

Mr. Waxman. Chairman LaFleur and Commissioner Bay, do you agree that the goal for FERC is not to stop change, but to ensure that the system responds appropriately as changes occur?

Ms. LaFleur. Yes, I think we have to adapt the part of the system that we regulate as new environmental regulations occur.

Mr. Waxman. Mr. Bay?

Mr. Bay. I agree with that as well.

Mr. Waxman. Now opponents of the Clean Power Plan claim that it is a complete departure from how the power sector has regulated and will threaten grid reliability.

Commissioner Norris, is this proposal a C change from everything that has come before, or does the plan build on regulatory structures already in place and trends that are already occurring?

Mr. Norris. Referring to the proposed EPA plan as the change?

Mr. Waxman. Yes, EPA plan.

Mr. Norris. No. Like I said, it is a gradual transition that is already occurring. We are already not building coal plants because the science is not changing. We are already having, as Commissioner LaFleur said, the advent of gas coming that is impacting the system, that is as a result of technology, the fracking technology, so science and technology is driving this change, not EPA.

Mr. Waxman. State PUCs, RTOs and ISOs already regulate electricity markets, and along with FERC and NERC, work to assure reliability. The power sector has dealt with many environmental regulations in the past, most recently the Mercury and Air Toxic Standards, and has maintained reliability. The shift to cleaner electricity is already underway. The Clean Power Plan will accelerate these changes and may pose greater challenges, but they are challenges that we already must and will address. I would assume you agree with that, Mr. Norris?

Mr. Norris. Do I agree that we can maintain reliability through this transition?

Mr. Waxman. Yes.

Mr. Norris. Yes --

Mr. Waxman. Chairman LaFleur, and Commissioner Bay, what do you think? EPA's Clean Power Plan is eminently, in my opinion, reasonable and quite modest proposal. It provides tremendous flexibility and ample time to the states and industry to reduce carbon pollution in the least burdensome way possible.

Do you, as Commissioner Norris stated, the question is not whether we reduce carbon pollution, but how, and EPA has an answer embodied in the Clean Power Plan, and that is what they are proposing as a start. So rather than ask that as a question, I want to make that comment.

And, Mr. Chairman, one last thing. The EPA is acting under the Clean Air Act which was adopted by the Congress. They are acting under decisions by the U.S. Supreme Court. There have been five to four decisions that is I have not liked, and there have been five to four decisions that you haven't liked, but Supreme Court decisions are the law of the land.

I yield back.

Mr. Whitfield. At this time I recognize the gentleman from Ohio, Mr. Latta, for five minutes.

Mr. Latta. Well, thank you, Mr. Chairman, for today's hearing, and also to the commissioners for being with us today. It is great to have you all here before us.

And if I could, I would like to start with Commissioner Clark if I may. And what are the implications of the State energy laws and regulations if they are included as part of an EPA-approved State implementation plan to comply with the Clean Power Plan?

And I just wondered if that could tie into your testimony, where you had mentioned that when you are looking at some of the, when this relationship is occurring, that States might get into a mother-may-I relationship with the EPA that never existed before. Would that tie into that?

Mr. Clark. Congressman, it does. The concern that I raised is I do think there is a risk that this is a rather dramatic change jurisdictionally, and States will at least need to consider it as they decide whether they are going to go down the path of a State compliance plan. The reason I say that is in the past, EPA might just be regulating emission sources either by source or a fleet, but not the entire regulatory regime in an integrated resource plan standpoint that a State might have.

So to the degree that a State goes down the path of creating effectively a carbon integrated resource plan, they will be putting into that things that have traditionally been set by State legislatures, renewable portfolio standards, building codes, energy efficiency standards, in addition to traditional sort of power plant decisions.

To the degree that then becomes bless by EPA and submitted and approved by EPA, it is a much different jurisdictional relationship than has existed before because if a State goes back and decides maybe the RPS should be 25 percent instead of 30 percent, or maybe our State building codes should be adjusted because something isn't working, in many ways it will have lost that opportunity because it will have become a part of a Federally-approved plan and would then need to seek approval from the EPA, depending on how it is structured to --

Mr. Latta. Let me follow-up. What would that do to costs in those States, especially when you are dealing with a district like mine that has 60,000 manufacturing jobs, and is that going to drive costs up? Is there going to be less flexibility that a State could do in the future? What would happen out there?

Mr. Clark. Congressman, again, I think it is a bit too early to tell specifically because we don't know what the compliance plans would look like or what a Federal compliance plan would look like. I would just point to the trend lines which is in those States that have moved more aggressively and have been first movers on some of these issues, the trend line has been towards increasing electric rate environment.

Mr. Latta. Thank you.

Chairman LaFleur, if I could turn to you, recently I have been hearing that in a number of States in competitive markets, electricity generators and electric distribution companies are seeking State public utility commission approval for the purchase power agreements or the PPAs, as a means to guarantee a contract between the power provider and the regulated utility company.

States are considering these because they are concerned about the impacts to their retail customers if those plants were to shut down. So the question is, if capacity markets were ensuring reliability and preserving essential base load capacity, then it seems that these PPAs would not be necessary. Are these actions by the State an indication of the market inadequacies out there?

Ms. LaFleur. Well, right now the capacity markets are under a lot of pressure because of all the changes in resource mix, and something that we are looking at very hard is how we make sure the capacity markets properly compensate all the increments that are need for reliability, and I think that will continue to be important, but there will still be a role for the States which regulate generation within their own authority.

Mr. Latta. Let me ask you, when you say that, you know, they might be under pressure out there, what is causing the pressure out there in the capacity markets?

Ms. LaFleur. I think some of the factors I already said. The first is the gas price being very low has really driven down the marginal revenues, so it is hard for some of the coal and nuclear units to recover their costs in the market and other resource changes as well.

Mr. Latta. Thank you very much.

Mr. Moeller, if I could turn to you, in your testimony you were talking about what could be happening out there is we could have higher costs involved out there. When you look at those higher costs again when you look at the States out there like the State of Ohio that is

70 percent generated by coal right now, if you look in that crystal ball down the road, what would happen to States like Ohio for costs when you look at what is happening with the EPA right now?

Mr. Moeller. I wouldn't want to predict how much rates would go up, but, again, even EPA admits that rates will be going up based on this rule. It would depend a lot on how they chose to come up with their State implementation plan. They could go the energy efficiency route, but that gets more and more expensive as you get more efficiency out of the system.

Transition to gas would probably be expensive because a lot of those coal units are relatively low cost. There are other ways to perhaps get there, but, again, this will result in higher rates, which I don't think is denied by anybody.

Mr. Latta. Thank you very much.

Mr. Chairman. I see my time is expired and I yield back.

Mr. Whitfield. At this time I recognize the gentleman from California, Mr. McNerney, for five minutes.

Mr. McNerney. Well I thank the chairman for holding the hearing and the commissioners for your testimony. I congratulate Mr. Bay on your confirmation.

Mr. Moeller, you had an interesting discussion of the pipeline challenge in New England because I assume it is from return on investment concerns of investors, the pipelines wouldn't be fully utilized. What would improve that financial barrier situation?

Mr. Moeller. Well, traditionally the pipelines have been paid for by the local distribution companies with 20 and 30 year contracts. They are the ones selling gas at retail. The new customer base is power plants, and in that market power plants don't know on a daily basis whether they are going to be called or not. They bid in. Sometimes they are taken. Sometimes they are not.

The pipes are basically full in New England. Almost everybody agrees that we need more pipe in New England, but how do you finance it under a new model? There are three proposals out there, one from the governors, one from the investor-owned utilities, and a recent one from a municipal group and we are hoping that part of this discussion can lead to a solution, but it is a concern we don't want replicated in other markets.

Mr. McNerney. Okay. Another question. You mentioned your concern about EPA not having the capability to do the granular analysis needed. I would assume the EPA does have that capability, so basically would you reiterate that you don't think they have that capability?

Mr. Moeller. Well in my opinion, I don't expect them to know electric markets like we do, just like we wouldn't know the details of Clean Air Act either. That is not really their job, but that is why I think we need a more formal relationship because we have the expertise. NERC has the expertise. The people that run the markets do and it is really drilling down into some very detailed engineering analysis, and it can be done.

Mr. McNerney. Well, you and other of the commissioners mentioned that you think one of the requirements for success of the rule, and I think it is cute that it is called the rule, is that you need open and transparent relationship between yourselves and the EPA and also the DOE. How can we achieve that, Chairwoman LaFleur? How can we achieve that transparency?

Ms. LaFleur. Well, I agree that we need an open and ongoing relationship with the EPA. I think the model that we adopted on the Mercury and Air Toxics Rule where we have regular monthly staff calls with the EPA, as well as meetings at the Commissioner level, is one we should follow here. I think we will know much more where the challenges are and what we need to do once the State implementation plans are done.

Mr. McNerney. Do you need a higher authority to make that transparency happen?

Ms. LaFleur. Well, I always love more authority, but I think we have the ability to be transparent within our existing jurisdiction.

Mr. McNerney. Mr. Waxman established that each of you feel there is a need for reduce carbon emissions. What do each of you feel, briefly if you would, would be the most efficient way to achieve that, the rule or some other method?

Ms. LaFleur. Well, I agree with Commissioner Norris that from the standpoint of reducing a pollutant most effectively, a nationwide cap and trade or some sort of nationwide system would probably be the most efficient. Given the structure of the Clean Air Act that we have, I think the EPA did a good job building in flexibility to use the authority they have.

Mr. McNerney. Mr. Moeller?

Mr. Moeller. Well, because carbon is ubiquitous in its concentration throughout the world, we have got to solve this on a worldwide basis, and I really think we should do it through market forces. As I mentioned in my testimony, getting prices more accurate at the wholesale and retail level throughout the world. Energy is subsidized I think a trillion dollars a year. Those are the kind of things that if we send the right pricing signals, people will use their energy more efficiently.

Mr. McNerney. Okay. Thank you.

Mr. Norris. Thanks. I partially agree with Mr. Moeller. Sending the right price signal is right, but you have got to get the external cost in that price. I think the most efficient way to do that personally is a carbon tax. I am not opposed to a cap and trade, but it takes a lot more pages for you all to right, and a carbon tax would be a lot simpler.

Mr. McNerney. Thank you.

Mr. Clark?

Mr. Clark. Congressman, from my standpoint, research and development is really the key in future energy technologies, and I am a supporter of government-supported research and development into those new technologies, the idea being that if new sources of energy can be developed in a way that no Nation or no developer would want to do anything but because it is both the cleanest and the most cost effective, then that solves both answers for you, and you don't have to worry about as much government intervention into the markets themselves because on its own --

Mr. McNerney. So that would take Federal or some higher source of funding for that research?

Mr. Clark. There can be all sorts of ways of developing those research dollars, yes.

Mr. Clark. Mr. Bay?

Mr. Bay. At this point 14 seconds or less, I would say innovation. I would say research and development. And I would say markets.

Mr. McNerney. [Off mic.]

Mr. Whitfield. We are always willing to talk about those issues.

At this time I recognize the gentleman from Texas, Mr. Olson, for five minutes.

Mr. Olson. I thank the chair, and welcome to our witnesses. A special welcome to you, Dr. Bay, as our next chairman. Welcome.

As you all know, our grid faces many challenges. You have to coordinate gas with electric power, and sometimes that can be difficult. Wind is plentiful but not at times when we need it, at times we don't need it. Subsidies sort the market and help shutter nuclear power plants, reliable nuclear power plants and as we have heard today, EPA adds to those challenges.

My first question is for the entire panel. In the Mercury Rule, the EPA included a way to pause the rule if reliability is threatened. It is all called, as you all know, a relief valve. As you all know, too, most of America's grid is run by impartial groups called ISOs. Now, the ISOs are asking EPA to include a reliability relief valve in the carbon rule. Yes or no, do you all agree that this could be a valuable part of the final rule?

Commissioner LaFleur.

Ms. LaFleur. I don't think it could be designed by the reliability safety valve in MATS, but I think there should be a way to consider reliability as a last resort if there is an issue.

Mr. Moeller. I think some kind of a safety value would be very helpful.

Mr. Olson. Commissioner Norris?

Mr. Norris. I apologize. I was not very clear on capturing the question, but if it is a safety valve, I am for safety valves.

Mr. Olson. Yeah. Safety valves, there is one for reliability. And so they want something for you know, a reliability rule in the Carbon rule, some sort of safety valve in the. It is out there for the ISOs. ISOs want to make sure they have that thing. It is part of the Mercury rule. It has been done with mercury. They just want to make sure that, hey, that is a good idea. Can we have that as well, just a safety valve for reliability as opposed to mercury.

Mr. Norris. Reliability is paramount, and we should do whatever we can to maintain reliability but not use a safety valve to empower people to push back what they are trying to achieve.

Mr. Olson. Commissioner Clark?

Mr. Clark. Congressman, yes, and I think it needs to be one that is done by an independent third party so that they can have greater visibility into the entire grid itself so as the State and regional plans are stitched together, someone independently is able to look at how they all work together and whether it will impact reliability.

Mr. Olson. Mr. Bay?

Mr. Bay. Congressman Olson, I certainly think it is an idea worth considering.

Mr. Olson. Okay, thank you.

My second question is for you, Commissioner Moeller. When power plants close we focus on the number of megawatts lost, but large power plants like coal and natural gas just don't provide bulk power. They also protect the grid with what is called ancillary services.

Unlike wind and solar, they can ramp up or ramp down immediately if needed. They can keep their power balanced at 60 hertz, right there 60 hertz, not 59.99 or 60.001. It is more important than reliability having that power, having the right power. And so my question is, are these EPA rules closing down the most important kinds of power on the grid, ones driven by coal and natural gas?

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Mr. Moeller. Well, it is very location-specific, Congressman. I can think of a big power plant in Montana that provides voltage support, a lot of power. If you were to take that out of the grid, it would have big impacts on the rest of the northwest system, and I am sure that that is the case in low pockets throughout the country.

And that is why I think drilling down into the granular nature of the reliability of closing plants is necessary, and we can take EPA's chart. They have projected which plants are going to be shut down, so the reliability study shouldn't be that difficult.

Mr. Olson. Yeah, so one further question. As EPA's second pillar of the carbon rules calls for a massive increase in power from natural gas, but they don't seem to realize that coordinating natural gas and electric power is a very delicate balance, and even worse now, the environmental groups are attacking the Using Greenhouse Gas Rule to try to turn around and stop FERC from approving natural gas pipelines. You can't have natural gas without the pipelines.

And so my question is, do you think EPA understands how difficult some of these assumptions are? Are they realistic?

That is for you, Mr. Moeller.

Mr. Moeller. I don't think they fully appreciate the challenges we have with getting more pipeline infrastructure. At least I haven't sensed that they do, because as I noted in my testimony, this set of new consumers of pipelines as power plants, not the traditional ones, local distribution companies that have provided the financing through long-term contracts, and we have got to address that and solve that issue or else the assumptions on pipeline expansion, I think, will be faulty.

Mr. Olson. My time I yield back. Thank you.

Mr. Whitfield. At this time I recognize the gentleman from Texas, Mr. Green, for five minutes.

Mr. Green. Thank you, Mr. Chairman.

I want to thank our commissioners, both new and old, for testifying today.

Reliability of transmission electricity is the backbone of our economy. Our industrial, commercial, and residential customers never need to question whether the power they need will be delivered when they need it. It is FERC's responsibility to maintain the reliability of the grid and FERC has quite a few other responsibilities, including pipelines, LNG facilities, and oil pipeline rates, to name a few.

Chair LaFleur, in your testimony you gave EPA's Mercury and Air Toxic Standards, or MATS, you state that EPA sought the advice of FERC upon the issuance. You stated that FERC issued a policy statement on potential violations MATS may induce based on FERC's reliability standard. Did the EPA respond to that, to FERC, and what you submitted?

Ms. LaFleur. Yes, Congressman Green. The EPA, in fact, we based our policy statement on a policy guidance memo they put out that indicated that power plants could seek a fifth year to comply with the advice of FERC and other reliability experts. Thus far we are just in the fourth year, so we haven't had any fifth year applications, but we anticipate a few.

Mr. Green. Well, Congressman Olson and I actually have passed a bill through the House that doesn't deal with FERC but deals with EPA and the Department of Energy, H.R. 271, that deals with the conflict that exists between EPA and the Department of Energy. That bill passed the House, and it may emerge sometime in a different form over in the Senate, but it also puts reliability as the most important.

Because again, I am from Texas, and Houston right now where it was 99 degrees when I left last week, and so reliability is important for our air conditioning to run in the summer just like it is for heating in the north in the winter.

Given the increasing complexity of EPA's regulations, does FERC anticipate additional conflicts with reliability?

Ms. LaFleur. I believe it is our responsibility to make sure that reliability is sustained. I think we will know much more when we see the different State plans, but there will undoubtedly be issues to work through as we work through the transformation, that is what we will do.

Mr. Green. You also discussed EPA's proposal and gas pipeline adequacy in your testimony, stating FERC emphasized capacity factors and existing constraints. Do you believe EPA adequately incorporated FERC's input?

Ms. LaFleur. I think EPA referenced in the rule the considerable need for new pipeline capacity to facilitate the Clean Power Plan, but it is going to be up to us to help get that pipeline capacity in the ground.

Mr. Green. Okay. Do you anticipate FERC's handling increased permitting requests for natural gas pipelines if States choose the EPA's regional policy option, which since FERC is a national agency.

Ms. LaFleur. I think our pipeline work will continue to grow for a number of reasons, yes.

Mr. Green. Okay.

Director Bay, until you are at least sworn in, as Director of Enforcement in your office and responsible for violations and inquiries in market manipulation, however unlike other Federal agencies, FERC does not have an office of compliance or any other resource or regulated community to address questions and concerns. Mr. Bay, do you believe that the office of compliance would benefit the regulating community, someone to just call and say we are looking at this option before it ends up in enforcement action?

Mr. Bay. We actually tried to do that, Congressman Green. There is a no action letter process whereby an entity can submit its question to FERC for consideration by staff on whether or not there would be a violation if the entity engages in a certain form of conduct.

In addition, we have a help line that is staffed to answer questions from the regulated community. And certainly we are often speakers at conferences in which we --

Mr. Green. Okay. I only have about 40 seconds left, but I am concerned that maybe we could use some more transparency on the enforcement and maybe an additional office of compliance.

Let me get to my last question. Mr. Clark, EPA's rule seems to assume transmission grade will not require much, if any, changes as a result of retirements, decreased margins or renewable sources whether they be large or small. In different regions of the country, what entities are responsible for building and maintaining new and existing transmission, and what challenges are they going to face under this new EPA model?

Mr. Clark. Congressman, there can be different entities in different parts of the country, either incumbent utilities or competitive utilities that are attempting to get into the transition business. Who plans that and makes the calls differs substantially in different parts of the country, and in more regulated, less restructured regions of the country, like the southeast and most of the west, it tends to be still traditional monopoly and vertically integrated utility companies regulated by States. In more market regions of the country, it tends to be probably an ISO or an RTO.

Mr. Green. Okay.

Thank you, Mr. Chairman. I know I have run out of time.

Mr. Whitfield. At this time the chair recognizes the gentleman from Virginia, Mr. Griffith, for five minutes.

Mr. Griffith. Thank you, Mr. Chair.

Ms. LaFleur, if I understood your testimony earlier, and I wrote down part of it but I don't want to put words in your mouth, given the structure of the Clean Air Act that we have, the EPA I think you said did a good job or something similar to that. I got it to that point and then I couldn't write fast enough. Is that an accurate statement of your opinion?

Ms. LaFleur. That is basically what I said. The question was what's the most efficient way to regulate carbon, and given the authority they have --

Mr. Griffith. Yes, ma'am. That wasn't my question. My question is, is that a statement of your opinion that the structure of the Clean Air Act that we have, under the structure that we currently have, the EPA did a good job in coming up with these regulations?

Ms. LaFleur. Yes.

Mr. Griffith. And so then I would ask you to reconcile for me when you take a look at Section 111 of the Clean Air Act where in Section D it says, the Administration shall prescribe regulations which shall establish a procedure under which each State shall submit to the administrator a plan which establishes standards of performance for the existing source for any air pollution for which air quality criteria have not been issued or which is not included on a list published under Section 108 A, and the critical part, or emitted from a source category which is regulated under Section 112 or 112 B.

And how do you reconcile that with the fact that electric generation units are currently regulated under 112, and therefore the EPA does not appear to have authority under the Clean Air Act to propose the regulations which they have enacted, and what they are relying on is a scrivener's error that took place in the redraft in, I believe, 1990, but in a case which I would cite for you all to go back and look at with your lawyers, in a case New Jersey v. EPA 517 F.3d 574, 2008, it appears that the EPA acknowledged that they didn't have this authority.

And the court ruled accordingly in view of the plain text in structure of Section 112, we grant the petitions and vacate the delisting rule, which was a previous lawsuit. This requires vacation of cameras regulations of both new and existing EGUs, electric generation units. EPA promulgated the camera regulations for existing EGUs under Section 111(d), but under EPA's own interpretation of the Section, it cannot be used to regulate sources listed under Section 112.

So it is not just my reading, but apparently the EPA in a court case made that same reading, and the EPA thus concedes that if EGUs remained listed under Section 112, as we hold they do, then camera regulations for existing sources must fail. So it would appear that the EPA is reaching way out, and under the existing law I would submit they don't have the authority and that they are asking for litigation.

Doesn't that make your job harder in trying to figure out where you are going to go when the EPA is stretching the law so far that they disagree currently with the decision of the court that they conceded was the correct reading of the law as late as 2008? Yes or no.

Ms. LaFleur. The legality will be decided by the courts, but we are going to do our job to try to keep the lights on in the meantime.

Mr. Griffith. And I appreciate that you all are going to try to keep the lights on, and that brings us to this whole pipeline issue and I worry about the EPA and folks filing lawsuits on trying to lay down new pipeline to get it to the power sources, and all of a sudden we have EPA regulations coming in and saying to us, wait a minute, wait a minute, you can't put the pipeline there, or we have lawsuits that last longer.

And, Mr. Norris, you said earlier you were confident in the American innovations and so forth, and I am too. The problem is the EPA apparently is so confident they believe that we can get it done in two years. We know from the Department of Energy, and I sometimes wish that all of you all would sit down and talk on a regular basis. The Department of Energy has told us the new clean coal technology will not be available for approximately ten years even if what we are working on now works, and I think there is some really exciting things. I love chemical looping, but we are looking at ten years. I think with some money we might be able to shorten it to seven years.

But under these proposed regulations, assuming that they go into effect, the States have to come up with their plan. Even though they have ten years to hit their target, their plan has to be completed with one year. That doesn't seem very reasonable to me. Do you believe that States really can come up with a plan not knowing where the pipelines are going to be, not knowing what technology is going to be available that can hit all of these very rigorous standards, come up with the plan now for ten years later? Yes or no. Thank you.

Mr. Moeller. I do.

Mr. Griffith. Thank you. You do.

Well, we only have five minutes, so I got to hurry to get it all in. I got more than I can handle here.

Somebody said earlier it is not the EPA regulations that are putting the coal power plants out of business; it is the price of natural gas. The problem is, is that coal and natural gas compete about even at $4 a unit, and for most of this year, it is true in the last week or so it has dropped back down under $4, but for most of 2014, the natural gas price has been over $4.

And so if it is not the price, I would submit to you all it must be EPA regulations which are in fact killing jobs across this country, and we are doing it at a time when this country can't afford it. The people in my district can't afford it. The consumers are the families of the middle class America. We are the ones being hurt. It is great to have all these lofty ideas, but I don't see it working, and I fear that we are going to have rolling brownouts in the future, and I fear that you all are going to have a really tough job because of these EPA regulations.

And with that, Mr. Chairman, I see my time is up, and I yield back.

Mr. Whitfield. At this time I recognize the gentlelady from California, Ms. Capps, for five minutes.

Mrs. Capps. Thank you, Mr. Chairman, and to all of the commissioners, thank you for your testimony today.

Despite what some have argued, it is clear to me that EPA engaged in unprecedented outreach in developing its Clean Power Plan. EPA met with public utility commissioners, grid operators, and utilities of all types among may others.

Chairwoman LaFleur, to emphasize it for the record, I would like to ask you about EPA's outreach to you and to FERC staff. In your written response to questions posed by the majority, you indicated that FERC staff met with EPA staff on several occasions while the proposal was being developed. Is that correct?

Ms. LaFleur. Yes, it is, Congresswoman Capps.

Mrs. Capps. And during these conversations, did FERC have an opportunity to flag issues that you all believed that EPA should be considering while developing their proposal?

Ms. LaFleur. Yes.

Mrs. Capps. Thank you.

As far as you know, did anyone at FERC tell EPA that the proposal would significantly undermine reliability.

Ms. LaFleur. That was not the sum of our advice. As I said in my testimony, our staff really emphasized that the pipeline and transmissions would need to be there to facilitate the plan, that that was a key driver as well as a need for regional cooperation.

Mrs. Capps. Thank you.

Another topic. One of the written questions from the majority asked whether FERC prepared the resource adequacy and reliability analysis that EPA released with the proposed rule. Would FERC normally prepare the supporting documents for another agency's rulemaking?

Ms. LaFleur. Not to my knowledge. I think that was prepared at EPA.

Mrs. Capps. So there is nothing unusual about EPA conducting its own supporting technical analysis for a proposed rule?

Ms. LaFleur. I honestly don't know what their normal practice is, but they did not come to us for that.

Mrs. Capps. Thank you.

And again moving on, we have heard arguments that FERC should immediately complete an independent reliability assessment of EPA's proposal. Chairwoman, in your testimony you indicated you don't think it makes sense for FERC to prepare such an analysis at this time. Why is that?

Ms. LaFleur. First of all, the rule is just in draft, but even if the rule were final, the way it is structured, there is 49 different States, have to come up with plans using four different building blocks, and some of them will do it on a State level, some regional, so there would be so many combinations and permutations we would need to go through, I think it would be more productive for us to focus on doing our jobs of getting the infrastructure built and then zero in if there are issues in a State.

Mrs. Capps. Thank you.

Again moving on, our power sector is already transitioning towards energy efficiency and renewable energy, and EPA's Clean Power Plan will accelerate that transition. That is my summary of it. If regulators in industry do the necessary planning and maintain focus on implementing the S? Rules targets, is this transition manageable, and can you elaborate on that a bit?

Ms. LaFleur. I think on balance it should be manageable. As I said, I think there is a lot of infrastructure we need to get built, and we need to have a process if there are specific issues. But from what I hear, many of the States are already well situated.

Mrs. Capps. Thank you.

You know, Mr. Chairman, I think it is clear that EPA sought and received FERC's input on the development of the Clean Power Plan, and that EPA will certainly continue to seek FERC's input as it finalizes the rule as it moves from the draft into the final rule stage. EPA's Clean Power Plan is a critical step to reducing carbon emissions and combatting climate change, and I hope we can all work together in the various agencies and Congress to ensure that these rules are as strong and as effective as possible.

And I know I have a minute left, but I am prepared to yield back.

Mr. Whitfield. Gentlelady yields back.

At this time I recognize the gentleman from Illinois, Mr. Shimkus, for five minutes.

Mr. Shimkus. Thank you, Mr. Chairman.

Again, welcome. We are actually glad to have you here, and I missed some of the impassioned questions, but the reality is there are people in coal countries of this nation that since this Administration was elected there has been a war on coal.

And I always refer people to President Obama's then meeting with the editorial board of the San Francisco Chronicle in 2008 when he said, I am just going to make it so costly to use coal, that they will move out of the market and I think we are living in that world. Your job is living in that world, how do we keep the lights on.

And I also would hope that your job would be trying to make sure there is enough base load and that we have competitive prices because if prices go up, then the whole economy is challenged by that. But the passion is sincere for those people who live in coal country and have the majority of their generation from coal-fired power plants.

Now I am from Illinois, so we have a big nuclear portfolio, too. We are fortunate in that, but I would say nuclear power is challenged today also.

So, Chairwoman LaFleur, I filed this question, and in your statement you talked about the FERC staff working on the operational grid, pipeline, transmission, regional cooperation, and I understand the work that commission staff has done, but I was intrigued by Commissioner Moeller's statement when he talked about requesting a more formal role.

Commissioner Moeller, can you explain to me what that means, and maybe that might address some of these questions about how much time, who is reviewing, who is making decisions. And what do you mean by a more formal role?

Mr. Moeller. Well Congressman, as Acting Chair LaFleur mentioned there were meeting between FERC staff and EPA, but it is kind of up to whoever heads the agency as to whether that information is going to be disseminated.

Now, to her credit, she did. But I like these issues. They may not be very glamorous, but they are very important in terms of the reliability implications of transitioning this fleet in a very short amount of time.

And so I don't want to endorse staff meetings and paperless meetings. I would prefer a more formal open, transparent process, where frankly we can get engineering expertise which will often probably disagree amongst themselves as to the reliability implications, and I don't think it is that hard because EPA even gave us the list of power plants that they project to shut down. So the information is out there courtesy of EPA.

Mr. Shimkus. So in that statement, and not trying to sow discord, but it is your opinion that there hasn't been an open, transparent system?

Mr. Moeller. I was never invited by EPA to either review the proposal or comment on it. It was done strictly --

Mr. Shimkus. Let me ask to all the commissioners here and the acting Commissioner, was anybody else invited to any of these meetings with the EPA? Obviously the commission, the staff is yours, but --

Ms. LaFleur. There is two different things going on. In the interagency review process, we were under strict confidentiality requirements about Xeroxing and releasing information, although I did offer the excerpts to all of my commissioner colleagues. Now that the rule is out, we can have all the open meetings we want.

Mr. Shimkus. And I only have a minute left. So I know Commissioner Moeller, you weren't. Commissioner Norris, were you involved in any of this prior?

Mr. Norris. Well, I was involved --

Mr. Shimkus. Or Commissioner Clark?

Mr. Clark. No.

Mr. Shimkus. Commissioner -- you weren't around yet. So welcome, I guess I should say.

And I will just end on this, again we appreciate it. You all know where we stand. I talk to a lot of people in the generating sector, and I was involved with public policy that moved us to competitive generating facilities instead of a, in regulated markets. I think there is now a question under this new regime of is it better for reliability, do you go back to regulated markets? How are merchant facilities going to survive?

Commissioner Clark, you are shaking your head. Do you want to comment real quick, and then I will end on that, Mr. Chairman. Thank you.

Mr. Clark. Congressman, you raise an intriguing point, and one that I have thought of from time to time, which is there is the potential in some restructured markets to have, to the degree that you are requiring a State-led basically integrated resource plan to be put on top of the market construct, that it is a form of almost soft re-regulation in some of those markets that had traditionally been trending in a much different way in a restructured environment.

Mr. Whitfield. At this time, I recognize the gentleman from Pennsylvania, Mr. Doyle, for five minutes.

Mr. Doyle. I thank my friend.

Commissioners, thank you and welcome. You have provided a great deal of insight and thought, and your responses to the majority's written questions were certainly exhaustive.

We are embarking on a fundamental shift in our energy sector, and I share the goal of reducing emissions of greenhouse gasses that are contributing to climate change, but we have to do it in a way that is prudent. Traditional energy sources, nuclear, coal, they are still going to play a critical role in ensuring reliability, and as we move forward towards supporting cleaner types of energy, we have to make sure we have the capability and the infrastructure to support them. The most recent proposed rule from the EPA on existing power plants is going to force a sectorship with a fairly expedited time frame, and the impact is real, particularly in my home State of Pennsylvania. So I appreciate your time today as we continue this critical conversation.

Chairwoman LaFleur, let me ask you, as you know, the 111(d) proposed rule includes both binding interim goals beginning in 2020 and final compliance goal in 2030. Now, if there is no hiccups or delays or extensions, many States will have their completed plans in place by hopefully 2017.

By 2020, my State, Pennsylvania, will have to reduce its carbon emissions from the 2012 baseline by 28 percent. That is just three years to make a 28 percent reduction. This will require swift action from utility planners, rather than long-term planning that could ease reliability concerns.

My question is by keeping the 2030 compliance goal in place but allowing States to determine the appropriate interim glide path, could EPA achieve the same carbon reduction goals while providing utility planners the necessary timeline to avoid reliability impacts and unnecessary stranded assets, and is this an approach that FERC would support?

Ms. LaFleur. I would want to think more about that, Congressman, and perhaps take it as a question for the record. It is not something that we discussed with EPA during the process. I do think that your

State is well served -- Pennsylvania has the advantage of being well served with gas pipelines and also being close to a region that -- being in a regional transmission organization where there might be regional solutions that would both afford more time and more options to the State; but, of course, it is not up to me to make their plan.

Mr. Doyle. Let me ask all of the commissioners. A recent Brattle study noted that looking at forward market prices and recent five-year cost trends, about half of merchant nuclear plants are not profitable. This is not a future problem. This is a problem that is staring at us right now today.

What happens to reliability if nuclear plants retire, especially when you factor in the number of coal plants shutting down because of EPA's MATS rule and the fact that the remaining base load coal fleet is under the same market pressures as nuclear? It seems to me that this is a real problem today long before the rule could impact the grid. What are the RTOs doing, particularly PJM in my area, to address this problem today?

Ms. LaFleur. Well I think it would be a problem if we lost our nuclear fleet. It is a very important part of our fleet. PJM, as well as FERC, are looking at both the capacity markets to make sure they properly compensate the reliability contribution of base load plant, as well as Commissioner Moeller referred to we are looking at price formation in the energy markets to make sure that those plants are getting fair market prices to support them.

Mr. Doyle. Would any other of the commissioners like to make a comment on that?

Mr. Moeller. Congressman, your specific question about what happens if we lose the fleet, the entire fleet would be devastating because it is so important to our grid. Individual plants, it really depends on the load pocket involved, and I know that New England is struggling with the closure of Vermont Yankee, and there are lots of ramifications of that.

But as Acting Chair LaFleur noted, both the RTOs and as a commission, we are looking at ways to better compensate the reliability implications of on-site fuel and trying to get the prices right in the price formation effort, which will better compensate those units.

Mr. Doyle. I am trying to understand when EPA says that the rule will preserve at-risk nuclear plants, how exactly does that work? I mean how will they preserve at-risk nuclear plants, and how soon does that happen?

Mr. Clark. Congressman, I share your concern. I think the answer is easier in certain regions of the country than others. If you come from a region that still happens to be a State-regulated monopoly, vertically integrated utility environment, it is probably less of a concern in that those public utility commissions can build in some of the those base costs into base rates.

In market regions of the country though, you are exactly right. We are struggling with that issue where there doesn't seem to be enough revenue from the market to support some of these, what I think most people acknowledge are very important nuclear plants.

Mr. Doyle. Thank you.

I see my time is up. Thank you, Mr. Chairman.

Mr. Whitfield. Thank you.

At this time I recognize the gentleman from Texas, Mr. Burgess, for five minutes.

Dr. Burgess. Thank you, Mr. Chairman. Welcome to our commissioners. We are really so grateful you spent the time with us.

Mr. Moeller, let me ask you a question because you caught my attention in your opening statement and of course you were talking about the commission has a responsibility to promote the reliability of the Nation's bulk power system, and then you specifically referenced heating and cooling. We talk a lot in this committee about public health concerns, about things. I mean, that is a major one, isn't it? We forget about, I mean, everyone understands that there can be cold-related deaths, but heat-related deaths actually can be more significant, at least in my experience.

Mr. Moeller. Absolutely. We talk about the lights staying on, which is great, but it is really heating and cooling that keeps people alive during extreme weather events, and particularly in your State, it gets mighty hot.

Dr. Burgess. Well, and even in States where it is not. I mean, we saw in France in 2003, when I forget the number, but I think it was in excess of 10,000 deaths during a heat wave that they had in France that they were unprepared to deal with, so it can be substantial. The effects on public health can be substantial.

You know, I think you point out in your testimony that the Federal Power Act restricts the duties of the commission, the authority to regulate interstate electricity transmission, wholesale electricity prices, and leaves the questions of electricity generation and intrastate distribution to the States, but with the proposed Clean Power Plan, this separation seems to be changed and puts the EPA in control of intrastate electricity matters.

Is that concerning to you as commissioner of the FERC that the EPA is claiming authority through really the regulatory process that Congress did not grant to you as a commission through statute?

Mr. Moeller. I think Commissioner Clark may want to elaborate more specifically to that point. But, I try to point out the fact that these are interstate markets, and if you impose a State-by-State enforcement solution, that is very challenging, particularly when you have States that, for instance, Idaho, that consumes a lot of coal-generated power but doesn't actually produce any within their State. The baseline how it works now going forward, very challenging.

Dr. Burgess. Commissioner Clark?

Mr. Clark. Sure. I would just reiterate what appeared in my presubmitted testimony, which is, just that this is a big change potentially as States enter into these compliance plans wherein they may be putting into the compliance plans all sorts of integrated resource planning type mechanisms like renewable portfolio standards and efficiency codes, as well as decisions that their State public utility commission is making and then seeking approval of those from the EPA.

To the degree that they later try to change that, depending on how inflexibly that is written in their particular compliance plan, it could cause issues where they later need to go and seek approval from the EPA, or if they depart from that, subject some entity in their State, either a generator, the State itself, to either an EPA complaint in enforceability, or even private citizens lawsuits against the plan that they have locked themselves into. So it is a jurisdictional issue that I think States will need to think about as they work through this process if the rule is upheld.

Dr. Burgess. They need to think about it, but it also strikes me that they may not have, I don't know. Are they going to have the protections that they need in order to do their job.

I just have to say as a father and a grandfather, I admire the forbearance of your sons to hang with you through this. I don't know what you promised them, but I suspect it must be substantial.

Mr. Clark. Thank you. I have a seven-year-old that is at home that we didn't risk this with.

Dr. Burgess. So noted.

Let me just ask you a question on, the reductions in actual capacity, the EPA seems to assume a reduction based on efficiency measures.

The EPA really cannot force citizens, though, on their purchase of electricity or power, so how can the EPA rely upon reductions in usage based upon efficiency without the ability to mandate how much power is consumed or not consumed?

Mr. Clark. Congressman, I think what is envisioned by the EPA's plan is that that is the sort of thing that would go into a State compliance plan. It does raise the question about, in my mind, who would be the entity that EPA would then enforce that standard against?

An energy efficiency measure is not like a power plant that EPA can go in and specifically tell to ramp down or up. If there is something that is not being met in the State energy efficiency goal, who would be the compliance entity that is targeted? Would it be the State itself, the installers of the energy efficiency? I just struggle a little bit to understand in the context of the Clean Air Act exactly how that would be enforced, but I appreciate the question.

Dr. Burgess. And I appreciate the very provocative answer in the form of a question.

Thank you, Mr. Chairman. I will yield back.

Mr. Whitfield. At this time the chair recognizes the gentleman from Georgia, Mr. Barrow, for five minutes.

Mr. Barrow. Thank you, Mr. Chairman. I want to talk about something we haven't talked about much today. To fully develop and deploy renewable energy in some remote areas is going to require infrastructure upgrades to get that energy from where it can be generated to where it is going to be needed.

And I know until 2011, the rule was pretty set. Infrastructure upgrades had to be paid for by those who were going to benefit from them. There was a direct benefit test. Back in 2011, you all released a regulation, it is called Order 1000, that basically proposes to broaden, to reallocate the cost of infrastructure upgrades to allow for the greater development of renewables in remote locations by spreading it across a broader base, including folks who won't benefit from it, won't consume the energy that is being produced.

Now, personally I am all for them paying the cost who get benefits, myself. But I want to ask each of you all, and direct this question to each of you in turn, what do you say to folks who are skeptical about spreading the cost of infrastructure upgrades beyond the base of those who are going to benefit directly from it?

Ms. LaFleur. Well, order 1000 preserved the principle that those who benefit are the ones who should pay for transmission. But it suggested a new type of benefit beyond reliability, which is well understood and why you build transmission. Economic benefits of reducing congestion, getting a cheaper power by building transmission.

And the third was enabling States to comply with State laws such as buying renewables, so the premise of the rule is that if a State passes a law requiring extra set renewables, then the transmission to facilitate compliance with that law does benefit that State. So it is a different type of benefit but still one that we believe the people who receive the benefit should pay.

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[12:01 p.m.]

Mr. Barrow. Commissioner LaFleur, am I correct in understanding, then, that a State like Georgia, which does not mandate the purchase of renewables in a certain quantity would not in any way be required to subsidize or contribute to the cost of upgrades elsewhere in order to provide for the --

Ms. LaFleur. That is correct. Georgia would be part of a region, there is a southeastern regional planning and only Federal, State and local enacted laws and regulations would be public policy requirements around which transmission had to be built. So if Georgia had no renewable requirement, they wouldn't have to build for renewable requirement.

Mr. Barrow. How about you, Commissioner Moeller, do you agree?

Ms. LaFleur. Excuse me?

Mr. Barrow. How about you, Commissioner Moeller, do you agree?

Mr. Moeller. There are parts of Order 1,000 I supported, parts that I wasn't supportive of it is in the courts now. But generally speaking, the concept of beneficiary pays is one that we try to embrace. The challenge with these assets is that they are often 30, 40 or 50-year assets and the power flows change and so who is paying for them now, other entities can benefit. So there is some art and there is some science in cost allocation. It is difficult, but most importantly, we want to get it built.

Mr. Barrow. Commissioner Norris, do you think those who pay bills --

Mr. Norris. Yes, the board supports the principle beneficiary pays, and I agree with both the previous commissioners. This is not an exact science. But, you get reliability benefits, you get economic benefits, and you get the access to renewable energy where it shows and by that plan. I would just add to what Commissioner LaFleur said is that the public policy only acquires that that be considered in the regional plan. It does not require that that be a part of the plan. It only enables public policy considerations to be a part of the process but does not require them to be in the plan.

Mr. Barrow. And what does that mean for folks who are served by companies that don't --

Mr. Norris. That means the regional planning process has to have in their planning process, a mechanism in which public policy laws or requirements get on the table for consideration. It doesn't require that they be adopted in the plan, only that there is a process by which they get considered.

Mr. Barrow. Commissioner Clark?

Mr. Clark. I would agree that the concept of beneficiary pays is a sound one. There have been a number of cases, Order 1,000, which I, too, have agreed with parts and disagreed with parts, but also specific cost allocation cases that have been taken to court, some of which I have agreed with, some of which I have not.

I think the courts are beginning to hem in the commission in terms of what is considered within bounds and what is considered without, outside of the lines. In a recent MISO case, it determined that the commission had made a sound judgment in terms of beneficiary pays and I thought the court was right. In the case of a recent PJM case; the commission had decided it was outside of the bounds and had not tied down that beneficiary pays analysis enough, and I agreed with the court in that case, as well.

Mr. Barrow. Commissioner Bay, last word.

Mr. Bay. The only thing I would add is that the 7th Circuit has said that the cost must be roughly commensurate with the benefits, and the commission has adopted that principle, as well in Order 1,000, and also has said that if you don't benefit, you don't pay.

Mr. Barrow. Thank you.

My time is up.

Mr. Whitfield. Time has expired.

At this time, recognize the gentleman from Pennsylvania, Mr. Pitts, for 5 minutes.

Mr. Pitts. Thank you, Mr. Chairman.

The Administration's Clean Power Plan that we are reviewing here today provides four emission reduction strategies, fuel switching from coal to natural gas is a potential component of two of these strategies.

One advises the coal firing of coal plants with natural gas or outright conversion to natural gas firing; the other involves increasing the dispatch rate for natural gas combined cycle power generation units. Pipeline companies are expanding their infrastructure to meet demands for clean burning natural gas, and in Lancaster County, which I represent, there is a proposal for a new line that would run through most or some of the most pristine farmland in the Nation.

Chairman LaFleur, I have two questions relating to this. Since many other communities will see similar projects in the coming years, what procedures do you have in place to make sure environmental concerns and the rights of property owners are given full consideration when reviewing these proposed roots for pipelines? And secondly, do you believe the Clean Power Plan would lead to a proliferation of new pipelines across the country?

Ms. LaFleur. Well, thank you for the question, Mr. Congressman.

The way our pipeline approval process works, we do a complete review of the environmental safety and community aspects, which includes scoping meetings, opportunities for public comment, open houses in communities around the pipelines. We are often asked why the process takes so long, and it is because of all the opportunity for comment that are fed into the process. I do believe we will have more pipelines as a result of the greater utilization of gas, but they have to be built with sensitivity to the concerns of the people whose communities we are crossing.

Mr. Pitts. Commissioner Moeller, right now, some States average a natural gas utilization rate in the single digits. Given that the EPA assumes that an average 70 percent utilization rate for natural gas is feasible, do you think that many States may fall short in this goal and that many consumers will simply be left with a larger electricity bill?

Mr. Moeller. Well, I think it would be extremely challenging, Congressman, to reach those 70 percent levels, generally. I will be looking forward to the comments on the rule that talk about particularly the operational aspects of that aspiration, and we will need to get the pipeline in place.

And the question is, does the timing of a new pipeline sync up with the enforcement timeline?

Mr. Pitts. Commissioner LaFleur, my understanding is that the proposed rule factors in new nuclear plants but only factors in 6 percent of the existing nuclear plants; in other words, if an existing nuclear plant shuts down, the impact on a State's ability to comply is limited to 6 percent of the energy that comes out of that plant, which doesn't seem like much of an incentive to take actions that will value the carbon-free energy that nuclear plants provide all day, every day.

Don't you think customers benefit from having plants that have 18 to 24 months of fuel on site, particularly when those plants can run at 97 percent of their capacity even during conditions like the polar vortex or the hottest day of the summer?

Ms. LaFleur. I think nuclear plants bring a lot of benefit to customers, including reliability benefits, the fuel security you mention. I don't believe that the EPA mandated what percentage any State could or could not rely on nuclear. That was a building block that was put out that a State could put together. If a State wanted to rely more on nuclear, less on something else, my understanding of the plan, it would be allowed.

Mr. Pitts. Mr. Moeller, would you like to comment?

Mr. Moeller. Well, I have talked to a few nuclear companies about it, and I think they are still analyzing it, but there is one train of thought that despite EPA's intention, that the 6 percent could actually be counterproductive to nuclear. It has to do with the calculations and replacing it with gas to meet your baseline better. But it is certainly worthy of further discussion. I admire EPA's attempt to try and booster the nuclear units, but there is a train of thought that actually could be counterproductive the way they proposed it.

Mr. Pitts. I yield back.

Mr. Whitfield. Gentleman yields back.

At this time, I recognize the gentleman from Kentucky, Mr. Yarmuth for 5 minutes.

Mr. Yarmuth. Thank you, Mr. Chairman.

And thanks to all the commissioners for this discussion. I think it has been a very thoughtful and interesting one.

I want to thank the chairman, my fellow Kentuckian, for returning us to the days of yesteryear with the discussion of Waxman-Markey, which, by the way, did not become law because a Republican minority in the Senate wouldn't let it become law, because it did have a majority of votes in the Senate after passing the House. But when I was considering whether to vote for that bill or not in the House, my primary concern was how it would affect the cost to my consumers, both business and residential.

And I talked to a lot of the businesses, all the big users of power; they were all kind of either for it or neutral on the bill. And then I talked to our utility company and asked them how it would affect residential rates, and they said that they projected that over 10 years the average residential user would experience a rate increase of 15 percent if they did nothing else, and so they didn't engage in any conservation practices.

And I think, understandably, this hearing is focused on the supply side of the energy equation, but the demand side of the energy equation is also critical to our ongoing consideration of our energy future.

And Mr. Norris, you talked about innovation primarily on the supply side, but there is an incredible amount of innovation going on on the demand side, which is going to affect supply and whether or not we have adequate energy in the future. So when we talk about rates,

rates don't necessarily mean billing amounts, is that correct? And there are huge amounts of the things going on out in the world of innovation right now which could dramatically affect what the bills are regardless of what the rates are. Is that not true and would you elaborate on that?

Mr. Norris. Very true. The chairman of our State commission, we had a utility, MidAmerican, who hadn't raised rates over 10 years, but I got complaints all the time about people's utility bills going up, and it is very simple: You are plugging more stuff in and turning more stuff on. So the demand side is a very important part of this equation.

As I said in my written testimony, the deployment of smart grid and smart meters are already taking place, and that continues to be a technological innovative area where we can do a lot more to make our consumption of electricity much more efficient, and we should.

Mr. Yarmuth. And, I mean, I am not aware of any decent-sized business that is not very much focused on reducing their energy costs and doing the types of things, whether it is turning their computers off at night or whether it is putting solar panels on their roofs or doing any number of things to reduce those costs.

Have you seen examples of, you know, can you kind of gauge what the opportunity in terms of utilization reduction on the demand side would be because of technology, just current technology right now? How much can an average business save by implementing -- or an average homeowner save by implementing some of the techniques that already exist?

Do you have an estimate on that?

Mr. Norris. How much is the potential, you say, for demand side reduction? Well, no, I don't have a number. I know that there is still a great opportunity for putting price responsiveness and demand response in both our retail and wholesale system. For consumers to get the right price signal, putting elasticity in our demand curve, I think there is a great potential, but I don't have an exact number for you.

Mr. Yarmuth. Right. And we know that, for instance, rates on solar panels have come down approximately 75 percent just in a matter of 5 years or so. So it is reasonable to expect that those kinds of technologies will make it much easier for consumers and for businesses to keep their cost in line, their energy costs in line, even if rates happen to rise at some significant rate.

Is that not true, Ms. LaFleur?

Ms. LaFleur. Yes, that is definitely true. And much earlier in my career, I used to run conservation programs for an electric company and there are a lot of things that businesses and residences can do, first of all, when they build in the first place to build inefficiency, but also retrofitting, lighting, motors and so forth.

Mr. Yarmuth. Okay. And we are actually seeing that in the automobile segment of the energy industry, too. Innovation has now vastly increased the amount of mileage, and unfortunately, that is having repercussions in the Highway Trust Fund because people are not buying as much gas and paying as much tax.

But anyway, I appreciate the discussion, and your work. Thank you very much.

Mr. Chairman, I yield back.

Mr. Whitfield. Thank you very much. The gentleman yields back, and that concludes today's hearing.

Mr. Rush. Mr. Chairman, I have a unanimous consent request.

Mr. Whitfield. Okay. What is it?

Mr. Rush. Mr. Chairman, I would ask that the record reflect that Commissioner Clark's two sons have been the most attentive and intense listeners we have had before this committee in years and years and years.

Mr. Whitfield. Without objection, so ordered.

Mr. Clark. Mr. Chairman, and ranking member, I appreciate the compliment, but you realize when you make it it is going to cost me a lot more money somewhere down the line paying them back. So thank you.

Mr. Whitfield. Well, I am sure that their classmates are going to be excited for them to tell about this hearing that we had on FERC and the clean plan, and they will be the most popular students in school.

And I am also going to ask unanimous consent that we enter into the record a statement from the American Public Power Association on this hearing.

[The information follows:]

******** COMMITTEE INSERT ********

Mr. Whitfield. And that will conclude the hearing.

I want to thank all of you for being here. We also thank you for your responsibility in what you do for our country. We look forward to working with you because we don't really have any easy answers here. There are many challenges facing all of us, and I know that even though we have philosophical differences, we do have the same goal and that is to have a strong economy and reliable abundant electricity.

So thank you all again. The record will remain open for 10 days.

And for the Clark children, I hope you will come back and see us again soon. Thank you very much.

[Whereupon, at 12:16 p.m., the subcommittee was adjourned.]