Heat Rate Reductions and Carbon Emissions

A Policy Mechanism for Regulating Coal Plants under 111(d) of the Clean Air Act

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Acknowledgements

Executive Summary

The Clean Air Act requires the EPA to regulate carbon dioxide and greenhouse gases to protect public health and welfare. Currently the agency is in the process of developing standards for existing coal power plants under section 111(d) of the CAA and are expected to issue the proposed rule this summer. These regulations have the potential to drastically reduce emissions in the United States. Of the policy proposals and recommendations that have been submitted to the EPA, most advocate for including flexibility mechanisms, such as emissions trading, crediting and offsets, in the guidance policy. However, such broad mechanisms have limited precedence under 111(d) and their legality is untested.

This paper explores a more conservative approach by regulating coal units within-the-fence-line. Specifically, the proposed policy would require uniform mandatory heat rate reductions for all coal units, regardless of initial heat rate. All coal units would be required to lower heat rates by 740-810 Btu/kWh, resulting in an 8% fleet-wide average. Inefficient units would be allowed to continue to operate alongside more efficient ones as long as each reduces their heat rate by the given amount.

The policy was modeled and this analysis finds that despite costs associated with installing heat-rate reducing technology, costs to plant operators and consumers are reduced. This is mainly due to the decreases in fuel costs that accompany the efficiency improvements. As a result, it is more economical for many coal plants to operate. US generation from coal increases 4% relative to a reference and electricity prices per kWh decrease. Costs associated with the policy do force some coal units into retirement. An additional 4.3 GW of coal capacity and 50 coal units are retired compared to the 4.4 GW that are expected to retire absent any policy. However, the units that close operate at low or zero capacity and specific regions are not disproportionally affected over others.

Carbon emissions are reduced by 68 megatons the first year that the policy goes into effect relative to the reference scenario and avoids 1,284 Mt of cumulative carbon emission over the lifetime of the analysis (2016-2030). However, overall, the policy does not force any changes in electrical generation. No new low-carbon resources are built as a result of the policy. Therefore, total emissions continue to rise through the end of the analysis as the economy grows. Despite starting below 2005 levels, emissions increase to 4.3% above 2005 levels by 2030.

Overall, the policy represents a less ambitious course of action to reduce carbon emissions from coal power plants but still allows reductions to take place at low economic costs and would likely stand up to challenges in court. While it is unlikely that the EPA will chose such a limited approach to regulating coal plants under 111(d), the proposed policy could serve as a sound option if other alternatives fail.

Introduction

The week of May 26, 2013, the Mauna Loa Observatory in Hawaii reached a striking milestone. For the first time ever, the weekly average carbon dioxide concentration hit 400 ppm, ushering us into a new and unprecedented echelon.[1] In March of 2014, concentrations again rose above 400 ppm.[2] It is apparent that this will soon become the norm. Record high concentrations have coincided with the warmest years and decades in human history,[3] a correlation that is beyond debate. The Intergovernmental Panel on Climate Change, which will publish the last installments of the Fifth Assessment Report in 2014, issued strong statements regarding human influence on the climate system and noted that the world is already experiencing the catastrophic impacts of climate change.[4]

Despite the imperative to curb emissions, comprehensive attempts have been stalled. To date, countries have been unable to agree to an international agreement. Domestically, the United States came close to passing a cap-and-trade program in 2010 but ultimately failed. As grander attempts have come up short, all eyes have turned to the Environmental Protection Agency (EPA). The Agency is required under the Clean Air Act (CAA) to regulate carbon dioxide and greenhouse gases, but until recently, it has been slow to move forward with regulation to address the largest sources of the pollutant. But this has changed in the past two years. In the coming months, the agency will release its draft proposal for regulating carbon dioxide from coal power plants, a policy that has the potential to lead to significant reductions.

Last year, on June 25, 2013, President Obama presented his Presidential Climate Action Plan aimed at taking concrete actions to reduce greenhouse gas emissions and prepare America for the harmful effects of climate change.[5] Specifically, his executive order instructed the EPA to move forward "expeditiously" to develop standards for US coal power plants.

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[1] National Oceanic and Atmospheric Administration (NOAA), "Trends in Atmospheric Carbon Dioxide: Up-to-date weekly average CO2 at Mauna Loa – Week beginning on March 30, 2014," (accessed on April 9, 2014), *http://www.esrl.noaa.gov/gmd/ccgg/trends/weekly.html*.

[2] *Ibid.*

[3] According to NOAA, 2013 was the fourth hottest year on record. *See* NOAA, "National Climatic Data Center: Global Analysis – Annual 2013," (accessed on April 9, 2014), *http://www.ncdc.noaa.gov/sotc/global/2013/13*.

[4] Intergovernmental Panel on Climate Change, "Press Release: A changing climate creates pervasive risks but opportunities exist for effective responses," (March 31, 2014), *http://www.ipcc.ch/pdf/ar5/pr_wg2/140330_pr_wgII_spm_en.pdf*

[5] White House, "The President's Climate Action Plan," (June 25, 2013), *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf*.

Coal power plants contribute 31% of domestic carbon dioxide emissions[6] while providing 32% of the total electricity.[7] But the amount of reductions that can result from regulating these entities largely depends on the stringency and comprehensiveness of the EPA's rule. Already, various non-profits, think tanks, and trade groups have submitted recommendations to the EPA for how to draft its rule. These proposals have ranged from market-based systems to more traditional command-and-control standards. Some have included provisions that allow crediting and offsets while others only regulate within-the-fence-line. Each proposal has its benefits and drawbacks – legally, economically, and in terms of emissions reductions. This paper explores a policy that regulates emissions from coal-power plants "within-the-fence-line," meaning that flexibility mechanisms such as renewable energy offsets, tradable standards, or end-use efficiency credits are not included. The policy proposed here requires a mandatory heat rate reduction for all coal plants in the United States, based on current available technology. While similar to other traditional command-and-control approaches, this proposal differs because it does not provide a baseline for plants to meet, but rather requires blanket reductions regardless of a unit's initial heat-rate. The policy is assessed to determine the economic and environmental impacts that would result if the agency took such an approach.

Background

In 2007, the Supreme Court ruled that carbon dioxide and other greenhouse gases qualify as air pollutants under the Clean Air Act and that the EPA must regulate them if they pose a threat to public health and well-being.[8] In the case *Massachusetts vs EPA*, the petitioners argued that the agency was not fulfilling its duties to protect the public from harm caused by climate change. The agency conducted a scientific analysis and released a report titled the "Endangerment and Cause or Contribute Findings for Greenhouse Gases," which concluded that greenhouse gases harm public health.[9] This finding made regulation of the pollutants a requirement and promulgated a series of actions by the agency to reduce

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[6] U.S. Energy Information Administration (EIA), "Energy-Related Carbon Dioxide Emissions by Sector and Source, United States," (accessed on March 3, 2014), *http://www.eia.gov/oiaf/aeo/tablebrowser/*.
[7] EIA, "Annual Energy Outlook Early Release," (December 16, 2013), *http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm*.
[8] Massachusetts v. Environmental Protection Agency (EPA) 549 U. S. 497 (2007), *http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf*.
[9] EPA, "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 239 (December 15, 2009), *http://www.epa.gov/climatechange/Downloads/endangerment/Federal_Register-EPA-HQ-OAR-2009-0171-Dec.15-09.pdf*.

emissions. In 2011, the EPA finalized emissions standards for cars and trucks and is in the process of developing standards for stationary sources.[10]

Despite the regulatory requirements, tackling greenhouse gas emissions under the Clean Air Act is a challenge. No one denies the fact that the law was not designed to regulate carbon dioxide. The pollutant, which is generated from all parts of the economy, has a long residence time in the atmosphere, mixes globally, and also comes from international sources. Furthermore, there are multiple potential avenues to regulate under the CAA. In some sections of the law, wording is broad and could be interpreted as applying to carbon dioxide. For instance, the National Ambient Air Quality Standards (NAAQS) program sets pollutant concentrations to ensure adequate margin of safety for the public.[11] Carbon dioxide may qualify as one of the criteria pollutants regulated under NAAQS but such an approach would be stringent and impossible for states to meet attainment.[12] Another option would be under Section 115 which allows the EPA Administrator to regulate a pollutant coming from the United States if it endangers the public health and welfare of a foreign country.[13] However, because this section has never been used since the Clean Air Act was passed in 1970, it is unlikely that the EPA would be able to justify such broad usage now.[14]

Weighing the legal authority and feasibility, the EPA chose to move forward under section 111 which applies to stationary sources of air pollutants. In September 2013, the EPA released a proposal for limiting carbon dioxide from new stationary sources. The rule, called a New Source Performance Standard (NSPS), requires coal and natural gas units yet to be built to meet a specific emissions rate based on the commercially available control technology. Specifically, new coal plants would have to meet a rate of 1,000-1,100 lbs/MWh in order to receive permission to be built.[15] While new source regulations do nothing to address the 1,264 existing coal power units,[16] it is an important procedural

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[10] 40 C.F.R §600 (2011).

[11] EPA, "National Ambient Air Quality Standards (NAAQS)," (accessed on April 18, 2014), *http://www.epa.gov/air/criteria.html.*

[12] Arnold W. Reitze, Jr., "Federal Control of Carbon Dioxide Emissions: What are the Options?," *Boston College Environmental Affairs Law Review* 36(1): 2009, *http://lawdigitalcommons.bc.edu/ealr/vol36/iss1/1*.

[13] 42 U.S.C §7415

[14] Burtraw, Dallas, Arthur G. Fraas, and Nathan Richardson, "Greenhouse Gas Regulation under the Clean Air Act: A guide for economists," Resources for the Future (February 2011).

[15] EPA, "EPA Technical Fact Sheet: Reducing Carbon Pollution from Power Plants," (September 20, 2013), *http://www2.epa.gov/sites/.*
production/files/2013-09/documents/20130920technicalfactsheet.pdf.

[16] EPIS, Inc., "AURORAxmp Electric Market Model (Version 11.2.1001)," [Software], (2013).

step to allow the agency to move forward with restrictions on existing sources[17] which falls under section 111(d) of the CAA. The law stipulates that existing source regulations only apply to the same category of sources regulated by new source performance standards.[18] Coal electrical generating units classify as a category so the EPA can only regulate them once NSPS have been finalized. It may not apply an existing source standard, for instance, to fuel oil electrical generators because it has not established a NSPS for that source. This is an important distinction that may limit the scope of what the EPA can regulate under 111(d).

The statute requires that the Administrator implement the "best system of emission reduction" that has been "adequately demonstrated,"[19] but what this means is heavily debated. A characteristic of the CAA is that it establishes the framework for regulation but in many sections contains intentionally broad language to give the agency some discretion when designing rules. There is no uniform policy design that the EPA uses for all its air quality regulations since the individual characteristics of each air pollutant and its sources are unique. Regulating carbon monoxide requires a policy approach that is very different from the approach for curtailing ozone pollution, even when both are regulated under NAAQS. For instance, carbon monoxide (CO) comes from inefficient combustion of mobile sources whereas ozone is a secondary pollutant that results from the reaction of volatile organic compounds (VOCs), nitrogen oxides, and sunlight. CO is more easily managed by regulating combustion engines and tailpipes whereas ozone requires more complex approaches targeting VOCs, combustion temperatures, and other factors. These characteristics influence the strategies that the EPA and states have used to limit ozone and CO.

For stationary sources, the EPA has similarly tailored rules to achieve the "best system of emission reduction" but it is still unclear how this phrase would apply to carbon dioxide emissions. Economically, the best system of emission reduction might include market-based trading between sources, and many academics and trade organizations have argued that the EPA should move forward with such an approach. Under other parts of the CAA, such as the Acid Deposition Program, market-based trading has been "adequately demonstrated" to be economically efficient and an effective tool of emission reduction. However, 111(d) has not been used often so the legality of how broad the EPA can interpret the phrase is widely untested, particularly for something as broad as carbon emissions from coal power

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[17] Tarr, Jeremy, "The Clean Air Act and Power Sector Carbon Standards: Basics of section 111(d)," Nicholas Institute (September 2013), *http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_pb_13-03.pdf.*
[18] 42 U.S.C§7411(d)
[19] 42 U.S.C §7411(a)(1)

plants.[20] Whenever 111(d) has been triggered, the EPA has usually opted for traditional, uniform standards. In few circumstances, the agency permitted trading emission credits across sources under 111(d). For instance, the EPA allowed municipal solid waste plants to trade nitrogen oxide emissions.[21] For these reasons, other academics and organizations have argued that a more traditional interpretation of the standard would be more appropriate in this case, particularly since any rule regarding carbon emissions will get challenged in court. The more traditional interpretation would limit the scope and is referred to as a "within-the-fence-line" approach. Regulating within-the-fence-line prevents the EPA from allowing credits, averaging, or trading and must only apply to the individual units.

Both Resources for the Future (RFF) and the National Resources Defense Council (NRDC) advocate for broader interpretations of "best system" that are more economically efficient and more comprehensive. RFF reviewed several policy scenarios of increasing flexibility. [22] The first was a strict standard on coal plants that allows trading between units. The second applies to all fossil fuel generators and allows trading between the sources. The final scenario expands flexibility by allowing credits and trading for nuclear and renewable sources. In all scenarios, units exceeding the standard were allowed to purchase emission credits from those under-emitting. As flexibility increased, the marginal abatement cost decreased to support the theory that broader policies are more economically-efficient. However, the paper found that increasing flexibility did not necessarily lead to greater emissions reductions.

NRDC developed a proposal that sets state-specific emissions standards (pounds of carbon dioxide per kWh) for existing coal power plants.[23] The proposal bases the standards on each state's electrical generation portfolio. States with larger coal generation would be granted a higher emissions rate than states with large natural gas generation. This allows coal-heavy states some initial leniency. However, over time, the metric changes and the emission rate is reduced so that coal heavy states would be required to make more significant reductions. NRDC recommends allowing credits for end-use energy efficiency, a form of flexibility in-line with a broader interpretation of "best system." Demand-side energy efficiency measures, such as weatherizing houses, and replacing old appliances are low-cost

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[20] Tarr, Jeremy, Jonas Monast, and Tim Profeta, "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act: Options, limits, and impacts," Nicholas Institute (January 2013), *http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.*

[21] 40 C.F.R §60.33(b)

[22] Burtraw, Dallas, and Matt Woerman, "Technology Flexibility and Stringency for Greenhouse Gas Regulations," Resources of the Future (July 2013), *http://www.rff.org/RFF/Documents/RFF-DP-13-24.pdf*.

[23] Lashof, Daniel A., Starla Yeh, David Doniger, Sheryl Carter, and Laurie Johnson, "Closing the Power Plant Carbon Pollution Loophole," Natural Resources Defense Council (March 2013), *http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.*

options for power plants to reduce emissions and have an added benefit of saving consumers money.[24] The inclusion of demand-side or end-use energy efficiency is something that the EPA has not done through 111(d) before.

Additionally, many states support a more flexible approach because they already have implemented similar carbon reduction policies, such as renewable portfolio standards, end-use efficiency programs, planned plant retirements, and greenhouse gas trading markets.[25] Most Northeastern states are part of the Regional Greenhouse Gas Initiative (RGGI), which is a utility-only carbon dioxide trading market.[26] California has a cap-and-trade market for utilities, refineries, and major industrial emitters.[27] To avoid redundancy, a coalition of these states argues that 111(d) carbon standards should allow crediting for these programs.[28]

Despite the popularity of flexibility, it is still unclear whether the EPA has the authority to allow for such approaches. 111(d) has clear language that the rule must only apply to sources regulated by new source standards of performance[29] which would exclude any "outside-the-fenceline" approaches. Even while touting the economic efficiency of the tradable standard, Dallas Burtraw of RFF recognizes that there is a trade-off between greater flexibility and greater legal risk[30] particularly given the limited precedent under 111(d). Several states have proposed that the EPA should take a more traditional approach. Texas[31], West Virginia[32], and North Carolina[33], to name a few, have all submitted requests in line with this.

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[24] McKinsey and Company, "Energy Efficiency: A compelling global resource," (2010).
[25] Monast, Jonas, et al., "Regulating Greenhouse Gas Emissions from Existing Sources: Section 111(d) and State Equivalency," *Environmental Law Reporter* 42 (2012): 10206-10215.
[26] Information available about the Regional Greenhouse Gas Initiative, Inc. online at *http://www.rggi.org/.*
[27] California Air Resources Board, "Cap-and-Trade Program," (last updated March 28, 2014), *http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.*
[28] "Comments of the Attorneys General of New York, California, Massachusetts, Delaware, New Mexico, Oregon, Washington, Connecticut, Maine, Maryland, Rhode Island, Vermont, District of Columbia on the design of a program to reduce carbon pollution from existing power plants," (December 22, 2013), *http://www.atg.wa.gov/uploadedFiles/Environment.pdf*.
[29] 42 U.S.C§7411(d)
[30] Burtraw, "Technology Flexibility."
[31] Texas Commission on Environmental Quality, "Comments on CO_2 emissions for EGUs, Section 111(d) of the Clean Air Act," (January 14, 2014), *http://s3.amazonaws.com/static.texastribune.org/media/documents/TCEQ_PUC_GHG_existing_plants_response_to_EPA_Jan_17_14.pdf.*
[32] West Virginia Department of Environmental Protection, "West Virginia's Principles to Consider in Establishing Carbon Dioxide Emission Guidelines for Existing Power Plants," (February 20, 2014),

Keeping in mind that any proposal will be challenged in court, a more cautious and legally sound approach might be wise. This paper explores a traditional "within-the-fenceline" standard as is proposed below.

Policy Simulation and Methods

Policy Description

The proposed policy would require mandatory heat rate reductions for all coal power plants in the United States.[34] The heat rate reductions would be categorized by unit size but uniform regardless of the initial heat rate. Units less than or equal to 200 Megawatts (MW) must reduce heat rates by 810 British Thermal Units per kilowatt-hour (Btu/kWh), units less than or equal to 500 MW must reduce heat rates by 745 Btu/kWh, and units greater than 500 MW must reduce heat rates by 740 Btu/kWh. If implemented across the entire fleet, this would equate to an average heat rate reduction of 8%.

While some proposed policies, such as the NRDC proposal, have focused on emission rates, this analysis uses heat rates as an equivalent proxy. In fossil fuel units, the net heat rate is directly correlated with the amount of carbon dioxide emitted.[35] The higher the heat rate, the more coal must be burned to produce the same amount of electricity. A one percent improvement in the heat rate reduces fuel use by one percent and results in reducing carbon emissions by one percent.[36] Coal-fired power plants in the United States require on average 10,400 British thermal units (Btu) to produce one kilowatthour (kWh) of electrical energy, but range from heat rates of 5,000 Btu/kWh to 32,779 Btu/kWh.[37] The proposed policy would improve the efficiency to a fleet-wide average of 9,505 Btu/kWh.

The heat rate reductions used in the main policy scenario are the central values of a range of possible heat rate reductions spanning from 355 Btu/kWh to 1,265 Btu/kWh (4% and 15% fleet-wide average

http://www.governor.wv.gov/Documents/WVDEP%20Principles%20for%20Existing%20EGU%20CO2%20Regulation.pdf.

[33] North Carolina Department of Environment and Natural Resources, "North Carolina §111(d) Principles," (January 27, 2014), *http://daq.state.nc.us/rules/EGUs/NC_111d_Principles.pdf*.

[34] In a white paper, Joshua Linn conducted an econometric analysis of a uniform heat rate standard for coal units but did not use an electrical dispatching model and differs from the policy and subsequent analysis presented here. *For more information see:*
Joshua Linn, "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act," (February 2013).

[35] EPA, "Technical Support Document for Advanced Notice of Proposed Rulemaking for Greenhouse Gases; Stationary Sources, Section VII," (June 2008), 16.

[36] *Ibid.*, 16.

[37] Sargent and Lundy, "Coal-Fired Power Plant Heat Rate Reductions," (January 22, 2009),
http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.

reductions respectively). These values are based on what is technologically feasible according to published literature, which are discussed in greater detail below. The policy would take effect in 2016 and will be assessed its emission reductions, costs, and distributional effects.

Data and Technology Assumptions

The possible reductions used in this model are based on technology documented in a report conducted by Sargent and Lundy, LLC in 2009 for Perrin Quarles Associates, Inc.[38] The report compiles existing technology that could be installed to meet the heat rate reduction requirements for coal-fired power plants. These technologies include:

- Economizers that capture heat escaping in flue gas
- Neural networks of computer processors and software to optimize plant operation
- Intelligent sootblowers to prevent ash buildup
- Air heaters and ducts that are better at preventing air leakage
- Acid dew point controls to allow lower air heater output temperatures
- New turbines
- Condenser maintenance to prevent particulate build-up
- Efficient boiler feed pumps
- Induced draft fans with variable frequency drives
- Efficiency improvements to environmental emissions control technologies.

Two additional studies were reviewed but did not provide the level of detail that Sargent and Lundy provides.[39] Sargent and Lundy relied on existing literature, interviews, and engineering expertise to develop the suite of technologies, technology costs, and associated heat rate reductions. All capital costs and operation and maintenance costs presented were current as of 2008. Data from the report was extracted to estimate the total capital costs, fixed operation and maintenance costs, variable costs, and heat rate reductions for the technologies on three different coal unit sizes (200 MW, 500 MW, 900 MW) which are presented in Appendix 1. Capital costs for a 200 MW unit range from $14.35-$29.85 million, whereas a 900 MW unit would incur costs between $38.45-$83.55 million. It is assumed that cost estimates and heat rate improvements relating to the 200 MW unit would apply to U.S coal units with

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[38] *Ibid.*

[39] National Energy Technology Laboratory (NETL), "Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States," US Department of Energy (DOE) (February 25, 2010).
   NETL, "Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants," (July 16, 2009).

capacities less than or equal to 200 MW. Similarly, costs and heat rates for the 500 MW unit would apply to those less than or equal to 500 MW and greater than 200 MW, and the cost estimates for the 900 MW unit would apply to any greater than 500 MW. A summary of these costs are displayed in Table 1. These costs need to be modified prior to their use in any modeling, which is discussed in the next section.

Table 1: Summary of Retrofit Heat Rate Reductions and Costs

Unit Size	Heat Rate Reduction (Btu/kWh)	Capital Cost ($ million)	Fixed Operation and Maintenance ($/year)	Variable Cost ($/year)
200 MW	355 – 1,265	$14.35 - $29.85	$305,000 - $505,000	$195,000 - $375,000
500 MW	335 – 1,155	$24.85 - $56.05	$448,000 - $795,000	$485,000 - $910,000
900 MW	305 – 1,105	$38.45 - $83.55	$590,000 - $111,0000	$850,000 - $1,600,000

It should be noted that, while Sargent and Lundy attempts to be exhaustive, some opportunities for efficiency improvement were not included in their study and therefore, not included in this report. Sargent and Lundy excluded modifications related to the handling of coal and coal ash in its analysis since systems would not yield significant heat rate reductions and are cost prohibitive.[40] Feedwater heaters, which are used to preheat feedwater prior to entering the boiler, were excluded for the same reasons.[41] Water treatment technology for boiler water was not included since most coal plants already have the most advanced technology installed.[42] Regarding the flue gas system, axial and centrifugal fans can provide better efficiency for a plant depending on whether it provides base-load or peak power.[43] It is difficult to predict the specific capacity of each plant but each fan has comparable costs and heat rate reductions. Therefore, the minimum and maximum values between the two types were included in the input data.

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[40] Sargent and Lundy, "Coal-Fired," 2-2.
[41] *Ibid.*, 3.2.
[42] *Ibid.,* 6-2.
[43] *Ibid.,* 4-2.

Model and Scenarios

The model used in this study was AURORAxmp, an electrical forecasting model developed by EPIS, Inc.[44] AURORA contains a database of the 13,600 generating units in 115 market areas in North America. Its database includes the capacities, fuel costs, heat rates, emission costs, and regional demands for each of these units. When conducting an analysis, AURORA optimizes demand while minimizing cost. When analyzing costs over long-terms, the model not only minimizes electrical dispatching costs but also assesses the economics of the plants as a whole and can decide whether to retire old resources or add new ones. This analysis ran long-term optimization models from 2013 through 2030 for all electrical generating units in the United States Eastern Interconnection to assess the environmental and economic impacts of the policy. Figure 1 displays the Eastern Interconnection. The model balanced dispatching every 4 hours on the 2nd Tuesday of every month. It is assumed that 100% of coal units would comply effective January 1, 2016.
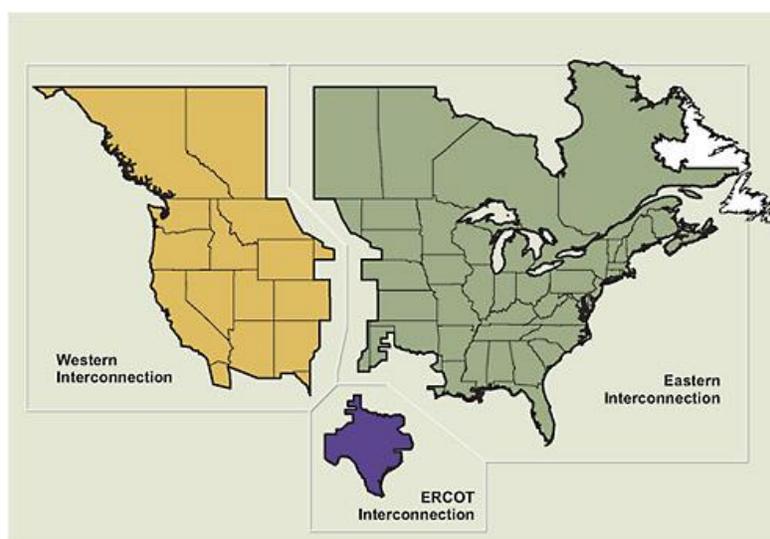

Figure 1: Electricity Grids of the United States and Canada[45]

While any policy implemented by the EPA would apply uniformly across the United States, the analysis only modeled the Eastern Interconnection. This was for time constraints but is sufficient for several reasons. Of the 1,264 coal units in the United States, 1,099 are in the Eastern Interconnection, accounting for 84% of the total US coal-fired electrical generation.[46] Within the Eastern Interconnection,

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[44] EPIS, Inc., "AURORAxmp Electric Market Model (Version 11.2.1001)," [Software], (2013).

[45] Image from National Academies Press, "America's Energy Future: Technology and Transformation," (2009), *http://www.nap.edu/openbook.php?record_id=12091&page=568*.

[46] Eastern Interconnection States' Planning Council, "Current State and Future Direction of Coal-fired Power in the Eastern Interconnection," (June 2013), *http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf.*

coal accounts for greater than 50% of generation for the four of the six reliability regions: the Midwest Reliability Corporation, the Regional First Corporation, the SERC Reliability Corporation, and the Southwest Power Pool.[47] In total, 78% of carbon emissions from electrical generation come from sources in the Eastern Interconnection.[48] For these reasons, modeling the Eastern Interconnection not only provides a good basis for what would be expected in other grids but captures the effects on the vast majority of coal plants in the United States. The Eastern Interconnection includes power markets in Quebec, Ontario, Manitoba and Saskatchewan (Figure 1) that would not be regulated under a U.S. standard. Therefore coal power plants in Canada were not modified to comply with the policy. However, they were included in the electrical dispatching, an important element if policy makers are concerned about emission leakage to Canada.

The report explores six policy scenarios assuming different costs and efficiency improvements, including a basecase scenario, a policy scenario, and four side scenarios. The side-scenarios were developed to test sensitivity to uncertainty regarding efficiency improvements and costs. These scenarios are explained in detail below.

> Basecase Scenario - The basecase scenario is a reference case against which to compare the policy scenarios. It includes emission costs associated with the Clean Air Interstate Rule and carbon dioxide prices under the Regional Greenhouse Gas Initiative, but does not include any quota requirements as part of state Renewable Portfolio Standards nor any costs associated with compliance for the Mercury and Air Toxics Standards (MATS).[49] The MATS standards were finalized in 2011 and will go into effect in 2015[50] and are predicted to have significant impacts on the coal industry.[51] However, the individual compliance costs for MATS depends on the type of coal a plant uses, how much it burns, its efficiency, and the types emission control technology already installed. While excluding MATS is problematic, attempting to capture MATS costs per unit would be very difficult absent detailed information about each coal unit. This is likely the

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[47] EPA, "Emissions and Generation Resource Integrated Database (eGrid): Eighth edition with 2009 data," (May 10, 2012), *http://www.epa.gov/cleanenergy/energy-resources/egrid/.*

[48] EPA, "eGrid."

[49] EPA, "Mercury and Air Toxics Standards: Basic Information," (last updated April 10, 2012), *http://epa.gov/mats/basic.html.*

[50] Macedonia, Jennifer, Joe Kruger, Lourdes Long, and Meghan McGuinness, "Environmental Regulation and Electric System Reliability," Bipartisan Policy Center (June 13, 2011), *http://bipartisanpolicy.org/sites/default/files/BPC%20Electric%20System%20Reliability.pdf.*

[51] EIA, "Today in Energy: AEO2014 project more coal-fired power plant retirements by 2016 than have been scheduled," (February 14, 2014), *http://www.eia.gov/todayinenergy/detail.cfm?id=15031#.*

reason that AURORA has not yet added MATS into its model and similarly, why this analysis did not attempt to do so manually. The full implications of this assumption are included in the Discussion section of this paper. AURORA includes a carbon price for all fossil units, in addition to those subject to RGGI, of $0.5 per ton starting in 2016. The $0.5/ton price is built to attempt to account for anticipated regulations on carbon, precisely what this paper is exploring. To avoid redundancy, this carbon price was removed in the Basecase and all other scenarios.

Policy Scenario – The primary scenario for this report models the effects of requiring mandatory heat rate reductions based on unit size. The achievable heat rate reductions which range from 740 Btu/kWh and 810 Btu/kWh are based on the commercially available technology provided in Sargent and Lundy's report. As Table 1 displays, there is a range of possible heat rate reductions and costs. The Policy Scenario, assumes median values of the range of heat rate improvements and costs presented in Table 1. In addition to the parameters laid out in the Basecase scenario, the Policy Scenario and additional side-scenarios include new fixed operation and maintenance costs and variable costs associated with the new technology starting in 2016 when the policy becomes effective.

Sensitivity Analysis: This report explores four side scenarios which were run to test the policy's sensitivity to uncertainty in retrofit costs and uncertainty in achievable heat rate reductions. For these four scenarios, the upper and lower bounds of Sargent and Lundy's estimates were used (Table 1).

- High Efficiency, High Cost Scenario - This scenario assumed the maximum possible heat rate reduction presented in the Sargent and Lundy's report and the maximum retrofit cost to coal plants. Coal units would achieve between 1,105 Btu/kWh and 1,265 Btu/kWh at an initial capital costs are between $29.85 million and $83.55 million per unit based on the size of the unit.

- High Efficiency, Low Cost Scenario – This model assumes that coal plants achieve the maximum possible heat rate reduction with the lowest retrofit cost. Coal units would reduce heat rates between 1,105 Btu/kWh and 1,265 Btu/kWh and have associated costs of $14.35 million – $38.45 million per unit based on the unit size.

- Low Efficiency, High Cost Scenario – This scenario assumes the minimum heat rate reduction presented in Sargent and Lundy's report and the maximum retrofit cost to coal

plants. Efficiency would improve by 305 to 355 Btu/kWh in 2016. Initial capital costs are between $29.85 million and $83.55 million.

- Low Efficiency, Low Cost Scenario – A final scenario assumes minimum heat rate reductions and minimum retrofit costs. Efficiency improves by 305 to 355 Btu/kWh and capital costs range between $14.35 million and $38.45 million.

The primary policy scenario results in an average 8% reduction across the fleet. The Low and High Efficiency Scenarios result in 4% and 15% reductions, respectively. However, it should be noted that a report by the Environmental Protection Agency estimates that the range of heat rate reductions in the US coal fleet is narrower and only 4 to 9 percent.[52] Under these assumptions, the High Efficiency scenarios are outside of the range and the primary Policy Scenario would be at the upper end of EPA's estimate.

Cost Assumptions

Prior to inputting the capital costs from Sargent and Lundy into the model, they needed to be corrected to account for inflation, labor, and taxes. AURORA performs such calculations when determining the economics of building new resources.[53] Each new resource, such as a wind turbine, pulverized coal unit, or natural gas combined cycle turbine has a different overnight cost, tax recovery period, project contingency, and debt equity percentage. AURORA assumes an inflation rate of 2.5%, federal tax of 35%, state tax of 5.9% and book life of 30 years for all technologies (Table 2).

Table 2: Capital Cost Adjustment Parameters in AURORA

Inflation Rate	2.50%
Federal Tax Rate	35%
State Tax Rate	5.90%
Debt Return (Interest Rate)	7.50%
Percentage of Capital as Debt	65%
Equity Return	35%
Book Life	30 years
Tax Recovery Period	20 years using IRS MACRS Tax Depreciation Rate
Project Contingency Factor	1.07
Labor and Materials Percentage of Cost	40% Labor, 60% Materials

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[52] EPA's analysis notes that specific constraints might make achievable heat-rate reductions closer to 2 to 5 percent. *See* EPA, "Technical Support Document," 16.

[53] AURORAxmp includes an Excel worksheet titled "Capital Work Calculations," which calculates the costs for each type of new resource prior to inputting the data into the model. See AURORAxmp Electrical Market Model (Version 11.2.1001).

AURORA uses these values to calculate the capital carrying cost rate, which is then input into the model.[54] Using the same worksheet that AURORA uses in its new resource calculations, the adjusted costs of the retrofits for coal plants in all regions in the Eastern Interconnection were found. It is assumed that the project contingency factor, debt return, and tax recovery values for the retrofits would be the same values that AURORA assumes for new coal power plants (Table 2). Costs were corrected for differences in wages based on the location, as AURORA does.[55]

Furthermore, capital costs were converted into annual fixed operation and maintenance costs. This was done to fit the structural constraints of AURORA, which does not have a specific location to enter capital costs. These annual costs were extended from 2016 through the end of the model in 2030 since the payback period is 30 years. The final adjusted values for the Policy scenario are displayed in Table 3. The bolded values in Table 3 are the final values that were input into AURORA. There is a range of total combined capital and FOM costs due to varying labor costs depending on the region.

Table 3: Final Retrofit Costs for Policy Scenario

	Capacity		
	Less than or equal to 200 MW	Greater than 200 MW and less than or equal to 500 MW	Greater than 500 MW
Heat Rate Reduction (Btu/kWh)	**810**	**745**	**740**
Capital Cost ($2010)	23,450,000	40,450,000	61,000,000
FOM ($/year)	405,000	621,500	850,000
Variable Cost ($/year)	285,000	697,500	1,225,000
Variable Cost ($/MWh)	**0.16**	**0.16**	**0.16**
Adjusted Overnight Cost[56] ($/kW) ($2010)	128.59	88.73	74.34
Base Capital Carrying Cost ($/MW-week)[57]	223.99 - 287.65	154.55 - 198.47	129.48 - 166.28
FOM ($/MW-week)	37.15 - 47.70	22.81 - 29.29	22.24 - 17.32
Total Combined Capital and FOM ($/MW-week)[58]	**261.14 - 335.35**	**177.36 - $227.76**	**146.80 - 188.52**

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[54] *Ibid.*
[55] AURORA bases its labor costs on EIA's AEO2011 Regional Labor Multiplier found in the National Energy Modeling System. This is discussed in greater detail in the AURORAxmp "Capital Work Calculations" worksheet.
[56] This is the capital cost in $/kW assuming installation in 2016.
[57] This is the overnight cost when adjusted for opportunity cost of capital and regional difference in cost of labor.
[58] Finally, base capital carrying cost and FOM costs are combined to estimate the non-variable retrofit costs.

Results

Heat Rate Reductions

Heat rates for all coal units in the Eastern Interconnection predictably decrease in 2016 in response to the phasing in of the policy. Figure 2, which displays the heat rates of all coal units in the Eastern Interconnection by capacity, helps to explain what is happening. As one can see, the units with the highest capacity are the most efficient (meaning that they have the lowest heat rate). Among the larger capacity units, the heat rate appears to be between 10,000 and 11,000 Btu/kWh. However, as the units decrease in size, the net heat rate strays to the right. The smallest plants are also the least efficient. Starting in 2016, all coal units, regardless of their initial heat rate, lower their heat rate by 740 to 810 Btu/kWh in the Policy Scenario. Figure 2 demonstrates that, contrary to a traditional command-and-control standard, the least efficient plants do not face more severe penalties compared to the more efficient plants. They are still allowed to continue to operate, so long as they achieve the mandatory heat rate reduction.
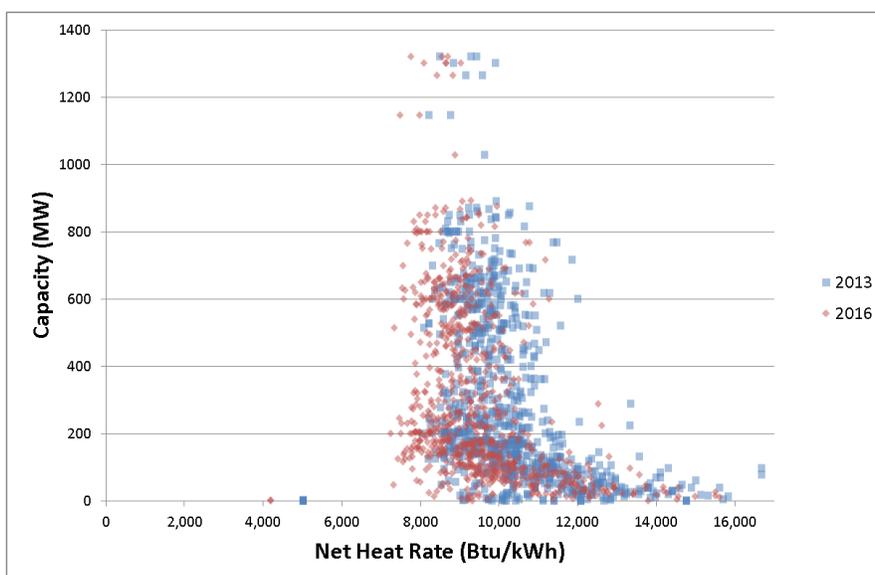

Figure 2: Distribution of coal units by heat rate

Few units have heat rates greater than 16,000 Btu/kWh, but they are not operational close in both the Basecase and Policy Scenarios. For instance, the Menasha #3 and #4 units in Menasha, Wisconsin have heat rates of 22,698 Btu/kWh and 19,703 Btu/kWh, respectively. These units have not been functional since 2009 and AURORA removes them from the model in 2014. For this reason, these extremes are not included in Figure 2. Otherwise, it is easy to see the correlation between units in 2013 and the same unit at a lower heat rate in 2016.

The phase in of the policy drops the average net heat rate from 10,300 Btu/kWh to 9,504 Btu/kWh – a decrease of 8% over 2013 levels (Table 4). As expected, the Policy Scenario produces results close to the center of the range of observed efficiency improvements. In the High Efficiency scenarios, the full-load heat rate dropped to approximately 9,065 Btu/kWh, achieving a 12% reduction in the average heat rate in 2016. Low Efficiency Scenarios exhibit smaller decreases to between 9,921 and 9,873 Btu/kWh (Table 4) or between 3.96% and 4.43%. After the initial phase-in, the average heat rate continues to decrease. By 2030, the average heat rate is 10.68% below the 2013 level in the Policy Scenario. The proposed policy does not require any heat rate reductions past 2016. Rather the decrease in heat rate is due to retirement of less efficient plants. Even in the Basecase Scenario, the average heat rate has decreased by 1.85% by 2030, demonstrating that some of these gains in the average heat rate would occur even absent 111(d) regulations.

Table 4: Heat Rates in all scenarios

Average Net Heat Rate (Btu/kWh)	Basecase	Policy Scenario	High Efficiency Scenarios		Low Efficiency Scenarios	
			High Cost	Low Cost	High Cost	Low Cost
2013	10,332	10,332	10,332	10,332	10,332	10,332
2016	10,284	9,505	9,064	9,071	9,874	9,921
2020	10,195	9,341	8,913	9,042	9,784	9,812
2025	10,184	9,259	8,829	8,977	9,675	9,692
2030	10,162	9,229	8,799	8,940	9,644	9,662
% Difference to 2013 in 2016	0.46%	8.01%	12.26%	12.19%	4.43%	3.96%
2020	1.32%	9.60%	13.72%	12.47%	5.30%	5.02%
2025	1.43%	10.38%	14.53%	13.10%	6.36%	6.18%
2030	1.65%	10.68%	14.83%	13.47%	6.66%	6.48%

Retrofit Costs

Total average costs for all coal plants in the Eastern Interconnection increase in 2016. The retrofit cost in the Policy Scenario phases in at $2.57 million per year in 2016 and remains steady through 2030 (Figure 3). Fixed operation and maintenance costs, which includes the retrofit cost, increased in the Policy Scenario from $6,335,146 per year to $8,734,101 per year.
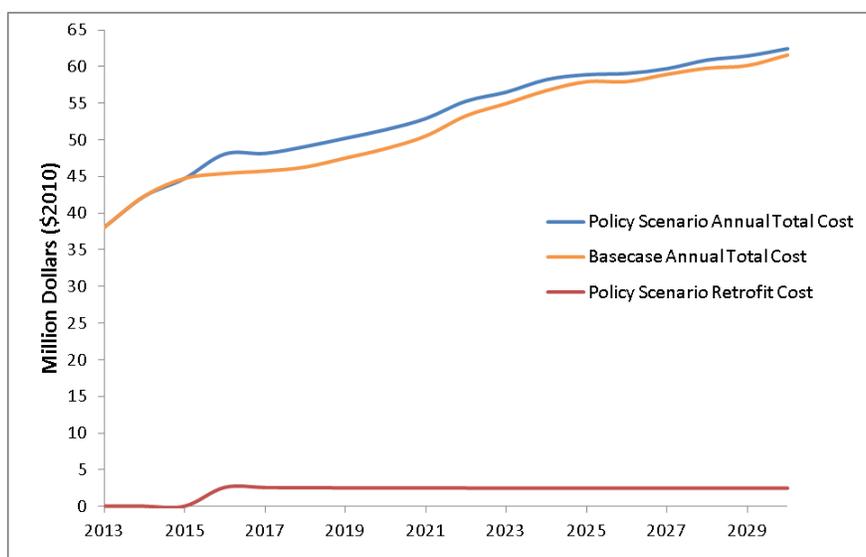
Figure 3: Average Total Costs and Retrofit Costs

The retrofit costs may seem significant, but they are relatively small in comparison to the total cost of operating a coal power plant. The initial capital cost estimates for the Policy Scenario were between $23 and $61 million dollars, depending on the plant size (Table 3) but only equate to average payments of $2.57 million when paid back over a period of 30 years. As a result, retrofit costs are only about 5% of the total operational costs. For instance, Allen #1, a 251 MW coal unit located in SERC paid $3,643,000 in 2016 for costs associated with the retrofit but had a total operational cost of $64,639,839. The largest share of the operational cost is due to fuel which totaled $42,734,000 in 2016. Variable costs were $8,572,000, and fixed costs (including the retrofit costs) were $12,527,000. For this plant, the policy-induced retrofit increases total cost of operation for the plant by 5.6%. While the retrofit cost is 5% on average, the distribution of these costs is not equal across all coal plant sizes. These retrofit costs represent a more significant percentage of total costs for smaller plants than for larger plants (7.90% for units ≤200 MW; 5.57% for units >200 MW and ≤500 MW; 4.46% for units >500 MW in 2016).

While fixed operation and maintenance costs increase, coal plants experience large reductions in fuel costs due to the heat rate improvements. This is apparent when looking at the cost per megawatt-hour (Figure 4). Because the cost per megawatt-hour is decreased in most scenarios, the cost increases displayed in Figure 3 do not actually portray the whole picture. The large improvement in fuel costs actually leads to an overall decrease in total costs per megawatt hour in the Policy scenario relative to the Basecase.
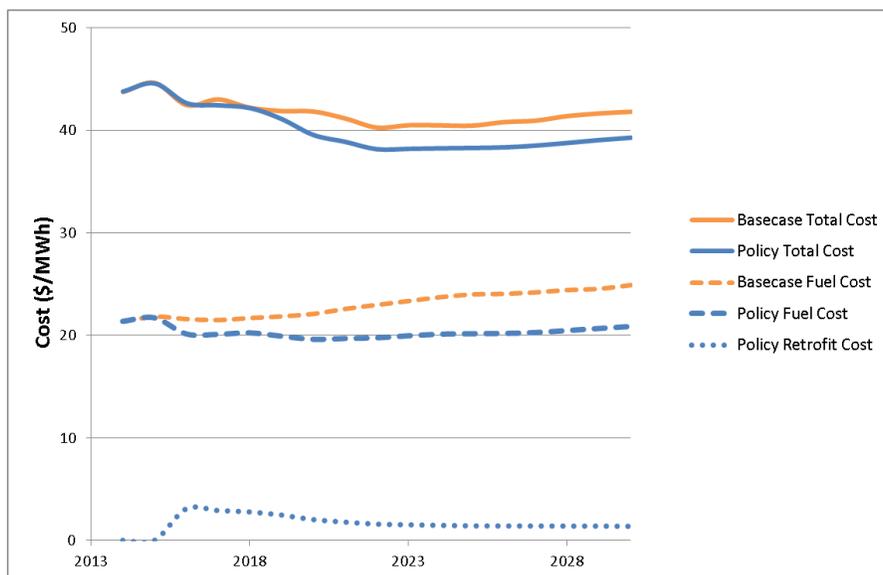
Figure 4: Costs per Megawatt-hour

For Allen #1, fuel costs were $42,734,000 in 2016 but this is less than the unit paid in fuel costs in 2015 despite producing more electricity in 2016 than in 2015 (Fuel costs in 2015 were $45,535,000). Allen #1 only consumed 1.49×10^{7} mmBtu of fuel in 2016 compared with 1.62×10^{7} mmBtu in 2015.

In the High Efficiency scenarios, like the Policy Scenario, total costs per megawatt-hour are reduced relative to the Basecase due to the gains in fuel efficiency and associated fuel costs (Figure 5). These reductions are even more pronounced in the High Efficiency Scenarios. Total costs per megawatt-hour in the High Efficiency Low Retrofit Cost scenario drop below $40/MWh in 2016.
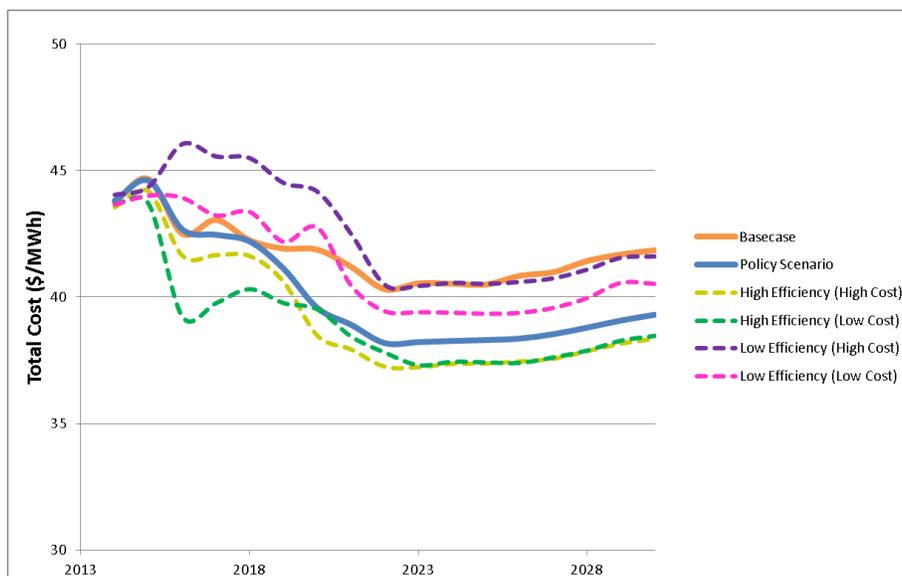

Figure 5: Total costs per megawatt-hour for all scenarios

However, in the Low Efficiency scenarios, the efficiency gains are not great enough to decrease total costs per megawatt-hour, therefore the total costs per megawatt-hour are greater than the Basecase. Costs in the low efficiency scenarios do eventually drop below the Basecase in 2022 as less efficient, more costly units are retired and replaced with other sources. All scenarios experience this decline in costs through 2022 associated with retirements and phase in of new resources. These impacts are discussed in subsequent sections.

Electrical Generation:

Electrical power generation from coal increases under the Policy Scenario relative to the Basecase. Reduced fuel costs and total costs per megawatt-hour from the installation of efficient technology makes it more economical for coal plants to operate. In Figure 3, total average costs increase, not necessarily because the retrofit increases total costs, but because coal plants are operating at higher capacities. That is why the cost per megawatt-hour provides a better understanding of what is happening. Table 5 displays the generation from coal units in the Eastern Interconnection. Generation under the Policy Scenario increases to 1,536 Terawatt-hours (TWh) in 2016 while generation only increases to 1,464 TWh under the Basecase – a difference of 5%.

Table 5: Electrical Generation from Coal in the Eastern Interconnection (Net generation and percent generation above Basecase)

Coal Output (TWh)	Basecase	Policy Scenario	High Efficiency		Low Efficiency	
			High Cost	Low Cost	High Cost	Low Cost
2013	1,238	1,238	1,236	1,236	1,238	1,236
2016	1,464	1,536	1,569	1,574	1,491	1,497
% Difference	0%	4.96%	7.18%	7.51%	1.86%	2.25%
2020	1,527	1,603	1,633	1,645	1,555	1,561
% Difference	0%	4.96%	6.93%	7.70%	1.86%	2.20%
2025	1,706	1,753	1,778	1,796	1,718	1,725
% Difference	0%	2.76%	4.22%	5.27%	0.67%	1.11%
2030	1,757	1,802	1,824	1,840	1,770	1,773
% Difference	0%	2.58%	3.82%	4.72%	0.72%	0.89%

In the side-scenarios, the High Efficiency scenario increases output by 7.2-7.5% while Low Efficiency scenarios only increase output by 1.9-2.3%, regardless of the retrofit costs. This demonstrates that the change in output is directly correlated with the efficiency gains and not the associated with the retrofit costs. Under this policy, heat rate improvements influence a plant's decision to operate rather than the costs since the costs are so low relative to the fuel efficiency gains. The direct relationship between efficiency and output can be seen in Figure 6. At higher heat rate improvements, coal plants will respond by increasing output. Lower heat rate improvements increase output less. While the relationship between output and efficiency appears linear, it is probably not so. There are diminishing returns to efficiency improvements because at some point, electrical demand will be met regardless of efficiency improvements among coal units.
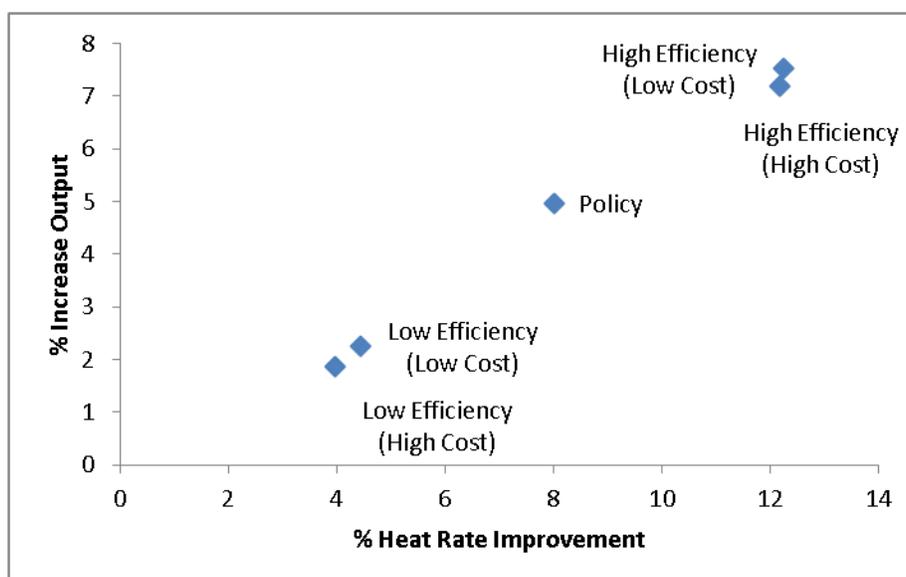

Figure 6: Relationship between Heat Rate Improvement and Output

It is somewhat surprising that output in the Low Efficiency Scenarios increases despite the fact that the cost per megawatt-hour is higher in these scenarios relative to the Basecase. It would be expected that higher operation costs would depress coal generation. However, it may be that, under the Low Efficiency Scenarios, some units benefit while some experience increased costs. Efficiency gains might make it more economical for some units to operate at a higher capacity which would increase the output relative to the Basecase. Alternatively, a few units might experience substantially higher costs which would raise the average cost per megawatt-hour. This would explain why output increases despite the fact that operational costs are higher for the Low Efficiency Scenarios. The fact that the Low Efficiency High Cost scenario only increases output by 1.86% while the Low Efficiency Low Cost scenario increases output 2.25% supports this. Output is constrained when costs are higher while keeping

efficiency gains constant. However, this cannot be verified unless each unit is analyzed in a case-by-case basis.

Because AURORA is an electrical dispatching model that balances load, increasing electrical generation from coal units requires decreases in output from other sources. Comparing the Policy Scenario to the Baseline, it is clear that increased coal output displaces natural gas (Figure 7). In Figure 7, one can see the ratio of change between natural gas and coal is nearly one-to-one. Natural gas makes up a larger share of the generation in the Basecase Scenario compared to the Policy Scenario.
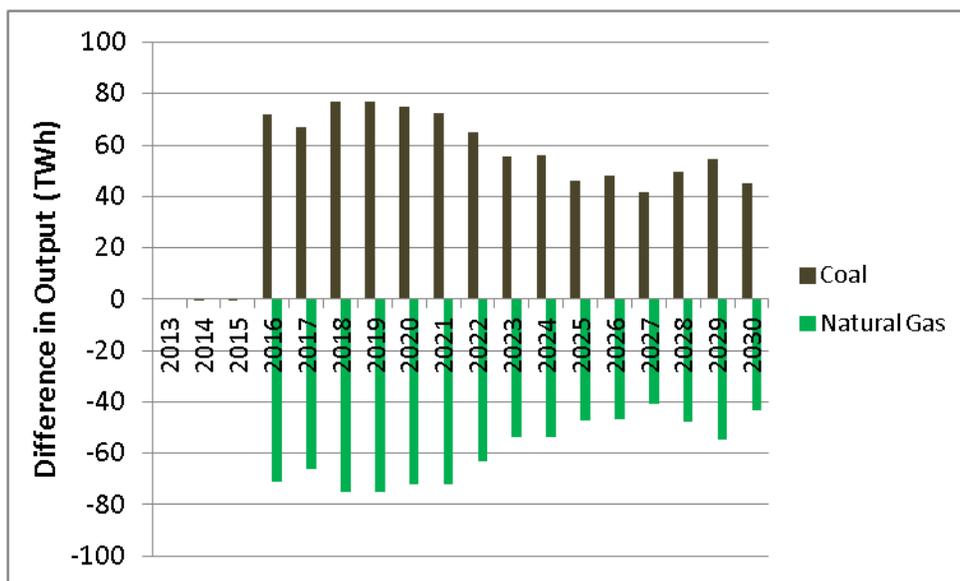

Figure 7: Difference in Output between Basecase and Policy Scenario

Nuclear power and hydropower are significant sources of electricity in the Eastern Interconnection but do not exhibit significant differences in output in the Basecase and Policy Scenarios. This is because hydropower and nuclear are very cheap sources of power in the Eastern Interconnection, run at high capacity, and do not directly compete with coal markets.

Similarly, if coal generation displaces natural gas generation, it can also displace coal generation from other regions. Under the Policy Scenario, coal generation in Canada actually decreases relative to the Basecase (Table 6). This negates concerns that regulation of coal units in the United States might result in emission leakage to Canada. Efficiency gains at coal plants in the US make Canadian generation less cost effective. However, even if coal costs increased in the United States relative to Canada, it is unlikely that much emission leakage would occur. Canada does not have adequate capacity to absorb much of

the US demand since Canadian coal capacity in the Eastern Interconnection totals 6,982 MW compared to 265,562 MW in the United States.

Table 6: Canadian Coal Electrical Generation

	Canadian Coal Output (TWh)	
	Basecase	**Policy Scenario**
2013	23.07	23.07
2016	26.00	25.19
% Difference	0%	-3.21%
2020	25.33	24.67
% Difference	0%	-2.67%
2025	34.00	33.29
% Difference	0%	-2.12%
2030	38.41	37.96
% Difference	0%	-1.19%

By 2025 and 2030, the difference in coal output between the policy scenarios and the Basecase decrease. Both Table 5 and Figure 7 exhibit this trend. In 2016, the Policy Scenario produces 72 more TWh of coal-fired electricity than the Basecase Scenario, but by 2030, the difference has diminished to 45 TWh. The decrease is influenced by new capacity coming online.

New Capacity and Retirements:

From 2013 through 2030, AURORA both adds new plants and retires old plants. In its long-term analysis, AURORA takes into account real levelized net present value to determine whether it is economical to retire an old plant and build a new plant. Any capacity that is retired must be balanced that by increasing the output of existing capacity or building new capacity. While AURORA allows for all types of power plants to be built, including coal, nuclear, solar, geothermal, wind, and natural gas, most options are cost prohibitive. In both the Basecase and Policy Scenario, the only units that AURORA adds are new natural gas units and wind power. New coal plants would have to be integrated gasification combined cycle (IGCC) units which are much more expensive than natural gas combined cycle (NGCC) turbines. In the Basecase Scenario, the Eastern Interconnection adds 94.6 GW of natural gas capacity through 2030 while in the Policy Scenario, it adds 89 GW. By comparison, it adds 0.6 GW and 0.4 GW of wind, respectively. Less natural gas is added in the Policy Scenario because of the increased generation from coal units. The influx of new natural gas largely replaces coal. While generation of coal increases in all

scenarios through 2030, as the economy growth, the rate of growth in coal generation slows as new natural gas units become more abundant.

Despite the fact that output from coal increases under the policy, there are coal units that retire. In the Policy Scenario, more coal units retire compared to the Basecase Scenario, specifically after the policy goes into effect (Figure 8). At the end of 2015, prior to new costs associated with the retrofits take effect, twelve more units retire in the Policy Scenario than do in the Basecase. Of the units that retire, most are already operating are very low or zero capacity. The United States has excess capacity of coal that is not regularly dispatched. In the Policy Scenario, some of this extra capacity is retired. The retrofits affect each unit differently since each has different operating costs, retrofit costs, and output. But units that not producing electricity would be impacted the most. It is more economical for them to retire than incur the retrofit costs. Under the Basecase Scenario, these units are kept on despite the fact that they do not produce much electricity, perhaps to serve as a reserve in case they are needed. An enhanced number of retirements continue in the Policy Scenario through 2026 and these are similarly, low and zero capacity units. While it does not make much sense that units would chose to retire in 2016, 2017, 2018, and 2019 after already paying for the retrofits as Figure 8 displays, this may a constraint of the model. It might not be accurately capturing a unit-operator's decision making.
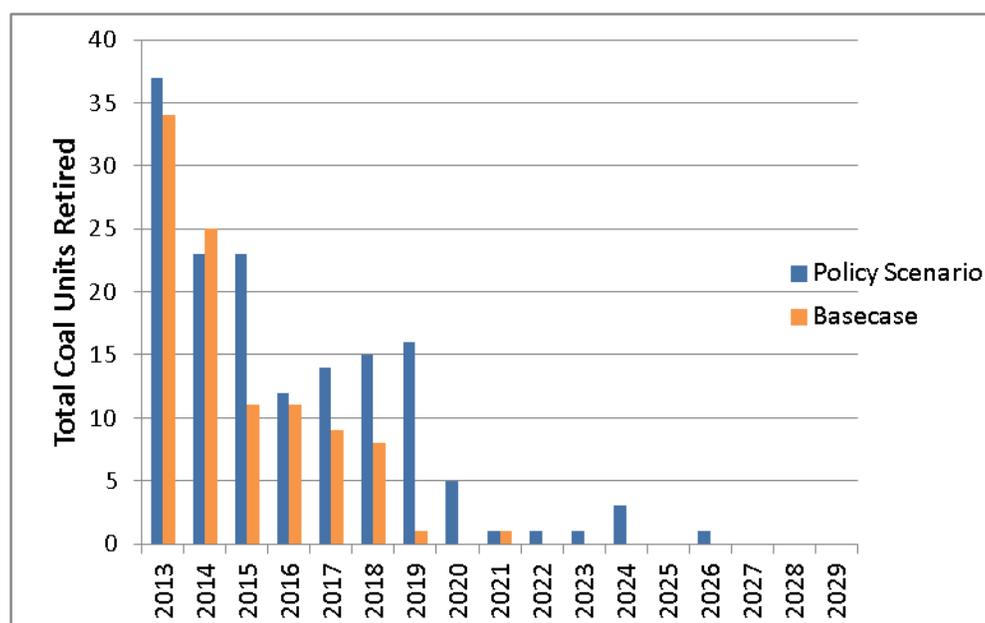

Figure 8: Retired Coal Units in Policy and Basecase

The total capacity that is retired over the same period follows this same trend (Figure 9). The Policy Scenario results in 8.7 GW of retired capacity by 2030 where only 4.4 GW would be retired in the

Basecase. In both scenarios, much capacity is retired prior to 2015 and is associated with planned retirements of old plants (Figure 8 and Figure 9).
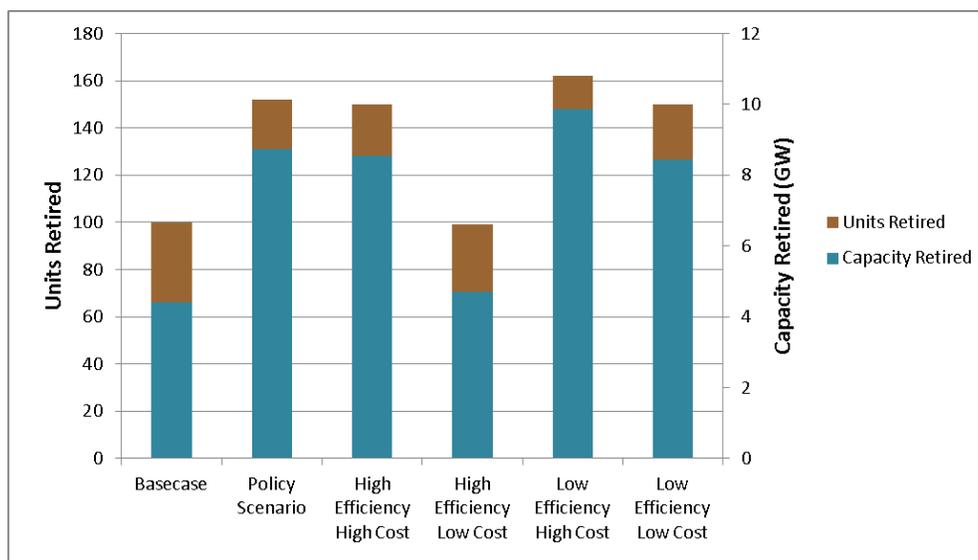

Figure 9: Total Coal Units and Total Coal Capacity Retired (2013-2030)

In some of the side scenarios, the effect is more pronounced. The Low Efficiency High Cost Scenario results in the most retirements (162 units through 2030), whereas the High Efficiency Low Cost scenario only retires 99 units. The High Efficiency Low Cost scenario has the least retirements due to a combination of two factors: low cost of retrofit technology and low fuel costs.

A primary concern of a national regulation is its regional effects. Most of the United States coal-fired electrical generation is in the Reliability First Corporation and the SERC Reliability Corporation which, when combined, add up to 61.5% of coal-fired electrical generation in the U.S. and 75.3% of coal-fired generation in the Eastern Interconnection.[59] The majority of the retirements associated with the policy occur in these regions, but this is not unreasonable given how many coal units are located there. The number of retirements seems proportional when viewed against the retirements that occur in the Basecase (Figure 10).
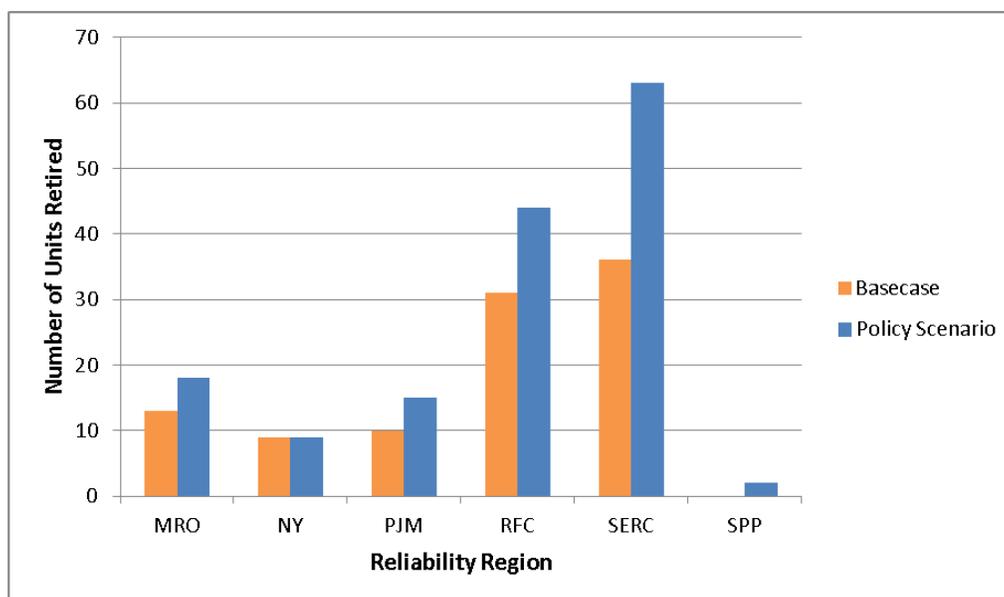
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[59] EPA, "eGrid."

Figure 10: Retirements by Region including Midwest Reliability Organization (MRO), NY (New York), PJM, ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), and Southwest Power Pool (SPP)

Electricity Prices:

In Policy Scenario and the four side-scenarios, electricity prices are lower relative to the Basecase due to the lower costs per megawatt-hour for coal plants, but overall, prices are not dramatically different. Electricity prices in the Policy Case are $52.24 per MWh ($2010) in 2025 and $52.75 per MWh in the Basecase Scenario, a difference of $0.50 per MWh or 0.05 cents per kWh. Scenarios assuming high retrofit costs have higher electricity prices than the Policy Scenario but are still below the Basecase. This demonstrates that despite uncertainty in the true cost of the policy, there is confidence that it would not lead to higher electricity prices. Furthermore, improvements in efficiency conclusively drive prices. The average electricity price assuming high costs and high efficiency is cheaper than the electricity price assuming low costs and low efficiency (Table 7). Towards the end of the analysis, electricity prices in the policy scenario increase above those of the Basecase but again, this difference is small.

Table 7: Electricity Prices in six scenarios

Average Electricity Price ($2010/MWh)	Basecase	Policy Scenario	High Efficiency		Low Efficiency	
			High Cost	Low Cost	High Cost	Low Cost
2013	40.18	40.18	40.25	40.25	40.18	40.25
2016	44.55	43.35	42.67	42.31	43.44	43.38
2020	45.17	44.43	43.87	44.44	44.74	44.54
2025	52.75	52.24	51.61	51.94	52.32	52.12
2030	55.91	56.21	55.42	55.20	56.67	55.55

Carbon Emissions and Effective Carbon Price:

The policy succeeds in reducing emissions relative to the Basecase. In 2016, emissions in the Eastern Interconnection are 4.1% below the Basecase a difference of 68 Megatons (Mt) (Table 8). The side-scenarios also succeed in reducing emissions relative to the Basecase. Scenarios assuming higher efficiency lower emissions between 6.2 and 6.7% in 2020. The Low Efficiency scenarios only result in reductions of 2.0% relative to the Basecase. Because all four side-scenarios are consistent, this demonstrates that the policy lower carbon emissions even in uncertainty about efficiency and retrofit costs.

Table 8: Carbon Emissions in US Eastern Interconnection in Megatons (Mt)

US EI Carbon Emissions	Basecase (Mt)	Policy Scenario (Mt)	High Efficiency (Mt)		Low Efficiency (Mt)	
			High Cost	Low Cost	High Cost	Low Cost
2016	1,664	1,596	1,555	1,557	1,628	1,631
% Difference	0%	-4.1%	-6.6%	-6.4%	-2.2%	-2.0%
2020	1,763	1,692	1,646	1,653	1,725	1,728
% Difference	0%	-4.0%	-6.7%	-6.2%	-2.1%	-2.0%
2025	1,974	1,874	1,821	1,831	1,919	1,924
% Difference	0%	-5.1%	-7.8%	-7.2%	-2.8%	-2.5%
2030	2,099	1,997	1,940	1,948	2,047	2,046
% Difference	0%	-4.9%	-7.6%	-7.2%	-2.5%	-2.5%

Emissions remain below the Basecase Scenario through 2030 despite the fact that overall emissions increase due to economic activity and population growth. The consistent reduction in emissions results in a substantial amount of cumulative avoided emissions when added up over the lifespan of the policy. Figure 11 displays the emissions under the Policy and Basecase Scenarios. The area between the two lines represents the number of avoided tons of carbon dioxide emissions. By 2030, under the Policy Scenario, 1,284 Mt of carbon dioxide were avoided.
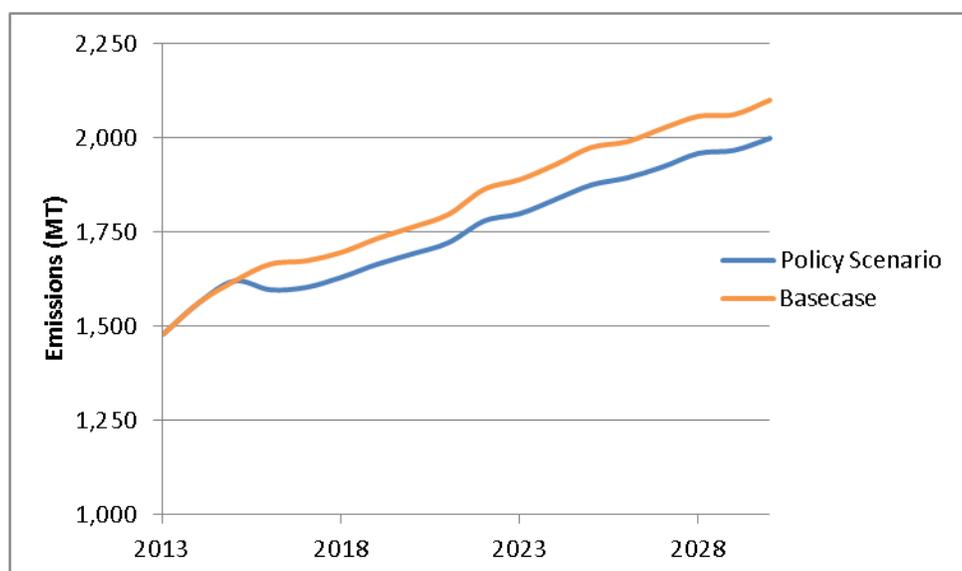
Figure 11: Eastern Interconnection Emissions

Despite the reductions, these results are not all positive. Emissions continue to grow as will ambient concentrations of carbon dioxide. The Obama Administration has committed to reducing US emissions 17% below 2005 levels by 2020 and views regulating carbon dioxide from power plants is a primary tool to achieve that goal.[60] While regulations under the Clean Air Act should not (and must not) be crafted with political commitments in mind, this report briefly explored whether this policy option would be able to meet the President's goal. In 2016, emissions in the Eastern Interconnection drop to 16.6% below 2005 levels. However, by 2020, emissions are only 11.7% below 2005 levels due to increasing economic activity. In 2030, emissions are projected to be 4.31% above 2005 levels. Furthermore, in the Basecase Scenario, emissions in 2016 are already 13.1% below 2005 without the policy. The emission gap between 2005 levels and the scenarios' projections is mostly due to a decrease in economic activity from the 2008 recession. Based on data from the Energy Information Administration, total energy-related emissions in 2011 were 8% below 2005 levels[61] and those from the electricity sector were 10% below 2005 levels.[62] Policy only decreases emissions by an additional few percentage points over the business-as-usual case.

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[60] White House, "The President's Climate Action Plan," (June 25, 2013), *http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf*.
[61] EIA, "U.S. Energy-Related Carbon Dioxide Emissions, 2012," (last updated October 21, 2013), *http://www.eia.gov/environment/emissions/carbon/*.
[62] EIA, "Table 9.1 Emissions from Energy Consumption at Conventional Power Plants and Combined-Heat-and-power Plants," (accessed April 17, 2014), *http://www.eia.gov/electricity/annual/html/epa_09_01.html.*

Part of the reason that emissions continue to rise is that the policy does not put a steady price on carbon dioxide. Calculating the effective price that the policy places on carbon emissions was difficult. Dividing the price of the retrofit by the difference in carbon emissions between the Basecase and Policy Scenarios is not sufficient since it does not take into account the efficiency gains that reduce costs. When the benefits of reduced fuel consumption are taken into account, the effective price of carbon is $40 per ton in 2016 ($2010). The effective price fluctuates annually but trends toward lower prices through 2019. The price is $19.7 per ton in 2019 ($2010). The price drops to zero by 2020 as the total cost per megawatt-hour in the Policy Scenario diverges from the Basecase as shown in Figure 4.

Discussion:

Implementing a mandatory heat-rate reduction for all coal plants in the United States, such as the one analyzed in this report, has its benefits and drawbacks. The policy is legally robust compared to some of the more flexible alternatives as discussed in the Background. It would represent a less ambitious course of action to reduce carbon emissions while allowing easily achievable reductions to take place at low economic costs. By 2020, annual emissions are 71.4 million metric tons below BAU and continue to diverge so that by 2030, the United States Eastern Interconnection is emitting 102 million metric tons fewer annually. As discussed above, the cumulative effects of these emissions reductions can be great (see Figure 11). While the policy comes close to meeting the Administration's political emissions commitments, it falls short, and most of the progress towards a 17% reduction below 2005 levels originates from economic activity outside the influence of the policy.[63]

The policy's effectiveness is not consistent for several reasons. First, it does not fix a steady price on carbon that accurately factors in the externalities of carbon dioxide. Secondly, it does not encourage shifting from coal power to other low-carbon or renewable energy. Part of the benefit of the policy is that it has low economic costs to consumers and unit operators. Retrofit costs are low relative to the total operational cost of a coal power plant. But the drawback is that the retrofit costs associated with the mandatory heat rate reduction are still not enough to make solar, geothermal, or wind power economical. As a result, when the economy grows, the only option is to increase coal and natural gas generation which leads to higher emissions. Furthermore, the policy allows inefficient plants to continue

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[63] EIA's projections have US energy-related emissions 9% below 2005 levels by 2020 assuming no additional policies. This projection includes expected decreases in carbon-intensity of non-electrical sectors such as transportation. My estimates bring the total reductions to 12.8% by 2020. I calculated this by adding EIA's 9% to the difference between my Basecase and Policy scenario.

to operate so long as they achieve the emission reduction. For economic impacts, this is a good thing; unit retirements are not severe and not substantially unfairly-distributed.[64] The efficiency gains realized by coal plants leads to increased coal capacity and lowered electricity prices. This phenomenon supports other analyses which found a rebound effect of 13-18% in output for an associated 4% decrease in heat rate.[65]

There is cause for concern in both the assumptions and modeling constraints. First, it is unlikely that these efficiency gains would take place in 2016. Even if fast-tracked, guidelines for implementation would not likely be finalized before June 30, 2016,[66] which does not even taken into account how long it would take for plants to comply. The effect is that the US would be less likely to meet a 17% reduction by 2020. However, other than that, there are no anticipated impacts of the policy being delayed by a few years.

As discussed in the Methods section, the range of reductions used in this report are based on the technologies included in Sargent and Lundy's analysis, but these reductions may be overly optimistic. The EPA estimated the range of possible improvements to yield heat rate decreases between 4% and 9% but realistic expectations are closer to 2-5% given "site-specific constraints."[67] Other analyses have assumed a 4% reduction rate was feasible.[68] Because technology presented in Sargent and Lundy's report is already commercially viable, it is likely that more than a few of the coal plants have already installed the technology. Furthermore, if installing the technology actually decreases fuel costs and makes it more economical to increase output, coal units should already be taking advantage of this. Sargent and Lundy's report only estimates *potential* improvements and does not list unit by unit efficiency gains and costs. To date, there has been no comprehensive analysis of the actual opportunities that exist for efficiency improvements. In this analysis, it is assumed that all coal plants in

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[64] While more closures occur in coal heavy areas, it is more equal than other analyses: Tarr, Jeremy, "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act."

[65] Linn, Joshua, Erin Mastrangelo, and Dallas Burtraw, "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act," Resources for the Future (February 2013), *http://www.rff.org/rff/Documents/RFF-DP-13-05.pdf.*

[66] White House, "Presidential Memorandum: Power Sector Carbon Pollution Standards," (June 25, 2013), *http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.*

[67] EPA "Technical Support Document," 16.

[68] Burtraw, Dallas, and Matthew Woerman, "Technology Flexibility and Stringency."

the Eastern Interconnection would achieve the same heat rate reductions despite this fact therefore the efficiency gains are likely overstated.

Part of what would deter coal plants from taking advantage of such efficiency gains are other environmental regulations. Whenever a stationary source undertakes major modifications, the Clean Air Act stipulates that it becomes subject to New Source Review (NSR). In most cases, existing sources are exempt from high standards for new sources, but when New Source Review is triggered an existing power plant would have to upgrade to meet the current standards of best available control technology for all air pollution regulations.[69] This would incur costs above what is taken into account in this analysis. In its recommendations to the EPA, Pennsylvania requested that the agency revise its rules for NSR so that any action under 111(d) does not trigger it.[70] If such a policy regarding NSR were adopted, the EPA would have to take a hard look at whether exempting retrofits in compliance with greenhouse gas standards would be legal under the CAA.

In addition to leaving out with costs associated with NSR, other costs are not included in the analysis. As was noted above, AURORAxmp does not include any costs associated with the Mercury and Air Toxics Standard (MATS) which take effect in 2015. Part of the challenge of estimating costs for MATS is that there is a wide range of what coal plants require to comply. Costs for MATS are estimated to be between $3/kW and $269/kW[71] dependent on the emission control technologies that the plant already has installed, its size, fuel source, and efficiency. MATS is expected to result in substantial power plant closures. The EIA estimates that 20 GW of coal will retire between 2014 and 2016, partially due to MATS. Other analyses predict between 10 and 66 GW of retirements by 2015 due to MATS and other standards.[72] By comparison, the business-as-usual case in AURORA only predicts 2.6 GW will retire between 2013 and 2016. If MATS were properly taken into account in the model, the added cost of the mandatory heat-rate reduction might force more coal plants into retirement or make other forms of electrical generation economical.

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[69] Tarr, Jeremy, "Regulating Carbon Dioxide under Section 111(d)."

[70] Pennsylvania Department of Environmental Protection, "Recommended Framework for the Section 111(d) Emissions Guidelines Addressing Carbon Dioxide Standards for Existing Fossil Fuel-Fired Power Plants," (April 10, 2014), *https://docs.google.com/file/d/0B4Y3VQLxjkxOd05jaWE4ZktjWXc/edit.*

[71] EPA, "Performance and Cost of Mercury and Multipollutant Emission Control Technology Applications on Electric Utility Boilers," (October 2003), *http://nepis.epa.gov/Adobe/PDF/P1000G5O.pdf.*

[72] Macedonia, Jennifer "Environmental Regulation and Electric System Reliability."

Conclusion:

Despite the many assumptions associated with the analysis, I am confident that the policy provides a good projection of what would result from a mandatory heat-rate reduction under the EPA. The sensitivity analyses of the policy demonstrate that the policy would perform as functioned even if there is uncertainty in the true cost and availability for reductions. The policy reflects what the EPA could accomplish if it took a strict, within-the-fence-line approach to regulation under 111(d). However, convention wisdom indicates that this is not the avenue that the EPA will choose. Given the Administration's prioritization of climate change, it is most likely that the final policy under 111(d) will be more ambitious and include some of the flexibility proposed in other analyses. Indeed, that might be the correct course of action given the pressing need for cuts in carbon emissions. Regardless, testing the efficacy of mandatory heat-rate reduction provides a good baseline to compare other proposals and could serve as a sound option if other alternatives fail.

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Appendix I

Technologies	200 MW				500 MW				900 MW			
	Heat Rate	Capital Cost ($ million)	FOM ($/yr)	Variable Cost ($/yr)	Heat Rate	Capital Cost ($ million)	FOM ($/yr)	Variable Cost ($/yr)	Heat Rate	Capital Cost ($ million)	FOM ($/yr)	Variable Cost ($/yr)
Boiler Island												
Boiler Operations	50 - 100	$2 - $3	$50,000	-	50 - 100	$4 - $5	$100,000	-	50 - 100	$7 - $8	$150,000	-
Neural Network	50 - 150	$0.50	$50,000	-	30 - 100	$0.75	$50,000	-	0 - 50	$0.75	$50,000	-
Sootblower	30 - 150	$0.30	$50,000	-	30 - 90	$0.50	$50,000	-	30 - 90	$0.50	$50,000	-
Air Heater Leakage	10 - 40	$0.3 - $0.5	$50,000	-	10 - 40	$0.6 - $0.7	$75,000	-	10 - 40	$1 - $1.2	$100,000	-
Air Heater Temperature	50 - 120	$1.5 - $3.5	$50,000	$170,000 - $350,000	50 - 120	$2.5 - $10	$75,000	$425,000 - $850,000	50 - 120	$3.5 - $18	$100,000	$750,000 - $1,500,000
Turbine Island												
Turbine Overhaul	100 - 300	$2 - $12	-	-	100 - 300	$4 - $20	-	-	100 - 300	$5 - $25	-	-
Condenser	30 - 70	-	$30,000	-	30 - 70	-	$60,000	-	30 - 70	-	$80,000	-
Boiler Feed Pumps	25 - 50	$0.25 - $0.35	-	-	25 - 50	$0.5 - $0.6	-	-	25 - 50	$0.7 - $0.8	-	-
Flue Gas System												
ID Fans or Variable Frequency Drives	10 - 150	$6 - $6.5	$25,000 - $50,000	-	10 - 150	$9 - $11	$38,000 - $85,000	-	10 - 150	$15 - $16	$60,000 - $130,000	-
Emissions Control Technologies												
FGD System	0 - 50	$0 - $1	$0 - $50,000	-	0 - 50	$0 - $3	$0 - $100,000	-	0 - 50	$0 - $5	$0 - $150,000	-
Particulate Control System	0 - 5	$0 - $0.2	$0 - $25,000	-	0 - 5	$0 - $0.5	$0 - $25,000	-	0 - 5	$0 - $0.8	$0 - $25,000	-
SCR System	0 - 10	$0 - $0.5	$0 - $25,000	$25,000	0 - 10	$0 - $1	$0 - $50,000	$60,000	0 - 10	$0 - $2	$0 - $100,000	$100,000
Water Treatment System												
Advanced Cooling Tower	0 - 70	$1.5	$0 - $75,000	-	0 - 70	$3	$0 - $125,000	-	0 - 70	$5 - $5	$0 - $175,000	-
TOTAL	355 - 1265	$14.35 - $29.85	$305,000 - $505,000	$195,000 - $375,000	335 - 1155	$24.85 - $56.05	$448,000 - $795,000	$485,000 - $910,000	305 - 1105	$38.45 - $83.55	$590,000 - $1,110,000	$850,000 - $1,600,000