To: Administrator B6 @epa.gov]
From: VallelyBartlett, Maeve (EEA)
Sent: Mon 11/3/2014 7:25:13 PM
Subject: FW: FERC Order 745

Here it is.

From: David Brewster [mailto:dbrewster@enernoc.com]
Sent: Monday, November 03, 2014 1:10 PM
To: VallelyBartlett, Maeve (EEA)
Subject: FERC Order 745

As discussed, here is a link to the case: http://www.cadc.uscourts.gov/internet/opinions.nsf/DE531DBFA7DE1ABE85257CE1004F4C53/$file/11-1486-1494281.pdf

It is a good read, particularly the dissent from Judge Edwards.

We very much appreciate your support.

David

From: David Brewster
Sent: Friday, October 31, 2014 11:28 PM
To: VallelyBartlett, Maeve (EEA)
Subject: Re: Meeting with the Mayor of Lyon

Thank you. I will reach out first thing Monday and leave a message if I don't get you live. I really appreciate your engagement. We need your (and Governor Patrick's) support to help us fight an awful DC Circuit Court of Appeals decision that would kill everything that States and the federal government have done to develop demand response in wholesale electricity markets over the past decade. The impacts would be huge: $500/household per year in increased electricity costs; stifled innovation; and a massive threat to EPA's 111(d).

Here is a good summary of the issue:

http://grist.org/climate-energy/radical-judge-kneecaps-clean-electricity-under-cover-of-boringness/

I look forward to speaking with you on Monday. Is there a good time for you to connect?

Thanks in advance.

David

On Oct 31, 2014, at 5:25 PM, VallelyBartlett, Maeve (EEA) <Maeve.VallelyBartlett@MassMail.State.MA.US> wrote:

David:
I am happy to chat anytime. My direct line is 617-626-1101.
Maeve

From: David Brewster [dbrewster@enernoc.com]
Sent: Friday, October 31, 2014 4:11 PM
To: VallelyBartlett, Maeve (EEA)
Subject: RE: Meeting with the Mayor of Lyon

Maeve,

I saw you last night at the Green Tie Gala but wasn't able to find my way to you to say hello. I would love to talk to you about the biggest threat to the demand response industry since we founded EnerNOC 13 years ago. Unfortunately, I do not have your direct number. Could we speak sometime on Monday? We would really appreciate your (and the Governor's) support at this critical juncture.

Please let me know if and when you are available to speak as soon as possible.

Best regards,
David

David Brewster, President
EnerNOC, Inc. | One Marina Park Drive | Suite 400 | Boston, MA | 02210 | USA
office: 617.224.9902 | mobile: 617.794.6227 | fax: 646.289.5863
dbrewster@enernoc.com<mailto:dbrewster@enernoc.com> |
www.enernoc.com<http://www.enernoc.com/>
EnerNOC - get more from energy

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To: Megan Ceronsky[mceronsky@edf.org]
From: Megan Ceronsky
Sent: Tue 12/9/2014 7:36:22 PM
Subject: EDF comments on the Clean Power Plan -- attachments
Att A - Laitner-McDonnell EE Analysis.pdf
Att B - Amici NY v FERC (HL) - excerpts.pdf
Att C - ATP Utility Boiler Conversion Cofiring.pdf

Hello—

Attached please find the attachments filed with EDF's comments on the Clean Power Plan.

Best,

Megan

Megan Ceronsky
Director of Regulatory Policy and Senior Attorney

Climate & Air Program

Environmental Defense Fund
1875 Connecticut Ave. NW Ste. 600

Washington, D.C. 20009
T *303 447 7224*
mceronsky@edf.org

Energy Efficiency as a Pollution Control Technology and a Net Job Creator under Section 111(d) Carbon Pollution Standards for Existing Power Plants

John A. "Skip" Laitner
Matthew T. McDonnell

Working paper prepared for the

Environmental Defense Fund

November 28, 2014

Table of Contents

Foreword

The American power sector is at a crossroadsAs states and utilities and advocates convene to think about how to comply with regulations to cut carbon emissions from our nation's fleet of power plants, it is critical that the solutions that make the most sense for consumers are pushed to the forefront

America has an opportunity to build a solid foundation for future economic growth by investing in common sense solutions like energy efficiency that cut emissions while reducing waste and saving American families and businesses money.

Energy efficiency is the most cost-effective means of meeting energy demand and reducing carbon emissions—because these investments more than pay themselves back in energy bill savings. As this report and other empirical evidence demonstrate, energy efficiency investments also create jobs and make our economy more competitive. By investing in energy efficiency now, we can enjoy the immediate environmental, economic, and energy-security benefits while sowing the seeds of future productivity and prosperity.

Yet as we think about undertaking a transition, and deploying cleaner energy solutions on a large-scale, it is important that we pause to ensure that these energy solutions are accessible to all customers—particularly those in our population who are the most vulnerable. And as Skip Arnold, Executive Director of Energy Outreach Colorado, a low-income energy consumer advocacy group, has pointed out, "Without extraordinary treatment, low-income households will not have access to these programs."

Under the newly proposed Clean Power Plan, EPA projects that by investing in energy efficiency household and business energy bills can decrease by about 8% by 2030.[1] *And this report shows that savings to families could be significantly greater with greater deployment of energy efficiency—securing a 15% improvement in energy efficiency by 2030 could generate annual average household savings of $157.*

Enabling demand-side energy efficiency to serve as an emission reduction compliance pathway is a smart option for consumers—but it is critical that as states begin to think about their compliance strategies, regulators and utilities address barriers to energy efficiency investments and ensure that savings will be available to all homes and businesses—especially including those in low-income communities.

As Mr. Arnold further notes, "For low-income energy efficiency/demand side management programs that target low-income housing to be effective, they must be implemented differently than similar programs that serve the general body of residential utility customers. Because of

[1] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants , at 3 -43 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

the very limited resources of low-income households and multi-family low-income housing providers, traditional rebate programs won't provide the resources necessary to make energy efficiency improvements to their facilities. In Colorado, and some other states, robust low-income energy efficiency programs delivered by utilities and nonprofit organizations have been implemented that go a long way in addressing this particular issue."

"We believe that there is an opportunity for the EPA to achieve the desired goal of reducing carbon emissions and at the same time lower home energy bills and create a safer, more comfortable home for our most vulnerable neighbors. But in order to do so, it is critical that EPA issues guidance that points to energy efficiency for low-income housing as an important and appropriate measure to achieve the desired goal. And as states look to implement Rule 111(d), ramping up low income energy efficiency programs should become a top priority."

Indeed, the potential for energy efficiency in the multifamily sector may be even greater than in other sectors of the economy: a 2009 study by Benningfield Group estimated the economic energy efficiency potential of multifamily homes at nearly 60%,[2] *compared to 26% in the overall U.S. economy.*[3] *In addition, if states decide to implement market-based measures, they can use the proceeds to help those struggling to pay their electricity bills. For example, in the first three years of the Regional Greenhouse Gas Initiative, the ten participating Northeast and Mid-Atlantic states devoted more than $127 million from the auction of allowances to direct bill assistance.*[4]

Many states and power companies have already realized the significant benefits of energy efficiency, setting energy efficiency standards and investing in efficiency retrofits and upgrades of buildings and appliances. But these programs fall far short of capturing our nation's vast energy efficiency resource, and fall short of reaching the potential to drive energy savings and cost savings with the low-income communities that could benefit most from the direct pocket-book savings.

As the Clean Power Plan is finalized, it will be a critical opportunity to mobilize investments in energy efficiency—and such investments are the right ones to prioritize if allies can use this opportunity to work together to ensure that the populations that are most in need have access to cost-saving and energy-saving programs.

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[2] Benningfield Group, *U.S. Multifamily Energy Efficiency Potential by 2020*, at 4 (Oct. 2009), *available at* http://www.benningfieldgroup.com/docs/Final_MF_EE_Potential_Report_Oct_2009_v2.pdf.

[3] McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy*, at 3 exh. A (July 2009), *available at* http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy.

[4] Analysis Group, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States: Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period*, at 19, 21 (Nov. 2011), *available at* http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Economic_Impact_RGGI_Report.pdf.

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Finding the ways that work

Executive Summary

This year residences and businesses in the United States will spend an estimated $360 billion to meet our total electricity demands – to cool and light our homes, listen to music or watch television, and power our commercial and industrial equipment. Electricity purchases will further enable our access to the Internet and will filter and purify the water that is delivered to our homes, schools, and businesses each and every day.

Although we will derive many important benefits as we pay our monthly electricity bills, the current electricity generation infrastructure annually produces 3.34 million tons of sulfur dioxide (SO_2) and 1.68 million tons of nitrogen oxides (NO_x) air pollution. These and other pollutants are expected to add $125 billion or more to this year's health care costs. Power plants are also the largest source of climate-disrupting carbon pollution in the United States, emitting an estimated 2 billion metric tons of carbon dioxide (CO_2) each year. Due to human activities — primarily the combustion of fossil fuels and deforestation —the concentration of carbon dioxide and other heat-trapping gases in the atmosphere is rapidly rising. The need to mitigate CO_2 emissions is truly urgent. The emerging evidence has led prominent physicist and climate scientist James Hansen to reach the "startling conclusion" that the continued exploitation of fossil fuels threatens not only the planet, but also the survival of humanity itself.

In June 2013, President Obama directed the U.S. Environmental Protection Agency (EPA) to undertake a rulemaking to establish limits on greenhouse gas emissions from existing power plants under section 111(d) of the Clean Air Act. The language of section 111(d) is sufficiently broad to encompass a flexible, system-based approach to securing carbon pollution reductions from existing power plants. A system-based approach provides an excellent opportunity for EPA to rely on customer friendly end-use energy efficiency as a building block for determining the available emissions reductions and to consider end-use energy efficiency as a compliance mechanism through which the power sector can achieve meaningful, low-cost emission reductions.

In this report we explore whether incentivizing energy efficiency through the carbon pollution standards or other policies also represents an important opportunity for economic growth and job creation. In other words, would more productive use of electricity and reduced levels of waste actually increase our social and economic well-being? Can the billions of dollars spent each year for electricity be used in other ways to more productively strengthen our nation's economy and reduce the harms imposed by fossil fuel fired generation?

The answer is clearly yes. The evidence presented here suggests that a 20 percent electricity savings by the year 2030 can catalyze a large net consumer savings that

- supports a gain of 800,000 jobs for the American economy, while raising wages by almost $45 billion;
- increases GDP by more than $26 billion;
- reduces carbon pollution by 971 million metric tons, and sulfur dioxide and nitrogen oxides by 700,000 and 800,000 tons, respectively.

An expanded emphasis on energy efficiency can extend these benefits across all sectors of the economy.

I. Introduction

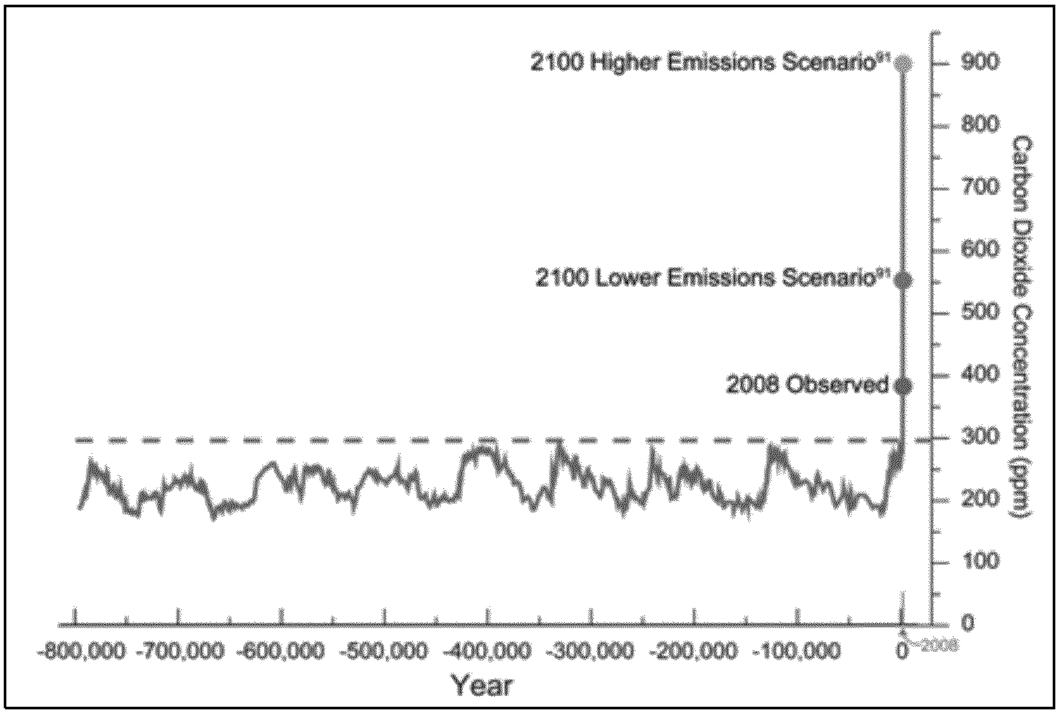
The Urgency of Action

The current electricity generation infrastructure annually produces 3.34 million tons of sulfur dioxide (SO_2) and 1.68 million tons of nitrogen oxides (NO_x) air pollution.[5] These and other pollutants were expected to add $125 billion or more to health care costs in 2013, leading to 18,000 premature deaths, 27,000 cases of acute bronchitis, and 240,000 episodes of respiratory distress. The noxious effects of these pollutants also include 2.3 million lost work days due to illness and as many as 13.5 million minor restricted activity days in which both children and adults must alter their normal activities because of respiratory health problems.[6]

Power plants are also the largest source of climate-disrupting carbon pollution in the United States, emitting an estimated 2 billion metric tons of carbon dioxide (CO_2) each year.[7] Due to human activities—primarily the combustion of fossil fuels and deforestation—the concentration of carbon dioxide and other heat-trapping gases in the atmosphere is rapidly rising. Atmospheric carbon dioxide (CO_2) levels have increased by approximately 38 percent since the Industrial Revolution (see Figure 1); current atmospheric concentrations of both CO_2 and methane (an even more potent greenhouse gas) are significantly higher than they have been for the last 800,000 years.[8]

1. *See* U.S. Dept. of Energy, Energy Info. Admin., *Annual Energy Outlook 2014 with Projections to 2040* (2014) at A19 Table A8, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf (hereinafter EIA 2014).
2. *See* Abt Assoc. Inc., *User's Manual for the Co-Benefits Risk Assessment (COBRA) Screening Model (2010)* (author-derived estimates based on emissions scenarios for 2010 given various health effects identified by EPA's Co-Benefits Risk Assessment (COBRA) model).
3. EIA 2014. Electricity production in 2014 represents about 26 percent of our nation's total energy costs but produces 39 percent of our nation's total CO_2 emissions. *Id.* tbls. 3, 18.
4. *See* U.S. Envtl. Prot. Agency, *Technical Support Document for Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* (2009) at ES-1 to -2 (hereinafter TSD); Intergovernmental Panel on Climate Change, *Climate Change 2007: The Physical Science Basis*, at 512 (S. Solomon et al. eds., 2007) (hereinafter IPCC 2007); U.S. Global Change Research Program, *Global Climate Change Impacts in the United States* (2009) (hereinafter USGCRP 2009).

Figure 1. 800,000-Year Record of Carbon Dioxide Concentration



Source: USGCRP (2009) at 13.

This chart shows a recent, rapid buildup in CO_2 concentrations in the atmosphere relative to the last 800,000 years, based upon analyses of air bubbles trapped in Antarctic ice. It also shows that unless we curb greenhouse gas emissions, atmospheric CO_2 concentrations will likely double or triple by the end of this century from pre-industrial levels.[9]

The increase in the amount of solar radiation that is trapped in the earth's atmosphere due to rising concentrations of greenhouse gases is causing average global temperatures to rise and presents severe risks to the health and well-being of Americans.

Rising temperatures will accelerate ground-level ozone (and smog) formation in polluted areas, and increase the frequency and duration of stagnant air masses that allow pollution to accumulate.[10] Higher ozone levels exacerbate respiratory illnesses, increasing asthma attacks and hospitalizations and increasing the risk of premature death.[11]

Rising temperatures will also result in heat waves that are hotter, longer, and more frequent.[12] Snowpacks will be smaller and snow melt accelerated, threatening water supplies in late summer in the West.[13] In addition, significant reductions in winter and spring precipitation are

5. USGCRP 2009 at 2.
6. TSD at 89-93, USGCRP 2009 at 93-94.
7. Environmental Protection Agency, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units* (March 2012) at 3-2 -3-3, 5-24 (hereinafter RIA).
8. IPCC 2007 at 750; 74 Fed. Reg. at 66524-25.
9. USGCRP 2009 at 10, 45-46.

projected for the South, especially in the Southwest, further imperiling water supplies.[14] Rising temperatures will likely increase the frequency, length, and severity of droughts, especially in the West.[15] Precipitation events in general and some types of storms, particularly hurricanes, are expected to become more intense, increasing the likelihood of severe flooding.[16] Water shortages and heavy precipitation events are likely to further stress flood control, drinking water, and wastewater infrastructure.[17]

Global sea levels are likely to rise between seven inches and four feet during the 21st century, both because of ice sheet melting and because seawater expands as it warms.[18] This amount of sea level rise, in combination with more powerful hurricanes, will increase the risks of erosion, storm surge damage, and flooding for coastal communities, especially along the Atlantic and Gulf coasts, Pacific Islands, and parts of Alaska.[19] Under a business as usual emission scenario, what is currently a once-a-century flood in New York City is projected to be twice as common by mid-century and 10 times as frequent by the end of the century.[20] With accelerated sea level rise, portions of major coastal cities, including New York and Boston, would be inundated during storm surges or even during regular high tides.[21] In the Gulf Coast area, an estimated 2,400 miles of major roadways are at risk of permanent flooding within 50 to 100 years due to anticipated sea level rise in the range of 4 feet.[22]

Due to ocean absorption of carbon dioxide, ocean acidity has increased 25 percent since pre-industrial times.[23] If atmospheric carbon dioxide doubles, oceanic acidity will also increase, leaving almost nowhere in the ocean where coral reefs can survive and threatening the ocean's food webs, which rely upon coral reefs as fish nurseries and planktonic animals that may be unable to survive a more acidic sea.[24] The loss of healthy ocean ecosystems would have devastating effects on the global food supply.

In addition, the more temperatures rise, the greater the risk that disruptive climate change thresholds could be reached more quickly. This, in turn, could generate abrupt environmental changes with potentially catastrophic impacts for natural systems and human societies.[25]

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10. USGCRP 2009 at 30; 74 Fed. Reg. at 66,532.
11. USGCRP 2009 at 30, 41-46; IPCC 2007 at 262-263, 783; 74 Fed. Reg. at 66,532-34; RIA at 3-5, 3-8..
12. USGCRP 2009 at 34-36, 44, 64; TSD at ES-4, 115; AR4, IPCC 2007 at 783; 74 Fed. Reg. at 66,525.
13. USGCRP 2009 at 47-51, 132-36; 74 Fed. Reg. at 66,532-33.
14. USGCRP 2009 at 37, 150; AR4, IPCC 2007 at 750.
15. USGCRP 2009 at 12, 36, 109-10, 142-43, 149-50. Super Typhoon Haiyan that roared into the Philippines and Vietnam in early November 2013 provides an unfortunate glimpse of future impacts. Officials predicted that the death toll could exceed 10,000 -- or more. *See* http://www.cbsnews.com/8301-202_162-57611690/typhoon-haiyan-slams-into-northern-vietnam/.
16. USGCRP 2009 at 109-10. "Superstorm Sandy" may be another example of these future impacts. It was the deadliest and most destructive hurricane of the 2012 Atlantic hurricane season, as well as the second-costliest hurricane in United States history. *See* http://en.wikipedia.org/wiki/Hurricane_Sandy.
17. USGCRP 2009 at 150.
18. USGCRP 2009 at 62.
19. RIA at 3-9.
20. RIA at 3-7, 3-9 – 3-10; National Research Council, *Advancing the Science of Climate Change* at 55-56, 59-60 (2010), *available at* http://www.nap.edu/openbook.php?record_id=12782.
21. USGCRP 2009 at 26; National Research Council, *Abrupt Climate Change, Inevitable Surprises* at v, 16, 154 (2002); US Climate Change Science Program, *Abrupt Climate Change* at 10 (2008); TSD at 66.

The need to act to mitigate these harms is truly urgent. These circumstances and the emerging evidence have led prominent physicist and climate scientist James Hansen to reach the "startling conclusion" that the continued exploitation of fossil fuels threatens not only the planet, but also the survival of humanity itself (Hansen 2009 at ix). Furthermore, the continued inefficient use of energy will contribute to a further weakening of the U.S. economy.[26] As we shall see in this analysis, for example, the inefficient use of electricity will cost the economy nationwide an estimated 800,000 jobs by 2030, which means$44 billion in lost wages in that year.

The Opportunity in Acting

There is little question that the production and use of electricity hold great economic value for the United States. But there is also little question that the curre nt infrastructure of fossil fuel fired electricity generation and electricity usage patterns are imposing heavy burdens on Americans in the form of health impacts, climate destabilization, water consumption, and job loss. In this report we ask the question of whether there is an opportunity cost being overlooked by current patterns of production and consumption of electricity. In other words , can more productive use of electricity and reduced waste actually increase our social and economic well-being? In short, can the billions of dollars spent each year for electricity be used in other ways to strengthen our nation's economy and reduce the harms imposed by fossil fuel fired generation? The answer is clearly yes.

In this working paper we set out to explore two questions. First we ask : How big is the energy efficiency resource? That is, h ow big of a benefit can energy efficiency deliver if seen as a pollution control strategy? And w hat scale of investment is required to drive reductions in conventional air pollution as well as greenhouse gas emissions ? Second, we provide a first order review of the jobs and economic impacts of efficiency -led emissions reductions. We provide an initial estimate of cost -effectiveness of the energy efficiency resource, and then explore how that change in spending might impact the nation's ability to support a greater number of jobs. With that backdrop, Section II of this paper examines the evidence of previous assessments to identify both the scale and the cost-effectiveness of energy efficiency in ways that might inform our investigation here . In Section III we provide an overview of the methodology we use to estimate the economic impa cts of increased investment in energy efficiency. Section IV summarizes the major results of this inquiry while Section V offers several conclusions and observations. Section VI identifies the many references that guided our inquiry. Finally, Appendix A p rovides an extended review of the energy efficiency resource while Appendix B presents further details about the economic model used to complete th is assessment.

22. Laitner 2013.

II. The Energy Efficiency Resource Potential

Energy efficiency has played a surprisingly enduring and critical role in our nation's economy. Efficiency is an incredibly low-cost resource and its benefits are wide-ranging and significant. These benefits include both reduced energy bills and a surprising number of non-energy benefits, from reduced operations and maintenance costs at industrial plants to improved quality and speed in the production of our nation's goods and services.[27] Not only could energy efficiency drive down emissions, mitigate adverse health effects, and bring down health costs associated with "business-as-usual" energy use, but these more productive investments could also stimulate a more robust economy by reducing the cost of energy services and spurring job creation.[28]

When it comes to the energy efficiency resource potential, current investments are still just scratching the surface. Building on Ayres and Warr (2009),[29] Laitner (2013) estimates that the U.S. economy is about 14 percent energy (in)efficient, with 86 percent of applied energy wasted in the production of goods and services.[30] What we waste in the generation and use of electricity is more than Japan needs to power its entire economy. Some progress has been made, however: investments in greater energy productivity, since 1970, have resulted in the U.S. economy consuming half the energy it would have otherwise required in 2010.[31]

Energy efficiency is a dynamic and long-term resource, as more fully described in Appendix A.[32] In fact, a McKinsey study estimates that, if executed at scale, a holistic approach to efficiency would yield gross energy savings worth more than $1.2 trillion, an amount well above the $520 billion needed through 2020 for upfront investment in efficiency measures (excluding program costs).[33] Such a program is estimated to reduce end-use energy consumption in 2020 by 9.1 quads, roughly 23 percent of projected demand, potentially abating up to 1.1 gigatons of greenhouse gases (GHG) annually.[34] However, the full energy efficiency potential includes more than simply the penetration of known advanced technologies. If we were to embrace a greater rate of infrastructure improvements along with

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23. *See* Lazard, Ltd., "Levelized Cost of Energy Analysis—Version 7.0" (2013).
24. By reducing U.S. energy use by 30 percent in 2020 and 55 percent in 2050, Laitner et al. (2010) estimate a range in savings per household from $81 in 2020 to $849 per household in 2050 as well as an increase in net jobs from 373,000 jobs created in 2020, 689,000 in 2030, and over 1.1 million in 2050.
25. Ayres, Robert U. and Benjamin Warr. *The Economic Growth Engine: How Energy and Work Drive Material Prosperity*. Northampton, MA: Edward Elgar Publishing, Inc., 2009 (hereinafter Ayres and Warr 2009).
26. *See* John A. "Skip" Laitner, *Linking Energy Efficiency to Economic Productivity: Recommendations for Improving the Robustness of the U.S. Economy* (2013); *see also* Robert U. Ayres and Benjamin Warr, *The Economic Growth Engine: How Energy and Work Drive Material Prosperity* (2009).
27. *See* John A. "Skip" Laitner et al., *The Long-Term Energy Efficiency Potential: What the Evidence Suggests* (2012) (hereinafter Laitner et al. 2012). One quad is a quadrillion Btus which, in the form of gasoline, is sufficient energy to energy to power about 12 million cars and trucks for one year of driving. In other forms of energy one quad is sufficient maintain about 5.4 million homes at current levels of consumption.
28. *See* Amory Lovins, *Reinventing Fire: Bold Business Solutions for the New Energy Era* (2011); Laitner et al. 2012; Hannah Choi Granade et al., *Unlocking Energy Efficiency in the U.S. Economy* (2009) (hereinafter Granade et al. 2009).
29. Granade et al. 2009.
30. Granade et al. 2009. The U.S. now emits about 6.6 billion tons or gigatons of total greenhouse gas emissions per year.

some displacement of the existing capital stock to make way for newer and more productive energy efficiency technologies, as well as new configurations of the built environment that reduce the distance people and goods must be transported, by 2050, we might achieve a 59 percent reduction in total energy use compared to the business as usual Energy Information Administration projection (consuming only 50 quads versus 122 quads by the year 2050).[35]

Reducing electricity demand through energy efficiency and demand side energy management—using only available technologies—has been demonstrated to be one of the most cost-effective means of reducing GHG emissions from the power sector.[36] The 2009 McKinsey study found that, after taking into account the upfront costs of installing efficiency improvements, the efficiency measures they identified would save American families and businesses $680 billion over ten years.[37] In addition, the study estimated that it would require 600,000 to 900,000 workers during the duration of the 10-year period to develop, produce, and implement the efficiency improvements, administer the programs, and verify the results.[38] Simply put, demand side energy efficiency offers tremendous potential to reduce power sector greenhouse gas emissions while simultaneously reducing utility bills for American families and businesses, improving grid reliability, reducing co-pollutant emissions, improving energy security, and creating jobs in the energy efficiency sector.

An extensive body of studies developed over many years suggests that energy efficiency can provide perhaps the largest single source of GHG emissions reductions in the coming decades.[39] Should we reduce electricity use by just 0.1 percent per year between now and 2050,[40] a recent study by Synapse Energy Economics indicates that by 2020, power sector CO_2 emissions would fall 25 percent below 2010 levels.[41] By 2050, the combination of energy efficiency and a variety of renewable energy technologies could reduce CO_2 emissions to 81 percent below 2010 levels.[42] By pursuing the larger achievable efficiency and renewable energy targets, the Synapse assessment also found that other environmental and health impacts of coal-fired electricity are dramatically reduced. Over $450 billion in health effects

31. Laitner et al. 2012.
32. The Analysis Group notes that "RGGI investment in energy efficiency depresses regional electrical demand, power prices, and consumer payments for electricity. This benefits all consumers through downward pressure on wholesale prices, yet it particularly benefits those consumers who actually take advantage of such programs, implement energy efficiency measures, and lower both their overall energy use and monthly energy bills. These savings stay in the pocket of electricity users. But positive macroeconomic impacts exist as well: the lower energy costs flow through the economy as collateral reductions in natural gas and oil consumption in buildings and increased consumer disposable income (from fewer dollars spent on energy bills), lower payments to out-of-state energy suppliers, and increased local spending or savings. Consequently, there are multiple ways that investments in energy efficiency lead to positive economic impacts; this reinvestment thus stands out as the most economically beneficial use of RGGI dollars." *See* Hibbard et al. 2011.
33. Granade et al. 2009.
34. Granade et al. 2009.
35. Laitner et al. 2012; *see also* L.D. Harvey, *Energy Efficiency and the Demand for Energy Services* (2010); Comm. on America's Energy Future, *Real Prospects for Energy Efficiency in the United States* (2010); Granade et al. 2009; American Physical Society, *Energy Future: Think Efficiency* (2008).
36. Resulting in energy consumption of 3,760 billion kilowatt-hours (kWh) in 2050 versus 5,590 billion kWh under a business-as-usual (BAU) projection.
37. *See* Geoff Keith et al., *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* (2011) (hereinafter Keith et al. 2011).
38. Keith et al. 2011.

related to air pollution would be avoided over the 2010 to 2050 study period, based on damage factors developed by the National Research Council.[43]

The evidence indicates that energy efficiency is not only a significant resource, but it also presents an immensely cost-effective pollution control strategy—with benefits exceeding costs over the investment life of individual measures or improvements. A study by the Lawrence Berkeley National Laboratory demonstrated that one-third of electricity and natural gas use in buildings could be saved (along with respective emissions) at a total cost of 2.7 cents per kilowatt-hour (¢/kWh) for electricity and between 2.5 and 6.9 dollars per million Btu for natural gas (all values in 2007 dollars).[44] The study suggested that the cost savings over the life of the measures would be nearly 3.5 times larger than the up-front investment required (in other words, a benefit-cost ratio of 3.5). At the same time, Amann (2006) suggests that non-energy benefits of energy efficiency upgrades might range from 50 to 300 percent of household energy bill savings.[45] These added benefits range from financial savings to energy bill relief, comfort, aesthetics, noise reduction, health and safety, and convenience. Worrell et al. (2003) and Lung et al. (2005) found comparable non-energy benefits that greatly enhance the cost-effectiveness of energy efficiency within the industrial sector as well.[46]

Indeed, efficiency has shown an ability to drive down emissions and mitigate health costs associated with "business as usual" energy use. But, efficiency has also demonstrated its ability to stimulate economic growth by reducing the cost of energy services and spurring job creation. ACEEE demonstrated efficiency's significant macroeconomic impact through its analysis under two policy scenarios: the Advanced Case (42 percent energy savings from 2050 reference case) and the Phoenix Case (59 percent energy savings from 2050 reference case).[47] The study suggested the cumulative capital investments in the efficiency upgrades for the Advanced Case will be about $2.4 trillion over the 39-year period 2012 to 2050 (in constant 2009 dollars). The significantly greater magnitude of efficiency changes in the Phoenix Case increases cumulative investments to $5.3 trillion in that same time period.[48] While this may seem like a significant investment, it is but a fraction of the $4.6 trillion per year the economy is likely to invest over this same time horizon.[49]

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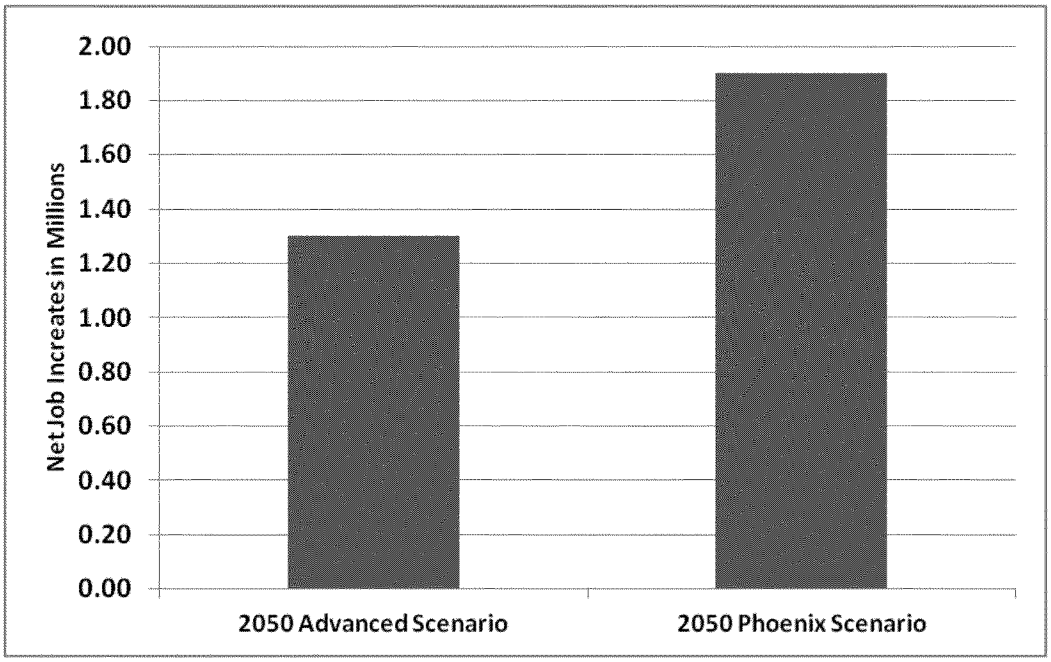
39. *Id.*
40. Rich Brown et al., *U.S. Building-Sector Energy Efficiency Potential* (2008). In 2012, the end-use price of electricity for the residential sector was 11.9¢/kWh in 2012 cents (about 10¢ in 2007 cents); in the commercial sector, 10.1¢/kWh in 2012 cents (about 9¢ in 2007 cents). AEO 2014 tbl. 8. The Henry Hub price for natural gas in April 2014 was $4.66 /MMBtu, or, in 2007 dollars, $4.07. EIA, Henry Hub Natural Gas Spot Price, http://www.eia.gov/dnav/ng/hist/rngwhhdM.htm (last visited May 23, 2014); Bureau of Labor Statistics, CPI Inflation Calculator, http://data.bls.gov/cgi-bin/cpicalc.pl.
41. Jennifer Amann, American Council for an Energy-Efficient Economy, *Valuation of Non-Energy Benefits to Determine Cost-Effectiveness of Whole House Retrofit Programs: A Literature Review* (2006).
42. Ernst Worrell et al., "Productivity Benefits of Industrial Energy Efficiency Measures," *Energy*, 1081-98 (2003); Robert Lung et al., American Council for an Energy-Efficient Economy, "Ancillary Benefits and Production Benefits in the Evaluation of Industrial Energy Efficiency Measures" (2005).
43. Laitner et al. 2012.
44. See Table 2 following the discussion in section III for a further comparison of this set of efficiency scenarios with three other long-term efficiency scenarios out to 2050.
45. Laitner et al. 2012. While energy efficiency appears significantly more costly under the Phoenix Scenario, it is roughly the equivalent of just one year's routine investment spread out over a 39-year period.

Figure 2: Net Employment Benefits from Two Efficiency Policy Scenarios



Source: Laitner et al. 2012

The capital investments in efficiency generate substantial cumulative energy bill savings of $15 trillion in the Advanced Case and $23.7 trillion in the Phoenix Case (also in 2009 dollars). Hence, energy efficiency not only proves to be a prudent investment, but it also delivers substantial economic savings that would drive a significant increase in overall employment (see Figure 2 above). The Advanced Case shows that investment in efficiency would produce a 1.3 million job gain in the year 2050. Perhaps unsurprisingly, efficiency investment in the Phoenix Case, benefiting from a larger investment and a bigger net energy bill savings, generates about a 1.9 million job gain in 2050.[50]

III. Assessing Total Employment Impacts

Having established that energy efficiency is an indispensable and cost-effective resource to reduce air pollution and greenhouse gas emissions, we now provide an analytical framework to evaluate the net economic and employment impacts of this resource. We utilize the U.S. Energy Information Administration's annual modeling to establish a reference case, or "business as usual" (BAU) scenario. We compare this to an "Efficiency-Led Scenario" in which the country moves toward a power system based on more productive investments in energy efficiency technologies, systems, and infrastructure. In this alternative scenario, a greater level of energy-efficient investments enables both new demands for energy services and the retirement of some existing electricity generation power plants. In this section we lay out three elements that form the basis of our assessment: (1) the standard projection for U.S. electricity consumption over the period 2012 through 2030; (2) the key characteristics of the alternative

46. Laitner et al. 2012.

investment scenario; and finally, (3) a description of the DEEPER modeling system used to evaluate the efficiency scenarios characterized in this report.

A. The Business-as-Usual Backdrop

The foundation for this assessment is the *Annual Energy Outlook* published by the Energy Information Administration (2012).[51] Although the forecast of energy and other market trends covers all uses of energy within our economy (including transportation fuels, natural gas, and other resources), here we will explore possible changes in our nation's electricity use beginning in 2012 through the year 2030. This includes the growth in the number of households, commercial, and industrial customers over that time along with the anticipated growth in the demand for electricity services by those users. It also includes both expected trends in electricity prices as well as a discussion of potential drivers of important shifts in electricity demand. In addition, since we are exploring the impacts on the economy, we will review the anticipated growth in the nation's jobs and Gross Domestic Product (GDP), also through the year 2030. Table 1 below provides the assumed reference case projections for key metrics against which we will compare the impacts of an efficiency-led scenario.

Table 1. Reference Case Projections for Key Economic Metrics 2012 and 2030

Metric	2012	2030	Annual Rate	Total Growth
The Macroeconomy				
GDP (billion 2005 dollars)	13,486	21,736	2.7%	61.2%
Real Investment (billion 2005 dollars)	1,875	4,066	4.4%	116.9%
Households (millions)	116.1	139.3	1.0%	20.0%
Nonfarm Employment (millions)	131.8	162	1.2%	22.9%
Electricity Sales				
Economy-Wide Electricity Use (billion kWh)	3,729	4,258	0.7%	14.2%
Average Retail Electricity Price (2010 $/kWh)	0.096	0.098	0.1%	2.1%
Annual Electricity Costs (billion 2010 dollars)	358.0	417.3	0.9%	16.6%
Emissions from Power Plants				
Sulfur Dioxide (million short tons)	3.79	1.62	-4.6%	-57.3%
Nitrogen Oxides (million short tons)	1.99	1.94	-0.1%	-2.6%
Carbon Dioxide (million metric tons equivalent)	2,146	2,258	0.3%	5.2%

Source: EIA (2012)

The summary in Table 1 above forecasts several positive trends even under the reference scenario. First, EIA projects the economy will grow at a faster clip than either the number of households or their increased use of electricity consumption, as measured by EIA's assessment of the nation's GDP. Jobs will also increase. While electricity expenditures will grow as well, they will rise more slowly than GDP. EIA's forecast clearly anticipates that the economy will make increasingly efficient use electricity to provide the nation's homes and businesses with needed goods and services.

47. As the project first began, we originally benchmarked the analysis described here to the energy and economic projections found in the *Annual Energy Outlook 2012* (EIA 2012). While we cite the updated information contained in *Annual Energy Outlook 2013* (EIA 2013), our analysis is still linked to EIA 2012. A series of quick diagnostic tests shows this does not materially impact the findings of this assessment.

Yet the business-as-usual rate of efficiency improvement still requires an increase in overall electricity consumption since the economy is projected to grow more quickly than the rate of efficiency improvement. While pollution control technologies are likely to reduce future air pollution from emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), as shown in Table 1, carbon dioxide (CO_2) emissions are likely to increase due to the increased fossil fuel combustion associated with the generation of electricity.[52]

Fortunately, we can do much better. We can reduce overall pollution levels and, at the same time, lower the nation's total electricity bill. The many studies summarized in Section II of this report indicate that a much larger set of energy efficiency gains beyond the business-as-usual improvements is possible. This is true for the residential, the commercial, and the industrial sectors of the economy. For example, if the energy efficiency opportunities highlighted in the study by Laitner et al. (2012) were to be developed and implemented, the total electricity demand for 2030, as shown in Table 1, would *decline* to 3,370 billion kilowatt-hours rather than *increase* to 4,258 billion kilowatt-hours.[53] What may be less obvious, however, is that the efficiency gains will prove to be less expensive than increasing the generation capacity to meet the higher electricity demands.

Finally, some readers may be surprised to learn how much the economy depends every year on the flow of normal investments as they affect our nation's homes, schools, businesses, roads, and bridges, as well as the many electric power plants, transmission lines, and industrial facilities needed to maintain a functioning economy. In Table 1 it appears that we will invest about $1,875 billion in new buildings and infrastructure, or in routine upgrades to existing infrastructure. By 2030 this will grow to an estimated $4,066 billion or about 18.7 percent of GDP. As we might imagine, and as shown in the analysis that follows, redirecting even one percent of the nation's annual investment to greater gains in electricity efficiency can provide the foundation to achieve a significant level of cost savings compared to the normal rate of energy efficiency improvements. In addition, as we shall also see, more productive investments will drive a small but positive gain in the nation's job market and achieve a cost-effective reduction in the nation's air pollution and greenhouse gas emissions. The next section of this working paper explores the cost and performance characteristics that might contribute to cost-effective electricity reductions in our homes, schools and businesses.

B. Key Attributes of the Energy Efficiency Scenario

In this assessment, we draw upon two previously referenced studies to define an exploratory scenario that helps evaluate energy efficiency as a pollution control strategy; and, more critically, to explore how energy efficiency investments might drive both significant cost savings

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48. Including transportation and other fuels such as natural gas, the energy-related CO_2 emissions are projected to grow from 5,570 to 5,670 million metric tons at a time when the scientific evidence suggests the need for very steep reductions in greenhouse gas emissions. As noted previously, total greenhouse gas emissions are estimated to be just under 7,000 million metric tons (or gigatons). The difference is the number of other non-energy-related CO_2 emissions which also contribute the total mix of greenhouse gases emitted each year.
49. Laitner, John A. "Skip," Steven Nadel, R. Neal Elliott, Harvey Sachs, and Siddiq Kahn. 2012. *The Long-Tern Energy Efficiency Potential: What the Evidence Suggests*. Washington, DC: American Council for an Energy-Efficient Economy.

and overall gains in employment. The first assessment is from Laitner et al. (2012), which explored the long-term energy efficiency potential for two scenarios through the year 2050.[54] That report examined a more complete set of efficiency options, including natural gas and petroleum efficiency improvements as well as electricity savings from all sectors of the economy. The second is Keith et al. (2011), a report from Synapse Energy Economics that focused explicitly on electricity savings alone.[55] Both assessments found that productive investments in energy efficiency upgrades generated a net positive economic benefit. Although both studies indicate that electricity savings of 30 to 37 percent from the reference case projected for 2050 are possible, the central case of this analysis is an assessment of the economic impacts of achieving a 20 percent efficiency gain by 2030.

To provide a sense of scale and cost-effectiveness of the efficiency resource more broadly, Table 2 highlights key metrics from both the ACEEE and Synapse scenarios. We also include two other studies: the *Energy Technology Perspectives* study published by the International Energy Agency (IEA/ETP 2010) and *Reinventing Fire* released by Lovins et al. (2011).[56]

Table 2. Key Metrics from Year 2050 Alternative Energy Future Studies

Metric	Year 2050 Impacts				
	ACEEE-Advanced	ACEEE-Phoenix	IEA ETP	Reinventing Fire	Synapse[1]
BAU GDP Index (2010 = 1.00)	2.79	2.79	1.95	2.58	2.71
BAU Energy Use (2010 = 1.00)	1.24	1.24	1.05	1.27	1.41
Efficiency Scenario Energy Use (2010 = 1.00)	0.72	0.51	0.47	0.69	0.67
Investment (Trillion 2009 Dollars)[2]	2.9	6.4	5.9	4.5	1.4
Savings (Trillion 2009 Dollars)[2]	15.0	23.7	15.1	9.5	4.4
Index Savings to Investment[3]	5.2	3.7	2.6	2.1	3.5

Table Notes: (1) While the first four studies reflect economy-wide energy savings, the Synapse report captures only the savings from electricity production and consumption. (2) The investments and savings data reflect cumulative values in constant dollars over the period 2010 through 2050. (3) The savings to investment index is a simple comparison of suggested energy bill savings compared to the total cost of investments, also over the period 2010 through 2050. Because there is no way to compare the discounted streams of savings and expenditures over time, this simple index is indicative of, but should not be construed as, a true benefit-cost ratio.

Interestingly, there is a wide range in the assumed future GDP growth among the five scenarios outlined in Table 1. The IEA projects an economy in 2050 that is about 1.95 times bigger than in 2010. ACEEE and Synapse, generally following the EIA's *Annual Energy Outlook*, suggest economic activity that will be 2.71 to 2.79 times larger than 2010. Reinventing Fire suggests a more moderate growth path so that economic activity is 2.58 times larger in 2050 compared to 2010. In comparing the business-as-usual energy growth in

50. Laitner, John A. "Skip," Steven Nadel, R. Neal Elliott, Harvey Sachs, and Siddiq Kahn. 2012. *The Long-Tern Energy Efficiency Potential: What the Evidence Suggests*. Washington, DC: American Council for an Energy-Efficient Economy.
51. Keith et al. 2011.
52. [IEA/ETP] International Energy Agency, Energy Technology Policy Division. 2010. *Energy Technology Perspectives: Scenarios & Strategies to 2050.* Paris, France: International Energy Agency; Lovins, Amory and the Rocky Mountain Institute. 2011. *Reinventing Fire: Bold Business Solutions for the New Energy Era*. White River Junction, VT: Chelsea Green Publishing.

the five scenarios with their respective 2050 efficiency gains, the evidence suggests potential 2050 savings that range between 42 and 59 percent.[57] Moreover, all of the scenarios suggest a net positive savings to investment ratio, ranging from 2.1 to 5.2 over the period of analysis within each scenario. To test the idea of how effective efficiency might be as a pollution control strategy, but reflecting larger uncertainties in the out-years, we take the analysis here to only 2030.

Our core scenario for this exploration assumes an electricity savings that, beginning in 2014, slowly ratchets up to reach 20 percent by 2030. The benefit-cost ratio of this scenario (as we shall see) is over 2.0. As we explain further in the section that follows, we assume that program costs will drive investments that, in turn, generate a 20 percent reduction in conventional electricity generation by 2030 so that the electricity savings, in constant dollars, are twice as large as the combination of program costs and investments, also in constant dollars.

We next turn to a description of the Dynamic Energy Efficiency Policy Evaluation Routine, or the DEEPER, Modeling System, which, in essence, is an econometric input-output analytical tool. Although recently given a new name, the model's origins can be traced back to modeling assessments that were first completed in the early 1990s (see Appendix B for historical information and other details on the DEEPER model).

C. Review of the DEEPER Economic Policy Model

The DEEPER model is "quasi-dynamic" in that the costs of energy efficiency improvements are based on the level of efficiency penetration over some period of time. The greater the efficiency penetration, the higher the costs, and the resulting payback periods begin to increase. Moreover, the model adjusts labor impacts given the anticipated productivity gains within key sectors of the U.S economy. As an example, if the construction and manufacturing sectors increase their output as a result of the alternative policy scenario, the employment benefits are likely to be affected – depending on assumptions about the expected labor productivity gains within each of those sectors.

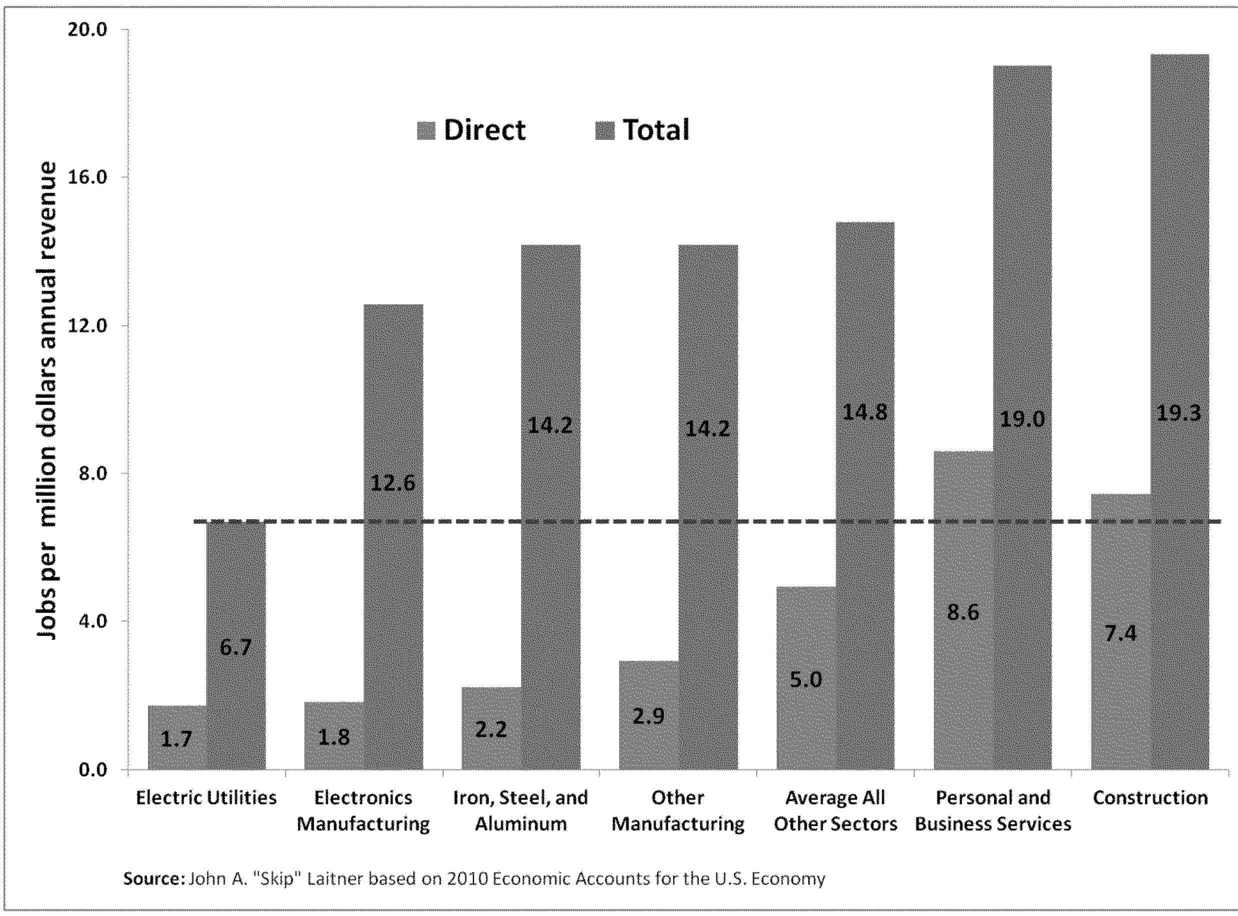
Input-output models initially were developed to trace supply linkages in the economy. For instance, an input-output accounting framework can show how purchases of lighting technologies or industrial equipment benefit the lighting and other equipment manufacturers in a state. In addition, because the input-output model has coefficients linking both directly and indirectly affected industries, the model can also reveal the multiplicative impacts that such purchases are likely to have on other industries and businesses that might supply the necessary goods and services to those manufacturers.

The net economic gains of any new investments in energy efficiency will depend on the structure of the economy, and which sectors are most affected by changes in new spending patterns that are promoted by investments in energy productivity rather than electricity supply.

53. As an example, the Synapse study projects a BAU energy growth index of 1.41, with an efficiency use index that falls to 0.67. Hence, (0.67 / 1.41 – 1) *100 percent = 52 percent.

To illustrate this point, Figure 3, below, compares the direct and total employment impacts that are supported for every one million dollars of revenue received by different sectors of the U.S. economy. These include electric utilities, manufa cturing, personal and business services, and construction.[58] For purposes of this study, a job is defined as sufficient economic activity to employ one person full-time for one year.

Figure 3. Labor Intensities for Key Sectors of the U.S. Economy



Of immediate interest in Figure 3 is the relatively small number of direct and total jobs supported by energy sector spending . Within the U nited States the electric utility industry provides, for example, only 6.7 total jobs per million dollars of revenues that it receives. This total includes jobs directly supported by the industry as well as those jobs linked to businesses which, in turn, provide goods and services to maintain the utilities' operation. And it also includes the additional jobs supported b y the respending of wages within the U.S. economy.

54. The model used for the assessment described here relies on the IMPLAN datasets for the United States. IMPLAN stands for "IMpact Analysis for PLANning." These 2010 historical economic accounts (IMPLAN 2012) provide a critical foundation for a wide range of modeling techniques, including the input -output model used as a basis for the assessment described he re. For more information on the use of this kind of analysis, see the discussion in Appendix B of this report. F or a more recent example of an assessment undertaken in the policy arena, see Busch et al. (2012) for an analysis of the recently adopted fuel-economy standards.

On the other hand, one million dollars spent in construction supports a total of 19.3 jobs, both directly and indirectly.

As it turns out, much of the job creation from energy efficiency programs is derived by the difference between jobs within the utility supply sectors and jobs that are supported by the respending of energy bill savings in other sectors of the economy.

D. An Illustration: Jobs from Improvements in Commercial Office Buildings

To illustrate how a simplified job impact analysis might be done, we will use the example of installing one million dollars of efficiency improvements in a large office building. O ffice buildings (traditionally large users of energy due to heating and air -conditioning loads, significant use of electronic office equipment, and the large numbers of persons employed and served) provide substantial opportunities for energy -saving invest ments. The results of this example are summarized in Table 3 below.

The assumption used in this example is that the investment has a positive 4 -year payback. In other words, the assumption is that for $1 million of energy efficiency improvements, the upgrades might be expected to save an average of $250,000 in reduced electricity costs over the useful life of the technologies. This level of savings is conservatively low but consistent with the low end of ranges cited elsewhere in this report. At the s ame time, if we anticipate that the efficiency changes will have an expected life of roughly 15 years, then we can establish a 15-year period of analysis. In this illustration, we further assume that the efficiency upgrades take place in the first year of the analysis, while the electricity bill savings occur in years 1 through 15. Moreover, we assume that only half the savings occur in the first year as it may take several months to actually start an average project with savings not beginning until halfway through the year.

Table 3. Job Impacts from Government Building Energy Efficiency Improvements

Expenditure Category	Amount (Million $)	Employment Coefficient	Job Impact
Installing Efficiency Improvements in Year 1	1.0	19.3	19.3
Diverting Expenditures to Fund Efficiency Improvements	-1.0	14.8	-14.8
Energy Bill Savings in Years 1 through 15	3.6	14.8	53.3
Lower Utility Revenues in Years 1 through 15	-3.6	6.7	-24.1
Net 15-Year Change			33.7

Note: The employment multipliers are taken from the appropriate sectors found in Figure 2. Based on the efficiency costs described in the text, the annual savings are about $250,000 with only one -half available in the first year. The jobs impact is the result of multiplying the row change in expenditure by the appropriate row multiplier. On average, this building upgrade would be said to support a net gain of about 2.2 jobs per year for 15 years. For more details, see the text that follows.

The analysis further assumes that we are interested in the *net effect* of employment and other economic changes. This means we must first examine all changes in business or consumer expenditures—both positive and negative —that result from a movement toward energy efficiency. Each change in expenditures must then be multiplied by the appropriate multiplier (taken from Figure 3) for each sector affected by the change in expenditures. The sum of these products will then yield the net result.

In our example, there are fou r separate changes in expenditures, each with their separate effect. As Table 3 indicates above, the overall impact of the scenario suggests a gain of 33.7 job-years (rounded) in the 15 -year period of analysis. This translates into an average gain of about 2.2 jobs each year for 15 years. In other words, the efficiency investment made in the office building is projected to sustain an average gain of 2.2 jobs each year over a 15 -year period compared to a "business -as-usual" scenario. Roughly speaking, if comparable projects like this scaled to more like $100 million in a single year, the number of jobs gained would similarly scale upward (to 3,370 job-years).[59]

E. Appropriate Modifications in the Energy Efficiency Scenarios

The economic assessment of the alternative energy scenarios was carried out in a very similar manner as the example described above. That is, the changes in energy expenditures brought about by investments in energy efficiency and renewable technologies were matched with their appropriate employment multipliers. There are several modifications to this technique, however.[60]

First, it was assumed that only 90 percent of both the efficiency investments and the subsequent savings are spent within the United States. We based this initial value on the 2010 IMPLAN dataset as it describes local purchase patterns that typically now occur in the United States. We anticipate that this is a conservative assumption since most efficiency projects are likely to be (or could be) carried out entirely by contractors and dealers within the United States. By way of illustration, if the share of domestic spending turned out to be 100 percent, for example, the overall job gain might grow another five percent or more compared to our standard scenario exercise.

Second, an adjustment in the employment impacts was made to account for assumed future changes in labor productivity. As outlined in the Bureau of Labor Statistics *Outlook 2010–2020*, productivity rates are expected to vary widely among sectors.[61] For instance, the BLS projects an economy-wide 1.5 percent annual average productivity gain as the economy better integrates information technologies and other improvements. To illustrate the impact of productivity gains on future employment patterns, let us assume a typical labor productivity increase of 2.2 percent per year. This means, for example, that compared to 2012, we might expect that a $1 million expenditure in the year 2030 will support only 68 percent of the number of jobs as in 2012.[62]

Third, for purposes of estimating electricity bill savings, it was assumed that current electricity prices for the residential, commercial, and industrial sectors in the United States would follow the same growth rate as those published by the Energy Information Administration in its *Annual Energy Outlook* 2012.[63]

Fourth, it was assumed that the large-scale efficiency upgrades are financed by bank loans that carry an average 6 percent interest rate over a 5-year period. While this does raise the

55. While this idea of scale more or less holds true, as costs begin to rise with a greater level of penetration of energy efficiency measures, the idea of diminishing returns could reduce overall cost-effectiveness of individual scenarios as a function of the total level of savings that might be achieve – in this case, for the year 2030. See generally the discussion on this point as highlighted by Table 6 that follows the main finding of this exploratory effort.
56. For a historical review of how this type of analysis is carried out, see Laitner, Bernow, and DeCicco (1998).
57. Bureau of Labor Statistics. 2012. Economic and Employment Projections 2010 to 2020. Washington, DC: U.S. Department of Labor. (Available at: http://www.bls.gov/news.release/ecopro.toc.htm).
58. The calculation is $1/(1.022)^{18} * 100$ equals $1/1.4796 * 100$, or 68 percent.
59. EIA 2012.

cost to end -users as a result of the interest that must be paid on bank loans, raising or lowering the interest rates in this analysis will not appreciably affect the results otherwise reported. Also, to limit the scope of the analysis, no parameters were established to account for any changes in interest rates as less capital -intensive technologies (i.e., efficiency investments) are substituted for conventional supply strategies, or in labor participation rates— all of which might affect overall spending patterns.

While the higher cost premiums associated with the energy efficiency investments might be expected to drive up the level of borrowing (in the short term), and therefore interest rates, this upward pressure would be offset to some degree by the investment avoided in new power plant capacity, exploratory well drilling, and new pipelines. Similarly, while an incre ase in demand for labor would tend to increase the overall level of wages (and thus lessen economic activity), the job benefits are small compared to the current level of unemployment or underemployment. Hence, the effect would be negligible.

Fifth, for the buildings and industrial sectors it was assumed that a program and marketing expenditure would be required to promote market penetration of the efficiency improvements. Based on other program reviews, this was set at 15 percent of the efficiency investment in the early years but declining to 5 percent of the much larger investments in the last year of the assessment.[64]

Finally, it should again be noted that, by design, this analysis does not account for the full effects of the efficiency investments s ince the savings beyond 2030 are not incorporated into the modeling assumptions. Nor does the analysis include other productivity benefits that are likely to stem from the efficiency investments. These can be substantial, especially in the industrial secto r. Industrial investments that increase energy efficiency often advance other economic goals such as improved product quality, lower capital and operating costs, increased employee productivity, or capturing specialized product markets.[65] To the extent the se "co-benefits" are realized in addition to the energy savings, the net economic impacts would be amplified beyond those reported here.

IV. Economic Impact of a Cost-Effective Energy Efficiency Scenario

The investment and savings data from the efficiency identified above (again reaching a 20 percent electricity savings through efficiency gains by 2020) were used to estimate the financial and the economy -wide impacts for the key benchmark years of 201 4, 2020, 2025, and 2030. Each change in sector spending was evaluated by the Investment and Spending module within the DEEPER model for a given year —relative to the baseline or business -as-usual scenario. These were then matched to their appropriate sector impact coefficients.

60. The assumption here is that program spending is necessary to encourage, monitor, and verify the requisite efficiency gains. In addition, training programs as well as increased research & development expenditures may also be needed to improve technology performance and market penetration. This range is generally con sistent with the findings of Friedrich et al. (2009). For other examples that integrate program spending into efficiency policy assessments, see Laitner et al. (2010) among other studies.
61. For a more complete discussion on this point, see Elliott, Laitner, and Pye (1997) and Worrell et al. (2003).

These changes were further evaluated by DEEPER's macroeconomic module to estimate the larger overall job and wage benefits for the U.S. economy.

Starting with very small impacts in 2014, the end -use energy efficiency target of a 20 p ercent savings by 2030 spur s both program costs and technology investments that, in turn, begin to change the patterns of electricity consumption and production. Program spending of $ 635 million in 201 4 is assumed to drive an initial $ 4,231 million in tech nology investments in that year. But these investments are assumed to be financed over time so that the actual outlays in 2014 are only $ 1,004 million. The initial impacts on electricity production are relatively small, reducing electricity bills by an est imated $2,834 million (about 0. 8 percent of the reference case electricity expenditures otherwise projected in that year). However, both program spending and the annualized efficiency payments rise to 2.3 and 39.5 billion dollars by 2030, respectively.

Table 4. Key Annual Financial and Economic Impacts from the Efficiency Scenario

	2014	2020	2025	2030	Average 2014-2030
Financial Costs (Million 2010 $)					
Program Costs	635	843	1,532	2,259	1,229
Efficiency Investments	4,231	8,486	21,741	45,184	17,040
Annualized Efficiency Payments	1,004	8,258	18,956	39,533	8,053
Energy Bill Savings	2,834	23,785	52,451	87,977	26,703
Net Energy Bill Savings	1,196	14,683	31,963	46,185	17,420
Cumulative Net Energy Savings	1,196	50,714	175,883	381,146	381,146
Net Savings per Household (actual $)	6	62	121	147	84
Macroeconomic Impacts					
Employment (actual)	49,504	206,419	484,032	818,827	316,612
Percent from Reference Case	0.04%	0.14%	0.31%	0.51%	
Wages (Million 2010 $)	2,453	9,868	24,877	44,503	16,295
Percent from Reference Case	0.03%	0.10%	0.25%	0.42%	
GDP (Million 2010 $)	2,262	4,261	13,752	26,262	8,869
Percent from Reference Case	0.01%	0.03%	0.07%	0.12%	

Source: Analysis as described in the text of the working paper.

The net savings on electricity bills (i.e., the savings after program costs and the annual payments for investments have been paid) exceeds $ 46 billion (rounded) in 2030, which is about 11 percent of the nation's reference case electricity bill for that year. The net residential or household savings start at only $ 6 in 2014, slowly increasing to $ 62 in 2020, and then rise steadily to an annual $147 savings for an average household by 2030.

As might be expected, the program spending and changed investment patterns have a distinct economic impact. The second set of impacts in Table 4 highlights the key employment and wage benefits for the same ye ars. Overall employment benefits begin with about 49,504 jobs in 2014, but grow steadily as both investments and electricity savings increase over time. By 2030, the total job gain reaches 818,827 jobs, about 0. 51 percent of the jobs otherwise available in that year. Wages associated with the added jobs similarly increase to just short of $45 billion by 2030.

Table 5. Net Employment Impacts (Actual Jobs)

	2014	2020	2025	2030	Average 2014-2030
Overall Jobs Impacts	49,504	206,419	484,032	818,827	353,860

Source: Analysis as described in the text of the working paper.

We also ran a series of sensitivity simulations to test the robustness of the 20 percent savings target in 2030. Table 6, below, summarizes those findings. In effect, we compare the year 2030 savings target with the net savings (in millions of 2010 dollars) in that year, the average savings per household (in actual but still constant 2010 dollars) also in 2030, and finally, the overall job gain that might be created in that last year of the efficiency scenario. In addition, we provide a benefit-cost ratio that discounts the savings and the program and investment costs over the period 2014 through 2030 using a 5 percent discount rate.

Table 6. Net Benefits as a Function of Efficiency Target

2030 Target	BCR	Average/HH	Net Savings	Net Jobs
5%	4.2	72	18,217	169,112
10%	3.3	127	33,036	350,199
15%	2.6	157	43,194	563,013
20%	2.1	147	46,185	818,827
25%	1.7	73	38,089	1,145,333
30%	1.3	-101	12,986	1,590,403

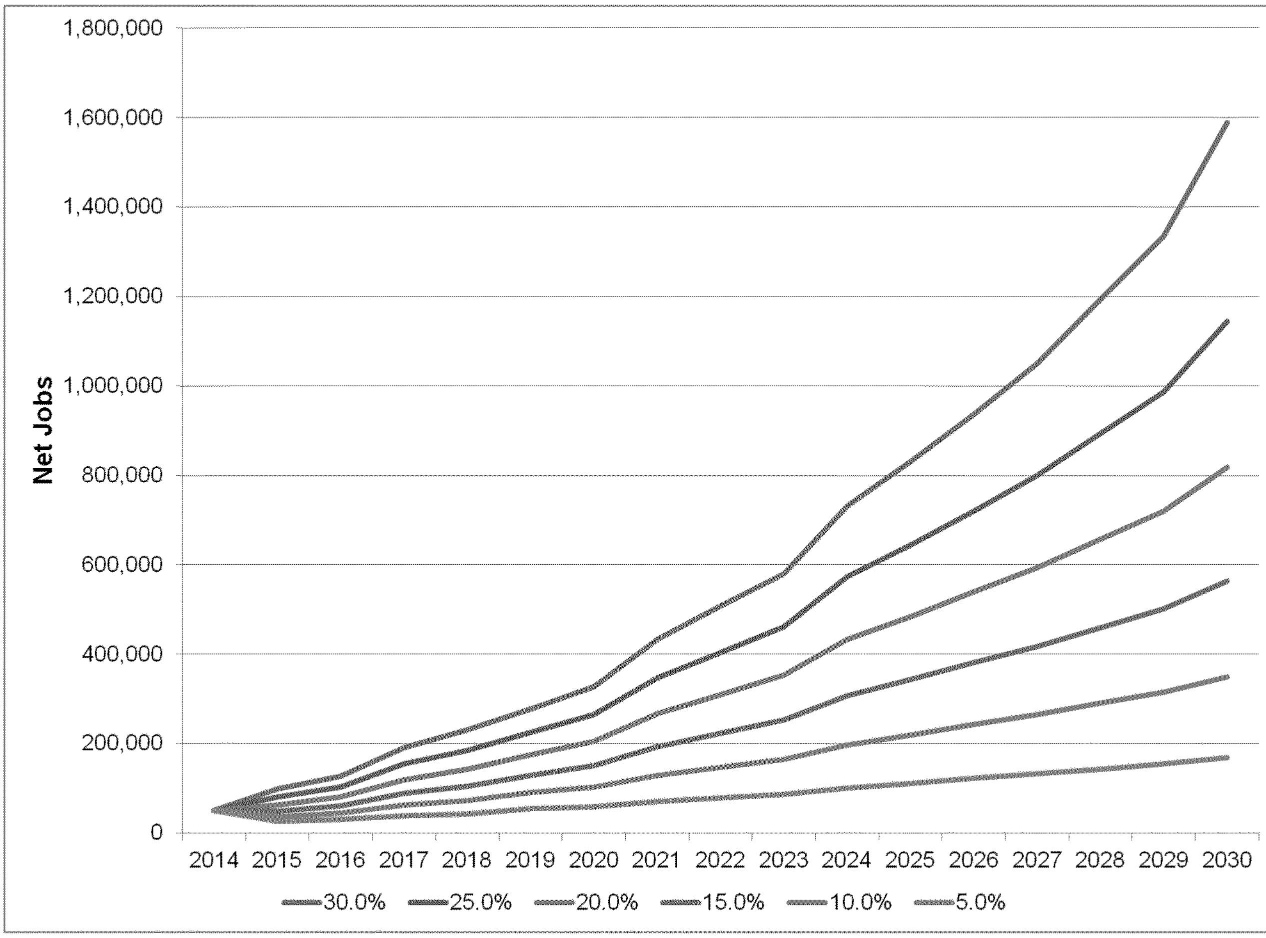
Source: Analysis as described in the text of the working paper.

Beginning with a 5 percent savings target, we find that the smallest effort shows the largest benefit-cost ratio (assuming all costs are discounted 5 percent annually). This makes sense as the least -cost resources are likely to be used up first . By themselves, however, the very cheapest efficiency resources do not generate sufficient savings to drive a very large gain in employment – in this case 169,112 jobs. The maximum net savings per household tops out at about 15 percent efficiency savings. That provides an average net return of $15 7 per household. At that level employment increases by about 563,013 jobs per year.

The maximum net energy bill s avings is reached at about the 20 percent target with a net return of $46,185 million which helps drive the gain of 818,827 jobs as we described in the text surrounding tables 4 and 5. The least cost-effective scenario calls for a 30 percent savings target; although less cost -effective, this scenario also generates the greatest number of total jobs because of the substantial construction activity generated in the later years to achieve this level of savings.

Figure 4 provides a graphic summary of overall job impacts by year as a function of the year 2030 savings from the reference case. Beginning with the assumption that first year savings in 2014 is about 0.75 percent of reference case sales, each of the scenarios slowly increases the gain in jobs as greater investments drive a greater level of savings. The year 2030 end -points are consistent with the results presented in Table 6 on the previous page.

Figure 4. Net Job Impacts of Energy Efficiency Scenarios by Year 2030 Percent Savings



Source: Analysis as described in the text of the working paper.

Finally, and although not part of the DEEPER modeling system, we also provide a working estimate of the reduction in air pollution and greenhouse gas emissions in the year 2030 for the 20 percent savings scenario. This is roughly calculated as the difference in the year 2030 electricity generation in the BAU compared to the efficiency-led scenario multiplied by the 2030 (avoided) average rate of emissions (pounds per kWh) of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions. The average rates of emissions in the 2030 efficiency-led scenario are further reduced by the 20 percent savings under the assumption that it is the marginal generation power plants (essentially the generally dirtier units) that will be displaced by the alternative pattern of investments guided by carbon pollution standards. Table 7 summarizes the reduced impacts of air pollution and greenhouse gas emissions.

Table 7. 20% Scenario Emissions Savings in 2030

	2030
Sulfur Dioxide (million short tons)	0.7
Nitrogen Oxides (million short tons)	0.8
Carbon Dioxide (million metric tons)	971

In short, mobilizing energy efficiency as a pollution reduction mechanism can provide dramatic reductions in air pollution and greenhouse gas emissions. Achieving a 20 percent improvement in efficiency by 2030 could reduce emissions of sulfur dioxide and nitrogen oxides by 700,000 and 800,000 tons, respectively, and cut carbon pollution by 971 million metric tons—nearly a full gigaton—even as consumers and businesses save money and new jobs are created. The emission reductions described in Table 7 are about 57 percent of the emissions projected in the power sector for the year 2030 in the business-as-usual case.

V. Conclusions

The evidence presented here documents the critical role that energy efficiency can play in positively shaping both our economy and our environment. If we choose to develop that resource as characterized in this working paper, a 20 percent electricity savings by the year 2030 can catalyze large net consumer savings as well as launch an important opportunity to stimulate greater job creation – even as we bring about a substantial reduction in carbon pollution and other harmful air pollutants.

Upcoming EPA rulemakings addressing carbon dioxide emissions from the power sector present a unparalleled opportunity to realize the massive economic and environmental benefits of energy efficiency. President Obama has directed the EPA to proceed with a rulemaking to establish limits on greenhouse gas emissions from existing power plants under section 111(d) of the Clean Air Act.[66] The language of section 111(d) is sufficiently broad to encompass a system-based approach to securing carbon pollution reductions from existing power plants.[67] A system-based approach could provide an excellent opportunity for EPA to consider end-use energy efficiency as a compliance mechanism through which the power sector can achieve meaningful, low-cost emission reductions.[68]

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62. *See* Sara Hayes and Garrett Herndon, *Trailblazing Without the Smog: Incorporating Energy Efficiency into Greenhouse Gas Limits for Existing Power Plants*, American Council for an Energy-Efficient Economy (2013).
63. *See* Megan Ceronsky and Tomás Carbonell, *Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants*, Environmental Defense Fund (2013).
64. *Id*.

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Appendix A: An Overview of the Energy Efficiency Resource

I. What is Energy Efficiency?

All interactions of matter involve flows of energy. This is true whether they have to do with earthquakes, the movement of the planets, or the various biological and industrial processes at work anywhere in the world. Within the context of a regional or national economy, the assumption is that energy should be used as efficiently as technically and economically feasible. An industrial plant working two shifts a day six days a week for 50 weeks per year, for example, may require more than $1 million per year in purchased energy if it is to maintain operation. An average American household may spend $2,000 or more per year for electricity and natural gas to heat, cool, and light the home as well as to power all of the appliances and gadgets within the house. And an over-the-road trucker may spend $60,000 or more per year on fuel to haul freight an average of 100,000 miles. Regardless of either the scale or the kind of activity, a more energy-efficient operation might lower overall costs for the manufacturing plant, for the household, and for the trucker. The question is whether the annual energy bill savings are worth either the cost or the effort that might be necessary to become more energy-efficient.[69]

As it turns out the U.S. economy is not especially energy-efficient. At current levels of consumption the U.S. economy converts about 14 percent of all the energy consumed into useful work – which means we waste about 86 percent of the energy resources now expended to maintain our economy.[70] Because of that very significant level of inefficiency, many in both the business and the policy community increasingly look to energy efficiency improvements as cost-effective investments to improve efficiency and reduce waste.

The current system of generating and delivering electricity to homes and businesses in the United States is just 32 percent efficient. That is, for every three lumps of coal or other fuel used to generate power, the energy from only one lump is actually delivered to homes and businesses in the form of electricity. What America wastes in the generation of electricity is more than Japan needs to power its entire economy. The technologies that power the fossil-fuel economy, for example the internal combustion engine and steam turbines, are no more efficient today than they were in 1960, when President Eisenhower was in office.[71] Laitner (2013) suggests that this level of inefficiency may actually constrain the greater productivity of the economy.[72] And yet, any number of technologies can greatly improve energy performance. Combined heat and power (CHP) systems, for example, can deliver efficiencies of 65 to 80 percent or more, at a substantial economic savings.[73] And an incredible array of waste-to-

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65. The energy expenditures are derived from several calculations by the author.
66. Laitner 2013, building on Ayres and Warr 2009.
67. Ayres, Robert U. and Edward H. Ayres. 2010. *Crossing the Energy Divide: Moving from Fossil Fuel Dependence to a Clean-Energy Future.* Upper Saddle River, N.J.: Wharton School of Publishing.
68. Laitner 2013.
69. Chittum, Anna and Terry Sullivan. 2012. *Coal Retirements and the CHP Investment Opportunity*. ACEEE Report IE123. Washington, DC: American Council for an Energy-Efficient Economy.

energy and recycled energy technologies can further increase overall efficiency and save money.[74]

II. Historical Impact of Energy Efficiency

As one of the richest and more technologically advanced regions of the world, the United States has expanded its economic output by more than three-fold since 1970. Per capita incomes are also twice as large today compared to incomes in 1970. Notably, however, the demand for energy and power resources grew by only 40 percent during the same period.[75] This decoupling of economic growth and energy consumption is a function of increased energy productivity: in effect, the ability to generate greater economic output (that is, more goods and services), but to do so with less energy. Because these past gains were achieved with an often ad hoc approach to energy efficiency improvements, there is compelling evidence to suggest that even greater energy productivity benefits can be achieved. Indeed, the evidence suggests that since 1970, energy efficiency in its many different forms has met three-fourths of the new demands for energy-related goods and services while new energy supplies have provided only one-fourth of the new energy-related demands.[76] But energy efficiency has been an invisible resource. Unlike a new power plant or a new oil well, we don't see energy efficiency at work. A new car that gets 25 miles per gallon, for example, may not seem all that much different than a car that gets 40 miles or more per gallon. And yet, the first car will consume 400 gallons of gasoline to go 10,000 miles in a single year while the second car will need only 250 gallons per year.[77] In effect, energy efficiency in this example is the energy we don't use to travel 10,000 miles per year. More broadly, energy efficiency may be thought of as the cost-effective investments in the energy we don't use either to produce or even increase the level of goods and services within the economy.

III. The Cost-Effective Potential for the Energy Efficiency Resource

Can the substantial investments that might be required to obtain more energy-efficient technologies save money for businesses and consumers? Here we turn to the evidence to provide different views of this question. The Lazard Asset Management firm (2013) provides a

70. Bailey, Owen and Ernst Worrell. 2005. Clean Energy Technologies A Preliminary Inventory of the Potential for Electricity Generation. LBNL-57451. Berkeley, CA: Lawrence Berkeley National Laboratory.
71. These and other economic and energy-related data cited are the author's calculations as they are drawn from various resources available from the Energy Information Administration (2013a and 2013b).
72. Laitner 2013.
77. In August 2012 the Department of Transportation and the Environmental Protection Agency finalized federal car and light truck fuel economy and greenhouse gas emissions standards for model years 2017 to 2025. The standards, together with those previously adopted for model years 2012 to 2016, mean an 80 percent increase to more than 50 miles per gallon for the average model year 2025 vehicle from the 2011 CAFE (Corporate Average Fuel Economy) requirement of 27.6 miles per gallon (Langer 2012). A separate study by the BlueGreen Alliance and the American Council for an Energy-Efficient Economy determined that the new 2025 fuel economy standards would be cost-effective and produce a gain of 576,000 jobs (Busch et al. 2012). The jobs provided by the new fuel economy standards are at the same scale as the jobs that likely would provided by energy efficiency improvements in the use of electricity as suggested in the text of the main report.

detailed review of the various costs associated with electricity generation expenditures.[78] They note, for instance, that new coal and nuclear power plants might cost an average of 8 to 14 cents per kilowatt-hour (kWh) of electricity. The costs for various renewable energy resources such as wind energy or photovoltaic energy systems (i.e., solar cells that convert sunlight directly into electricity) range from 6 to 20 cents per kWh. And both Lazard (2013) and the American Council for an Energy-Efficient Economy (ACEEE) estimate a range of energy efficiency measures that might cost the equivalent of 3 to 5 cents per kWh of electricity service demands.[79] McKinsey & Company (2007) assessed the energy efficiency resource as having at least a 10 percent return on energy efficiency investments.[80] When spread out over an annual $170 billion energy efficiency market potential, McKinsey suggests an average 17 percent return might be expected across that spread of annual investments.[81] A subsequent study suggests that through 2020 there is sufficient cost-effective opportunity to reduce our nation's energy use by more than 20 percent – if we choose to invest in the more efficient use of our energy resources.[82]

Similarly, the AEC (1991) and the Energy Innovations (1997) reports show a benefit-cost ratio that also approached two to one.[83] More recently, the Union of Concerned Scientists published a detailed portfolio of technology and program options that would lower U.S. heat-trapping greenhouse gas emissions 56 percent below 2005 levels in 2030.[84] The result of their analysis indicated an annual $414 billion savings for U.S. households, vehicle owners, businesses, and industries by 2030. After subtracting the annual $160 billion costs (constant 2006 dollars) of the various policy and technology options, the net savings are on the order of $255 billion per year. Over the entire 2010 through 2030 study period, the net cumulative savings to consumers and businesses were calculated to be on the order of $1.7 trillion under their so-called Blueprint case.

Most recently, Laitner et al. (2012) documented an array of untapped cost-effective energy efficiency resources roughly equivalent to 250 billion barrels of oil.[85] That is a scale sufficient to enable the U.S. to reduce total energy needs by about one-half compared to standard reference case projections for the year 2050. These productivity gains could generate from 1.3

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74. Lazard, 2013. Lazard, Ltd. "Levelized Cost of Energy Analysis – Version 7.0." September, 2013.
75. *Id.*; Elliott, R. Neal, Rachel Gold, and Sara Hayes. 2011. Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency. ACEEE White Paper. Washington, DC: American Council for an Energy-Efficient Economy.
76. McKinsey. 2007. *Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?* The Conference Board and McKinsey & Company.
77. *Id.*
78. McKinsey. 2009. *Unlocking Energy Efficiency in the U.S. Economy*. McKinsey & Company.
79. Alliance to Save Energy, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Union of Concerned Scientists, and Tellus Institute. 1991. *America's Energy Choices: Investing in a Strong Economy and a Clean Environment*. Cambridge, MA: Union of Concerned Scientists; Energy Innovations. 1997. *Energy Innovations: A Prosperous Path to a Clean Environment*. Washington, DC: Alliance to Save Energy, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Tellus Institute, and Union of Concerned Scientists.
80. Cleetus Rachel, Stephen Clemmer, and David Friedman. 2009. *Climate 2030: A National Blueprint for a Clean Energy Economy*. Cambridge, MA: Union of Concerned Scientists.
81. Laitner, John A. "Skip," Steven Nadel, Harvey Sachs, R. Neal Elliott, and Siddiq Khan. 2012 *The Long-Term Energy Efficiency Potential : What the Evidence Suggests*, ACEEE Research Report E104, Washington, DC: American Council for an Energy-Efficient Economy. 2012.

to 1.9 million jobs while saving all residential and business consumers a net $400 billion per year, or the equivalent of about $2,600 per household annually (in 2010 dollars). Indeed, in *World Energy Outlook 2012*, the Internationa l Energy Agency (IEA 2012) highlighted the potential for energy efficiency to save 18 percent of the 2010 global energy consumption by 2035. More critically, the IEA notes that Global GDP would be 0.4 percent higher in 2035 as a result of those efficiency improvements.

There are two final aspects of the evidence to briefly review. The first is associated with the non-energy benefits that typically result from energy efficiency investments. The second reflects the changes one might normally expect in the cost and performance of technologies over time.

When energy efficiency measures are implemented in industrial, commercial, or residential settings, several "non-energy" benefits such as maintenance cost savings and revenue increases from greater production can often result in addition to the anticipated energy savings. The magnitude of non-energy benefits from energy efficiency measures is significant. These added savings or productivity gains range from reduced maintenance costs and lower waste of both water and chemicals to increased product yield and greater product quality. In one study of 52 industrial efficiency upgrades, all undertaken in separate in dustrial facilities, Worrell et al. (2003) found that these non -energy benefits were sufficiently large that they lowered the aggregate simple payback for energy efficiency projects from 4.2 years to 1.9 years.[86] Unfortunately, these non-energy benefits fr om energy efficiency measures are often omitted from conventional performance metrics. This leads, in turn, to overly modest payback calculations and an imperfect understanding of the full impact of additional efficiency investments.

Several other studi es have quantified non -energy benefits from energy efficiency measures and numerous others have reported linkages from non -energy benefits and completed energy efficiency projects. In one, the simple payback from energy savings alone for 81 separate industrial energy efficiency projects was less than 2 years, indicating annual returns higher than 50 percent. When non -energy benefits were factored into the analysis, the simple payback fell to just under one year.[87] In residential buildings, non-energy benefits have been estimated to represent between 10 to 50 percent of household energy savings.[88] If the additional benefits from energy efficiency measures were captured in conventional performance models, such figures would make them more compelling. Building on that perspective, a new assessment by the Regulatory Assistance Project suggests there is, in fact, a "layer cake of benefits from electric energy efficiency".[89] The layers or array of benefits fall s

82. Worrell, Ernst, John A. Laitner, Michael Ruth, and Hodayah Finman. 2003. "Productivity Benefits of Industrial Energy Efficiency Measures." *Energy* (2003), 28, 1081-98.
83. Lung, Robert Bruce, Aimee McKane, Robert Leach, Donald Marsh. 2005. "Ancillary Benefits and Production Benefits in the Evaluation of Industrial Energy Efficiency Measures." *Proceedings of the 2005 Summer Stu dy on Energy Efficiency in Industry*. Washington, DC: American Council for an Energy-Efficient Economy.
84. Amann, Jennifer. 2006. *Valuation of Non -Energy Benefits to Determine Cost -Effectiveness of Whole House Retrofit Programs: A Literature Review.* ACEEE Report A061. Washington, DC: American Council for an Energy - Efficient Economy.
85. Lazar, Jim and Ken Colburn. 2013. Recognizing the Full Value of Energy Efficiency. Montpelier, VT: Regulatory Assistance Project, at 10.

into three categories: utility system benefits, participant benefits, and societal benefits – each with six different types of positive returns. Using information provided by Efficiency Vermont as one example, Lazar and Colburn found that the mix of energy efficiency benefits typically included in utility revenue requirements approach 7-8 cents/kWh, but the full set of efficiency benefits could be as high as 18 cents/kWh.[90] Laitner et al. (2013) suggest that new business models are needed to fully capture the complete array of benefits.[91]

As a strong complement to the likelihood of large-scale non-energy benefits typically omitted from most climate policy assessments, there is also a significant body of evidence that indicates that technology is hardly static and non-dynamic. The rapid technological change seen especially in semiconductor-enabled technologies has led to cheaper, higher performing, and more energy-efficient technologies.[92] The increasing penetration of information and communication technologies interacting with energy-related behaviors and products suggests that energy efficiency resources may become progressively cheaper and more dynamic through the 21st century.[93] Given this and many other comparable studies, one might safely conclude that progress in the cost and performance of energy efficient technologies will continue, and that new public policies will greatly increase the continued rate of improvement.[94]

We can extend the issue of cost effectiveness even further to examine policy scenarios rather than discrete technologies. Laitner and McKinney (2008) provided a meta-review of 48 past policy studies that were undertaken primarily at the state or regional level.[95] The set of studies included in this assessment generally examined the costs of economy-wide efficiency investments made over a 15 to 25 year time horizon. The analysis found that even when both

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86. In many ways the landmark volume, *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, by Lovins et al. (2002) underscores the many benefits which are mostly excluded from marketplace transactions. From the Small Is Profitable website: The report describes 207 ways "in which the size of 'electrical resources' – devices that make, save, or story electricity – affects their economic value. It finds that properly considering the economic benefits of 'distributed' (decentralized electrical resources typically raises their value by a large factor, often approximately tenfold, by improving system planning, utility construction and operation, and service quality, and by avoiding societal costs." *See*, http://www.smallisprofitable.org/.
87. Laitner, John A. "Skip," Matthew T. McDonnell and Heidi M. Keller. 2013. "Shifting Demand: From the Economic Imperative of Energy Efficiency to Business Models that Engage and Empower Consumers." In *End of Electricity Demand Growth: How Energy Efficiently Can Bring an End to the Need for More Power Plants*, Fereidoon P. Sioshansi (editor), Elsevier, 2013.
88. Laitner, John A. "Skip", Christopher Poland Knight, Vanessa McKinney, and Karen Ehrhardt-Martinez. 2009. *Semiconductor Technologies: The Potential to Revolutionize U.S. Energy Productivity.* Washington, DC: American Council for an Energy-Efficient Economy.
89. Laitner, John A. "Skip" and Karen Ehrhardt-Martinez. 2008. *Information and Communication Technologies: The Power of Productivity; How ICT Sectors Are Transforming the Economy While Driving Gains in Energy Productivity.* Washington, DC: American Council for an Energy-Efficient Economy.
90. McKinsey. 2009. *Unlocking Energy Efficiency in the U.S. Economy*. McKinsey & Company; Koomey, Jonathan. 2008. "Testimony of Jonathan Koomey, Ph.D. Before the Joint Economic Committee of the United States Congress," For a hearing on Efficiency: The Hidden Secret to Solving Our Energy Crisis." Washington, DC: Joint Economic Committee of the United States Congress. June 30, 2008.
91. Laitner, John A. "Skip" and Vanessa McKinney. 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments.* ACEEE Report E084. Washington, DC: American Council for an Energy-Efficient Economy.

program costs and technology investments were compared, the savings appeared to be twice the cost of the suggested policies.

IV. Overcoming Barriers to Improving Energy Efficiency

Although some economists have questioned the magnitude of the energy efficiency resource, close examination of the evidence indicates that the resource is in fact vast . Allcott and Greenstone (2012), for example, suggest that "recent empirical work in a variety of contexts implies that on average the magnitude of profitable unexploited investment opportunities is much smaller than engineering-accounting studies suggest."[96] In effect, they pose the central economic question, "Is there an Energy Efficiency Gap?" In other words, is energy efficiency a sufficiently large, cost-effective resource that can be relied upon as a meaningful energy policy option?(Allcott and Greenstone 2012). In fact, the issue was rigorously explored as early as 1995. Levine et al. (1995), for example, examined this issue in a significant journal article, "Energy Efficiency Policy and Market Failures." [97] After a careful review they concluded, "[w]e believe that energy efficiency policies aimed at improving energy efficiency at a lower cost than society currently pays for energy services represent good public policy. Programs that lead to increased economic efficiency as well as energy efficiency should continue to be pursued." More recently, Nadel and Langer (2012), in a thoughtful review of Allcott and Greenstone, suggest that "while the authors have some useful points to make, in general they interpret available data in ways that best support their points, downplaying other important findings in the various articles they cite." [98] Nadel and Langer argue that a fuller consideration of the evidence shows that there is in fact a large, cost-effective energy efficiency resource available to be harvested.

Another relevant area of inquiry examines why cost-effective efficiency opportunities remain unexploited given the cost-savings potential. There is a range of market imperfections, market barriers, and real world behaviors that leaves substantial room for public policy to induce behavioral changes that produce economic benefits. One classic example is the misaligned incentive that exists for those living in rental units when the renter pays the energy bills but the landlord purchases large energy-using appliances such as refrigerators and water heaters. In this case, the purchaser of the durable good does not reap the benefits of greater energy efficiency and has no incentive to select highly efficient appliances . The Market Advisory Committee of the California Air Resources Board (2007) provides a short overview of this and other key market failures.[99, 100] A deeper exploration of the types of market barriers is beyond

92. Allcott Hunt and Michael Greenstone. 2012. " Is There an Energy Efficiency Gap?" *Journal of Economic Perspectives* 26 (1) : 3-28
93. Levine, Mark D. Jonathan G. Koomey, James E. McMahon, Alan H. Sanstad, and Eric Hirst. 1995, "Energy Efficiency Policy and Market Failures." Annual Review of Energy and the Environment 20: 535-555.
94. Nadel, Steven and Therese Langer. 2012. Comments on the July 2012 Revision of "Is There an Energy Efficiency Gap?" ACEEE White Paper. Washington, DC: American Council for an Energy-Efficient Economy.
95. California Air Resources Board. 2007. Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California. http://www.energy.ca.gov/2007publications/ARB-1000-2007-007/ARB-1000-2007-007.PDF. Sacramento, Calif.: California Air Resources Board, Market Advisory Committee.
96. Following are examples of important market failures: (1) Step-Change Technology Development —where temporary incentives will be needed to encourage companies to deploy new technologies at large scale to the public good, because there is otherwise excessive technology, market, and policy risk. Examples of remedies are

the scope of this working paper, but others have done work to map this terrain. [101] A flexible framework to reduce greenhouse gas emissions from existing fossil fuel power plants that empowers states and companies to invest in energy efficiency to reduce pollution would provide an important opportunity to eliminate these barriers.

One important implication of the literature on market imperfections and energy efficiency is that price signals alone may not drive optimal levels of energy efficiency investment. This concept was explored by Hanson and Laitner (2004). [102] In one of the few top-down models that explicitly reflects both policies and behavioral changes as a complement to pricing signals, this study found that the combination of both price and non-pricing policies actually resulted in a significantly greater level of energy efficiency gains and a lower carbon allowance price to achieve the same level of emissions reductions, thereby achieving an overall reduction in the costs of achieving those reductions.

Appendix B: Methodology of the DEEPER Modeling System

To evaluate the macroeconomic impacts of reductions in fossil fuel fired plant emissions from demand-side efficiency improvements, we use the proprietary **D**ynamic **E**nergy **E**fficiency **P**olicy **E**valuation **R**outine, or DEEPER model. The model was developed by John A. "Skip" Laitner and has a 22-year history of use and development, though it was renamed "DEEPER" in 2007. It was most recently used in a study for the BlueGreen Alliance and the American Council for an Energy-Efficient Economy (ACEEE) evaluating the overall job impacts of the recently enacted fuel economy standards. [103]

The DEEPER Modeling System is a quasi-dynamic input-output (I/O) model [104] of the U.S. economy that draws upon social accounting matrices [105] from the MIG, Inc. (formerly the Minnesota IMPLAN Group), [106] energy use data from the U.S. Energy Information Administration's Annual Energy Outlook (AEO), and employment and labor data from the

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renewable portfolio obligations, biofuel requirements, and California's Low Carbon Fuel Standard. (2) Fragmented supply chains—where economically rational investments (for example, energy efficiency in buildings) are not executed because of the complex supply chain. Examples of remedies are building codes. (3) Consumer behavior—where individuals have demonstrated high discount rates for investment in energy efficiency that is inconsistent with the public good. Examples of remedies are vehicle and appliance efficiency standards and rebate programs (California Air Resources Board 2007, p.19).

97. See, for example, Levine et al. 1995 previously referenced, but also Brown (2001); Levinson and Niemann (2004); Sathaye and Murtishaw (2004); Murtishaw and Sathaye (2006); Geller et al. (2006); Brown et al. (2009).

98. Hanson, Donald A. and John A. "Skip" Laitner. 2004. "An Integrated Analysis of Policies that Increase Investments in Advanced Energy-Efficient/Low-Carbon Technologies." *Energy Economics* 26:739-755.

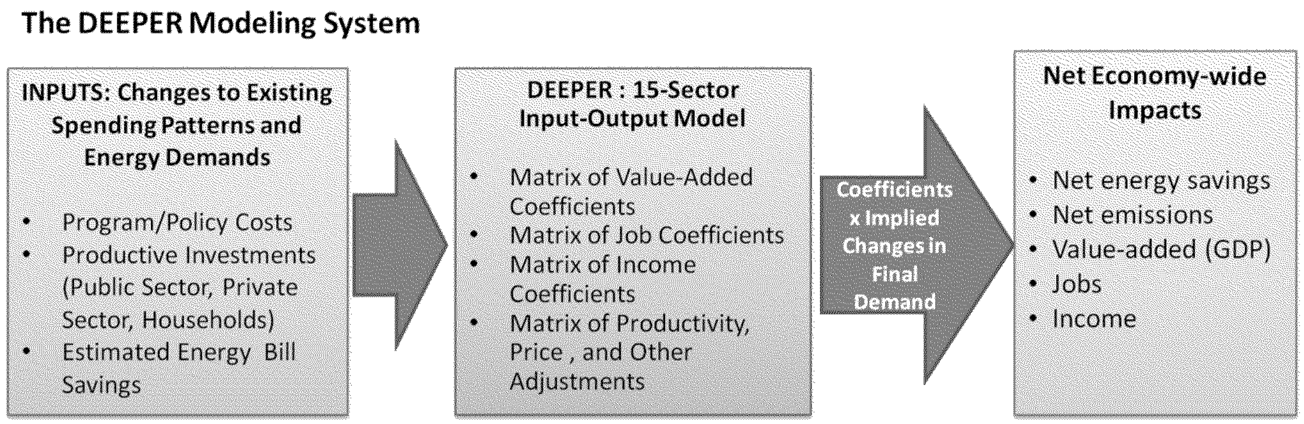
99. Busch, Chris, John Laitner, Rob McCulloch, Ivana Stosic. 2012. *Gearing Up: Smart Standards Create Good Jobs Building Cleaner Cars*. Washington, DC: BlueGreen Alliance and the American Council for an Energy-Efficient Economy (Available at: http://www.bluegreenalliance.org/news/publications/gearing-up).

101. Input-output models use economic data to study the relationships among producers, suppliers, and consumers. They are often used to show how interactions among all three impact the macroeconomy.

102. A social accounting matrix is a data framework for an economy that represents how different institutions — households, industries, businesses, and governments — all trade goods and services with one another.

103. See http://implan.com/V4/Index.php.

Bureau of Labor Statistics (BLS). The Excel -based tool contains approximately eight interdependent worksheets. The model functions as laid out in the flow diagram below:



DEEPER results are driven by adjustments to energy service demands and alternative investment patterns resulting from projected changes in policies and prices between baseline and policy scenarios. The model is capable of evaluating policies at the national level through 2050. However, given uncertainty surrounding future economic conditions and the life of the impacts resulting from the policies analyzed, it is often used to evaluate out 15 –20 years. Although the DEEP ER Model, like most I/O models, is not a general equilibrium model, [107] it does provide accounting detail that balances changes in investments and expenditures within the economy. With consideration for goods or services that are imported, it balances the variety of changes across all sectors of the economy.[108]

The Macroeconomic Module contains the factors of production — including capital (or investment), labor, and energy resources — that drive the U.S. economy for a given "base year." DEEPER uses a set of e conomic accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other.[109]

The Macroeconomic Module translates the selected different policy scenarios, including necessary program spending and research and development (R&D) expenditures, into an annual array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. DEEPER evaluates the policy -driven investment path for the various financing strat egies, as well as the net energy bill savings anticipated over the study period. It also evaluates the impacts of avoided or reduced investments and expenditures otherwise required by the electric and natural gas sectors.

104. General equilibrium models operate on the assumption that a set of prices exists for an economy to ensure that supply and demand are in an overall equilibrium.
105. When both equilibrium and dynamic input -output models use the same technology assumptions, both models should generate a reasonably comparable set of outcomes. See Hanson and Laitner (2005) for a diagnostic assessment that reached that conclusion.
106. Further details on this set of linkages can be found in Hanson and Laitner (2009).

The resulting positive and negative changes in spending and investments in each year are converted into sector-specific changes in aggregate demand.[110] These results then drive the I/O matrices utilizing a predictive algebraic expression known as the Leontief Inverse Matrix.[111]

Employment quantities are adjusted annually according to assumptions about the anticipated labor productivity improvements based on forecasts from the Bureau of Labor Statistics. The DEEPER Macroeconomic Module traces how changes in spending will ripple through the U.S. economy in each year of the assessment period. The end result is a net change between the reference and policy scenarios in jobs, income, and value-added,[112] which is typically measured as Gross Domestic Product (GDP) or value-added Gross Regional Product (GRP) for the study region (e.g., the national, state, or local economies).

Like all economic models, DEEPER has strengths and weaknesses. It is robust by comparison to some I/O models because it can account for price and quantity changes over time and is sensitive to shifts in investment flows. It also reflects sector-specific labor intensities across the U.S economy. However, it is important to remember when interpreting results for the DEEPER model that the results rely heavily on the quality of the information that is provided and the modeler's own assumptions and judgment. The results are unique to the specified policy design. The results reflect differences between scenarios in a future year, and like any prediction of the future, they are subject to uncertainty.

109. This is the total demand for final goods and services in the economy at a given time and price level.
110. For a more complete discussion of these concepts, see Miller and Blair (2009).
111. This is the market value of all final goods and services produced within a country in a given period.

Appendix A and B Bibliography

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In the

Supreme Court of the United States

STATE OF NEW YORK, ET AL., Petitioners,
v.
FEDERAL ENERGY REGULATORY COMM'N, ET AL.

ENRON POWER MARKETING, INC., Petitioner,
v.
FEDERAL ENERGY REGULATORY COMM'N, ET AL.

On Writ of Certiorari to the United States
Court of Appeals for the District of Columbia Circuit

BRIEF AMICUS CURIAE OF ELECTRICAL ENGINEERS, ENERGY ECONOMISTS AND PHYSICISTS IN SUPPORT OF RESPONDENTS IN NO. 00-568

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Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers

C-14-EDF

to:

Environmental Defense Fund
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November 30, 2014

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Contents

Background

Conversion of existing coal fired boilers to co-fire or to fire 100% natural gas has been performed for a number of reasons, but mainly to reduce emissions of pollutants associated with coal firing.

The purpose of this analysis is to a) demonstrate the technical feasibility of increased use of natural gas at existing coal-fired power plants in the United States; b) illustrate common engineering and logistical issues that arise when power plants undertake such projects, as well as ways in which those issues have been successfully overcome; and c) identify the range of capital and operating costs associated with such projects.

Executive Summary

Conversion from coal to natural gas firing and co-firing of natural gas with coal is not a new phenomenon for coal-fired electric utility boilers, but it is one that has taken on increasing significance in recent years. As demonstrated in this report, experience with conversion of coal to natural gas and also co-firing of natural gas with coal goes back several decades. As such, the technical issues associated with conversions or co-firing are very well understood. Utilization of natural gas offers several benefits: reduction of air emissions and reduction of solid or liquid waste emissions, reduction of parasitic loads, and reduced operating and maintenance costs, just to name a few. On the other side of the ledger, utilization of natural gas will have a slight adverse impact on boiler efficiency, and bears with it an increase in fuel costs which until recently have been deterrents to wider use of natural gas in boilers.

In recent years the economics of converting to natural gas has changed for many facilities. First, natural gas prices fell rapidly a few years ago – reaching a historic low in real (inflation adjusted) cost in 2012 - and although gas prices have risen from that low, natural gas prices have – for most locations in the US - been much more stable than in the past. Second, increased stringency of environmental regulations have increased the cost of burning coal. As such, utilities have become reluctant to expend capital on aging coal units that are less economically viable than in the past. As will be demonstrated in the case studies in this report, avoiding the costs associated with complying with US EPA's Mercury and Air Toxic Standards (MATS) or the Regional Haze Rule (RHR, and the need to install Best Available Retrofit Technology, or BART) have been important motivators in the conversion of some of these facilities to natural gas. There are other factors as well. Some of these facilities have low capacity factors in part due to increased renewable generation and natural gas combined cycle that have displaced coal from base load use to cycling duty. In some of these cases it was more economical to convert the now cycling coal boiler to natural gas than to build new simple cycle combustion turbines for peaking conditions that have similar heat rates as the boiler.

The case studies that form a key element of this report demonstrate that natural gas conversions are being applied in a wide variety of circumstances – throughout several regions of the United States, on boilers of a wide range of sizes from under 100 MW to over 500 MW, on boilers burning a wide range of coals, and on boilers with low as well as high capacity factors. In most cases gas conversion was selected as the lowest cost means of complying with environmental regulations, such as MATS or the RHR. Although in some cases only minor changes were necessary to the natural gas supply infrastructure, in other cases pipelines of over 30 miles in length are being constructed to provide adequate supply. In this respect, depending upon the access to natural gas, the pipeline might be the largest factor in the cost of a natural gas conversion, and it has been a surmountable issue in these circumstances. For the most part, where cost information was available, the cost of the boiler modifications were usually lower than anticipated by EPA in the Technical Support Document for the proposed Clean Power Plan. [1] This is because EPA's cost estimates for natural gas conversion include several elements that are not necessary in many cases.

Table E.1 summarizes data on each of the units examined in the Case Studies in this report. The full year data from 2009 and 2013 are selected as years before and after the changes to the five units where conversions are complete. The majority of the case studies addressed in this report are projects that are currently in progress, and before and after performance information is not available. For those five units where before and after performance information is available, reductions in emission rates (measured in lb/MWh) averaged over 99% for SO_2, 48% for NOx and 38% for CO_2. Although each of the five units where before and after data is available is used as a peaking unit, the best CO_2 emission reductions were experienced on the two units that also have the highest capacity factors. Since most of the projects that are currently in progress recently operated with higher capacity factors than those that are completed and where we have the before and after data, it is likely that reductions in CO_2 emission rates should be on the order of or better than the best of these five units, or about 45%.

With few exceptions, capacity factors were significantly lower in 2013 than in 2009, with the median dropping from 44% to 28% for the Case Study units examined. This is consistent with industry-wide reductions in capacity factor for coal units due to lower natural gas prices. Therefore, although capacity factors dropped for those units where conversions have been completed, this likely would have happened regardless of whether or not a natural gas conversion occurred.

An important and perhaps surprising finding is the fact that some of these gas

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[1] US Environmental Protection Agency, "GHG Abatement Measures - Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602", June 10, 2014.

conversions are being performed on units that in 2013 were operated as base loaded power plants as opposed to units that have become marginally economical and limited to peaking or cycling operation. This indicates that conversion to natural gas may not be confined to facilities that are strictly peaking or cycling in nature. It is unclear what the long-term plans are for these converted units. If the converted units are expected to operate at high capacity factors over the long term, future conversion to natural gas combined cycle may be expected because of the lower heat rate of combined cycle power plants. Brunner Island is a project that is unique in that it is a plant that is equipped with a modern wet FGD system. Although this possible co-firing project is in the very early stages of development, it is very notable that a scrubbed facility would consider co-firing natural gas.

Table E.1. Summary of Data on Natural Gas Conversion Units in Case Studies
Completed units in ***bold and shaded***

Plant Name	Unit	MW	State	Firing type	Coal	heat rate[1]	YR on line	Emission rate[2] 2009 SO2	2009 NOx	2009 CO2	2013 SO2	2013 NOx	2013 CO2	% Redn, or year complete SO2	NOx	CO2	Capacity Factor[3] 2009	2013
E C Gaston	1	254	AL	wall	Bit.	9,837	1960	30.3	3.9	2,013	25.9	4.0	2,154				41%	28%
E C Gaston	2	256	AL	wall	Bit.	9,928	1960	31.3	4.0	2,058	26.3	4.1	2,186		2015		49%	27%
E C Gaston	3	254	AL	wall	Bit.	9,843	1961	34.6	5.0	2,307	28.5	4.4	2,337				32%	21%
E C Gaston	4	256	AL	wall	Bit.	9,766	1962	24.9	3.1	1,649	24.0	3.7	1,962				18%	27%
Irvington	4	156	AZ	wall	Bit., Subbit.	10,732	1967	3.0	3.3	1,715	6.3	4.6	2,123		2018		31%	32%
Cherokee	4	352	CO	tang	Bit., Subbit.	10,880	1968	1.8	3.0	1,969	1.6	3.0	2,081		2017		56%	68%
Edge Moor	***3***	***86***	***DE***	***tang***	***Bit.***	***11,954***	***1957***	***5.4***	***1.6***	***2,327***	***0.0***	***0.8***	***1,261***	***100%***	***51%***	***46%***	***36%***	***10%***
Edge Moor	***4***	***174***	***DE***	***tang***	***Bit.***	***11,279***	***1966***	***8.5***	***1.7***	***1,954***	***0.0***	***0.7***	***1,081***	***100%***	***57%***	***45%***	***22%***	***10%***
Yates	Y6BR	352	GA	tang	Bit.	10,492	1974	20.3	2.6	1,988	22.0	2.6	1,966		2015		50%	29%
Yates	Y7BR	355	GA	tang	Bit.	10,487	1974	18.5	2.6	1,938	21.7	2.2	1,970				44%	15%
Harding St.	50	106	IN	tang	Bit	10,541	1958	31.9	2.3	2,130	39.3	2.4	2,051				68%	73%
Harding St.	60	106	IN	tang	Bit.	10,491	1961	32.4	2.4	2,114	37.9	2.4	1,983		2016		69%	72%
Harding St.	70	435	IN	tang	Bit.	10,517	1973	2.2	0.9	1,889	1.3	1.7	2,059				75%	82%
Laskin	1	55	MN	tang	Bit., Subbit.	12,783	1953	4.5	2.3	2,552	1.5	2.0	2,463		2015		58%	56%
Laskin	2	51	MN	tang	Bit., Subbit.	12,875	1953	4.5	2.4	2,563	1.5	2.0	2,456				63%	58%
Meramec	1	119	MO	tang	Bit Subbit	10845	1953	6.2	1.4	2,299	4.7	1.3	2,297		2015		85%	42%
Meramec	2	120	MO	tang	Bit, Subbit	10644	1954	6.1	1.3	2,283	4.9	1.3	2,400				78%	48%
Deepwater	***8***	***73***	***NJ***	***wall***	***Bit.***	***10,331***	***1954***	***9.6***	***3.6***	***1,841***	***0.0***	***2.2***	***1,200***	***100%***	***39%***	***35%***	***13%***	***5%***
Avon Lake	10	96	OH	tang	Bit	12829	1949	2.5	0.4	205	3.0	0.4	205		2016		5%	10%
Avon Lake	12	640	OH	cell	Bit	9823	1970	22.4	3.1	1,812	26.3	2.7	1,796				58%	48%
Muskogee	4	505	OK	tang	PRB	10,593	1977	5.9	3.4	2,200	4.6	3.6	2,171		2018		57%	44%

										Emission rate[2]				% Redn, or year complete			Capacity Factor[3]	
Plant Name	**Unit**	**MW**	**State**	**Firing type**	**Coal**	**heat rate[1]**	**YR on line**	**2009 SO2**	**2009 NOx**	**2009 CO2**	**2013 SO2**	**2013 NOx**	**2013 CO2**	**SO2**	**NOx**	**CO2**	**2009**	**2013**
Muskogee	5	517	OK	tang	PRB	10,652	1978	5.2	3.0	2,016	4.3	2.9	2,023				75%	51%
Brunner Isl	1	312	PA	tang	Bit	10023	1961	18.6	2.6	1,658	3.2	3.5	1,884				88%	58%
Brunner Isl	2	371	PA	tang	Bit	9695	1965	17.9	2.6	1,651	3.6	3.3	1,858		TBD – likely a cofiring project		73%	50%
Brunner Isl	3	744	PA	tang	Bit	9502	1969	6.5	2.8	1,794	3.3	3.3	1,827				72%	55%
New Castle	3	93	PA	wall	Bit	11265	1952	23.6	3.8	2,215	25.1	4.0	2,149				21%	12%
New Castle	4	95	PA	wall	Bit	11028	1958	20.5	3.1	2,011	23.2	3.4	2,007		2016		28%	15%
New Castle	5	132	PA	wall	Bit	10846	1964	24.1	4.5	2,207	26.0	4.7	2,189				23%	15%
Clinch River	1	230	VA	vert	Bit.	10,227	1958	8.8	2.4	2,073	7.8	2.1	2,027				23%	21%
Clinch River	2	230	VA	vert	Bit.	10,179	1958	9.1	2.5	2,022	8.0	2.1	2,050		2015		12%	14%
Clinch River	3	230	VA	vert	Bit.	10,179	1958	8.2	2.0	1,916	8.4	1.8	2,099				46%	14%
Blount St.	***8***	***51***	***WI***	***wall***	***Bit.***	***14,500***	***1957***	***25.8***	***4.2***	***2,479***	***0.0***	***2.3***	***1,794***	***99.9%***	***44.8%***	***27.6%***	***4%***	***2%***
Blount St.	***9***	***50***	***WI***	***wall***	***Bit.***	***14,278***	***1961***	***25.8***	***4.3***	***2,401***	***0.0***	***2.5***	***1,608***	***99.9%***	***41.1%***	***33.0%***	***3%***	***2%***
Valley	1	67	WI	wall	Bit.	14,500	1968	0.8	0.3	205	0.7	0.2	205				42%	31%
Valley	2	67	WI	wall	Bit.	14,500	1968	0.8	0.3	205	0.7	0.2	205		2015/16		44%	30%
Valley	3	67	WI	wall	Bit.	14,500	1969	0.8	0.3	205	0.7	0.2	205				37%	22%
Valley	4	67	WI	wall	Bit.	14,500	1969	0.8	0.3	205	0.7	0.2	205				39%	27%
Naughton	3	330	WY	tang	PRB	10,517	1971	4.3	4.7	2,285	3.5	2.7	2,029		2015		75%	97%
														Median Capacity Factor			***44%***	***28%***

Comments

1. Heat rate in Btu/kWh net from NEEDS v5.13

2. Emissions in lb/MWh of gross generation except Valley and Avon Lake 10, which is in lb/MMBtu

3. Except for Valley Station and Avon Lake unit 10, capacity factor is estimated from reported gross generation and nameplate rating. Because no generation data was reported for Valley Station or Avon Lake unit 10, reported heat input, nameplate MW rating and heat rate were used to estimate capacity factor.

Program Results

Introduction

Natural gas combustion is primarily used in gas turbine applications for power generation with coal being the dominant fuel for fueling utility boilers. Recently, in response to increased availability of natural gas, what appears to be more stable natural gas pricing, and environmental requirements for coal plants, some power plant owners have converted or have announced plans to convert existing coal-fired facilities to natural gas fired facilities. Although in some cases existing coal-fired generating units have been replaced with new natural gas combined cycle units, in some cases existing coal-fired boilers have been or will be retrofit to burn natural gas. Natural gas has the following advantages over coal when used in a boiler:

- Lower NOx emissions and virtually no SO_2, PM, or mercury emissions because natural gas has negligible fuel nitrogen, sulfur or mercury and its combustion produces negligible PM.
- Lower maintenance costs – Due to the absence of slagging or boiler fouling in the furnace, absence of fly ash build up in the ductwork and no need to pulverize and transport solid fuel, maintenance is much less on a gas-fired plant than when firing coal. As a result, there is much less maintenance necessary when firing natural gas and a resulting improvement in unit availability (both planned and unplanned outages). Operating and Maintenance costs could be reduced by as much as 50%.[2]
- Lower parasitic loads – Reduced electricity demand for fuel preparation (coal transport, crushing, pulverizers, etc.) and reduced electrical demand from air pollution control equipment will reduce parasitic loads. This will result in an increase in net output. This has been estimated as about 5 MW on a 250 MW unit, or about 2%.[3]
- Lower CO_2 emissions per unit of heat input and per unit of electricity produced – Natural gas combustion results in roughly 55-60% of the CO_2 emitted per unit of heat input as compared to coal. Natural gas will reduce boiler efficiency which increases heat rate somewhat. After accounting for the beneficial impact on parasitic loads, this will result in about a 2% adverse impact on heat rate[3] – assuming that modifications are not made to recover boiler efficiency. Adjusting for the impact on heat rate, on an electricity-produced basis, natural gas produces

[2] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

[3] Brian Reinhart, P.E., Alap Shah, Mark Dittus, Ken Nowling, Bob Slettehaugh, "Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch", POWER-GEN International 2012.

roughly 56%-61% of the CO_2 compared to coal when used in a boiler.

The principal disadvantages of natural gas as a fuel are:

- Generally higher cost than coal per Btu of heat input.
- Somewhat reduced boiler efficiency due to the increased moisture level in the exhaust gas. This will vary based upon the fuel being used. For example, the impact is greater for bituminous fuel because bituminous fuel has lower moisture content than subbituminous or lignite. The impact is estimated to result in a 200 Btu/kWh (roughly 2%) increase in heat rate when converting to 100% natural gas (coal type was not indicated in the study).[3] Another study showed examined the effects of cofiring natural gas with different coals, with the results in Table 1.

Table 1. Impact of cofiring natural gas with different coals.[4]

Fuel	Heat Rate Difference from Base	CO_2 Reduction
Base – 100% PRB Coal	0	0
100% Bituminous Coal	-1.3%	8%
Bit. Coal/24% NG	+0.9%	9%
PRB Coal/37% NG	+0.15%	17%

- Unlike coal, natural gas is not stockpiled at the plant and is also used for residential and other services – increasing the risk of supply disruption. The risk of having service interrupted during periods where residential demand is high may be addressed with firm, uninterruptible service. However, this will entail purchasing the natural gas at a higher cost.

The following sections of this report will discuss:

- The background on use of natural gas in power generation boilers
- Description of the modifications necessary to co-fire natural gas or to convert to 100% natural gas firing.
- Case studies on coal to gas conversions

[4] ASME Power Plant Efficiency Webinar, September 25, 2014

Background on Use of Natural Gas in Power Generation Boilers

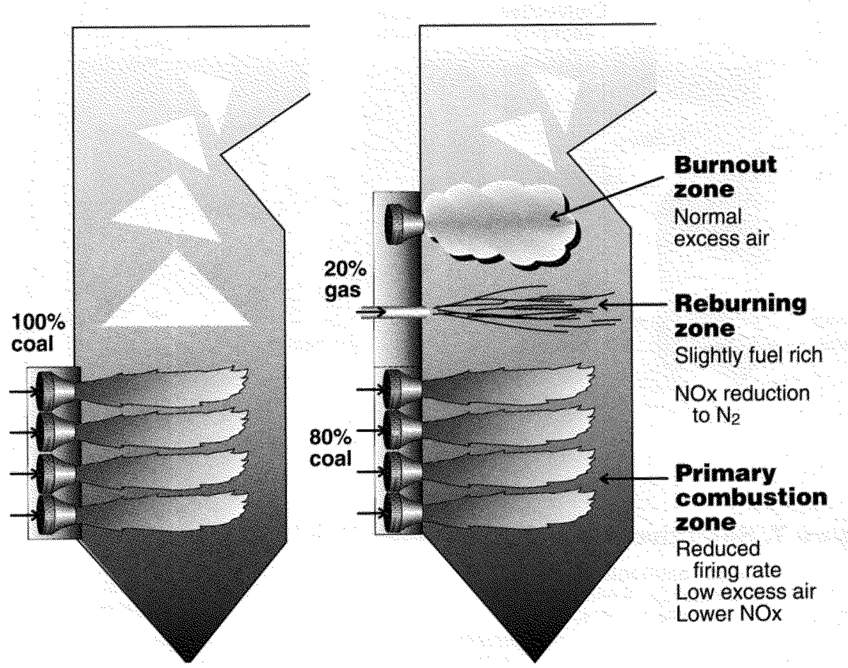
Use of natural gas in coal-fired power generation boilers is not a new phenomenon. For example, conversion of coal-fired boilers to natural gas occurred decades ago in New York City. At the turn of the 19th and 20th century New York City built a network of coal-fired power plants to provide electricity to the railway system because it needed relief from the soot from coal-fueled steam train engines. As natural gas became more available to New York, many of these steam generators that were originally built to burn coal were later converted to 100% natural gas firing because of the desire to reduce the pollutant emissions from these boilers and the associated impact on New York City residents. With time, these boilers have largely been replaced with natural gas combined cycle systems because they are much more efficient in converting the heat of the fuel to electricity than boilers.[5, 6]

Interest in co-firing or converting coal boilers to natural gas increased again in the 1980's and 1990s. Cofiring of natural gas in coal-fired boilers is typically done in many coal-fired boilers upon start-up of the boiler. Boilers start with gas igniters that heat up the furnace and allow ignition of the coal. Interest in cofiring of natural gas at higher loads increased in the 1980's and 1990's with emphasis on reducing NOx emissions from coal-fired boilers. When co-firing, gas may be admitted into the coal burner region, or it may be admitted downstream of the coal burners. One approach for co-firing natural gas that can be used to reduce NOx emissions is natural gas fuel reburn, where natural gas is fired downstream of the primary combustion zone – typically at a point above the coal burners since in most boilers flue gas flow is upward, as shown in Figure 1.

[5] Museum of the City of New York, "Construction of the 74th Street Power Station", http://mcnyblog.org/2012/06/12/constructionof-the-74th-street-power-station/

[6] IEEE, "The Railway Power Stations of New York City", http://www.ieeeghn.org/wiki/index.php/The_Railway_Power_Stations_of_New_York_City

Figure 1. Conventional gas reburning compared to normal firing.



In fact, in the 1980s and 1990s there was a substantial amount of experience gained through the various retrofit uses of natural gas in utility boilers for the primary purpose of NOx reduction. These technologies are distinguished by the amount of natural gas used and where it is introduced into the boiler, and include:

- Seasonal fuel conversion - firing gas as the principal fuel in lieu of coal or oil during the ozone season when NOx emissions were of greatest concern
- Cofiring natural gas with coal at the burner level
- Conventional Gas Reburning, which at the time achieved over 50% NOx reduction through addition of up to about 25% heat input with natural gas downstream of the coal burners.
- Advanced Gas Reburning for higher NOx reduction than possible with conventional gas reburn by combination of Selective Non-Catalytic Reduction (SNCR) with gas reburning
- Fuel Lean Gas Reburn™ (FLGR), which at the time achieved on the order of 35% to 45% NOx reduction with combustion of up to about 10% of heat input with natural gas downstream of the coal burners.
- Amine Enhanced FLGR, which has been demonstrated to achieve 50% to 70% NOx reduction by combination of FLGR with SNCR.

Gas cofiring has also been deployed on boilers that converted from eastern to western fuels. Due to the lower Btu value of the western fuel – which requires that more fuel be fed to the furnace to achieve the same heat input - and limitations on fuel delivery systems, it became necessary on some units to co-fire natural gas to achieve full load.

Table 2 shows the results of a 1998 utility survey of NOx performance from converting from coal to 100% gas on commercial facilities – in some cases demonstrations. These were performed with the primary objective of reducing NOx emissions. Except for the NIPSCO Michigan City unit 12 and the Mitchell unit 4, 50% or more NOx reduction was achieved in every situation. Of course, modern low NOx burner technology for both coal and natural gas fuel would alter the NOx levels from what is shown here, and as shown, most of the units on Table 2 did not have low NOx burners at the time. As a result, advanced combustion controls allowed these units to change back to near 100% operation on coal. Nevertheless, this data demonstrates that gas conversions are not a new phenomenon and can have significant pollutant emission benefits.

Table 3 shows the results of 1990's era gas reburning and fuel lean gas reburning commercial-scale demonstrations and commercial installations. Nearly all of these operated commercially for several years. Several eventually installed low NOx burners to achieve compliance with NOx regulations and could turn off the gas reburn systems. As demonstrated here, these technologies that were used for cofiring natural gas with coal while reducing NOx are not new, but have been available for decades.

Since CO_2 emissions were not the focus of the studies in Tables 2 or 3, the data on CO_2 emissions was not reported; however, it is reasonable to expect that CO_2 emissions would be reduced by roughly 45% for the full gas conversions in Table 2 and by lesser amounts in proportion to the gas use for the reburning or fuel-lean gas reburning results in Table 3.

Table 2. 1990's Era Results from Utility Survey of NOx Performance from Converting Unit from Coal to 100% Gas[7]

Utility	Station	Unit	MW	Demo MW	Yr Online	Type	LNB?	NOx Coal	NOx Gas	% Rem	Com-ments
NIPSCO	Mich Cty	12	540	469	1974	CY	N	2.10	1.20	42.9	(1)
NIPSCO	Mich Cty	12	540	469	1974	CY	N	1.35	1.20	11.1	(2)
PS CO	Cherokee	3	150	158	1962	FF	Y	0.48	0.20	58.3	(3)
PSEG	Mercer	2	326	308	1961	FFW	N	1.80	0.85	52.8	
AZ Elec	Apache	2	195	175	1978	OF	Y	0.63	0.18	71.4	
AZ Elec	Apache	3	195	175	1979	OF	Y	0.59	0.18	69.5	
PSEG	Hudson	2	660	610	1968	OF	N	1.80	0.90	50.0	(4)
IL Pwr	Henepin	1	75	70	1953	TF	N	0.60	0.15	75.0	(5)
IL Pwr	Henepin	1	75	70	1953	TF	OFA	0.35	0.10	71.4	(6)
IL Pwr	Henepin	2	231	214	1959	TF	N	0.70	0.25	64.3	
IL Pwr	Wood R	4	113	93	1954	TF	N	0.70	0.25	64.3	
Com Ed	Fisk	19	374	318	1959	TF	N	0.70	0.28	60.0	
NIPSCO	Mitchell	4	138	125	1956	TF	N	0.40	0.30	25.0	(7)

Comments:

(1) Illinois Basin Coal
(2) PRB/SWY Coal Blend
(3) limited to 80 MW due to gas supply
(4) Unique Slagging Boiler Design
(5) 34% co-fire was 0.40 # NOx/MMBtu
(6) 34% co-fire was 0.20 # NOx/MMBtu
(7) on 70% PRB coa

CY Cyclone firing
FF Front firing
OF Opposed firing
TF Tangential firing
OFA Overfire Air
LNB: Low NOx Burner

As Tables 2 and 3 demonstrate, gas conversions and gas co-firing have been performed on a wide range of boilers, fuel types, and boiler sizes. In addition to these sites, natural gas reburning was deployed commercially at the CP Crane station near Baltimore, and the TVA Allen unit 1 in 1998. These were taken out of service only a few years later. The reason that gas conversions, and gas co-firing such as gas reburning and fuel lean gas reburning are not more widely deployed today is because low NOx coal combustion technology advanced to the point where it was more economical to use low NOx burners to control NOx emissions than to use natural gas. But, as this experience demonstrates, the technology to convert a coal unit to natural gas or co-fire natural gas in a coal unit is well established.

[7] Survey originally performed by Energy Ventures Analysis, "Evaluation of Coal and Oil Boiler Performance and Emissions on Gas - Prepared for Coalition for Gas-Based Environmental Solutions", republished in Staudt, J., Natural Gas NOx Controls, for Gas Research Institute,WP98-35, November 1998

Table 3. 1990's Era Reburning (RB) and Fuel Lean Gas Reburning (FL) Applications, Commercial and Commercial-Scale Demonstrations[8]

Plant	MW	Furnace	Tech-nology	Primary Fuel	Reburn Fuel (%)	Baseline NOx	Outlet NOx	% Red'n
Kodak	60	Cyclone	RB	Coal , 2.25% S	Gas (22)	1.38	0.55*	60
Hennepin	71	Tang, dry	RB	Coal, 2.8 % S	Gas (18)	0.75	0.245	67
Lakeside	33	Cyclone	RB	Coal , 3.6% S	Gas (26)	0.95	0.34	66
Cherokee	158	Wall, dry	RB	Coal, 0.4 % S	Gas (22)	0.75	0.26	64
Greenidge	104	Tang. dry	RB	Coal, 1.8% S	Gas (15)	0.62	0.30	52
Niles	114	Cyclone	RB	Coal	Gas	650 ppm	300 ppm	53
Allen	330	Cyclone	RB	Coal	Gas	NA	NA	NA
Longannet 2	600	Wall, dry	RB	Coal, low S	Gas (~20)	~320 ppm	~160 ppm	50
Mercer	320	Wall, wet	FL	Coal, 0.4 % S	Gas (~7)	1.5		
Riverbend	140	Tang. Dry	FL	Coal, 0.7% S	Gas (~5)	0.45	~0.28	~40%
Joliet	340	Cyclone	FL	Coal	Gas (6)	1.106	0.68	38
Elrama	112	Roof	FL	Coal	Gas (5)	0.59	~0.4	30-35

Natural Gas Conversion or Co-firing as a means of CO_2 reduction

In its Technical Support Document associated with the section 111(d) rule EPA concluded that conversion of coal to natural gas was generally an expensive means to reduce CO_2 emissions when compared to other means.[9] On the other hand, this report will demonstrate that some facilities are, in fact, converting to natural gas. These conversions are motivated by a number of factors that include avoiding capital expenses for other regulations, such as the Mercury and Air Toxic Standards (MATS) and Regional Haze Rule as well as concern over future CO_2 emissions regulations or the need to convert from wet to dry ash handling to mitigate water pollution concerns. Finally, conversion of a boiler to a natural gas peaking unit is typically much less expensive than building a simple-cycle combustion turbine. Unlike combined cycle power plants, simple-cycle turbines do not offer heat rate advantages over a steam cycle. Converted coal plants can become cost effective alternatives to simple-cycle turbines as cycling or peaking units.

[8] Staudt, J., Natural Gas NOx Controls, for Gas Research Institute,WP98-35, November 1998

[9] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602, pp 6-9, 6-10

Therefore, when other benefits of gas conversion or cofiring of natural gas are factored into the economics, these projects can be economically viable.

Modifications for Gas Conversion or Cofiring

Modifications to the facility that are necessary to convert a boiler to 100% gas firing or to co-fire natural gas include:

- Those modifications to the boiler that are necessary to burn natural gas and
- Those modifications that are needed to supply adequate amounts of natural gas to the boiler.

Modifications to the boiler for 100% natural gas conversion

Some of these modifications are necessary, and some are beneficial but not essential.

Replacement or modification of burners – This is usually necessary, but may not be if the facility already has burners capable of firing adequate amounts of natural gas. Existing coal burners can be modified by addition of natural gas injection spuds or other modifications. In other cases it may be necessary or even preferable to replace the burners. The decision to replace existing burners will depend upon the condition of the existing burners, their ability to be modified, and the NOx and CO emission limits that may apply. It will also depend upon whether or not the facility wants to maintain the option of burning coal sometime in the future. The cost of this will vary depending upon whether or not the modifications entail new burners or simply modification of existing burners.

Windbox modifications – The windbox of the boiler is the common plenum that provides combustion air to the burners. In some cases it is necessary to modify the windbox to assure proper distribution of combustion air after burners are replaced or modified. But, for the most part, any windbox modifications are typically minor. Extensive windbox modifications can increase the expense substantially, but are rarely needed.

Controls and sensors – Gas flames are physically different than coal flames, being far less luminous. New flame detectors and controls will be required for the gas-fired burners.

Flue Gas recirculation (FGR) – FGR may be used for furnace gas temperature control and also for NOx control. FGR is not necessary in most cases, but has been needed in some cases. For example, if the reason for the conversion is partly motivated by a need to reduce NOx emissions, FGR will help reduce emissions lower and over a wider load range. FGR, if installed, can increase the cost substantially because it may entail additional fans, ductwork, modifications to the boiler, and fan electrical supply and controls.

Furnace modifications – There are several factors that impact a gas versus coal furnace design. A furnace designed to burn coal tends to be larger than one designed to burn gas. Also, the presence of some slag on the walls of a coal furnace will impact heat transfer, and this slag will not be present when firing natural gas. Moreover, heat transfer in the furnace is affected by the luminosity of the flame, which is much greater for a coal flame. Finally, the spacing of convective pass tubing of a coal furnace is not as close in order to allow for possible ash build up. As a result of all of these effects, the heat balance between steam generation in the furnace and superheat and reheat in the convective section will be impacted to some degree when a coal fired boiler is converted to fire 100% natural gas. This must be evaluated on a case-by-case basis for each conversion project. To the degree that these effects are significant, modifications in heat transfer surface may be necessary or beneficial.

Air preheater modifications/replacement – Due to the cleaner nature of the exhaust from the natural gas flame and the fact that the exhaust gas may have more moisture in it than a coal flame (some coals, like lignite, have high moisture content while others, like bituminous, have lower moisture content), it may be beneficial to modify the air preheater to achieve better boiler efficiency. This can be one of the more expensive modifications. In most cases, it is not possible to justify this added cost unless the unit will be heavily operated.

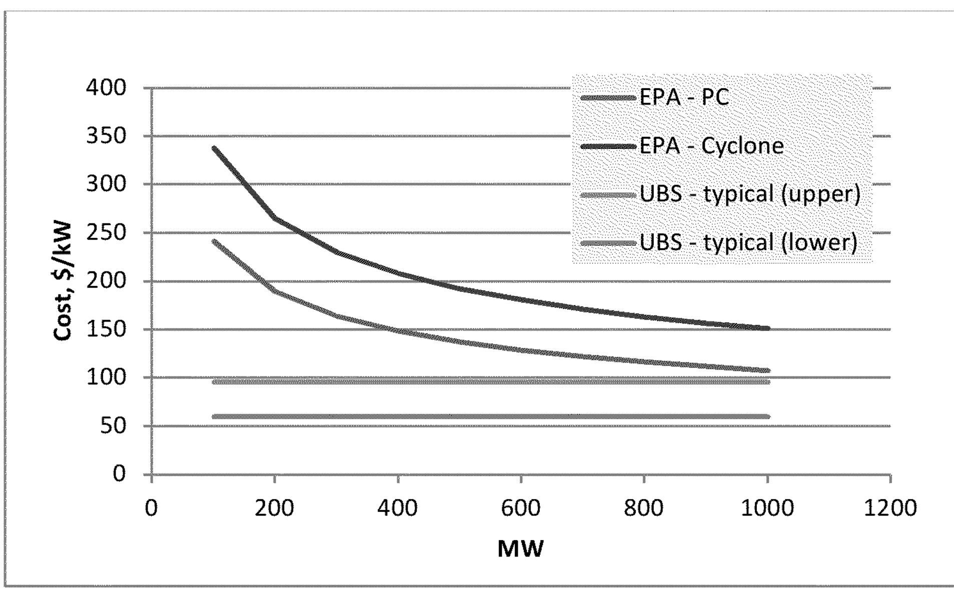
With few exceptions, these modifications can be incorporated into other planned outages, so that the impact on the plant operation is small or negligible.

EPA estimated that the cost of the boiler modifications needed for a gas conversion are as shown in Figure 2 for pulverized coal (PC) and cyclone boilers.[10] Costs are represented in terms of $/kW as a function of size (MW). The cost function covers new gas burners and piping, windbox modifications, air heater upgrades, gas recirculating fans, and control system

[10] Developed from equations in Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602 GHG Abatement Measures, page 6-4

modifications.[11] *However, in most cases all of these modifications, many of which drive up cost considerably, are not necessary.* For example, air preheater upgrades and flue gas recirculation, while often desirable, are often not performed because of the substantial added cost. Conversion to natural gas could be as simple as installing a gas nozzle on an existing coal burner and tying into the existing natural gas supply system.[12] While EPA's estimates included all of the possible modifications and have much higher cost, typical gas conversion costs are in the range of \$50/kW-\$80/kW for the material and installation of the boiler modifications and roughly another 15-20% to cover owner's costs, and these costs are also shown on Figure 2 as well.[13] Therefore, depending upon the extent of the modifications needed, the cost may vary quite a bit. Assuming a capital cost of \$100/kW, a capital recovery factor of 13% and a capacity factor of 50%, this equates to a levelized cost of about \$3/MWh. The cost of increasing natural gas supply to the plant would be in addition to the costs of the boiler modifications.

Figure 2. Estimated cost for the boiler modifications associated with gas conversions.
Note: EPA estimates include all possible modifications, while those cited to UBS are typical



Fuel costs will generally increase because natural gas is more expensive than coal. The difference will depend upon the relative cost of the fuels for the specific plant. For example, for facilities that burn Central Appalachian coal, the difference in fuel cost between natural gas and

[11] http://www.epa.gov/powersectormodeling/docs/v513/Chapter_5.pdf
[12] Brian Reinhart, Alap Shah, Mark Dittus, Ken Nowling, Bob Slettehaugh, "Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch", POWER-GEN International 2012.
[13] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

coal is much less than that for a boiler that burns local, surface-mined coal. The increased fuel costs will be partially offset by reduced operation and maintenance costs, as discussed earlier and examined in some of the Case Studies later in this report.

Modifications to the boiler for natural gas cofiring

Modifying a boiler for natural gas cofiring can sometimes be done with fairly minimal modifications, depending upon the intent and how much gas will be co-fired. Facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters. In this case gas cofiring up to the capacity of the gas igniters can be performed at no additional capital cost. In some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications. Some equipment that may be added include:

Gas injectors - If natural gas is used for reburning, modifications to the upper furnace area will be necessary, and will, in most cases, require some pressure part changes to install locations for the gas injectors and perhaps overfire air.

Sensors and controls – Sensors are needed to monitor flames for the purpose of safety.

As noted earlier in this document, gas reburning was used commercially and demonstrated commercially in the 1990s as a means of NOx control. The cost of natural gas reburning was typically estimated to be on the order of $15/kW for normal reburning, which included the gas injectors, overfire air, and associated controls. Using the Chemical Engineering Plant Cost Index (CEPCI) to escalate these costs to 2014 costs results in about $23/kW.[14] Actual costs would be less in many cases because today many boilers are already equipped with overfire air, and that part of the modification may be unnecessary today. In the case of fuel lean gas reburning, the only boiler modification is associated with the gas injectors, and overfire air is not necessary. As a result, fuel lean gas reburn would be a slightly less expensive retrofit.

Gas supply modifications

If the plant does not currently have adequate natural gas available on site for cofiring or for natural gas conversion, it will be necessary to increase supply. Natural gas must be brought on site through a pipeline. To keep gas prices reasonable and to have adequate gas capacity, power plants prefer to have natural gas delivered from a large, interstate pipeline rather than through a local distribution network. This requires pressure reducing capability as well as a

[14] Applying 1995 CEPCI of 381.1 and May 2014 CEPCI of 574.3 to $15/kW results in a cost of $22.6/kW in 2014

pipeline sized adequately for the demand. Depending upon the size of the power plant and the increase in demand placed on the interstate pipeline, it may be necessary for the interstate pipeline to increase its capacity as well. Areas around the boiler where gas piping will be added and where there is a risk of any gas leakage may be classified as areas with a risk of explosion hazard. In order to address the risk of explosion hazard, this may even entail making changes to electrical equipment in the vicinity of where there may be a risk of gas leakage.

The costs of these gas supply modifications will be driven primary by distance over which the gas line connecting the plant to the interstate pipleline must be built and the quantity of gas that must be moved. Estimates will vary based upon the needs for rights of way and other local factors, but are in the range of about $1 million per mile, with some cases more expensive.[15] EPA made estimates for over 400 plants. The costs were developed for each unit at the plant based upon the proximity to a natural gas pipeline and the estimated quantity of gas needed.[16] ATP calculated the cost per mile on a unit basis by dividing the total cost of the pipeline per unit by the mileage to the pipeline and determined the cost on a plant basis by simply adding up the cost for each unit at each plant and dividing by the mileage. In this respect the plant cost will be conservatively high because separate lines for individual units could be combined into a single, larger line at less cost. The results are shown in Table 4. From these values, a cost in the range of about $1 million to $1.5 million per mile might be regarded as typical, although for some cases the costs may be outside this range.

Table 4. Estimated cost of natural gas pipeline, developed from EPA data.

	$million/mile	
	unit basis	**plant basis**
median	$0.85	$1.60
average	$0.83	$1.97

There have been a number of announced and completed natural gas conversion projects and they are listed in Table 5. This table is not a complete listing of all announced projects, only those that have been verified. In some cases projects were announced and then cancelled. In other cases the decision was made to convert to natural gas combined cycle or a combustion turbine. It is also possible that some announced projects may not be on this list.

[15] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

[16] May be downloaded at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Table 5. Summary of announced coal to gas conversion or cofiring projects

State	Plant Name	Unit	MW	Status or completion date
AL	E C Gaston	1	254	Complete by 2015[17] ~30 mile pipeline
AL	E C Gaston	2	256	
AL	E C Gaston	3	254	
AL	E C Gaston	4	256	
AL	Greene County	1	254	Complete by 2016[18]
AL	Greene County	2	243	
AZ	Cholla	1	116	Convert in 2025[19]
AZ	Cholla	3	271	
AZ	Sundt, Irvington	4	156	Complete by 2018[20]
CO	Cherokee	4	352	Complete 2017[21] 34 mi. pipeline
DE	Edge Moor	3	86	Completed
DE	Edge Moor	4	174	Completed
GA	Yates	Y6BR	352	Complete by 2015[17]
GA	Yates	Y7BR	355	
IL	Joliet	71	250	Complete by 2016[22]
IL	Joliet	72	251	
IL	Joliet	81	252	
IL	Joliet	82	253	
IL	Joliet	9	590	
IN	IPL - Harding Street Station (EW Stout)	5	106	Complete by 2016[23]
IN	IPL - Harding Street Station (EW Stout)	6	106	
IN	IPL - Harding Street Station (EW Stout)	7	435	
IA	Riverside	9	128	Complete by 2016[24]
MS	Watson	4	232	Complete by April 2015[18]
MS	Watson	5	474	
MN	Hoot Lake	2	58	Complete by 2020[25]
MN	Hoot Lake	3	80	
MN	Laskin Energy Center	1	55	Complete in 2015[26]
MN	Laskin Energy Center	2	51	
MO	Meramec	1	119	Units 1 & 2 to be converted in 2016[27]
MO	Meramec	2	120	

[17] Georgia Power 2013 Integrated Resource Plan
[18] http://online.wsj.com/articles/sierra-club-ends-opposition-to-southern-co-clean-coal-plant-in-mississippi-1407184753
[19] http://www.azcentral.com/story/money/business/2014/09/11/aps-plans-close-one-four-generators-cholla-power-plant/15455255/
[20] http://www.epa.gov/region9/air/actions/pdf/az/azfip-finalrule-june2014.pdf
http://tucson.com/business/local/tep-south-side-plant-to-stop-coal-burning-by-end/article_7db6cd7c-e2ed-5a31-88d2-198b22333ebc.html
[21] http://www.xcelenergycherokeepipeline.com/
[22] NRG Energy Investor Presentation, September 2014
[23] http://www.ibj.com/ipl-moves-to-drop-coal-from-harding-street-power-plant/PARAMS/article/49080
[24] http://qctimes.com/news/local/riverside-plant-to-switch-from-coal-to-gas/article_5d4b8f40-6511-11e2-b7cd-0019bb2963f4.html
[25] http://www.mprnews.org/story/2013/01/31/business/hoot-lake-plant-stop-burning-coal
[26] http://www.allete.com/our_businesses/minnesota_power.php
http://finance-commerce.com/2013/01/minnesota-power-converting-coal-plant-to-natural-gas/
[27] http://phx.corporate-ir.net/phoenix.zhtml?c=91845&p=irol-newsArticle&ID=1972924&highlight=

State	Plant Name	Unit	MW	Status or completion date
NJ	Deepwater	1	82	Completed
NJ	Deepwater	8	73	Completed
NY	Dunkirk	1	75	Requires construction of 9 or 11 mile pipeline. To be complete 2015[28]
NY	Dunkirk	2	75	
NY	Dunkirk	3	185	
NY	Dunkirk	4	185	
OH	Avon Lake	7	96	To be complete 2016, ~20 mile pipeline to be built.[29]
OH	Avon Lake	9	640	
OK	Muskogee	4	505	Complete by 2017[30]
OK	Muskogee	5	517	
PA	Brunner Island	1	312	Pipeline being added, unclear which units to be converted or use of cofiring [31, 32]
PA	Brunner Island	2	371	
PA	Brunner Island	3	744	
PA	New Castle	3	93	Complete by 2016[33]
PA	New Castle	4	95	
PA	New Castle	5	132	
VA	Clinch River	1	230	Two of three to be converted by September 2015, third to shutdown[34]
VA	Clinch River	2	230	
VA	Clinch River	3	230	
WI	Blount Street	8	51	Completed[35]
WI	Blount Street	9	50	
WI	Valley (WEPCO)	1	67	Complete in 2015/16
WI	Valley (WEPCO)	2	67	
WI	Valley (WEPCO)	3	67	
WI	Valley (WEPCO)	4	67	
WY	Naughton	3	330	By 2017[36]
Notes: This table is likely to be an incomplete list of all announced projects. Also, an effort was made toverify that the units on this table were not subsequently retired or are not being converted to combustion turbines or combined cycle.				

Other conversions that were announced, but the owners later decided to retire the units include Big Sandy and Muskingum River plants. In some other cases the facility owners chose to

[28] http://www.buffalonews.com/business/residents-tell-state-to-make-decision-on-duelling-dunkirk-plant-pipeline-plans-20141023

[29] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO, In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company 11/27/2013 10:16:21 AM in Case No(s). 13-2315-PL-ACE
http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

[30] http://newsok.com/oklahoma-gas-and-electric-co.-files-1.1-billion-application-for-environmental-compliance-replacement-natural-gas-plant/article/5134375

[31] http://www.power-eng.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

[32] http://www.elp.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

[33] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html
http://dis.puc.state.oh.us/TiffToPDf/A1001001A13K27B01622D11734.pdf

[34] http://www.platts.com/latest-news/coal/louisvillekentucky/aeps -clinch-river-power-plant-in-virginia-to-21100599

[35] http://host.madison.com/business/in-march-blount-street-plant-to-make-gas-its-primary/article_28618898-0489-11df-8a48-001cc4c002e0.html

[36] Pacificorp 2013 Integrated Resource Plan, Public Session Technical Workshop, July 8, 2013

retire the boiler and replace it with natural gas combined cycle or combustion turbines. In the case of Avon Lake, at one point it was expected that these units would be retired, but a more recent decision was made to convert this plant to natural gas.

The natural gas conversions that have been recently announced were primarily in response to tightened environmental regulations, such as the Mercury and Air Toxic Standards (MATS) or Regional Haze Rule (RHR). The owners determined that a natural gas conversion was the lowest cost approach for compliance with these rules. In addition, it is likely that some owners factored in the likely costs of compliance with stricter water pollution rules relating to ash management and future CO_2 emission limits.

As shown, these conversions span a wide range of locations and a wide range of plant sizes and coal types (bituminous and subbituminous). Notably, there are no lignite-fired units. Lignite-fired boilers are mine-mouth plants and therefore have very low fuel costs. The largest plants shown here are over 500 MW and the smallest units on the table are only about 50 MW. There are smaller units still that have been or will be converted to natural gas. In the following section case studies will be examined for the following facilities: Gaston, Irvington, Cherokee, Edge Moor, Yates, Harding Street, Laskin, Meramec, Deepwater, Avon Lake, Muskogee, Brunner Island, New Castle, Clinch River, Blount Street, Valley and Naughton.

Time frame for projects

In general, the boiler modifications will require under a year to perform once the contract is released, including detailed design procurement and installation,[37] and additional time should be provided for activities by the owner prior to placing the order – perhaps 18 months altogether for all activities relating to the boiler (excluding permitting). The impact to boiler outage should be no more than a few weeks, which can normally be incorporated into typical outage times. However, if the modifications are relatively modest, the time could be much less and should have no impact to outages.

The time-limiting factor may be the pipeline-related activities. If a new pipeline must be built, as opposed to expansion of existing pipeline, it is necessary to gain rights of way. In the case of the 34 mile pipeline for the Cherokee plant, construction started in early 2014 and was expected to be complete in October 2014 – under one year. Of course, prior to construction it

[37] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

was necessary to obtain the necessary rights of way and construction permits. The project was initially approved by the Colorado Public Utilities Commission in late 2010.[38] Not factoring in the work performed prior to that agreement (no doubt preliminary engineering and feasibility studies were necessary) the experience at Cherokee indicates for such an extensive pipeline four years might be needed – although construction is less than a year. On the other hand some other pipeline projects may be moving along a faster track. Another example of a plant that requires a new pipeline is Avon Lake in Ohio. In February 2014 the Public Utilities Commission of Ohio approved of NRG Gas Pipeline as a utility that could build a new, roughly 20-mile pipeline along one of two routes proposed in their November 2013 application.[39, 40] The company is working to acquire the needed property and the plant should be operating on natural gas by spring 2016.[41, 42] Boiler modifications could be performed concurrently with the pipeline construction. As a result, total construction activities should be a year or less for most facilities with engineering and other necessary planning activities preceding them.

The Dunkirk station conversion near Buffalo, NY is still another project that is in the works. Dunkirk is owned by NRG Energy. One of two alternative pipeline proposals will be selected by the New York State Public Service Commission. One, by National Fuel Gas Company, is a 9.3 mile pipeline that would cost an estimated $34.5 million. Another is an 11.3 mile pipeline by the plant owner's affiliate, Dunkirk Gas Corporation, at a yet undetermined cost. The project is planned to be completed in September 2015.[43] This project, then, will require less than a year to construct and put in place once the pipeline alternative is selected. In addition, there was planning and other preparation that likely required a year or so.

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[38] http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_-_Clean_Jobs_Plan

[39] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

[40] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO, In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, 11/27/2013 10:16:21 AM

[41] http://chronicle.northcoastnow.com/2014/08/28/neighbors-learn-planned-pipeline/

[42] http://avonlakefacts.com/history.html

[43] http://www.buffalonews.com/business/residents-tell-state-to-make-decision-on-duelling-dunkirk-plant-pipeline-plans-20141023

Case Studies

The following are plants where natural gas conversions have been performed or are planned. The conversions being performed at these facilities will be examined in more detail in the following Case Studies.

- Gaston
- Irvington
- Cherokee
- Edge Moor
- Yates
- Harding Street
- Laskin
- Meramec
- Deepwater
- Avon Lake
- Muskogee
- Brunner Island
- New Castle
- Clinch River
- Blount Street
- Valley
- Naughton

Case Study 1. Plant Gaston Units 1-4, Alabama

Plant Gaston, shown in Figure 3, is located near Shelby, Alabama and operated by Alabama Power, part of Southern Company. In May 2012, Alabama Power announced its plans to convert units 1-4 at roughly 250 MW each to natural gas rather than continue to operate on coal and install pollution controls needed to comply with the Mercury and Air Toxics Standards (MATS). Construction on the project commenced in early 2014 with blasting completed by May 2014.[44] The project is planned for completion by 2015 – or less than three years from announcement to completion. Assuming a year for evaluation, this indicates a total time likely of under four years. Unit 5, which is larger, will continue to burn coal. Because the facility did not originally have adequate natural gas on site (startup fuel was oil), it is necessary to construct a 30-mile natural gas pipeline to connect it to a gas supply located about 30 miles south of the plant.

Plant Gaston units 1-4 are all wall-fired boilers that burn bituminous coal. Table 6 shows information on each of the units at Plant Gaston including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 based upon information reported to US EPA under the Title IV program. The 2013 estimated capacity factors for the units are in the range of 20%-30%.[45] As such, these are not base loaded and primarily cycle to meet load demands.

Cost information on the project was redacted from the publicly available Integrated Resource Planning documents and is therefore not available.

Table 6. Information on Plant Gaston units 1-4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
E C Gaston	1	254	AL	wall	Bit.	9837	28%	1960	29	4.0	2,154
	2	256	AL	wall	Bit.	9928	27%	1960	29	4.1	2,186
	3	254	AL	wall	Bit.	9843	21%	1961	25	4.4	2,337
	4	256	AL	wall	Bit.	9766	27%	1962	27	3.7	1,962

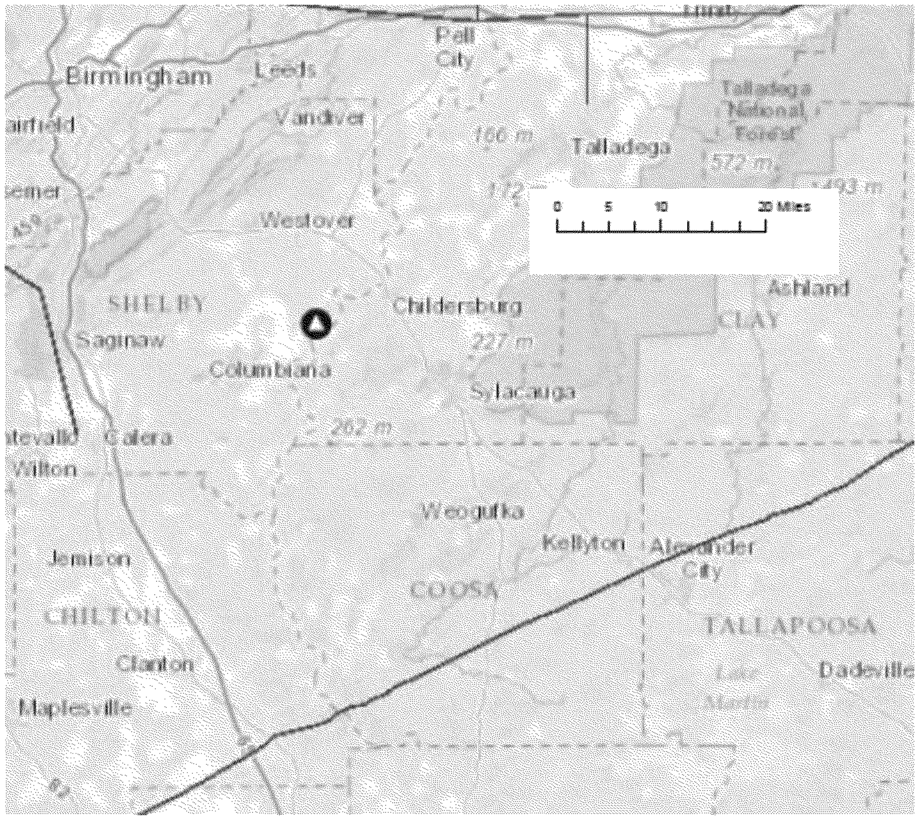
[44] http://www.dykon-blasting.com/Archives/Latex- Gaston/index.htm

[45] Capacity factor is estimated from reported 2013 gross output and rated capacity

Figure 3. Plant Gaston.

Figure 4 shows the location of Plant Gaston (the black circle) compared to the Transcontinental interstate gas pipeline (the blue line). Plant Gaston, located southeast of Birmingham, will be connected to the interstate gas pipeline located to the south that passes through Coosa County.

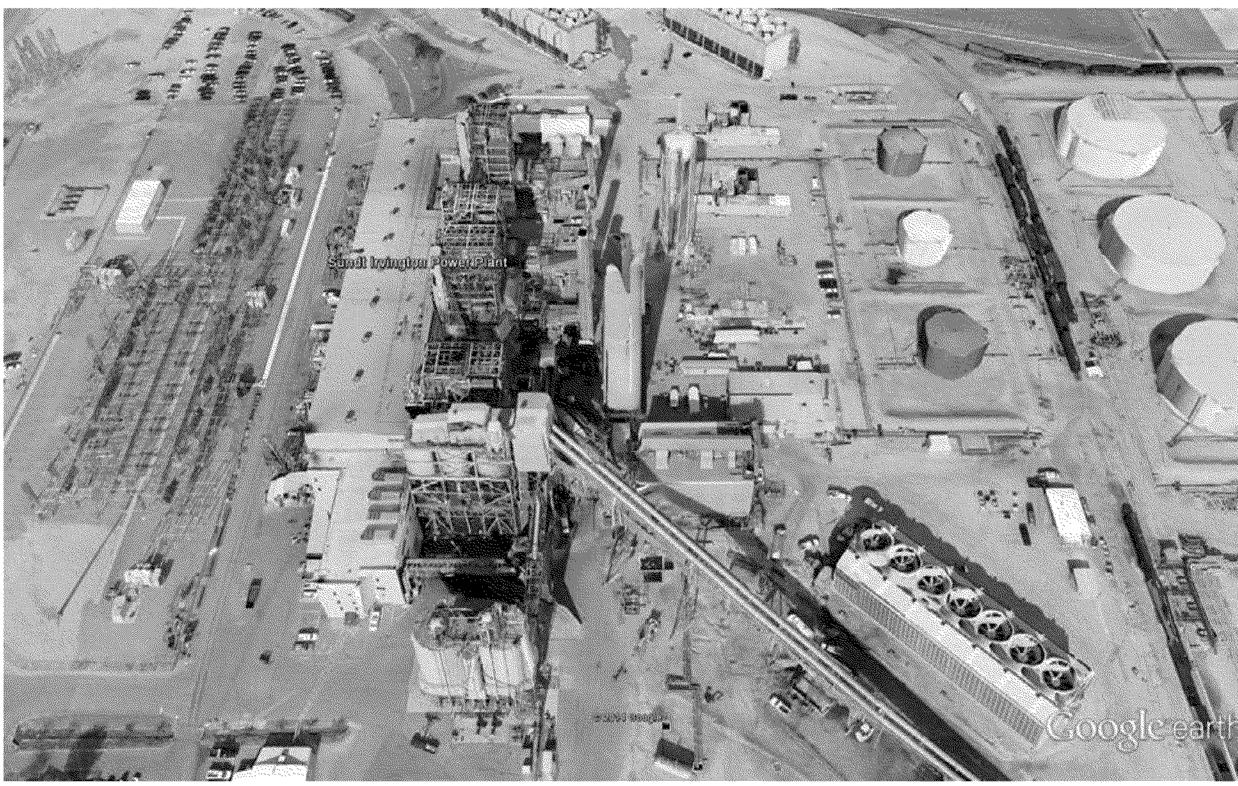
Figure 4. Location of Plant Gaston (black circle with white triangle) and interstate gas pipeline (blue line) it will tie in to. (Source, Energy Information Administration)



Case Study 2. Irvington (Sundt) unit 4, Arizona

Irvington Unit 4 (shown in the foreground of Figure 5) is the sole coal-fired unit at the otherwise gas-fired Irvington (also known as Sundt) station. The facility was originally all gas fired, but unit 4 was converted to coal in the 1980s.[46] After over 30 years of coal operation, Tucson Electric has agreed to convert the 156 MW unit 4 back to natural gas firing, consistent with the other units at the site, as part of its plan to comply with Arizona's regional haze requirements.

Figure 5. Irvington station with Unit 4 in foreground



Irvington unit 4 is a wall-fired boiler that, according to EPA's NEEDS v5.13 database, burns bituminous and subbituminous coal. Table 7 shows information on Irvington 4 including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 based upon information reported to US EPA under the Title IV program.

[46] Tucson Electric Power Irvington Generating Station Air Quality Permit # 1052 TECHNICAL SUPPORT DOCUMENT (TSD) May 18, 2007 http://pima.gov/deq/permits/PDF/1052TSD.pdf

The conversion was motivated as a lower cost approach than SCR to reduce NOx emissions for compliance with Regional Haze Rule requirements and will be completed before the end of 2017. Tucson Electric reached the agreement with US EPA to do the conversion in January 2014. Because natural gas is on site and is already available to unit 4, which was originally a gas unit, the cost of converting was very low, reportedly on the order of hundreds of thousands of dollars.[47]

Table 7. Information on Irvington unit 4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO_2	2013 NOx	2013 CO_2
Irvington	4	156	AZ	wall	Bit., Subbit.	10732	32%	196 7	6.3	4.6	2,123

[47] http://tucson.com/business/local/tep-south-side-plant-to-stop-coal-burning-by-end/article_7db6cd7c-e2ed-5a31-88d2-198b22333ebc.html

Case Study 3. Cherokee unit 4, Colorado

Cherokee station, operated by Xcel Energy, is located just north of Denver, CO. Xcel Energy has agreed to shut down units 1-3, convert 352 MW unit 4 to natural gas and will build a new 569 MW natural gas combined cycle plant on the site. Units 1-2 are already retired. Unit 3 will be retired in 2015. Unit four is shown in the foreground of Figure 6 and its conversion to natural gas will be completed in 2017.

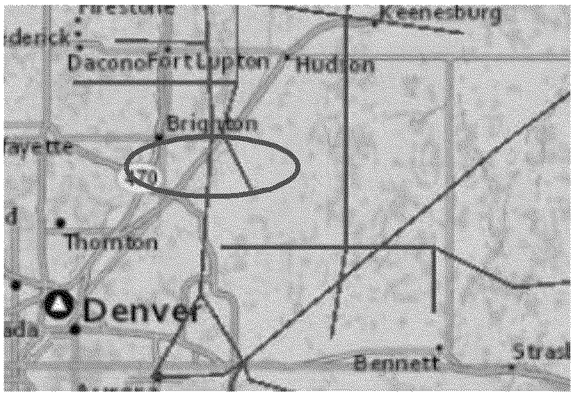
Figure 6. Cherokee generating station, with unit 4 in the foreground.

The project required installation of 34 miles of new, 24-inch steel, high-pressure natural gas transmission pipeline from a new Fort Lupton natural gas metering facility, as shown in Figure 7. Work on the pipeline commenced early 2014 and is completed, in time for the 2015 start-up of the combined cycle plant.[48, 49] The total cost of the pipeline was $110 million to include design, land acquisition, construction and testing.[50]

[48] http://www.xcelenergycherokeepipeline.com/
[49]http://www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Power%20Projects/Kiewit%20569%20MW%20Natural%20Gas-fired%20Cherokee%20Power%20Plant%20to%20Use%20Less%20Water%20than%20Present.htm
[50] http://www.xcelenergycherokeepipeline.com/

Figure 7. Cherokee station (black circle with white triangle near Denver) in relation to Fort Upton natural gas metering facility (circled in red)

Source: Energy Information Administration



Cherokee unit 4 is a tangentially-fired boiler that, according to EPA's NEEDS v5.13 database, burns bituminous and subbituminous coal. Table 8 shows information on Cherokee 4 including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 and capacity factor based upon information reported to US EPA under the Title IV program.

Cherokee unit 4 is a BART affected unit, and the timing of the gas conversion is consistent with the need to comply with BART.

Table 8. Information on Cherokee unit 4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Cherokee	4	352	CO	tange ntial	Bit., Subbit.	10,880	68%	196 9	1.6	3.0	2,081

Case Study 4. Edge Moor Power Plant units 3 and 4, Delaware

After Conectiv sold the Edge Moor plant (shown in Figure 8) to Calpine in 2010, Calpine made the decision to convert the two coal-fired boilers on the site to natural gas. Both units are tangentially fired boilers that burned bituminous coal. Unit 3 is 86 MW and Unit 4 is 174 MW. Natural gas was already available on site.

Figure 8. Edge Moor Power Plant

Table 9 shows information on the two units, to include a comparison of emissions between 2009 (when coal was last fired for a full year) and 2013 (when the facility burned 100% natural gas). As shown, the emissions of all pollutants dropped dramatically, 100% drop in SO_2 emission rate, 50% or better reduction in NOx emission rate, and 45% reduction in CO_2 emission rate. Also, at only 10% capacity factor, the units are operated only as peaking units.

Table 9. Information on Edge Moor units 3 and 4, to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	2013 Cap. Fctr.	Yr on line	2009 lb/MWh			2013 lb/MWh		
									SO2	NOx	CO2	SO2	NOx	CO2
Edge Moor	3	86	DE	tangential	Bit.	11,954	10%	1957	5.4	1.6	2,327	0.0	0.8	1,261
Edge Moor	4	174	DE	tangential	Bit.	11,279	10%	1966	8.5	1.7	1,954	0.0	0.7	1,081

Case Study 5. Yates units 6 and 7, Georgia

Plant Yates is operated by Georgia power and is located southwest of Atlanta. Georgia Power decided to convert both roughly 350 MW units 6 & 7, shown in Figure 9, to natural gas rather than install additional controls for MATS compliance. The plants are already equipped to burn some gas and routinely cofired it during the peak months of May through September,[51] but will need to make some modifications in order to burn gas full time, including installation of oxidation catalyst.[52]

Figure 9. Yates units 6 & 7,

[51] 2013 EIA Form 923 data shows 1,320,400 mcf of natural gas burned during those months
[52] http http://www.bentley.com/en-US/Engineering+Architecture+Construction+Software+Resources/User+Stories/Be+Inspired+Project+Portfolios/United+States/Plant+Yates+Southern+Company.htm://www.times-herald.com/local/20140330-Plant-Yates-update

Cost information on the project was redacted from the publicly available Integrated Resource Planning documents; however, some estimates place the project cost at $40 million, or roughly $57/kW.[53]

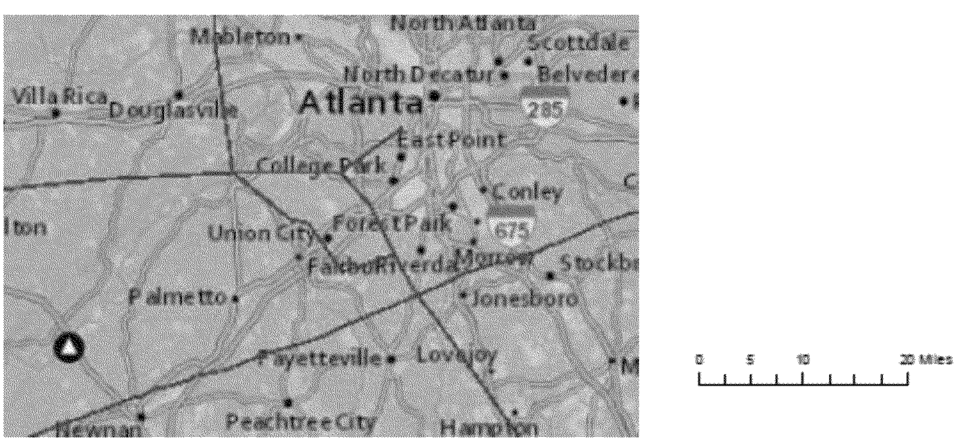
Table 10 shows data on the two tangentially-fired units, to include 2013 emission rates and capacity factor. As shown, both units had been operated at lower capacity factors, with most operation during the summer peaking months.

Table 10. Information on Plant Yates 6 & 7, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Yates	Y6BR	352	GA	tangential	Bit.	10492	29%	1974	22.0	2.6	1,966
Yates	Y7BR	355	GA	tangential	Bit.	10487	15%	1974	21.7	2.2	1,970

Figure 10 shows the location of Plant Yates (black circle with white triangle) relative to Atlanta and to the nearby Transco Interstate gas pipeline. There is a 6.5 mile, 370 MMCFD pipeline from the Transco pipeline to Plant Yates that was installed in 1999.[54]

Figure 10. Plant Yates (black circle with white triangle) and nearby interstate gas pipelines (blue lines).



[53] http://www.times-herald.com/local/20140330-Plant-Yates-update
[54] http://www.georgiapower.com/about-energy/energy- sources/natural -gas-safety.cshtml

Case Study 6. Harding Street Station, Indiana

All remaining operable boilers at Harding Street Station, located in Indianapolis, will be retrofit to burn natural gas by 2016 in lieu of installing controls for MATS compliance or new water pollution equipment. The three tangentially-fired boilers, to the right in Figure 11, with a combined output of nearly 550 MW were operated in 2013 at capacity factors of about 70% or greater in 2013. The project will add roughly $1 to the average ratepayer's monthly bill, but alternatives that would have continued use of coal would have had a greater cost.[55]

Figure 11. Harding Street Station – Units 5-7 to the right

Table 11 shows data on the three units, to include 2013 emission rates and capacity factor. As shown, all three units had been operated at factors of about 70% or greater, suggesting base load or very limited load cycling. Natural gas was already located on site, as the facility has six

[55] http://www.ibj.com/ipl-moves-to-drop-coal-from-harding-street-power-plant/PARAMS/article/49080

combustion turbines and two small natural gas fired boilers that based upon review of EPA's Air Markets Program Data do not appear to have operated on coal at any time at least since 1990.

Table 11. Information on Harding Street Station units 5, 6, 7, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Harding Street Station	5	106	IN	tangential	Bit.	10541	73%	1958	39.3	2.4	2,051
	6	106	IN	tangential	Bit.	10491	72%	1961	37.9	2.4	1,983
	7	435	IN	tangential	Bit.	10517	82%	1973	1.3	1.7	2,059

Case Study 7. Laskin Energy Center, Minnesota

Minnesota Power will be converting its two 61-year old, 55 MW boilers at Laskin Energy Center, shown in Figure 12, to natural gas in 2015 in lieu of installing controls for MATS compliance. The retrofit is expected to be completed over a routine outage at a projected cost of roughly $15 million, or about $136/kW for all modifications.[56]

Figure 12. Laskin Energy Center

Table 12 shows data on the two units at Laskin, to include 2013 capacity factor, current heat rate (from NEEDS v5.13) and 2013 emission rates. According to NEEDS v5.13, the two units fired bituminous and subbituminous coal and used a wet scrubber for PM control. Capacity factors in 2013 are 50%-60%, indicating that these units perform load following duty but also operate a substantial amount of time.

[56] http://finance-commerce.com/2013/01/minnesota-power-converting-coal-plant-to-natural-gas/

Table 12. Information on Laskin units 1 & 2, to include 2013 emission rates

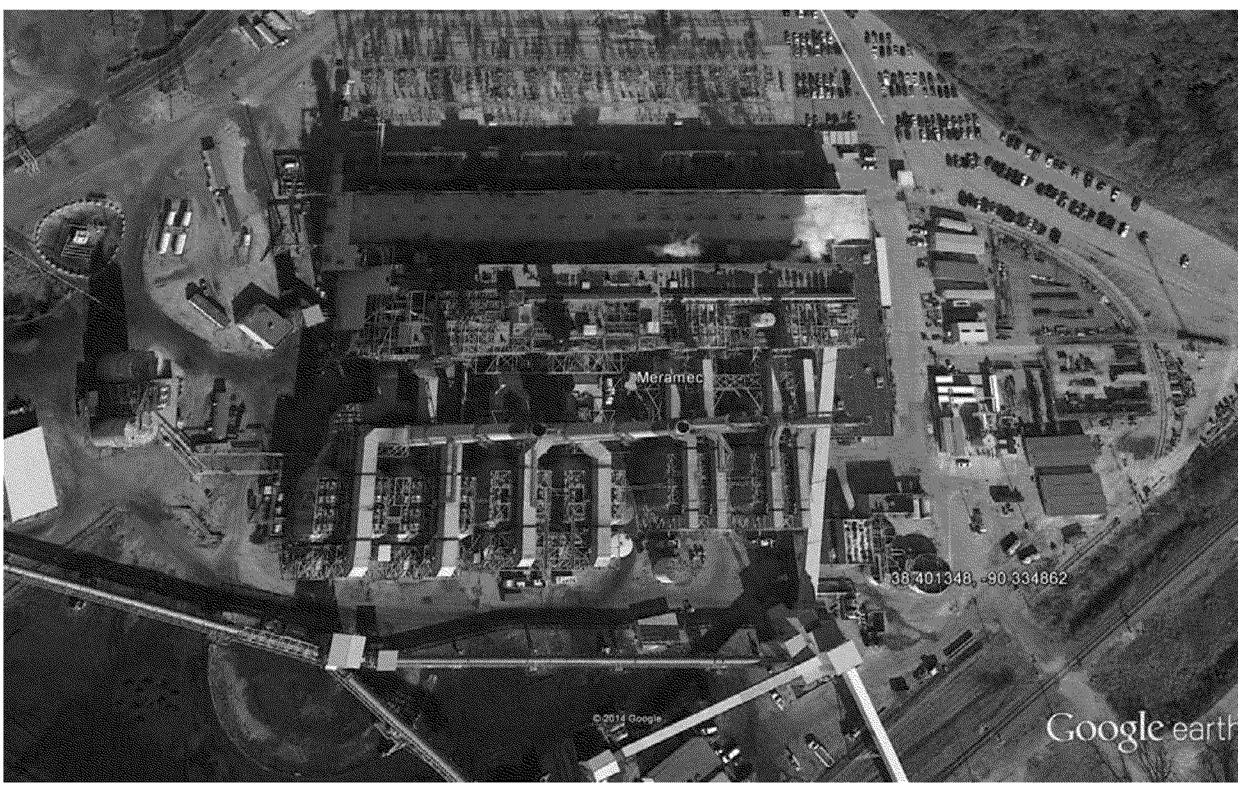
Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Laskin	1	55	MN	Tangential	Bit., Subbit.	12783	56%	1953	1.5	2.0	2,463
	2	51	MN	Tangential	Bit., Subbit.	12875	58%	1953	1.5	2.0	2,456

Case Study 8. Meramec Power Plant, Missouri

Meramec Power plant shown in Figure 13, has four units. In their 2014 Integrated Resource Plan (IRP), Ameren Missouri announced plans to convert units 1 and 2 to natural gas in 2015 and to retire all four Meramec units in 2022.[57] Although the plant already uses some natural gas, it is currently only utilized for the combustion turbines that are on site and for start-up. It is likely that the existing pipeline to the plant may need to be expanded somewhat to provide adequate fuel for units 1 & 2.

The costs of the modifications were not available in the IRP.

Figure 13. Meramec Power Plant



As shown in Figure 14, natural gas is available to the plant from the adjacent interstate pipeline, which is located southwest of Saint Louis where the Meramec River meets the Mississippi River.

[57] Ameren Missouri 2014 Integrated Resource Plan, Chapter 9

Figure 14. Location of Meramec Plant (black circle with white triangle southwest of Saint Louis) and interstate gas pipelines (blue lines).

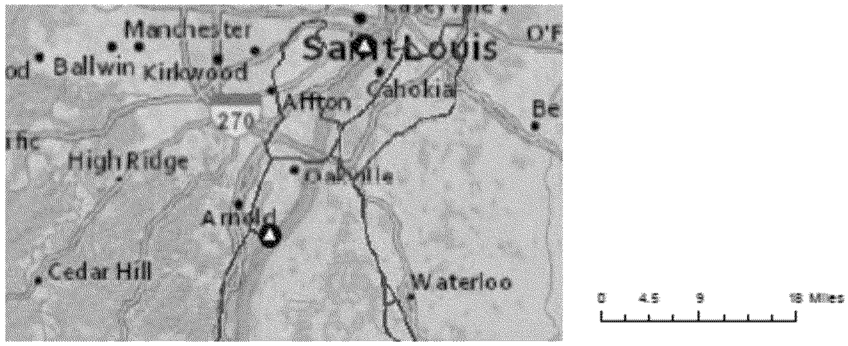


Table 13 includes data on the two units that are planned for conversion. As shown, these units appear to be load following units based upon their 2013 capacity factor, which is in the 40-50% range.

Table 13. Information on Meramec units 1 & 2, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Meramec	1	119	MO	tang	Bit Subbit	10845	42%	1953	4.7	1.3	2,297
	2	120	MO	tang	Bit, Subbit	10644	48%	1954	4.9	1.3	2,400

Case Study 9. Deepwater, New Jersey

Deepwater power plant on the Delaware River in New Jersey is shown in Figure 15. The units operate as peaking units. Unit 1 is a cyclone boiler that was converted to natural gas many years ago and rarely operates now. Unit 8 was converted from bituminous coal to natural gas in 2010. There was pre-existing natural gas infrastructure and therefore little additional infrastructure to add.

Figure 15. Deepwater Power Plant

The units operate only in a peaking mode, with very low capacity factors in the range of 5% as shown in Table 14.

Table 14. Information on Deepwater unit 8, to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	2009 Cap. Fctr.	2013 Cap. Fctr.	Yr on line	2009 lb/MWh			2013 lb/MWh		
										SO2	NOx	CO2	SO2	NOx	CO2
Deepwater	8	73	NJ	wall	Bit.	10,331	11%	5%	1954	9.6	3.6	1,841	0.0	2.2	1,200

Case Study 10. Avon Lake, Ohio

Avon Lake power plant, shown in Figure 16, was destined for shut down by 2015 by previous owner GenOn. NRG Energy, after completing the acquisition of GenOn in December 2012,[58] announced in June 2013 that they would convert the Avon Lake and New Castle plants to natural gas.[59] There was no natural gas on site, and NRG applied in November 2013 to the Public Utilities Commission of Ohio (PUCO) for permission to create and operate its own natural gas pipeline company[60] and received approval in February 2014.[61]

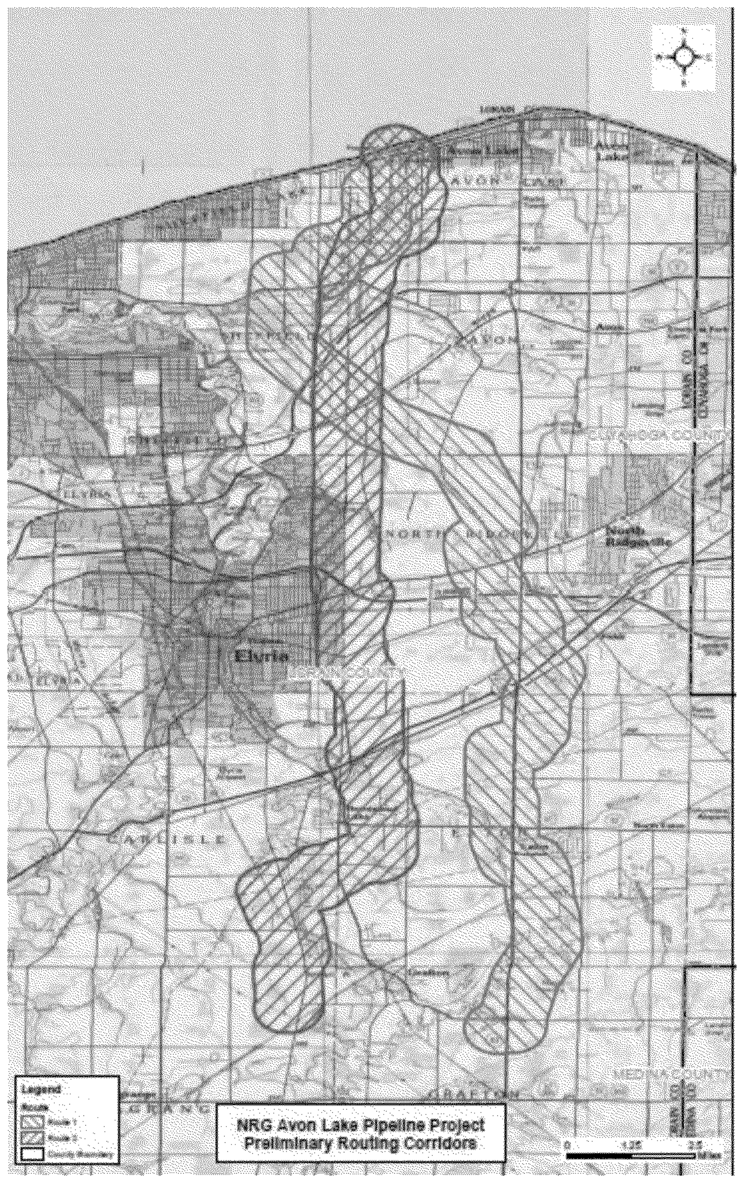
Figure 16. Avon Lake Power Plant

As of August 2014, NRG was obtaining the property rights from landowners in Lorain County, Ohio to build a 20-mile, 24-inch diameter underground pipeline which requires a 50-foot permanent easement for operation and maintenance. The route of the pipeline, with the two original options shown in Figure 17 (the green route is apparently what was selected), would

[58] http://www.bizjournals.com/houston/news/2012/12/14/nrggenon-merger-complete.html
[59] http://www.newsnet5.com/news/local-news/oh-lorain/avon-lake-power-plant-to-switch-from-coal-to-natural-gas-station-was-slated-to-close-in-2015
[60] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, APPLICATION, November 27, 2013
[61] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

extend south from the power plant to an existing natural gas pipeline owned and operated by Dominion East Ohio. [62] NRG has not disclosed the total cost of the pipeline or power plant conversion.

Figure 17. Two originally proposed routes for the natural gas pipeline for the Avon Lake Power Plant conversion [63]



[62] http://chronicle.northcoastnow.com/2014/08/28/neighbors-learn-planned-pipeline/#
[63] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, APPLICATION, November 27, 2013

Table 15 shows data on Avon Lake power plant, including 2013 emissions rates. As shown here, Avon Lake 20 is a large unit, over 600 MW, and a low heat rate of under 10,000 Btu/kWh. Unit 12, the larger of the two, had been operating as a load following role as of 2013. Future use is likely to be for peaking or load following use as well.

Table 15. Information on Avon Lake to include 2013 emission rates

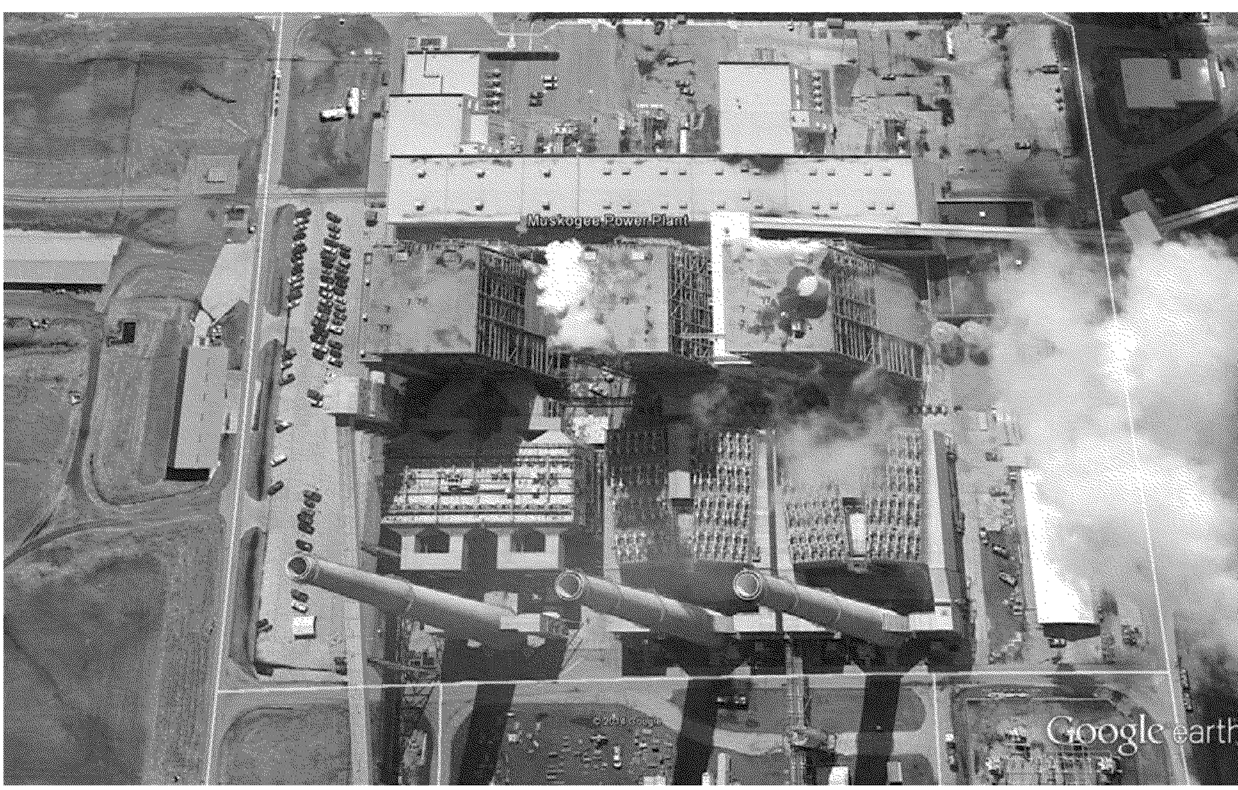
Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh, lb/MMBtu* 2013 SO2	2013 NOx	2013 CO2
Avon Lake	10	96	OH	tang	Bit	12829	10%	1949	3.0	0.4	205
	12	640	OH	cell	Bit	9823	48%	1970	26.3	2.7	1,796

*Avon Lake 10 emission rates in lb/MMBtu and Avon Lake 20 emission rates in lb/MWh

Case Study 11. Muskogee Units 4 & 5, Oklahoma

Oklahoma Gas and Electric will be converting each of the over 500 MW Muskogee Units 4 & 5, shown in Figure 18, to natural gas. According to EIA 923 data, a small amount of natural gas is already burned at the site, likely for start-up, but additional capacity is needed. The 2014 Integrated Resource Plan shows an expected overnight capital cost of $35.7 million per unit. The capital cost includes new pipeline capacity as well as boiler modifications. However, this will provide an expected $5.57 million per unit in annual savings in fixed operating costs and $0.12/MWh in reduced variable operating and maintenance costs.[64] Based upon the 2012 IRP, a new gas pipeline accounted for most of that capital cost.[65] Both Muskogee units 4 & 5 are BART eligible units and the decision to convert the two units to gas in 2018, in time for the January 2019 Regional Haze Rule deadlines, was made after the US Supreme Court declined to consider OG&E's appeal of a lower court ruling. Muskogee unit 6, shown on the left in Figure 18, is not a BART unit and will continue to burn coal.

Figure 18. Muskogee power plant, units 4 & 5 are the two units to the right.



[64] Oklahoma Gas and Electric Company, 2014 Integrated Resource Plan, bear in mind that variable operating costs are separate from fuel costs.

[65] Oklahoma Gas and Electric Company, 2012 Integrated Resource Plan – then estimated the capital cost to be $70 million for the pipeline and $5.7 million for each boiler modification.

Details on the pipeline construction were not available in the IRPs. Figure 19 shows the location of the Muskogee plant relative to the nearby interstate natural gas pipelines. Although it appears that the natural gas pipeline to the west of the plant is very nearby, it is in fact on the other side of the Arkansas River and the city of Muskogee. With the plant conversion announced in 2014 and to be completed in 2018, this indicates a four year period to complete the project, not including any planning activities prior to 2014.

Figure 19. Muskogee Plant (upper black circle with white triangle) and interstate natural gas pipelines (blue lines), source: EIA

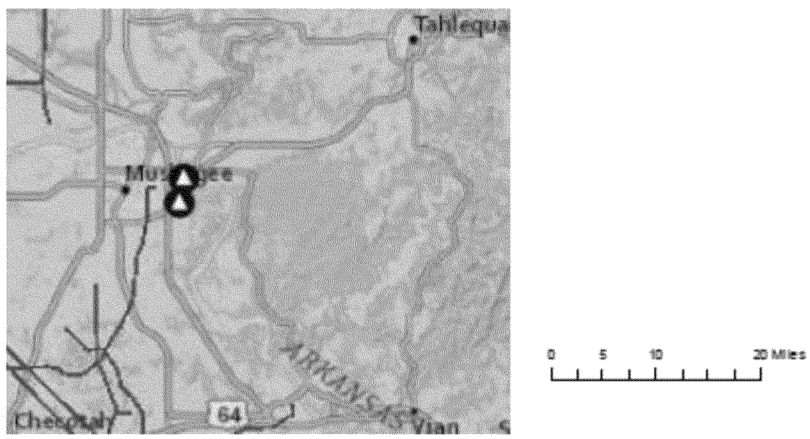


Table 16 shows the information on Muskogee units 4&5, to include 2013 emission rates, estimated capacity factor based upon 2013 Title IV data, and heat rate (from NEEDS v5.13). At over 500 MW each, they are among the largest units identified in this study for coal to gas conversion. Both units burn subbituminous (PRB) coal and in 2013 operated with capacity factors around 50%, indicating that they operated that year in primarily in a load following mode.

Table 16. Information on Muskogee units 4 & 5, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Muskogee	4	505	OK	tangential	Subbit.	10593	44%	1977	6.3	4.6	2,123
	5	517	OK	tangential	Subbit.	10652	51%	1978	4.6	3.6	2,171

Case Study 12. Brunner Island, Pennsylvania

PPL Brunner Island is a large (over 1400 MW) scrubbed facility with three units shown in Figure 20. As a scrubbed plant, Brunner Island is unique among the facilities. According to the National Electric Energy Data System (NEEDS), the scrubbers went on line in 2008 and 2009. So, they are modern wet FGD systems.

On September 27, 2014 the Pennsylvania Department of Environmental Protection announced that it plans to issue an air permit change allowing gas firing at PPL Brunner Island. The permit will allow "for the addition of natural gas as a fuel firing option for the three existing utility boilers (Source IDs 031A, 032 and 033A) and their associated coal mill heaters that will involve the tying in of a natural gas pipeline (Source ID 301), as well as the construction of two natural gas-fired pipeline heaters (Source ID 050) at the Brunner Island Steam Electric Station in East Manchester Township, York County."[66]

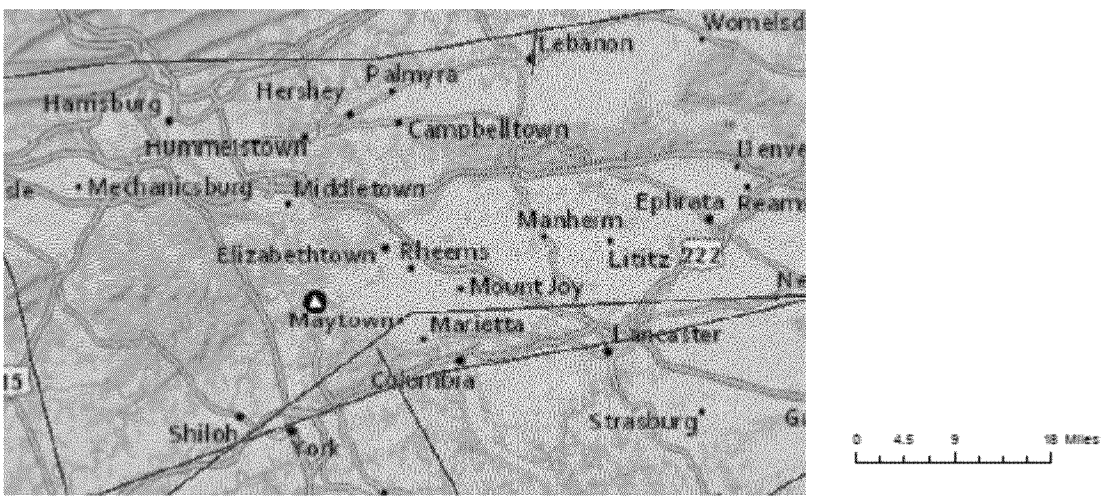
Figure 20. Brunner Island Power Plant

[66] http://www.power-eng.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

The project has not yet been decided for certain. According to PPL spokesman George Lewis, PPL is still in the process of exploring gas co-firing as an option for the Brunner Island plant. "It's important to note that a decision has not been made on whether to go ahead with the project,"[67] Because the project is at an early stage, cost information is not yet available.

The plant, located southeast of Harrisburg, PA, is less than ten miles from an interstate pipeline, as shown in Figure 21.

Figure 21. Location of Brunner Island Power Plant (black circle with white triangle) and interstate natural gas pipeline (blue lines), source: EIA



It may be of note that, although Brunner Island is scrubbed, it is not equipped with SCR for NOx control. As such, gas cofiring would provide Brunner Island additional flexibility in reducing NOx emissions further and be an option that might help PPL avoid installation of SCR for NOx control at Brunner Island in the event that the reinstated Cross State Air Pollution Rule imposes more stringent NOx emission requirements on the plant in the future. It would also provide them additional flexibility to mitigate CO_2 emissions. Other considerations are that the location, in central Pennsylvania, situates it well in relation to Marcellus shale gas.

[67] http://generationhub.com/2014/09/29/ppl-permits-gas-firing-at-big-brunner-island-coal

Table 17 shows data on Brunner Island, including 2013 emission rates and capacity factor. Brunner Island is significant in the fact that it is scrubbed and has some fairly large units – one over 700 MW. The 2013 capacity factors in the range of 50% are significantly lower than they were in 2009 when capacity factors were above 70% for all three units. This drop in capacity factor is likely the result of the drop in natural gas prices during that time. Brunner Island power plant is located just to the east of the Marcellus shale gas sources.

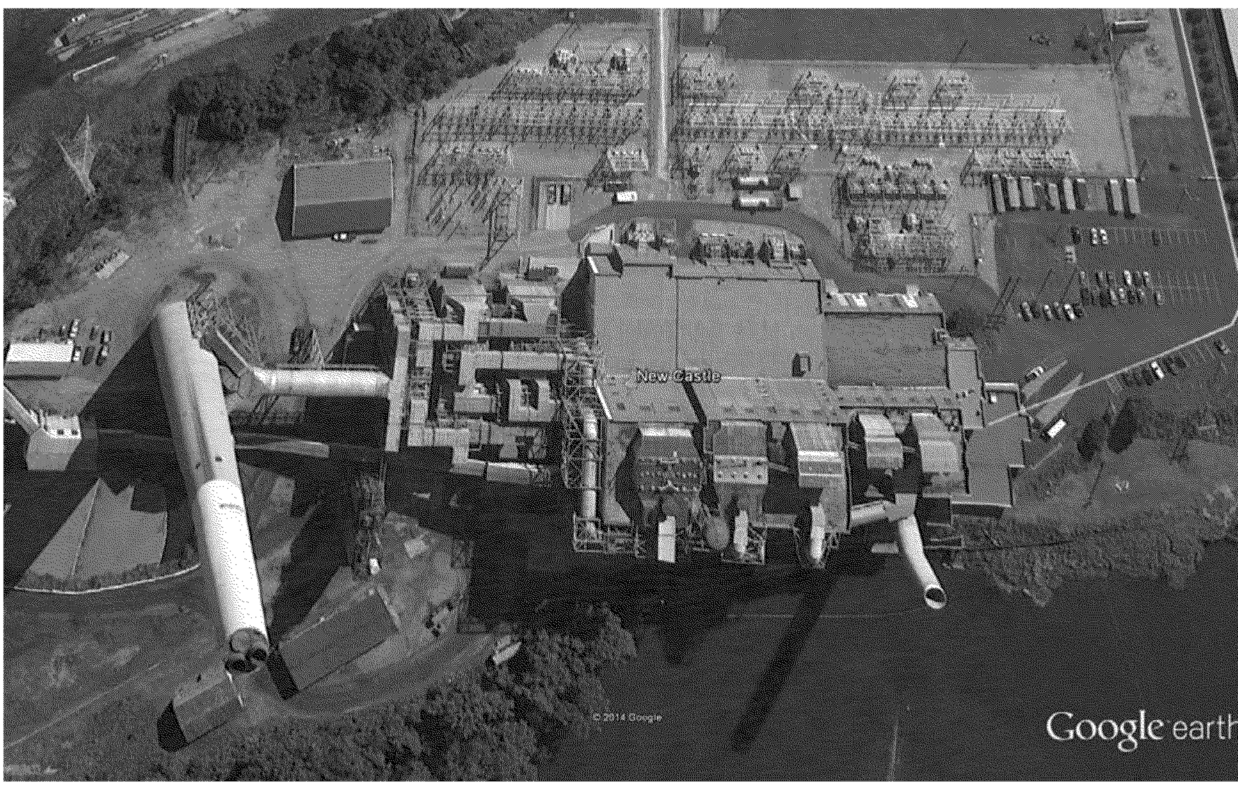
Table 17. Information on Brunner Island, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Brunner Island	1	312	PA	tang	Bit	10023	58%	1961	3.2	3.5	1,884
	2	371	PA	tang	Bit	9695	50%	1965	3.6	3.3	1,858
	3	744	PA	tang	Bit	9502	55%	1969	3.3	3.3	1,827

Cast Study 13 New Castle, Pennsylvania

NRG Energy announced that they will be converting New Castle power plant to natural gas. The facility, shown in Figure 22, has three units ranging from 93 to 132 MW in size and was destined to be shut down by April 2015 until NRG Energy announced in June 2013 that they would convert the plant to natural gas by May 2016.[68]. The conversion is scheduled to be completed in 2016 and will likely operate as a peaking unit. In September 2014, Pennsylvania Department of Environmental Protection announced its plans to issue a permit for the gas conversion, which would include the addition of gas burners to the boilers.[69]

Figure 22. New Castle Power Plant

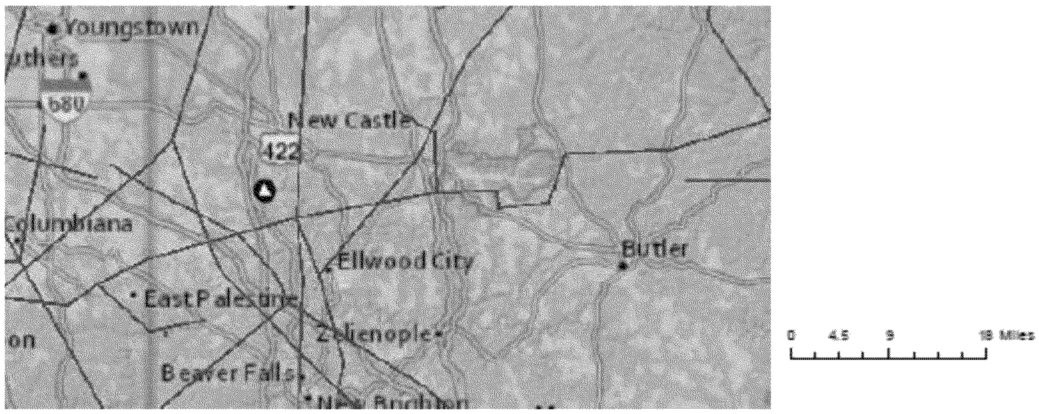


New Castle power plant is located in the middle of the Marcellus shale gas region of western Pennsylvania and is only a few miles from an interstate natural gas pipeline. The plant did not previously burn natural gas. Therefore, a natural gas pipeline will need to be built to connect the plant to the interstate pipeline, shown in Figure 23.

[68] http://www.post-gazette.com/local/region/2013/06/24/New-Castle-power-plant-switching-to-natural-gas/stories/201306240188

[69] http://www.power-eng.com/articles/2014/09/nrg-nears-permit-for-coal-to-gas-conversion-at-new-castle.html

Figure 23. New Castle Power Plant (black circle with white triangle) and interstate natural gas pipelines (blue lines), source: EIA



Data on the New Castle Plant is shown in Table 18, including emission rates and capacity factor. The units are only in the 100 MW range and will likely be operated as peaking units in the future. Capacity factors dropped off by about half between 2009 and 2013, likely due to reduced natural gas prices.

Table 18. Information on New Castle Power Plant, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
New Castle	3	93	PA	wall	Bit	11265	12%	1952	25.1	4.0	2,149
	4	95	PA	wall	Bit	11028	15%	1958	23.2	3.4	2,007
	5	132	PA	wall	Bit	10846	15%	1964	26.0	4.7	2,189

Case Study 14. Clinch River Power Plant, Virginia

Appalachian Power, part of AEP, has decided to retire one of the Clinch River units in Russell County, VA, and will convert the other two to natural gas. Clinch River Plant is shown in Figure 24. One Clinch River unit will be switched to gas in September 2015, the other in February 2016. A third 240-MW coal unit was planned for shutdown in 2014. The two remaining 230 MW units will be operating on 100% natural gas starting spring of 2016, in time to avoid retrofitting equipment for compliance with MATS. The total cost of the project, including pipeline for natural gas, is estimated to be $56 million, or $107/kW, well below the cost of a new combined cycle plant or combustion turbine. The impact to the average residential customer is estimated at less than fifty cents a month.[70] Information was not available on how much of the cost was related to the pipeline versus the boiler modifications.

Figure 24. The Clinch River Power Plant

[70] http://www.tricities.com/workittricities/business_news/article_44610142-bf81-11e3-9eae-0017a43b2370.html
http://www.platts.com/latest-news/coal/louisvillekentucky/aeps-clinch-river-power-plant-in-virginia-to-21100599

Clinch River was once one of the world's most efficient power plants. In 1960 it was the first power plant to operate with a heat rate below 9,000 Btu/kWh for a full calendar year. For the conversion it was necessary to add natural gas pipeline. Approval was sought from Virginia and West Virginia regulators in spring of 2013. In April 2014 the pipeline contract had already been awarded and both units should be operating on gas in early 2016.[70] As shown in Figure 25, Clinch River is located under ten miles from the nearest interstate pipeline.

Figure 25. Clinch River Power Plant (black circle with white triangle) and interstate natural gas pipelines (blue line)
Source: Energy Information Administration

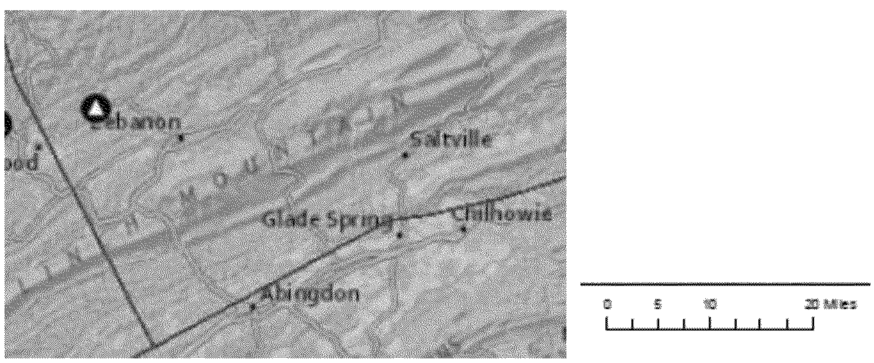


Table 19 shows data on Clinch River Power Plant, including 2013 emission rates and estimated capacity factor. As shown, the units had been operating in 2013 more or less as cycling or peaking units.

Table 19. Information on Clinch River units 1-3 to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
	1	230	VA	vertical	Bit.	10227	21%	1958	7.8	2.1	2,027
Clinch River	2	230	VA	vertical	Bit.	10179	14%	1958	8.0	2.1	2,050
	3	230	VA	vertical	Bit.	10179	14%	1958	8.4	1.8	2,099

Case Study 15. Blount Street, Wisconsin

Blount Street Station, shown in Figure 26, is in Madison, WI and has two roughly 50 MW units. With demand for electricity from the plant greatly reduced, in 2010 Madison Gas & Electric converted the plant to natural gas. The two boilers operate only as peaking units now.

Figure 26. Blount Street Station

Table 20 shows data on Blount Street Station, to include 2009 and 2013 emission rates. As shown, emission rates dropped significantly, 100% for SO_2, about 45% for NOx and about 28-33% for CO_2. As noted, the units are only operated for peaking use.

Table 20. Information on Blount Street units 8 & 9 to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	Yr in Srvc	2009 Cap. Fctr	2013 Cap. Fctr	2009 lb/MWh			2013 lb/MWh		
										SO2	NOx	CO2	SO2	NOx	CO2
Blount Street	8	51	WI	wall	Bit.	14500	1957	4%	2%	25.8	4.2	2,479	0.0	2.3	1,794
	9	50	WI	wall	Bit.	14278	1961	3%	2%	25.8	4.3	2,401	0.0	2.5	1,608

Case Study 16. Valley units 1-4, Wisconsin

Valley units 1-4, shown in Figure 27, supplies electricity to the grid and steam to nearby customers in downtown Milwaukee. Conversion of each of the four 67 MW units will be completed in 2015 and 2016, thereby avoiding the retrofit of equipment for MATS compliance. The total cost of the project is $62 million for the plant modifications and $4.25 million to install 1,800 feet of high pressure natural gas supply and regulation equipment.[71] This equates to a total cost of $247/kW. The relatively high cost of the boiler retrofit is a result of the small size (67 MW each) and the extensive modifications to the boiler and steam supply system that included:

- Removing the coal burners and associated coal piping from the existing four boilers;
- De-energizing and decommissioning coal conveyors, coal silos, coal mills, coal feeders, the bottom ash removal system, and the fly ash removal system;
- Installing new natural gas burners in each of the four boilers;
- Installing a natural gas header and associated valves to supply fuel to the new gas burners;
- Installing new flue gas recirculation (FGR) fans and associated ductwork and electrical work for use in the control of emissions from the boilers;
- Sealing each boiler after removal of existing burners, soot blowers, and bottom seal equipment;
- Installing boiler let-down valves to reliably support steam supply to the district heating system under single steam turbine operation; and
- Updating the control system to integrate new equipment into Valley's distributed control system.

The $62 million cost is broken down into:

- Structures and improvements $9,000,000
- Boiler plant equipment 46,200,000
- Accessory electric equipment 5,600,000
- Miscellaneous power plant equipment 1,200,000
- Total $62,000,000

Table 21 shows data on Valley Station to include 2013 emission rates (expressed in lb/MMBtu because generation data was not available in the Title IV data). As shown, the capacity factors of the units in 2013 were in the range of 22% to 31%, meaning that these units served more as cycling units. The heat rate for Valley is high because Valley produces both power and heating steam. The plant fixed and variable operating costs will be reduced.

[71] PUBLIC SERVICE COMMISSION OF WISCONSIN, Final Decision, Application of Wisconsin Electric Power Company for Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility, March 17, 2014

Figure 27. Valley Station

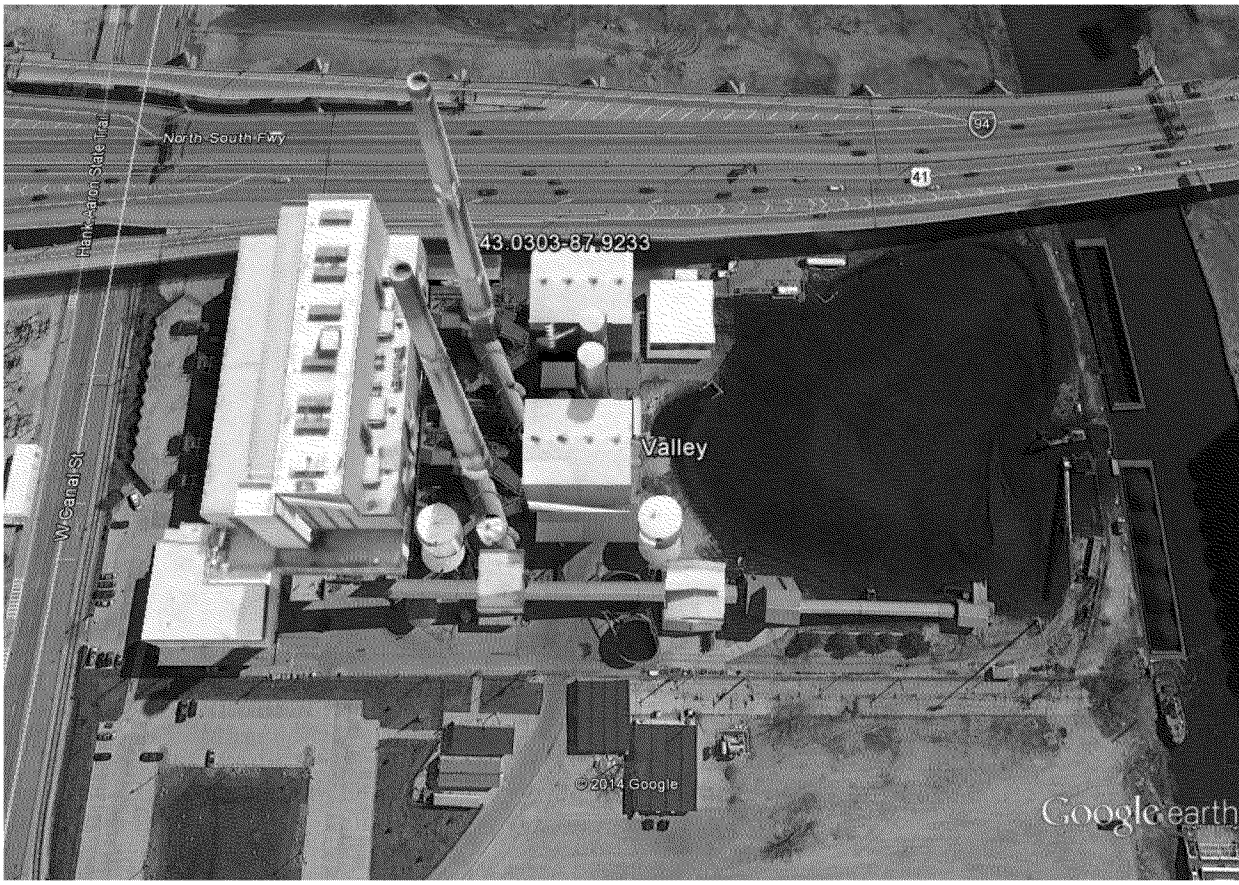


Table 21. Information on Valley units 1-4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MMBtu 2013 SO2	2013 NOx	2013 CO2
Valley	1	67	WI	wall	Bit.	14500	31%	1968	0.7	0.2	205
	2	67	WI	wall	Bit.	14500	30%	1968	0.7	0.2	205
	3	67	WI	wall	Bit.	14500	22%	1969	0.7	0.2	205
	4	67	WI	wall	Bit.	14500	27%	1969	0.7	0.2	205

Case Study 17. Naughton Unit 3, Wyoming

The Naughton unit 3 in Wyoming is a 330 MW BART-affected unit that burns Powder River Basin coal and is shown in Figure 28. Pacificorp, the owners, elected to convert the unit to natural gas for compliance with the Regional Haze Rule. Although base-loaded, Naughton plant is located adjacent to gas pipelines and has access to natural gas. March 4, 2014 comments from the Oregon PUC indicates a conversion date in 2018. This document also indicates that Oregon PUC staff would like Pacificorp to further consider retirement as an alternative to conversion in their 2015 IRP.[72, 73] Cost information was not available in the IRP documentation.

Figure 28. Naughton Power Plant

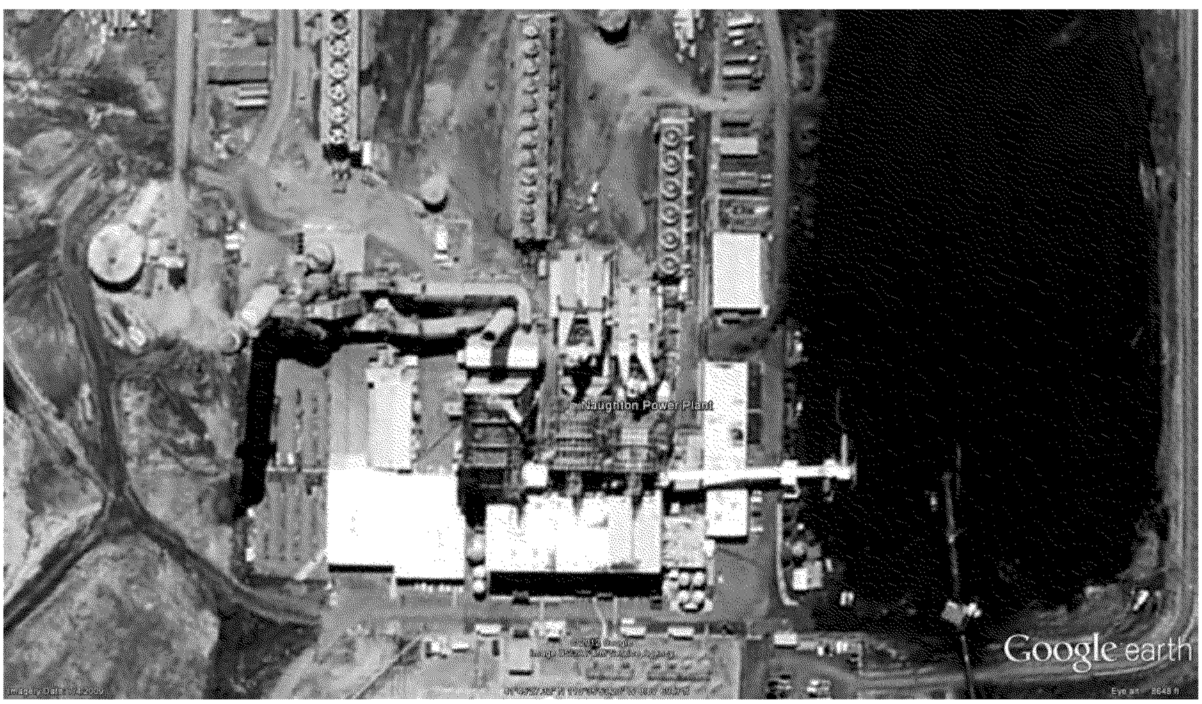


Table 22 shows information on Naughton unit 3, including 2013 emission rates and estimated capacity factor based upon Title IV data and NEEDS v5.13 reported heat rate and MW output. As shown, Naughton 3 is a base loaded unit.

[72] PUBLIC UTILITY COMMISSION OF OREGON STAFF REPORT PUBLIC MEETING DATE: March 17, 2014; http://www.puc.state.or.us/meetings/pmemos/2014/031714/regILC%2057.pdf

[73] BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 57; "In the Matter of PACIFICORP, dba PACIFIC POWER ORDER; 2013 Integrated Resource Plan. DISPOSITION: 2013 IRP ACKNOWLEDGED WITH EXCEPTIONS AND REVISIONS JUL 0 8 2014

Table 22. Information on Naughton unit 3, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Naughton	3	330	WY	tangential	PRB	10,517	97%*	1971	3.5	2.7	2,029

* This capacity factor was estimated from Title IV reported generation and the nameplate capacity in NEEDSv5.13. Although it seems very high, Pacificorp assumed a 90% capacity factor in their 2007 BART analysis.[74] So, the Naughton unit 3 capacity factor was likely around 90% or better in 2013.

[74] See Appendix A of "Final Report BART Analysis for Naughton Unit 3 Prepared For: PacifiCorp" by CH2MHill, December 2007

Natural Gas Transmission Infrastructure Proximity to Coal Power Plants

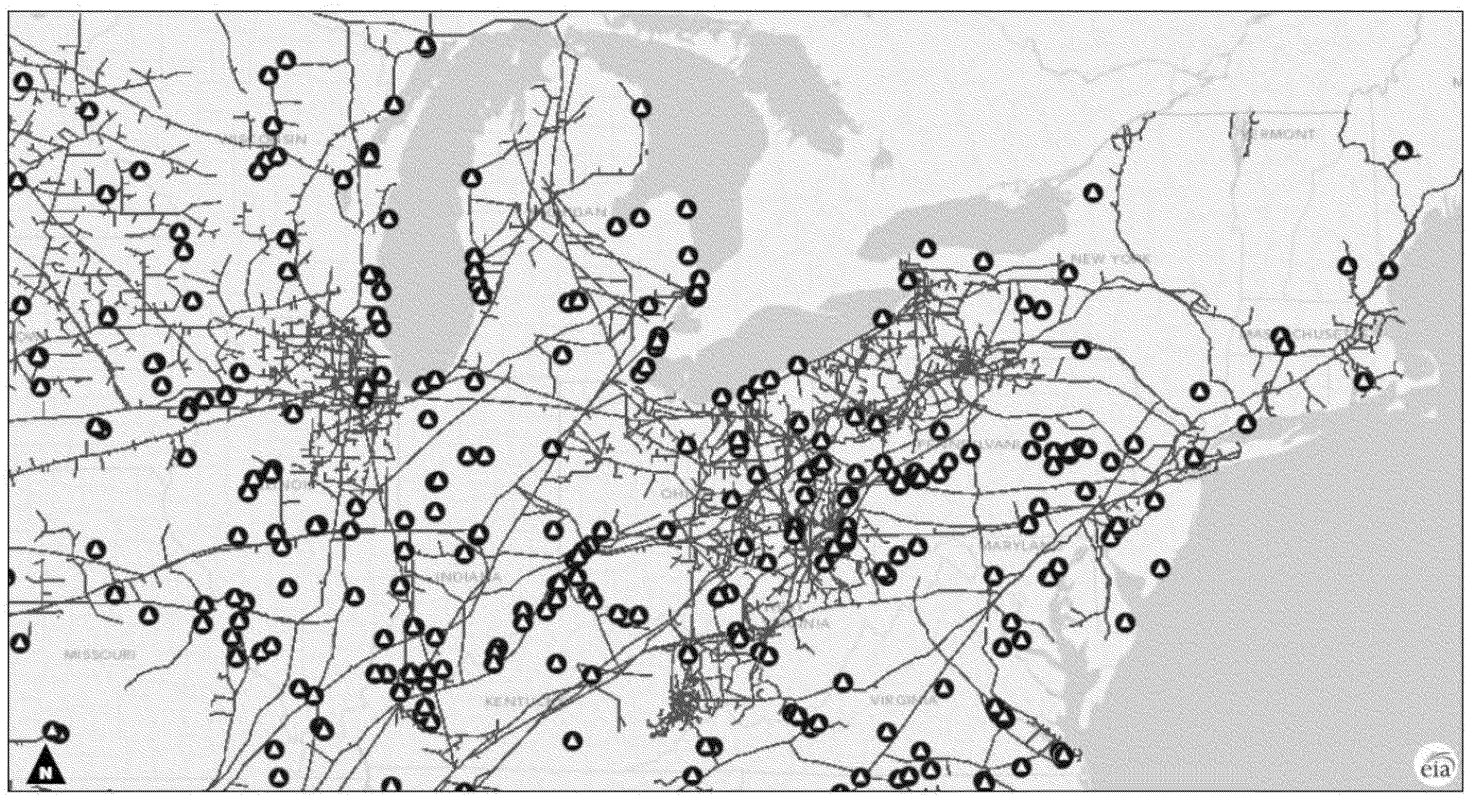
Natural Gas is available in most parts of the United States and, if not available on site, is often located someplace near an existing coal fired power plant. Figures 29 through 33 show the locations of coal-fired power plants (including some large coal-fired industrial plants, such as paper mills) in round black circles with white triangles and the location of interstate pipelines in blue lines. As shown, the vast majority of coal fired plants is located in the general vicinity of an interstate pipeline and, as such, could have access to natural gas. There are, however, a small number of power plants in fairly remote locations that would require longer pipelines to gain access to natural gas.

Figures 29-33 do not provide information on the need to enlarge or expand existing pipeline infrastructure to accommodate increased natural gas demand from the power sector. In their analysis, EPA attempted to incorporate this into their analysis, and this is perhaps why in some cases they concluded that some plants required extensive pipeline needs. For example, they determined that conversion would require 310 miles of pipeline for the Presque Isle Power Plant near Marquette, MI. On the other hand, as shown in Figure 34, the Presque Isle Power Plant is only a few miles from an interstate pipeline. So, making the connection to the interstate pipeline could not possibly explain the length of pipeline estimated by EPA. It is likely that this is what EPA has estimated is needed to enlarge the existing interstate pipeline infrastructure. But, it is also may be that these assumptions are conservative, as demonstrated by EPA's analysis of Edge Moor plant in Delaware. EPA estimated that 24.7 miles of pipeline must be constructed for Edge Moor 3; however, Edge Moor 3 has already been converted to natural gas.

In any event, the existence of this infrastructure does eliminate one of the major hurdles to expansion of infrastructure along these routes where pipelines already exist– the need to gain rights of way.

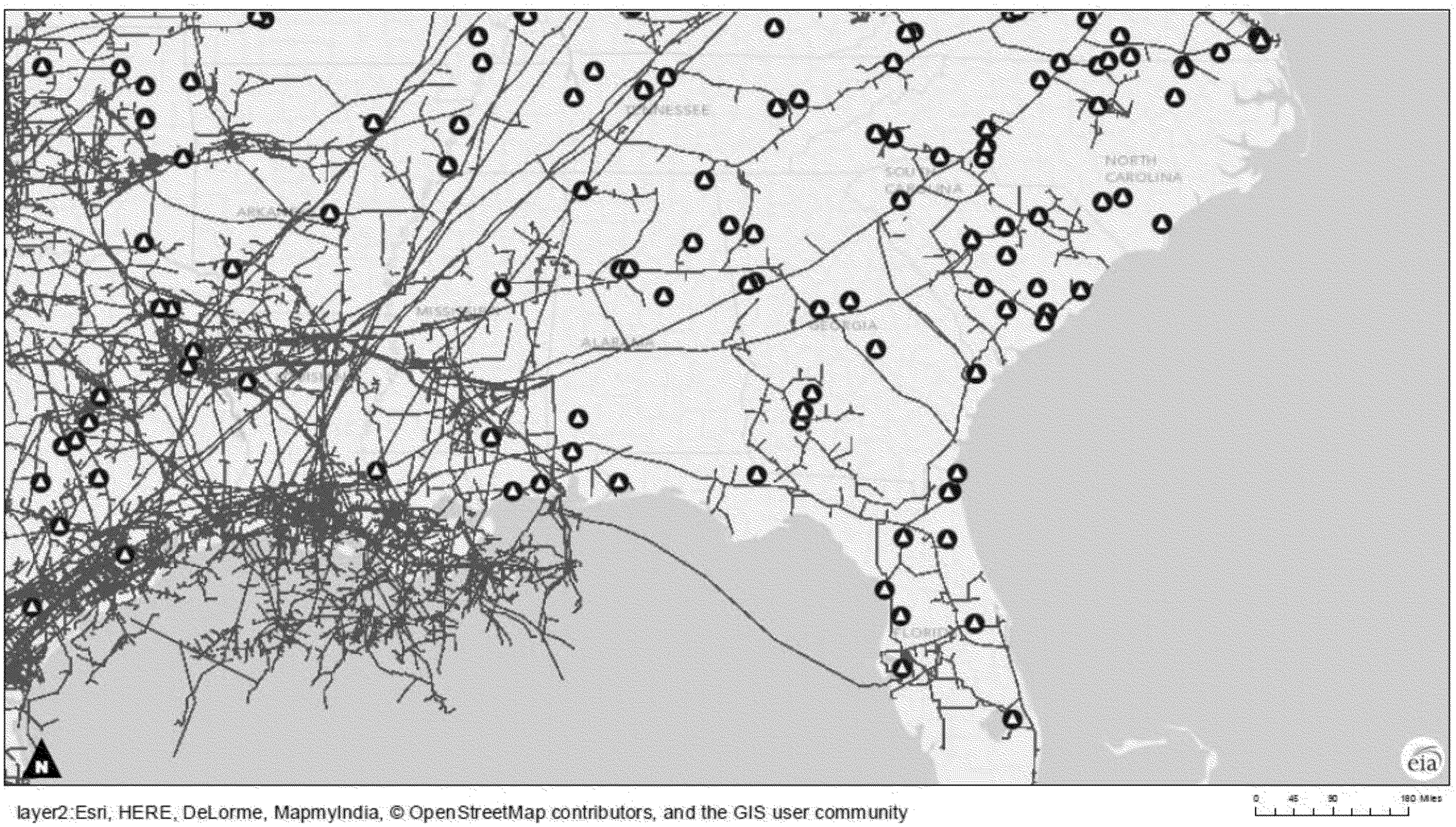
Another factor that has played into the conversion of many coal fired power plants is the increased availability of natural gas from shale gas, and especially from the Marcellus region that spans from upstate New York through Pennsylvania, Ohio and West Virginia. This formation, shown in Figure 35, has had a steady increase in natural gas production from about 2 million cubic feet per day in 2010 to about 16 million cubic feet per day today, as shown in Figure 36.

Figure 29. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Northeast United States. Source: Energy Information Administration



layer2:Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, and the GIS user community

Figure 30. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Southeast United States. Source: Energy Information Administration



layer2:Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, and the GIS user community

Figure 31. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Upper Great Plains United States. Source: Energy Information Administration

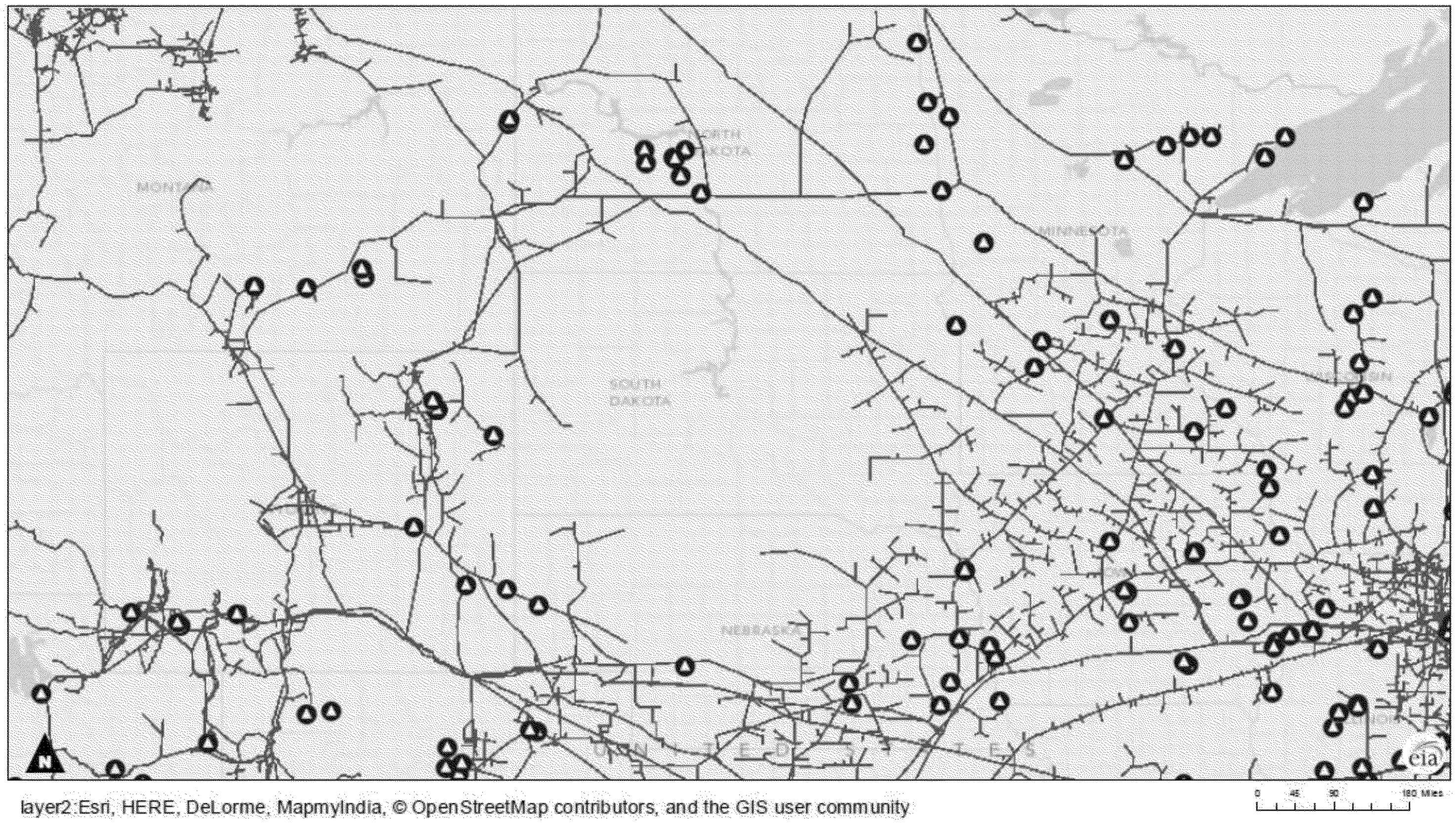
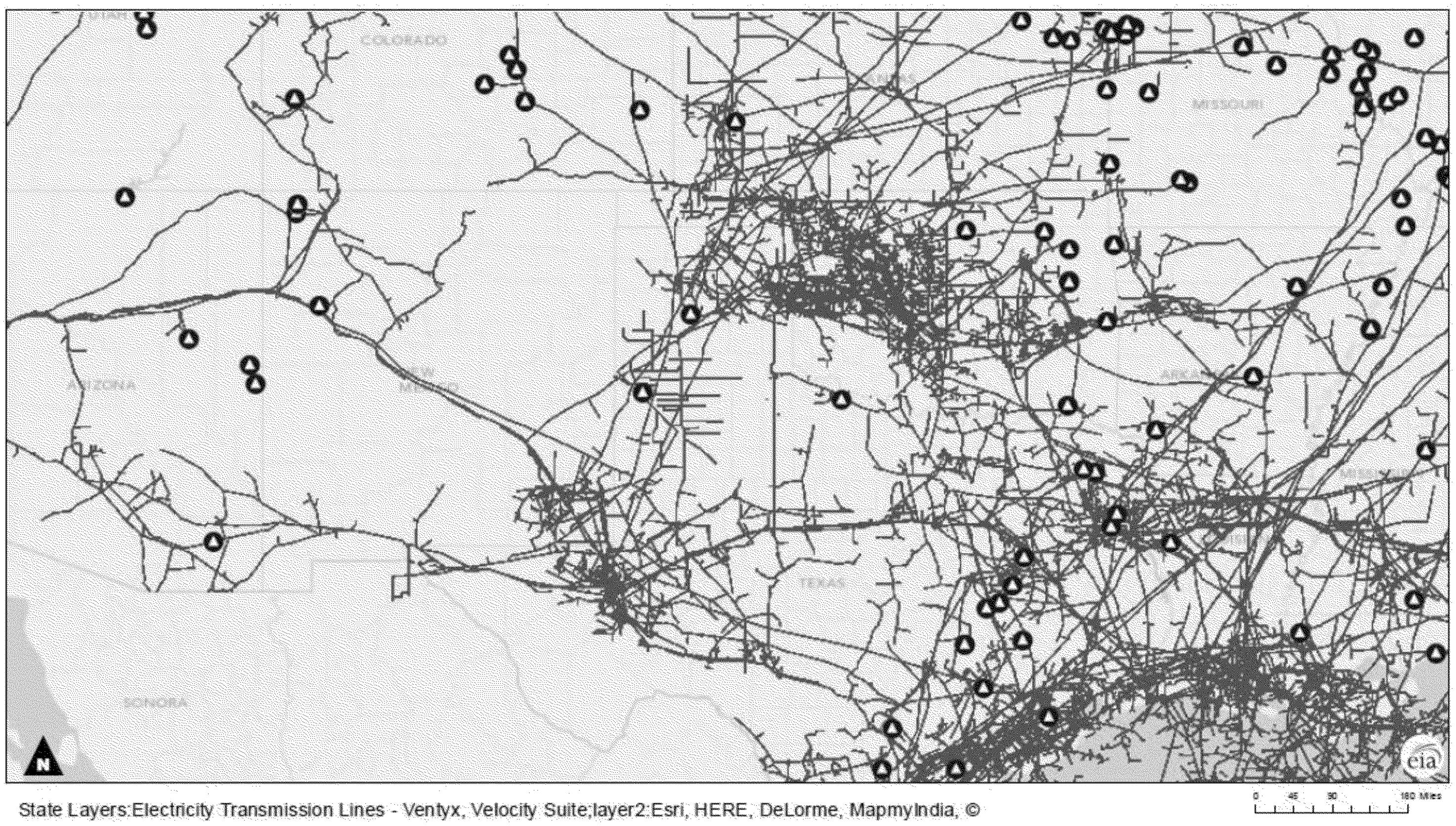
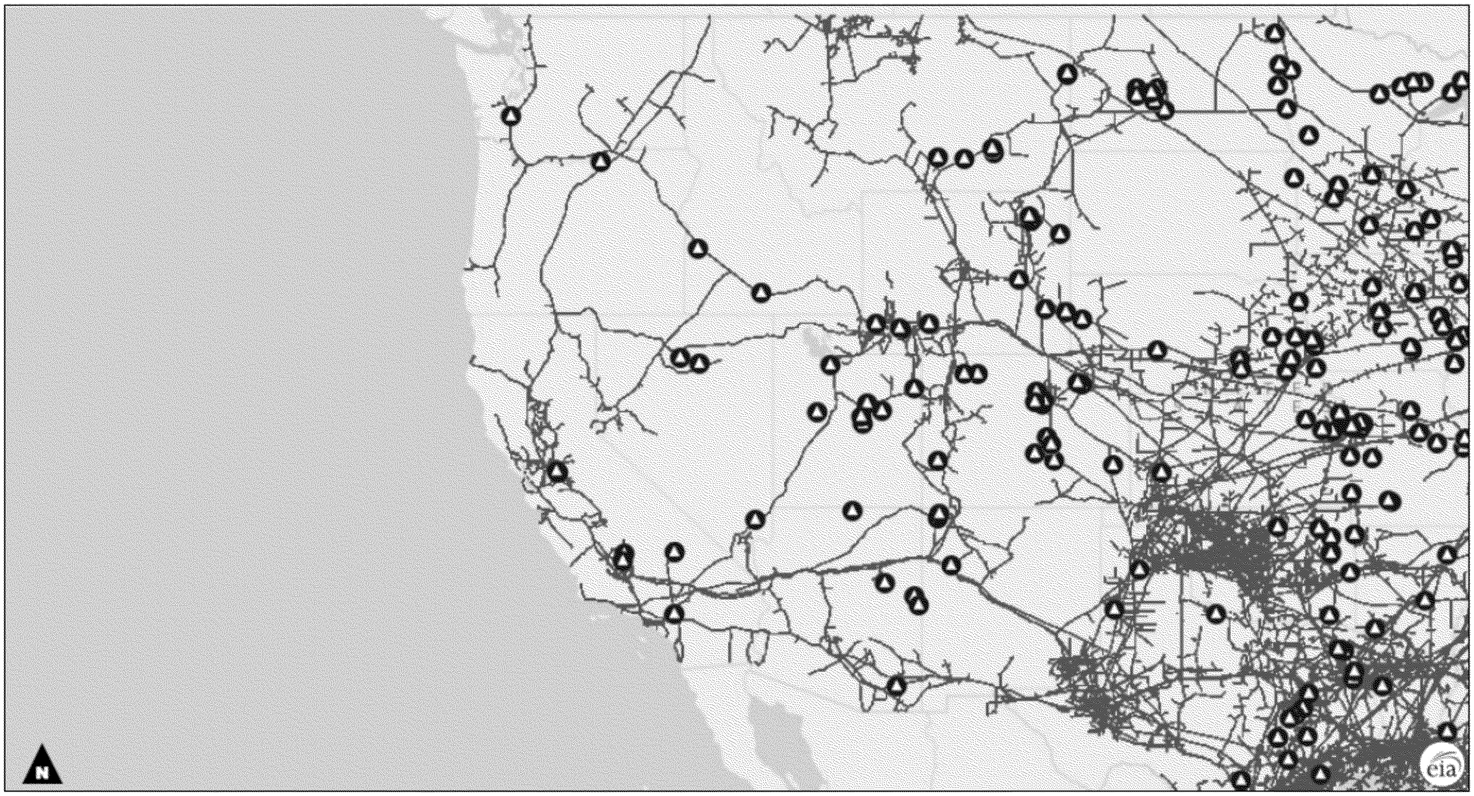


Figure 32. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Lower Great Plains United States. Source: Energy Information Administration



State Layers:Electricity Transmission Lines - Ventyx, Velocity Suite;layer2:Esri, HERE, DeLorme, MapmyIndia, ©

Figure 33. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Upper Western United States. Source: Energy Information Administration



State Layers:Electricity Transmission Lines - Ventyx, Velocity Suite;layer2:Esri, HERE, DeLorme, MapmyIndia, ©

0 90 180 360 Miles

Figure 34. Presque Isle Power Plant (black circle with white triangle above Marquette, MI), and Interstate Gas Pipelines (blue lines), map is from EIA

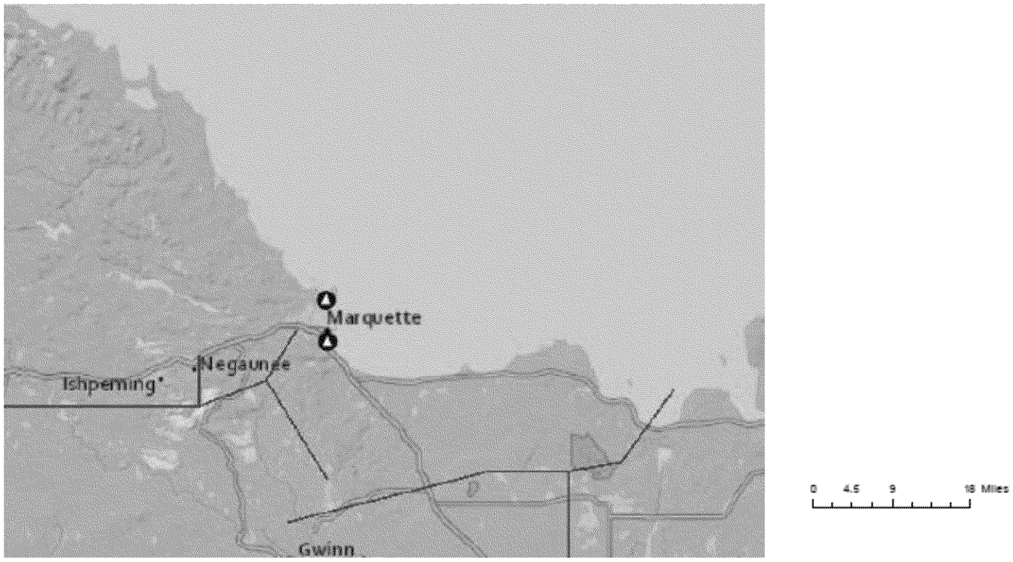
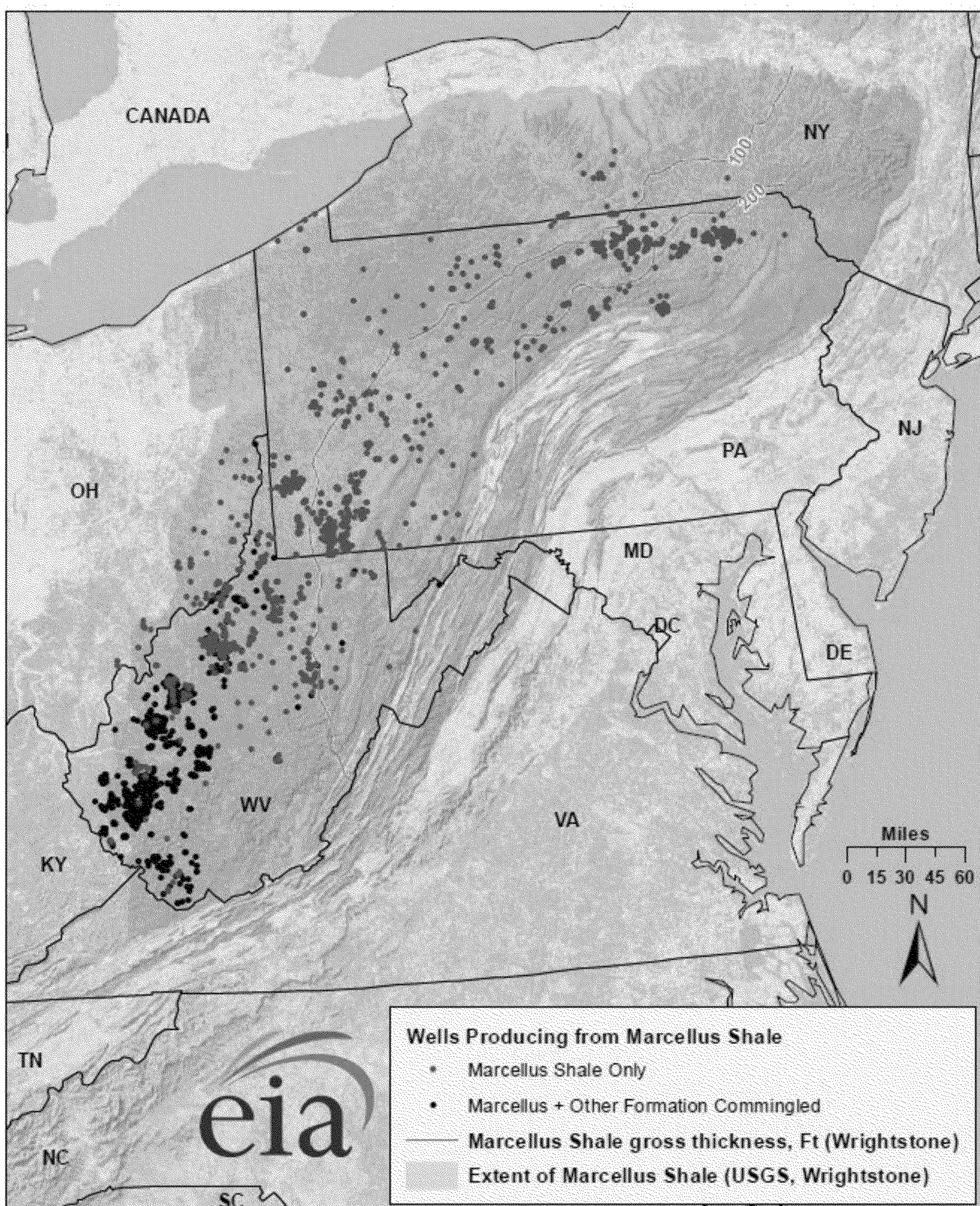
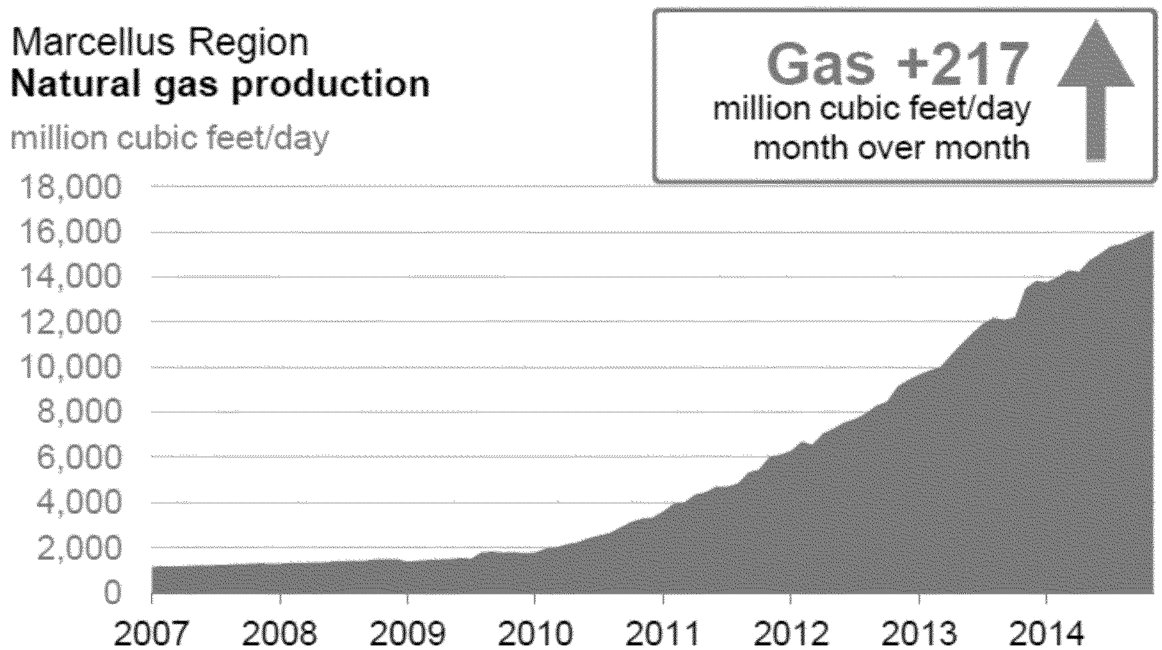


Figure 35. The Marcellus Shale Gas Play, Appalachian Basin (EIA)



Source: US Energy Information Administration based on data from WVGES, PA DCNR, OH DGS, NY DEC, VA DMME, USGS, Wrightstone (2009). Only wells completed after 1-1-2003 are shown. Updated June 1, 2011

Figure 36. Marcellus Region Natural Gas Production (source: EIA)



To: Megan Ceronsky[mceronsky@edf.org]
From: Megan Ceronsky
Sent: Tue 12/2/2014 9:24:07 PM
Subject: Comments of EDF in Docket No. EPA-HQ-OAR-2013-0602
Att A - Laitner-McDonnell EE Analysis.pdf
Att B - Amici NY v FERC (HL) - excerpts.pdf
Att C - ATP Utility Boiler Conversion Cofiring.pdf
EDF 111d Comments FINAL.pdf

Hello—

Attached please find EDF's comments, filed yesterday, on the Clean Power Plan. We appreciate this opportunity.

Best regards,

Megan

Megan Ceronsky
Director of Regulatory Policy and Senior Attorney

Climate & Air Program

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Energy Efficiency as a Pollution Control Technology and a Net Job Creator under Section 111(d) Carbon Pollution Standards for Existing Power Plants

John A. "Skip" Laitner
Matthew T. McDonnell

Working paper prepared for the

Environmental Defense Fund

November 28, 2014

Table of Contents

Foreword

The American power sector is at a crossroadsAs states and utilities and advocates convene to think about how to comply with regulations to cut carbon emissions from our nation's fleet of power plants, it is critical that the solutions that make the most sense for consumers are pushed to the forefront

America has an opportunity to build a solid foundation for future economic growth by investing in common sense solutions like energy efficiency that cut emissions while reducing waste and saving American families and businesses money.

Energy efficiency is the most cost-effective means of meeting energy demand and reducing carbon emissions—because these investments more than pay themselves back in energy bill savings. As this report and other empirical evidence demonstrate, energy efficiency investments also create jobs and make our economy more competitive. By investing in energy efficiency now, we can enjoy the immediate environmental, economic, and energy-security benefits while sowing the seeds of future productivity and prosperity.

Yet as we think about undertaking a transition, and deploying cleaner energy solutions on a large-scale, it is important that we pause to ensure that these energy solutions are accessible to all customers—particularly those in our population who are the most vulnerable. And as Skip Arnold, Executive Director of Energy Outreach Colorado, a low-income energy consumer advocacy group, has pointed out, "Without extraordinary treatment, low-income households will not have access to these programs."

Under the newly proposed Clean Power Plan, EPA projects that by investing in energy efficiency household and business energy bills can decrease by about 8% by 2030.[1] *And this report shows that savings to families could be significantly greater with greater deployment of energy efficiency—securing a 15% improvement in energy efficiency by 2030 could generate annual average household savings of $157.*

Enabling demand-side energy efficiency to serve as an emission reduction compliance pathway is a smart option for consumers—but it is critical that as states begin to think about their compliance strategies, regulators and utilities address barriers to energy efficiency investments and ensure that savings will be available to all homes and businesses—especially including those in low-income communities.

As Mr. Arnold further notes, "For low-income energy efficiency/demand side management programs that target low-income housing to be effective, they must be implemented differently than similar programs that serve the general body of residential utility customers. Because of

[1] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants , at 3 -43 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

the very limited resources of low-income households and multi-family low-income housing providers, traditional rebate programs won't provide the resources necessary to make energy efficiency improvements to their facilities. In Colorado, and some other states, robust low-income energy efficiency programs delivered by utilities and nonprofit organizations have been implemented that go a long way in addressing this particular issue."

"We believe that there is an opportunity for the EPA to achieve the desired goal of reducing carbon emissions and at the same time lower home energy bills and create a safer, more comfortable home for our most vulnerable neighbors. But in order to do so, it is critical that EPA issues guidance that points to energy efficiency for low-income housing as an important and appropriate measure to achieve the desired goal. And as states look to implement Rule 111(d), ramping up low income energy efficiency programs should become a top priority."

Indeed, the potential for energy efficiency in the multifamily sector may be even greater than in other sectors of the economy: a 2009 study by Benningfield Group estimated the economic energy efficiency potential of multifamily homes at nearly 60%,[2] compared to 26% in the overall U.S. economy.[3] In addition, if states decide to implement market-based measures, they can use the proceeds to help those struggling to pay their electricity bills. For example, in the first three years of the Regional Greenhouse Gas Initiative, the ten participating Northeast and Mid-Atlantic states devoted more than $127 million from the auction of allowances to direct bill assistance.[4]

Many states and power companies have already realized the significant benefits of energy efficiency, setting energy efficiency standards and investing in efficiency retrofits and upgrades of buildings and appliances. But these programs fall far short of capturing our nation's vast energy efficiency resource, and fall short of reaching the potential to drive energy savings and cost savings with the low-income communities that could benefit most from the direct pocket-book savings.

As the Clean Power Plan is finalized, it will be a critical opportunity to mobilize investments in energy efficiency—and such investments are the right ones to prioritize if allies can use this opportunity to work together to ensure that the populations that are most in need have access to cost-saving and energy-saving programs.

[2] Benningfield Group, *U.S. Multifamily Energy Efficiency Potential by 2020*, at 4 (Oct. 2009), *available at* http://www.benningfieldgroup.com/docs/Final_MF_EE_Potential_Report_Oct_2009_v2.pdf.

[3] McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy*, at 3 exh. A (July 2009), *available at* http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy.

[4] Analysis Group, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States: Review of the Use of RGGI Auction Proceeds from the First Three-Year Compliance Period*, at 19, 21 (Nov. 2011), *available at* http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Economic_Impact_RGGI_Report.pdf.

Executive Summary

This year residences and businesses in the United States will spend an estimated $360 billion to meet our total electricity demands – to cool and light our homes, listen to music or watch television, and power our commercial and industrial equipment. Electricity purchases will further enable our access to the Internet and will filter and purify the water that is delivered to our homes, schools, and businesses each and every day.

Although we will derive many important benefits as we pay our monthly electricity bills, the current electricity generation infrastructure annually produces 3.34 million tons of sulfur dioxide (SO_2) and 1.68 million tons of nitrogen oxides (NO_x) air pollution. These and other pollutants are expected to add $125 billion or more to this year's health care costs. Power plants are also the largest source of climate-disrupting carbon pollution in the United States, emitting an estimated 2 billion metric tons of carbon dioxide (CO_2) each year. Due to human activities — primarily the combustion of fossil fuels and deforestation —the concentration of carbon dioxide and other heat-trapping gases in the atmosphere is rapidly rising. The need to mitigate CO_2 emissions is truly urgent. The emerging evidence has led prominent physicist and climate scientist James Hansen to reach the "startling conclusion" that the continued exploitation of fossil fuels threatens not only the planet, but also the survival of humanity itself.

In June 2013, President Obama directed the U.S. Environmental Protection Agency (EPA) to undertake a rulemaking to establish limits on greenhouse gas emissions from existing power plants under section 111(d) of the Clean Air Act. The language of section 111(d) is sufficiently broad to encompass a flexible, system-based approach to securing carbon pollution reductions from existing power plants. A system-based approach provides an excellent opportunity for EPA to rely on customer friendly end-use energy efficiency as a building block for determining the available emissions reductions and to consider end-use energy efficiency as a compliance mechanism through which the power sector can achieve meaningful, low-cost emission reductions.

In this report we explore whether incentivizing energy efficiency through the carbon pollution standards or other policies also represents an important opportunity for economic growth and job creation. In other words, would more productive use of electricity and reduced levels of waste actually increase our social and economic well-being? Can the billions of dollars spent each year for electricity be used in other ways to more productively strengthen our nation's economy and reduce the harms imposed by fossil fuel fired generation?

The answer is clearly yes. The evidence presented here suggests that a 20 percent electricity savings by the year 2030 can catalyze a large net consumer savings that

- supports a gain of 800,000 jobs for the American economy, while raising wages by almost $45 billion;
- increases GDP by more than $26 billion;
- reduces carbon pollution by 971 million metric tons, and sulfur dioxide and nitrogen oxides by 700,000 and 800,000 tons, respectively.

An expanded emphasis on energy efficiency can extend these benefits across all sectors of the economy.

I. Introduction

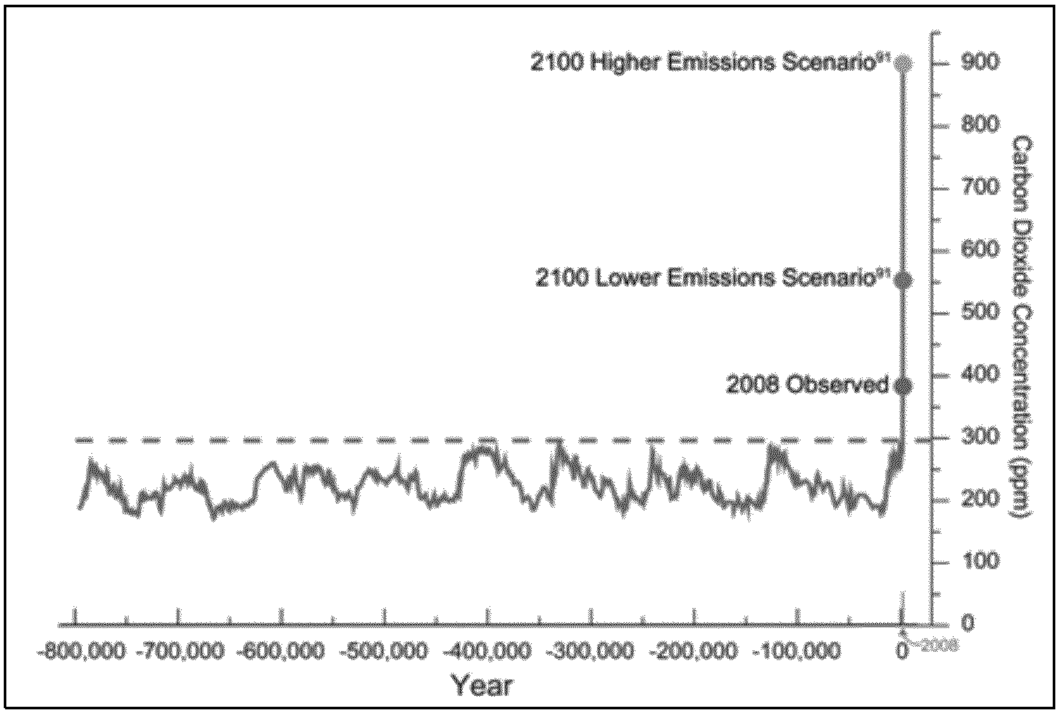
The Urgency of Action

The current electricity generation infrastructure annually produces 3.34 million tons of sulfur dioxide (SO_2) and 1.68 million tons of nitrogen oxides (NO_x) air pollution.[5] These and other pollutants were expected to add $125 billion or more to health care costs in 2013, leading to 18,000 premature deaths, 27,000 cases of acute bronchitis, and 240,000 episodes of respiratory distress. The noxious effects of these pollutants also include 2.3 million lost work days due to illness and as many as 13.5 million minor restricted activity days in which both children and adults must alter their normal activities because of respiratory health problems.[6]

Power plants are also the largest source of climate-disrupting carbon pollution in the United States, emitting an estimated 2 billion metric tons of carbon dioxide (CO_2) each year.[7] Due to human activities—primarily the combustion of fossil fuels and deforestation—the concentration of carbon dioxide and other heat-trapping gases in the atmosphere is rapidly rising. Atmospheric carbon dioxide (CO_2) levels have increased by approximately 38 percent since the Industrial Revolution (see Figure 1); current atmospheric concentrations of both CO_2 and methane (an even more potent greenhouse gas) are significantly higher than they have been for the last 800,000 years.[8]

1. *See* U.S. Dept. of Energy, Energy Info. Admin., *Annual Energy Outlook 2014 with Projections to 2040* (2014) at A19 Table A8, *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf (hereinafter EIA 2014).
2. *See* Abt Assoc. Inc., *User's Manual for the Co-Benefits Risk Assessment (COBRA) Screening Model (2010)* (author-derived estimates based on emissions scenarios for 2010 given various health effects identified by EPA's Co-Benefits Risk Assessment (COBRA) model).
3. EIA 2014. Electricity production in 2014 represents about 26 percent of our nation's total energy costs but produces 39 percent of our nation's total CO_2 emissions. *Id.* tbls. 3, 18.
4. *See* U.S. Envtl. Prot. Agency, *Technical Support Document for Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act* (2009) at ES-1 to -2 (hereinafter TSD); Intergovernmental Panel on Climate Change, *Climate Change 2007: The Physical Science Basis*, at 512 (S. Solomon et al. eds., 2007) (hereinafter IPCC 2007); U.S. Global Change Research Program, *Global Climate Change Impacts in the United States* (2009) (hereinafter USGCRP 2009).

Figure 1. 800,000-Year Record of Carbon Dioxide Concentration



Source: USGCRP (2009) at 13.

This chart shows a recent, rapid buildup in CO_2 concentrations in the atmosphere relative to the last 800,000 years, based upon analyses of air bubbles trapped in Antarctic ice. It also shows that unless we curb greenhouse gas emissions, atmospheric CO_2 concentrations will likely double or triple by the end of this century from pre-industrial levels.[9]

The increase in the amount of solar radiation that is trapped in the earth's atmosphere due to rising concentrations of greenhouse gases is causing average global temperatures to rise and presents severe risks to the health and well-being of Americans.

Rising temperatures will accelerate ground-level ozone (and smog) formation in polluted areas, and increase the f requency and duration of stagnant air masses that allow pollution to accumulate.[10] Higher ozone levels exacerbate respiratory illnesses, increasing asthma attacks and hospitalizations and increasing the risk of premature death.[11]

Rising temperatures will also result in heat waves that are hotter, longer, and more frequent.[12] Snowpacks will be smaller and snow melt accelerated, threatening water supplies in late summer in the West.[13] In addition, significant reductions in winter and spring precipitation are

5. USGCRP 2009 at 2.
6. TSD at 89-93, USGCRP 2009 at 93-94.
7. Environmental Protection Agency, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Generating Units* (March 2012) at 3-2 -3-3, 5-24 (hereinafter RIA).
8. IPCC 2007 at 750; 74 Fed. Reg. at 66524-25.
9. USGCRP 2009 at 10, 45-46.

projected for the South, especially in the Southwest, further imperiling water supplies.[14] Rising temperatures will likely increase the frequency, length, and severity of droughts, especially in the West.[15] Precipitation events in general and some types of storms, particularly hurricanes, are expected to become more intense, increasing the likelihood of severe flooding.[16] Water shortages and heavy precipitation events are likely to further stress flood control, drinking water, and wastewater infrastructure.[17]

Global sea levels are likely to rise between seven inches and four feet during the 21st century, both because of ice sheet melting and because seawater expands as it warms.[18] This amount of sea level rise, in combination with more powerful hurricanes, will increase the risks of erosion, storm surge damage, and flooding for coastal communities, especially along the Atlantic and Gulf coasts, Pacific Islands, and parts of Alaska.[19] Under a business as usual emission scenario, what is currently a once-a-century flood in New York City is projected to be twice as common by mid-century and 10 times as frequent by the end of the century.[20] With accelerated sea level rise, portions of major coastal cities, including New York and Boston, would be inundated during storm surges or even during regular high tides.[21] In the Gulf Coast area, an estimated 2,400 miles of major roadways are at risk of permanent flooding within 50 to 100 years due to anticipated sea level rise in the range of 4 feet.[22]

Due to ocean absorption of carbon dioxide, ocean acidity has increased 25 percent since pre-industrial times.[23] If atmospheric carbon dioxide doubles, oceanic acidity will also increase, leaving almost nowhere in the ocean where coral reefs can survive and threatening the ocean's food webs, which rely upon coral reefs as fish nurseries and planktonic animals that may be unable to survive a more acidic sea.[24] The loss of healthy ocean ecosystems would have devastating effects on the global food supply.

In addition, the more temperatures rise, the greater the risk that disruptive climate change thresholds could be reached more quickly. This, in turn, could generate abrupt environmental changes with potentially catastrophic impacts for natural systems and human societies.[25]

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10. USGCRP 2009 at 30; 74 Fed. Reg. at 66,532.
11. USGCRP 2009 at 30, 41-46; IPCC 2007 at 262-263, 783; 74 Fed. Reg. at 66,532-34; RIA at 3-5, 3-8..
12. USGCRP 2009 at 34-36, 44, 64; TSD at ES-4, 115; AR4, IPCC 2007 at 783; 74 Fed. Reg. at 66,525.
13. USGCRP 2009 at 47-51, 132-36; 74 Fed. Reg. at 66,532-33.
14. USGCRP 2009 at 37, 150; AR4, IPCC 2007 at 750.
15. USGCRP 2009 at 12, 36, 109-10, 142-43, 149-50. Super Typhoon Haiyan that roared into the Philippines and Vietnam in early November 2013 provides an unfortunate glimpse of future impacts. Officials predicted that the death toll could exceed 10,000 -- or more. *See* http://www.cbsnews.com/8301-202_162-57611690/typhoon-haiyan-slams-into-northern-vietnam/.
16. USGCRP 2009 at 109-10. "Superstorm Sandy" may be another example of these future impacts. It was the deadliest and most destructive hurricane of the 2012 Atlantic hurricane season, as well as the second-costliest hurricane in United States history. *See* http://en.wikipedia.org/wiki/Hurricane_Sandy.
17. USGCRP 2009 at 150.
18. USGCRP 2009 at 62.
19. RIA at 3-9.
20. RIA at 3-7, 3-9 – 3-10; National Research Council, *Advancing the Science of Climate Change* at 55-56, 59-60 (2010), *available at* http://www.nap.edu/openbook.php?record_id=12782.
21. USGCRP 2009 at 26; National Research Council, *Abrupt Climate Change, Inevitable Surprises* at v, 16, 154 (2002); US Climate Change Science Program, *Abrupt Climate Change* at 10 (2008); TSD at 66.

The need to act to mitigate these harms is truly urgent. These circumstances and the emerging evidence have led prominent physicist and climate scientist James Hansen to reach the "startling conclusion" that the continued exploitation of fossil fuels threatens not only the planet, but also the survival of humanity itself (Hansen 2009 at ix). Furthermore, the continued inefficient use of energy will contribute to a further weakening of the U.S. economy.[26] As we shall see in this analysis, for example, the inefficient use of electricity will cost the economy nationwide an estimated 800,000 jobs by 2030, which means$44 billion in lost wages in that year.

The Opportunity in Acting

There is little question that the production and use of electricity hold great economic value for the United States. But there is also little question that the curre nt infrastructure of fossil fuel fired electricity generation and electricity usage patterns are imposing heavy burdens on Americans in the form of health impacts, climate destabilization, water consumption, and job loss. In this report we ask the question of whether there is an opportunity cost being overlooked by current patterns of production and consumption of electricity. In other words , can more productive use of electricity and reduced waste actually increase our social and economic well-being? In short, can the billions of dollars spent each year for electricity be used in other ways to strengthen our nation's economy and reduce the harms imposed by fossil fuel fired generation? The answer is clearly yes.

In this working paper we set out to explore two questions. First we ask : How big is the energy efficiency resource? That is, h ow big of a benefit can energy efficiency deliver if seen as a pollution control strategy? And w hat scale of investment is required to drive reductions in conventional air pollution as well as greenhouse gas emissions ? Second, we provide a first order review of the jobs and economic impacts of efficiency -led emissions reductions. We provide an initial estimate of cost -effectiveness of the energy efficiency resource, and then explore how that change in spending might impact the nation's ability to support a greater number of jobs. With that backdrop, Section II of this paper examines the evidence of previous assessments to identify both the scale and the cost-effectiveness of energy efficiency in ways that might inform our investigation here . In Section III we provide an overview of the methodology we use to estimate the economic impa cts of increased investment in energy efficiency. Section IV summarizes the major results of this inquiry while Section V offers several conclusions and observations. Section VI identifies the many references that guided our inquiry. Finally, Appendix A p rovides an extended review of the energy efficiency resource while Appendix B presents further details about the economic model used to complete th is assessment.

22. Laitner 2013.

II. The Energy Efficiency Resource Potential

Energy efficiency has played a surprisingly endu ring and critical role in our nation's economy. Efficiency is an incredibly low -cost resource and its benefits are wide -ranging and significant. These benefits include both reduced energy bills and a surprising number of non -energy benefits, from reduced o perations and maintenance costs at industrial plants to improved quality and speed in the production of our nation's goods and services.[27] Not only could energy efficiency drive down emissions, mitigate adverse health effects, and bring down health costs associated with "business-as-usual" energy use, but these more productive investments could also stimulate a more robust economy by reducing the cost of energy services and spurring job creation.[28]

When it comes to the energy efficiency resource potentia l, current investments are still just scratching the surface. Building on Ayres and Warr (2009), [29] Laitner (2013) estimates that the U.S. economy is about 14 percent energy (in)efficient, with 86 percent of applied energy wasted in the production of goods and services.[30] What we waste in the generation and use of electricity is more than Japan needs to power its entire economy . Some progress has been made, however: investments in greater energy productivity, since 1970, have resulted in the U.S. economy consuming half the energy it would have otherwise required in 2010.[31]

Energy efficiency is a dynamic and long -term resource, as more fully described in Appendix A.[32] In fact, a McKinsey study estimates that, if executed at scale, a holistic approach to efficiency would yield gross energy savings worth more than $1.2 trillion , an amount well above the $520 billion needed through 2020 for upfront investment in efficiency measures (excluding program costs). [33] Such a program is estimated to reduce end -use energy consumption in 2020 by 9.1 quads, roughly 23 percent of projected demand, potentially abating up to 1.1 gigatons of greenhouse gases (GHG) annually. [34] However, the full energy efficiency potential includes more than simply the penetration of known advanced technologies. If we were to embrace a greater rate of infrastructure improvements along with

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23. *See* Lazard, Ltd., "Levelized Cost of Energy Analysis—Version 7.0" (2013).
24. By reducing U.S. energy use by 30 percent in 2020 and 55 percent in 2050, Laitner et al. (2010) estimate a range in savings per household from $81 in 2020 to $849 per household in 2050 as well as an increase in net jobs from 373,000 jobs created in 2020, 689,000 in 2030, and over 1.1 million in 2050.
25. Ayres, Robert U. and Benjamin Warr. *The Economic Growth Engine: How Energy and Work Drive Material Prosperity.* Northampton, MA: Edward Elgar Publishing, Inc., 2009 (hereinafter Ayres and Warr 2009).
26. *See* John A. "Skip" Laitner, *Linking Energy Efficiency to Economic Productivity: Recommendations for Improving the Robustness of the U.S. Economy* (2013); *see also* Robert U. Ayres and Benjamin Warr, *The Economic Growth Engine: How Energy and Work Drive Material Prosperity* (2009).
27. *See* John A. "Skip" Laitner et al., *The Long-Term Energy Efficiency Potential: What the Evidence Suggests* (2012) (hereinafter Laitner et al. 2012). One quad is a quadrillion Btus which, in the form of gasoline, is sufficient energy to energy to power about 12 million cars and trucks for one year of driving. In other forms of energy one quad is sufficient maintain about 5.4 million homes at current levels of consumption.
28. *See* Amory Lovins, *Reinventing Fire: Bold Business Solutions for the New Energy Era* (2011); Laitner et al. 2012; Hannah Choi Granade et al., *Unlocking Energy Efficiency in the U.S. Economy* (2009) (hereinafter Granade et al. 2009).
29. Granade et al. 2009.
30. Granade et al. 2009. The U.S. now emits about 6.6 billion tons or gigatons of total greenhouse gas emissions per year.

some displacement of the existing capital stock to make way for newer and more productive energy efficiency technologies, as well as new configurations of the built environment that reduce the distance people and goods must be transported, by 2050, we might achieve a 59 percent reduction in total energy use compared to the business as usual Energy Information Administration projection (consuming only 50 quads versus 122 quads by the year 2050).[35]

Reducing electricity demand through energy efficiency and demand side energy management—using only available technologies—has been demonstrated to be one of the most cost-effective means of reducing GHG emissions from the power sector.[36] The 2009 McKinsey study found that, after taking into account the upfront costs of installing efficiency improvements, the efficiency measures they identified would save American families and businesses $680 billion over ten years.[37] In addition, the study estimated that it would require 600,000 to 900,000 workers during the duration of the 10-year period to develop, produce, and implement the efficiency improvements, administer the programs, and verify the results.[38] Simply put, demand side energy efficiency offers tremendous potential to reduce power sector greenhouse gas emissions while simultaneously reducing utility bills for American families and businesses, improving grid reliability, reducing co-pollutant emissions, improving energy security, and creating jobs in the energy efficiency sector.

An extensive body of studies developed over many years suggests that energy efficiency can provide perhaps the largest single source of GHG emissions reductions in the coming decades.[39] Should we reduce electricity use by just 0.1 percent per year between now and 2050,[40] a recent study by Synapse Energy Economics indicates that by 2020, power sector CO_2 emissions would fall 25 percent below 2010 levels.[41] By 2050, the combination of energy efficiency and a variety of renewable energy technologies could reduce CO_2 emissions to 81 percent below 2010 levels.[42] By pursuing the larger achievable efficiency and renewable energy targets, the Synapse assessment also found that other environmental and health impacts of coal-fired electricity are dramatically reduced. Over $450 billion in health effects

31. Laitner et al. 2012.
32. The Analysis Group notes that " RGGI investment in energy efficiency depresses regional electrical demand, power prices, and consumer payments for electricity. This benefits all consumers through downward pressure on wholesale prices, yet it particularly benefits those consumers who actually take advantage of such programs, implement energy efficiency measures, and lower both their overall energy use and monthly energy bills. These savings stay in the pocket of electricity users. But positive macroeconomic impacts exist as well: the lower energy costs flow through the economy as collateral reductions in natural gas and oil consumption in buildings and increased consumer disposable income (from fewer dollars spent on energy bills), lower payments to out-of-state energy suppliers, and increased local spending or savings. Consequently, there are multiple ways that investments in energy efficiency lead to positive economic impacts; this reinvestment thus stands out as the most economically beneficial use of RGGI dollars." *See* Hibbard et al. 2011.
33. Granade et al. 2009.
34. Granade et al. 2009.
35. Laitner et al. 2012; *see also* L.D. Harvey, *Energy Efficiency and the Demand for Energy Services* (2010); Comm. on America's Energy Future, *Real Prospects for Energy Efficiency in the United States* (2010); Granade et al. 2009; American Physical Society, *Energy Future: Think Efficiency* (2008).
36. Resulting in energy consumption of 3,760 billion kilowatt-hours (kWh) in 2050 versus 5,590 billion kWh under a business-as-usual (BAU) projection.
37. *See* Geoff Keith et al., *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* (2011) (hereinafter Keith et al. 2011).
38. Keith et al. 2011.

related to air pollution would be avoided over the 2010 to 2050 study period, based on damage factors developed by the National Research Council.[43]

The evidence indicates that energy efficiency is not only a significant resource, but it also presents an immensely cost-effective pollution control strategy—with benefits exceeding costs over the investment life of individual measures or improvements. A study by the Lawrence Berkeley National Laboratory demonstrated that one-third of electricity and natural gas use in buildings could be saved (along with respective emissions) at a total cost of 2.7 cents per kilowatt-hour (¢/kWh) for electricity and between 2.5 and 6.9 dollars per million Btu for natural gas (all values in 2007 dollars).[44] The study suggested that the cost savings over the life of the measures would be nearly 3.5 times larger than the up-front investment required (in other words, a benefit-cost ratio of 3.5). At the same time, Amann (2006) suggests that non-energy benefits of energy efficiency upgrades might range from 50 to 300 percent of household energy bill savings.[45] These added benefits range from financial savings to energy bill relief, comfort, aesthetics, noise reduction, health and safety, and convenience. Worrell et al. (2003) and Lung et al. (2005) found comparable non-energy benefits that greatly enhance the cost-effectiveness of energy efficiency within the industrial sector as well.[46]

Indeed, efficiency has shown an ability to drive down emissions and mitigate health costs associated with "business as usual" energy use. But, efficiency has also demonstrated its ability to stimulate economic growth by reducing the cost of energy services and spurring job creation. ACEEE demonstrated efficiency's significant macroeconomic impact through its analysis under two policy scenarios: the Advanced Case (42 percent energy savings from 2050 reference case) and the Phoenix Case (59 percent energy savings from 2050 reference case).[47] The study suggested the cumulative capital investments in the efficiency upgrades for the Advanced Case will be about $2.4 trillion over the 39-year period 2012 to 2050 (in constant 2009 dollars). The significantly greater magnitude of efficiency changes in the Phoenix Case increases cumulative investments to $5.3 trillion in that same time period.[48] While this may seem like a significant investment, it is but a fraction of the $4.6 trillion per year the economy is likely to invest over this same time horizon.[49]

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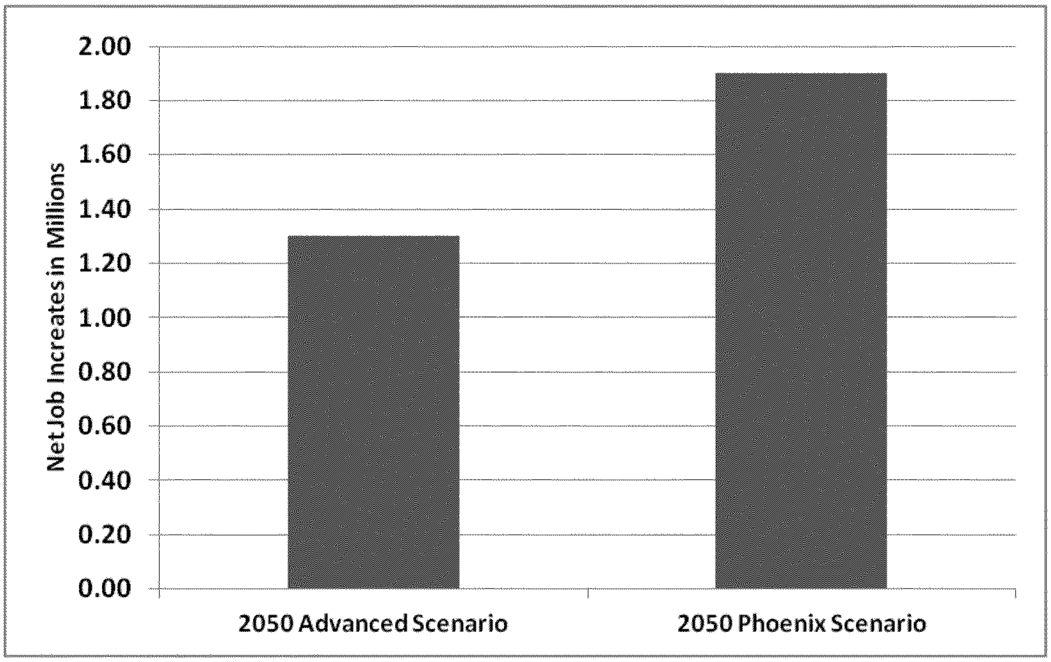
39. *Id.*
40. Rich Brown et al., *U.S. Building-Sector Energy Efficiency Potential* (2008). In 2012, the end-use price of electricity for the residential sector was 11.9¢/kWh in 2012 cents (about 10¢ in 2007 cents); in the commercial sector, 10.1¢/kWh in 2012 cents (about 9¢ in 2007 cents). AEO 2014 tbl. 8. The Henry Hub price for natural gas in April 2014 was $4.66/MMBtu, or, in 2007 dollars, $4.07. EIA, Henry Hub Natural Gas Spot Price, http://www.eia.gov/dnav/ng/hist/rngwhhdM.htm (last visited May 23, 2014); Bureau of Labor Statistics, CPI Inflation Calculator, http://data.bls.gov/cgi-bin/cpicalc.pl.
41. Jennifer Amann, American Council for an Energy-Efficient Economy, *Valuation of Non-Energy Benefits to Determine Cost-Effectiveness of Whole House Retrofit Programs: A Literature Review* (2006).
42. Ernst Worrell et al., "Productivity Benefits of Industrial Energy Efficiency Measures," *Energy*, 1081-98 (2003); Robert Lung et al., American Council for an Energy-Efficient Economy, "Ancillary Benefits and Production Benefits in the Evaluation of Industrial Energy Efficiency Measures" (2005).
43. Laitner et al. 2012.
44. See Table 2 following the discussion in section III for a further comparison of this set of efficiency scenarios with three other long-term efficiency scenarios out to 2050.
45. Laitner et al. 2012. While energy efficiency appears significantly more costly under the Phoenix Scenario, it is roughly the equivalent of just one year's routine investment spread out over a 39-year period.

Figure 2: Net Employment Benefits from Two Efficiency Policy Scenarios



Source: Laitner et al. 2012

The capital investments in efficiency generate substantial cumulative energy bill savings of $15 trillion in the Advanced Case and $23.7 trillion in the Phoenix Case (also in 2009 dollars). Hence, energy efficiency not only proves to be a prudent investment, but it also delivers substantial economic savings that would drive a significant increase in overall employment (see Figure 2 above). The Advanced Case shows that investment in efficiency would produce a 1.3 million job gain in the year 2050. Perhaps unsurprisingly, efficiency investment in the Phoenix Case, benefiting from a larger investment and a bigger net energy bill savings, generates about a 1.9 million job gain in 2050.[50]

III. Assessing Total Employment Impacts

Having established that energy efficiency is an indispensable and cost-effective resource to reduce air pollution and greenhouse gas emissions, we now provide an analytical framework to evaluate the net economic and employment impacts of this resource. We utilize the U.S. Energy Information Administration's annual modeling to establish a reference case, or "business as usual" (BAU) scenario. We compare this to an "Efficiency-Led Scenario" in which the country moves toward a power system based on more productive investments in energy efficiency technologies, systems, and infrastructure. In this alternative scenario, a greater level of energy-efficient investments enables both new demands for energy services and the retirement of some existing electricity generation power plants. In this section we lay out three elements that form the basis of our assessment: (1) the standard projection for U.S. electricity consumption over the period 2012 through 2030; (2) the key characteristics of the alternative

46. Laitner et al. 2012.

investment scenario; and finally, (3) a description of the DEEPER modeling system used to evaluate the efficiency scenarios characterized in this report.

A. The Business-as-Usual Backdrop

The foundation for this assessment is the *Annual Energy Outlook* published by the Energy Information Administration (2012).[51] Although the forecast of energy and other market trends covers all uses of energy within our economy (including transportation fuels, natural gas, and other resources), here we will explore possible changes in our nation's electricity use beginning in 2012 through the year 2030. This includes the growth in the number of households, commercial, and industrial customers over that time along with the anticipated growth in the demand for electricity services by those users. It also includes both expected trends in electricity prices as well as a discussion of potential drivers of important shifts in electricity demand. In addition, since we are exploring the impacts on the economy, we will review the anticipated growth in the nation's jobs and Gross Domestic Product (GDP), also through the year 2030. Table 1 below provides the assumed reference case projections for key metrics against which we will compare the impacts of an efficiency-led scenario.

Table 1. Reference Case Projections for Key Economic Metrics 2012 and 2030

Metric	2012	2030	Annual Rate	Total Growth
The Macroeconomy				
GDP (billion 2005 dollars)	13,486	21,736	2.7%	61.2%
Real Investment (billion 2005 dollars)	1,875	4,066	4.4%	116.9%
Households (millions)	116.1	139.3	1.0%	20.0%
Nonfarm Employment (millions)	131.8	162	1.2%	22.9%
Electricity Sales				
Economy-Wide Electricity Use (billion kWh)	3,729	4,258	0.7%	14.2%
Average Retail Electricity Price (2010 $/kWh)	0.096	0.098	0.1%	2.1%
Annual Electricity Costs (billion 2010 dollars)	358.0	417.3	0.9%	16.6%
Emissions from Power Plants				
Sulfur Dioxide (million short tons)	3.79	1.62	-4.6%	-57.3%
Nitrogen Oxides (million short tons)	1.99	1.94	-0.1%	-2.6%
Carbon Dioxide (million metric tons equivalent)	2,146	2,258	0.3%	5.2%

Source: EIA (2012)

The summary in Table 1 above forecasts several positive trends even under the reference scenario. First, EIA projects the economy will grow at a faster clip than either the number of households or their increased use of electricity consumption, as measured by EIA's assessment of the nation's GDP. Jobs will also increase. While electricity expenditures will grow as well, they will rise more slowly than GDP. EIA's forecast clearly anticipates that the economy will make increasingly efficient use electricity to provide the nation's homes and businesses with needed goods and services.

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47. As the project first began, we originally benchmarked the analysis described here to the energy and economic projections found in the *Annual Energy Outlook 2012* (EIA 2012). While we cite the updated information contained in *Annual Energy Outlook 2013* (EIA 2013), our analysis is still linked to EIA 2012. A series of quick diagnostic tests shows this does not materially impact the findings of this assessment.

Yet the business-as-usual rate of efficiency improvement still requires an increase in overall electricity consumption since the economy is projected to grow more quickly than the rate of efficiency improvement. While pollution control technologies are likely to reduce future air pollution from emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), as shown in Table 1, carbon dioxide (CO_2) emissions are likely to increase due to the increased fossil fuel combustion associated with the generation of electricity.[52]

Fortunately, we can do much better. We can reduce overall pollution levels and, at the same time, lower the nation's total electricity bill. The many studies summarized in Section II of this report indicate that a much larger set of energy efficiency gains beyond the business-as-usual improvements is possible. This is true for the residential, the commercial, and the industrial sectors of the economy. For example, if the energy efficiency opportunities highlighted in the study by Laitner et al. (2012) were to be developed and implemented, the total electricity demand for 2030, as shown in Table 1, would *decline* to 3,370 billion kilowatt-hours rather than *increase* to 4,258 billion kilowatt-hours.[53] What may be less obvious, however, is that the efficiency gains will prove to be less expensive than increasing the generation capacity to meet the higher electricity demands.

Finally, some readers may be surprised to learn how much the economy depends every year on the flow of normal investments as they affect our nation's homes, schools, businesses, roads, and bridges, as well as the many electric power plants, transmission lines, and industrial facilities needed to maintain a functioning economy. In Table 1 it appears that we will invest about $1,875 billion in new buildings and infrastructure, or in routine upgrades to existing infrastructure. By 2030 this will grow to an estimated $4,066 billion or about 18.7 percent of GDP. As we might imagine, and as shown in the analysis that follows, redirecting even one percent of the nation's annual investment to greater gains in electricity efficiency can provide the foundation to achieve a significant level of cost savings compared to the normal rate of energy efficiency improvements. In addition, as we shall also see, more productive investments will drive a small but positive gain in the nation's job market and achieve a cost-effective reduction in the nation's air pollution and greenhouse gas emissions. The next section of this working paper explores the cost and performance characteristics that might contribute to cost-effective electricity reductions in our homes, schools and businesses.

B. Key Attributes of the Energy Efficiency Scenario

In this assessment, we draw upon two previously referenced studies to define an exploratory scenario that helps evaluate energy efficiency as a pollution control strategy; and, more critically, to explore how energy efficiency investments might drive both significant cost savings

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48. Including transportation and other fuels such as natural gas, the energy-related CO_2 emissions are projected to grow from 5,570 to 5,670 million metric tons at a time when the scientific evidence suggests the need for very steep reductions in greenhouse gas emissions. As noted previously, total greenhouse gas emissions are estimated to be just under 7,000 million metric tons (or gigatons). The difference is the number of other non-energy-related CO_2 emissions which also contribute the total mix of greenhouse gases emitted each year.
49. Laitner, John A. "Skip," Steven Nadel, R. Neal Elliott, Harvey Sachs, and Siddiq Kahn. 2012. *The Long-Tern Energy Efficiency Potential: What the Evidence Suggests*. Washington, DC: American Council for an Energy-Efficient Economy.

and overall gains in employment. The first assessment is from Laitner et al. (2012), which explored the long-term energy efficiency potential for two scenarios through the year 2050.[54] That report examined a more complete set of efficiency options, including natural gas and petroleum efficiency improvements as well as electricity savings from all sectors of the economy. The second is Keith et al. (2011), a report from Synapse Energy Economics that focused explicitly on electricity savings alone.[55] Both assessments found that productive investments in energy efficiency upgrades generated a net positive economic benefit. Although both studies indicate that electricity savings of 30 to 37 percent from the reference case projected for 2050 are possible, the central case of this analysis is an assessment of the economic impacts of achieving a 20 percent efficiency gain by 2030.

To provide a sense of scale and cost-effectiveness of the efficiency resource more broadly, Table 2 highlights key metrics from both the ACEEE and Synapse scenarios. We also include two other studies: the *Energy Technology Perspectives* study published by the International Energy Agency (IEA/ETP 2010) and *Reinventing Fire* released by Lovins et al. (2011).[56]

Table 2. Key Metrics from Year 2050 Alternative Energy Future Studies

	Year 2050 Impacts				
Metric	ACEEE-Advanced	ACEEE-Phoenix	IEA ETP	Reinventing Fire	Synapse[1]
BAU GDP Index (2010 = 1.00)	2.79	2.79	1.95	2.58	2.71
BAU Energy Use (2010 = 1.00)	1.24	1.24	1.05	1.27	1.41
Efficiency Scenario Energy Use (2010 = 1.00)	0.72	0.51	0.47	0.69	0.67
Investment (Trillion 2009 Dollars)[2]	2.9	6.4	5.9	4.5	1.4
Savings (Trillion 2009 Dollars)[2]	15.0	23.7	15.1	9.5	4.4
Index Savings to Investment[3]	5.2	3.7	2.6	2.1	3.5

Table Notes: (1) While the first four studies reflect economy-wide energy savings, the Synapse report captures only the savings from electricity production and consumption. (2) The investments and savings data reflect cumulative values in constant dollars over the period 2010 through 2050. (3) The savings to investment index is a simple comparison of suggested energy bill savings compared to the total cost of investments, also over the period 2010 through 2050. Because there is no way to compare the discounted streams of savings and expenditures over time, this simple index is indicative of, but should not be construed as, a true benefit-cost ratio.

Interestingly, there is a wide range in the assumed future GDP growth among the five scenarios outlined in Table 1. The IEA projects an economy in 2050 that is about 1.95 times bigger than in 2010. ACEEE and Synapse, generally following the EIA's *Annual Energy Outlook*, suggest economic activity that will be 2.71 to 2.79 times larger than 2010. Reinventing Fire suggests a more moderate growth path so that economic activity is 2.58 times larger in 2050 compared to 2010. In comparing the business-as-usual energy growth in

50. Laitner, John A. "Skip," Steven Nadel, R. Neal Elliott, Harvey Sachs, and Siddiq Kahn. 2012. *The Long-Tern Energy Efficiency Potential: What the Evidence Suggests*. Washington, DC: American Council for an Energy-Efficient Economy.
51. Keith et al. 2011.
52. [IEA/ETP] International Energy Agency, Energy Technology Policy Division. 2010. *Energy Technology Perspectives: Scenarios & Strategies to 2050.* Paris, France: International Energy Agency; Lovins, Amory and the Rocky Mountain Institute. 2011. *Reinventing Fire: Bold Business Solutions for the New Energy Era*. White River Junction, VT: Chelsea Green Publishing.

the five scenarios with their respective 2050 efficiency gains, the evidence suggests potential 2050 savings that range between 42 and 59 percent.[57] Moreover, all of the scenarios suggest a net positive savings to investment ratio, ranging from 2.1 to 5.2 over the period of analysis within each scenario. To test the idea of how effective efficiency might be as a pollution control strategy, but reflecting larger uncertainties in the out-years, we take the analysis here to only 2030.

Our core scenario for this exploration assumes an electricity savings that, beginning in 2014, slowly ratchets up to reach 20 percent by 2030. The benefit-cost ratio of this scenario (as we shall see) is over 2.0. As we explain further in the section that follows, we assume that program costs will drive investments that, in turn, generate a 20 percent reduction in conventional electricity generation by 2030 so that the electricity savings, in constant dollars, are twice as large as the combination of program costs and investments, also in constant dollars.

We next turn to a description of the Dynamic Energy Efficiency Policy Evaluation Routine, or the DEEPER, Modeling System, which, in essence, is an econometric input-output analytical tool. Although recently given a new name, the model's origins can be traced back to modeling assessments that were first completed in the early 1990s (see Appendix B for historical information and other details on the DEEPER model).

C. Review of the DEEPER Economic Policy Model

The DEEPER model is "quasi-dynamic" in that the costs of energy efficiency improvements are based on the level of efficiency penetration over some period of time. The greater the efficiency penetration, the higher the costs, and the resulting payback periods begin to increase. Moreover, the model adjusts labor impacts given the anticipated productivity gains within key sectors of the U.S economy. As an example, if the construction and manufacturing sectors increase their output as a result of the alternative policy scenario, the employment benefits are likely to be affected – depending on assumptions about the expected labor productivity gains within each of those sectors.

Input-output models initially were developed to trace supply linkages in the economy. For instance, an input-output accounting framework can show how purchases of lighting technologies or industrial equipment benefit the lighting and other equipment manufacturers in a state. In addition, because the input-output model has coefficients linking both directly and indirectly affected industries, the model can also reveal the multiplicative impacts that such purchases are likely to have on other industries and businesses that might supply the necessary goods and services to those manufacturers.

The net economic gains of any new investments in energy efficiency will depend on the structure of the economy, and which sectors are most affected by changes in new spending patterns that are promoted by investments in energy productivity rather than electricity supply.

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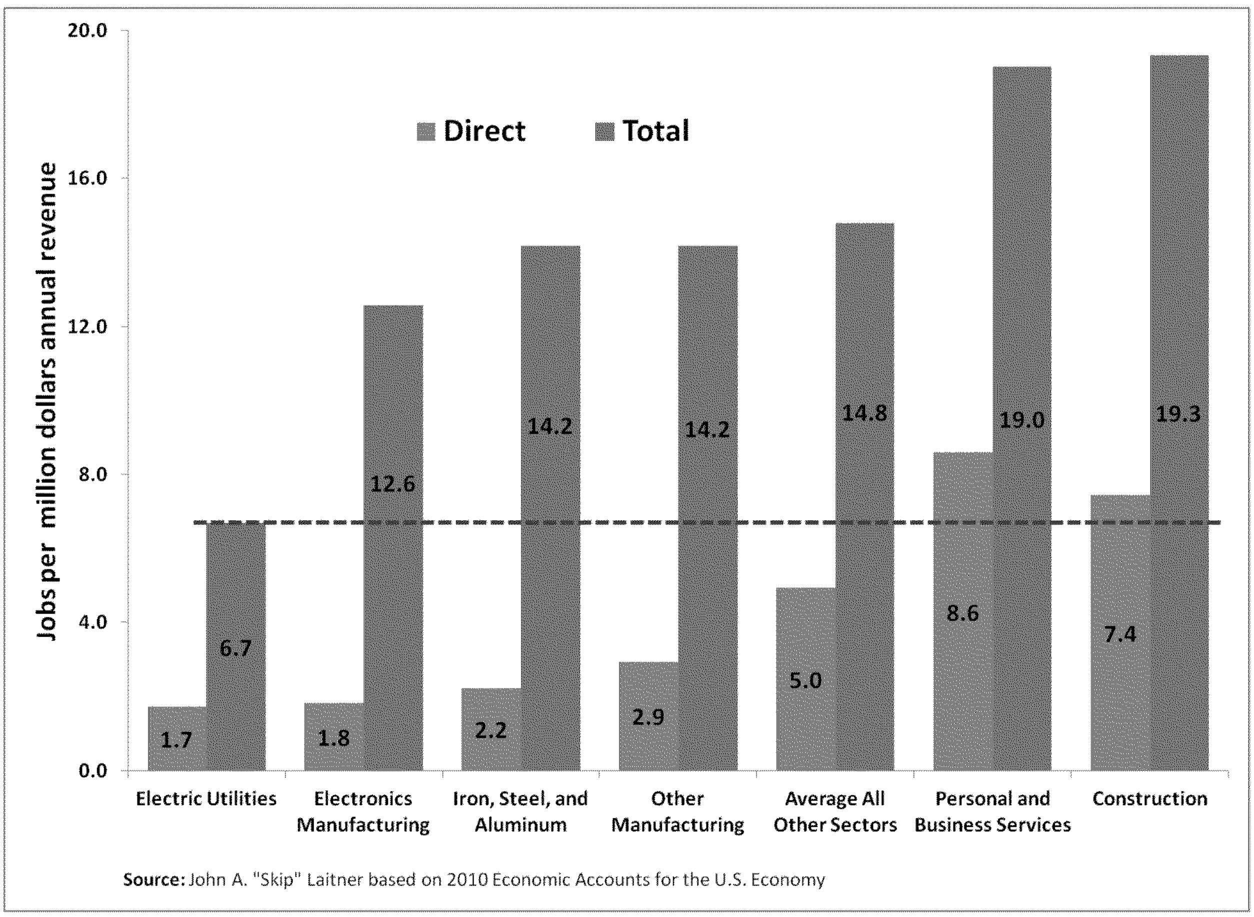
53. As an example, the Synapse study projects a BAU energy growth index of 1.41, with an efficiency use index that falls to 0.67. Hence, (0.67 / 1.41 – 1) *100 percent = 52 percent.

To illustrate this point, Figure 3, below, compares the direct and total employment impacts that are supported for every one million dollars of revenue received by different sectors of the U.S. economy. These include electric utilities, manufa cturing, personal and business services, and construction.[58] For purposes of this study, a job is defined as sufficient economic activity to employ one person full-time for one year.

Figure 3. Labor Intensities for Key Sectors of the U.S. Economy



Of immediate interest in Figure 3 is the relatively small number of direct and total jobs supported by energy sector spending . Within the U nited States the electric utility industry provides, for example, only 6.7 total jobs per million dollars of revenues that it receives. This total includes jobs directly supported by the industry as well as those jobs linked to businesses which, in turn, provide goods and services to maintain the utilities' operation. And it also includes the additional jobs supported b y the respending of wages within the U.S. economy.

54. The model used for the assessment described here relies on the IMPLAN datasets for the United States. IMPLAN stands for "IMpact Analysis for PLANning." These 2010 historical economic accounts (IMPLAN 2012) provide a critical foundation for a wide range of modeling techniques, including the input -output model used as a basis for the assessment described he re. For more information on the use of this kind of analysis, see the discussion in Appendix B of this report. F or a more recent example of an assessment undertaken in the policy arena, see Busch et al. (2012) for an analysis of the recently adopted fuel-economy standards.

On the other hand, one million dollars spent in construction supports a total of 19.3 jobs, both directly and indirectly.

As it turns out, much of the job creation from energy efficiency programs is derived by the difference between jobs within the utility supply sectors and jobs that are supported by the respending of energy bill savings in other sectors of the economy.

D. An Illustration: Jobs from Improvements in Commercial Office Buildings

To illustrate how a simplified job impact analysis might be done, we will use the example of installing one million dollars of efficiency improvements in a large office building. Office buildings (traditionally large users of energy due to heating and air-conditioning loads, significant use of electronic office equipment, and the large numbers of persons employed and served) provide substantial opportunities for energy-saving investments. The results of this example are summarized in Table 3 below.

The assumption used in this example is that the investment has a positive 4-year payback. In other words, the assumption is that for $1 million of energy efficiency improvements, the upgrades might be expected to save an average of $250,000 in reduced electricity costs over the useful life of the technologies. This level of savings is conservatively low but consistent with the low end of ranges cited elsewhere in this report. At the same time, if we anticipate that the efficiency changes will have an expected life of roughly 15 years, then we can establish a 15-year period of analysis. In this illustration, we further assume that the efficiency upgrades take place in the first year of the analysis, while the electricity bill savings occur in years 1 through 15. Moreover, we assume that only half the savings occur in the first year as it may take several months to actually start an average project with savings not beginning until halfway through the year.

Table 3. Job Impacts from Government Building Energy Efficiency Improvements

Expenditure Category	Amount (Million $)	Employment Coefficient	Job Impact
Installing Efficiency Improvements in Year 1	1.0	19.3	19.3
Diverting Expenditures to Fund Efficiency Improvements	-1.0	14.8	-14.8
Energy Bill Savings in Years 1 through 15	3.6	14.8	53.3
Lower Utility Revenues in Years 1 through 15	-3.6	6.7	-24.1
Net 15-Year Change			33.7

Note: The employment multipliers are taken from the appropriate sectors found in Figure 2. Based on the efficiency costs described in the text, the annual savings are about $250,000 with only one-half available in the first year. The jobs impact is the result of multiplying the row change in expenditure by the appropriate row multiplier. On average, this building upgrade would be said to support a net gain of about 2.2 jobs per year for 15 years. For more details, see the text that follows.

The analysis further assumes that we are interested in the *net effect* of employment and other economic changes. This means we must first examine all changes in business or consumer expenditures—both positive and negative—that result from a movement toward energy efficiency. Each change in expenditures must then be multiplied by the appropriate multiplier (taken from Figure 3) for each sector affected by the change in expenditures. The sum of these products will then yield the net result.

In our example, there are four separate changes in expenditures, each with their separate effect. As Table 3 indicates above, the overall impact of the scenario suggests a gain of 33.7 job-years (rounded) in the 15-year period of analysis. This translates into an average gain of about 2.2 jobs each year for 15 years. In other words, the efficiency investment made in the office building is projected to sustain an average gain of 2.2 jobs each year over a 15-year period compared to a "business-as-usual" scenario. Roughly speaking, if comparable projects like this scaled to more like $100 million in a single year , the number of jobs gained would similarly scale upward (to 3,370 job-years).[59]

E. Appropriate Modifications in the Energy Efficiency Scenarios

The economic assessment of the alternative energy scenarios was carried out in a very similar manner as the example described above. That is, the changes in energy expenditures brought about by investments in energy efficiency and renewable technologies were matched with their appropriate employment multipliers. There are several modifications to this technique, however.[60]

First, it was assumed that only 90 percent of both the efficiency investments and the subsequent savings are spent within the United States. We based this initial value on the 2010 IMPLAN dataset as it describes local purchase patterns that typically now occur in the United States. We anticipate that this is a conserv ative assumption since most efficiency projects are likely to be (or could be) carried out entirely by contractors and dealers within the United States. By way of illustration, if the share of domestic spending turned out to be 100 percent, for example, the overall job gain might grow another five percent or more compared to our standard scenario exercise.

Second, an adjustment in the employment impacts was made to account for assumed future changes in labor productivity. As outlined in t he Bureau of Labor Statistics *Outlook 2010–2020*, productivity rates are expected to vary widely among sectors.[61] For instance, the BLS projects an economy-wide 1.5 percent annual average productivity gain as the economy better integrates information techno logies and other improvements . To illustrate the impact of productivity gains on future employment patterns, let us assume a typical labor productivity increase of 2.2 percent per year. This means, for example, that compared to 2012, we might expect that a $1 million expenditure in the year 2030 will support only 6 8 percent of the number of jobs as in 2012.[62]

Third, for purposes of estimating electricity bill savings, it was assumed that current electricity prices for the residential, commercial, and industrial sectors in the United States would follow the same growth rate as those published by the Energy Information Administration in its *Annual Energy Outlook* 2012.[63]

Fourth, it was assumed that the large -scale efficiency upgrades are financed by bank loans that carry an average 6 percent interest rate over a 5-year period. While this does raise the

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55. While this idea of scale more or less holds true, as costs begin to rise with a greater level of penetration of energy efficiency measures, the idea of diminishing returns could reduce overall cost-effectiveness of individual scenarios as a function of the total level of savings that might be achieve – in this case, for the year 2030. See generally the discussion on this point as highlighted by Table 6 that follows the main finding of this exploratory effort.
56. For a historical review of how this type of analysis is carried out, see Laitner, Bernow, and DeCicco (1998).
57. Bureau of Labor Statistics. 2012. Economic and Employment Projections 2010 to 2020. Washington, DC: U.S. Department of Labor. (Available at: http://www.bls.gov/news.release/ecopro.toc.htm).
58. The calculation is $1/(1.022)^{18} * 100$ equals 1/1.4796 * 100, or 68 percent.
59. EIA 2012.

cost to end -users as a result of the interest that must be paid on bank loans, raising or lowering the interest rates in this analysis will not appreciably affect the results otherwise reported. Also, to limit the scope of the analysis, no parameters were established to account for any changes in interest rates as less capital -intensive technologies (i.e., efficiency investments) are substituted for conventional supply strategies, or in labor participation rates — all of which might affect overall spending patterns.

While the higher cost premiums associated with the energy efficiency investments might be expected to drive up the level of borrowing (in the short term), and therefore interest rates, this upward pressure would be offset to some degree by the investment avoided in new power plant capacity, exploratory well drilling, and new pipelines. Similarly, while an incre ase in demand for labor would tend to increase the overall level of wages (and thus lessen economic activity), the job benefits are small compared to the current level of unemployment or underemployment. Hence, the effect would be negligible.

Fifth, for the buildings and industrial sectors it was assumed that a program and marketing expenditure would be required to promote market penetration of the efficiency improvements. Based on other program reviews, this was set at 15 percent of the efficiency investment in the early years but declining to 5 percent of the much larger investments in the last year of the assessment.[64]

Finally, it should again be noted that, by design, this analysis does not account for the full effects of the efficiency investments s ince the savings beyond 2030 are not incorporated into the modeling assumptions. Nor does the analysis include other productivity benefits that are likely to stem from the efficiency investments. These can be substantial, especially in the industrial secto r. Industrial investments that increase energy efficiency often advance other economic goals such as improved product quality, lower capital and operating costs, increased employee productivity, or capturing specialized product markets.[65] To the extent the se "co-benefits" are realized in addition to the energy savings, the net economic impacts would be amplified beyond those reported here.

IV. Economic Impact of a Cost-Effective Energy Efficiency Scenario

The investment and savings data from the efficiency identified above (again reaching a 20 percent electricity savings through efficiency gains by 2020) were used to estimate the financial and the economy -wide impacts for the key benchmark years of 2014, 2020, 2025, and 2030. Each change in sector spending was evaluated by the Investment and Spending module within the DEEPER model for a given year —relative to the baseline or business -as-usual scenario. These were then matched to their appropriate sector impact coefficients.

60. The assumption here is that program spending is necessary to encourage, monitor, and verify the requisite efficiency gains. In addition, training programs as well as increased research & development expenditures may also be needed to improve technology performance and market penetration. This range is generally con sistent with the findings of Friedrich et al. (2009). For other examples that integrate program spending into efficiency policy assessments, see Laitner et al. (2010) among other studies.
61. For a more complete discussion on this point, see Elliott, Laitner, and Pye (1997) and Worrell et al. (2003).

These changes were further evaluated by DEEPER's macroeconomic module to estimate the larger overall job and wage benefits for the U.S. economy.

Starting with very small impacts in 2014, the end -use energy efficiency target of a 20 p ercent savings by 2030 spur s both program costs and technology investments that, in turn, begin to change the patterns of electricity consumption and production. Program spending of $ 635 million in 201 4 is assumed to drive an initial $ 4,231 million in tech nology investments in that year. But these investments are assumed to be financed over time so that the actual outlays in 2014 are only $ 1,004 million. The initial impacts on electricity production are relatively small, reducing electricity bills by an est imated $2,834 million (about 0. 8 percent of the reference case electricity expenditures otherwise projected in that year). However, both program spending and the annualized efficiency payments rise to 2.3 and 39.5 billion dollars by 2030, respectively.

Table 4. Key Annual Financial and Economic Impacts from the Efficiency Scenario

	2014	2020	2025	2030	Average 2014-2030
Financial Costs (Million 2010 $)					
Program Costs	635	843	1,532	2,259	1,229
Efficiency Investments	4,231	8,486	21,741	45,184	17,040
Annualized Efficiency Payments	1,004	8,258	18,956	39,533	8,053
Energy Bill Savings	2,834	23,785	52,451	87,977	26,703
Net Energy Bill Savings	1,196	14,683	31,963	46,185	17,420
Cumulative Net Energy Savings	1,196	50,714	175,883	381,146	381,146
Net Savings per Household (actual $)	6	62	121	147	84
Macroeconomic Impacts					
Employment (actual)	49,504	206,419	484,032	818,827	316,612
Percent from Reference Case	0.04%	0.14%	0.31%	0.51%	
Wages (Million 2010 $)	2,453	9,868	24,877	44,503	16,295
Percent from Reference Case	0.03%	0.10%	0.25%	0.42%	
GDP (Million 2010 $)	2,262	4,261	13,752	26,262	8,869
Percent from Reference Case	0.01%	0.03%	0.07%	0.12%	

Source: Analysis as described in the text of the working paper.

The net savings on electricity bills (i.e., the savings after program costs and the annual payments for investments have been paid) exceeds $ 46 billion (rounded) in 2030, which is about 11 percent of the nation's reference case electricity bill for that year. The net residential or household savings start at only $ 6 in 2014, slowly increasing to $ 62 in 2020, and then rise steadily to an annual $147 savings for an average household by 2030.

As might be expected, the program spending and changed investment patterns have a distinct economic impact. The second set of impacts in Table 4 highlights the key employment and wage benefits for the same ye ars. Overall employment benefits begin with about 49,504 jobs in 2014, but grow steadily as both investments and electricity savings increase over time. By 2030, the total job gain reaches 818,827 jobs, about 0. 51 percent of the jobs otherwise available in that year. Wages associated with the added jobs similarly increase to just short of $45 billion by 2030.

Table 5. Net Employment Impacts (Actual Jobs)

	2014	2020	2025	2030	Average 2014-2030
Overall Jobs Impacts	49,504	206,419	484,032	818,827	353,860

Source: Analysis as described in the text of the working paper.

We also ran a series of sensitivity simulations to test the robustness of the 20 percent savings target in 2030. Table 6, below, summarizes those findings. In effect, we compare the year 2030 savings target with the net savings (in millions of 2010 dollars) in that year, the average savings per household (in actual but still constant 2010 dollars) also in 2030, and finally, the overall job gain that might be created in that last year of the efficiency scenario. In addition, we provide a benefit-cost ratio that discounts the savings and the program and investment costs over the period 2014 through 2030 using a 5 percent discount rate.

Table 6. Net Benefits as a Function of Efficiency Target

2030 Target	BCR	Average/HH	Net Savings	Net Jobs
5%	4.2	72	18,217	169,112
10%	3.3	127	33,036	350,199
15%	2.6	157	43,194	563,013
20%	2.1	147	46,185	818,827
25%	1.7	73	38,089	1,145,333
30%	1.3	-101	12,986	1,590,403

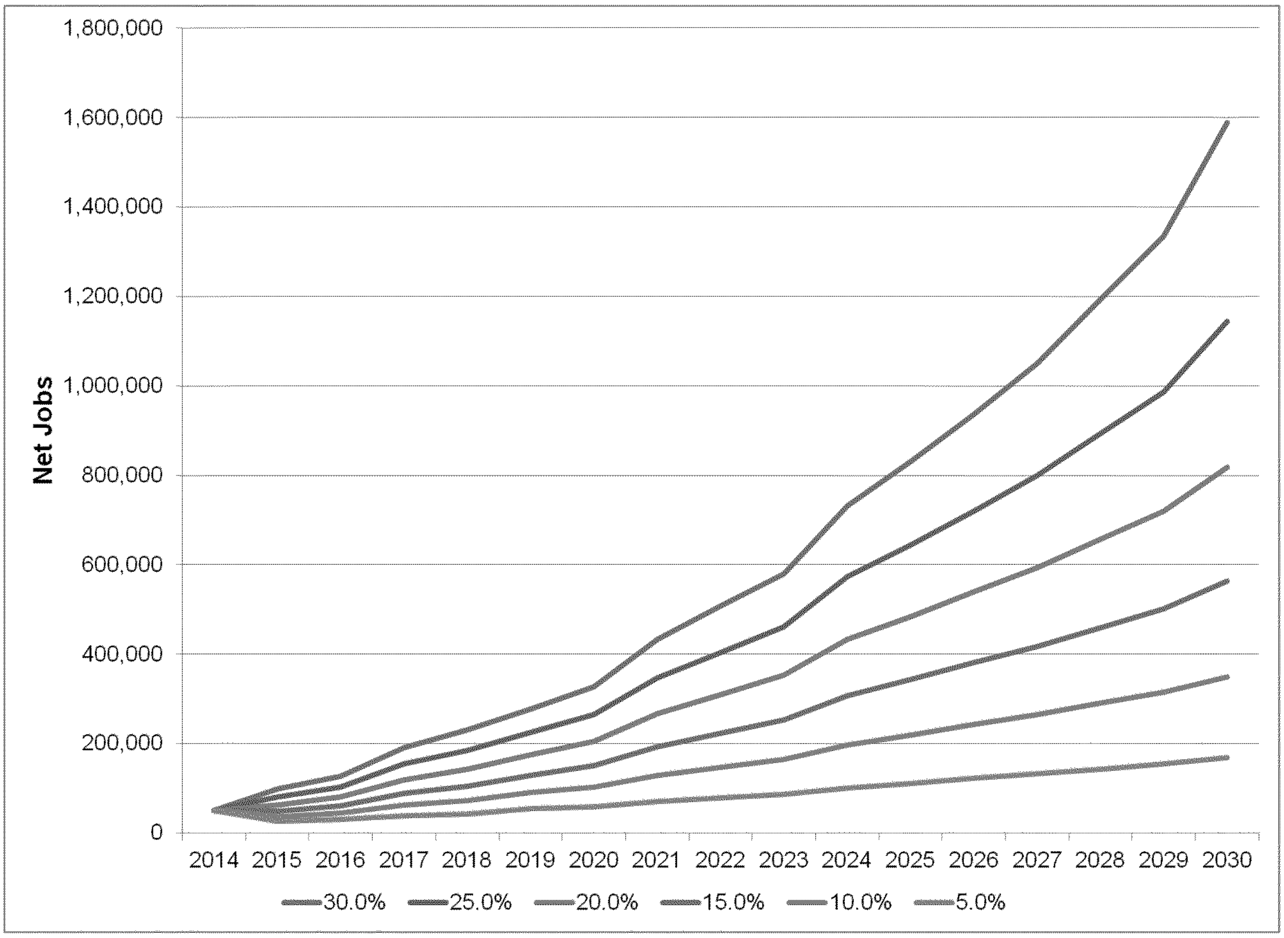
Source: Analysis as described in the text of the working paper.

Beginning with a 5 percent savings target, we find that the smallest effort shows the largest benefit-cost ratio (assuming all costs are discounted 5 percent annually). This makes sense as the least -cost resources are likely to be used up first . B y themselves , however, the very cheapest efficiency resources do not generate sufficient savings to drive a very large gain in employment – in this case 169 ,112 jobs. The maximum net savings per household tops out at about 15 percent efficiency savings. That provides an average net return of $15 7 per household. At that level employment increases by about 563,013 jobs per year.

The maximum net energy bill s avings is reached at about the 20 percent target with a net return of $46,185 million which helps drive the gain of 818,827 jobs as we described in the text surrounding tables 4 and 5. The least cost-effective scenario calls for a 30 percent savings target; although less cost -effective, this scenario also generates the greatest number of total jobs because of the substantial construction activity generated in the later years to achieve this level of savings.

Figure 4 provides a graphic summary of overall job impacts by year as a function of the year 2030 savings from the reference case. Beginning with the assumption that first year savings in 2014 is about 0.75 percent of reference case sales, each of the scenarios slowly increases the gain in jobs as greater investments drive a greater level of savings. The year 2030 end -points are consistent with the results presented in Table 6 on the previous page.

Figure 4. Net Job Impacts of Energy Efficiency Scenarios by Year 2030 Percent Savings



Source: Analysis as described in the text of the working paper.

Finally, and although not part of the DEEPER modeling system, we also provide a working estimate of the reduction in air pollution and greenhouse gas emissions in the year 2030 for the 20 percent savings scenario. This is roughly calculated as the difference in the year 2030 electricity generation in the BAU compared to the efficiency-led scenario multiplied by the 2030 (avoided) average rate of emissions (pounds per kWh) of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions. The average rates of emissions in the 2030 efficiency-led scenario are further reduced by the 20 percent savings under the assumption that it is the marginal generation power plants (essentially the generally dirtier units) that will be displaced by the alternative pattern of investments guided by carbon pollution standards. Table 7 summarizes the reduced impacts of air pollution and greenhouse gas emissions.

Table 7. 20% Scenario Emissions Savings in 2030

	2030
Sulfur Dioxide (million short tons)	0.7
Nitrogen Oxides (million short tons)	0.8
Carbon Dioxide (million metric tons)	971

In short, mobilizing energy efficiency as a pollution reduction mechanism can provide dramatic reductions in air pollution and greenhouse gas emissions. Achieving a 20 percent improvement in efficiency by 2030 could reduce emissions of sulfur dioxide and nitrogen oxides by 700,000 and 800,000 tons, respectively, and cut carbon pollution by 971 million metric tons—nearly a full gigaton—even as consumers and businesses save money and new jobs are created. The emission reductions described in Table 7 are about 57 percent of the emissions projected in the power sector for the year 2030 in the business-as-usual case.

V. Conclusions

The evidence presented here documents the critical role that energy efficiency can play in positively shaping both our economy and our environment. If we choose to develop that resource as characterized in this working paper, a 20 percent electricity savings by the year 2030 can catalyze large net consumer savings as well as launch an important opportunity to stimulate greater job creation – even as we bring about a substantial reduction in carbon pollution and other harmful air pollutants.

Upcoming EPA rulemakings addressing carbon dioxide emissions from the power sector present a unparalleled opportunity to realize the massive economic and environmental benefits of energy efficiency. President Obama has directed the EPA to proceed with a rulemaking to establish limits on greenhouse gas emissions from existing power plants under section 111(d) of the Clean Air Act.[66] The language of section 111 (d) is sufficiently broad to encompass a system-based approach to securing carbon pollution reductions from existing power plants.[67] A system-based approach could provide an excellent opportunity for EPA to consider end-use energy efficiency as a compliance mechanism through which the power sector can achieve meaningful, low-cost emission reductions.[68]

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62. *See* Sara Hayes and Garrett Herndon, *Trailblazing Without the Smog: Incorporating Energy Efficiency into Greenhouse Gas Limits for Existing Power Plants*, American Council for an Energy-Efficient Economy (2013).
63. *See* Megan Ceronsky and Tomás Carbonell, *Section 111(d) of the Clean Air Act: The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants*, Environmental Defense Fund (2013).
64. *Id*.

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Appendix A: An Overview of the Energy Efficiency Resource

I. What is Energy Efficiency?

All interactions of matter involve flows of energy. This is true whether they have to do with earthquakes, the movement of the planets, or the various biological and industrial processes at work anywhere in the world. Within the context of a regional or national economy, the assumption is that energy should be used as efficiently as technically and economically feasible. An industrial plant working two shifts a day six days a week for 50 weeks per year, for example, may require more than $1 million per year in purchased energy if it is to maintain operation. An average American household may spend $2,000 or more per year for electricity and natural gas to heat, cool, and light the home as well as to power all of the appliances and gadgets within the house. And an over-the-road trucker may spend $60,000 or more per year on fuel to haul freight an average of 100,000 miles. Regardless of either the scale or the kind of activity, a more energy-efficient operation might lower overall costs for the manufacturing plant, for the household, and for the trucker. The question is whether the annual energy bill savings are worth either the cost or the effort that might be necessary to become more energy-efficient.[69]

As it turns out the U.S. economy is not especially energy-efficient. At current levels of consumption the U.S. economy converts about 14 percent of all the energy consumed into useful work – which means we waste about 86 percent of the energy resources now expended to maintain our economy.[70] Because of that very significant level of inefficiency, many in both the business and the policy community increasingly look to energy efficiency improvements as cost-effective investments to improve efficiency and reduce waste.

The current system of generating and delivering electricity to homes and businesses in the United States is just 32 percent efficient. That is, for every three lumps of coal or other fuel used to generate power, the energy from only one lump is actually delivered to homes and businesses in the form of electricity. What America wastes in the generation of electricity is more than Japan needs to power its entire economy. The technologies that power the fossil-fuel economy, for example the internal combustion engine and steam turbines, are no more efficient today than they were in 1960, when President Eisenhower was in office.[71] Laitner (2013) suggests that this level of inefficiency may actually constrain the greater productivity of the economy.[72] And yet, any number of technologies can greatly improve energy performance. Combined heat and power (CHP) systems, for example, can deliver efficiencies of 65 to 80 percent or more, at a substantial economic savings.[73] And an incredible array of waste-to-

65. The energy expenditures are derived from several calculations by the author.
66. Laitner 2013, building on Ayres and Warr 2009.
67. Ayres, Robert U. and Edward H. Ayres. 2010. *Crossing the Energy Divide: Moving from Fossil Fuel Dependence to a Clean-Energy Future.* Upper Saddle River, N.J.: Wharton School of Publishing.
68. Laitner 2013.
69. Chittum, Anna and Terry Sullivan. 2012. *Coal Retirements and the CHP Investment Opportunity*. ACEEE Report IE123. Washington, DC: American Council for an Energy-Efficient Economy.

energy and recycled energy technologies can further increase overall efficiency and save money.[74]

II. Historical Impact of Energy Efficiency

As one of the richest and more technologically advanced regions of the world, the United States has expanded its economic output by more than three-fold since 1970. Per capita incomes are also twice as large today compared to incomes in 1970. Notably, however, the demand for energy and power resources grew by only 40 percent during the same period.[75] This decoupling of economic growth and energy consumption is a function of increased energy productivity: in effect, the ability to generate greater economic output (that is, more goods and services), but to do so with less energy. Because these past gains were achieved with an often ad hoc approach to energy efficiency improvements, there is compelling evidence to suggest that even greater energy productivity benefits can be achieved. Indeed, the evidence suggests that since 1970, energy efficiency in its many different forms has met three-fourths of the new demands for energy-related goods and services while new energy supplies have provided only one-fourth of the new energy-related demands.[76] But energy efficiency has been an invisible resource. Unlike a new power plant or a new oil well, we don't see energy efficiency at work. A new car that gets 25 miles per gallon, for example, may not seem all that much different than a car that gets 40 miles or more per gallon. And yet, the first car will consume 400 gallons of gasoline to go 10,000 miles in a single year while the second car will need only 250 gallons per year.[77] In effect, energy efficiency in this example is the energy we don't use to travel 10,000 miles per year. More broadly, energy efficiency may be thought of as the cost-effective investments in the energy we don't use either to produce or even increase the level of goods and services within the economy.

III. The Cost-Effective Potential for the Energy Efficiency Resource

Can the substantial investments that might be required to obtain more energy-efficient technologies save money for businesses and consumers? Here we turn to the evidence to provide different views of this question. The Lazard Asset Management firm (2013) provides a

70. Bailey, Owen and Ernst Worrell. 2005. Clean Energy Technologies A Preliminary Inventory of the Potential for Electricity Generation. LBNL-57451. Berkeley, CA: Lawrence Berkeley National Laboratory.
71. These and other economic and energy-related data cited are the author's calculations as they are drawn from various resources available from the Energy Information Administration (2013a and 2013b).
72. Laitner 2013.
77. In August 2012 the Department of Transportation and the Environmental Protection Agency finalized federal car and light truck fuel economy and greenhouse gas emissions standards for model years 2017 to 2025. The standards, together with those previously adopted for model years 2012 to 2016, mean an 80 percent increase to more than 50 miles per gallon for the average model year 2025 vehicle from the 2011 CAFE (Corporate Average Fuel Economy) requirement of 27.6 miles per gallon (Langer 2012). A separate study by the BlueGreen Alliance and the American Council for an Energy-Efficient Economy determined that the new 2025 fuel economy standards would be cost-effective and produce a gain of 576,000 jobs (Busch et al. 2012). The jobs provided by the new fuel economy standards are at the same scale as the jobs that likely would provided by energy efficiency improvements in the use of electricity as suggested in the text of the main report.

detailed review of the various costs associated with electricity generation expenditures.[78] They note, for instance, that new coal and nuclear power plants might cost an average of 8 to 14 cents per kilowatt-hour (kWh) of electricity. The costs for various renewable energy resources such as wind energy or photovoltaic energy systems (i.e., solar cells that convert sunlight directly into electricity) range from 6 to 20 cents per kWh. And both Lazard (2013) and the American Council for an Energy-Efficient Economy (ACEEE) estimate a range of energy efficiency measures that might cost the equivalent of 3 to 5 cents per kWh of electricity service demands.[79] McKinsey & Company (2007) assessed the energy efficiency resource as having at least a 10 percent return on energy efficiency investments.[80] When spread out over an annual $170 billion energy efficiency market potential, McKinsey suggests an average 17 percent return might be expected across that spread of annual investments.[81] A subsequent study suggests that through 2020 there is sufficient cost-effective opportunity to reduce our nation's energy use by more than 20 percent – if we choose to invest in the more efficient use of our energy resources.[82]

Similarly, the AEC (1991) and the Energy Innovations (1997) reports show a benefit-cost ratio that also approached two to one.[83] More recently, the Union of Concerned Scientists published a detailed portfolio of technology and program options that would lower U.S. heat-trapping greenhouse gas emissions 56 percent below 2005 levels in 2030.[84] The result of their analysis indicated an annual $414 billion savings for U.S. households, vehicle owners, businesses, and industries by 2030. After subtracting the annual $160 billion costs (constant 2006 dollars) of the various policy and technology options, the net savings are on the order of $255 billion per year. Over the entire 2010 through 2030 study period, the net cumulative savings to consumers and businesses were calculated to be on the order of $1.7 trillion under their so-called Blueprint case.

Most recently, Laitner et al. (2012) documented an array of untapped cost-effective energy efficiency resources roughly equivalent to 250 billion barrels of oil.[85] That is a scale sufficient to enable the U.S. to reduce total energy needs by about one-half compared to standard reference case projections for the year 2050. These productivity gains could generate from 1.3

74. Lazard, 2013. Lazard, Ltd. "Levelized Cost of Energy Analysis – Version 7.0." September, 2013.
75. *Id.*; Elliott, R. Neal, Rachel Gold, and Sara Hayes. 2011. Avoiding a Train Wreck: Replacing Old Coal Plants with Energy Efficiency. ACEEE White Paper. Washington, DC: American Council for an Energy-Efficient Economy.
76. McKinsey. 2007. *Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost?* The Conference Board and McKinsey & Company.
77. *Id.*
78. McKinsey. 2009. *Unlocking Energy Efficiency in the U.S. Economy*. McKinsey & Company.
79. Alliance to Save Energy, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Union of Concerned Scientists, and Tellus Institute. 1991. *America's Energy Choices: Investing in a Strong Economy and a Clean Environment*. Cambridge, MA: Union of Concerned Scientists; Energy Innovations. 1997. *Energy Innovations: A Prosperous Path to a Clean Environment*. Washington, DC: Alliance to Save Energy, American Council for an Energy-Efficient Economy, Natural Resources Defense Council, Tellus Institute, and Union of Concerned Scientists.
80. Cleetus Rachel, Stephen Clemmer, and David Friedman. 2009. *Climate 2030: A National Blueprint for a Clean Energy Economy*. Cambridge, MA: Union of Concerned Scientists.
81. Laitner, John A. "Skip," Steven Nadel, Harvey Sachs, R. Neal Elliott, and Siddiq Khan. 2012 *The Long-Term Energy Efficiency Potential : What the Evidence Suggests*, ACEEE Research Report E104, Washington, DC: American Council for an Energy-Efficient Economy. 2012.

to 1.9 million jobs while saving all residential and business consumers a net $400 billion per year, or the equivalent of about $2,600 per household annually (in 2010 dollars). Indeed, in *World Energy Outlook 2012* , the Internationa l Energy Agency (IEA 2012) highlighted the potential for energy efficiency to save 18 percent of the 2010 global energy consumption by 2035. More critically, the IEA notes that Global GDP would be 0.4 percent higher in 2035 as a result of those efficiency improvements.

There are two final aspects of the evidence to briefly review. The first is associated with the non-energy benefits that typically result from energy efficiency investments. The second reflects the changes one might normally expect in the cost and performance of technologies over time.

When energy efficiency measures are implemented in industrial, commercial, or residential settings, several "non-energy" benefits such as maintenance cost savings and revenue increases from greater production can often result in addition to the anticipated energy savings. The magnitude of non-energy benefits from energy efficiency measures is significant. These added savings or productivity gains range from reduced maintenance costs and lower waste of both water and chemicals to increased product yield and greater product quality. In one study of 52 industrial efficiency upgrades, all undertaken in separate in dustrial facilities, Worrell et al. (2003) found that these non -energy benefits were sufficiently large that they lowered the aggregate simple payback for energy efficiency projects from 4.2 years to 1.9 years.[86] Unfortunately, these non-energy benefits fr om energy efficiency measures are often omitted from conventional performance metrics. This leads, in turn, to overly modest payback calculations and an imperfect understanding of the full impact of additional efficiency investments.

Several other studi es have quantified non -energy benefits from energy efficiency measures and numerous others have reported linkages from non -energy benefits and completed energy efficiency projects. In one, the simple payback from energy savings alone for 81 separate industrial energy efficiency projects was less than 2 years, indicating annual returns higher than 50 percent. When non -energy benefits were factored into the analysis, the simple payback fell to just under one year.[87] In residential buildings, non-energy benefits have been estimated to represent between 10 to 50 percent of household energy savings.[88] If the additional benefits from energy efficiency measures were captured in conventional performance models, such figures would make them more compelling. Building on that perspective, a new assessment by the Regulatory Assistance Project suggests there is, in fact, a "layer cake of benefits from electric energy efficiency".[89] The layers or array of benefits fall s

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82. Worrell, Ernst, John A. Laitner, Michael Ruth, and Hodayah Finman. 2003. "Productivity Benefits of Industrial Energy Efficiency Measures." *Energy* (2003), 28, 1081-98.
83. Lung, Robert Bruce, Aimee McKane, Robert Leach, Donald Marsh. 2005. "Ancillary Benefits and Production Benefits in the Evaluation of Industrial Energy Efficiency Measures." *Proceedings of the 2005 Summer Stu dy on Energy Efficiency in Industry*. Washington, DC: American Council for an Energy-Efficient Economy.
84. Amann, Jennifer. 2006. *Valuation of Non -Energy Benefits to Determine Cost -Effectiveness of Whole House Retrofit Programs: A Literature Review.* ACEEE Report A061. Washington, DC: American Council for an Energy - Efficient Economy.
85. Lazar, Jim and Ken Colburn. 2013. Recognizing the Full Value of Energy Efficiency. Montpelier, VT: Regulatory Assistance Project, at 10.

into three categories: utility system benefits, participant benefits, and societal benefits – each with six different types of positive returns. Using information provided by Efficiency Vermont as one example, Lazar and Colburn found that the mix of energy efficiency benefits typically included in utility revenue requirements approach 7-8 cents/kWh, but the full set of efficiency benefits could be as high as 18 cents/kWh.[90] Laitner et al. (2013) suggest that new business models are needed to fully capture the complete array of benefits.[91]

As a strong complement to the likelihood of large-scale non-energy benefits typically omitted from most climate policy assessments, there is also a significant body of evidence that indicates that technology is hardly static and non-dynamic. The rapid technological change seen especially in semiconductor-enabled technologies has led to cheaper, higher performing, and more energy-efficient technologies.[92] The increasing penetration of information and communication technologies interacting with energy-related behaviors and products suggests that energy efficiency resources may become progressively cheaper and more dynamic through the 21st century.[93] Given this and many other comparable studies, one might safely conclude that progress in the cost and performance of energy efficient technologies will continue, and that new public policies will greatly increase the continued rate of improvement.[94]

We can extend the issue of cost effectiveness even further to examine policy scenarios rather than discrete technologies. Laitner and McKinney (2008) provided a meta-review of 48 past policy studies that were undertaken primarily at the state or regional level.[95] The set of studies included in this assessment generally examined the costs of economy-wide efficiency investments made over a 15 to 25 year time horizon. The analysis found that even when both

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86. In many ways the landmark volume, *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, by Lovins et al. (2002) underscores the many benefits which are mostly excluded from marketplace transactions. From the Small Is Profitable website: The report describes 207 ways "in which the size of 'electrical resources' – devices that make, save, or story electricity – affects their economic value. It finds that properly considering the economic benefits of 'distributed' (decentralized electrical resources typically raises their value by a large factor, often approximately tenfold, by improving system planning, utility construction and operation, and service quality, and by avoiding societal costs." *See*, http://www.smallisprofitable.org/.
87. Laitner, John A. "Skip," Matthew T. McDonnell and Heidi M. Keller. 2013. "Shifting Demand: From the Economic Imperative of Energy Efficiency to Business Models that Engage and Empower Consumers." In *End of Electricity Demand Growth: How Energy Efficiently Can Bring an End to the Need for More Power Plants*, Fereidoon P. Sioshansi (editor), Elsevier, 2013.
88. Laitner, John A. "Skip", Christopher Poland Knight, Vanessa McKinney, and Karen Ehrhardt-Martinez. 2009. *Semiconductor Technologies: The Potential to Revolutionize U.S. Energy Productivity.* Washington, DC: American Council for an Energy-Efficient Economy.
89. Laitner, John A. "Skip" and Karen Ehrhardt-Martinez. 2008. *Information and Communication Technologies: The Power of Productivity; How ICT Sectors Are Transforming the Economy While Driving Gains in Energy Productivity.* Washington, DC: American Council for an Energy-Efficient Economy.
90. McKinsey. 2009. *Unlocking Energy Efficiency in the U.S. Economy*. McKinsey & Company; Koomey, Jonathan. 2008. "Testimony of Jonathan Koomey, Ph.D. Before the Joint Economic Committee of the United States Congress," For a hearing on Efficiency: The Hidden Secret to Solving Our Energy Crisis." Washington, DC: Joint Economic Committee of the United States Congress. June 30, 2008.
91. Laitner, John A. "Skip" and Vanessa McKinney. 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments.* ACEEE Report E084. Washington, DC: American Council for an Energy-Efficient Economy.

program costs and technology investments were compared, the savings appeared to be twice the cost of the suggested policies.

IV. Overcoming Barriers to Improving Energy Efficiency

Although some economists have questioned the magnitude of the energy efficiency resource, close examination of the evidence indicates that the resource is in fact vast . Allcott and Greenstone (2012), for example, suggest that "recent empirical work in a variety of contexts implies that on average the magnitude of profitable unexploited investment opportunities is much smaller than engineering-accounting studies suggest."[96] In effect, they pose the central economic question, "Is there an Energy Efficiency Gap?" In other words, is energy efficiency a sufficiently large, cost-effective resource that can be relied upon as a meaningful energy policy option?(Allcott and Greenstone 2012). In fact, the issue was rigorously explored as early as 1995. Levine et al. (1995), for example, examined this issue in a significant journal article, "Energy Efficiency Policy and Market Failures." [97] After a careful review they concluded, "[w]e believe that energy efficiency policies aimed at improving energy efficiency at a lower cost than society currently pays for energy services represent good public policy. Programs that lead to increased economic efficiency as well as energy efficiency should continue to be pursued." More recently, Nadel and Langer (2012), in a thoughtful review of Allcott and Greenstone, suggest that "while the authors have some useful points to make, in general they interpret available data in ways that best support their points, downplaying other important findings in the various articles they cite." [98] Nadel and Langer argue that a fuller consideration of the evidence shows that there is in fact a large, cost-effective energy efficiency resource available to be harvested.

Another relevant area of inquiry examines why cost-effective efficiency opportunities remain unexploited given the cost-savings potential. There is a range of market imperfections, market barriers, and real world behaviors that leaves substantial room for public policy to induce behavioral changes that produce economic benefits. One classic example is the misaligned incentive that exists for those living in rental units when the renter pays the energy bills but the landlord purchases large energy-using appliances such as refrigerators and water heaters. In this case, the purchaser of the durable good does not reap the benefits of greater energy efficiency and has no incentive to select highly efficient appliances . The Market Advisory Committee of the California Air Resources Board (2007) provides a short overview of this and other key market failures.[99, 100] A deeper exploration of the types of market barriers is beyond

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92. Allcott Hunt and Michael Greenstone. 2012. " Is There an Energy Efficiency Gap?" *Journal of Economic Perspectives* 26 (1) : 3-28
93. Levine, Mark D. Jonathan G. Koomey, James E. McMahon, Alan H. Sanstad, and Eric Hirst. 1995, "Energy Efficiency Policy and Market Failures." Annual Review of Energy and the Environment 20: 535-555.
94. Nadel, Steven and Therese Langer. 2012. Comments on the July 2012 Revision of "Is There an Energy Efficiency Gap?" ACEEE White Paper. Washington, DC: American Council for an Energy-Efficient Economy.
95. California Air Resources Board. 2007. Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California. http://www.energy.ca.gov/2007publications/ARB-1000-2007-007/ARB-1000-2007-007.PDF. Sacramento, Calif.: California Air Resources Board, Market Advisory Committee.
96. Following are examples of important market failures: (1) Step-Change Technology Development —where temporary incentives will be needed to encourage companies to deploy new technologies at large scale to the public good, because there is otherwise excessive technology, market, and policy risk. Examples of remedies are

the scope of this working paper, but others have done work to map this terrain. [101] A flexible framework to reduce greenhouse gas emissions from existing fossil fuel power plants that empowers states and companies to invest in energy efficiency to reduce pollution would provide an important opportunity to eliminate these barriers.

One important implication of the literature on market imperfections and energy efficiency is that price signals alone may not drive optimal levels of energy efficiency investment. This concept was explored by Hanson and Laitner (2004). [102] In one of the few top-down models that explicitly reflects both policies and behavioral changes as a complement to pricing signals, this study found that the combination of both price and non-pricing policies actually resulted in a significantly greater level of energy efficiency gains and a lower carbon allowance price to achieve the same level of emissions reductions, thereby achieving an overall reduction in the costs of achieving those reductions.

Appendix B: Methodology of the DEEPER Modeling System

To evaluate the macroeconomic impacts of reductions in fossil fuel fired plant emissions from demand-side efficiency improvements, we use the proprietary **D**ynamic **E**nergy **E**fficiency **P**olicy **E**valuation **R**outine, or DEEPER model. The model was developed by John A. "Skip" Laitner and has a 22-year history of use and development, though it was renamed "DEEPER" in 2007. It was most recently used in a study for the BlueGreen Alliance and the American Council for an Energy-Efficient Economy (ACEEE) evaluating the overall job impacts of the recently enacted fuel economy standards. [103]

The DEEPER Modeling System is a quasi-dynamic input-output (I/O) model [104] of the U.S. economy that draws upon social accounting matrices [105] from the MIG, Inc. (formerly the Minnesota IMPLAN Group), [106] energy use data from the U.S. Energy Information Administration's Annual Energy Outlook (AEO), and employment and labor data from the

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renewable portfolio obligations, biofuel requirements, and California's Low Carbon Fuel Standard. (2) Fragmented supply chains—where economically rational investments (for example, energy efficiency in buildings) are not executed because of the complex supply chain. Examples of remedies are building codes. (3) Consumer behavior—where individuals have demonstrated high discount rates for investment in energy efficiency that is inconsistent with the public good. Examples of remedies are vehicle and appliance efficiency standards and rebate programs (California Air Resources Board 2007, p.19).

97. See, for example, Levine et al. 1995 previously referenced, but also Brown (2001); Levinson and Niemann (2004); Sathaye and Murtishaw (2004); Murtishaw and Sathaye (2006); Geller et al. (2006); Brown et al. (2009).

98. Hanson, Donald A. and John A. "Skip" Laitner. 2004. "An Integrated Analysis of Policies that Increase Investments in Advanced Energy-Efficient/Low-Carbon Technologies." *Energy Economics* 26:739-755.

99. Busch, Chris, John Laitner, Rob McCulloch, Ivana Stosic. 2012. *Gearing Up: Smart Standards Create Good Jobs Building Cleaner Cars.* Washington, DC: BlueGreen Alliance and the American Council for an Energy-Efficient Economy (Available at: http://www.bluegreenalliance.org/news/publications/gearing-up).

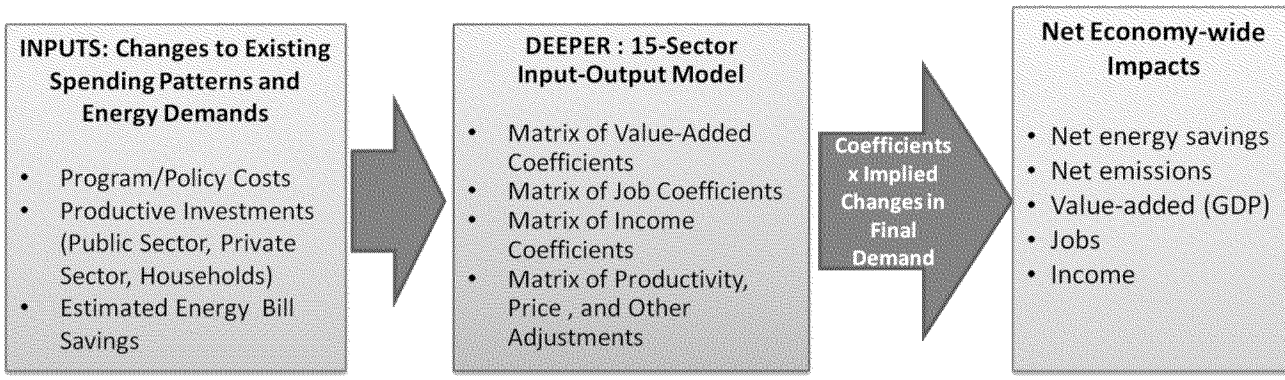
101. Input-output models use economic data to study the relationships among producers, suppliers, and consumers. They are often used to show how interactions among all three impact the macroeconomy.

102. A social accounting matrix is a data framework for an economy that represents how different institutions — households, industries, businesses, and governments — all trade goods and services with one another.

103. See http://implan.com/V4/Index.php.

Bureau of Labor Statistics (BLS). The Excel -based tool contains approximately eight interdependent worksheets. The model functions as laid out in the flow diagram below:

The DEEPER Modeling System



DEEPER results are driven by adjustments to energy service demands and alternative investment patterns resulting from projected changes in policies and prices between baseline and policy scenarios. The model is capable of evaluating policies at the national level through 2050. However, given uncertainty surrounding future economic conditions and the life of the impacts resulting from the policies analyzed, it is often used to evaluate out 15 –20 years. Although the DEEP ER Model, like most I/O models, is not a general equilibrium model, [107] it does provide accounting detail that balances changes in investments and expenditures within the economy. With consideration for goods or services that are imported, it balances the variety of changes across all sectors of the economy.[108]

The Macroeconomic Module contains the factors of production — including capital (or investment), labor, and energy resources — that drive the U.S. economy for a given "base year." DEEPER uses a set of e conomic accounts that specify how different sectors of the economy buy (purchase inputs) from and sell (deliver outputs) to each other.[109]

The Macroeconomic Module translates the selected different policy scenarios, including necessary program spending and research and development (R&D) expenditures, into an annual array of physical energy impacts, investment flows, and energy expenditures over the desired period of analysis. DEEPER evaluates the policy -driven investment path for the various financing strat egies, as well as the net energy bill savings anticipated over the study period. It also evaluates the impacts of avoided or reduced investments and expenditures otherwise required by the electric and natural gas sectors.

104. General equilibrium models operate on the assumption that a set of prices exists for an economy to ensure that supply and demand are in an overall equilibrium.
105. When both equilibrium and dynamic input -output models use the same technology assumptions, both models should generate a reasonably comparable set of outcomes. See Hanson and Laitner (2005) for a diagnostic assessment that reached that conclusion.
106. Further details on this set of linkages can be found in Hanson and Laitner (2009).

The resulting positive and negative changes in spending and investments in each year are converted into sector-specific changes in aggregate demand.[110] These results then drive the I/O matrices utilizing a predictive algebraic expression known as the Leontief Inverse Matrix.[111]

Employment quantities are adjusted annually according to assumptions about the anticipated labor productivity improvements based on forecasts from the Bureau of Labor Statistics. The DEEPER Macroeconomic Module traces how changes in spending will ripple through the U.S. economy in each year of the assessment period. The end result is a net change between the reference and policy scenarios in jobs, income, and value-added,[112] which is typically measured as Gross Domestic Product (GDP) or value-added Gross Regional Product (GRP) for the study region (e.g., the national, state, or local economies).

Like all economic models, DEEPER has strengths and weaknesses. It is robust by comparison to some I/O models because it can account for price and quantity changes over time and is sensitive to shifts in investment flows. It also reflects sector-specific labor intensities across the U.S economy. However, it is important to remember when interpreting results for the DEEPER model that the results rely heavily on the quality of the information that is provided and the modeler's own assumptions and judgment. The results are unique to the specified policy design. The results reflect differences between scenarios in a future year, and like any prediction of the future, they are subject to uncertainty.

109. This is the total demand for final goods and services in the economy at a given time and price level.
110. For a more complete discussion of these concepts, see Miller and Blair (2009).
111. This is the market value of all final goods and services produced within a country in a given period.

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In the

Supreme Court of the United States

STATE OF NEW YORK, ET AL., Petitioners,
v.
FEDERAL ENERGY REGULATORY COMM'N, ET AL.

ENRON POWER MARKETING, INC., Petitioner,
v.
FEDERAL ENERGY REGULATORY COMM'N, ET AL.

On Writ of Certiorari to the United States
Court of Appeals for the District of Columbia Circuit

BRIEF AMICUS CURIAE OF ELECTRICAL ENGINEERS, ENERGY ECONOMISTS AND PHYSICISTS IN SUPPORT OF RESPONDENTS IN NO. 00-568

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Andover Technology Partners 978-683-9599
Consulting to the Air Pollution Control Industry

Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers

C-14-EDF

to:

Environmental Defense Fund
257 Park Avenue South
New York, NY 10010

November 30, 2014

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Contents

Background

Conversion of existing coal fired boilers to co-fire or to fire 100% natural gas has been performed for a number of reasons, but mainly to reduce emissions of pollutants associated with coal firing.

The purpose of this analysis is to a) demonstrate the technical feasibility of increased use of natural gas at existing coal-fired power plants in the United States; b) illustrate common engineering and logistical issues that arise when power plants undertake such projects, as well as ways in which those issues have been successfully overcome; and c) identify the range of capital and operating costs associated with such projects.

Executive Summary

Conversion from coal to natural gas firing and co-firing of natural gas with coal is not a new phenomenon for coal-fired electric utility boilers, but it is one that has taken on increasing significance in recent years. As demonstrated in this report, experience with conversion of coal to natural gas and also co-firing of natural gas with coal goes back several decades. As such, the technical issues associated with conversions or co-firing are very well understood. Utilization of natural gas offers several benefits: reduction of air emissions and reduction of solid or liquid waste emissions, reduction of parasitic loads, and reduced operating and maintenance costs, just to name a few. On the other side of the ledger, utilization of natural gas will have a slight adverse impact on boiler efficiency, and bears with it an increase in fuel costs which until recently have been deterrents to wider use of natural gas in boilers.

In recent years the economics of converting to natural gas has changed for many facilities. First, natural gas prices fell rapidly a few years ago – reaching a historic low in real (inflation adjusted) cost in 2012 - and although gas prices have risen from that low, natural gas prices have – for most locations in the US - been much more stable than in the past. Second, increased stringency of environmental regulations have increased the cost of burning coal. As such, utilities have become reluctant to expend capital on aging coal units that are less economically viable than in the past. As will be demonstrated in the case studies in this report, avoiding the costs associated with complying with US EPA's Mercury and Air Toxic Standards (MATS) or the Regional Haze Rule (RHR, and the need to install Best Available Retrofit Technology, or BART) have been important motivators in the conversion of some of these facilities to natural gas. There are other factors as well. Some of these facilities have low capacity factors in part due to increased renewable generation and natural gas combined cycle that have displaced coal from base load use to cycling duty. In some of these cases it was more economical to convert the now cycling coal boiler to natural gas than to build new simple cycle combustion turbines for peaking conditions that have similar heat rates as the boiler.

The case studies that form a key element of this report demonstrate that natural gas conversions are being applied in a wide variety of circumstances – throughout several regions of the United States, on boilers of a wide range of sizes from under 100 MW to over 500 MW, on boilers burning a wide range of coals, and on boilers with low as well as high capacity factors. In most cases gas conversion was selected as the lowest cost means of complying with environmental regulations, such as MATS or the RHR. Although in some cases only minor changes were necessary to the natural gas supply infrastructure, in other cases pipelines of over 30 miles in length are being constructed to provide adequate supply. In this respect, depending upon the access to natural gas, the pipeline might be the largest factor in the cost of a natural gas conversion, and it has been a surmountable issue in these circumstances. For the most part, where cost information was available, the cost of the boiler modifications were usually lower than anticipated by EPA in the Technical Support Document for the proposed Clean Power Plan. [1] This is because EPA's cost estimates for natural gas conversion include several elements that are not necessary in many cases.

Table E.1 summarizes data on each of the units examined in the Case Studies in this report. The full year data from 2009 and 2013 are selected as years before and after the changes to the five units where conversions are complete. The majority of the case studies addressed in this report are projects that are currently in progress, and before and after performance information is not available. For those five units where before and after performance information is available, reductions in emission rates (measured in lb/MWh) averaged over 99% for SO_2, 48% for NOx and 38% for CO_2. Although each of the five units where before and after data is available is used as a peaking unit, the best CO_2 emission reductions were experienced on the two units that also have the highest capacity factors. Since most of the projects that are currently in progress recently operated with higher capacity factors than those that are completed and where we have the before and after data, it is likely that reductions in CO_2 emission rates should be on the order of or better than the best of these five units, or about 45%.

With few exceptions, capacity factors were significantly lower in 2013 than in 2009, with the median dropping from 44% to 28% for the Case Study units examined. This is consistent with industry-wide reductions in capacity factor for coal units due to lower natural gas prices. Therefore, although capacity factors dropped for those units where conversions have been completed, this likely would have happened regardless of whether or not a natural gas conversion occurred.

An important and perhaps surprising finding is the fact that some of these gas

[1] US Environmental Protection Agency, "GHG Abatement Measures - Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602", June 10, 2014.

conversions are being performed on units that in 2013 were operated as base loaded power plants as opposed to units that have become marginally economical and limited to peaking or cycling operation. This indicates that conversion to natural gas may not be confined to facilities that are strictly peaking or cycling in nature. It is unclear what the long-term plans are for these converted units. If the converted units are expected to operate at high capacity factors over the long term, future conversion to natural gas combined cycle may be expected because of the lower heat rate of combined cycle power plants. Brunner Island is a project that is unique in that it is a plant that is equipped with a modern wet FGD system. Although this possible co-firing project is in the very early stages of development, it is very notable that a scrubbed facility would consider co-firing natural gas.

Table E.1. Summary of Data on Natural Gas Conversion Units in Case Studies
Completed units in ***bold and shaded***

								Emission rate[2]						% Redn, or year complete			Capacity Factor[3]	
Plant Name	Unit	MW	State	Firing type	Coal	heat rate[1]	YR on line	2009 SO2	2009 NOx	2009 CO2	2013 SO2	2013 NOx	2013 CO2	SO2	NOx	CO2	2009	2013
E C Gaston	1	254	AL	wall	Bit.	9,837	1960	30.3	3.9	2,013	25.9	4.0	2,154				41%	28%
E C Gaston	2	256	AL	wall	Bit.	9,928	1960	31.3	4.0	2,058	26.3	4.1	2,186		2015		49%	27%
E C Gaston	3	254	AL	wall	Bit.	9,843	1961	34.6	5.0	2,307	28.5	4.4	2,337				32%	21%
E C Gaston	4	256	AL	wall	Bit.	9,766	1962	24.9	3.1	1,649	24.0	3.7	1,962				18%	27%
Irvington	4	156	AZ	wall	Bit., Subbit.	10,732	1967	3.0	3.3	1,715	6.3	4.6	2,123		2018		31%	32%
Cherokee	4	352	CO	tang	Bit., Subbit.	10,880	1968	1.8	3.0	1,969	1.6	3.0	2,081		2017		56%	68%
Edge Moor	***3***	***86***	***DE***	***tang***	***Bit.***	***11,954***	***1957***	***5.4***	***1.6***	***2,327***	***0.0***	***0.8***	***1,261***	***100%***	***51%***	***46%***	***36%***	***10%***
Edge Moor	***4***	***174***	***DE***	***tang***	***Bit.***	***11,279***	***1966***	***8.5***	***1.7***	***1,954***	***0.0***	***0.7***	***1,081***	***100%***	***57%***	***45%***	***22%***	***10%***
Yates	Y6BR	352	GA	tang	Bit.	10,492	1974	20.3	2.6	1,988	22.0	2.6	1,966		2015		50%	29%
Yates	Y7BR	355	GA	tang	Bit.	10,487	1974	18.5	2.6	1,938	21.7	2.2	1,970				44%	15%
Harding St.	50	106	IN	tang	Bit	10,541	1958	31.9	2.3	2,130	39.3	2.4	2,051				68%	73%
Harding St.	60	106	IN	tang	Bit.	10,491	1961	32.4	2.4	2,114	37.9	2.4	1,983		2016		69%	72%
Harding St.	70	435	IN	tang	Bit.	10,517	1973	2.2	0.9	1,889	1.3	1.7	2,059				75%	82%
Laskin	1	55	MN	tang	Bit., Subbit.	12,783	1953	4.5	2.3	2,552	1.5	2.0	2,463		2015		58%	56%
Laskin	2	51	MN	tang	Bit., Subbit.	12,875	1953	4.5	2.4	2,563	1.5	2.0	2,456				63%	58%
Meramec	1	119	MO	tang	Bit Subbit	10845	1953	6.2	1.4	2,299	4.7	1.3	2,297		2015		85%	42%
Meramec	2	120	MO	tang	Bit, Subbit	10644	1954	6.1	1.3	2,283	4.9	1.3	2,400				78%	48%
Deepwater	***8***	***73***	***NJ***	***wall***	***Bit.***	***10,331***	***1954***	***9.6***	***3.6***	***1,841***	***0.0***	***2.2***	***1,200***	***100%***	***39%***	***35%***	***13%***	***5%***
Avon Lake	10	96	OH	tang	Bit	12829	1949	2.5	0.4	205	3.0	0.4	205		2016		5%	10%
Avon Lake	12	640	OH	cell	Bit	9823	1970	22.4	3.1	1,812	26.3	2.7	1,796				58%	48%
Muskogee	4	505	OK	tang	PRB	10,593	1977	5.9	3.4	2,200	4.6	3.6	2,171		2018		57%	44%

Plant Name	Unit	MW	State	Firing type	Coal	heat rate[1]	YR on line	2009 SO2	2009 NOx	2009 CO2	2013 SO2	2013 NOx	2013 CO2	SO2	NOx	CO2	2009	2013
										Emission rate[2]					% Redn, or year complete		Capacity Factor[3]	
Muskogee	5	517	OK	tang	PRB	10,652	1978	5.2	3.0	2,016	4.3	2.9	2,023				75%	51%
Brunner Isl	1	312	PA	tang	Bit	10023	1961	18.6	2.6	1,658	3.2	3.5	1,884				88%	58%
Brunner Isl	2	371	PA	tang	Bit	9695	1965	17.9	2.6	1,651	3.6	3.3	1,858		TBD – likely a cofiring project		73%	50%
Brunner Isl	3	744	PA	tang	Bit	9502	1969	6.5	2.8	1,794	3.3	3.3	1,827				72%	55%
New Castle	3	93	PA	wall	Bit	11265	1952	23.6	3.8	2,215	25.1	4.0	2,149				21%	12%
New Castle	4	95	PA	wall	Bit	11028	1958	20.5	3.1	2,011	23.2	3.4	2,007		2016		28%	15%
New Castle	5	132	PA	wall	Bit	10846	1964	24.1	4.5	2,207	26.0	4.7	2,189				23%	15%
Clinch River	1	230	VA	vert	Bit.	10,227	1958	8.8	2.4	2,073	7.8	2.1	2,027				23%	21%
Clinch River	2	230	VA	vert	Bit.	10,179	1958	9.1	2.5	2,022	8.0	2.1	2,050		2015		12%	14%
Clinch River	3	230	VA	vert	Bit.	10,179	1958	8.2	2.0	1,916	8.4	1.8	2,099				46%	14%
Blount St.	***8***	***51***	***WI***	***wall***	***Bit.***	***14,500***	***1957***	***25.8***	***4.2***	***2,479***	***0.0***	***2.3***	***1,794***	***99.9%***	***44.8%***	***27.6%***	***4%***	***2%***
Blount St.	***9***	***50***	***WI***	***wall***	***Bit.***	***14,278***	***1961***	***25.8***	***4.3***	***2,401***	***0.0***	***2.5***	***1,608***	***99.9%***	***41.1%***	***33.0%***	***3%***	***2%***
Valley	1	67	WI	wall	Bit.	14,500	1968	0.8	0.3	205	0.7	0.2	205				42%	31%
Valley	2	67	WI	wall	Bit.	14,500	1968	0.8	0.3	205	0.7	0.2	205		2015/16		44%	30%
Valley	3	67	WI	wall	Bit.	14,500	1969	0.8	0.3	205	0.7	0.2	205				37%	22%
Valley	4	67	WI	wall	Bit.	14,500	1969	0.8	0.3	205	0.7	0.2	205				39%	27%
Naughton	3	330	WY	tang	PRB	10,517	1971	4.3	4.7	2,285	3.5	2.7	2,029		2015		75%	97%
															Median Capacity Factor		***44%***	***28%***

Comments

1. Heat rate in Btu/kWh net from NEEDS v5.13

2. Emissions in lb/MWh of gross generation except Valley and Avon Lake 10, which is in lb/MMBtu

3. Except for Valley Station and Avon Lake unit 10, capacity factor is estimated from reported gross generation and nameplate rating. Because no generation data was reported for Valley Station or Avon Lake unit 10, reported heat input, nameplate MW rating and heat rate were used to estimate capacity factor.

Program Results

Introduction

Natural gas combustion is primarily used in gas turbine applications for power generation with coal being the dominant fuel for fueling utility boilers. Recently, in response to increased availability of natural gas, what appears to be more stable natural gas pricing, and environmental requirements for coal plants, some power plant owners have converted or have announced plans to convert existing coal-fired facilities to natural gas fired facilities. Although in some cases existing coal-fired generating units have been replaced with new natural gas combined cycle units, in some cases existing coal-fired boilers have been or will be retrofit to burn natural gas. Natural gas has the following advantages over coal when used in a boiler:

- Lower NOx emissions and virtually no SO_2, PM, or mercury emissions because natural gas has negligible fuel nitrogen, sulfur or mercury and its combustion produces negligible PM.
- Lower maintenance costs – Due to the absence of slagging or boiler fouling in the furnace, absence of fly ash build up in the ductwork and no need to pulverize and transport solid fuel, maintenance is much less on a gas-fired plant than when firing coal. As a result, there is much less maintenance necessary when firing natural gas and a resulting improvement in unit availability (both planned and unplanned outages). Operating and Maintenance costs could be reduced by as much as 50%.[2]
- Lower parasitic loads – Reduced electricity demand for fuel preparation (coal transport, crushing, pulverizers, etc.) and reduced electrical demand from air pollution control equipment will reduce parasitic loads. This will result in an increase in net output. This has been estimated as about 5 MW on a 250 MW unit, or about 2%.[3]
- Lower CO_2 emissions per unit of heat input and per unit of electricity produced – Natural gas combustion results in roughly 55-60% of the CO_2 emitted per unit of heat input as compared to coal. Natural gas will reduce boiler efficiency which increases heat rate somewhat. After accounting for the beneficial impact on parasitic loads, this will result in about a 2% adverse impact on heat rate[3] – assuming that modifications are not made to recover boiler efficiency. Adjusting for the impact on heat rate, on an electricity-produced basis, natural gas produces

[2] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

[3] Brian Reinhart, P.E., Alap Shah, Mark Dittus, Ken Nowling, Bob Slettehaugh, "Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch", POWER-GEN International 2012.

roughly 56%-61% of the CO_2 compared to coal when used in a boiler.

The principal disadvantages of natural gas as a fuel are:

- Generally higher cost than coal per Btu of heat input.
- Somewhat reduced boiler efficiency due to the increased moisture level in the exhaust gas. This will vary based upon the fuel being used. For example, the impact is greater for bituminous fuel because bituminous fuel has lower moisture content than subbituminous or lignite. The impact is estimated to result in a 200 Btu/kWh (roughly 2%) increase in heat rate when converting to 100% natural gas (coal type was not indicated in the study).[3] Another study showed examined the effects of cofiring natural gas with different coals, with the results in Table 1.

Table 1. Impact of cofiring natural gas with different coals.[4]

Fuel	Heat Rate Difference from Base	CO_2 Reduction
Base – 100% PRB Coal	0	0
100% Bituminous Coal	-1.3%	8%
Bit. Coal/24% NG	+0.9%	9%
PRB Coal/37% NG	+0.15%	17%

- Unlike coal, natural gas is not stockpiled at the plant and is also used for residential and other services – increasing the risk of supply disruption. The risk of having service interrupted during periods where residential demand is high may be addressed with firm, uninterruptible service. However, this will entail purchasing the natural gas at a higher cost.

The following sections of this report will discuss:

- The background on use of natural gas in power generation boilers
- Description of the modifications necessary to co-fire natural gas or to convert to 100% natural gas firing.
- Case studies on coal to gas conversions

[4] ASME Power Plant Efficiency Webinar, September 25, 2014

Background on Use of Natural Gas in Power Generation Boilers

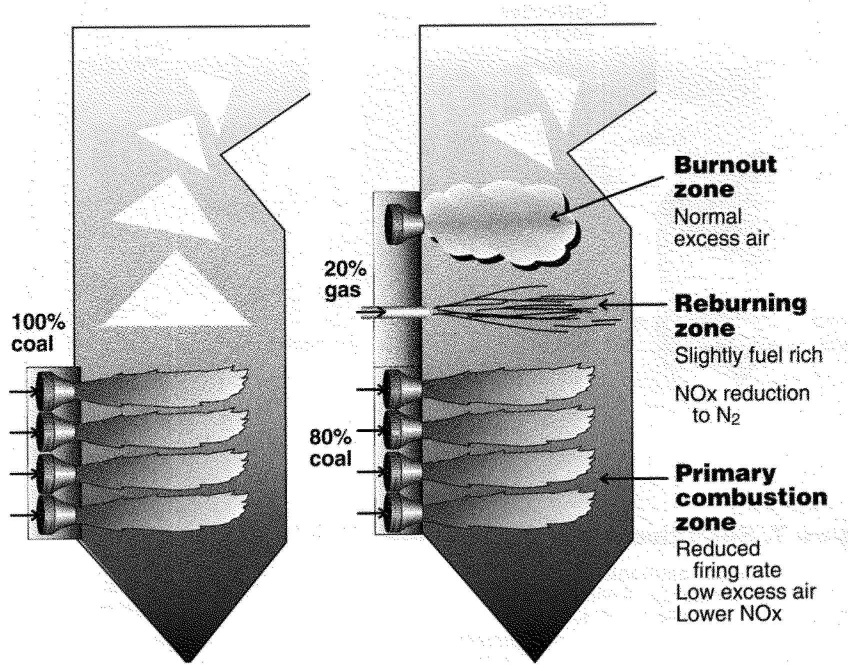
Use of natural gas in coal-fired power generation boilers is not a new phenomenon. For example, conversion of coal-fired boilers to natural gas occurred decades ago in New York City. At the turn of the 19th and 20th century New York City built a network of coal-fired power plants to provide electricity to the railway system because it needed relief from the soot from coal-fueled steam train engines. As natural gas became more available to New York, many of these steam generators that were originally built to burn coal were later converted to 100% natural gas firing because of the desire to reduce the pollutant emissions from these boilers and the associated impact on New York City residents. With time, these boilers have largely been replaced with natural gas combined cycle systems because they are much more efficient in converting the heat of the fuel to electricity than boilers.[5, 6]

Interest in co-firing or converting coal boilers to natural gas increased again in the 1980's and 1990s. Cofiring of natural gas in coal-fired boilers is typically done in many coal-fired boilers upon start-up of the boiler. Boilers start with gas igniters that heat up the furnace and allow ignition of the coal. Interest in cofiring of natural gas at higher loads increased in the 1980's and 1990's with emphasis on reducing NOx emissions from coal-fired boilers. When co-firing, gas may be admitted into the coal burner region, or it may be admitted downstream of the coal burners. One approach for co-firing natural gas that can be used to reduce NOx emissions is natural gas fuel reburn, where natural gas is fired downstream of the primary combustion zone – typically at a point above the coal burners since in most boilers flue gas flow is upward, as shown in Figure 1.

[5] Museum of the City of New York, "Construction of the 74th Street Power Station", http://mcnyblog.org/2012/06/12/construction-of-the-74th-street-power-station/

[6] IEEE, "The Railway Power Stations of New York City", http://www.ieeeghn.org/wiki/index.php/The_Railway_Power_Stations_of_New_York_City

Figure 1. Conventional gas reburning compared to normal firing.



In fact, in the 1980s and 1990s there was a substantial amount of experience gained through the various retrofit uses of natural gas in utility boilers for the primary purpose of NOx reduction. These technologies are distinguished by the amount of natural gas used and where it is introduced into the boiler, and include:

- Seasonal fuel conversion - firing gas as the principal fuel in lieu of coal or oil during the ozone season when NOx emissions were of greatest concern
- Cofiring natural gas with coal at the burner level
- Conventional Gas Reburning, which at the time achieved over 50% NOx reduction through addition of up to about 25% heat input with natural gas downstream of the coal burners.
- Advanced Gas Reburning for higher NOx reduction than possible with conventional gas reburn by combination of Selective Non-Catalytic Reduction (SNCR) with gas reburning
- Fuel Lean Gas Reburn™ (FLGR), which at the time achieved on the order of 35% to 45% NOx reduction with combustion of up to about 10% of heat input with natural gas downstream of the coal burners.
- Amine Enhanced FLGR, which has been demonstrated to achieve 50% to 70% NOx reduction by combination of FLGR with SNCR.

Gas cofiring has also been deployed on boilers that converted from eastern to western fuels. Due to the lower Btu value of the western fuel – which requires that more fuel be fed to the furnace to achieve the same heat input - and limitations on fuel delivery systems, it became necessary on some units to co-fire natural gas to achieve full load.

Table 2 shows the results of a 1998 utility survey of NOx performance from converting from coal to 100% gas on commercial facilities – in some cases demonstrations. These were performed with the primary objective of reducing NOx emissions. Except for the NIPSCO Michigan City unit 12 and the Mitchell unit 4, 50% or more NOx reduction was achieved in every situation. Of course, modern low NOx burner technology for both coal and natural gas fuel would alter the NOx levels from what is shown here, and as shown, most of the units on Table 2 did not have low NOx burners at the time. As a result, advanced combustion controls allowed these units to change back to near 100% operation on coal. Nevertheless, this data demonstrates that gas conversions are not a new phenomenon and can have significant pollutant emission benefits.

Table 3 shows the results of 1990's era gas reburning and fuel lean gas reburning commercial-scale demonstrations and commercial installations. Nearly all of these operated commercially for several years. Several eventually installed low NOx burners to achieve compliance with NOx regulations and could turn off the gas reburn systems. As demonstrated here, these technologies that were used for cofiring natural gas with coal while reducing NOx are not new, but have been available for decades.

Since CO_2 emissions were not the focus of the studies in Tables 2 or 3, the data on CO_2 emissions was not reported; however, it is reasonable to expect that CO_2 emissions would be reduced by roughly 45% for the full gas conversions in Table 2 and by lesser amounts in proportion to the gas use for the reburning or fuel-lean gas reburning results in Table 3.

Table 2. 1990's Era Results from Utility Survey of NOx Performance from Converting Unit from Coal to 100% Gas[7]

Utility	Station	Unit	MW	Demo MW	Yr Online	Type	LNB?	NOx Coal	NOx Gas	% Rem	Com-ments
NIPSCO	Mich Cty	12	540	469	1974	CY	N	2.10	1.20	42.9	(1)
NIPSCO	Mich Cty	12	540	469	1974	CY	N	1.35	1.20	11.1	(2)
PS CO	Cherokee	3	150	158	1962	FF	Y	0.48	0.20	58.3	(3)
PSEG	Mercer	2	326	308	1961	FFW	N	1.80	0.85	52.8	
AZ Elec	Apache	2	195	175	1978	OF	Y	0.63	0.18	71.4	
AZ Elec	Apache	3	195	175	1979	OF	Y	0.59	0.18	69.5	
PSEG	Hudson	2	660	610	1968	OF	N	1.80	0.90	50.0	(4)
IL Pwr	Henepin	1	75	70	1953	TF	N	0.60	0.15	75.0	(5)
IL Pwr	Henepin	1	75	70	1953	TF	OFA	0.35	0.10	71.4	(6)
IL Pwr	Henepin	2	231	214	1959	TF	N	0.70	0.25	64.3	
IL Pwr	Wood R	4	113	93	1954	TF	N	0.70	0.25	64.3	
Com Ed	Fisk	19	374	318	1959	TF	N	0.70	0.28	60.0	
NIPSCO	Mitchell	4	138	125	1956	TF	N	0.40	0.30	25.0	(7)

Comments:

(1) Illinois Basin Coal
(2) PRB/SWY Coal Blend
(3) limited to 80 MW due to gas supply
(4) Unique Slagging Boiler Design
(5) 34% co-fire was 0.40 # NOx/MMBtu
(6) 34% co-fire was 0.20 # NOx/MMBtu
(7) on 70% PRB coa

CY Cyclone firing
FF Front firing
OF Opposed firing
TF Tangential firing
OFA Overfire Air
LNB: Low NOx Burner

As Tables 2 and 3 demonstrate, gas conversions and gas co-firing have been performed on a wide range of boilers, fuel types, and boiler sizes. In addition to these sites, natural gas reburning was deployed commercially at the CP Crane station near Baltimore, and the TVA Allen unit 1 in 1998. These were taken out of service only a few years later. The reason that gas conversions, and gas co-firing such as gas reburning and fuel lean gas reburning are not more widely deployed today is because low NOx coal combustion technology advanced to the point where it was more economical to use low NOx burners to control NOx emissions than to use natural gas. But, as this experience demonstrates, the technology to convert a coal unit to natural gas or co-fire natural gas in a coal unit is well established.

[7] Survey originally performed by Energy Ventures Analysis, "Evaluation of Coal and Oil Boiler Performance and Emissions on Gas - Prepared for Coalition for Gas-Based Environmental Solutions", republished in Staudt, J., Natural Gas NOx Controls, for Gas Research Institute,WP98-35, November 1998

Table 3. 1990's Era Reburning (RB) and Fuel Lean Gas Reburning (FL) Applications, Commercial and Commercial-Scale Demonstrations[8]

Plant	MW	Furnace	Tech-nology	Primary Fuel	Reburn Fuel (%)	Baseline NOx	Outlet NOx	% Red'n
Kodak	60	Cyclone	RB	Coal , 2.25% S	Gas (22)	1.38	0.55*	60
Hennepin	71	Tang, dry	RB	Coal, 2.8 % S	Gas (18)	0.75	0.245	67
Lakeside	33	Cyclone	RB	Coal , 3.6% S	Gas (26)	0.95	0.34	66
Cherokee	158	Wall, dry	RB	Coal, 0.4 % S	Gas (22)	0.75	0.26	64
Greenidge	104	Tang. dry	RB	Coal, 1.8% S	Gas (15)	0.62	0.30	52
Niles	114	Cyclone	RB	Coal	Gas	650 ppm	300 ppm	53
Allen	330	Cyclone	RB	Coal	Gas	NA	NA	NA
Longannet 2	600	Wall, dry	RB	Coal, low S	Gas (~20)	~320 ppm	~160 ppm	50
Mercer	320	Wall, wet	FL	Coal, 0.4 % S	Gas (~7)	1.5		
Riverbend	140	Tang. Dry	FL	Coal, 0.7% S	Gas (~5)	0.45	~0.28	~40%
Joliet	340	Cyclone	FL	Coal	Gas (6)	1.106	0.68	38
Elrama	112	Roof	FL	Coal	Gas (5)	0.59	~0.4	30-35

Natural Gas Conversion or Co-firing as a means of CO_2 reduction

In its Technical Support Document associated with the section 111(d) rule EPA concluded that conversion of coal to natural gas was generally an expensive means to reduce CO_2 emissions when compared to other means.[9] On the other hand, this report will demonstrate that some facilities are, in fact, converting to natural gas. These conversions are motivated by a number of factors that include avoiding capital expenses for other regulations, such as the Mercury and Air Toxic Standards (MATS) and Regional Haze Rule as well as concern over future CO_2 emissions regulations or the need to convert from wet to dry ash handling to mitigate water pollution concerns. Finally, conversion of a boiler to a natural gas peaking unit is typically much less expensive than building a simple-cycle combustion turbine. Unlike combined cycle power plants, simple-cycle turbines do not offer heat rate advantages over a steam cycle. Converted coal plants can become cost effective alternatives to simple-cycle turbines as cycling or peaking units.

[8] Staudt, J., Natural Gas NOx Controls, for Gas Research Institute,WP98-35, November 1998

[9] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0602, pp 6-9, 6-10

Therefore, when other benefits of gas conversion or cofiring of natural gas are factored into the economics, these projects can be economically viable.

Modifications for Gas Conversion or Cofiring

Modifications to the facility that are necessary to convert a boiler to 100% gas firing or to co-fire natural gas include:

- Those modifications to the boiler that are necessary to burn natural gas and
- Those modifications that are needed to supply adequate amounts of natural gas to the boiler.

Modifications to the boiler for 100% natural gas conversion

Some of these modifications are necessary, and some are beneficial but not essential.

Replacement or modification of burners – This is usually necessary, but may not be if the facility already has burners capable of firing adequate amounts of natural gas. Existing coal burners can be modified by addition of natural gas injection spuds or other modifications. In other cases it may be necessary or even preferable to replace the burners. The decision to replace existing burners will depend upon the condition of the existing burners, their ability to be modified, and the NOx and CO emission limits that may apply. It will also depend upon whether or not the facility wants to maintain the option of burning coal sometime in the future. The cost of this will vary depending upon whether or not the modifications entail new burners or simply modification of existing burners.

Windbox modifications – The windbox of the boiler is the common plenum that provides combustion air to the burners. In some cases it is necessary to modify the windbox to assure proper distribution of combustion air after burners are replaced or modified. But, for the most part, any windbox modifications are typically minor. Extensive windbox modifications can increase the expense substantially, but are rarely needed.

Controls and sensors – Gas flames are physically different than coal flames, being far less luminous. New flame detectors and controls will be required for the gas-fired burners.

Flue Gas recirculation (FGR) – FGR may be used for furnace gas temperature control and also for NOx control. FGR is not necessary in most cases, but has been needed in some cases. For example, if the reason for the conversion is partly motivated by a need to reduce NOx emissions, FGR will help reduce emissions lower and over a wider load range. FGR, if installed, can increase the cost substantially because it may entail additional fans, ductwork, modifications to the boiler, and fan electrical supply and controls.

Furnace modifications – There are several factors that impact a gas versus coal furnace design. A furnace designed to burn coal tends to be larger than one designed to burn gas. Also, the presence of some slag on the walls of a coal furnace will impact heat transfer, and this slag will not be present when firing natural gas. Moreover, heat transfer in the furnace is affected by the luminosity of the flame, which is much greater for a coal flame. Finally, the spacing of convective pass tubing of a coal furnace is not as close in order to allow for possible ash build up. As a result of all of these effects, the heat balance between steam generation in the furnace and superheat and reheat in the convective section will be impacted to some degree when a coal fired boiler is converted to fire 100% natural gas. This must be evaluated on a case-by-case basis for each conversion project. To the degree that these effects are significant, modifications in heat transfer surface may be necessary or beneficial.

Air preheater modifications/replacement – Due to the cleaner nature of the exhaust from the natural gas flame and the fact that the exhaust gas may have more moisture in it than a coal flame (some coals, like lignite, have high moisture content while others, like bituminous, have lower moisture content), it may be beneficial to modify the air preheater to achieve better boiler efficiency. This can be one of the more expensive modifications. In most cases, it is not possible to justify this added cost unless the unit will be heavily operated.

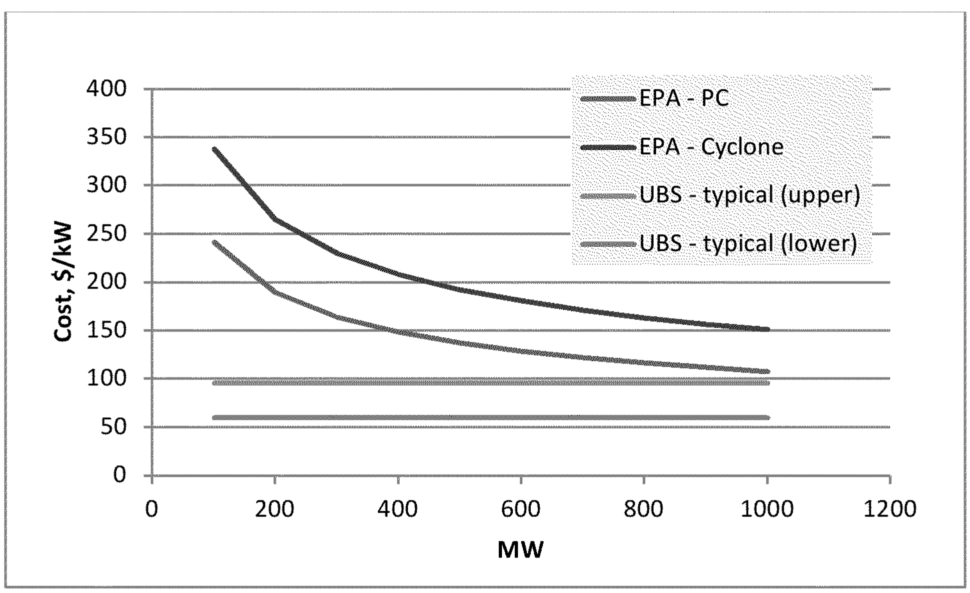
With few exceptions, these modifications can be incorporated into other planned outages, so that the impact on the plant operation is small or negligible.

EPA estimated that the cost of the boiler modifications needed for a gas conversion are as shown in Figure 2 for pulverized coal (PC) and cyclone boilers.[10] Costs are represented in terms of $/kW as a function of size (MW). The cost function covers new gas burners and piping, windbox modifications, air heater upgrades, gas recirculating fans, and control system

[10] Developed from equations in Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units Docket ID No. EPA-HQ-OAR-2013-0602 GHG Abatement Measures, page 6-4

modifications.[11] *However, in most cases all of these modifications, many of which drive up cost considerably, are not necessary.* For example, air preheater upgrades and flue gas recirculation, while often desirable, are often not performed because of the substantial added cost. Conversion to natural gas could be as simple as installing a gas nozzle on an existing coal burner and tying into the existing natural gas supply system.[12] While EPA's estimates included all of the possible modifications and have much higher cost, typical gas conversion costs are in the range of $50/kW-$80/kW for the material and installation of the boiler modifications and roughly another 15-20% to cover owner's costs, and these costs are also shown on Figure 2 as well.[13] Therefore, depending upon the extent of the modifications needed, the cost may vary quite a bit. Assuming a capital cost of $100/kW, a capital recovery factor of 13% and a capacity factor of 50%, this equates to a levelized cost of about $3/MWh. The cost of increasing natural gas supply to the plant would be in addition to the costs of the boiler modifications.

Figure 2. Estimated cost for the boiler modifications associated with gas conversions.
Note: EPA estimates include all possible modifications, while those cited to UBS are typical



Fuel costs will generally increase because natural gas is more expensive than coal. The difference will depend upon the relative cost of the fuels for the specific plant. For example, for facilities that burn Central Appalachian coal, the difference in fuel cost between natural gas and

[11] http://www.epa.gov/powersectormodeling/docs/v513/Chapter_5.pdf
[12] Brian Reinhart, Alap Shah, Mark Dittus, Ken Nowling, Bob Slettehaugh, "Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch", POWER-GEN International 2012.
[13] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

coal is much less than that for a boiler that burns local, surface-mined coal. The increased fuel costs will be partially offset by reduced operation and maintenance costs, as discussed earlier and examined in some of the Case Studies later in this report.

Modifications to the boiler for natural gas cofiring

Modifying a boiler for natural gas cofiring can sometimes be done with fairly minimal modifications, depending upon the intent and how much gas will be co-fired. Facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters. In this case gas cofiring up to the capacity of the gas igniters can be performed at no additional capital cost. In some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications. Some equipment that may be added include:

Gas injectors - If natural gas is used for reburning, modifications to the upper furnace area will be necessary, and will, in most cases, require some pressure part changes to install locations for the gas injectors and perhaps overfire air.

Sensors and controls – Sensors are needed to monitor flames for the purpose of safety.

As noted earlier in this document, gas reburning was used commercially and demonstrated commercially in the 1990s as a means of NOx control. The cost of natural gas reburning was typically estimated to be on the order of $15/kW for normal reburning, which included the gas injectors, overfire air, and associated controls. Using the Chemical Engineering Plant Cost Index (CEPCI) to escalate these costs to 2014 costs results in about $23/kW.[14] Actual costs would be less in many cases because today many boilers are already equipped with overfire air, and that part of the modification may be unnecessary today. In the case of fuel lean gas reburning, the only boiler modification is associated with the gas injectors, and overfire air is not necessary. As a result, fuel lean gas reburn would be a slightly less expensive retrofit.

Gas supply modifications

If the plant does not currently have adequate natural gas available on site for cofiring or for natural gas conversion, it will be necessary to increase supply. Natural gas must be brought on site through a pipeline. To keep gas prices reasonable and to have adequate gas capacity, power plants prefer to have natural gas delivered from a large, interstate pipeline rather than through a local distribution network. This requires pressure reducing capability as well as a

[14] Applying 1995 CEPCI of 381.1 and May 2014 CEPCI of 574.3 to $15/kW results in a cost of $22.6/kW in 2014

pipeline sized adequately for the demand. Depending upon the size of the power plant and the increase in demand placed on the interstate pipeline, it may be necessary for the interstate pipeline to increase its capacity as well. Areas around the boiler where gas piping will be added and where there is a risk of any gas leakage may be classified as areas with a risk of explosion hazard. In order to address the risk of explosion hazard, this may even entail making changes to electrical equipment in the vicinity of where there may be a risk of gas leakage.

The costs of these gas supply modifications will be driven primary by distance over which the gas line connecting the plant to the interstate pipleline must be built and the quantity of gas that must be moved. Estimates will vary based upon the needs for rights of way and other local factors, but are in the range of about $1 million per mile, with some cases more expensive.[15] EPA made estimates for over 400 plants. The costs were developed for each unit at the plant based upon the proximity to a natural gas pipeline and the estimated quantity of gas needed.[16] ATP calculated the cost per mile on a unit basis by dividing the total cost of the pipeline per unit by the mileage to the pipeline and determined the cost on a plant basis by simply adding up the cost for each unit at each plant and dividing by the mileage. In this respect the plant cost will be conservatively high because separate lines for individual units could be combined into a single, larger line at less cost. The results are shown in Table 4. From these values, a cost in the range of about $1 million to $1.5 million per mile might be regarded as typical, although for some cases the costs may be outside this range.

Table 4. Estimated cost of natural gas pipeline, developed from EPA data.

	$million/mile	
	unit basis	**plant basis**
median	$0.85	$1.60
average	$0.83	$1.97

There have been a number of announced and completed natural gas conversion projects and they are listed in Table 5. This table is not a complete listing of all announced projects, only those that have been verified. In some cases projects were announced and then cancelled. In other cases the decision was made to convert to natural gas combined cycle or a combustion turbine. It is also possible that some announced projects may not be on this list.

[15] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

[16] May be downloaded at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Table 5. Summary of announced coal to gas conversion or cofiring projects

State	Plant Name	Unit	MW	Status or completion date
AL	E C Gaston	1	254	Complete by 2015[17] ~30 mile pipeline
AL	E C Gaston	2	256	
AL	E C Gaston	3	254	
AL	E C Gaston	4	256	
AL	Greene County	1	254	Complete by 2016[18]
AL	Greene County	2	243	
AZ	Cholla	1	116	Convert in 2025[19]
AZ	Cholla	3	271	
AZ	Sundt, Irvington	4	156	Complete by 2018[20]
CO	Cherokee	4	352	Complete 2017[21] 34 mi. pipeline
DE	Edge Moor	3	86	Completed
DE	Edge Moor	4	174	Completed
GA	Yates	Y6BR	352	Complete by 2015[17]
GA	Yates	Y7BR	355	
IL	Joliet	71	250	Complete by 2016[22]
IL	Joliet	72	251	
IL	Joliet	81	252	
IL	Joliet	82	253	
IL	Joliet	9	590	
IN	IPL - Harding Street Station (EW Stout)	5	106	Complete by 2016[23]
IN	IPL - Harding Street Station (EW Stout)	6	106	
IN	IPL - Harding Street Station (EW Stout)	7	435	
IA	Riverside	9	128	Complete by 2016[24]
MS	Watson	4	232	Complete by April 2015[18]
MS	Watson	5	474	
MN	Hoot Lake	2	58	Complete by 2020[25]
MN	Hoot Lake	3	80	
MN	Laskin Energy Center	1	55	Complete in 2015[26]
MN	Laskin Energy Center	2	51	
MO	Meramec	1	119	Units 1 & 2 to be converted in 2016[27]
MO	Meramec	2	120	

[17] Georgia Power 2013 Integrated Resource Plan
[18] http://online.wsj.com/articles/sierra-club-ends-opposition-to-southern-co-clean-coal-plant-in-mississippi-1407184753
[19] http://www.azcentral.com/story/money/business/2014/09/11/aps-plans-close-one-four-generators-cholla-power-plant/15455255/
[20] http://www.epa.gov/region9/air/actions/pdf/az/azfip-finalrule-june2014.pdf
http://tucson.com/business/local/tep-south-side-plant-to-stop-coal-burning-by-end/article_7db6cd7c-e2ed-5a31-88d2-198b22333ebc.html
[21] http://www.xcelenergycherokeepipeline.com/
[22] NRG Energy Investor Presentation, September 2014
[23] http://www.ibj.com/ipl-moves-to-drop-coal-from-harding-street-power-plant/PARAMS/article/49080
[24] http://qctimes.com/news/local/riverside-plant-to-switch-from-coal-to-gas/article_5d4b8f40-6511-11e2-b7cd-0019bb2963f4.html
[25] http://www.mprnews.org/story/2013/01/31/business/hoot-lake-plant-stop-burning-coal
[26] http://www.allete.com/our_businesses/minnesota_power.php
http://finance-commerce.com/2013/01/minnesota-power-converting-coal-plant-to-natural-gas/
[27] http://phx.corporate-ir.net/phoenix.zhtml?c=91845&p=irol-newsArticle&ID=1972924&highlight=

State	Plant Name	Unit	MW	Status or completion date
NJ	Deepwater	1	82	Completed
NJ	Deepwater	8	73	Completed
NY	Dunkirk	1	75	Requires construction of 9 or 11 mile pipeline. To be complete 2015[28]
NY	Dunkirk	2	75	
NY	Dunkirk	3	185	
NY	Dunkirk	4	185	
OH	Avon Lake	7	96	To be complete 2016, ~20 mile pipeline to be built.[29]
OH	Avon Lake	9	640	
OK	Muskogee	4	505	Complete by 2017[30]
OK	Muskogee	5	517	
PA	Brunner Island	1	312	Pipeline being added, unclear which units to be converted or use of cofiring [31, 32]
PA	Brunner Island	2	371	
PA	Brunner Island	3	744	
PA	New Castle	3	93	Complete by 2016[33]
PA	New Castle	4	95	
PA	New Castle	5	132	
VA	Clinch River	1	230	Two of three to be converted by September 2015, third to shutdown[34]
VA	Clinch River	2	230	
VA	Clinch River	3	230	
WI	Blount Street	8	51	Completed[35]
WI	Blount Street	9	50	
WI	Valley (WEPCO)	1	67	Complete in 2015/16
WI	Valley (WEPCO)	2	67	
WI	Valley (WEPCO)	3	67	
WI	Valley (WEPCO)	4	67	
WY	Naughton	3	330	By 2017[36]
Notes: This table is likely to be an incomplete list of all announced projects. Also, an effort was made toverify that the units on this table were not subsequently retired or are not being converted to combustion turbines or combined cycle.				

Other conversions that were announced, but the owners later decided to retire the units include Big Sandy and Muskingum River plants. In some other cases the facility owners chose to

[28] http://www.buffalonews.com/business/residents-tell-state-to-make-decision-on-duelling-dunkirk-plant-pipeline-plans-20141023

[29] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO, In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company 11/27/2013 10:16:21 AM in Case No(s). 13-2315-PL-ACE
http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

[30] http://newsok.com/oklahoma-gas-and-electric-co.-files-1.1-billion-application-for-environmental-compliance-replacement-natural-gas-plant/article/5134375

[31] http://www.power-eng.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

[32] http://www.elp.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

[33] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html
http://dis.puc.state.oh.us/TiffToPDf/A1001001A13K27B01622D11734.pdf

[34] http://www.platts.com/latest-news/coal/louisvillekentucky/aeps -clinch-river-power-plant-in-virginia-to-21100599

[35] http://host.madison.com/business/in-march-blount-street-plant-to-make-gas-its-primary/article_28618898-0489-11df-8a48-001cc4c002e0.html

[36] Pacificorp 2013 Integrated Resource Plan, Public Session Technical Workshop, July 8, 2013

retire the boiler and replace it with natural gas combined cycle or combustion turbines. In the case of Avon Lake, at one point it was expected that these units would be retired, but a more recent decision was made to convert this plant to natural gas.

The natural gas conversions that have been recently announced were primarily in response to tightened environmental regulations, such as the Mercury and Air Toxic Standards (MATS) or Regional Haze Rule (RHR). The owners determined that a natural gas conversion was the lowest cost approach for compliance with these rules. In addition, it is likely that some owners factored in the likely costs of compliance with stricter water pollution rules relating to ash management and future CO_2 emission limits.

As shown, these conversions span a wide range of locations and a wide range of plant sizes and coal types (bituminous and subbituminous). Notably, there are no lignite-fired units. Lignite-fired boilers are mine-mouth plants and therefore have very low fuel costs. The largest plants shown here are over 500 MW and the smallest units on the table are only about 50 MW. There are smaller units still that have been or will be converted to natural gas. In the following section case studies will be examined for the following facilities: Gaston, Irvington, Cherokee, Edge Moor, Yates, Harding Street, Laskin, Meramec, Deepwater, Avon Lake, Muskogee, Brunner Island, New Castle, Clinch River, Blount Street, Valley and Naughton.

Time frame for projects

In general, the boiler modifications will require under a year to perform once the contract is released, including detailed design procurement and installation,[37] and additional time should be provided for activities by the owner prior to placing the order – perhaps 18 months altogether for all activities relating to the boiler (excluding permitting). The impact to boiler outage should be no more than a few weeks, which can normally be incorporated into typical outage times. However, if the modifications are relatively modest, the time could be much less and should have no impact to outages.

The time-limiting factor may be the pipeline-related activities. If a new pipeline must be built, as opposed to expansion of existing pipeline, it is necessary to gain rights of way. In the case of the 34 mile pipeline for the Cherokee plant, construction started in early 2014 and was expected to be complete in October 2014 – under one year. Of course, prior to construction it

[37] UBS Investment Research Coal to Gas Plant Conversion Conference Call Transcript, Interview with Angelos Kokkinos of Babcock Power, May 29, 2013

was necessary to obtain the necessary rights of way and construction permits. The project was initially approved by the Colorado Public Utilities Commission in late 2010.[38] Not factoring in the work performed prior to that agreement (no doubt preliminary engineering and feasibility studies were necessary) the experience at Cherokee indicates for such an extensive pipeline four years might be needed – although construction is less than a year. On the other hand some other pipeline projects may be moving along a faster track. Another example of a plant that requires a new pipeline is Avon Lake in Ohio. In February 2014 the Public Utilities Commission of Ohio approved of NRG Gas Pipeline as a utility that could build a new, roughly 20-mile pipeline along one of two routes proposed in their November 2013 application. [39, 40] The company is working to acquire the needed property and the plant should be operating on natural gas by spring 2016.[41, 42] Boiler modifications could be performed concurrently with the pipeline construction. As a result, total construction activities should be a year or less for most facilities with engineering and other necessary planning activities preceding them.

The Dunkirk station conversion near Buffalo, NY is still another project that is in the works. Dunkirk is owned by NRG Energy. One of two alternative pipeline proposals will be selected by the New York State Public Service Commission. One, by National Fuel Gas Company, is a 9.3 mile pipeline that would cost an estimated $34.5 million. Another is an 11.3 mile pipeline by the plant owner's affiliate, Dunkirk Gas Corporation, at a yet undetermined cost. The project is planned to be completed in September 2015.[43] This project, then, will require less than a year to construct and put in place once the pipeline alternative is selected. In addition, there was planning and other preparation that likely required a year or so.

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[38] http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_-_Clean_Jobs_Plan
[39] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html
[40] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO, In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, 11/27/2013 10:16:21 AM
[41] http://chronicle.northcoastnow.com/2014/08/28/neighbors-learn-planned-pipeline/
[42] http://avonlakefacts.com/history.html
[43] http://www.buffalonews.com/business/residents-tell-state-to-make-decision-on-duelling-dunkirk-plant-pipeline-plans-20141023

Case Studies

The following are plants where natural gas conversions have been performed or are planned. The conversions being performed at these facilities will be examined in more detail in the following Case Studies.

- Gaston
- Irvington
- Cherokee
- Edge Moor
- Yates
- Harding Street
- Laskin
- Meramec
- Deepwater
- Avon Lake
- Muskogee
- Brunner Island
- New Castle
- Clinch River
- Blount Street
- Valley
- Naughton

Case Study 1. Plant Gaston Units 1-4, Alabama

Plant Gaston, shown in Figure 3, is located near Shelby, Alabama and operated by Alabama Power, part of Southern Company. In May 2012, Alabama Power announced its plans to convert units 1-4 at roughly 250 MW each to natural gas rather than continue to operate on coal and install pollution controls needed to comply with the Mercury and Air Toxics Standards (MATS). Construction on the project commenced in early 2014 with blasting completed by May 2014.[44] The project is planned for completion by 2015 – or less than three years from announcement to completion. Assuming a year for evaluation, this indicates a total time likely of under four years. Unit 5, which is larger, will continue to burn coal. Because the facility did not originally have adequate natural gas on site (startup fuel was oil), it is necessary to construct a 30-mile natural gas pipeline to connect it to a gas supply located about 30 miles south of the plant.

Plant Gaston units 1-4 are all wall-fired boilers that burn bituminous coal. Table 6 shows information on each of the units at Plant Gaston including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 based upon information reported to US EPA under the Title IV program. The 2013 estimated capacity factors for the units are in the range of 20%-30%.[45] As such, these are not base loaded and primarily cycle to meet load demands.

Cost information on the project was redacted from the publicly available Integrated Resource Planning documents and is therefore not available.

Table 6. Information on Plant Gaston units 1-4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
E C Gaston	1	254	AL	wall	Bit.	9837	28%	1960	29	4.0	2,154
	2	256	AL	wall	Bit.	9928	27%	1960	29	4.1	2,186
	3	254	AL	wall	Bit.	9843	21%	1961	25	4.4	2,337
	4	256	AL	wall	Bit.	9766	27%	1962	27	3.7	1,962

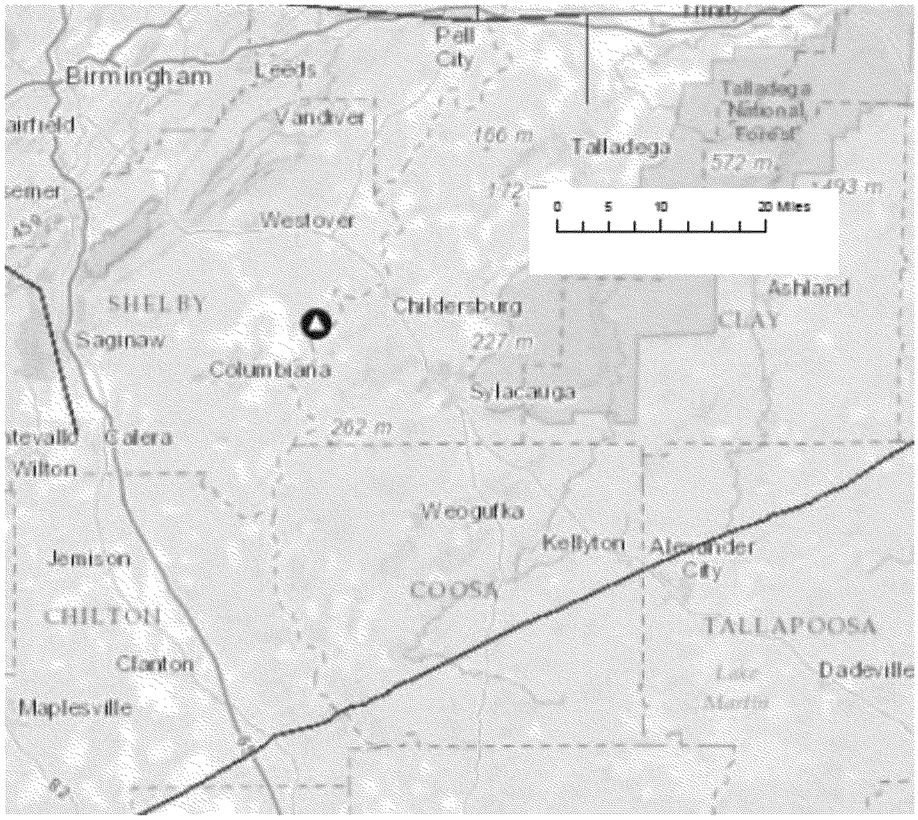
[44] http://www.dykon-blasting.com/Archives/Latex- Gaston/index.htm

[45] Capacity factor is estimated from reported 2013 gross output and rated capacity

Figure 3. Plant Gaston.

Figure 4 shows the location of Plant Gaston (the black circle) compared to the Transcontinental interstate gas pipeline (the blue line). Plant Gaston, located southeast of Birmingham, will be connected to the interstate gas pipeline located to the south that passes through Coosa County.

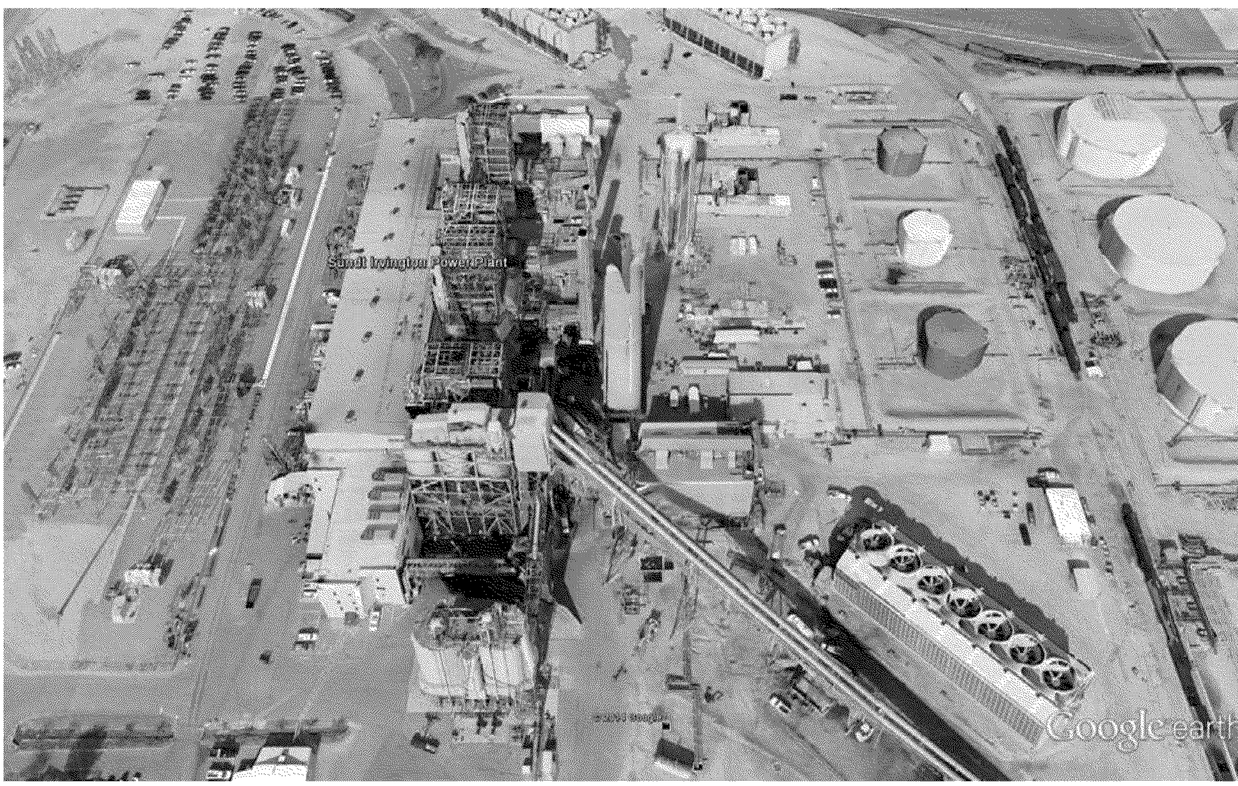
Figure 4. Location of Plant Gaston (black circle with white triangle) and interstate gas pipeline (blue line) it will tie in to. (Source, Energy Information Administration)



Case Study 2. Irvington (Sundt) unit 4, Arizona

Irvington Unit 4 (shown in the foreground of Figure 5) is the sole coal-fired unit at the otherwise gas-fired Irvington (also known as Sundt) station. The facility was originally all gas fired, but unit 4 was converted to coal in the 1980s.[46] After over 30 years of coal operation, Tucson Electric has agreed to convert the 156 MW unit 4 back to natural gas firing, consistent with the other units at the site, as part of its plan to comply with Arizona's regional haze requirements.

Figure 5. Irvington station with Unit 4 in foreground



Irvington unit 4 is a wall-fired boiler that, according to EPA's NEEDS v5.13 database, burns bituminous and subbituminous coal. Table 7 shows information on Irvington 4 including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 based upon information reported to US EPA under the Title IV program.

[46] Tucson Electric Power Irvington Generating Station Air Quality Permit # 1052 TECHNICAL SUPPORT DOCUMENT (TSD) May 18, 2007 http://pima.gov/deq/permits/PDF/1052TSD.pdf

The conversion was motivated as a lower cost approach than SCR to reduce NOx emissions for compliance with Regional Haze Rule requirements and will be completed before the end of 2017. Tucson Electric reached the agreement with US EPA to do the conversion in January 2014. Because natural gas is on site and is already available to unit 4, which was originally a gas unit, the cost of converting was very low, reportedly on the order of hundreds of thousands of dollars.[47]

Table 7. Information on Irvington unit 4, to include 2013 emission rates

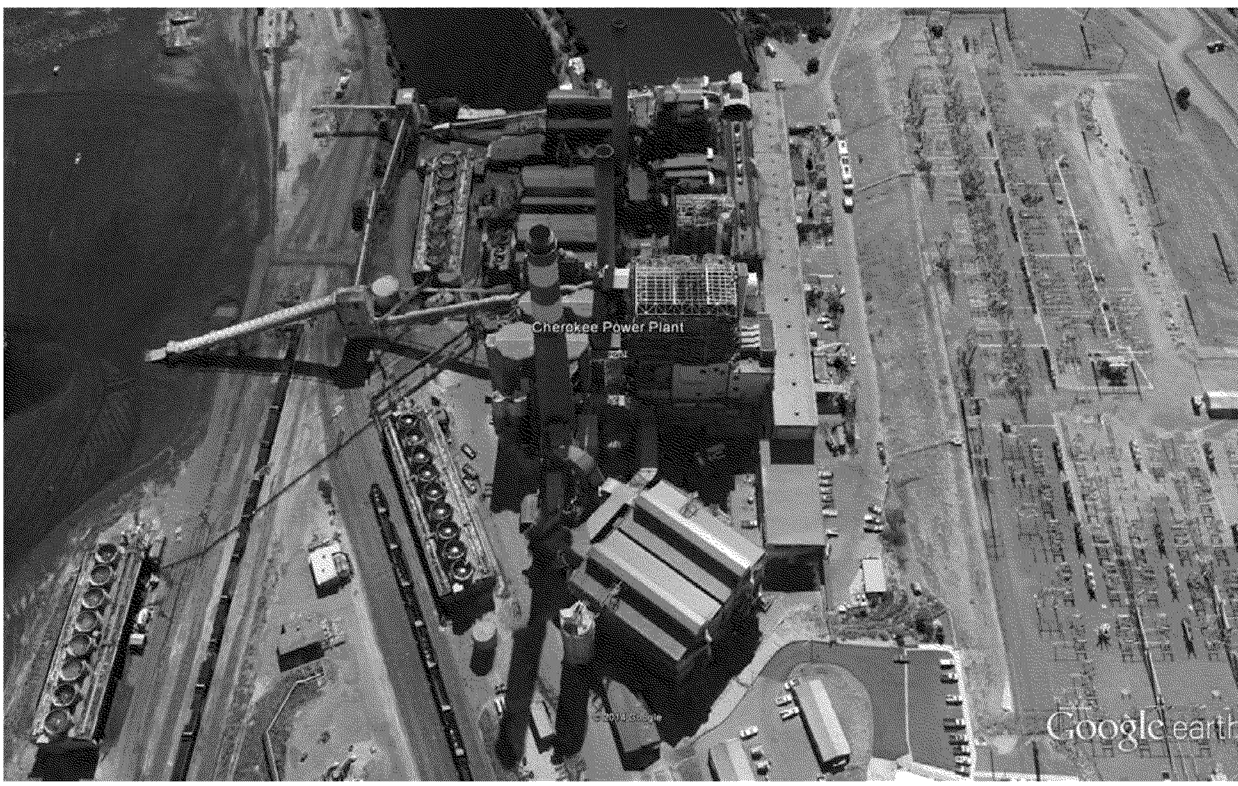
Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Irvington	4	156	AZ	wall	Bit., Subbit.	10732	32%	196 7	6.3	4.6	2,123

[47] http://tucson.com/business/local/tep-south-side-plant-to-stop-coal-burning-by-end/article_7db6cd7c-e2ed-5a31-88d2-198b22333ebc.html

Case Study 3. Cherokee unit 4, Colorado

Cherokee station, operated by Xcel Energy, is located just north of Denver, CO. Xcel Energy has agreed to shut down units 1-3, convert 352 MW unit 4 to natural gas and will build a new 569 MW natural gas combined cycle plant on the site. Units 1-2 are already retired. Unit 3 will be retired in 2015. Unit four is shown in the foreground of Figure 6 and its conversion to natural gas will be completed in 2017.

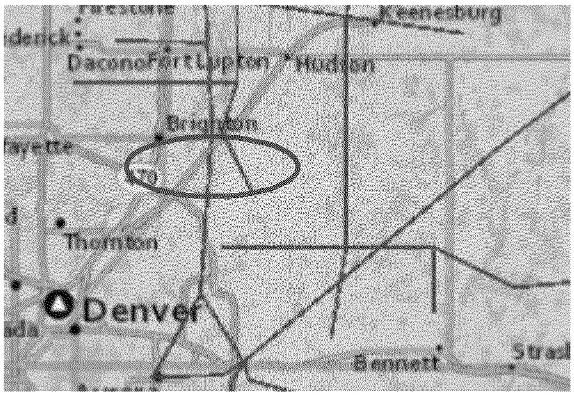
Figure 6. Cherokee generating station, with unit 4 in the foreground.



The project required installation of 34 miles of new, 24-inch steel, high-pressure natural gas transmission pipeline from a new Fort Lupton natural gas metering facility, as shown in Figure 7. Work on the pipeline commenced early 2014 and is completed, in time for the 2015 start-up of the combined cycle plant.[48, 49] The total cost of the pipeline was $110 million to include design, land acquisition, construction and testing.[50]

[48] http://www.xcelenergycherokeepipeline.com/
[49]http://www.mcilvainecompany.com/Decision_Tree/subscriber/Tree/DescriptionTextLinks/Power%20Projects/Kiewit%20569%20MW%20Natural%20Gas-fired%20Cherokee%20Power%20Plant%20to%20Use%20Less%20Water%20than%20Present.htm
[50] http://www.xcelenergycherokeepipeline.com/

Figure 7. Cherokee station (black circle with white triangle near Denver) in relation to Fort Upton natural gas metering facility (circled in red)



Source: Energy Information Administration

Cherokee unit 4 is a tangentially-fired boiler that, according to EPA's NEEDS v5.13 database, burns bituminous and subbituminous coal. Table 8 shows information on Cherokee 4 including 2013 calculated emission rates in lb/MWh for SO_2, NOx and CO_2 and capacity factor based upon information reported to US EPA under the Title IV program.

Cherokee unit 4 is a BART affected unit, and the timing of the gas conversion is consistent with the need to comply with BART.

Table 8. Information on Cherokee unit 4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Cherokee	4	352	CO	tangential	Bit., Subbit.	10,880	68%	1969	1.6	3.0	2,081

ED_000197-2-00018898-00033

Case Study 4. Edge Moor Power Plant units 3 and 4, Delaware

After Conectiv sold the Edge Moor plant (shown in Figure 8) to Calpine in 2010, Calpine made the decision to convert the two coal-fired boilers on the site to natural gas. Both units are tangentially fired boilers that burned bituminous coal. Unit 3 is 86 MW and Unit 4 is 174 MW. Natural gas was already available on site.

Figure 8. Edge Moor Power Plant

Table 9 shows information on the two units, to include a comparison of emissions between 2009 (when coal was last fired for a full year) and 2013 (when the facility burned 100% natural gas). As shown, the emissions of all pollutants dropped dramatically, 100% drop in SO_2 emission rate, 50% or better reduction in NOx emission rate, and 45% reduction in CO_2 emission rate. Also, at only 10% capacity factor, the units are operated only as peaking units.

Table 9. Information on Edge Moor units 3 and 4, to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	2013 Cap. Fctr.	Yr on line	2009 lb/MWh			2013 lb/MWh		
									SO2	NOx	CO2	SO2	NOx	CO2
Edge Moor	3	86	DE	tangential	Bit.	11,954	10%	1957	5.4	1.6	2,327	0.0	0.8	1,261
Edge Moor	4	174	DE	tangential	Bit.	11,279	10%	1966	8.5	1.7	1,954	0.0	0.7	1,081

Case Study 5. Yates units 6 and 7, Georgia

Plant Yates is operated by Georgia power and is located southwest of Atlanta. Georgia Power decided to convert both roughly 350 MW units 6 & 7, shown in Figure 9, to natural gas rather than install additional controls for MATS compliance. The plants are already equipped to burn some gas and routinely cofired it during the peak months of May through September,[51] but will need to make some modifications in order to burn gas full time, including installation of oxidation catalyst.[52]

Figure 9. Yates units 6 & 7,

[51] 2013 EIA Form 923 data shows 1,320,400 mcf of natural gas burned during those months

[52] http http://www.bentley.com/en-US/Engineering+Architecture+Construction+Software+Resources/User+Stories/Be+Inspired+Project+Portfolios/United+States/Plant+Yates+Southern+Company.htm://www.times-herald.com/local/20140330Plant-Yates-update

Cost information on the project was redacted from the publicly available Integrated Resource Planning documents; however, some estimates place the project cost at $40 million, or roughly $57/kW.[53]

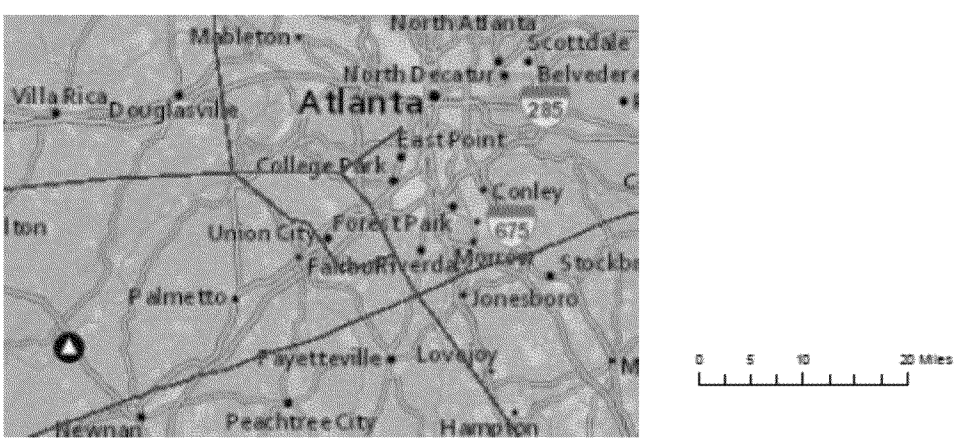
Table 10 shows data on the two tangentially-fired units, to include 2013 emission rates and capacity factor. As shown, both units had been operated at lower capacity factors, with most operation during the summer peaking months.

Table 10. Information on Plant Yates 6 & 7, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Yates	Y6BR	352	GA	tangential	Bit.	10492	29%	1974	22.0	2.6	1,966
Yates	Y7BR	355	GA	tangential	Bit.	10487	15%	1974	21.7	2.2	1,970

Figure 10 shows the location of Plant Yates (black circle with white triangle) relative to Atlanta and to the nearby Transco Interstate gas pipeline. There is a 6.5 mile, 370 MMCFD pipeline from the Transco pipeline to Plant Yates that was installed in 1999.[54]

Figure 10. Plant Yates (black circle with white triangle) and nearby interstate gas pipelines (blue lines).



[53] http://www.times-herald.com/local/20140330-Plant-Yates-update
[54] http://www.georgiapower.com/about-energy/energy- sources/natural -gas-safety.cshtml

Case Study 6. Harding Street Station, Indiana

All remaining operable boilers at Harding Street Station, located in Indianapolis, will be retrofit to burn natural gas by 2016 in lieu of installing controls for MATS compliance or new water pollution equipment. The three tangentially-fired boilers, to the right in Figure 11, with a combined output of nearly 550 MW were operated in 2013 at capacity factors of about 70% or greater in 2013. The project will add roughly $1 to the average ratepayer's monthly bill, but alternatives that would have continued use of coal would have had a greater cost.[55]

Figure 11. Harding Street Station – Units 5-7 to the right

Table 11 shows data on the three units, to include 2013 emission rates and capacity factor. As shown, all three units had been operated at factors of about 70% or greater, suggesting base load or very limited load cycling. Natural gas was already located on site, as the facility has six

[55] http://www.ibj.com/ipl-moves-to-drop-coal-from-harding-street-power-plant/PARAMS/article/49080

combustion turbines and two small natural gas fired boilers that based upon review of EPA's Air Markets Program Data do not appear to have operated on coal at any time at least since 1990.

Table 11. Information on Harding Street Station units 5, 6, 7, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Harding Street Station	5	106	IN	tangential	Bit.	10541	73%	1958	39.3	2.4	2,051
	6	106	IN	tangential	Bit.	10491	72%	1961	37.9	2.4	1,983
	7	435	IN	tangential	Bit.	10517	82%	1973	1.3	1.7	2,059

Case Study 7. Laskin Energy Center, Minnesota

Minnesota Power will be converting its two 61-year old, 55 MW boilers at Laskin Energy Center, shown in Figure 12, to natural gas in 2015 in lieu of installing controls for MATS compliance. The retrofit is expected to be completed over a routine outage at a projected cost of roughly $15 million, or about $136/kW for all modifications.[56]

Figure 12. Laskin Energy Center

Table 12 shows data on the two units at Laskin, to include 2013 capacity factor, current heat rate (from NEEDS v5.13) and 2013 emission rates. According to NEEDS v5.13, the two units fired bituminous and subbituminous coal and used a wet scrubber for PM control. Capacity factors in 2013 are 50%-60%, indicating that these units perform load following duty but also operate a substantial amount of time.

[56] http://finance-commerce.com/2013/01/minnesota-power-converting-coal-plant-to-natural-gas/

Table 12. Information on Laskin units 1 & 2, to include 2013 emission rates

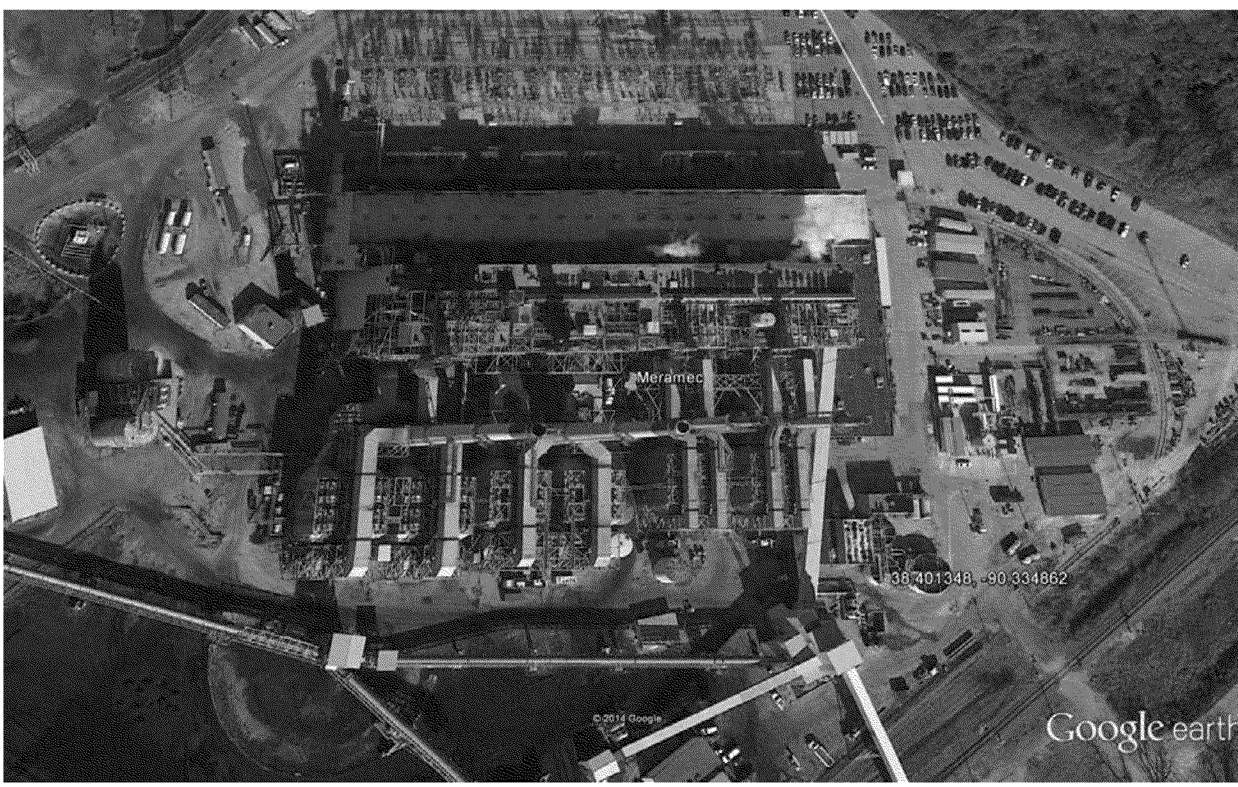
Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Laskin	1	55	MN	Tangential	Bit., Subbit.	12783	56%	1953	1.5	2.0	2,463
	2	51	MN	Tangential	Bit., Subbit.	12875	58%	1953	1.5	2.0	2,456

Case Study 8. Meramec Power Plant, Missouri

Meramec Power plant shown in Figure 13, has four units. In their 2014 Integrated Resource Plan (IRP), Ameren Missouri announced plans to convert units 1 and 2 to natural gas in 2015 and to retire all four Meramec units in 2022.[57] Although the plant already uses some natural gas, it is currently only utilized for the combustion turbines that are on site and for start-up. It is likely that the existing pipeline to the plant may need to be expanded somewhat to provide adequate fuel for units 1 & 2.

The costs of the modifications were not available in the IRP.

Figure 13. Meramec Power Plant



As shown in Figure 14, natural gas is available to the plant from the adjacent interstate pipeline, which is located southwest of Saint Louis where the Meramec River meets the Mississippi River.

[57] Ameren Missouri 2014 Integrated Resource Plan, Chapter 9

Figure 14. Location of Meramec Plant (black circle with white triangle southwest of Saint Louis) and interstate gas pipelines (blue lines).

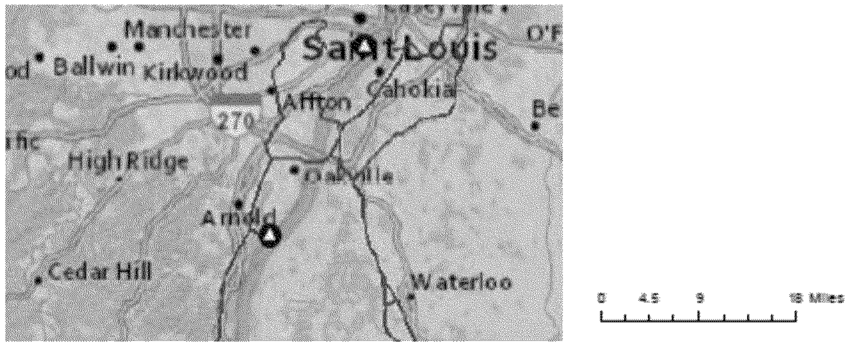


Table 13 includes data on the two units that are planned for conversion. As shown, these units appear to be load following units based upon their 2013 capacity factor, which is in the 40-50% range.

Table 13. Information on Meramec units 1 & 2, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Meramec	1	119	MO	tang	Bit Subbit	10845	42%	1953	4.7	1.3	2,297
	2	120	MO	tang	Bit, Subbit	10644	48%	1954	4.9	1.3	2,400

Case Study 9. Deepwater, New Jersey

Deepwater power plant on the Delaware River in New Jersey is shown in Figure 15. The units operate as peaking units. Unit 1 is a cyclone boiler that was converted to natural gas many years ago and rarely operates now. Unit 8 was converted from bituminous coal to natural gas in 2010. There was pre-existing natural gas infrastructure and therefore little additional infrastructure to add.

Figure 15. Deepwater Power Plant

The units operate only in a peaking mode, with very low capacity factors in the range of 5% as shown in Table 14.

Table 14. Information on Deepwater unit 8, to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	2009 Cap. Fctr.	2013 Cap. Fctr.	Yr on line	2009 lb/MWh			2013 lb/MWh		
										SO2	NOx	CO2	SO2	NOx	CO2
Deepwater	8	73	NJ	wall	Bit.	10,331	11%	5%	1954	9.6	3.6	1,841	0.0	2.2	1,200

Case Study 10. Avon Lake, Ohio

Avon Lake power plant, shown in Figure 16, was destined for shut down by 2015 by previous owner GenOn. NRG Energy, after completing the acquisition of GenOn in December 2012,[58] announced in June 2013 that they would convert the Avon Lake and New Castle plants to natural gas.[59] There was no natural gas on site, and NRG applied in November 2013 to the Public Utilities Commission of Ohio (PUCO) for permission to create and operate its own natural gas pipeline company[60] and received approval in February 2014.[61]

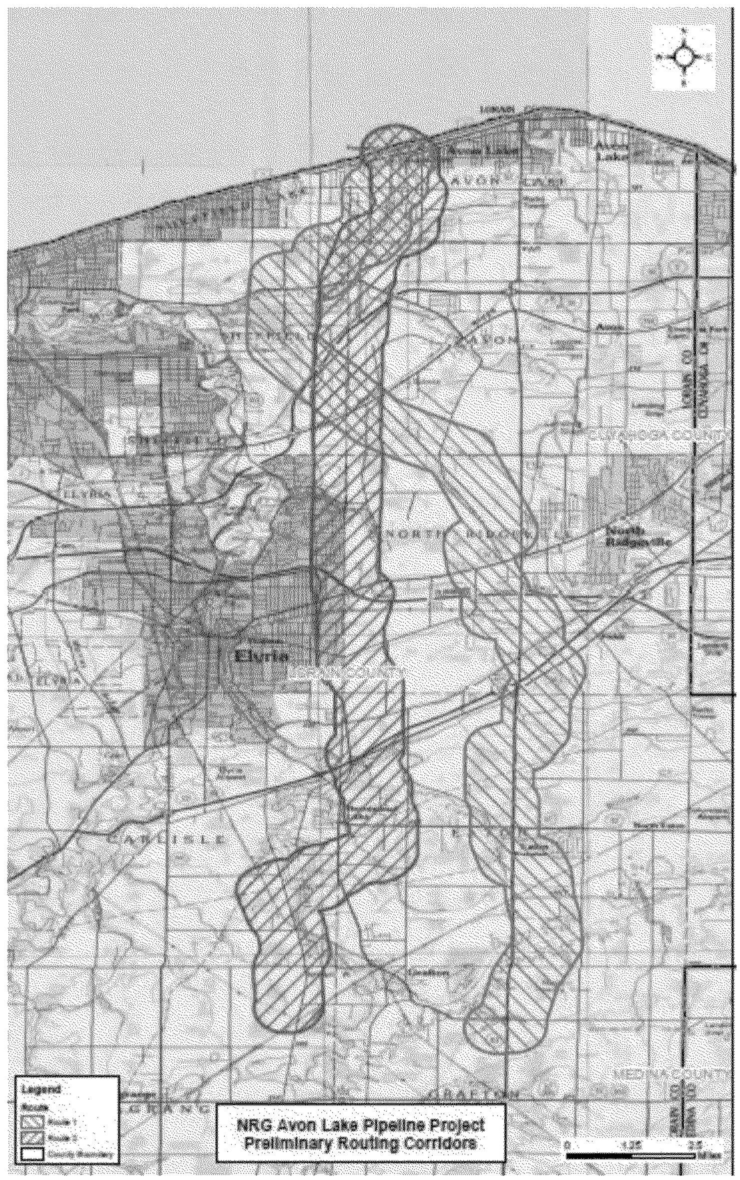
Figure 16. Avon Lake Power Plant

As of August 2014, NRG was obtaining the property rights from landowners in Lorain County, Ohio to build a 20-mile, 24-inch diameter underground pipeline which requires a 50-foot permanent easement for operation and maintenance. The route of the pipeline, with the two original options shown in Figure 17 (the green route is apparently what was selected), would

[58] http://www.bizjournals.com/houston/news/2012/12/14/nrggenon-merger-complete.html
[59] http://www.newsnet5.com/news/local-news/oh-lorain/avon-lake-power-plant-to-switch-from-coal-to-natural-gas-station-was-slated-to-close-in-2015
[60] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, APPLICATION, November 27, 2013
[61] http://www.cleveland.com/business/index.ssf/2014/02/nrg_energy_plans_to_build_natu.html

extend south from the power plant to an existing natural gas pipeline owned and operated by Dominion East Ohio. [62] NRG has not disclosed the total cost of the pipeline or power plant conversion.

Figure 17. Two originally proposed routes for the natural gas pipeline for the Avon Lake Power Plant conversion [63]



[62] http://chronicle.northcoastnow.com/2014/08/28/neighbors-learn-planned-pipeline/#

[63] BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO In the Matter of the Application of NRG Ohio Pipeline Company LLC for Authority to Operate as an Ohio Pipeline Company, Case No. 13-2315-PL-ACE, APPLICATION, November 27, 2013

Table 15 shows data on Avon Lake power plant, including 2013 emissions rates. As shown here, Avon Lake 20 is a large unit, over 600 MW, and a low heat rate of under 10,000 Btu/kWh. Unit 12, the larger of the two, had been operating as a load following role as of 2013. Future use is likely to be for peaking or load following use as well.

Table 15. Information on Avon Lake to include 2013 emission rates

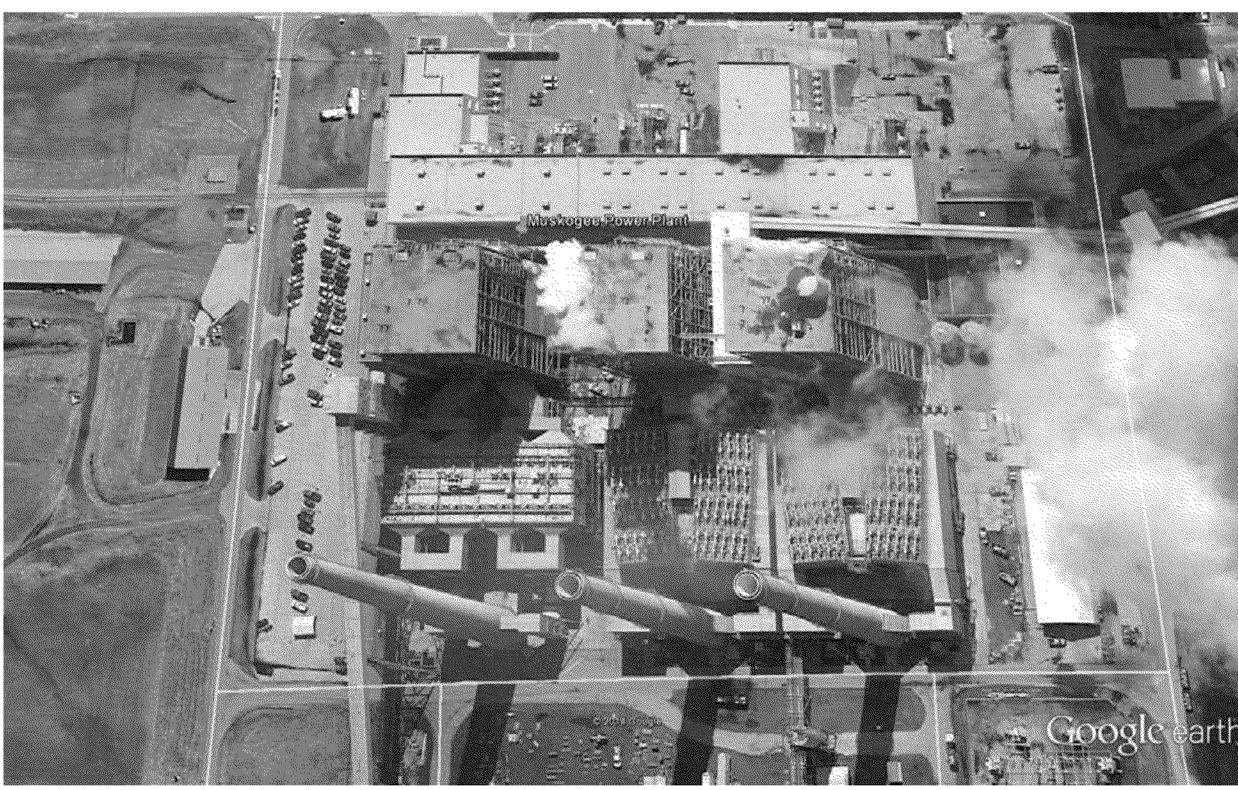
Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh, lb/MMBtu* 2013 SO2	2013 NOx	2013 CO2
Avon Lake	10	96	OH	tang	Bit	12829	10%	1949	3.0	0.4	205
	12	640	OH	cell	Bit	9823	48%	1970	26.3	2.7	1,796

*Avon Lake 10 emission rates in lb/MMBtu and Avon Lake 20 emission rates in lb/MWh

Case Study 11. Muskogee Units 4 & 5, Oklahoma

Oklahoma Gas and Electric will be converting each of the over 500 MW Muskogee Units 4 & 5, shown in Figure 18, to natural gas. According to EIA 923 data, a small amount of natural gas is already burned at the site, likely for start-up, but additional capacity is needed. The 2014 Integrated Resource Plan shows an expected overnight capital cost of $35.7 million per unit. The capital cost includes new pipeline capacity as well as boiler modifications. However, this will provide an expected $5.57 million per unit in annual savings in fixed operating costs and $0.12/MWh in reduced variable operating and maintenance costs.[64] Based upon the 2012 IRP, a new gas pipeline accounted for most of that capital cost.[65] Both Muskogee units 4 & 5 are BART eligible units and the decision to convert the two units to gas in 2018, in time for the January 2019 Regional Haze Rule deadlines, was made after the US Supreme Court declined to consider OG&E's appeal of a lower court ruling. Muskogee unit 6, shown on the left in Figure 18, is not a BART unit and will continue to burn coal.

Figure 18. Muskogee power plant, units 4 & 5 are the two units to the right.



[64] Oklahoma Gas and Electric Company, 2014 Integrated Resource Plan, bear in mind that variable operating costs are separate from fuel costs.

[65] Oklahoma Gas and Electric Company, 2012 Integrated Resource Plan – then estimated the capital cost to be $70 million for the pipeline and $5.7 million for each boiler modification.

Details on the pipeline construction were not available in the IRPs. Figure 19 shows the location of the Muskogee plant relative to the nearby interstate natural gas pipelines. Although it appears that the natural gas pipeline to the west of the plant is very nearby, it is in fact on the other side of the Arkansas River and the city of Muskogee. With the plant conversion announced in 2014 and to be completed in 2018, this indicates a four year period to complete the project, not including any planning activities prior to 2014.

Figure 19. Muskogee Plant (upper black circle with white triangle) and interstate natural gas pipelines (blue lines), source: EIA

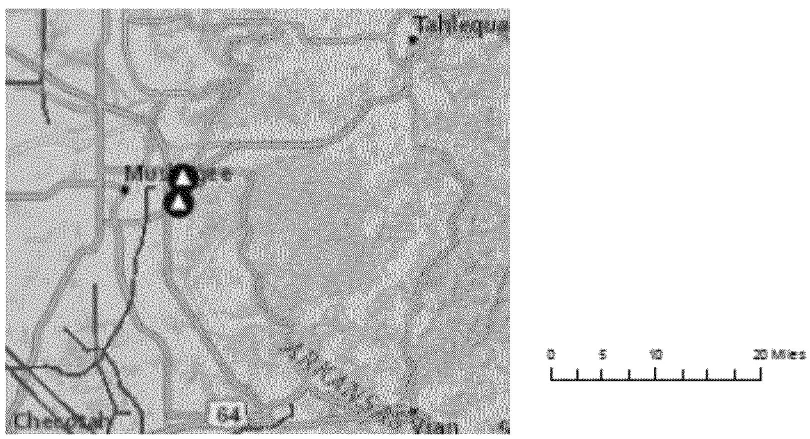


Table 16 shows the information on Muskogee units 4&5, to include 2013 emission rates, estimated capacity factor based upon 2013 Title IV data, and heat rate (from NEEDS v5.13). At over 500 MW each, they are among the largest units identified in this study for coal to gas conversion. Both units burn subbituminous (PRB) coal and in 2013 operated with capacity factors around 50%, indicating that they operated that year in primarily in a load following mode.

Table 16. Information on Muskogee units 4 & 5, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
Muskogee	4	505	OK	tangential	Subbit.	10593	44%	1977	6.3	4.6	2,123
	5	517	OK	tangential	Subbit.	10652	51%	1978	4.6	3.6	2,171

Case Study 12. Brunner Island, Pennsylvania

PPL Brunner Island is a large (over 1400 MW) scrubbed facility with three units shown in Figure 20. As a scrubbed plant, Brunner Island is unique among the facilities. According to the National Electric Energy Data System (NEEDS), the scrubbers went on line in 2008 and 2009. So, they are modern wet FGD systems.

On September 27, 2014 the Pennsylvania Department of Environmental Protection announced that it plans to issue an air permit change allowing gas firing at PPL Brunner Island. The permit will allow "for the addition of natural gas as a fuel firing option for the three existing utility boilers (Source IDs 031A, 032 and 033A) and their associated coal mill heaters that will involve the tying in of a natural gas pipeline (Source ID 301), as well as the construction of two natural gas-fired pipeline heaters (Source ID 050) at the Brunner Island Steam Electric Station in East Manchester Township, York County."[66]

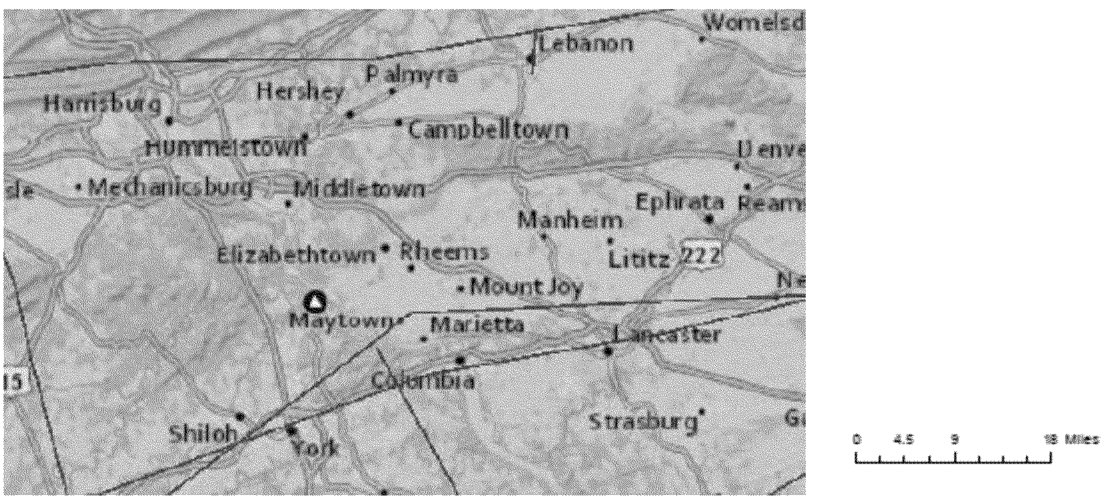
Figure 20. Brunner Island Power Plant

[66] http://www.power-eng.com/articles/2014/09/ppl-permits-gas-firing-at-big-brunner-island-coal-plant.html

The project has not yet been decided for certain. According to PPL spokesman George Lewis, PPL is still in the process of exploring gas co-firing as an option for the Brunner Island plant. "It's important to note that a decision has not been made on whether to go ahead with the project,"[67] Because the project is at an early stage, cost information is not yet available.

The plant, located southeast of Harrisburg, PA, is less than ten miles from an interstate pipeline, as shown in Figure 21.

Figure 21. Location of Brunner Island Power Plant (black circle with white triangle) and interstate natural gas pipeline (blue lines), source: EIA



It may be of note that, although Brunner Island is scrubbed, it is not equipped with SCR for NOx control. As such, gas cofiring would provide Brunner Island additional flexibility in reducing NOx emissions further and be an option that might help PPL avoid installation of SCR for NOx control at Brunner Island in the event that the reinstated Cross State Air Pollution Rule imposes more stringent NOx emission requirements on the plant in the future. It would also provide them additional flexibility to mitigate CO_2 emissions. Other considerations are that the location, in central Pennsylvania, situates it well in relation to Marcellus shale gas.

[67] http://generationhub.com/2014/09/29/ppl-permits-gas-firing-at-big-brunner-island-coal

Table 17 shows data on Brunner Island, including 2013 emission rates and capacity factor. Brunner Island is significant in the fact that it is scrubbed and has some fairly large units – one over 700 MW. The 2013 capacity factors in the range of 50% are significantly lower than they were in 2009 when capacity factors were above 70% for all three units. This drop in capacity factor is likely the result of the drop in natural gas prices during that time. Brunner Island power plant is located just to the east of the Marcellus shale gas sources.

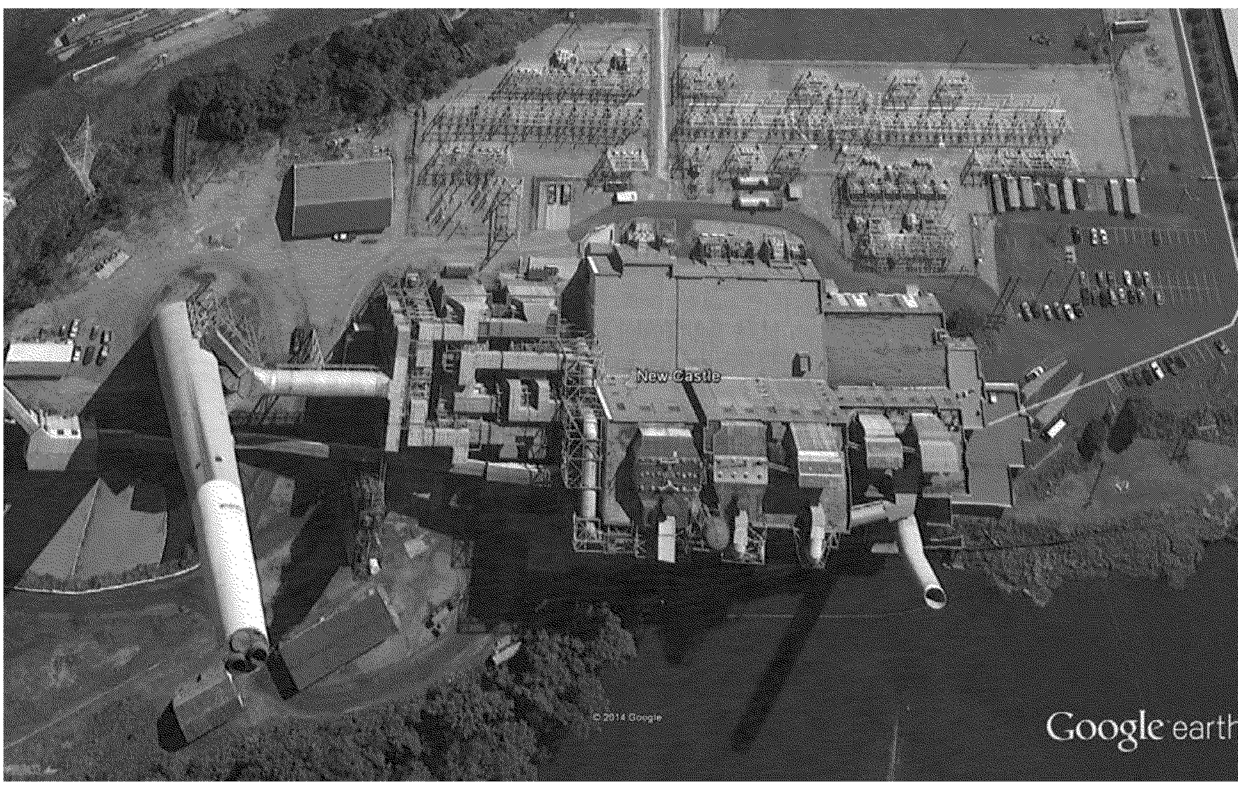
Table 17. Information on Brunner Island, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Brunner Island	1	312	PA	tang	Bit	10023	58%	1961	3.2	3.5	1,884
	2	371	PA	tang	Bit	9695	50%	1965	3.6	3.3	1,858
	3	744	PA	tang	Bit	9502	55%	1969	3.3	3.3	1,827

Cast Study 13 New Castle, Pennsylvania

NRG Energy announced that they will be converting New Castle power plant to natural gas. The facility, shown in Figure 22, has three units ranging from 93 to 132 MW in size and was destined to be shut down by April 2015 until NRG Energy announced in June 2013 that they would convert the plant to natural gas by May 2016.[68]. The conversion is scheduled to be completed in 2016 and will likely operate as a peaking unit. In September 2014, Pennsylvania Department of Environmental Protection announced its plans to issue a permit for the gas conversion, which would include the addition of gas burners to the boilers.[69]

Figure 22. New Castle Power Plant

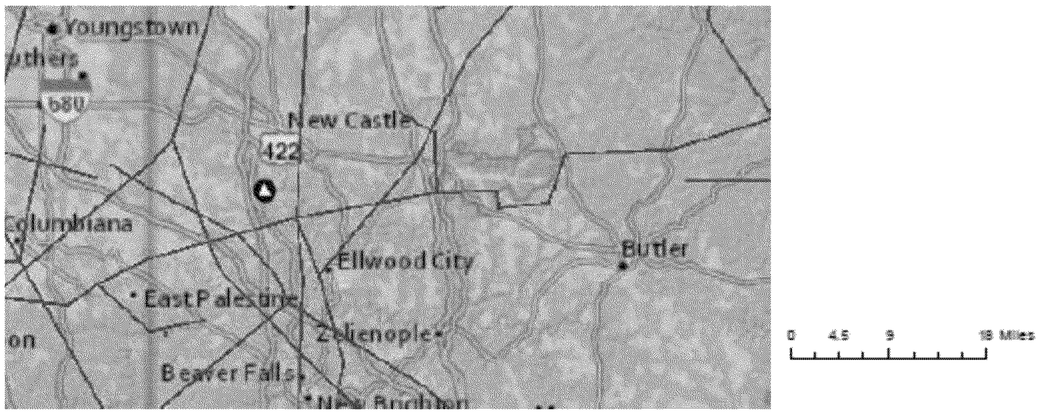


New Castle power plant is located in the middle of the Marcellus shale gas region of western Pennsylvania and is only a few miles from an interstate natural gas pipeline. The plant did not previously burn natural gas. Therefore, a natural gas pipeline will need to be built to connect the plant to the interstate pipeline, shown in Figure 23.

[68] http://www.post-gazette.com/local/region/2013/06/24/New-Castle-power-plant-switching-to-natural-gas/stories/201306240188

[69] http://www.power-eng.com/articles/2014/09/nrg-nears-permit-for-coal-to-gas-conversion-at-new-castle.html

Figure 23. New Castle Power Plant (black circle with white triangle) and interstate natural gas pipelines (blue lines), source: EIA



Data on the New Castle Plant is shown in Table 18, including emission rates and capacity factor. The units are only in the 100 MW range and will likely be operated as peaking units in the future. Capacity factors dropped off by about half between 2009 and 2013, likely due to reduced natural gas prices.

Table 18. Information on New Castle Power Plant, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh		
									2013 SO2	2013 NOx	2013 CO2
New Castle	3	93	PA	wall	Bit	11265	12%	1952	25.1	4.0	2,149
	4	95	PA	wall	Bit	11028	15%	1958	23.2	3.4	2,007
	5	132	PA	wall	Bit	10846	15%	1964	26.0	4.7	2,189

Case Study 14. Clinch River Power Plant, Virginia

Appalachian Power, part of AEP, has decided to retire one of the Clinch River units in Russell County, VA, and will convert the other two to natural gas. Clinch River Plant is shown in Figure 24. One Clinch River unit will be switched to gas in September 2015, the other in February 2016. A third 240-MW coal unit was planned for shutdown in 2014. The two remaining 230 MW units will be operating on 100% natural gas starting spring of 2016, in time to avoid retrofitting equipment for compliance with MATS. The total cost of the project, including pipeline for natural gas, is estimated to be $56 million, or $107/kW, well below the cost of a new combined cycle plant or combustion turbine. The impact to the average residential customer is estimated at less than fifty cents a month.[70] Information was not available on how much of the cost was related to the pipeline versus the boiler modifications.

Figure 24. The Clinch River Power Plant

[70] http://www.tricities.com/workittricities/business_news/article_44610142-bf81-11e3-9eae-0017a43b2370.html
http://www.platts.com/latest-news/coal/louisvillekentucky/aeps-clinch-river-power-plant-in-virginia-to-21100599

Clinch River was once one of the world's most efficient power plants. In 1960 it was the first power plant to operate with a heat rate below 9,000 Btu/kWh for a full calendar year. For the conversion it was necessary to add natural gas pipeline. Approval was sought from Virginia and West Virginia regulators in spring of 2013. In April 2014 the pipeline contract had already been awarded and both units should be operating on gas in early 2016.[70] As shown in Figure 25, Clinch River is located under ten miles from the nearest interstate pipeline.

Figure 25. Clinch River Power Plant (black circle with white triangle) and interstate natural gas pipelines (blue line)
Source: Energy Information Administration

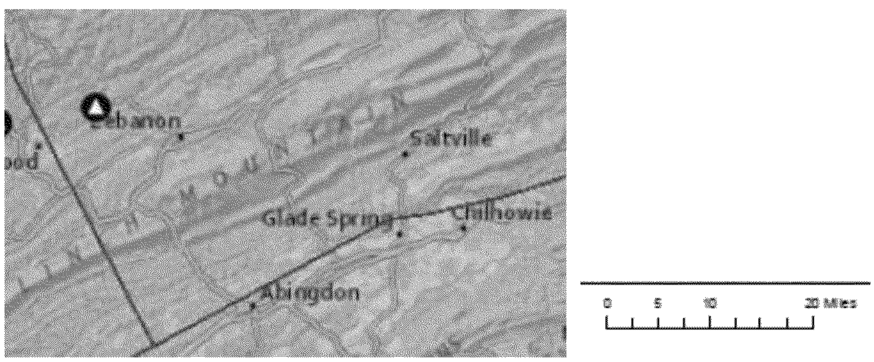


Table 19 shows data on Clinch River Power Plant, including 2013 emission rates and estimated capacity factor. As shown, the units had been operating in 2013 more or less as cycling or peaking units.

Table 19. Information on Clinch River units 1-3 to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
	1	230	VA	vertical	Bit.	10227	21%	1958	7.8	2.1	2,027
Clinch River	2	230	VA	vertical	Bit.	10179	14%	1958	8.0	2.1	2,050
	3	230	VA	vertical	Bit.	10179	14%	1958	8.4	1.8	2,099

Case Study 15. Blount Street, Wisconsin

Blount Street Station, shown in Figure 26, is in Madison, WI and has two roughly 50 MW units. With demand for electricity from the plant greatly reduced, in 2010 Madison Gas & Electric converted the plant to natural gas. The two boilers operate only as peaking units now.

Figure 26. Blount Street Station

Table 20 shows data on Blount Street Station, to include 2009 and 2013 emission rates. As shown, emission rates dropped significantly, 100% for SO_2, about 45% for NOx and about 28-33% for CO_2. As noted, the units are only operated for peaking use.

Table 20. Information on Blount Street units 8 & 9 to include 2009 and 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	Heat Rate	Yr in Srvc	2009 Cap. Fctr	2013 Cap. Fctr	2009 lb/MWh			2013 lb/MWh		
										SO2	NOx	CO2	SO2	NOx	CO2
Blount Street	8	51	WI	wall	Bit.	14500	1957	4%	2%	25.8	4.2	2,479	0.0	2.3	1,794
	9	50	WI	wall	Bit.	14278	1961	3%	2%	25.8	4.3	2,401	0.0	2.5	1,608

Case Study 16. Valley units 1-4, Wisconsin

Valley units 1-4, shown in Figure 27, supplies electricity to the grid and steam to nearby customers in downtown Milwaukee. Conversion of each of the four 67 MW units will be completed in 2015 and 2016, thereby avoiding the retrofit of equipment for MATS compliance. The total cost of the project is $62 million for the plant modifications and $4.25 million to install 1,800 feet of high pressure natural gas supply and regulation equipment.[71] This equates to a total cost of $247/kW. The relatively high cost of the boiler retrofit is a result of the small size (67 MW each) and the extensive modifications to the boiler and steam supply system that included:

- Removing the coal burners and associated coal piping from the existing four boilers;
- De-energizing and decommissioning coal conveyors, coal silos, coal mills, coal feeders, the bottom ash removal system, and the fly ash removal system;
- Installing new natural gas burners in each of the four boilers;
- Installing a natural gas header and associated valves to supply fuel to the new gas burners;
- Installing new flue gas recirculation (FGR) fans and associated ductwork and electrical work for use in the control of emissions from the boilers;
- Sealing each boiler after removal of existing burners, soot blowers, and bottom seal equipment;
- Installing boiler let-down valves to reliably support steam supply to the district heating system under single steam turbine operation; and
- Updating the control system to integrate new equipment into Valley's distributed control system.

The $62 million cost is broken down into:

- Structures and improvements $9,000,000
- Boiler plant equipment 46,200,000
- Accessory electric equipment 5,600,000
- Miscellaneous power plant equipment 1,200,000
- Total $62,000,000

Table 21 shows data on Valley Station to include 2013 emission rates (expressed in lb/MMBtu because generation data was not available in the Title IV data). As shown, the capacity factors of the units in 2013 were in the range of 22% to 31%, meaning that these units served more as cycling units. The heat rate for Valley is high because Valley produces both power and heating steam. The plant fixed and variable operating costs will be reduced.

[71] PUBLIC SERVICE COMMISSION OF WISCONSIN, Final Decision, Application of Wisconsin Electric Power Company for Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility, March 17, 2014

Figure 27. Valley Station

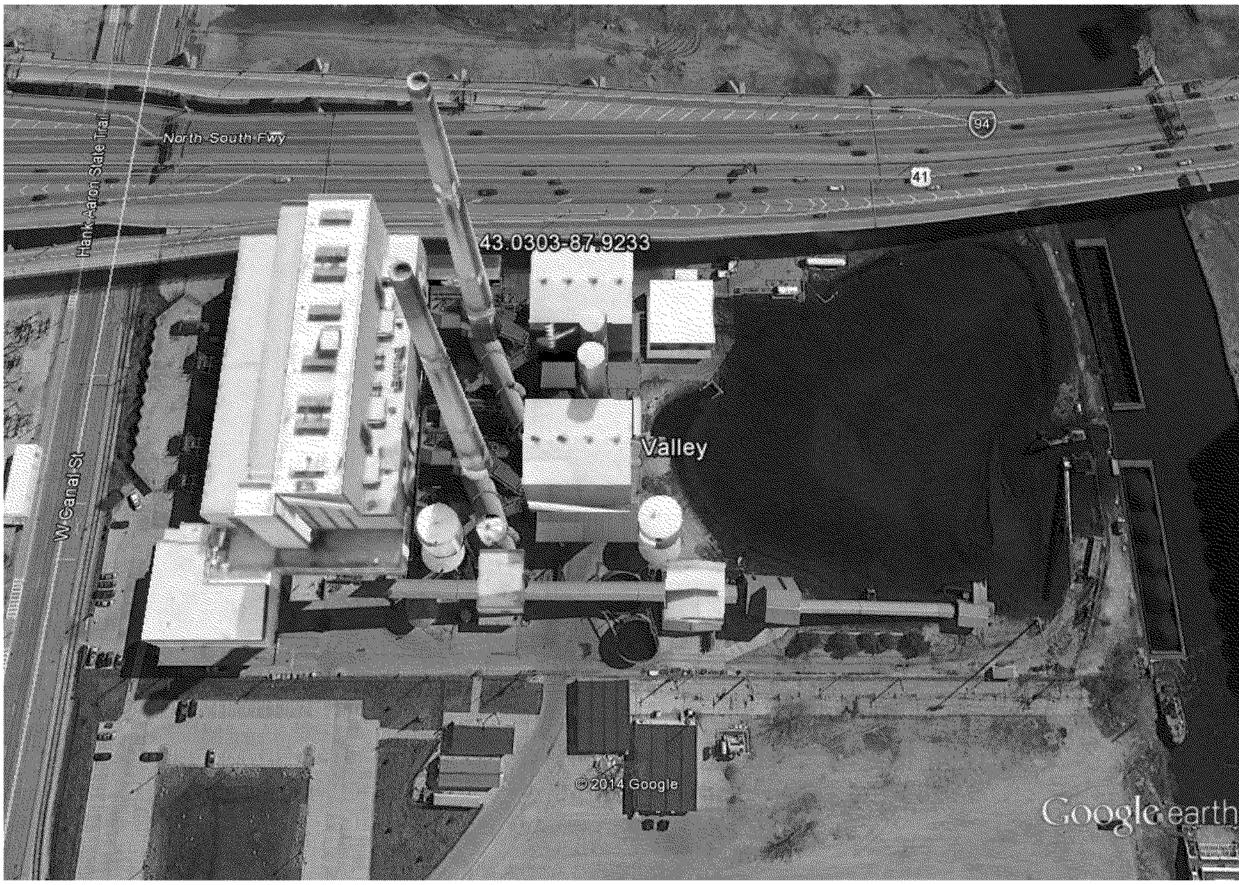


Table 21. Information on Valley units 1-4, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MMBtu 2013 SO2	2013 NOx	2013 CO2
Valley	1	67	WI	wall	Bit.	14500	31%	1968	0.7	0.2	205
	2	67	WI	wall	Bit.	14500	30%	1968	0.7	0.2	205
	3	67	WI	wall	Bit.	14500	22%	1969	0.7	0.2	205
	4	67	WI	wall	Bit.	14500	27%	1969	0.7	0.2	205

Case Study 17. Naughton Unit 3, Wyoming

The Naughton unit 3 in Wyoming is a 330 MW BART-affected unit that burns Powder River Basin coal and is shown in Figure 28. Pacificorp, the owners, elected to convert the unit to natural gas for compliance with the Regional Haze Rule. Although base-loaded, Naughton plant is located adjacent to gas pipelines and has access to natural gas. March 4, 2014 comments from the Oregon PUC indicates a conversion date in 2018. This document also indicates that Oregon PUC staff would like Pacificorp to further consider retirement as an alternative to conversion in their 2015 IRP.[72, 73] Cost information was not available in the IRP documentation.

Figure 28. Naughton Power Plant

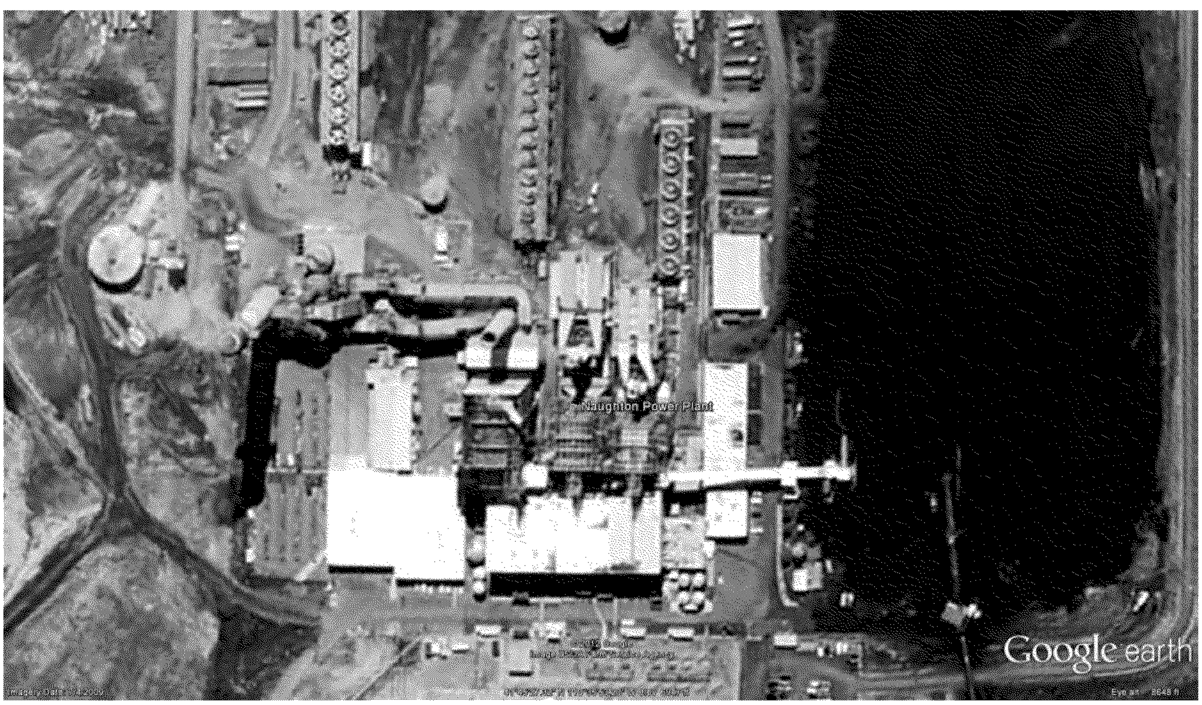


Table 22 shows information on Naughton unit 3, including 2013 emission rates and estimated capacity factor based upon Title IV data and NEEDS v5.13 reported heat rate and MW output. As shown, Naughton 3 is a base loaded unit.

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[72] PUBLIC UTILITY COMMISSION OF OREGON STAFF REPORT PUBLIC MEETING DATE: March 17, 2014; http://www.puc.state.or.us/meetings/pmemos/2014/031714/reg1LC%2057.pdf

[73] BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON LC 57; "In the Matter of PACIFICORP, dba PACIFIC POWER ORDER; 2013 Integrated Resource Plan. DISPOSITION: 2013 IRP ACKNOWLEDGED WITH EXCEPTIONS AND REVISIONS JUL 0 8 2014

Table 22. Information on Naughton unit 3, to include 2013 emission rates

Plant Name	Unit	MW	State	Firing type	Coal	heat rate	2013 Capacity factor	YR on line	Emission rates, lb/MWh 2013 SO2	2013 NOx	2013 CO2
Naughton	3	330	WY	tangential	PRB	10,517	97%*	1971	3.5	2.7	2,029

* This capacity factor was estimated from Title IV reported generation and the nameplate capacity in NEEDSv5.13. Although it seems very high, Pacificorp assumed a 90% capacity factor in their 2007 BART analysis.[74] So, the Naughton unit 3 capacity factor was likely around 90% or better in 2013.

[74] See Appendix A of "Final Report BART Analysis for Naughton Unit 3 Prepared For: PacifiCorp" by CH2MHill, December 2007

Natural Gas Transmission Infrastructure Proximity to Coal Power Plants

Natural Gas is available in most parts of the United States and, if not available on site, is often located someplace near an existing coal fired power plant. Figures 29 through 33 show the locations of coal-fired power plants (including some large coal-fired industrial plants, such as paper mills) in round black circles with white triangles and the location of interstate pipelines in blue lines. As shown, the vast majority of coal fired plants is located in the general vicinity of an interstate pipeline and, as such, could have access to natural gas. There are, however, a small number of power plants in fairly remote locations that would require longer pipelines to gain access to natural gas.

Figures 29-33 do not provide information on the need to enlarge or expand existing pipeline infrastructure to accommodate increased natural gas demand from the power sector. In their analysis, EPA attempted to incorporate this into their analysis, and this is perhaps why in some cases they concluded that some plants required extensive pipeline needs. For example, they determined that conversion would require 310 miles of pipeline for the Presque Isle Power Plant near Marquette, MI. On the other hand, as shown in Figure 34, the Presque Isle Power Plant is only a few miles from an interstate pipeline. So, making the connection to the interstate pipeline could not possibly explain the length of pipeline estimated by EPA. It is likely that this is what EPA has estimated is needed to enlarge the existing interstate pipeline infrastructure. But, it is also may be that these assumptions are conservative, as demonstrated by EPA's analysis of Edge Moor plant in Delaware. EPA estimated that 24.7 miles of pipeline must be constructed for Edge Moor 3; however, Edge Moor 3 has already been converted to natural gas.

In any event, the existence of this infrastructure does eliminate one of the major hurdles to expansion of infrastructure along these routes where pipelines already exist– the need to gain rights of way.

Another factor that has played into the conversion of many coal fired power plants is the increased availability of natural gas from shale gas, and especially from the Marcellus region that spans from upstate New York through Pennsylvania, Ohio and West Virginia. This formation, shown in Figure 35, has had a steady increase in natural gas production from about 2 million cubic feet per day in 2010 to about 16 million cubic feet per day today, as shown in Figure 36.

Figure 29. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Northeast United States. Source: Energy Information Administration

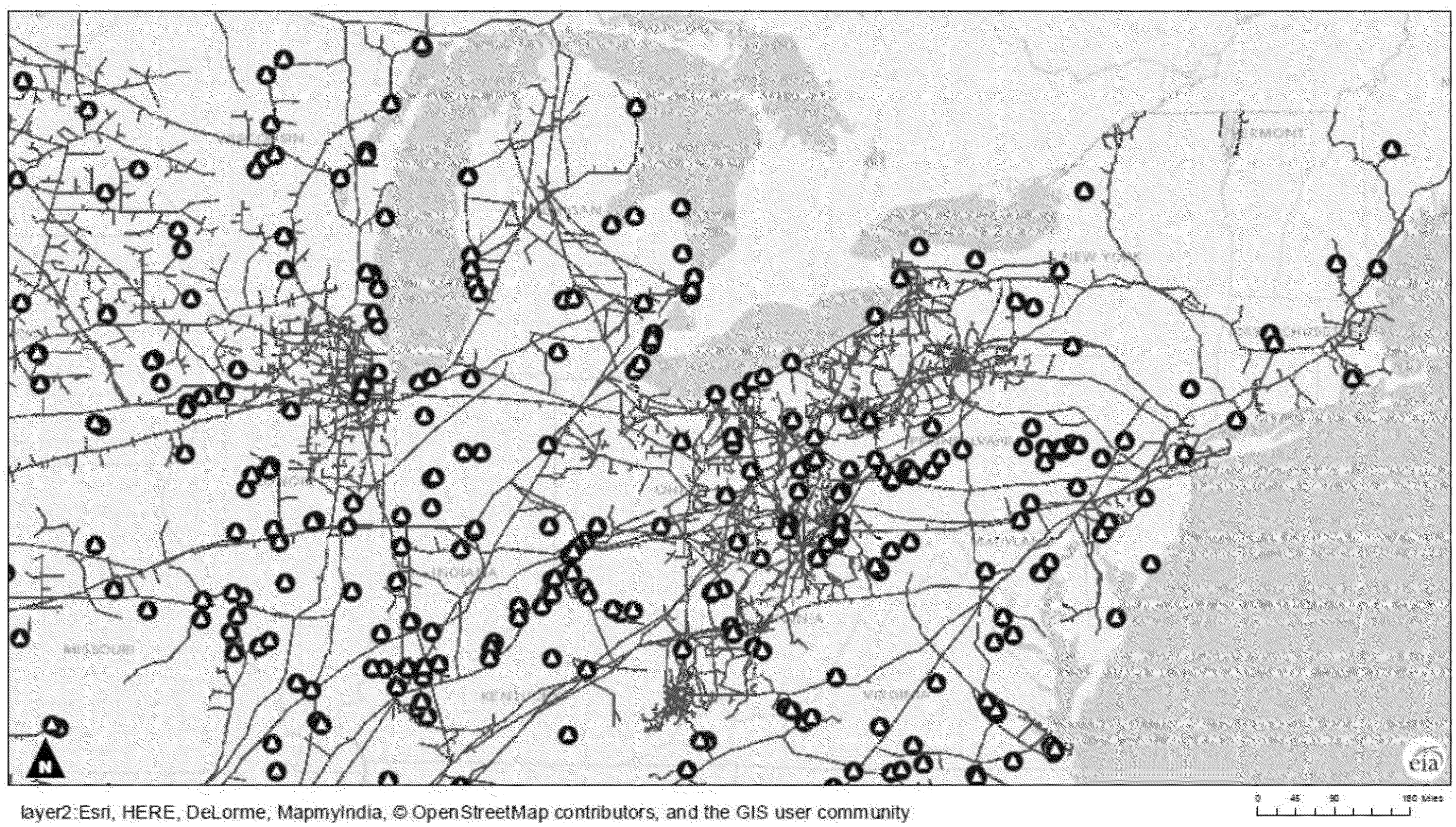
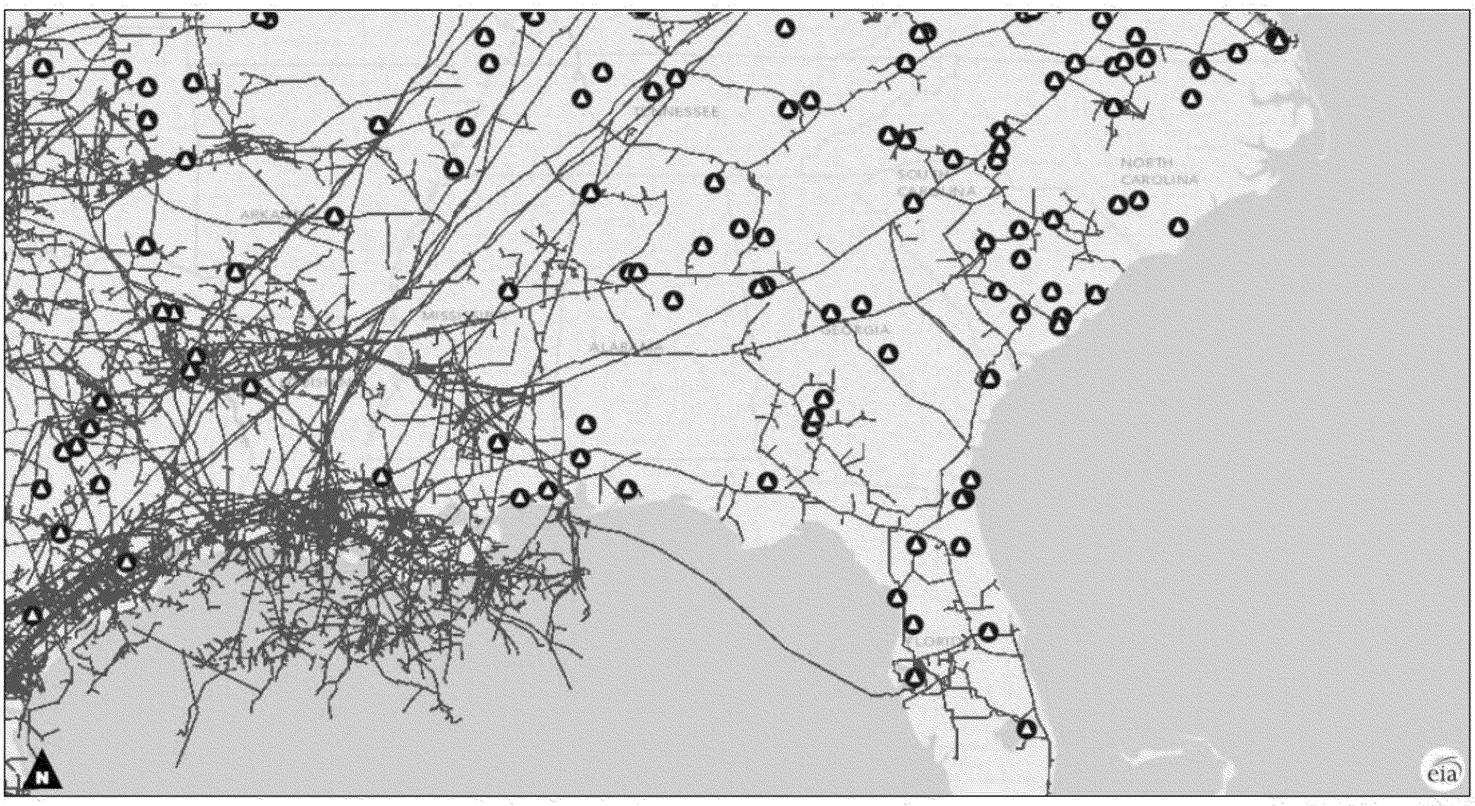


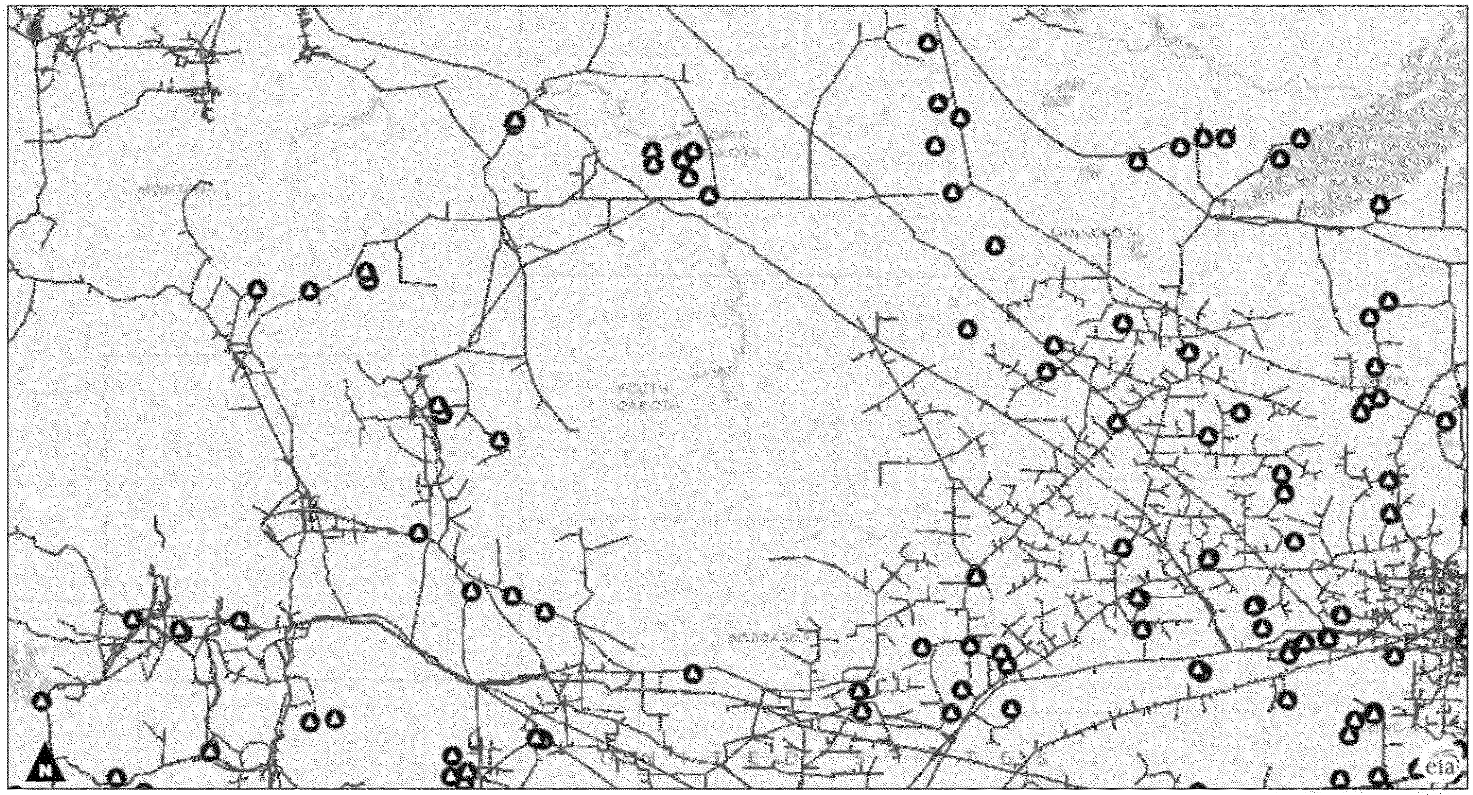
Figure 30. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Southeast United States. Source: Energy Information Administration



layer2:Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, and the GIS user community

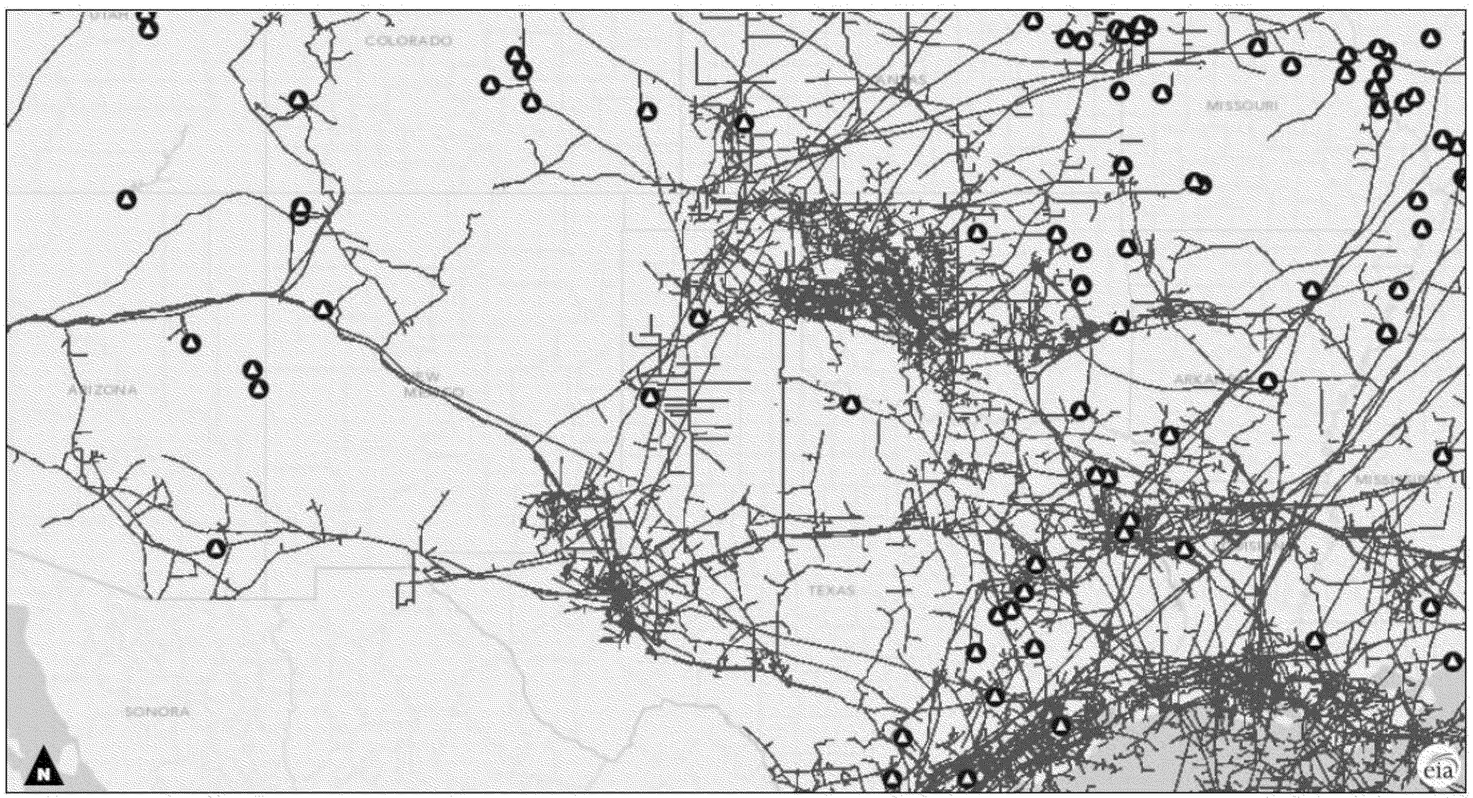
0 45 90 180 Miles

Figure 31. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Upper Great Plains United States. Source: Energy Information Administration



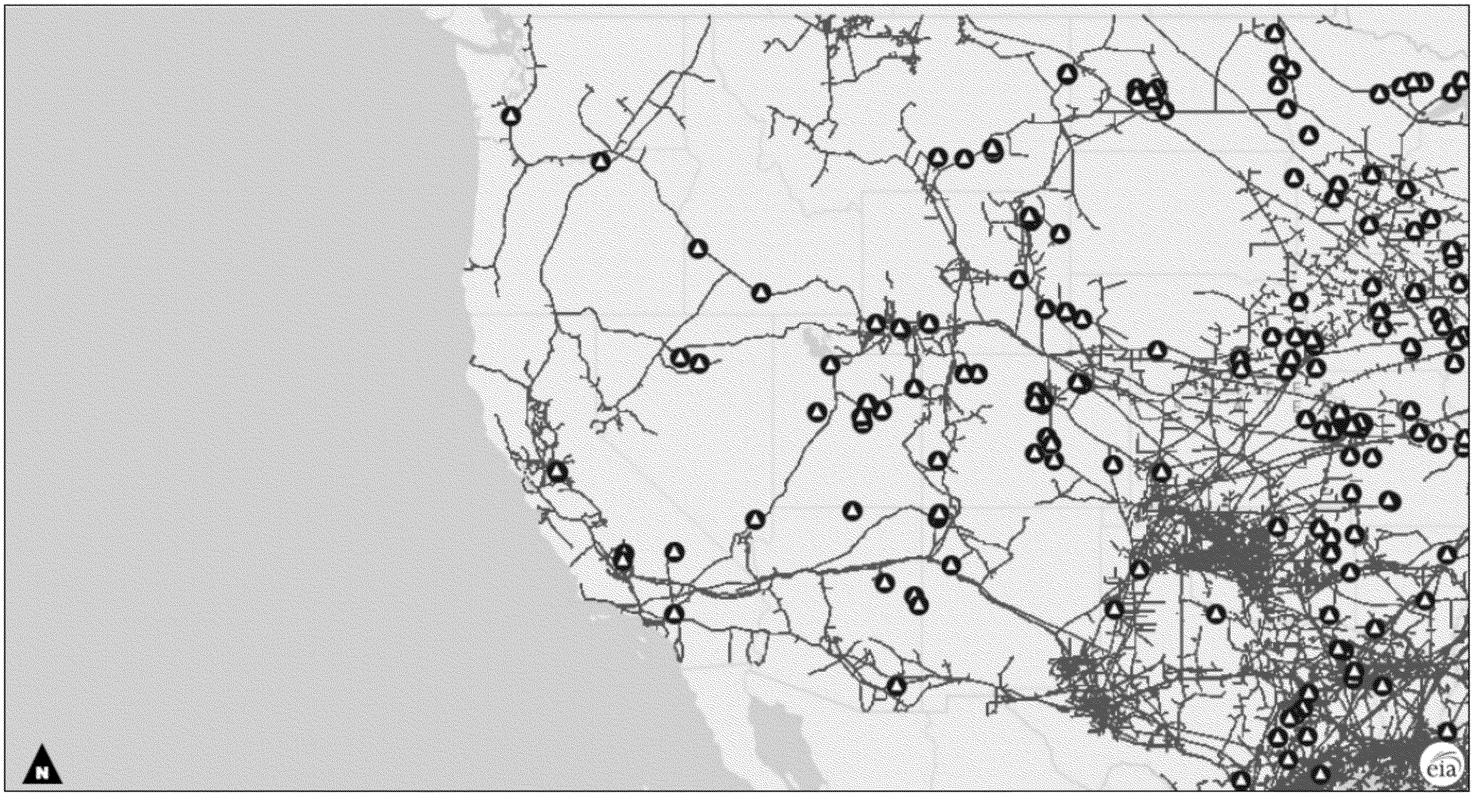
layer2:Esri, HERE, DeLorme, MapmyIndia, © OpenStreetMap contributors, and the GIS user community

Figure 32. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Lower Great Plains United States. Source: Energy Information Administration



State Layers:Electricity Transmission Lines - Ventyx, Velocity Suite;layer2:Esri, HERE, DeLorme, MapmyIndia, ©

Figure 33. Locations of Coal Power Plants (black circles with white triangles) and interstate natural gas transmission pipelines in the Upper Western United States. Source: Energy Information Administration

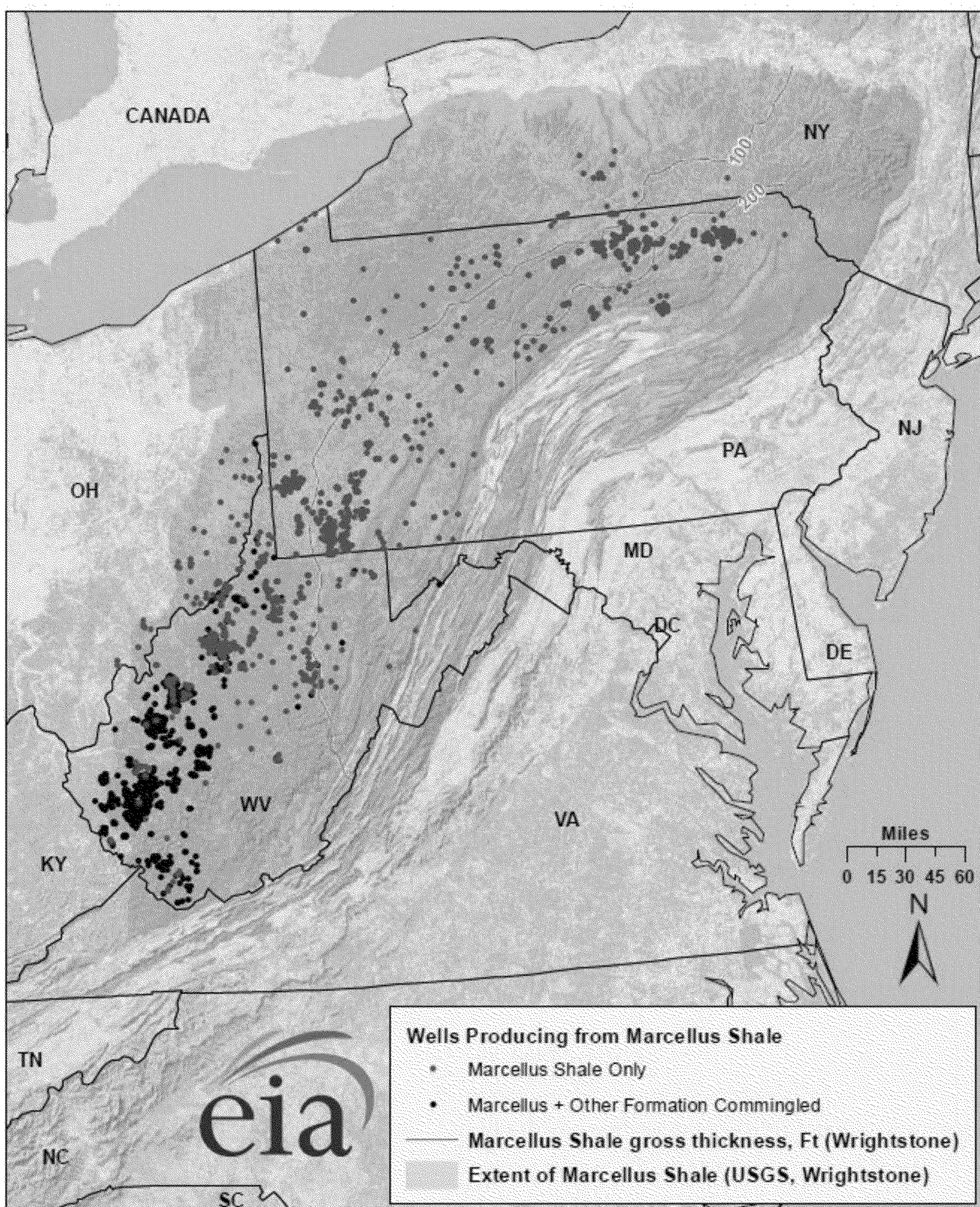


State Layers:Electricity Transmission Lines - Ventyx, Velocity Suite;layer2:Esri, HERE, DeLorme, MapmyIndia, ©

0 90 180 360 Miles

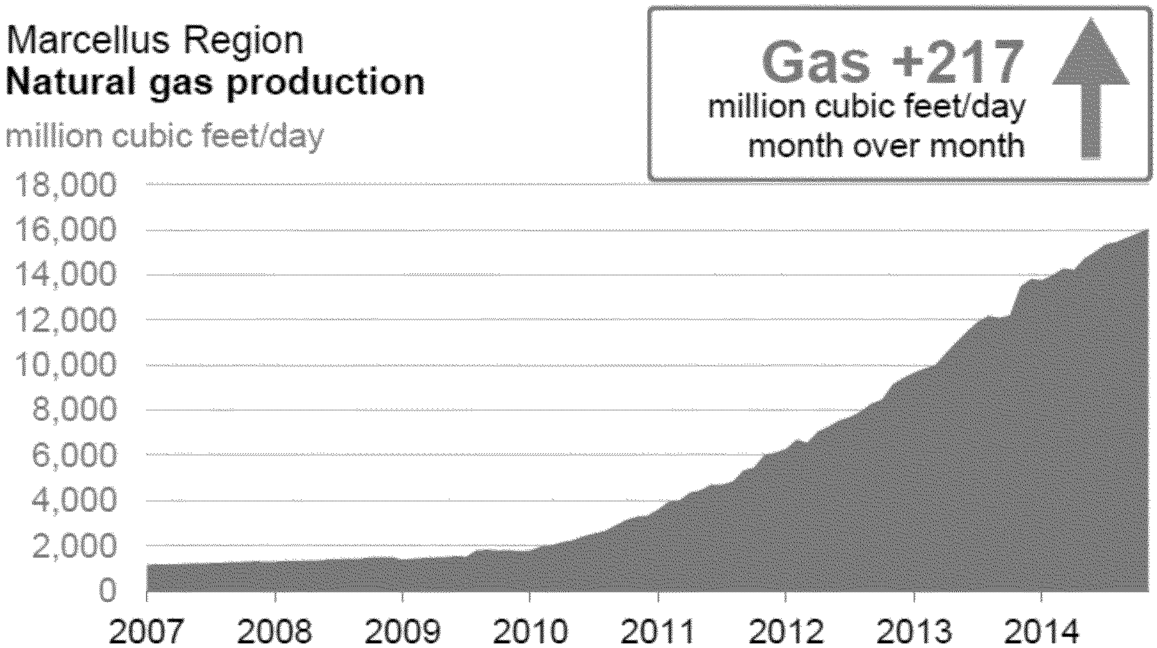
Figure 34. Presque Isle Power Plant (black circle with white triangle above Marquette, MI), and Interstate Gas Pipelines (blue lines), map is from EIA

Figure 35. The Marcellus Shale Gas Play, Appalachian Basin (EIA)



Source: US Energy Information Administration based on data from WVGES, PA DCNR, OH DGS, NY DEC, VA DMME, USGS, Wrightstone (2009). Only wells completed after 1-1-2003 are shown. Updated June 1, 2011

Figure 36. Marcellus Region Natural Gas Production (source: EIA)



ENVIRONMENTAL DEFENSE FUND
Finding the ways that work

BY EMAIL AND ELECTRONIC FILING

The Hon. Gina McCarthy
Administrator, U.S. Environmental Protection Agency
EPA Docket Center
Mail Code 28221T
1200 Pennsylvania Ave., NW
Washington, DC 20460

Attn: Docket ID No. EPA-HQ-OAR-2013-0602

Re: Comments of Environmental Defense Fund on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34, 830 (June 18, 2014); 79 Fed. Reg. 64,543 (Oct. 30, 2014) (Notice of data availability); 79 Fed. Reg. 67,406 (Nov. 13, 2014) (Notice; additional information regarding the translation of emission rate-based CO2 goals to mass-based equivalents)

The Environmental Defense Fund (EDF) appreciates the opportunity to provide the following comments on the Environmental Protection Agency's (EPA) June 18, 2014 proposed rule to establish performance standards for carbon pollution from existing electric utility generating units (EGUs).[1] Representing over 750,000 members nationwide, EDF is a national non-profit, non-partisan organization dedicated to protecting human health and the environment by effectively applying science, economics, and the law. EDF has long recognized the urgent and critical threat that climate change poses to public health and welfare, and it is one of our top priorities to advocate for rigorous measures to secure rapid reductions in emissions of climate-destabilizing pollutants – especially emissions of carbon dioxide from fossil fuel-fired EGUs, which currently account for nearly 40 percent of the United States' carbon pollution. Accordingly, we strongly support EPA's initiative to establish the first nation-wide limits on carbon pollution from fossil fuel-fired EGUs using its existing authorities under section 111(b) and (d) of the Clean Air Act.[2]

EPA's proposed rule for existing EGUs is a vital part of this initiative. Our comments below are directed at ensuring that these pollution standards meet the Clean Air Act's standard—that they deliver the maximum possible emission reductions considering cost and the other statutory factors—and are

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (proposed June 18, 2014).
[2] 42 U.S.C. § 7411(b), (d).

coordinated effectively with EPA's standards for newly constructed, modified, and reconstructed fossil fuel-fired EGUs.

All prior written and oral testimony and submissions to the Agency in this matter, including all citations and attachments, as well as all of the documents cited to in these comments and attached hereto are hereby incorporated by reference as part of the administrative record in this EPA action, Docket ID No. EPA–HQ–OAR–2013–0602.

We appreciate the opportunity to provide comments on this important rulemaking. Please direct any inquiries regarding these comments to Megan Ceronsky, Director of Regulatory Policy and Senior Attorney at EDF, or Tomás Carbonell, Senior Attorney at EDF.

Respectfully submitted,

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Attachments:

Attachment A: John A. "Skip" Laitner & Matthew T. McDonnell, *Energy Efficiency as a Pollution Control Technology and a Net Job Creator Under Section 111(d) Carbon Pollution Standards for Existing Power Plants* (Nov. 28, 2014)

Attachment B: Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents in No. 00-568, *New York v. FERC*, 535 U.S. 1 (2002)

Attachment C: Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers* (Nov. 30, 2014)

TABLE OF CONTENTS

Executive Summary

EDF strongly supports EPA's proposed Clean Power Plan. In these comments we discuss the urgency of acting to address carbon pollution from the largest source in our country and lay out the strong legal foundation upon which the Clean Power Plan is based. We strongly support EPA's approach to identifying the "best system of emission reduction" to address carbon pollution from power plants; EPA's approach fulfills the statutory requirements and appropriately reflects the uniquely unified and interconnected nature of the electric grid and the generation resources that energize it as well as the end-users who use power from it. We describe the consistency of this rulemaking with past federal clean air standards addressing power plant emissions and the distinct roles of the Federal Energy Regulatory Commission and public utility regulators in regulating aspects of the power sector, roles they will play in the context of these standards and have played in the context of all prior power plant emission standards. We explore the conflict between the 1990 House and the Senate amendments to Section 111(d) and EPA's clear authority to address carbon pollution from power plants in that context. We discuss the key role that environmental justice must play in EPA's mission and how environmental justice concerns should be addressed in the context of the Clean Power Plan.

We then examine the technical foundation for EPA's four building blocks, and recommend changes to the proposal that would more accurately reflect the potential to reduce carbon pollution from regulated fossil fuel-fired plants and drive greater pollution reductions. Finally, we recommend adjustments to address the potential for emission "leakage" across state lines, discuss the importance of ensuring that the Act's requirement for enforceability is met through federally enforceable plan components and standards or "backstops" enforceable against regulated sources that ensure state targets are attained, and explain the irreducible components of a state submittal requesting a delay in the deadline for state plan submission.

In summary, the comments make the following recommendations:

A. Summary

We strongly support EPA in moving forward with the proposed Clean Power Plan in a strengthened form. We strongly support EPA's proposed "best system of emission reduction", which looks at the real-world potential to reduce carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-emitting power plants and less on the highest-emitting power plants. We urge EPA to finalize these historic and urgently needed carbon pollution standards by June 1, 2015, as set forth in the Presidential Memorandum on Power Sector Carbon Pollution Standards.

We also urge EPA to strengthen the environmental benefits of the standards by:

- Recognizing the full potential across the electric system and all resource types to reduce emissions and especially utilizing updated cost and performance data for renewables and energy efficiency to ensure we achieve more at lower cost;

- Strengthening the emissions outcome in 2020 – near term emissions reductions are vital for climate security; and

- Significantly strengthening the emissions outcome in the later years – 2030 is far too long to achieve such modest emission reductions.

B. Background

It is imperative that we dramatically reduce carbon pollution. The science is clear: rising concentrations of heat-trapping gases like carbon dioxide in the atmosphere will destabilize our climate and lead to severe impacts on our health and well-being and risk triggering catastrophic climate change.

We are already seeing the impacts of climate change on our communities and facing substantial costs from these impacts. But the costs that our children and grandchildren will face if we fail to act now are simply unacceptable.

The National Climatic Data Center reports that the United States experienced seven climate disasters that each caused more than a billion dollars of damage in 2013, including devastating floods and extreme droughts in a number of western states. These are precisely the type of impacts projected to affect American communities with increasing frequency and severity as climate-destabilizing emissions continue to accumulate in the atmosphere.

The Third National Climate Assessment, released earlier this year, found that if greenhouse gas emissions are not reduced it is likely that American communities will experience:

- increased severity of health-harming smog and particulate pollution in many regions;
- intensified precipitation, hurricanes, and storm surges;
- reduced precipitation and runoff in the arid West;
- reduced crop yields and livestock productivity;
- increases in fires, insect pests, and the prevalence of diseases transmitted by food, water, and insects; and
- increased risk of illness and death due to extreme heat.

We must act now to reduce carbon pollution and mitigate these impacts. Fossil fuel-fired power plants are the largest source of greenhouse gases in our nation, and the solutions are at hand to reduce carbon pollution from the power sector. Reducing carbon pollution will also result in important reductions in health-harming co-pollutants such as mercury, nitrogen oxides, sulfur dioxide, and particulates. Reducing these co-pollutants will reduce asthma attacks, heart attacks, hospital admissions, missed school and work days, and premature deaths.

C. Best System of Emission Reduction

We strongly support EPA's proposed "best system of emission reduction," which sets targets for each state's CO2-emitting power plants by looking at the real-world potential to reduce their carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-emitting power plants and less on the highest-emitting power plants.

Under the Clean Air Act and Supreme Court precedent identifying greenhouse gases as "air pollutants" covered under the Act, EPA is required to identify the "best" system of emission reduction that has been "adequately demonstrated" considering cost, energy requirements, and other health and environmental outcomes. We know that the system of emission reduction proposed by EPA is adequately demonstrated because power companies and states across the country are effectively using each of the building blocks to cut emissions of carbon pollution and other dangerous air pollutants from fossil fuel-fired power plants. We agree with EPA that it is the "best" system as defined by the Clean Air Act because it has the potential to secure large reductions in carbon pollution at reasonable cost, and will provide companies and states with flexibility to manage energy requirements and identify the emission reduction pathways that make the most sense for them.

This system of emission reduction reflects the reality of the electricity system, within which different power generation sources and demand-side energy efficiency resources are managed dynamically to ensure that energy demand is met at each moment in time. Companies and states have long been relying on the interconnected nature of the electric grid to reduce harmful pollution from power plants. Because supply and demand must be continuously balanced on the grid, adding renewable electricity backs down generation at fossil fuel-fired plants—and reduces emissions accordingly. Likewise, improving energy efficiency lowers demand for electricity, reducing power generation and thus emissions. States and power companies have been increasing use of natural gas plants which has reduced emissions from coal-fired power plants. Coal-fired power plants can (and many already do) co-fire with natural gas, which reduces combustion emissions. Coal plants can also be converted to burn natural gas which reduces combustion emissions, which has occurred at many facilities. These techniques—deploying non-emitting generation resources, improving energy efficiency, and switching to lower-polluting fuels—are traditional methods of addressing air pollution issues under the Clean Air Act.

EPA's proposed system of emission reduction — an emission limit that power plants can achieve through compliance measures including efficiency improvements at power plants, shifts from coal to gas-fired power generation, deployment of renewable energy, and harvesting energy efficiency —meets the requirements of the Clean Air Act. The emission reduction techniques included in the targets are "adequately demonstrated" and enable sources to achieve the greatest emission reductions considering cost, impacts on energy, and other health and environmental outcomes (note comments below on expanding and strengthening the BSER). The flexibility of this system enables states to secure emission reductions cost effectively, to manage impacts on energy and ensure that there are no effects on reliability, and to reduce carbon emissions by building on existing state clean energy and efficiency programs. This system allows states to secure all of the co-benefits of transitioning to cleaner energy and harvesting energy efficiency, reducing not only carbon pollution but also the burden of other health-harming air pollution on their communities. Investment in renewable generation and energy efficiency will drive job creation. The fuel savings of renewable resources and energy efficiency improvements will lower utility bills for families and businesses. Those savings will then be spent on other goods and services, stimulating the economy, as states with strong energy efficiency programs are already experiencing.

The system of emission reduction identified by EPA can achieve even greater emission reductions than is reflected in EPA's analysis.

The BSER building blocks proposed by EPA include:

1) Making existing coal plants more efficient
2) Using existing natural gas plants more effectively
3) Increasing renewable and nuclear generation
4) Increasing end-use energy efficiency

A careful analysis of the emission reduction opportunities in each of the four blocks identified by EPA demonstrates that even greater savings are available from each of the four blocks. As discussed in detail below and in EPA's Notice of Data Availability Released on October 27, 2014, EPA must also fix the formula for calculating state targets to properly account for reductions in emissions from renewable energy and energy efficiency.

D. BSER Building Block 1 & 2

EPA's analysis appropriately considered the potential for efficiency improvements at power plants to drive reductions in emissions when combined with the rest of the proposed system of emission reduction. EPA identifies opportunities for improvements that can be made based on specific power plant upgrades and also for operational and maintenance changes. EPA determined that coal-fired power plants can achieve at least a six percent improvement in performance. This is a conservative estimate. Analysis of carbon emissions at coal plants shows that even greater reductions would be available if power plants simply had to match the lowest emission rate actually achieved by the plant over the past decade.

In its Notice of Data Availability, EPA requested comment on whether it should consider, alongside existing NGCC plants, redispatch from coal plants to new NGCC and the potential to co-fire with natural gas or convert to natural gas at existing coal boilers. While we believe that scaling up energy efficiency and renewable energy is the best and least-cost compliance pathway and will urge states to focus their compliance plans on clean energy, we urge EPA to set targets that reflect the opportunities presented by all three coal to natural gas options. Already all three of these pathways are being deployed across the country even without any carbon pollution standards in place—and as such they are clearly adequately demonstrated, and reasonable in cost. All three of these pathways secure significant reductions in combustion carbon emissions, as well as significant reductions in harmful co-pollutants like mercury, NO_X, SO_X, and particulates at the power plant stack. These co-benefits will have enormous near-term benefits to public health. In addition to providing tremendous health benefits, fuel switching will reduce the need for and the costs of pollution controls on coal-fired power plants.

However, given the increase in the use and extraction of natural gas already underway in the country, we strongly urge EPA to address emissions of methane, a potent climate pollutant, from oil and natural gas development under the Clean Air Act. President Obama committed to taking action on methane as part of the Climate Action Plan. It is vital that EPA follow through on this pledge by promptly commencing a rulemaking to set standards limiting emissions of dangerous climate and public health harming pollutants from new and existing sources in this sector.

In its original proposed rule, EPA considered the potential to shift power generation from existing coal-fired power plants to underutilized natural gas combined cycle (NGCC) plants. EPA did not include new NGCC plants in setting state targets but suggested that it was considering whether states should be allowed to use new NGCC plants for compliance purposes. EPA must ensure symmetry between the resources available for compliance purposes and the resources used to determine the targets. Thus, unless a potential compliance option is too costly or not adequately demonstrated, it must be included in setting the target if EPA will allow its use for compliance purposes.

E. BSER Building Block 3

EPA appropriately considered the potential to reduce emissions from coal and gas fired power plants by deploying renewable energy. But EPA has significantly underestimated the amount of renewable energy that can be deployed at reasonable cost. In its proposal, EPA included two frameworks for analyzing the potential for emission reductions via renewable energy deployment—the use of regional averages of renewable energy policies and a technical-economic potential analysis. Both significantly underestimate the actual potential by failing to reflect the dramatic cost reductions that have occurred in recent years. In order to properly assess the potential from renewable energy, EPA must use up-to date data. Current data show that wind and solar costs are each approximately 45 percent less costly than EPA assumed in its analysis. We urge EPA to use current data and any subsequently published data on costs and technical potential in order to evaluate the quantity of renewable energy that can be deployed at reasonable cost in each state. We further urge EPA to ensure that the rate of renewable energy deployment assumed in EPA's analysis is at least as fast as the historical rates of deployment.

F. BSER Building Block 4

EPA's Proposed Standards properly considered the potential to use improved demand-side energy efficiency to drive reductions in carbon pollution, which will also drive reductions in the harmful co-pollutants emitted by fossil fuel-fired power plants. By making investments to increase energy efficiency in our homes, businesses and factories, we can reduce carbon pollution while also lowering utility bills, creating jobs, and stimulating the economy.[3] Based on its analysis, EPA determined that states can eventually achieve incremental annual energy savings of 1.5 percent of retail sales. This level of energy efficiency is readily achievable and, if anything, underestimates the amount of energy efficiency that can be achieved. In reaching its determination that 1.5 percent annual savings are possible from energy

[3] *See generally* John A. "Skip" Laitner and Matthew T. McDonnell, *Energy Efficiency as a Pollution Control Technology and a Net Job Creator Under Section 111(d) Carbon Pollution Standards for Existing Power Plants* (Nov. 2014) (Attachment A).

efficiency, EPA excluded a number of important additional opportunities for energy efficiency such as building codes, transmission and distribution, voltage optimization, and combined heat and power—which indicates how conservative EPA's analysis is. The country's energy efficiency resource is vast, and grows continuously as new technologies are developed. Further, EPA also underestimates the potential for energy efficiency by assuming that states will only be able to ramp up energy efficiency programs extremely slowly. But new energy efficiency programs can be implemented more quickly than EPA assumes, as demonstrated by the faster expansion of efficiency programs achieved in practice by many states. EPA should use a faster ramp up rate, allowing for greater overall emission reductions from energy efficiency.

EPA's analysis also overestimated the cost of improving energy efficiency by using cost assumptions more than fifty percent above the costs observed in practice—including costs observed in the assessments cited by EPA. EPA should use more realistic program cost numbers and data on the true scale of demand-side energy efficiency potential in its analysis of the potential for carbon reductions.

G. Formula Change for Building Block 3 & 4

EPA should ensure that the calculation of state targets fully reflects the role of renewable energy and energy efficiency in reducing carbon pollution.

In its October 27, 2014 Notice of Data Availability, EPA explains that the original formula used in its proposed rule failed to correctly account for the emission reductions generated by renewables and energy efficiency. As EPA explains, the formula used in the proposed rule failed to account for the reduction in generation at coal and gas power plants that will occur when additional renewables are added to the grid and when we improve energy efficiency. When EPA sets final state targets, it should use the corrected formula proposed in the Notice of Data Availability. This is particularly important because it will ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

H. Strengthening the CPP

All of the suggested changes to the CPP proposal noted above have the potential to strengthen the public health and environmental outcome and we believe this can be accomplished at reasonable cost.

The impact of using outdated cost and performance numbers for renewables and energy efficiency in estimating the cost of the Clean Power Plan is substantial. EPA found that under the Clean Power Plan, the power sector could reduce its emissions by 30% in 2030 below 2005 levels, costing between $7.5 billion and $8.8 billion. But because EPA used unreasonably high and out-of-date cost assumptions for renewable energy and energy efficiency, EPA substantially overstates the costs of compliance with the standard and underestimates the potential to make these critical carbon reductions. A study by the Natural Resources Defense Council found that simply by updating the cost and performance parameters for renewable generation and energy efficiency to be consistent with today's technologies, compliance could be achieved at net savings of $1.8 billion in 2020 and $6.6 billion in 2030. In the final rule, EPA should update its cost numbers and strengthen the state targets to reflect the emission reductions available based on current data on availability and cost.

I. Environmental Justice

The Clean Power Plan will result in significant improvements in air quality across the country. EPA estimates that it will result in a twenty-five percent drop in the pollutants that lead to soot and smog. However, we urge EPA to include in the final guidance a robust discussion of the ways in which state plans can be designed to ensure that communities bearing a disproportionate share of ambient air pollution burdens have those burdens reduced. State plans will determine how the carbon pollution reductions required by the state targets are achieved—and with those reductions, reductions in harmful co-pollutants will follow. This will be particularly important in the context of state planning around attainment of ozone ambient air quality standards and other clean air protections, enabling comprehensive planning to ensure that states are ensuring that carbon pollution is reduced and other harmful air pollution problems are addressed.

J. State Plan Flexibility & Minimum Requirements to Ensure Enforceability

We support EPA's proposal to give states flexibility to design tailored plans to meet their carbon pollution reduction targets. States will be able to build their plans on the foundation of existing clean energy and efficiency policies, and shape their plans to capture the emission reduction opportunities that deliver the greatest co-benefits for their citizens—cleaner air, more efficient homes and businesses with lower utility bills, and a vibrant clean energy economy.

In order to satisfy the requirements of the Clean Air Act and EPA's long-standing regulations, the Clean Power Plan must ensure that emission reductions secured under the plan are verifiable and enforceable. State plans taking a source-based approach can do this by requiring that each power plant achieve the target rate by keeping its emissions below the target rate or purchasing necessary credits or, in a "mass-based" system by holding sufficient emission allowances. EPA must define minimum requirements for measurement and verification of energy efficiency and renewable energy that will be used as credits in a rate-based system.

In order to ensure enforceability, a state taking a "state commitment" approach must also incorporate a "backstop" mechanism that will ensure that any shortfall in emission reductions will be remedied and that applies to the regulated emission sources. States can help regulated sources comply by requiring actions such as implementation of energy efficiency or purchase of renewable energy by other entities such as load-serving utilities. But it is important that the state plan ensures, through the backstop, that there is an enforceable mechanism that ensures that the emission reductions will be achieved. The backstop mechanism could be designed by the state and should be incorporated in its plan. In order to ensure that the requirements of the Act are met and protect environmental integrity of the standards, backstops must be triggered automatically by any shortfall and apply directly to the regulated sources.

K. Conversion of State Targets from Rate to Mass

We support the conversion of rate targets to mass-based targets. EPA must ensure that the conversion process provides equivalence between the two targets.

We support EPA's effort to facilitate state adoption of mass-based targets. EPA must provide clear and rigorous guidance to ensure that a state plan adopting a mass-based approach is equivalent to the rate-based target. In addition, in order to fulfill the statutory mandate to address harmful air pollution through limitations on emissions, EPA must ensure that states will achieve the necessary reductions through the actions taken in their plans and that emission reductions are not eroded due to changes in electricity generation between neighboring states that have different plan structures (rate vs. mass) or different target rates.

L. Model State Plans

In order to support state plan development, EPA should provide model plan components that states could utilize (for example flexible, source-permit-based rate-based programs and mass-based programs with trading). EPA should emphasize model components facilitating state deployment of renewable energy and demand-side energy efficiency. EPA should also specify minimum criteria or requirements for each policy approach to ensure enforceability. Further, EPA should provide guidance on the full range of potential multistate approaches—from agreements about renewable energy and energy efficiency, to frameworks allowing emission reduction credits to cross state lines, to joint state plans.

M. Strong Interim Targets, Compliance Periods & Program Review

Strong interim targets are essential to deliver near-term reductions in carbon pollution and begin to transition the power sector towards lower-polluting infrastructure, deploying investments in renewable energy and energy efficiency that will create jobs and stimulate the economy.

The interim standard that takes effect beginning in 2020 is amply achievable. The extensive analysis of the building blocks, set out below, addresses important and cost-effective ways the building blocks can be strengthened by achieving deeper emissions reductions over a more accelerated time frame. These include achieving deeper reductions at the source through cost-effective co-firing and repowering with lower emitting fuels that is being widely deployed at coal plants today, the demonstrated potential to deploy more extensive and cost-effective renewable energy resources, and the rapid mobilization of demand side energy efficiency including a broader array of efficiency solutions than considered by EPA.

EPA expressly recognized that a more rigorous standard could be achieved by 2025, finding that it is achievable for power sector emissions to be 29 percent below 2005 levels in 2025 based on the changes reflected in the four building blocks. EPA's finding that a deeper reduction in 2025 is achievable based on solutions adequately demonstrated meets the pertinent statutory criteria for determining the best system of emission reduction and thereby requires EPA to establish such a standard in 2025 that “reflects the degree of emission limitation achievable.” Alternatively, EPA must establish a five year compliance requirement beginning in 2025 and continuing through 2029 that is far more rigorous than the 2020-2029 10-year average interim standard.

EPA must also provide a legally enforceable timeline for securing reductions no later than 2030. As EPA recognizes, Congress has woven an updating mechanism into the fabric of section 111 that commands the Agency refresh the BSER for new sources “at least every eight years” and is inextricably connected with updating the existing source standards. EPA must carry out its legal responsibility by committing to determine in 2025, through a legally enforceable mechanism, the BSER that applies over time – and that is not stagnant in maintaining in 2030 the standard of performance established a decade earlier. Rather, the BSER analysis must be, as Congress intended, a is vibrant, rigorous, and dynamic tool in securing for our nation’s public health, environmental quality, and prosperity--no later than the 2030 timeframe--the additional far deeper “degree of emission reductions achievable.”

Introduction

The Intergovernmental Panel on Climate Change's recent report, "Climate Change 2013: The Physical Science Basis," includes several grim findings:

- Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.[4]

- It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.[5]

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.[6]

Climate impacts are already affecting American communities—and the impacts are projected to intensify. The U.S. Global Change Research Program has determined that if greenhouse gas emissions are not reduced it is likely that American communities will experience:

- increased severity of dangerous smog in cities;[7]

- intensified precipitation events, hurricanes, and storm surges;[8]

- reduced precipitation and runoff in the arid West;[9]

- reduced crop yields and livestock productivity;[10]

- increases in fires, insect pests, and the prevalence of diseases transmitted by food, water, and insects;[11] and

- increased risk of illness and death due to extreme heat.[12]

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[4] Intergovernmental Panel on Climate Change Working Group I, Summary for Policymakers, at 4 (2013), *available at* http://www.climatechange2013.org/images/report/WG1AR5_SPM_FINAL.pdf.
[5] *Id.* at 17.
[6] *Id.* at 19.
[7] U.S. Global Change Research Program, Global Climate Change Impacts in the United States, at 92-93 (2009), *available at* http://downloads.globalchange.gov/usimpacts/pdfs/climate-impacts-report.pdf.
[8] *Id.* at 34-36.
[9] *Id.* at 45.
[10] *Id.* at 74-75, 78.
[11] *Id.* at 82-83.

Extreme weather imposes a high cost on our communities, our livelihoods, and our lives. The National Climatic Data Center reports that the United States experienced seven climate disasters each causing more than a billion dollars of damage in 2013, including the devastating floods in Colorado and extreme droughts in western states.[13] These are precisely the type of impacts projected to affect American communities with increasing frequency and severity as climate-destabilizing emissions continue to accumulate in the atmosphere.

Power plants are far and away the largest source of greenhouse gas emissions in the United States.[14] In 2012, fossil fuel fired power plants emitted more than 2 billion metric tons of CO_2e, or 40% of U.S. carbon pollution and nearly one-third of total U.S. greenhouse gas emissions.[15]

Section 111 of the Clean Air Act provides for the establishment of nationwide emission standards for major stationary sources of dangerous air pollution—including, since 1971, power plants.[16] In response to the Supreme Court's decision in *Massachusetts v. EPA*[17] that the Clean Air Act's protections encompass greenhouse gas emissions and to EPA's science-based determination that these climate-destabilizing emissions endanger public health and welfare,[18] EPA is now developing § 111 Carbon Pollution Standards for power plants.

EPA is developing carbon pollution-reduction standards for new and existing power plants under Clean Air Act § 111(b) and (d) respectively. Emission standards for existing pollution sources are developed and implemented through a dynamic federal-state collaboration, the legal underpinnings of which are described here. Through this collaboration, reflected in the Clean Power Plan proposed by EPA in June under § 111(d), EPA and the states can put in place strong standards that will drive cost-effective reductions in carbon pollution and support our nation's transition to a cleaner, safer, smarter power infrastructure.

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[12] *Id.* at 90-91.

[13] National Climatic Data Center, Billion-Dollar U.S. Weather/Climate Disasters 1980-2013 (2014), *available at* www.ncdc.noaa.gov/billions/events.pdf.

[14] Unless otherwise indicated, this document uses the term "power plants" or "electric generating units" (EGUs) generically to refer to existing EGUs covered by the requirements of the proposed Clean Power Plan.

[15] EPA, DRAFT Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, at ES-5 to ES-7, tbl. ES-2 (Feb. 2014), *available at* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf. Of the heat-trapping pollutants emitted by sources in the United States, carbon dioxide is by far the most prevalent. Transportation emissions are the only greenhouse gas emission source that approaches the scale of power plants.

[16] *See, e.g.,* Congressional Research Service, "Climate Change: Potential Regulation of Stationary Greenhouse Gas Sources Under the Clean Air Act," Larry Parker and James E. McCarthy, 7-5700, R40585 (May 14, 2009).

[17] 549 U.S. 497 (2007).

[18] 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).

Background

Section 111(b) directs EPA to identify ("list") categories of stationary sources that significantly contribute to dangerous air pollution, and to establish emission standards for air pollutants emitted by new sources in the listed categories.[19] Power plants were listed in 1971.[20] Section 111(d) directs the development of emission standards for pollutants emitted by existing sources in the listed categories. Emission standards are not established under § 111(d) if a source category's emissions of a specific pollutant are regulated under the provisions of the Clean Air Act addressing hazardous or criteria air pollutants.[21] [22]

The Clean Air Act provides that an emission standard (for new or existing sources) must reflect the emission reductions achievable through application of the "best system of emission reduction" that EPA finds has been adequately demonstrated, taking into account costs and any non-air quality health and environmental impacts and energy requirements.[23] For existing sources, once EPA guidance is issued identifying the best system of emission reduction and the emission reductions achievable under that system, the standards are implemented through state plans submitted to EPA for approval.[24] These plans must provide for the enforcement of the emission standards.[25]

The CPP is Consistent with Longstanding Regulation of Power Plants Under the CAA

EPA has long regulated pollutant emissions from power plants, which the largest single source of most air pollutants in the nation. Soon after Congress enacted the 1970 Clean Air Act amendments that first provided for a strong federal role in addressing air pollution, EPA established national standards for

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[19] 42 U.S.C. § 7411(b)(1).
[20] Air Pollution Prevention and Control: List of Categories of Stationary Sources, 36 Fed. Reg. 5931 (Mar. 31, 1971) (listing "Fossil fuel-fired steam generators of more than 250 million B.t.u. per hour heat input").
[21] 42 U.S.C. § 7411(d). Congress enacted § 111 in the 1970 Clean Air Amendments. Emissions of criteria pollutants from all sources are addressed through the detailed State Implementation Plan process set forth in § 110, *id.* § 7410, and hazardous air pollutants are the subject of a detailed framework of protections set out in § 112, *id.* § 7412. In its 1975 implementing regulations and for the subsequent 15 years EPA treated § 111(d) as a means of 'filling the gap,' and addressing pollutants that were not otherwise covered by § 110 or 112. *See* 40 Fed. Reg. 53,340, 53,340 (Nov. 17, 1975). In 1990, the House and Senate passed conflicting amendments to § 111(d), both of which were included in the Clean Air Act Amendments of 1990. In a 2005 rulemaking, after conducting a thorough analysis of the language and legislative history of the two versions, EPA described one way to reconcile them in a manner that comported with the overall thrust of the Clean Air Act Amendments of 1990. EPA concluded that it has authority under § 111(d) to regulate any air pollutant not listed under § 112(b) (i.e., any non-hazardous air pollutant), even if the source category to be regulated under § 111 is also being regulated under § 112. *See* 70 Fed. Reg. 15,994, 16,030-32 (Mar. 29, 2005). Thus, the only pollutants EPA may *not* regulate under § 111(d) are hazardous air pollutants emitted from a source category that is actually being regulated under § 112 and criteria pollutants.
[22] 42 U.S.C. § 7411(d).
[23] *Id.* § 7411(a)(1).
[24] *Id.* § 7411(d)(1)(A).
[25] *Id.* § 7411(d)(1)(B).

emissions of SO_2 from coal-fired power plants.[26] Reflecting Congressional recognition of the extraordinary impact of energy generation on air pollution and the need to address that pollution while ensuring electricity supply, numerous provisions of the statute authorize, and in many cases require, EPA to consider energy-related impacts of pollution standards. EPA has established pollution standards for fossil fuel-fired power plants to address emissions of, among other things, sulfur dioxide; nitrogen oxides; particulate matter; and mercury, acid gases, and other hazardous air pollutants. As a result, harmful emissions of many of these pollutants have been dramatically reduced or soon will be, without harming the power sector's ability to deliver affordable, reliable electricity. The regulation of CO_2 emissions from power plants under the Clean Power Plan is no different. The flexibility provided in Section 111(d) and the authority delegated to EPA to consider energy impacts has enabled the Agency to propose, in the Clean Power Plan, a flexible framework that empowers states to deploy measures that will cost-effectively reduce CO_2 emissions without any adverse impact on electric reliability. Furthermore, in taking a flexible-systems based approach to CO_2 regulation, EPA has accommodated and recognized state-driven efforts to reduce emissions using this flexible toolkit.

The impact of coal-fired power plants on air quality is very significant. In addition to being major sources of fine particles (PM2.5), coal-fired power plants emit approximately 70% of total U.S. SO_2 emissions, 46% of mercury emissions, 19% of NO_x emissions, and one-third of anthropogenic greenhouse gas emissions, in the form of CO_2.[27]

Cognizant of the relationship between energy generation and air pollution, Congress has specifically authorized, if not required, EPA to consider this relationship in numerous provisions of the Clean Air Act.[28] Throughout the Clean Air Act, Congress expressly compels EPA to consider the "energy impacts"

[26] "Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971," 36 Fed. Reg. 24,876, 24, 879 (Dec. 23, 1971) (codified at 40 C.F.R. § 60.40-46.)
[27] James E. McCarthy, Clean Air Issues in the 113th Congress, Congressional Research Service Report (June 27, 2014) at 5.
[28] *See, e.g.*, 42 U.S.C. §§ 7408(b)(1) (requiring Administrator to issue information on pollution control techniques, including energy requirements for controls); 7408 (f)(2)(C) (requiring Administrator to provide information on energy impact of pollution control measures); 7409(d)(2)(C)(requiring Administrator to appoint a committee to advise EPA on, inter alia, "energy effects" that may result from strategies for NAAQS attainment and maintenance); 7410(f)(providing a process to temporarily suspend SIP requirements in response to "energy emergencies"); 7411(a)(1)(mandating that "energy requirements" must be taken into account in selection of best system of emission reduction); 7411(j)(1)(A)(ii) (authorizing waiver for innovate systems of emission reduction based on inter alia, "lower cost in terms of energy . . . impact"); 7412(d)(2)(compelling consideration of energy requirements in establishing emission standards); 7412(f)(2)(A)(compelling consideration of "energy" as a factor in setting emission standards); 7429(a)(2)(compelling consideration of energy requirements in setting emission standards); 7491(g)(1)(requiring "energy. . . impacts of compliance" to be taken into account in reasonable progress determination) 7491(g)(2)(requiring "energy . . . impacts of compliance" to be taken into account in determining best available retrofit technology); 7511b(e)(1)(A)(compelling consideration of "energy impacts" in determination of best available controls); 7617(c)(5)(requiring economic impact analysis to include "effects of standard or regulation on energy use")7651(b)(stating that the purpose of Title IV is "to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy"); 7651b(f)(stating that nothing in the Title IV allowances trading program shall be construed as modifying the Federal Power Act or affecting FERC authority under that act); 7651c(f)(providing for emissions allowances based on avoided energy generation); 7651f(b)(2)(D)(requiring consideration of energy impacts in establishing NO_X emission limitation for boilers); and 7651(g)(c)(1)(B)(allowing emission limitations to be satisfied by reduced utilization achieved through

of pollution control measures when setting emission standards.[29] Furthermore, with respect to emissions of hazardous pollutants, SO_2, and NO_X, Congress specifically provided for the regulation of fossil-fuel fired power plants.[30]

The long history of EPA's regulation of power plants also demonstrates how some members of the power industry have repeatedly responded to urgently needed, health-protective pollution standards by denying the harms caused by power plant pollution and by making exaggerated claims that clean air standards constituted regulatory overreach into the energy market that would disrupt electric reliability. In 1974, an advertisement by American Electric Power Company, one of the largest sources of power plant pollution in the country, alleged that EPA emission standards for SO_2 would cause: "Literally thousands unemployed. Millions lost in state tax revenues and more millions lost by businesses that supply the coal industry."[31] In 1982, AEP sent mailers to its customers claiming that proposed EPA controls to avoid acid rain would cost the company and its customers $2 billion a year based on a study described by the Congressional Research Service as using "questionable assumptions."[32] In 1990, an AEP official told the Boston Globe that CAA legislation to address acid rain could lead to "the potential destruction of the Midwest economy."[33] In 2004, opposing standards to control hazardous air pollutants emitted by power plants, AEP claimed that "there is a lack of any demonstrated link between power plant emissions and inhalation based health effects risks."[34] In 2011, AEP's sustainability report claimed that "power plant particulate emissions are not a significant risk to public health,"[35] and AEP's chairman and CEO claimed that Clean Air Act pollution standards would cause AEP to "prematurely shut down nearly 25% of [its] current coal-fueled generating capacity, cut hundreds of good power-plant jobs, and invest billions of dollars in capital" and stated that, "The sudden increase in electricity rates and impacts on state economies will be significant."[36]

The reality of Clean Air Act standards for power plants has demonstrated such fear-mongering to be entirely baseless. The federal clean air standards addressing SO_2, $NO_{x,}$ hazardous air pollutants (including mercury), and particulate matter have without exception achieved pollution reductions without affecting the provision of reliable, affordable power. Since the Clean Air Act was passed in 1970, particulate matter emissions have been cut by 83% and SO_2 emissions by 58%--while our population grew by over

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energy conservation); *see also id.* at 7412(n)(1)(specifically requiring EPA to make determinations regarding the regulation of emissions of hazardous pollutants from electric utility steam generating units).
[29] *See* above.
[30] *See* 42 U.S.C.§§ 7412(n)(1) (requiring EPA to make determinations regarding the regulation of emissions of hazardous pollutants from electric utility steam generating units; 7651b (SO_2 emission limitation and trading program for existing and new power plants); and 7651f (NO_X emission limitation and trading program for existing and new power plants).
[31] The Washington Post, Oct. 25, 1974, AEP Display Ad 32, "Amen!"
[32] Sarasota Herald-Tribune, Sept. 4, 1982, "The dirty politics of clean air."
[33] Boston Globe, Oct.17, 2010, "A clear water revival." *accessible at* http://articles.boston.com/2010-10-17/news/29321038 1 acid-rain-power-plant-global-warming. (viewed 8/18/2011).
[34] AEP Comments on EPA's Proposed National Emissions Standards for Hazardous Air Pollutants, June 29, 2004, EPA Rulemaking Docket, Doc ID: EPA-HQ-OAR-2002-0056-3558.
[35] AEP 2011 Corporate Accountability Report, p. 22. *accessible at* http://www.aepsustainability.com/docs/2011_AEP_CAReport.pdf.
[36] AEP Press Release, June 9, 2011, "AEP shares plan for compliance with proposed EPA regulations." *accessible at* http://www.aep.com/environmental/news/?id=1697 (viewed 8/18/2011).

50% and the economy by over 200%. In 1990, power companies predicted that addressing SO_2 pollution would cost $1000-$1500/ton and electricity prices would increase up to 10% in many states. The actual pollution reduction cost has been between $100-$200/ton for most of the program, and electricity prices fell in most states. As a result of the reductions in pollution achieved, acid rain has been dramatically reduced and the limits on SO_2 were met faster and at a dramatically lower price than expected in 1990.[37] Between 1990 and 2006, when electric utilities were claiming that electricity rates would increase substantially because of EPA regulations, rates actually fell in most states—by 47% in Arkansas, 32% in Georgia, 64% in Illinois, 28% in Indiana, 35% in Michigan, 30% in North Carolina, 18% in Ohio, 36% in Pennsylvania, 40% in Utah, and 36% in Virginia.[38] In the meantime, our nation's preeminent public health organizations—including the American Lung Association and the American Academy of Pediatrics—have documented the serious respiratory, cardiovascular, and development harm—particularly for children and the elderly—caused by power plant pollutants, and the importance of addressing these emissions.[39] Because of the health harms reduced by federal clean air standards, the benefits of the Clean Air Act will have exceeded the costs of pollution reductions by 30:1 between 1990-2020.[40]

More recently, in challenging the Cross-State Air Pollution Rule (CSAPR), energy industry petitioners claimed that meeting the Phase I emission budget requirements of the rule would lead to the idling of generating facilities, threaten electric system reliability, and cause blackouts.[41] Yet emissions data collected by EPA from the years when the Phase I requirements would have been in effect but for the litigation shows that actual emissions were within the rule's budgets—demonstrating conclusively that compliance would not have caused the disastrous consequences predicted by industry challengers.[42] Furthermore, EPA determined that the vast majority of the emissions reductions required by Phase II of the rule could be met by power plants resuming operation of already installed *but unused* pollution control devices.[43] With respect to the Mercury and Air Toxic Standards (MATS), energy industry claims about

[37] *See* U.S. House of Representatives Committee on Energy & Commerce, June 16, 2009, "Industry claims about the costs of the Clean Air Act." accessible at http://democrats.energycommerce.house.gov/Press 111/20090616/dc_industryjobs.pdf (viewed 8/18/2011).
[38] *See* U.S. House of Representatives Committee on Energy & Commerce, June 16, 2009, "Industry claims about the costs of the Clean Air Act." accessible at http://democrats.energycommerce.house.gov/Press 111/20090616/dc_industryjobs.pdf (viewed 8/18/2011); U.S. Environmental Protection Agency, April 2011, "The benefits and costs of the Clean Air Act from 1990 to 2020." accessible at http://www.epa.gov/oar/sect812/prospective2.html (viewed 8/18/2011).
[39] American Lung Association, American Thoracic Society, American Public Health Association, Asthma and Allergy Foundation of America, American Academcy of Pediatrics, Physicians for Social Responsibility, Letter to Representative Joe Barton, May 10, 2011. Accessible at: http://www.lungusa.org/get-involved/advocate/advocacy-documents/doctors-letter-.pdf.
[40] Environmental Protection Agency, April 2011, "The Benefits and Costs of the Clean Air Act from 1990 to 2020." Accessible at http://www.epa.gov/air/sect812/feb11/fullreport.pdf.
[41] *See EME Homer City Generation, L.P. v. U.S. EPA,* No. 11-1302 (D.C. Cir.), Luminant Mot. for Stay (Dkt. No. 1329866) (filed Sept. 15, 2011), at 16-20; Kansas Util.'s Mot. for Stay (Dkt. No. 1337158) (filed Oct. 21, 2011), at 6-14; Wisc. Electric Power Co.'s Mot. for Stay (Dkt No. 1339347) (filed Nov. 1, 2011), at 10; Entergy Corp. Stay Mot. (Dkt. No. 1338085) (filed Oct. 26, 2011), at 12-19; Ohio Mot. for Stay (Dkt. No. 1342027) (filed Nov. 15, 2011), at 18-19.
[42] *See EME Homer City Generation, L.P. v. U.S. EPA*, No. 11-1302 (D.C. Cir.), EPA Motion to Lift the Stay Entered on December 8, 2011 (Dkt. No 1499505.)(filed June 26, 2014), at 17-20.
[43] *See id.* at 19-20.

the extent of compliance costs have also proven to be inflated. First Energy claimed in 2011 that its MATS compliance costs would be $2-3 billion dollars, but by 2013 that estimate fell to $465 million.[44] Southern Company's initial estimates of compliance costs fell by 900 million dollars between the time the rule was proposed and 2012;[45] AEP's estimate of its costs of compliance also dropped by billions of dollars over this period.[46]

The Clean Power Plan is also consistent with EPA's long tradition of working collaboratively with states to foster pioneering state efforts to reduce pollution.

States have led the way in promoting renewable energy and energy-efficiency as pollution reduction measures. EPA has accommodated this state-driven innovation by providing avenues for states to satisfy Clean Air Act requirements through the use of such measures.

The development of the Regional Haze Rule exemplifies how EPA has responded to state-driven efforts to achieve pollution reduction through renewable energy and energy efficiency measures. The Western Governors' Association (WGA) provided recommendations to EPA in the context of the Agency's development of regional haze rules[47] that called for a compliance alternative under which state implementation plans for western states would include renewable energy and energy efficiency as a pollution control strategy.[48] EPA reopened the comment period specifically to address the recommendations of the WGA, and proposed adding a new regulation, 40 C.F.R. § 51.309, that provided the alternative compliance program sought by the WGA's recommendations.[49] EPA ultimately finalized that alternative compliance measure, which fully reflected the WGA's recommendations regarding renewable energy and energy efficiency measures.[50]

The NO_X SIP call also demonstrates how EPA has facilitated the use of renewable energy and energy-efficiency measures by employing a flexible approach that allows states to rely on these measures for cost-effective emission reductions. In that rulemaking, EPA determined state emission budgets by considering the level of NO_X reductions that could be obtained by applying pollution control technologies

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[44]*See* FirstEnergy, 2011 Q3 Earnings Call (Anthony Alexander, CEO) http://seekingalpha.com/article/304211-firstenergys-ceo-discusses-q3-2011-results-earnings-call-transcript; FirstEnergy, 2013 Q3 Earnings Call (Anthony Alexander, CEO) http://seekingalpha.com/article/1808342-firstenergy-management-discusses-q3-2013-results-earnings-call-transcript.
[45]*See* Southern Company, 2012 Q2 Earnings Call (Art Beattie, CFO) http://seekingalpha.com/article/749651-southern-management-discusses-q2-2012-results-earnings-call-transcript.
[46] *See* AEP, 2012 Q4 Earnings Call (Nicholas K. Akins, CEO) http://seekingalpha.com/article/1188551-american-electric-power-management-discusses-q4-2012-results-earnings-call-transcript
[47] 62 Fed. Reg. 41,138 (July 31, 1997).
[48] *See* Notice of Availability of Additional Information Related to Proposed Regional Haze Regulations; Solicitation of Comments, 63 Fed. Reg. 46952 (Sept. 3, 1998); Letter from Western Governors Association to Carol Browner (June 29, 1998), at 16-18, *available at* http://www.epa.gov/ttn/oarpg/t1/fr_notices/wgagclet.pdf.
[49] *See* Notice of Availability of Additional Information Related to Proposed Regional Haze Regulations; Solicitation of Comments, 63 Fed. Reg. 46952 (Sept. 3, 1998).
[50] *See* 64 Fed. Reg. 35,714, 35,754 (stating that section § 51.309 provides "an alternative to the general provisions of section 51.308").

to utility sources, but specifically provided that state SIPs could rely on energy efficiency and renewables as a strategy for meeting the NO_x budgets.[51]

Notably, in 2002 the George W. Bush Administration specifically called for the utilization of renewable energy development and energy-efficiency as pollution reduction measures,[52] and much of EPA's work to facilitate pioneering state efforts to develop renewables and energy efficiency as pollution reduction measures progressed under that Administration. For example, EPA has provided extensive guidance to states on incorporating renewable energy and demand-side energy reduction measures into section 110 State Implementation Plans and demonstrating compliance with NAAQS or attainment goals through the use of those measures.[53] In the last decade, a number of states have incorporated renewable energy requirements and energy-efficiency measures into EPA approved SIPs. For example, in 2005, EPA approved inclusion of county government commitments to purchase 5% of their annual electricity consumption from wind power in Maryland's SIP.[54] This approval allowed the county commitments to be credited toward NO_X reduction goals for NAAQS attainment.[55] In 2006, EPA Region 6 approved a Louisiana SIP revision for attaining the 8-hr ozone standard in Shreveport that included a performance contract whereby the City of Shreveport installed energy-saving equipment in city-owned buildings to reduce energy use by 9121 MWh per year.[56] In 2007, Virginia, Maryland, and the District of Columbia submitted SIP revisions for 8-hr ozone in the Washington non-attainment area that included commitments by municipalities to purchase renewable energy certificates representing 123 million kWh of wind energy each year from 2004 to 2009.[57] The SIP submissions also included commitments by local and state governments to replace conventional traffic lights with LED lights.[58] In 2008, EPA approved the inclusion of energy efficiency measures aimed at reducing NO_X emissions for Dallas-Fort Worth into the Texas SIP.[59] The SIP mandated the statewide adoption of the International Residential Code (IRC) and the International Energy Conservation Code (IECC), and directed counties to develop ordinances to

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[51] *See* 63 Fed. Reg. 57,356, 57,362, 57438 (Oct. 27, 1998).
[52] *See* Fact Sheet: President Bush Announces Clear Skies & Global Climate Change Initiatives (Feb. 12, 2002) *available at* http://georgewbush-whitehouse.archives.gov/news/releases/2002/02/20020214.html.
[53] *See, e.g.*, U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012; U.S. EPA, Office of Air and Radiation, Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP), September 2004; U.S. EPA, Office of Air and Radiation, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric Sector Energy Efficiency and Renewable Energy Measures, August 2004.
[54] 70 Fed. Reg. 24,988 (May 12, 2005).
[55] *Id*. at 24,989.
[56] U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[57] According to EPA guidance, these submittals were approved by EPA Regions in 2007, but there appears to be no record of those approvals in the Federal Register. See U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[58] U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[59] *See* 73 Fed.Reg. 47,835, 47,836 (Aug. 15, 2008).

impose energy efficiency requirements on the construction of new homes to reduce electricity consumption in those counties by at least 5% each year for 5 years.[60]

Under the Obama Administration, EPA has continued to work closely with states engaged in pioneering efforts to reduce power plant pollution through renewable energy and energy efficiency measures. For example, EPA has collaborated with the Connecticut Department of Environmental Protection (CTDEP) to develop pathways for the state to use its renewable portfolio standard (RPS) requirements and extensive energy efficiency programs for CAA planning and compliance under section 110.[61] Having assessed the effect of its EE and RE projects on NO_X emissions during high demand days as part of the weight of evidence analysis in its 2007 8-hr ozone attainment demonstration, CTDEP contacted EPA Region 1 for guidance on additional opportunities for incorporating RE and EE programs into its CAA planning.[62] Region 1 responded by providing CTDEP with a guidance letter outlining key issues and questions for CTDEP to consider in incorporating RE/EE measures into its SIP as federally enforceable control measures.[63]

In addressing interstate air pollution, EPA across Republican and Democratic administrations has also recognized and facilitated state efforts to reduce pollution through renewable energy and energy-efficiency measures. Both CAIR and CSAPR provided states with latitude to achieve required emission reductions through renewable energy utilization or measures to improve energy efficiency.[64] Specifically, CAIR ensured that states would have flexibility in establishing allowance set-asides for both energy efficiency and renewables.[65] CSAPR gave states the option of developing state plans to achieve reductions through alternative measures to those established in FIPs,[66] and provided for state creation of allowance set-asides for energy efficiency and renewables.[67]

In summary, Congress has provided EPA with the authority, and mandate, to address air pollution from power plants. Because power plants emit a large portion of the air pollution in the United States, addressing emissions from this category of sources is of utmost importance to protecting human health and environmental quality. Throughout the Clean Air Act, Congress has recognized the relationship between pollution from power plants and energy generation, and has expressly instructed EPA on the

[60] *See* Texas Commission on Environmental Quality, Revisions to the State Implementation Plan (SIP) for the Control of Ozone Air Pollution, Apr. 27, 2005, at ES-5, 5-2, 5-3; U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-8-K-9.
[61] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9-K-10, K-12-K-14.
[62] *See id.*
[63] *Id.* at K-14-K-15.
[64] *See* 70 Fed. Reg. 25,162, 25, 165, 25,256, 25, 279 (May 12, 2005) (Clean Air Interstate Rule); 76 Fed. Reg. 48,208, 48,209-11, 48, 319 (Aug. 8, 2011) (Cross-State Air Pollution Rule).
[65] *See* 70 Fed. Reg. at 25, 279 ("NO_X allocation methodology elements for which States will have flexibility include…The use of allowance set-asides . . . for energy efficiency [and, inter alia,] renewables[.]").
[66] 76 Fed. Reg. at 48,209 ("Each state has the option of replacing these federal rules [in the FIP] with state rules to achieve the required amount of emission reductions from sources selected by the state.")
[67] 76 Fed. Reg. at 48,319 (discussing treatment of energy efficiency), 48,327-28 (final rule provides states with option of allocating allowances to renewable energy facilities).

consideration of energy impacts in establishing emissions standards. Since 1971, when first empowered to do so by the Clean Air Act Amendments of 1970, EPA has established standards for dangerous emissions from fossil-fuel fired power plants. These regulations have achieved emissions reductions without affecting electric reliability. Finally, for more than fifteen years, and under three different Administrations, EPA has worked to facilitate state-pioneered efforts to achieve pollution reductions through development of renewables and improved energy-efficiency. For these reasons, it is clear that the CPP is consistent with EPA's long history of addressing harmful emissions from power plants, and constitutes a natural and necessary step forward in protecting the public from carbon pollution.

I. The Legal Foundation for the Clean Power Plan

Section 111(d) provides for dynamic federal-state collaboration in securing emission reductions from existing sources, with state flexibility to identify the optimal systems of emission reduction for their state while achieving the necessary environmental performance. EPA's longstanding § 111(d) implementing regulations[68] provide for EPA to issue "emission guidelines" in which the Agency fulfills its § 111 duty to identify the "best system of emission reduction" for a specific pollutant and listed source category.[69] EPA then identifies the emission reductions achievable using that system. States are given the flexibility to deploy different systems of emission reduction than the "best" system identified by EPA, so long as they achieve equivalent or better emission reductions.[70] The achievement of equivalent emission reductions enables state plans to be deemed "satisfactory" in the statutorily required review.[71] The statute provides that when states do not submit a satisfactory plan, EPA must develop and implement emission standards for the sources in that state.[72]

A. The statute gives EPA ample authority to oversee state compliance with § 111(d).

Although some have posited that the states have the sole authority to determine the stringency of emission standards under § 111(d), this disregards the plain language of § 111. Section 111(a)(1) elucidates that it is EPA—not the states—that identifies the best system of emission reduction considering the statutory factors:

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[73]

That definition specifically refers to "the Administrator"[74] as the entity that "determines" what constitutes the best system of emission reduction based on the statutory factors such as optimal environmental performance ("best") and cost. It is the Administrator who "tak[es] into account the cost of achieving

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[68] 40 C.F.R pt. 60, subpt. B. EPA's regulations for the general implementation of § 111(d) have not been challenged since they were promulgated in 1975. *See* 40 Fed. Reg. 53,340 (Nov. 17, 1975); *see also* Clean Air Mercury Rule, 70 Fed. Reg. 28,606 (May 18, 2005), *vacated on other grounds by New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). Any challenge would now be time-barred. 42 U.S.C. § 7607(b); *see also Am. Rd. & Transp. Builders Ass'n v. EPA*, 705 F.3d 453, 457-58 (D.C. Cir. 2013); *Am. Rd. & Transp. Builders Ass'n v. EPA*, 588 F.3d 1109, 1113 (D.C. Cir. 2009).

[69] 40 C.F.R. § 60.22(b)(5) (guidelines will "reflect[] the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved").

[70] *See* 40 C.F.R. § 60.24.

[71] *Id.*; 42 U.S.C. § 7411(a); *id.* § 7411(d)(2).

[72] 42 U.S.C. § 7411(d)(2).

[73] *Id.* § 7411(a)(1) (emphasis added).

[74] *Id.* § 7602(a) (defining "Administrator" to be "the Administrator of the Environmental Protection Agency").

such reduction and any nonair quality health and environmental impact and energy requirements." Significantly, that definition is explicitly made applicable to the entirety of § 111.[75]

Under § 111(d)(1)(A), state plans must impose "standards of performance" on existing sources[76] according to the criteria provided in the "standard of performance" definition quoted above.[77] Section 111(d)(2) directs states to submit "satisfactory" plans, implementing such standards of performance, to EPA for review and approval.[78] EPA's regulations and emission guidelines have long interpreted the Agency's § 111(d) responsibility to determine whether state plans are "satisfactory" as governed by whether the plans implement emission standards that reflect the emission reductions achievable under the best system of emission reduction identified by the Administrator.[79]

EPA's review of state plans is guided by the statutory parameters defining a "standard of performance"—do state plans establish emission standards that achieve emission reductions equivalent to or better than those achievable using the best system of emission reduction? This interpretation of the statute flows inexorably from its plain language and structure, and EPA's interpretation of its substantive role under § 111(d) carries the weight of nearly four decades of Agency statutory interpretation and practice under the 1975 § 111(d) implementing regulations.[80] It is implausible that Congress provided statutory criteria that state plans must meet and further provided for EPA to review state plans, but did not intend for the statutory criteria to direct the review.[81] Indeed, for EPA to approve state plans without regard to whether those plans satisfy the statutory criteria for standards of performance would be arbitrary.

Yet the language of § 111 requires substantive review of state plans by EPA even more directly. A "standard of performance" is defined as "a standard for emissions of air pollutants *which reflects the*

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[75] *See id.* § 7411(a) ("For purposes of this section . . .").
[76] *Id.* § 7411(d)(1)(A).
[77] *Id.* § 7411(a) (all definitions, including "standard of performance," apply "[f]or purposes of this *section*" (emphasis added)).
[78] *Id.* § 7411(d)(2) (discussing results if "the State fails to submit a *satisfactory* plan" (emphasis added)).
[79] *See* State Plans for the Control of Existing Facilities, 39 Fed. Reg. 36,102 (Oct. 7. 1974); *see also* State Plans for the Control of Certain Pollutants from Existing Facilities, 40 Fed. Reg. 53,340, 53,342-44 (Nov. 17, 1975) (rejecting commenters' argument that EPA does not have authority to require states to establish emissions standards that are at least as stringent as EPA's emission guidelines); *id.* at 53,346 (defining "emission guideline" as "a guideline . . . which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.").
[80] *Id.* EPA has issued § 111(d) emission guidelines for a number of source categories. *See* 42 Fed. Reg. 12,022 (Mar. 1, 1977) (phosphate fertilizer plants); 42 Fed. Reg. 55,796 (Oct. 18, 1977) (sulfuric acid plants); 44 Fed. Reg. 29,828 (May 22, 1979) (kraft pulp mills); 45 Fed. Reg. 26,294 (Apr. 17, 1980) (primary aluminum plants); 61 Fed. Reg. 9,905 (Mar. 12, 1996) (municipal solid waste landfills).
[81] EPA noted in its 1975 implementing regulations that § 111(d) is silent on the criteria by which state plans might be judged "satisfactory," and that therefore those criteria must be inferred from the context of § 111. *See* 40 Fed. Reg. at 53,342. The criteria were located in § 111(a)(1)'s definition of "standard of performance," mirrored in EPA's definition of "emission guideline." *Compare* Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1683 (1970), *with* 40 Fed. Reg. at 53,346. Moreover, the agency suggested that the criteria for state plans served the same function as the criteria for standards of performance issued under § 111(b). 40 Fed. Reg. at 53,342 ("it seems clear that some substantive criterion was intended to govern *not only the Administrator's promulgation of standards but also his review of State plans*" (emphasis added)). Thus, EPA's emission guidelines have always been closely tied to the statutory definition of "standard of performance" in § 111(a)(1).

degree of emission limitation achievable through the application of the best system of emission reduction" identified by the Administrator. An emission standard that fails on its face to secure the degree of emission reductions achievable under the best system of emission reduction is outside the statutory definition of standards of performance and does not meet the requirement that the "State establish[] standards of performance" for existing sources. State plans that fail to include a standard of performance cannot be approved as "satisfactory" by EPA under any reading of § 111.

In addition to being inconsistent with the language of § 111, exclusive state authority over the substance of existing source standards would be contrary to the purpose of the 1970 Clean Air Act—"to provide for a more effective program to improve the quality of the Nation's air"[82]—because air quality could *worsen* if state plans were not subject to any enforceable substantive standards. Evidence of the central role for protective federal standard setting is found throughout the Clean Air Act, including in § 116, which prohibits the states from adopting or enforcing emission standards less stringent than those set by EPA.[83]

Preserving that basic role for EPA in protecting the nation's air quality was a central theme of the regulations EPA adopted in 1975 to implement § 111(d). As EPA noted in the rulemaking:

> [I]t would make no sense to interpret section 111(d) as requiring the Administrator to base approval or disapproval of State plans solely on procedural criteria. Under that interpretation, States could set extremely lenient standards— even standards permitting greatly increased emissions—so long as EPA's procedural requirements were met. Given that the pollutants in question are (or may be) harmful to public health and welfare, and that section 111(d) is the only provision of the Act requiring their control, it is difficult to believe that Congress meant to leave such a gaping loophole in a statutory scheme otherwise designed to force meaningful action.[84]

In sum, both the language of § 111 and the overall purpose of the 1970 Clean Air Act amendments require a strong substantive role for EPA in ensuring that standards for existing sources meet the statutory requirements.

B. EPA's responsibility includes establishing binding emission guidelines for states.

Similarly, some stakeholders have questioned EPA's authority to establish binding emission guidelines that identify the "best system of emission reduction" and the resulting emissions reductions that each state plan must achieve. That argument fails in light of the structure of § 111(d) and in light of congressional intent. It is also contrary to EPA's reasonable interpretation of its statutory responsibility, laid out in the long-established regulations implementing § 111.

EPA's interpretation of § 111(d) as authorizing it to adopt emission guidelines makes eminent sense in light of the core delegation of authority to EPA to determine the best system of emission reduction and the statute's overall structure. The guidelines provide states with the parameters a state plan must fit

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[82] Clean Air Amendments of 1970, Pub. L. No. 91-604, 84 Stat. 1676, 1676.
[83] 42 U.S.C. § 7416.
[84] 40 Fed. Reg. at 53,343.

within in order to be found "satisfactory" by the Administrator.

Moreover, while Congress did not detail the process by which EPA would evaluate and approve state plans, there is considerable evidence that Congress subsequently recognized and approved the guidelines process that EPA established in its 1975 regulations. In 1977, for example, when Congress modified the definition of "standard of performance," the House committee explained that under § 111(d) "[t]he Administrator would establish *guidelines* as to what the best system for each . . . category of existing sources is."[85] Then, in 1990, in § 129 of the Clean Air Act, Congress directed EPA to adopt standards for solid waste combustion that would mirror the § 111 process, expressly referring to the "*guidelines* (under section 7411(d) of this title . . .)."[86]). The 1990 CAA amendments added section 129 to supplement EPA's pre-existing authority (and mandate) under section 111 to regulate emissions from solid waste incinerators. For existing solid waste incinerators to which section 129 is applicable, section 129 explicitly requires EPA to promulgate guidelines "pursuant to section 7411 (d) of this title and this section [that] shall include . . . emissions limitations" and requires the States to submit to EPA within a year following promulgation of the guidelines a plan to implement and enforce those guidelines.[87] Thus, section 129 expressly mandates that EPA's role in undertaking joint 111(d)/129 regulatory action is to establish emission limitations for solid waste incineration units whereas the state's role is to establish a plan to implement those emission limitations. This division of regulatory authority is the same as the division established by EPA's 1975 implementing regulations for 111(d). When Congress enacted section 129 in 1990, it explicitly codified that joint 111(d)/129 standards would be established by the same process EPA had developed in its 1975 implementing regulation to govern 111(d) standards. This demonstrates that Congress was not only aware of the procedures established by EPA's 1975 implementing regulations, but also approved of those procedures. In summary, both the 1977 and 1990 amendments demonstrate that Congress has recognized and legislated in reliance upon EPA's guidelines process under § 111(d).

Congress is not alone in affirming the place of emissions guidelines in the § 111(d) structure. The Supreme Court recently noted that states issue § 111(d) standards "in compliance with [EPA] guidelines and subject to federal oversight."[88]

C. EPA's authority to set quantitative requirements in emission guidelines is well-established and reflects EPA's longstanding interpretation of § 111(d).

It is well-established that EPA has authority to set quantitative requirements in emission guidelines, which states must implement via state plans. The proposed rule reflects EPA's longstanding interpretation of the distinct Federal and State roles under § 111(d), as established in the 1975 implementing regulations.

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[85] H.R. Rep. No. 95-294, at 195 (1977) (emphasis added).
[86] 42 U.S.C. § 7429(a)(1)(A) (emphasis added).
[87] 42 U.S.C. § 7429(b)(1)-(2).
[88] *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537-38 (2011).

In the 1975 rulemaking to implement § 111(d), EPA received a number of comments questioning the Agency's authority to set those substantive guidelines.[89] In response, EPA demonstrated its authority to do so with a detailed analysis of the language, purpose, and legislative history of § 111(d).[90] EPA's regulations for the general implementation of § 111(d) have not been challenged since they were promulgated in 1975.[91] Any challenge would now be time-barred.[92] Notably, when EPA promulgated the Clean Air Mercury Rule (CAMR) in 2005, which, in accordance with the 1975 implementing regulations, established substantive emission limitations for power plants under § 111(d), EPA's interpretation of its authority in the 1975 implementing regulations was not challenged by any of the parties in the ensuing litigation on CAMR.[93] Thus, because the regulations were neither challenged upon promulgation, nor in the specific and very recent context of their application to regulate emissions from power plants, EPA's authority to issue emission guidelines is settled.[94]

D. States can deploy locally designed solutions to meet EPA's emission guidelines.

Although EPA adopts emission guidelines identifying the best system of emission reduction, § 111(d) (and EPA's implementing regulations) provide for state tailoring and flexibility in meeting those guidelines. The statute does not require states (or sources) to use the exact system of emission reduction identified by EPA. Instead, states simply must achieve the level of emission reductions that would be achieved under that best system, and can deploy the system or systems of emission reduction most appropriate for the emission sources in their state.[95]

With this federal-state collaboration, § 111 is very similar to the process implemented under § 110, under which states put in place plans to achieve National Ambient Air Quality Standards for criteria pollutants. This parallel structure reflects the directive in section 111(d) that EPA establish "a procedure similar to that provided by" § 110, under which states develop their plans and submit them to EPA for review.[96] Under § 110, the safe level of ambient pollution is an expert, science-based determination made by EPA, but states have considerable discretion in determining how to reduce emissions to that level. The state plan submission and review "procedure" under § 110 provides for EPA review of each state plan to ensure that "it meets all the applicable requirements" of § 110—including implementation and enforcement of the National Ambient Air Quality Standards as well as other requirements relevant to ensuring the effectiveness of the plans.[97] Thus, sections 110 and 111(d) have an appropriately parallel

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89 40 Fed. Reg. at 53,342.
90 *Id.* at 53,342-44.
91 *See* 40 Fed. Reg. 53,340 (Nov. 17, 1975); *see also* Clean Air Mercury Rule, 70 Fed. Reg. 28,606 (May 18, 2005), *vacated on other grounds by New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).
92 42 U.S.C. § 7607(b); *see also Am. Rd. & Transp. Builders Ass'n v. EPA*, 705 F.3d 453, 457-58 (D.C. Cir. 2013); *Am. Rd. & Transp. Builders Ass'n v. EPA*, 588 F.3d 1109, 1113 (D.C. Cir. 2009).
93 *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).
94 *See* 42 U.S.C. § 7607(b) (60-day review period for Clean Air Act rulemakings).
95 *See id.* § 7411(a) (a "standard of performance" must "reflect[]" the emission reductions achievable through use of the best system, but need not actually use the best system).
96 *Id.* § 7411(d)(1).
97 *Id.* § 7410(k)(3). Section 110 requires, *inter alia*, state plans to provide for "implementation, maintenance, and enforcement of" National Ambient Air Quality Standards, *id.* § 7410(a)(1), the use of emissions monitoring equipment as prescribed by EPA, *id.* § 7410(a)(2)(F), and any air quality modeling requirements prescribed by EPA,

structure under EPA's interpretation of the statute — under both provisions, EPA uses its expertise to identify the emission reductions that must be achieved, states use their discretion to develop plans to achieve the emission reductions, and EPA reviews plans to ensure they are meeting the relevant statutory criteria.

In sum, § 111(d) establishes a collaborative federal-state process for regulating existing sources in which EPA establishes quantitative emission guidelines and the states deploy locally tailored and potentially innovative solutions to achieve the required emission reductions.

E. A System of Emission Reduction That Achieves the Rigorous Cuts in Carbon Pollution Demanded by Science and Does so Cost-Effectively is Eminently Consistent with the § 111 Criteria and Is Plainly Authorized by § 111

In the proposed Clean Power Plan, EPA has identified the "best system of emission reduction" as a flexible, system-based framework comprised of four building blocks: (1) heat rate (efficiency) improvements at coal-fired power plants; (2) shifting utilization from higher emitting coal-fired power plants to underutilized natural gas combined cycle power plants; (3) deploying zero carbon energy such as wind and solar; and (4) improving demand-side energy efficiency. This system of emission reduction mirrors what is happening on the ground. Across the country, states and power companies are reducing emissions from fossil fuel fired power plants by making those plants more efficient, increasing the use of lower-carbon generation capacity and zero-emitting energy, and investing in demand-side energy efficiency. At their core, these approaches all have the same result—reducing emissions from existing high-emitting fossil fuel fired power plants and improving the emission performance of the power plant source category. The broad employment of this system across the country indicates that it is demonstrated in practice—and indeed, these approaches have been in use for decades.[98]

When seen through the lens of § 111, the system described above is fundamentally an emissions averaging system, achieving broadly based reductions from the power plant source category. Improving efficiency at plants, deploying zero-emitting energy on the grid, investing in demand-side energy efficiency to reduce demand, and shifting utilization towards lower-emitting generation all reduce

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id. § 7410(a)(2)(K). *See also, e.g.*, *North Dakota v. EPA*, 730 F.3d, 750, 760-61 (8th Cir. 2013) (holding that EPA is charged with "more than the ministerial task of routinely approving SIP submissions" under CAA § 169A) (citing *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461 (2004); *Oklahoma v. EPA*, 723 F.3d 1201 (10th Cir. 2013)).

[98] *See, e.g.*, World Resources Institute, Power Sector Opportunities for Reducing Carbon Dioxide Emissions: Michigan (Sept. 2013), *available at* http://www.wri.org/publication/power-sector-opportunities-for-reducing-carbon-dioxide-emissions-michigan; World Resources Institute, Power Sector Opportunities for Reducing Carbon Dioxide Emissions: North Carolina (Sept. 2013), *available at* http://www.wri.org/publication/power-sector-opportunities-for-reducing-carbon-dioxide-emissions-north-carolina; World Resources Institute, Power Sector Opportunities for Reducing Carbon Dioxide Emissions: Ohio (Aug. 2013), *available at* http://www.wri.org/publication/power-sector-opportunities-for-reducing-carbon-dioxide-emissions-ohio. *See generally* World Resources Institute, GHG Mitigation in the United States: An Overview of the Current Policy Landscape, at 10-12 (2012), *available at* http://www.wri.org/publication/ghg-mitigation-us-policy-landscape; Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/ (last visited Feb. 27, 2014).

emissions from fossil fuel fired units as a group. This system of emission reduction is conceptually more expansive than the typical end of the pipe pollution-control technology installed at a plant but satisfies the statutory language and purpose of § 111(d) and is a reasonable interpretation of that provision. This system will employ emissions averaging across the regulated sources in order to recognize the pollution reductions achieved by changes in utilization at plants and among plants.

By incorporating an averaging framework, this system can create flexibility to identify the most cost effective emission reductions across the regulated sources. Because sources are allowed to average emission reductions, the system will give sources flexibility to reduce emissions onsite or secure emission reductions from other sources that can achieve reductions beyond those necessary for their own compliance at lower cost. Each source will be required to comply with the emission standard established but can meet its compliance obligation by securing emission reductions at other units in the source category. By recognizing the emission reductions achieved by the deployment of low-carbon generation, shifts in utilization toward lower- or non-emitting generation, and improvements in demand-side energy efficiency, the system will create flexibility for states and regulated sources and enhance the cost-effectiveness and environmental co-benefits of the emission standards.

As discussed below, the language of § 111 is broad enough to encompass such an emission reduction system. Moreover, under § 111(d), where the goal is maximizing the reduction of carbon pollution from existing power plants considering cost and wider environmental and energy impacts, this emission reduction system best satisfies the statutory factors.

1. Section 111 gives EPA wide discretion to establish a system of emission reduction that achieves rigorous reductions in carbon pollution through locally tailored solutions.

The language and structure of § 111 give EPA expansive authority to determine which system of emission reduction best serves the statutory goals. The marked breadth of the language indicates Congress' broad delegation of authority to EPA. Neither the term "best system of emission reduction" nor its components are given technical definitions in the Act. In common usage, a "system" is defined as "a complex unity formed of many often diverse parts subject to a common plan or serving a common purpose."[99] Clearly the ordinary meaning of the term "system" does not limit EPA to choosing end-of-pipe control technologies or other mechanical interventions at the plant. Rather, EPA may choose to base its standards on a "complex unity . . . serving a common purpose" that is consistent with the other statutory requirements. A system of emission reduction that reflects the unified nature of the electric grid and achieves cost-effective emission reductions from the source category by treating all fossil fuel fired power plants as an interconnected group, averaging emissions across plants and recognizing changes in plant use that reduce emissions, fits securely within this framework.

The history of § 111 demonstrates that Congress deliberately rejected terms that were more restrictive than "best system of emission reduction," and that it was especially important to Congress for EPA to have flexibility in identifying solutions to reduce emissions from existing sources. The original 1970 language provided a definition of the standard applicable to existing sources under § 111 that is rather

[99] Webster's Third New International Dictionary 2322 (1967).

similar to the current definition: "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated."[100] Congress subsequently identified this standard as a "standard of performance"—the same term Congress used to describe the standards applicable to new sources under § 111.[101]

The 1970 legislative history reveals that the terms "standard of performance" and "best system of emission reduction" rely on broad concepts beyond mere add-on technologies. Because the current definition is almost identical to the 1970 definition,[102] we can look to the 1970 legislative history to inform our understanding of the phrase "standard of performance."

Section 111 was first adopted in the Clean Air Act Amendments of 1970.[103] To understand the 1970 legislative history, it is necessary to distinguish between provisions in the precursors to § 111 related to *new* sources and those related to *existing* sources.

In the House bill (H.R. 17255), proposed § 112 would have added a new section to the Clean Air Act titled Emission Standards for New Stationary Sources.[104] That provision used the phrase "emission standards," which was not defined anywhere in the bill. The House bill only focused on these emission standards for new sources; it did not have a provision providing for emission standards for existing sources.

The Senate bill (S. 4358), by contrast, called for federal regulation of both existing sources (proposed § 114[105]) and new sources (proposed section 113).[106] For existing sources, the bill expected "emission

[100] Clean Air Amendments of 1970, Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1683. The original definition lacks the language directing EPA to consider "any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1).
[101] *See* Pub. L. No. 95-95, § 109(b), 91 Stat. 685, 699 (1977).
[102] Again, the only difference between the current definition of "standard of performance" and the 1970 definition is that now it specifies that EPA must also consider "any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). The language about "non-air quality health and environmental impact and energy requirements" was added in 1977. *See* Pub. L. No. 95-95, § 109(c), 91 Stat. 685, 700 (1977).
[103] Clean Air Act Amendments of 1970, Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1683.
[104] H.R. 17255, 91st Cong., 2d Sess. § 5, 116 Cong. Rec. 19,225 (1970) (proposing a new section 112 for the Clean Air Act).
[105] Proposed section 114 did not expressly refer *just* to existing sources; on its face it made no distinction between new or existing sources. S. 4358, 91st Cong., 2d Sess. § 6(b) (1970). However, the Senate report (S. Rep. 91-1196) plainly said that section 114 "would be applied to existing stationary sources." S. Rep. No. 91-1196, at 19 (1970). Furthermore, Senator Cooper from Kentucky, the ranking Republican member on the main Senate committee considering the bill, also plainly stated that section 114 would apply to existing sources. *See* 116 Cong. Rec. 32,918 (1970) (stating in floor debate that "section 114 requires the Secretary to set emission standards for specific industrial pollutants -- applicable to old plants as well as new. This procedure would apply to the same industries designated for new source standards of performance in section 113.")
[106] S. 4358, 91st Cong., 2d Sess. § 6(b) (1970).

standards"—an undefined term. For new sources, the bill expected "standards of performance" [107] —the phrase later codified in § 111.

The Senate bill included broad language describing what a "standard of performance" would entail. The "standards of performance" called for by proposed § 113 for new sources were to "reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the *latest available control technology, processes, operating methods, or other alternatives*."[108] Thus, it is plain that the Senate contemplated that standards of performance would be based on more than add-on technologies alone.

Moreover, the Senate report accompanying the bill revealed that the standards of performance would not be limited to just reducing pollution but could also *prevent* pollution. From the Senate committee report:

"[P]erformance standards should be met through application of the latest available emission control technology or through other means of *preventing or controlling* air pollution."[109]

The Senate report went on to emphasize how innovative this new concept of a "standard of performance" was. The report noted that this was "a term which has not previously appeared in the Clean Air Act" and that the term "refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods."[110]

That broad, innovative concept from the Senate of a "standard of performance" was incorporated into the version of § 111 proposed by the Conference Committee and ultimately codified. Although the definition of "standard of performance" in section 111(a)(1) of the Conference bill did not define that phrase exactly as the Senate had with reference to "latest available control technology, processes, operating methods, or other alternatives," the Conference bill used an equally broad and equally innovative phrase—"best system of emission reduction."[111]

The Conference bill did not define "best system of emission reduction" and the Conference Committee report did not discuss that phrase, but the Senate deliberations after the Conference Committee confirmed that the final version of the bill reflected the Senate's broad understanding of the basis for the standards. The Senate's summary of the conference bill stated: "The [Conference] agreement authorizes regulations to require new major industry plants . . . [to] achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives," reflecting the language the Senate originally used to describe a "standard of performance."[112] This broad inquiry, well

[107] S. 4358, 91st Cong. § 6(b) (1970).
[108] S. 4358, 91st Cong. § 6(b) (1970) (emphasis added).
[109] S. Rep. No. 91-1196, at 16 (1970) (emphasis added).
[110] *Id.* at 17.
[111] H.R. 17255 (conf. bill), 91st Cong., 2d Sess. § 4(a) (as reported by Senate-House Conf. Comm., Dec. 17, 1970) (enacted); H.R. Rep. No. 91-1783 (1970).
[112] 116 Cong. Rec. 42,384 (1970) (Senate Agreement to Conference Report on H.R. 17255). That same Senate statement also noted that the "conference agreement, as did the Senate bill, provides for national standards of

beyond mere add-on technology, would be accomplished by the federal government looking to the "best system of emission reduction" as the basis for the § 111 standards.

The Senate also contributed something else very important to the Conference bill—the idea of regulating existing sources. Section 114 of the Senate bill was the only provision in either chamber that required existing source standards. The Conference bill then took that concept and included it as subsection (d) of § 111.[113] Section 111(d) in the final bill is identical to today's version in all pertinent respects except one: In 1970, existing sources were subject to "emission standards," an undefined term, rather than "standards of performance."[114] In 1977, Congress amended section 111(d) to provide specifically that existing sources, like new sources, would be subject to "standards of performance."[115] Thus, the legislative history of the phrase "standard of performance" from 1970—emphasizing a broad inquiry into processes, operating methods, and other alternatives to reduce and prevent pollution—is entirely relevant to interpreting the present version of the existing source standards under section 111(d), and supports the flexible, system-wide approach taken by EPA in the proposed Clean Power Plan.

Furthermore, although Congress made changes to the definition of "standard of performance" in 1977 that introduced additional requirements and distinctions between the standards for new and existing sources, with the 1990 amendments, Congress essentially restored the 1970 version of the term. Changes to the definition made in the 1977 Amendments to the Clean Air Act required § 111 standards for new sources to reflect "the best *technological* system of *continuous* emission reduction."[116] In contrast, the § 111 standards for existing sources were to reflect the "best system of continuous emission reduction,"[117] which, as clarified by the Conference Report, need not be a technological system.[118] In 1990, Congress removed the requirements that standards for new sources be based on "technological" systems and that standards for both new and existing sources achieve "continuous" reductions, restoring use of broad "system" language for both new and existing source standards.[119] Thus, the 1990 version of § 111 that Congress adopted was strikingly similar to the 1970 version, calling for "standards of performance" for both new and existing sources that would reflect the "best system of emission reduction." It is noteworthy that even during the period of time when Congress determined a more specific definition of "standard of

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performance on emission from new stationary sources," again confirming the analogy to the prior Senate version. *Id.* at 42,385.

[113] H.R. 17255 (conf. bill), 91st Cong., 2d Sess. § 4(a) (1970) (enacted); H.R. Rep. No. 91-1783 (1970); Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1684. The Senate version of the existing source provision (proposed section 114) and the final version differed in this respect: The Senate would have required EPA to set and enforce the standards for existing sources, with the states having an option to take over enforcement. *See* S. 4358, 91st Cong. § 6(b) (1970).The final bill, rather than simply offering an opportunity to the states, required the states to submit plans, along the lines of section 110, for EPA approval. H.R. 17255 (conf. bill), 91st Cong., 2d Sess. § 4(a) (1970)(enacted).

[114] 42 U.S.C. § 1857c-6(a)(1) (1970).

[115] *See* Pub. L. No. 95-95, § 109(b), 91 Stat. 685, 699 (1977).

[116] Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700 (emphases added).

[117] *Id.*

[118] The conference committee explained that the amendments "make[] clear that standards adopted for existing sources under section 111(d) of the act are to be based on available means of emission control (*not necessarily technological*)." H.R. Rep. No. 95-564, at 129 (1977) (Conf. Rep.) (emphasis added).

[119] Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631.

performance" was advisable for new sources, it did not take this approach for existing sources. The current text of the Clean Air Act reflects both Congress' more recent decision to allow EPA to select a non-technological system of emission reduction when promulgating standards for new sources under § 111 as well as Congress' longstanding policy of allowing that approach for existing sources.[120]

Courts have recognized that the identification of the best system of emission reduction is an expansive, flexible endeavor, in the service of securing the maximum emission reductions, finding that EPA may weigh "cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present."[121] Further, courts have noted that EPA's choice of the best system of emission reduction should encourage the development of systems that achieve greater emission reductions at lower costs and deliver energy and nonair health and environmental benefits.[122]

In short, § 111 gives EPA wide discretion to identify an emission reduction system that relies on solutions such as averaging to maximize environmental performance and enhance cost-effectiveness.

2. The language of § 111 is sufficiently broad to authorize the selection of an averaging system as the best system of emission reduction, thus expressing state goals as average, state-wide performance levels is reasonable and consistent with EPA's authority under the Clean Air Act

Although the term "best system of emission reduction" is broad, it is not unbounded. Section 111 requires the "best" system to be the system adequately demonstrated to achieve the maximum emission reductions from the regulated sources, considering cost and impacts on non-air quality health or environmental impacts and energy requirements. The system must also provide the foundation for state standards of performance to apply a "standard for emissions" to "any existing source" in the listed category. EPA must seek out the system that best serves these clearly enunciated goals of § 111.

[120] Congress' use of the broad term "system" in section 111 of the CAA is also consistent with its use of that term in other sections of the CAA and other federal environmental laws. *See, e.g.*, 42 U.S.C. § 7412(d)(2) (emissions standards for hazardous air pollutants must reflect the maximum degree of reductions achievable "through application of measures, processes, methods, systems or techniques" including pollution reduction through process changes or substitution of materials, operational standards, and other measures); -(r)(7)(A) (EPA's regulations for preventing the accidental release of hazardous air pollutants may make distinctions between various "devices and systems," signaling that devices and systems are not coextensive); 33 U.S.C. § 1292(2)(B) (Clean Water Act's definition of "treatment works" includes any "method or system for preventing, abating, reducing, storing, treating, separating, or disposing of municipal waste").

[121] *Sierra Club v. Costle*, 657 F.2d 298, 321, 330 (D.C. Cir. 1981).

[122] *Id.* at 346-47. Courts have also recognized that standards under the Clean Air Act will often require changes in the methods of production or operation for regulated sources. *Id.* at 364 ("Recognizing that the Clean Air Act is a technology-forcing statute, we believe EPA does have authority to hold the industry to a standard of improved design and operation advances."); *International Harvester Co. v. Ruckelshaus*, 478 F.2d 615, 640 (D.C. Cir. 1973) (under certain mobile source provisions, satisfaction of the CAA "might occasion fewer models and a more limited choice of engine types," as long as consumer demand can "be generally met").

We strongly support EPA's decision to propose state goals in the form of average performance levels that reflect state-wide application of the BSER. As EPA recognizes in the preamble,[123] this approach has clear policy advantages. Because CO_2 is a dispersed pollutant whose effects on the atmosphere are the same regardless of where it is emitted, EPA's averaging approach is as environmentally effective as an alternative approach establishing guidelines specific to particular EGUs. At the same time, the averaging approach allows each state valuable flexibility to determine the most locally appropriate mix of measures to reduce carbon pollution – and to establish standards of performance for individual EGUs that recognize the unique circumstances of specific facilities. For example, the proposed state-wide averaging approach automatically takes into account reductions in carbon intensity associated with shifting generation from high-emitting EGUs to lower-emitting facilities, and allows states to flexibly adjust the amount of dispatch shift that occurs in their generating fleet both geographically and over time. Similarly, the state-wide averaging approach allows states to themselves put in place flexible, averaging compliance frameworks to capture emission reductions attributable to zero-emitting resources, such as renewables. Lastly, the state-wide averaging approach is also compatible with existing state programs, such as renewable portfolio standards and emissions trading programs, which could be incorporated into state plans and used to meet the state goals. Given the interconnected nature of the power sector and the fact that the most cost-effective, well-established techniques for reducing carbon pollution from existing EGUs rely on reducing aggregate emissions from the power sector, EPA's approach is eminently reasonable.

As the proposed emission guidelines recognize, there are many available options for reducing carbon dioxide emissions from existing power plants through modifications or upgrades at these plants. An analysis focused on these "onsite" measures would by necessity be expansive in scope—including not only significant improvements to the efficiency or "heat rate" of the plant, but also other emission reduction measures such as co-firing or re-powering with lower-carbon fuels;[124] utilizing renewable energy sources to provide supplemental steam heating;[125] using available waste heat to remove moisture from coal or switching to higher-rank coal;[126] and implementing combined heat and power (CHP) systems at plants near industrial facilities or district heating systems,[127] among other solutions. For example, engineering firms have estimated that with modest modifications, coal-fired power plants can derive as

[123] 79 Fed Reg at 34,890-92, 34,894.
[124] *See* F.J. Binkiewicz, Jr. et al., Natural Gas Conversions of Existing Coal-Fired Boilers (Babcock & Wilcox White Paper MS-14, 2010), *available at* http://www.babcock.com/library/Documents/MS-14.pdf; Brian Reinhart et al., *A Case Study on Coal to Natural Gas Fuel Switch* (Black & Veatch, 2012), *available at* http://bv.com/Home/news/thought-leadership/energy-issues/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.
[125] *See* Craig Turchi et al., Solar-Augment Potential of U.S. Fossil-Fired Power Plants (National Renewable Energy Laboratory, 2011), *available at* http://www.nrel.gov/docs/fy11osti/50597.pdf. Several projects are currently under way to augment existing coal-fired power plants in Australia and the United States with concentrated solar thermal power systems. *See Hybrid Renewable Energy Systems Case Studies*, Clean Energy Action Project, http://www.cleanenergyactionproject.com/CleanEnergyActionProject/Hybrid_Renewable_Energy_Systems_Case_Studies.html (last visited Feb. 27, 2014).
[126] *See* EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units, at 31-33 (Oct. 2010), *available at* http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf (describing a commercially-available on-site drying process that can reduce CO_2 emissions from a pulverized coal boiler by approximately 4%).
[127] *See id.* at 34-35.

much as 50% of their heat input from natural gas.[128] Co-firing at this level could yield emission reductions of 20%, and could be combined with heat rate and other improvements to achieve even deeper reductions at a specific plant.

Here, however, EPA has appropriately determined that a more flexible averaging system best satisfies the statutory factors in the unique context of carbon pollution from the power sector.[129] Flexible averaging programs implemented under the Clean Air Act and by states and companies have demonstrated that they can significantly lower the cost of cutting pollution because they facilitate capture of the lowest-cost emission reduction opportunities.[130] In the context of carbon pollution standards for existing power plants, a flexible averaging framework that rigorously quantifies the emission reductions achieved via increased utilization of lower and zero-emitting generation and investments in demand-side energy efficiency can achieve very substantial carbon pollution reductions cost-effectively while enabling proactive management of generation capacity and enhancement of grid reliability. Indeed, a flexible system will facilitate efficient compliance not only with the Clean Power Plan but also with other applicable air quality and energy regulations, allowing states and companies to make sensible investments in multi-pollutant emission reductions and clean, safe, and reliable electricity infrastructure. Such a system will enable states to consider the "remaining useful life" of sources as the Clean Air Act provides[131] and optimize investments in existing and new generation to secure the necessary emission reductions. A flexible system that facilitates a variety of emission reduction pathways is also the system already being deployed by a number of states and companies, mobilizing innovative emission reduction measures and securing significant reductions in carbon pollution.[132]

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[128] *See* Reinhart et al., *supra* note 124.

[129] EPA has allowed averaging or trading programs where they provide greater emissions reductions than source-specific technology standards. *See*, *e.g.*, Regional Haze Regulations, 64 Fed. Reg. 35,714, 35,739 (July 1, 1999) (allowing state plans "to adopt alternative measures in lieu of BART where such measures would achieve even greater reasonable progress toward the national visibility goal").

[130] For example, a recent survey of economic research found that the Clean Air Act's flexible Acid Rain Program has achieved "a range of 15-90 percent savings, compared to counterfactual policies that specified the means of regulation in various ways and for various portions of the program's regulatory period." Gabriel Chan, Robert Stavins, Robert Stowe & Richard Sweeney, The SO_2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation, at 5 (2012), *available at* http://belfercenter.ksg.harvard.edu/files/so2-brief_digital4_final.pdf.

[131] 42 U.S.C. § 7411(d)(1).

[132] Some have suggested that the general Clean Air Act definition of "standard of performance" in § 302(l) also applies in the context of § 111, and precludes an averaging approach because it requires "continuous emission reduction." *Id.* § 7602(l). It is unlikely that the § 302(l) definition applies given that Congress provided a specific and different definition of the term "[f]or purposes of" § 111, 42 U.S.C. § 7411(a). *See Reynolds v. United States*, 132 S. Ct. 975, 981 (2012) (specific statutory language supersedes general language); *Fourco Glass Co. v. Transmirra Prods. Corp.*, 353 U.S. 222, 228 (1957) (same). However, even if § 302(l) were found to apply, an averaging approach qualifies as "a requirement of continuous emission reduction" per the § 302(l) definition because covered sources must collectively achieve the emission limitations, which apply continuously. Even in a flexible program each source meets its obligations continuously. Under an averaging framework each source must secure the emission reductions needed, onsite or from other plants, to continuously be in compliance with the standard.

It is also worth noting that the generally applicable definition of "emission standard" in § 302(k) likely does inform the otherwise undefined phrase "standard for emissions" within the definition of "standard of performance" in § 111(a)(1). *See* 42 U.S.C. § 7416 (referring to an "emission standard or limitation . . . under section 7411"). A §

EPA's proposed approach is also fully consistent with the Clean Air Act. First, as the preamble explains,[133] section 111(d) itself does not preclude EPA's emission guidelines from applying the BSER on a state-wide basis or expressing the guidelines as an average performance level for each state. EPA issues emission guidelines as part of its statutory responsibility under section 111(d) to ensure that state plans are "satisfactory," in that they establish, implement, and enforce "standards of performance" that reflect EPA's judgment as to the BSER for existing sources. The statute does not preclude the emission guidelines from specifying an average level of performance that reflects the BSER, and that sets the degree of stringency that will be required for "satisfactory" state plans. EPA's proposed approach is an appropriate application of the broad language of section 111(a)(1) and (d) to the unique circumstances affecting the power sector, which as noted above consists of a diverse population of interconnected sources.

EPA's proposal is consistent with the way EPA (and the courts) have flexibly applied the Clean Air Act to complex source categories, including the power sector. Under section 110(a)(2)(D) of the Clean Air Act, for example, EPA has adopted a series of rulemakings that limit interstate transport of NO_x and SO_2 from the power sector by establishing state-wide emission budgets based on state or regional application of pollution control measures. In the case of the 1998 NO_x SIP Call, these budgets were based on IPM modeling of a multi-state emissions trading system designed to achieve an average emission rate expressed in pounds per unit of heat input – taking into account changes in dispatch and other measures available to reduce aggregate NO_x emissions from the power sector.[134] Similarly, EPA's 2011 Cross State Air Pollution Rule – recently upheld by the Supreme Court as a "permissible, workable, and equitable interpretation" of section 110[135] — established state-wide budgets for NO_x and SO_2 that were based on power sector modeling of emission reductions achievable through "increased dispatch of lower-emitting generation" and fuel-switching, among other compliance options.[136] In both of these major power sector rulemakings, EPA established state-wide emission targets that reflected system-based measures to achieve aggregate emission reductions from the power sector — just as EPA proposes to do here.

In addition, the Clean Air Act provides that the procedure for establishing standards of performance for existing sources under § 111(d) is to be "similar" to that of § 110, and § 110 expressly provides that emission limitations and control measures can include "fees, marketable permits, and auctions of emissions rights." The direct link to § 110 thus further reinforces the appropriateness of such flexible approaches under § 111(d).

302(k) "emission standard" or "emission limitation" is defined as "a requirement . . . which limits the quantity, rate, or concentration of emissions of air pollutants *on a continuous basis*." *Id.* § 7602(k) (emphasis added). An averaging approach qualifies as an "emission standard" or "emission limitation," because covered sources must meet a limitation that applies continuously. Indeed, Congress used the term "emission limitation" in 1990 to describe its Acid Rain Program. *See id.* §§ 7651b(a)(1), 7651c(a).

[133] 79 Fed Reg at 34,891.

[134] *See* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57,356, 57,400-401 (Oct. 27, 1998) ("NOx SIP Call") (explaining approach to developing cost curves and state emission budgets).

[135] EPA v. EPE Homer City Generation, L.P., 134 S. Ct. 1584, 1610 (2014).

[136] Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed Reg. 48,208, 48,252, 279-80 (Aug. 8, 2011).

EPA has also applied averaging approaches extensively in setting emission standards for mobile sources and fuels. Under Title II of the Clean Air Act, EPA has long interpreted its authority to establish "emission standards" for motor vehicles to allow for *average* standards that apply to broad categories of vehicles and engines.[137] In promulgating its first particulate matter and NO_x emission standards for heavy duty vehicles in 1985, EPA defended the averaging concept as "fully consistent with the technology-forcing mandate of the Act" and essential to establishing rigorous standards for a diverse group of sources.[138] The D.C. Circuit specifically upheld EPA's use of averaging in those standards – noting the "absence of any clear evidence that Congress meant to prohibit averaging" and the reasonable policy arguments EPA advanced in favor of the approach.[139] Similarly, EPA's regulations phasing out lead in gasoline took the form of an average standard for the "total pool" of gasoline produced by each refiner; EPA's assumption that refiners would participate in a yet-to-be created inter-refinery credit trading system, which was integral to the stringency of the standard, was likewise upheld by the D.C. Circuit.[140]

Thus, average standards such as those proposed in the Clean Power Plan are a time-tested regulatory approach under the Clean Air Act and a reasonable application of the ambiguous language of section 111. In the context of § 111 and greenhouse gas emissions, a flexible system that enables a wide variety of available solutions to achieve rigorous and cost-effective carbon pollution reductions manifestly fulfills the statutory criteria for the "best" system.

3. Summary

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[137] *See* Control of Air Pollution from New Motor Vehicles and New Motor Vehicle Engines; Gaseous Emission Regulations for 1987 and Later Model Year Light-Duty Vehicles, and for 1988 and Later Model Year Light-Duty Trucks and Heavy-Duty Engines; Particulate Emission Regulations for 1988 and Later Model Year Heavy-Duty Diesel Engines, 50 Fed. Reg. 10,606 (Mar. 15, 1985) (describing averaging system and noting that it is similar to the averaging system established for light-duty vehicles and trucks in 1983).

[138] *Id.* ("Private and state sponsored environmental groups, as well as the Manufacturers of Emission Controls Association (MECA), claimed that averaging as proposed was inconsistent with EPA's responsibility under section 202(a)(3)(A)(iii) of the Act to set standards that require use of the best technology that is expected to be available at the time the standards are implemented…The Agency finds the averaging concept, as applied by the standards promulgated, to be fully consistent with the technology-forcing mandate of the Act. Particulate trap technology is heretofore untried on the fleet level. EPA believes that the 0.25 g/BHP-hr standard which, through averaging, effectively requires use of traps on 70 percent of all heavy-duty vehicles will significantly reduce the risk of widespread noncompliance while allowing manufacturers to gain valuable experience with this new technology. To promulgate this standard without allowing averaging. . . would increase the technological risk associated with the standard because traps would have to be used in even the most difficult design applications.").

[139] *See Natural Resources Defense Council v. Thomas,* 805 F.2d 410, 425 (D.C. Cir. 1986) ("Lacking any clear congressional prohibition of averaging, the EPA's agreement that averaging will allow manufacturers more flexibility in cost allocation while ensuring that a manufacturer's overall fleet still meets the emissions reduction standards makes sense.").

[140] *See Small Refiner Lead Phase-Down Task Force v. EPA,* 705 F.2d 506, 536 (D.C. Cir. 1983). Note that although sec. 211(g) of the Clean Air Act placed numerical limits on average lead standards for small refiners, that section made no mention of inter-refinery trading for purposes of standard-setting or compliance. See Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 223, 91 Stat. 685, 764 (1977). In addition, EPA's pre-1977 regulations for refiners established "total pool" average lead standards despite the absence of explicit authorization for such standards in the Act. *See* Clean Air Act Amendments of 1970, Pub. L. No. 91-604, § 211, 84 Stat. 1676, 1698 (1970). Those early standards were also upheld by the D.C. Circuit, *see Ethyl Corp. v. EPA,* 541 F.2d 1 (D.C. Cir. 1976), and Congress effectively ratified EPA's approach in 1977 by enacting a special provision for small refiners prescribing maximum levels of stringency for average lead limits.

Across the country, states and power companies are reducing emissions from fossil fuel fired power plants by improving plant efficiency, by increasing the use of lower-carbon generation capacity and zero-emitting energy, and by investing in demand-side energy efficiency and demand management. The widespread and long-established use of this system and its success in achieving cost-effective carbon pollution reductions for diverse states and companies indicate that it satisfies the statutory criteria for the "best system of emission reduction." This system allows states and companies to adjust to locally relevant factors and generation-fleet characteristics, deploying the emission reduction strategies most appropriate and effective. The language of § 111 is sufficiently broad to encompass a system-based approach to securing carbon pollution reductions from existing power plants. Indeed, the constraints provided by § 111—directing EPA to identify the system of emission reduction best able to secure rigorous carbon emission reductions considering cost and impacts on energy and other environmental considerations—strongly suggest that a system-based approach is optimal in satisfying the statutory requirements by securing the vital cuts in carbon pollution that science demands through locally-tailored and innovative solutions.

F. EPA's Alternative BSER is Also Reasonable and Fully Supported by Section 111(d).

EPA has proposed an alternative approach for determining the ''best system of emission reduction . . . adequately demonstrated,'' under which the BSER would be "identified as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs." 79 Fed. Reg. at 34,889. "Under this approach, the measures in building blocks 2, 3, and 4 . . . would serve as bases for quantifying the reduced generation (and therefore emissions) at affected EGUs." *Id.* In addition to supporting EPA's primary BSER approach, we support EPA's alternative approach because it satisfies the statutory requirement to identify the best system of emission reduction that is adequately demonstrated and because this methodology reflects the reality of how the measures in building blocks 2, 3, and 4—in practice—secure reductions.[141]

EPA properly concludes that this alternative BSER meets all applicable statutory requirements. That is, EPA correctly notes that its alternative approach: (1) identifies a "system" of emissions reduction, (2) that is adequately demonstrated, and (3) that EPA could reasonably choose as the "best" among alternatives. As discussed in section I.E, "system of emission reduction" is a markedly broad term that indicates Congress' intention to provide EPA with ample flexibility in identifying the most effective means of controlling emissions. Congress envisioned that "system" would encompass operational changes or other measures to both control and prevent pollution—not just add-on technological devices.[142] This intention is manifest in the statutory text; in common usage, a "system" is defined as "a complex unity formed of

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[141] EPA's proposal to determine that BSER is a combination of building blocks 1, 2, 3 and 4 is also proper for the reasons discussed in this section, as it is based on measures that either improve the carbon intensity of the affected EGUs or reduces emissions from affected sources by decreasing the need for generation by those sources.
[142] *See, e.g.*, 116 Cong. Rec. 42,384 (1970) (Senate Agreement to Conference Report on H.R. 17255) ("The [Conference] agreement authorizes regulations to require new major industry plants . . . [to] achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives").

many often diverse parts subject to a common plan or serving a common purpose."[143] As such, the plain meaning of the term "system" includes curtailing generation at high-emitting facilities in concert with replaced generation at lower-emitting sources serving the common purpose of providing a reliable electric supply while reducing emissions. This system is adequately demonstrated. As EPA has explained, the measures in building blocks 2, 3, and 4 are already in widespread use in the industry. 79 Fed. Reg. at 34,890. Numerous states and utilities have used the measures in these building blocks effectively to reduce generation from high-emitting sources, as discussed below in sections IV.H. to IV.J. EPA's proposed finding that certain levels of reduced generation are part of the "best" adequately demonstrated system of emission reduction is based on several appropriate factors: emission reductions can be achieved at reasonable cost, do not jeopardize reliability, result in significant emission reductions, are consistent with current trends in the electricity sector, and promote the development and implementation of technology that is important for continued emissions reductions. 79 Fed. Reg. at 34,889.

At the same time that Congress established the current BSER standard, Congress designed a trading system that would lead some EGUs to shut down or reduce utilization while shifting electricity generation to other cleaner facilities. In the 1990 Clean Air Act Amendments, Congress enacted Title IV of the Clean Air Act to control the EGU emissions that cause acid rain through an emissions trading program. 42 U.S.C. § 7651. Congress intended curtailments to be one of the methods by which EGUs could reduce emissions and meet program requirements. *See, e.g.*, § 7651g(c)(1)(B) (providing for "an affected source . . . for which the owner or operator proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit"). Congress also created a specific mechanism by which affected units could receive allowances for "avoided emissions" by paying for renewable energy and energy efficiency measures. § 7651n(f)-(g) (setting aside 300,000 allowances in a "Conservation and Renewable Energy Reserve"). Congress further provided for the reactivation of inoperative "very clean units" through a streamlined permitting process, § 7651n(c), presumably so that these low-emitting units could replace the curtailed generation of dirtier units. Thus, Congress was not just aware that shifting generation from high-emitting to low-emitting resources was an available system for reducing power-sector emissions—Congress took deliberate steps to enable this cost-effective system for protecting human health and the environment.

Title IV clearly illustrates Congress's recognition that the integrated nature of the power system provides unique opportunities for reducing harmful pollution. Section 111(d), in contrast to Title IV, does not require such an approach in every case—which is wholly sensible given the gap-filling role of section 111(d) in addressing diverse source categories and pollutants not addressed elsewhere under the Act. For some pollutants and sources, an emission guideline based on a specific technology would be appropriate. But in using broad language directing EPA to identify the "best system of emission reduction," Congress clearly signaled that the Agency's analysis of systems of emission reduction was to be expansive. And in this circumstance, where reliance on the uniquely integrated nature of the power grid to reduce carbon pollution can provide the greatest emission reductions the most cost-effectively, EPA's approach in the Clean Power Plan fulfills the statutory directive.

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[143] Webster's Third New International Dictionary 2322 (1967).

EPA, states, and the courts, too, have long understood that utilization is a key determinant of emissions levels, and that reduced utilization can achieve air quality goals. Since the 1990s, regulators implementing the CAA have routinely relied on mechanisms such as "synthetic minor" permits and "plantwide applicability limits" by which owners of sources may avoid certain permitting requirements if they agree to operate facilities so as to keep pollution levels below stated regulatory annual emissions thresholds, even though their facilities' physical capacity to emit exceeds the thresholds.[144] These mechanisms rest on the recognition that pollution is a function of a source's emissions rate and the time it is in use, and that limiting utilization can be an effective way of limiting pollution. And they demonstrate that, in certain instances at least, reductions in operation (or promises not to increase operations) are appropriate regulatory tools under the Clean Air Act. Indeed, long before the 1990 Clean Air Act Amendments, it was well understood that reduced utilization of a facility was one means of reducing emissions. In 1979, the D.C. Circuit recognized that under the PSD program "EPA has authority to require inclusion in state plans of provision for the correction of any violation of allowable increments or maximum allowable concentrations, and may even require, in appropriate instances, the relatively severe correctives of a rollback in operations . . ." *Alabama Power Co. v. Costle*, 636 F.2d 323, 363 (D.C. Cir. 1979). Section 111's "best system of emission reduction" standard must encompass this basic mechanism for reducing emissions.[145]

EPA's alternative approach to BSER is appropriate because it reflects the reality that the measures in building blocks 2, 3, and 4 reduce emissions precisely because they allow high-emitting sources to reduce generation, and electricity services to be provided through less-polluting means. As EPA properly noted, the "the operation of the electrical grid through integrated generation, transmission, and distribution networks creates fungibility for electricity and electricity services." 79 Fed. Reg. at 34,889-90. That is, the unique nature of the electrical grid gives generators enormous flexibility in how they reduce emissions. The alternative approach to BSER would be a commonsense response to the fact that affected

[144] A plantwide applicability limit is a voluntary limit or "cap" on a facility's total emissions which is established based on the facility's historical emissions. This limit provides flexibility for a facility to make modifications without triggering major New Source Review requirements as long as the emissions cap is not exceeded. EPA, Fact Sheet, New Source Review: Solicitation of Comments on When New Source Review Applies for a Physical or Operational Change to a Facility (July 16, 1998), available at http://www.epa.gov/ttn/oarpg/t1/fact_sheets/nsrna.pdf. A synthetic minor permit is a permit that includes enforceable permit conditions that ensure that emissions will not exceed the regulatory major source threshold. *See, e.g.*, Virginia DEQ, Types of Air Permits, http://www.deq.virginia.gov/Programs/Air/PermittingCompliance/Permitting/TypesofAirPermits.aspx ("[State Operating Permits] are most often used by stationary sources to establish federally enforceable limits on potential to emit to avoid major New Source Review permitting (PSD and Nonattainment permits), Title V permitting, and/or major source MACT applicability. When a source chooses to use a SOP to limit their emissions below major source permitting thresholds, it is commonly referred to as a "synthetic minor" source.").

[145] Congress sought to encourage reduced utilization in as a tool for protecting and improving air quality in the transportation sector. In the 1977 Clean Air Act Amendments, Congress enacted section 108(f), which required EPA to publish guidance on policies for reducing transportation-sector emissions, including several policies to reduce vehicle-miles travelled. Public Law 95-95, 91 Stat. 685, 689-90 (Aug. 7, 1977) (requiring EPA to provide information on policies such as carpool lanes, park and rides, bike infrastructure, employer-sponsored transit programs, and programs that discourage single-passenger car trips). In 1990, Congress revised section 108(f) by, *inter alia*, requiring EPA to provide current guidance on transportation-sector policies and periodically update its guidance. Pub. Law 101-549, 101 Stat. 2399, 2465-66 (Nov. 15, 1990). Thus, Congress' interest in reduced utilization as a cost-effective emissions-control strategy spans decades.

sources can reduce emissions cost-effectively (through a wide variety of means) by reducing generation as low-emitting sources and energy efficiency satisfy the demand for electricity services.

Many existing programs for reducing electricity-sector GHG emissions work precisely because high-emitting sources reduce generation as low-emitting sources increase their generation. For instance, the New York State Department of Public Service conducted extensive modeling to predict the economic and environmental effects of that state's RPS and concluded that increased renewable energy generation under the policy would displace generation from higher-emitting sources, primarily natural gas-, coal-, and oil-fired units.[146] A recent white paper concluded that renewables introduced in states with RPSs in the RGGI region almost entirely substitute for coal base load.[147] Energy efficiency programs also have a proven track record of reducing electricity demand and, consequently, allowing high-emitting sources to reduce emissions.[148] Freely available tools, such as EPA's AVERT, allow policymakers, utilities, and other stakeholders quantify the CO_2, NO_x, and SO_2 impacts of state and multi-state renewable energy and energy efficiency programs.[149]

States and local governments also implement energy efficiency programs to improve local air quality—again, precisely because such programs lead to reduced generation at emitting facilities.[150] EPA has long encouraged states to take advantage of energy efficiency measures to cost-effectively control EGU emissions. The agency's 1998 NO_x SIP Call Rule allowed states to set aside allowances in their cap-and-trade programs for reductions achieved through renewable energy and energy efficiency measures and, in

[146] New York Department of Public Service, Final Generic Environmental Impact Statement (2004) at 111 (Table 6.4-1), available at http://www.dps.ny.gov/NY_RPS_FEIS_8-26-04.pdf. The potential for clean energy to displace fossil-fuel-fired generation also has important benefits for public health. *See id.* at 2ES ("Modeling reveals that the addition of new renewable energy sources at the 25 percent target level could annually reduce NOX emissions by 4000 tons (6.8%), SO2 emissions by 10,000 tons (5.9%), and carbon dioxide (CO2) emissions by 4,129,000 tons (7.7%).").

[147] Brian C. Murray, Peter T. Maniloff, Evan M. Murray, "Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors" at 18, available at http://sites.nicholasinstitute.duke.edu/environmentaleconomics/files/2014/05/RGGI_final.pdf (quantitatively attributed emissions effects to policy and market factors in the RGGI region).

[148] Vital reductions are occurring at both the state- and utility- levels. For instance, the Minnesota Department of Commerce estimates that investments required under the state's Conservation Improvement Program saved nearly 900,000 MWh of electricity in 2010, resulting in over 800,000 tons of reduced CO_2 emissions. MDOC, Division of Energy Resources "Minnesota Conservation Improvement Program Energy and Carbon Dioxide Savings Report for 2009-2010" at 3 (Table 1) (2012), available at http://mn.gov/commerce/energy/images/CIPCO2Rpt2012.pdf. *See also* Georgetown Climate Center, "Reducing Carbon Emissions in the Power Sector: State and Company Success" at 24 ("Since 2001, Entergy has spent $14.7 million on 61 energy efficiency improvements that have resulted in nearly 5.3 million metric tons of CO_2 savings and $30 million in annual fuel savings.").

[149] EPA, AVoided Emissions and genRation Tool (AVERT), http://epa.gov/avert/.

[150] EPA, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix K: State, Tribal and Local Examples and Opportunities" at K-8 to K-9 (July 2012), available at http://epa.gov/airquality/eere/pdfs/appendixK.pdf (To meet federal ambient air quality standards, Texas reduces NOx emissions "through reduced demand for fossil-fuel generation at power plants, as a result of EE measures implemented in new construction for single and multi-family residences in 2003."); *id.* at K-9 (Louisiana's plan for achieving federal ambient air quality standards included energy conservation measures at City buildings in Shreveport, which were "estimated to have saved 9,121 megawatt-hours (mWhs) of electricity per year with NOx emission reductions of 0.041 tons per ozone season-day").

2007, seven states had set-asides for these kinds of reductions.[151] Implementing the NO_x SIP Call with set-asides for energy-efficiency reductions, states have noted the economic benefits of achieving reductions in this manner.[152] In CAIR, EPA also enabled states to incorporate renewable energy and energy efficiency into their NO_x trading programs, and several states took advantage of this flexibility.[153] For instance, Connecticut set aside 10% of its summer ozone season allowances for renewable energy and energy efficiency projects.[154] Energy efficiency and renewable energy will likely become even greater components of state ambient air quality planning in the future, as states take advantage of EPA's recent guidance on incorporating such programs into SIPs.[155]

In the marketplace, renewable generation and energy efficiency displace generation at affected units because they can meet electricity demand at lower marginal cost. A recent article succinctly described the mechanism by which low-emitting sources displace higher-emitting sources in electricity capacity markets:

> In comparison to conventional fossil-fired generation, renewables are likely to have a lower running cost. Consequently, renewable generators can often bid much lower than conventional generation. This will lead to renewable generation being dispatched ahead of conventional plants. Thus, renewable generation displaces conventional generation in bid-based markets. This displacement lowers the capacity factor of conventional generators and reduces the time conventional generators are selling in the market.[156]

Similarly, where energy efficiency resources are available on forward capacity markets they compete directly and successfully against higher-emitting sources to meet the capacity needs of the electricity grid.[157]

The particular generation that a low- or zero-emitting resource will replace—and, consequently, the resultant emissions reductions on the grid—depend on the resource's location. Specifically, the units that

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[151] U.S. Department of Energy, Eastern States Harness Clean Energy to Promote Air Quality (2007) at 4, available at http://www.nrel.gov/docs/fy08osti/42143.pdf.

[152] *See, e.g.*, Ohio EPA, Guidance Manual: Energy Efficiency/Renewable Energy and Innovative Technology Projects at 1, available at http://www.epa.ohio.gov/portals/27/files/OhioGuidanceFINAL.pdf ("A more energy efficient process results in not only less NOx emissions but also cost savings. Cost savings is the catalyst that will keep successful energy efficient processes operating long after the set-asides cease.").

[153] U.S. Department of Energy, Eastern States Harness Clean Energy to Promote Air Quality (2007) at 4-6.

[154] *Id.* at 5.

[155] *See* EPA, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans (July 2012), available at http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf.

[156] Peter H. Griffes, "Renewable Generation and Capacity Markets", International Association for Energy Economics Newsletter (Third Quarter 2014) at 27-28, available at www.iaee.org/en/publications/newsletterdl.aspx?id=242.

[157] World Resources Institute, "Seeing is Believing: Creating a New Climate Economy in the United States" (Working Paper October 2014) at 53 ("In the Independent System Operator (ISO) New England grid region, the electric efficiency resources clearing the forward capacity market more than doubled between the first auction held in 2008 and 2013, accounting for nearly 30 percent of new capacity in the 2013 auction (to be provided in the 2016–17 time- frame). Electric energy efficiency resources clearing the market also nearly doubled in the PJM interconnection grid region during auctions held between 2009 and 2013, accounting for 20 percent of new capacity in the 2013 auction (also for the 2016–17 timeframe)." (footnotes omitted)).

set a transmission region's marginal price have historically been a primary driver of how low- or zero-emitting resources reduced generation at affected units. Historical data on these "locational marginal units" demonstrates the ability of clean energy and energy efficiency to displace generation from high-emitting sources. Models for estimating the GHG emission reductions from energy efficiency programs incorporate data about the hourly marginal emissions rates for local electricity, even when the programs do not place energy efficiency resources on the electricity capacity market.[158]

EPA has also correctly observed that "[r]eduction of, or limitation on, the amount of generation is already a well- established means of reducing emissions of pollutants in the electric sector." 79 Fed. Reg. at 34,889 (listing several emission control programs under which reduced generation is an available compliance option). Reduced generation is already a prominent consideration in compliance planning for EGUs, and ICF's Integrated Planning Model's optimization process incorporates "reduce running regime" as one of the main compliance options for policies that set an emissions cap.[159]

G. The Unique Characteristics of the Power Sector and Associated Carbon Pollution

As EPA effectively describes in the preamble and legal TSD,[160] the unique features of the Clean Power Plan arise from – indeed, are driven by – the distinctive characteristics of carbon pollution from the power sector. Other source categories for which EPA has issued performance standards under section 111, including the five source categories which are subject to section 111(d) standards, are characterized by functionally independent facilities that emit pollutants with primarily local or regional effects. For such source categories, EPA has appropriately issued performance standards that reflect the application of cleaner processes, technologies, or techniques to emissions from individual sources. This approach responds to the need to protect local and regional air quality from emissions associated with such sources, and is well-suited to sectors in which standardized technologies and practices are available to reduce pollution from individual sources.

The characteristics of carbon pollution from the power sector, by contrast, call for the distinctive regulatory approach reflected in the Clean Power Plan – an approach that, as we argue elsewhere in these comments, also fits comfortably within the broad language of section 111; comports with other Clean Air Act regulatory programs affecting the power sector; and reflects policies that utilities and states around the country are already employing to reduce carbon pollution. Unlike other industrial sectors regulated under section 111(b) and (d), the power sector does not consist of functionally independent facilities –

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158 *See, e.g.*, Energy and Environmental Economics, Inc. Report to the California Energy Commission PIER, Developing a Greenhouse Gas Tool for Buildings in California: Methodology and User's Manual v.2 (2009) at 8, available at https://ethree.com/GHG/GHG%20Tool%20for%20Buildings%20in%20CA%20v2%20April09.pdf ("The greenhouse gas (GHG) emissions of a building's electricity consumption are calculated by multiplying the hourly, or time of use, load profile of the building with an estimated hourly GHG emissions profile of California's electricity generation.").

159 ICF International, Edison Electric Institute, "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet" at 8 (2011), available at http://www.psc.utah.gov/utilities/electric/12docs/1203592/239801Exhibit%20G%20to%20Fisher%20Testimony%2012-3-2012.pdf.

160 *See* 79 Fed. Reg. at 34,880-881; Legal TSD at 43-45.

rather, it consists of an interconnected network of facilities that operate as a continuously-balanced and centrally-coordinated machine, or system.[161] Key distinguishing features of this system include:

- **Real-time balancing of supply and demand via centralized dispatch**. Due to the lack of large-scale electricity storage facilities, the electric grid has always required continuous matching of electricity supply and demand – a process that is carried out in practice by balancing authorities or system operators that centrally manage the resources on the grid.[162] Depending on the region, these functions can be carried out by vertically integrated utilities, RTOs/ISOs, transmission operators, or other entities. These entities continuously "dispatch" available generating resources (and in many cases, demand-side resources as well) to meet demand in a cost-effective way and ensure reliability, either through a real-time energy market or other centralized method of ordering and coordinating power supply from the various resources on the grid.[163] Through these mechanisms, the portfolio of generating resources that serves the grid changes from hour to hour in response to changes in cost, reliability considerations, environmental constraints, and other dynamic factors. Producing electricity on the interconnected grid also means that other basic aspects of a generator's operations are determined by the needs of the grid; for instance, generators must produce electricity at the same nominal frequency in synchronization.[164]

- **Fungible and commingled product**. Although electric generating resources do have diverse operating characteristics that influence the rate and timing of their output, the generation from any given EGU can be seamlessly substituted with that of any other — and is thoroughly commingled with generation from all other sources connected to the grid. This makes electricity one of the most thoroughly fungible of industrial products. From a supply standpoint, this fungibility is reflected in the fact that utilities and grid operators routinely and continuously coordinate output from different resources to optimize the availability and cost of power. Another unique result is that utilities whose transmission networks are connected

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[161] A useful primer on the structure of the nation's electric system appears in *The Future of the Electric Grid,* at 2-7, 243-249 (Massachusetts Institute of Technology, 2011). *See also* PHILLIP F. SCHEWE, THE GRID: A JOURNEY THROUGH THE HEART OF OUR ELECTRIFIED WORLD 1 (2007) ("Taken in its entirety, the grid is a machine, the most complex machine ever made.")

[162] *The Future of the Electric Grid* at 4, 6.

[163] *See id.* at 34 ("Power systems require a level of centralized planning and operation to ensure system reliability. System operators at control centers carry out many of these centralized functions. . . .In areas with traditional vertically integrated utilities, economic dispatch and unit commitment are calculated based on known start-up and fuel costs for generators; in restructured areas, a similar result is obtained through bidding in wholesale markets. Control centers then refine these day-ahead estimates as often as every 5-15 minutes, dispatching each generator to minimize total system costs given the load level, generator availability, and transmission constraints."). *See also* Paul L. Joskow, Creating a Smarter U.S. Electricity Grid, 26 J. ECON. PERSP. 29, 33 (2012) ("Electricity is the ultimate 'just-in-time' manufacturing process, where supply must be produced to meet demand in real time.").

[164] Brief of Amici Curiae Electrical Engineers, Energy Economists and Physicists (May 31, 2001) at 9, *New York v. FERC*, 535 U.S. 1 (2002) (Nos. 00-568 and 00-809) (signed by 21 amici and two supporters after filing date, including seven professors of electrical engineering, seven professional electrical engineers, five economists and management consultants with expertise in the power sector, and four professors who study the power sector in the fields of industrial engineering, planning and public policy, economics, and applied economics and management) (excerpts included as an appendix to these comments).

by "tie lines" buy power from one another to satisfy demand; for instance, companies buy electricity when it is cheaper to procure than generate or when their generation resources cannot satisfy demand alone.[165] (And is described further below, the vast majority of the power generation sources in the country are interconnected on two massive grids.) Moreover, due to the commingling of power on the grid, minute-to-minute changes in the composition of the electric generating portfolio take place in a way that is largely invisible to the consumer. Indeed, even if a consumer preferred power from a particular source, it would be impossible for the generator or power system operators to direct the energy from a particular generator to a particular user.[166] Energy flowing onto the power grid energizes the entire grid, and consumers draw undifferentiated energy from the grid.[167]

- **Substitutability of demand and supply**. Related to the fungibility of electricity is the extent to which reduction in electricity demand serves as a substitute for supply.[168] Thanks to an array of cost-effective energy efficiency and demand response technologies, there are a large number of ways in which consumers can use *less* electricity while maintaining the *same* (or greater) level of utility or "electricity services." From the standpoint of the interconnected power system, which is continuously balanced at every moment in time, such demand-side measures are effectively equivalent to supply resources: every megawatt in demand reduction translates automatically and immediately into a megawatt reduction in needed supply. This phenomenon is most vividly illustrated in the energy and capacity markets operated by regional transmission operators and independent system operators, many of which allow demand response and/or energy efficiency to compete directly with generation to meet energy and capacity needs.[169] It is also illustrated in the extensive modeling that EPA and others have undertaken to quantify the effects of energy efficiency programs and measures on hourly dispatch and overall emissions from the power sector.[170] There are few, if any other products where a reduction in demand leads automatically to changes in output and supply; a refinery, for example, might respond to local changes in demand for gasoline by exporting a

[165] *Id.* at 14.
[166] *Id.* at 10 (quoting Florida Power & Light Co., 404 U.S. 453, 460 (1972)).
[167] *Id.* at 9.
[168] *See, e.g.,* Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 at P 20-21, 49 (2012) (reviewing comments and expert testimony supporting the substitutability of supply-side and demand-side resources in organized wholesale energy markets, and concluding that ". . . . a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand. Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand."); North American Electric Reliability Corporation (NERC), Summer Reliability Report, May 2014, at 25 (noting that "Energy Efficiency/Conservation programs . . . are counted as [either] a resource or as a load modifier, depending on the type of the program offered" in reliability analyses) *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf.
[169] *See, e.g,* Although the authority of FERC to establish compensation level for demand response resources in wholesale energy markets is currently being litigated, *see Electric Power Supply Ass'n v. FERC,* No. 11-1486 et al. (D.C. Cir. May 23, 2014), this legal dispute does not affect the reality of how demand and supply interact on wholesale markets.
[170] *See, e.g.,* EPA, "Avoided Emissions and Generation Tool: A Tool that Estimates the Emissions Benefits of Energy Efficiency and Renewable Energy Policies and Programs," http://epa.gov/avert/ (last visited Nov. 10, 2014).

greater share of its products or storing product in anticipation of future demand. Such responses are generally unavailable to electric generating units.

- **Dispersed nature of carbon pollution**. Carbon dioxide is a globally dispersed pollutant whose harmful effects on our atmosphere are virtually identical regardless of where it is emitted. Accordingly, the climate benefits of mitigating carbon pollution depend entirely on the *aggregate* level of reductions from the power sector, rather than the distribution of those reductions.

- **Lack of source-specific control technologies**. Due to the limited readily-available technologies that can be implemented at individual fossil fuel-fired EGUs to mitigate carbon pollution, states and power companies that have sought to decrease carbon pollution in recent years have almost exclusively relied on system-based approaches that leverage the capacity of the power system to reduce aggregate emissions through flexible changes in the generating portfolio and cost-effective efficiency measures. As described elsewhere, these states and companies have successfully reduced carbon pollution cost-effectively, without creating any reliability problems, and while securing concomitant reductions in other harmful air pollutants emitted by fossil fuel-fired power plants.

The proposed Clean Power Plan responds to these distinctive aspects of the power sector by establishing state-wide performance targets that will ensure aggregate reductions in carbon pollution over time, and that give states flexibility to leverage the dynamic nature of the power system in various ways to achieve these aggregate targets. The level of aggregate reductions required are based on a system-wide analysis that recognizes that all existing fossil fuel-fired EGUs are part of a large, coordinated system for generating and delivering electricity. For this reason, EPA appropriately considers the various mechanisms that are available to states to reduce emissions as a whole from existing EGUs — including shifts in dispatch from high-emitting units to low or zero-emitting units, or to demand-side efficiency. Indeed, as EPA recognizes, an approach that failed to account for the actual behavior of the interconnected power system could undermine the emission reduction goals of section 111 by increasing the economic competitiveness of higher-emitting EGUs relative to other resources.

As we note elsewhere in these comments, this is a time-tested approach to reducing emissions from the power sector under the Clean Air Act, and one that states and utilities themselves have recognized and demonstrated. The Acid Rain Program created as part of the 1990 Clean Air Act amendments, for example, explicitly reflected a system-wide approach whose purpose was "to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of [Title IV], for reducing air pollution and other adverse impacts of energy production and use."[171] System-wide approaches were also inherent to the design of the NO_x SIP Call and the Cross-State Air Pollution Rule, both of which have been upheld by the courts as appropriate exercises of EPA's authority to protect public health against harmful ozone and particulate

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[171] 42 U.S.C. § 7651(b); *see also* 42 U.S.C. § 7651c(f), (g) (establishing a reserve of allowances and requiring EPA to issue allowances "for each ton of sulfur dioxide emissions avoided by an electric utility . . . through the use of qualified energy conservation measures or qualified renewable energy").

pollution that crosses state lines.[172] And at least three jurisdictions have adopted state implementation plans (SIP) — approved by EPA — that rely on renewable energy and energy efficiency programs to achieve needed reductions in emissions of harmful power sector pollution.[173] These examples show that, in practice, the interconnected nature of the power sector has been recognized and harnessed by Congress, EPA, and individual states when designing pollution control programs under the Clean Air Act. The proposed Clean Power Plan is consonant with this long tradition.

H. EPA Should Find that Partial CCS is an Alternative Adequately Demonstrated System of Emission Reduction

Although EPA has properly identified the CPP's flexible Building Block system as the "best" system of emission reduction, partial carbon capture and storage (CCS) is an adequately demonstrated alternative that would be the BSER *in the absence of* the Building Block system. A partial CCS standard similar to the standard proposed for new EGUs would reduce CO_2 emissions from super critical pulverized coal plants by 33 percent and from IGCC plants by18 percent[174]—far exceeding the reductions that could be achieved by the 6% heat rate improvement under Building Block 1—and would also achieve significantly greater reductions of co-pollutants.[175] In the final rule, EPA should provide a more detailed assessment of partial CCS as an alternative BSER. Partial CCS is a statutorily satisfactory system of emissions reduction that achieves far greater emissions reductions than Building Block 1 (heat rate improvements) alone.

As explained below, partial CCS satisfies the statutory criteria for BSER:

CCS is adequately demonstrated for retrofit to existing EGUs.

As EPA documented at length in the TSD for the proposed carbon pollution standards for new EGUs, the individual technologies used in CCS systems have been available for decades and have been applied at a

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[172] *See Michigan v. EPA*, 213 F.3d 663 (D.C. Cir. 2000)(upholding NO_x SIP call rulemaking); *EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584 (2014)(upholding Cross-State Air Pollution Rule).

[173] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9 (describing EPA approval of SIPs for Texas, Maryland, Virginia, the District of Columbia, and Louisiana incorporating renewable energy or energy efficiency measures); *see, e.g.*, Approval and Promulgation of Air Quality Implementation Plans; Texas; Revisions to Chapter 117 and Emission Inventories for the Dallas/Fort Worth 8-Hour Ozone Nonattainment Area, 73 Fed.Reg. 47835, 47836 (Aug. 15, 2008) (EPA approval of the inclusion of EE measures aimed at reducing NOx emissions for Dallas-Fort Worth into the Texas SIP); Approval and Promulgation of Air Quality Implementation Plans; Maryland and Virginia; Non-Regulatory Voluntary Emission Reduction Program Measures, 70 Fed. Reg. 24,987 (May 12, 2005) (EPA approval of inclusion of county government commitments to purchase 5% of their annual electricity consumption from wind power in Maryland's SIP).

[174] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-452/R-13-003 (Sept. 2013) at 5-35, Table 5-10.214, *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf.

[175] *Id.* at 5-39.

commercial scale in other industrial sectors. Utilities have made significant progress towards applying this technology to coal-fired EGUs, including several successful demonstration-scale projects at existing facilities. And in October 2014, the Canadian utility SaskPower activated the first commercial-scale CCS project for the power sector: a rebuilt 139 MW unit at its Boundary Dam plant, equipped with CCS technology capable of capturing 90 percent of the unit's CO_2 emissions.

Coal-fired power plants designed for demonstration-scale CCS application include AES's coal-fired Warrior Run (Cumberland, MD) (capturing 110,000 metric tons CO_2 /year) and Shady Point (Panama, OK) (capturing 66,000 metric tons CO_2 /year), both equipped with amine scrubbers designed to process a slip stream of the plant's flue gas.[176] SaskPower's Boundary Dam plant in Canada, a coal-fired power plant retro-fitted for CCS at commercial scale, in the testing stage at the time of the proposed rule, came online in October 2014.[177] Mississippi Power's Kemper County Energy Facility, a second coal-fired power plant designed to employ CCS at a commercial scale, is expected to begin operation in 2016.[178] In July 2014, retrofit construction began on the Petra Nova Carbon Capture Project at the existing 240 MW W.A. Parish coal-fired power plant near Houston, Texas; capture at a rate of 1.6 million tons CO_2 per year will begin by the end of 2016.[179]

The Boundary Dan project will result in the capture of over one million metric tons of CO_2 per year, and was undertaken in part to comply with Canadian emission standards for existing EGUs[180] Although SaskPower has yet to release official data since operations began, SaskPower CEO Robert Watson has stated that the carbon capture equipment is performing as expected with respect to the amount of power required for operation of the equipment, and noted that SaskPower anticipates achieving the full 90% capture rate "in not too long at all."[181]

SaskPower's currently operational, commercial scale Boundary Dam plant project – along with other evidence in the record for the proposed NSPS for new EGUs — shows that partial carbon capture is adequately demonstrated for existing coal-fired power plants. "Adequately demonstrated" does not mean that all existing sources are able to meet the requirement, *see Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785-86, nor does it require the available technology to be in "actual routine use" at the time of the rulemaking. *See Portland Cement Ass'n v. Ruckleshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) ("*Portland Cement I*"). Rather,

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[176] *See* 79 Fed. Reg. at 1474-75 (citing J.J Dooley et al., An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830).

[177] Laverty, Gene, SaskPower launches C$1.4B carbon capture project, SNL (Oct. 1, 2014), *available at* https://www.snl.com/Cache/snlpdf_d204175b-8901-454b-85ed-2b4f93463194.pdf.

[178] *See* Southern Co. and Mississippi Power Co., SEC Form 8-K (Oct. 27, 2014) at 3., *available at* http://www.sec.gov/Archives/edgar/data/66904/000009212214000064/msmonthlyreport8-k10x14.htm.

[179] *See* WA Parish Carbon Capture Project, http://www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.

[180] Stéphenne, Karl, Start-Up of World's First Commercial Post-Combustion Coal Fired CCS Project: Contribution of Shell Cansolv to SaskPower Boundary Dam ICCS Project, Energy Procedia (to be published in 2014/2015) at 2, *available at* https://sequestration.mit.edu/tools/projects/GHGT-12%20paper/boundary_dam_update_2014.pdf.

[181] Marshall, Christa, World's first coal carbon capture project set for startup this week, E&E Reporter (Sept. 30, 2014).

> [t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.
> . . .
> [T]he question of availability is partially dependent on 'lead time', the time in which the technology will have to be available.
> . . .
> If actual tests are not relied on, but instead a prediction is made, 'its validity . . . rests on the reliability of [the] prediction and the nature of [the] assumption.

Portland Cement I, 486 F.2d at 391-92 (citing and quoting *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)). Moreover, EPA can "extrapolat[e] . . . a technology's performance in other industries", and look beyond domestic facilities to those used abroad. *Lignite Energy Council,* 198 F.3d 930, 934 n.3 (D.C. Cir. 1999). The *Portland Cement I* court found that the term "adequately demonstrated" required a showing by EPA "that there *will be* 'available technology' *during the regulated future*." *Portland Cement I*, 486 F.2d at 391 (emphasis added). Thus the question is whether the technology will be available at the time that implementation is required.

EPA can and must encourage new and less-polluting technologies through the standards it sets under section 111. The legislative history of section 111 and the relevant case law affirm the technology-forcing nature of the statute. For instance, the 1977 Senate Report discusses the need "to assure the use of available technology and to stimulate the development of new technology." S. Rep. No. 95-127 at 171. To that end, "[t]he statutory factors which EPA must weigh [when setting performance standards] are broadly defined and include within their ambit subfactors such as technological innovation." *Sierra Club*, 657 F.2d 298, 346 (D.C. Cir. 1981). In *Sierra Club*, the court explained: "Recognizing that the Clean Air Act is a technology-forcing statute, we believe EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard.... As a result, we uphold EPA's judgment that the standard can be set at a level that is higher than has been actually demonstrated over the long term by currently operating lime scrubbers at plants burning high sulfur coal."[182] *see also Portland Cement Ass'n v. EPA* (*"Portland Cement III"*), 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology). These standards should reflect the use of the "best" control options, including those achieving the deepest reductions, consistent with Congress's intent to encourage technological advancement in controls.

The operational status of the Boundary Dam project demonstrates the viability of large scale CO_2 capture and shows that CCS can be accomplished on a commercial scale, including as a retro-fit to an existing

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[182] 657 F.2d 298, 364 (D.C. Cir. 1981) (footnote omitted). *See also Portland Cement Ass'n v. EPA* (*"Portland Cement III"*), 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology).

plant. Furthermore, the current status of the Boundary Dam project and the development rate of CCS technology evinced by the record support the conclusion that retrofitted CCS technology will be more widely available for commercial use by 2020, when the rule's requirements must be implemented.

With respect to the CO_2 transportation required to facilitate storage where nearby geologic sequestration is not feasible, EPA has properly concluded that the necessary technology is adequately demonstrated and feasible. *See* 79 Fed. Reg at 1472. As EPA notes, CO_2 has been transported via pipelines in the U.S. for almost 40 years, and approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. *See id.* EPA has determined that 95 percent of the 500 largest CO_2 point sources are within 50 miles of a possible geologic sequestration site. *See id.*

Similarly, with respect to the storage component of CCS, as EPA properly identified in the proposal for NSPS for GHG emissions from new EGUs, geologic sequestration of CO_2 is available and adequately demonstrated. EPA has cited to numerous CO_2 commercial storage projects as well as field studies that demonstrate the feasibility of geologic sequestration. *See* 79 Fed. Reg. at 1472-74. For example, since 1996 the Sleipner natural gas processing project in the North Sea has separated CO_2 from natural gas and sequestered .9 Mtpa of CO_2 in an offshore deep saline reservoir.[183] Additionally, the oil and natural gas industry in the United States and abroad has five decades of experience in injecting captured CO_2 into geologic formations. Department of Energy ("DOE") studies indicate that the U.S. has ample CO_2 storage potential. *See* 79 Fed. Reg. at 1473. As mentioned above, the majority of existing coal-fired power plants are located in regions where there is a high likelihood of nearby geologic storage availability.[184]

The costs of CCS do not preclude its identification as the best system of emission reduction.

In the proposed rule, EPA asserts that it will not propose partial CCS as the BSER because the costs would be "substantial" and affect electricity prices.[185] Yet even if the costs of retro-fitting the existing EGU fleet for partial CCS would be "substantial" and affect electricity prices, those costs will be within EPA's discretion under section 111 as long as they are not "exorbitant" or "more than the industry can bear." *See Portland Cement I*, 486 F.2d at 391; *Essex Chemical Corp.*, 486 F.2d 427, 433 (D.C. Cir. 1973); *Sierra Club*, 657 F.2d 298, 383 (D.C. Cir. 1981); *Lignite Energy Council*, 198 F.3d at 933. Consequently, EPA is not foreclosed from determining that CCS is the BSER. Furthermore, CCS costs may be defrayed by the use of captured CO_2 for enhanced oil recovery, or reduced by implementation of partial CCS at lower proportions of capture.

Section 111(a)(1) of the CAA directs EPA to include costs among the factors it considers when determining the BSER. In a line of cases spanning several decades, the D.C. Circuit held that the statute is

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[183] Pacific Northeast Nat'l Laboratory, *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009* (June 2009), n. 203, at 5-6; Global CCS Inst., *Sleipner CO2 Injection* (project data current as of Sept. 7, 2014), *available at* http://www.globalccsinstitute.com/project/sleipner%C2%A0co2-injection.

[184] MIT, The Future of Coal, at 58-59 (2007) ("The majority of coal-fired power plants are situated in regions where there are high expectations of having CO2 sequestration sites nearby. In these cases, the cost of transport and injection of CO_2 should be less than 20% of total cost for capture, compression, transport, and injection.").

[185] *See* 79 Fed. Reg. at 34,856-57, 34,876.

satisfied as long as the costs of the BSER are not "excessive" or "exorbitant." *See Portland Cement I*, 486 F.2d at 391; *Essex Chemical Corp.*, 486 F.2d at 433; *Sierra Club*, 657 F.2d at 383; *Lignite Energy Council*, 198 F.3d at 933. Section 111 allows EPA to take a broad view of the costs of the proposed standard at the national and regional level, which includes consideration of the pollution benefits that would be achieved, the avoided costs of carbon pollution on society as well as the co-benefits of reducing harmful $PM_{2.5}$ and ozone pollution. *See Sierra Club*, 657 F.2d at 330. When setting a standard of performance under section 111, "EPA has authority to weigh cost, energy, and environmental impacts *in the broadest sense at the national and regional levels* and over time as opposed to simply at the plant level in the immediate present." *Sierra Club*, 657 F.2d at 330. Notably, the D.C. Circuit has never upheld a challenge to a section 111 standard based on cost. 79 Fed. Reg. at 1464. For example, in *Portland Cement I*, the court upheld an NSPS for particulate matter emissions, even though control technologies amounted to roughly 12 percent of the capital investment for an entire new plant and consumed five to seven percent of a plant's total operating costs. 486 F.2d 375, 387-88. Likewise, the court upheld particulate matter ("PM") standards that were anticipated to increase the cost of cement by one to seven percent, with little projected decrease in demand. *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 191 (D.C. Cir. 2011); *see also* 73 Fed. Reg. 34,072, 34,077, 34,086 (June 16, 2008). With respect to the electricity generating industry, the *Lignite Energy Council* court held that a two percent increase in the cost of producing electricity was not exorbitant, and upheld the 1997 nitrogen oxides ("NO_x") NSPS for EGUs and industrial boilers. *See* 198 F.3d at 933 (citing 62 Fed. Reg. 36, 948, 36,958 (July 9, 1997)).

In the CPP proposal, EPA explains that the costs of CCS may be "substantial" and potentially affect electricity prices:

> [T]he cost of integrating a retrofit CCS system into an existing facility would be expected to be substantial, and some existing EGUs might have space limitations and thus might not be able to accommodate the expansion needed to install CCS. Further, the aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. For these reasons, although some individual facilities may find implementation of CCS to be a viable CO2 mitigation option . . . EPA is not proposing . . . CCS as a component of the BSER[.]

See 79 Fed. Reg. at 34,857.[186] Yet such cost impacts—in the absence of an alternative system of emission reduction that is less costly and achieves very significant emission reductions—may well not be outside of the appropriate bounds of a best system of emission reduction analysis.

Furthermore, in evaluating the costs of partial CCS, EPA has discretion to include a consideration of revenue generated as a result of injection of CO_2 for enhanced oil recovery (EOR) operations. Section 111 allows a broad consideration of costs, including the sale of byproducts, and EPA may properly take the possibility of EOR sales into account when evaluating the costs of the proposed performance standard. *See Sierra Club v. Costle*, 657 F.2d at 330 ("[S]ection 111 . . . gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts in the broadest sense…over

[186] *See also*, EPA, GHG Abatement Measures TSD (June 18, 2014) at 7-5 to 7-6 (concluding that the costs of CCS would be unreasonable, significantly affect nationwide electricity prices and could affect reliability).

time."). We note, however, that ensuring permanent sequestration of CO_2 injected for EOR would be essential to implementing CCS as the BSER, as EOR operations have not been designed for this purpose historically. Nonetheless, because EPA's assessment of the costs of CCS may properly include the potential for EOR at some subset of the fleet, the costs of CCS would, in some locations, be reduced by this source of revenue generation.

The D.C. Circuit has held that the agency has authority to evaluate all of the statutory factors in a BSER determination "in the broadest possible sense," and to consider costs "at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." *Sierra Club*, 657 F.2d at 331. Given that, it is appropriate for EPA to consider revenue streams from the co-production of CO_2 in its determination that carbon capture and storage ("CCS") is BSER for coal-fired EGUs. Furthermore, as EPA asserts, if costs of *disposal* of byproducts must be taken into account during cost analysis, *revenue* from the sale of economically valuable products as a co-benefit of achieving a particular performance standard should also be taken into account. *See* 79 Fed. Reg. at 1,464. To the extent that the sale of captured CO_2 may generate revenues for plant operators, those revenues should be factored into a determination of the proposed rule's costs.

EPA's prior actions are consistent with the notion that byproduct revenue may be considered when the agency sets a performance standard. For example, in 2012, EPA and the National Highway Traffic Safety Administration finalized new fuel economy standards for lightduty vehicles. *See* 77 Fed. Reg. 62,624 (Oct. 15, 2012). In its cost analysis, the agencies determined that the benefits that would result from more stringent standards would "far outweigh higher vehicle costs" to consumers, largely due to the 170 billion gallons of fuel that would be saved throughout the lives of vehicles sold over an eight-year period. *Id.* at 62,629, 62,631. From a macroeconomic standpoint, these savings are functionally indistinguishable from the revenue that would accrue if those 170 billion gallons of fuel were a direct byproduct of the new technology, rather than the amount saved due to reduced demand. That same year, EPA analyzed revenues from the sale of natural gas and condensate recovered through the installation of pollution controls when describing costs associated with the NSPS for oil and natural gas production. *See* 77 Fed. Reg. 49,490, 49,534 (Aug. 16, 2012) (estimating that the proposed standards would save approximately $11 million annually if revenues from additional recovery were considered).

Finally, EPA could employ flexibility measures that would reduce the cost of CCS. For example, to reduce overall costs in the initial years following CCS technology installation, EPA could incorporate a gradual ramp-up rate in the percentage of capture that would allow for lower operational costs. A gradual introduction of CCS would also allow the industry to realize reductions in cost and improvements in performance that are likely to result from increasing familiarity with and development of CCS technology. For example, SaskPower executives have stated that they expect to retrofit additional coal-fired EGUs with CCS, and that the next such project will likely have 20-30% lower capital costs than Boundary Dam.[187] Studies of CCS technology development have also estimated that the cost of

[187] Matthew Bandyk, *SaskPower Looking to Spur More CCS with Boundary Dam Project*, SNL (Nov. 7, 2013 5:26 PM ET), http://www.snl.com/interactivex/article.aspx?id=25792864&KPLT=6.

electricity from CCS-equipped plants would likely decrease by 10-18% after approximately 100 GW of CCS capacity has been installed.[188]

In summary, EPA may ultimately determine that the costs of CCS, though significant, are nonetheless within the appropriate bounds, particularly in light of opportunities to defray costs through EOR, and to adjust the proportion of capture assumed in setting the standard.

EPA's technical feasibility concerns should be addressed through the analysis of cost.

Although the preamble to the proposed rule appears to reject partial CCS on the ground of cost alone, the GHG Abatement Measures TSD makes it clear that EPA also based its decision on the conclusion that CCS "may not be technically or logistically feasible in a number of cases."[189] Whereas the preamble appears to treat the spatial requirements and geographic factors relevant to CCS as considerations that will inflate the cost of CCS, the TSD addresses these concerns as part of an analysis of feasibility.[190]

In the TSD, EPA explains that:

> Some existing facilities are located in areas where CO2 storage is not geologically favorable and are not near an existing CO2 pipeline.
> . . .
> Integrating a retrofit CCS system into an existing facility is much more challenging. Some existing sources have a limited footprint and may not have the land available to add partial CCS system. Integration of the existing steam system with a retrofit CCS system can be particularly challenging.[191]

Although EPA states that CCS may not be feasible "in a number of cases," such a consideration does not bar the Agency from selecting CCS as the BSER because section 111 does not require EPA to find that *all* existing sources be able to meet the requirement. *See Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785-86. To the extent that EPA is asserting that these site-specific concerns show that CCS is not adequately demonstrated for any retrofit applications, such a conclusion would be unwarranted because it is well established that an emission reductions system can be "adequately demonstrated" even though some existing units may not be able to meet the resultant standard. *See id.*

Furthermore the difficulty that some existing sources might have in adopting CCS due to site-specific spatial constraints or distance from CO_2 pipelines or geologic units appropriate for sequestration are properly assessed as part of the projected cost of CCS rather than as technical feasibility. *Cf. Honeywell Int'l, Inc. v. EPA, 374 F.3d 1363, 1372 (D.C. Cir. 2004)* (finding that EPA decision to allow certain businesses to continue to use certain chemical agents on "technical feasibility" ground that it might be

[188] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide 8* (June 2012).
[189] *Id.* at 7-6; *see also id.* at 7-4 to 7-5 (discussing technical feasibility).
[190] *See id.* at 7-4 to 7-5; 79 Fed. Reg. at 34,857.
[191] GHG Abatement Measures TSD at 7-4.

burdensome to those businesses to switch to another agent was actually a decision based on cost.) As the D.C. Circuit has stated, "it is often possible to fit a round peg in a square hole if enough money is spent to make the round peg fit. In other words, a given change in manufacturing technique may be 'technically infeasible' only as compared to some baseline of what it would cost to change the technique." *Id.* For example, though the *current* footprint of a particular plant might not be large enough to accommodate CCS, it might nonetheless be feasible for the plant to expand its footprint by acquiring adjacent land at a cost that would not be exorbitant. Thus, rather than speculating that some number of plants may have spatial and geographic factors that would make CCS "infeasible," EPA should assess how widespread such constraints are and factor that information into its determination regarding the cost of CCS.

In summary, because the case law makes clear that the BSER need not be feasibly applied at *every* source, EPA is not required to base its evaluation of the feasibility or cost of CCS on some subset of facilities where source-specific spatial or geographic constraints would prohibit its use. Although spatial and geographic factors may generally increase the average cost of CCS, those costs will not necessarily be "exorbitant" or "more than the industry can bear." Consequently, EPA could ultimately conclude that CCS is a potential BSER (though inferior to the flexible, system-based BSER currently proposed).

In addition, EPA can and should take into account likely reductions in the cost of CCS that will accompany increasing deployment of the technology. As noted above, utilities such as SaskPower and researchers in the field of pollution control have predicted that the costs of CCS will decline significantly as the industry gains experience with the technology – just as has occurred with well-established technologies for power plants, such as flue gas desulfurization and selective catalytic reduction.[192]

Finally, it is noteworthy that because EPA has discretion to sub-categorize sources,[193] the Agency could distinguish between sources based on proximity to EOR or other spatial or geographic factors. By sub-categorizing in this way, EPA could find that partial CCS is the BSER for the sub-category of plants where physical constraints would not impose excessive costs.

EPA may reasonably evaluate the costs associated with a standard by looking at the degree of pollution control it achieves

Section 111 makes clear that EPA must consider the degree of emission limitation achieved, as well as the costs of achieving it, when formulating a performance standard. 42 U.S.C. § 7411(a)(1). This does not require the application of a strict cost-benefit test; rather, reviewing courts have upheld performance standards so long as the costs are not exorbitant (i.e., too high for the industry to bear) in light of the pollution reduction benefits they will yield. For example, in Sierra Club, the court upheld sulfur dioxide ("SO2") standards that would cost industry tens of billions of dollars between 1987 and 1995, but would provide significant benefits, including 100,000–200,000 tons of SO2 emission reductions per year, cost

[192] *See* Congressional Budget Office, *supra; see also* Edward S. Rubin, *Reducing the Cost of CCS Through "Learning by Doing,"* Presentation to the Clearwater Coal Conference (June 2, 2014), *available at* http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2014/Reducing%20the%20Cost%20of%20CCS%20through%20Learning%20by%20Doing.pdf

[193] 42 U.S.C. § 7411(b)(2).

savings of over \$1 billion per year, and a 200,000 barrel-per-day reduction in oil consumption. 657 F.2d at 314, 327-28.

While there exists no dollars-per-ton-removed cost-effectiveness level to serve as a "rule of thumb," the Portland Cement III court upheld PM standards for Portland cement plants that EPA had determined were "well within the range of cost-effectiveness" at about \$3,969 per ton of PM emissions removed. 665 F.3d 191; see also 73 Fed. Reg. 34,072, 34,076-077 (June 16, 2008) (discussing costs per ton removed by EPA's BSER for PM, and noting that the agency had previously deemed PM regulations for EGUs to be reasonably cost-effective at \$8,400 per ton of PM removed). Similarly, in Lignite, the court upheld NOx performance standards that would cost \$1,770 per ton removed, despite the availability of cheaper but less protective alternatives advocated by industry petitioners. 198 F.3d at 933; 62 Fed. Reg. 36,948, 36,953 (July 9, 1997).

Partial CCS would achieve significant emission reductions directly from EGUs.

Partial CCS can achieve emission reductions that are far greater than reductions generated by other alternative standards, such as a standard based on heat rate improvements alone. In the absence of a flexible Building Block scheme that can provide comparable CO_2 reductions more cost effectively, EPA could conclude that partial CCS would be the BSER because those reductions are considerable, the technology is adequately demonstrated for existing coal-fired power plants, and the costs have not been shown to be outside the range allowable under statute as elucidated by the case law. In evaluating alternative systems of emission reductions, EPA must consider the degree of the pollution reduction benefits that a proposed standard would achieve along with the costs of achieving it. *See Sierra Club*, 657 F.2d at 314, 327-28 (upholding costly SO_2 standards that would provide significant pollution benefits); *Essex Chem. Corp.*, 486 F.2d at 437 (acid mist standards were reasoned and cost benefit analysis was not required). A partial CCS standard would achieve significant reductions in CO_2 emissions that are urgently needed in the power sector. A partial CCS standard similar to the standard proposed for new EGUs would reduce CO_2 emissions from super critical pulverized coal plants by 33 percent (600 lb CO_2/MWh net) and from IGCC plants by18 percent (300 lb CO_2/MWh net).[194] Such a partial CCS standard would also result in additional co-benefits of reducing NO_x, SO_2, and $PM_{2.5}$.[195] These emissions reductions far exceed those anticipated to result from, for example, the 6% heat rate improvement under Building Block 1. Consequently, partial CCS is a superior system of emission reduction compared to alternative systems of emission reduction, and would be the BSER if the building block approach proposed by EPA were not available.

[194] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-452/R-13-003 (Sept. 2013) at 5-35, Table 5-10.214, *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf.
[195] *Id.* at 5-39.

I. The Best System of Emission Reduction Identified in the Clean Power Plan Reflects the Approach Taken by States and Power Companies Across the Country to Reduce Carbon and Other Harmful Air Pollutants Using Mechanisms that Reflect the Integrated Nature of the Power Sector

Across the country, states and companies are taking system-based approaches to achieve carbon pollution reductions, with a long track record of successful implementation. These programs are cost-effective and enable significant reductions because they take advantage of the unique opportunities for emission reductions provided by the interconnected electric grid. In fact, proven techniques for controlling GHGs that approach EGUs as part of an integrated system are the dominant approach for controlling EGU emissions of GHGs.

One of the most widespread and oldest approaches for states to reduce power sector emissions is the Renewable Portfolio Standard (RPS). As captured in the following chart, twenty-nine states and the District of Columbia have enacted RPSs, beginning in 1983. In many of these states, RPS requirements have been in force for ten or more years. There is also significant variation in program design among the RPS; states have made different decisions about key RPS features, such as resource eligibility, the program target, set-asides, and flexibility mechanisms.[196] The long experience with different kinds of RPS has allowed policymakers to understand best practices for RPS design.[197] In particular, the best practices guide states in developing programs that are enforceable, consistent with the structure of the electricity market, socially beneficial, cost-effective, flexible, and predictable.[198] RPS have had a significant impact on GHG emissions from the power sector. Several RPSs are slated to become even more stringent in coming years, leading to even greater reductions.[199]

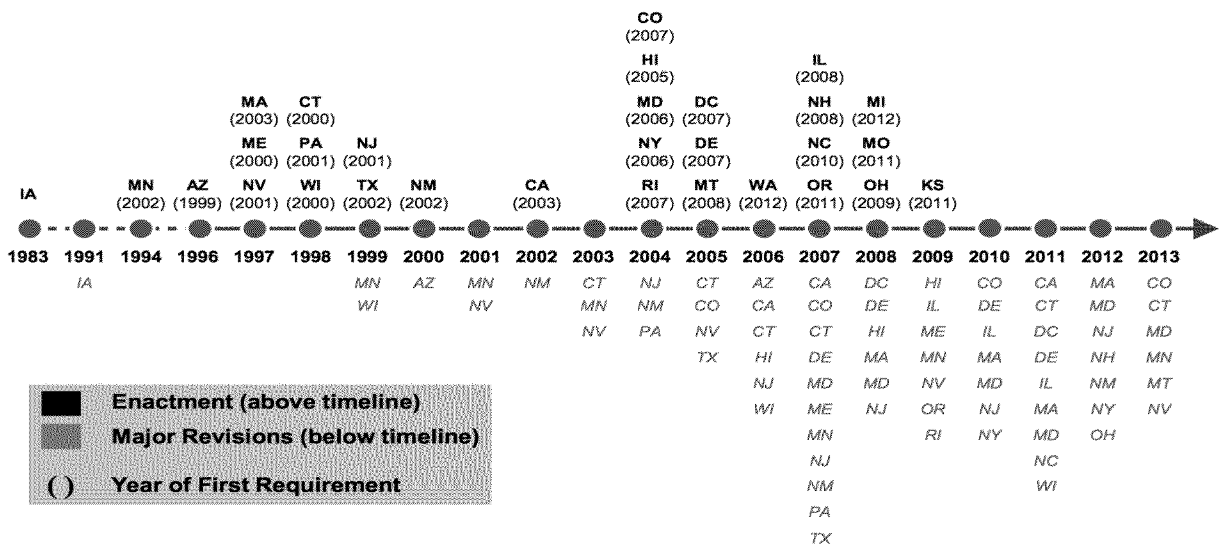
[196] *See generally* R. Wiser, K. Porter, and R. Grace, Lawrence Berkeley National Laboratory, Evaluating Experience with Renewables Portfolio Standards in the United States (2004), available at http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2054439.pdf; Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standard Policies (September 2014), available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

[197] *See, e.g.*, State/Federal RPS Collaborative, Recommended Principles and Best Practices for State Renewable Portfolio Standards (2009), available at http://www.cesa.org/assets/Uploads/Resources-post-8-16/Principles-Best-Practices-RPS-2.pdf; Clean Energy States Alliance, The State of State Renewable Portfolio Standards (2013), available at http://www.cesa.org/assets/2013-Files/RPS/State-of-State-RPSs-Report-Final-June-2013.pdf.

[198] Wiser et al, Evaluating Experience with Renewables Portfolio Standards in the United States at 25-30.

[199] Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standard Policies (September 2014), available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

Figure 1. Timeline of RPS Enactment and Initial Requirements



Source: Lawrence Berkeley National Laboratory (2013), http://emp.lbl.gov/sites/all/files/rps_summit_nov_2013.pdf

Several studies have documented the ability to expand on these historical successes by integrating much more renewable energy on the grid. A recent study of the PJM system found that it will not have any significant issues operating with wind and solar generation providing up to 30% of its energy.[200] In every scenario examined, integrating renewables into the PJM system would lead to lower operation & maintenance costs and a lower locational marginal price of electricity (which reflects the cost of generation and transmission), while reduction in CO_2 emissions relative to business as usual would range from 12% to 41%.[201] A study commissioned by the Minnesota Department of Commerce and conducted in coordination with the Midcontinent Independent System Operator (MISO) has found the state of Minnesota could obtain 40% or more of its electricity from wind and solar energy without suffering any grid reliability issues.[202] Accordingly, grid operators around the country are poised to duplicate the

[200] GE Energy Consulting, PJM Renewable Integration Study, Executive Summary Report (March 2014) at 6-7, available at http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx.
[201] *Id.* at 7.
[202] GE Energy Consulting, Minnesota Renewable Energy Integration and Transmission Study (October 2014) (modeling the ability of the MISO grid to accommodate the renewable energy required by RPSs in the MISO region).

success of the RGGI region, which demonstrated the ability to dramatically increase its use of renewable generation while maintaining grid reliability.[203]

Another well-demonstrated state policy for reducing GHG emissions from the power sector as a whole is the energy efficiency resource standard (EERS). Currently, twenty states have an EERS and an additional seven states have energy efficiency goals.[204] As with RPSs, states have taken a variety of approaches in designing EERSs that meet specific state needs.[205] Key policy-design elements include the stringency of the standard, flexibility mechanisms, and methodology for measuring savings.[206] Almost all the current EERSs were enacted five or more years ago.[207] Over this time, these policies have proven to be an achievable means of reducing emissions from the power sector.[208] And the diversity of EERS design has allowed stakeholders to analyze best practices.[209] The Institute for Electric Innovation recently found that if rate-payer funded energy efficiency programs continue to grow at trend, they will reduce total U.S. electricity use by 5.9% by 2025.[210]

Energy efficiency programs are especially suitable for wide-scale deployment because they present an enormous opportunity for cost-savings. Investments made to meet state energy efficiency targets regularly save customers over $2 for every $1 invested, and in some cases up to $5.[211] For example, the largest utility in Minnesota, Xcel energy, reported that its energy efficiency programs in 2012 alone would provide a net benefit of $376 million to its electricity customers.[212] Across the country, there are many money-saving energy-efficiency opportunities that are yet to be realized. In 2010, National Academy of Science reported that full deployment of cost-effective energy-efficiency technologies in buildings would eliminate the need to add new generation capacity.[213] This study identified opportunities to reduce power consumption in residential and commercial buildings that (together) would save over

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[203] RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830 (June 18, 2014) (Docket No. EPA-HQ-OAR-2013-0602) (Nov. 5, 2014) at 3, 20, available at http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf.
[204] Database of State Incentives for Renewables & Efficiency, Energy Efficiency Resource Standards (February 2013), available at http://www.dsireusa.org/documents/summarymaps/EERS_map.pdf.
[205] *See id.*
[206] See generally Karen L. Palmer, Samuel Grausz, Blair Beasley, and Timothy J. Brennan, Putting a floor on energy savings: Comparing state energy efficiency resource standards, 25 Utilities Policy 43 (2013).
[207] *See id.* at 45, Table 1.
[208] *See* ACEE, EERS: A Progress Report on State Experience (2011) at 9-10 (Thirteen of the twenty states with EERS policies in place for over two years are achieving 100% or more of their goals, three states are achieving over 90% of their goals, and only three states are realizing savings below 80% of their goals.").
[209] *See generally* Steven Nadel, ACEE, Energy Efficiency Resource Standards: Experience and Recommendations (2006), available at http://www.epatechforum.org/documents/2005-2006/2006-05-16/2006-05-16-ACEEE%20Report%20on%20EE%20Portfolio%20Standards.pdf.
[210]IEE Report, Factors Affecting Electricity Consumption in the U.S. (2010 - 2035) (March 2013) at 1, available at http://www.edisonfoundation.net/iei/documents/IEE_FactorsAffectinguSElecconsumption_Final.pdf.
[211] Bianco, et al, Seeing is Believing: Creating a New Climate Economy in the United States, World Resources Institute Working Paper, at (2014) at 52, available at http://www.wri.org/sites/default/files/seeingisbelieving_working_paper.pdf (hereinafter "Seeing is Believing").
[212] Xcel Energy, 2012 Status Report & Associated Compliance Filings: Minnesota Electric and Natural Gas Conservation Improvement Program Docket No. E,G002/CIP-09-198 (2013) at 2, available at http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-DSM-CIP-2012-Status-Report.pdf. These savings dwarf the $98.1 million spend on electric energy efficiency programs. *Id.*
[213] National Academy of Sciences, et al, Real Prospects for Energy Efficiency in the United States (2010) at 5.

1,200 TWh in 2030 and yield a return on investment in less than three years.[214] Another recent report identified building retrofit opportunities with the potential to mitigate more than 600 million metric tons of CO_2 per year, returning more than one trillion dollars in energy saving over ten years on a $279 billion dollar investment.[215] The many opportunities for reducing power-sector emissions through energy efficiency give states a range of well-demonstrated options for inclusion in their state plans.[216]

Where energy efficiency resources compete on the market, it is clear that they are a cost-effective way to meet consumer needs while reducing power-sector GHG emissions. Over the past decade, efficiency has remained the least-cost electricity option; with an average cost of 2.8 cents per kilowatt hour, energy efficiency programs are about one-half to one-third the cost of new electricity generation options.[217] In some regions, efficiency is beginning to feature in forward capacity markets directly competing for the right to meet the capacity needs of the electric grid.[218] Comparing the cost of energy efficiency and affected-source generation in this context clarifies the interconnected nature of the electric system and the appropriateness of taking a system-based approach to reducing GHG emissions from EGUs.

Individual states have crafted strategies for reducing power-sector emissions that combine several tailored policies. In Colorado, emissions reductions are being driven by the Clean Air - Clean Jobs Act, an energy efficiency standard, and a renewable energy standard. The Clean Air - Clean Jobs Act required Colorado's utilities to propose plans for achieving integrated multipollutant reductions from coal-fired power plants, prompting utilities like Xcel Energy design systems-based plans that shift generation to cleaner sources.[219] The Act has enormous public health benefits and is expected to create about 1,500 jobs during the construction of cleaner facilities.[220] Illinois also has a unique suite of policies with proven results; Illinois has an energy efficiency standard that requires utilities to save two percent of electricity

[214] *Id.* at 69-70, 78. *See also* Granade, et a., McKinsey Global Energy and Materials, Unlocking Energy Efficiency in the U.S. Economy (2009) at iv-v ("Our research indicates that by 2020, the United States could reduce annual energy consumption by 23 percent from a business-as-usual (BAU) projection by deploying an array of NPV-positive efficiency measures, saving 9.1 quadrillion BTUs of end-use energy . . . . If captured at full potential, energy efficiency would abate approximately 1.1 gigatons of CO_{2e} of greenhouse gas emissions per year in 2020 relative to BAU projections.").
[215] The Rockefeller Foundation and DB Climate Change Advisors, United States Building Energy Efficiency Retrofits (2012) at 7, available at http://www.rockefellerfoundation.org/uploads/files/791d15ac-90e1-4998-8932-5379bcd654c9-building.pdf.
[216] *See generally* National Academy of Sciences, Real Prospects for Energy Efficiency in the United States, chapter 2 (quantifying the opportunities for electricity savings from different building energy efficiency measures).
[217] Maggie Molina, ACEE, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (2014) at iii, available at http://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf.
[218] Bianco, Seeing is Believing at 53.
[219] Xcel Energy, Colorado Clean Air - Clean Jobs Plan, available at http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_-_Clean_Jobs_Plan (explaining that Xcel's plan calls for the retirement of certain coal-fired units, the replacement of a retired unit with a modern natural gas plant, fuel-switching at one plant, and retrofits).
[220] *Id.* ("We expect to reduce nitrogen oxides by about 86 percent, sulfur dioxide emissions by 83 percent and mercury emissions by 82 percent from the plants included in the plan. The project will contribute to a projected system-wide reduction in carbon dioxide emissions since 2005 of 35 percent by 2020. The University of Colorado Leeds School of Business forecasts the project will have a total economic impact of about $590 million on the state of Colorado between 2010 and 2026, resulting in about 1,500 jobs at the peak of construction.").

annually by 2015 and reduce rate-payer spending,[221] an RPS that requires 25 percent of electricity to come from renewables by 2025 and drives a booming local economy in wind energy,[222] and has required any new coal-fired power plants to capture and store some of their carbon emissions.[223]

The nine states participating in the Regional Greenhouse Gas Initiative (RGGI) have already demonstrated that a systems-based approach to reducing power sector GHG emissions can achieve vast reductions with economic benefits. Since 2005, the RGGI states have reduced their power sector CO_2 emissions by 40 percent, while the regional economy has grown 7 percent.[224] The RGGI states now have nearly six years of experience with a fully operational carbon market.[225] Even during the first three years of the RGGI cap-and-trade program, the mandatory system had been functioning properly and seamlessly introducing a carbon price into the electricity market.[226] Experience with RGGI demonstrated that not only that the initial system-wide targets were achievable, but that even more ambitious targets were within reach: in 2013, the RGGI states lowered the program's emissions cap by 45 percent, starting in 2014.[227]

RGGI's enormous economic benefits demonstrate that integrating energy efficiency into power-sector GHG-reduction is not just available, but an economic boon. During the first three years of its cap-and-trade program, RGGI added $1.6 billion in economic value to the ten-state region.[228] In general, this positive impact results from the injection of carbon-allowance revenue into the economy and consumer savings on energy.[229] During this three-year period, RGGI state investments in energy efficiency created about 16,000 "job years."[230] Electricity consumers (including households, businesses, government users,

[221] 220 Ill. Comp. Stat. 5/8-103(b) (2013). *See also* Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 14 ("in the first year (2008-2009) of the Illinois Public Utilities Act, Ameren Illinois Utilities (AIU) customers saved almost 90,000 MWh, far exceeding AIU's goal for that year. In Plan Year 3 (June 2010-May 2011), another major utility, Commonwealth Edison Company (ComEd), achieved about 662,000 MWh net energy savings through its energy-efficiency and demand-response programs.) (footnote omitted).
[222] Ill. Pub. Act 095-0481 (2007). *See also* Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 14 ("The state has experienced significant growth in wind power development as a result—electricity generation from wind increased by more than six million MWh from 2005-2011. Growth in wind energy from 2003 to 2010 alone created almost 10,000 new local jobs during construction and a lifetime economic benefit of $3.2 billion, according to one analysis. In 2011, Illinois avoided about five million tons of CO_2 emissions from renewable resource integration, along with four million tons of NO_X.") (footnotes omitted).
[223] Ill. Clean Coal Portfolio Standard, Public Act 095-1027 (2009).
[224] Kelly Speakes-Backman, Testimony on Questions Concerning EPA's Proposed Clean Power Plan, House Committee on Energy and Commerce (Sept. 9, 2014) at 4, available at http://docs.house.gov/meetings/IF/IF03/20140909/102623/HHRG-113-IF03-Wstate-Speakes-BackmanK-20140909.pdf.
[225] *Id.*
[226] Paul J. Hibbard, et al, Analysis Group, The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States (2011) at 43.
[227] U.S. Energy Information Administration, Lower emissions cap for Regional Greenhouse Gas Initiative takes effect in 2014 (Feb. 3, 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=14851.
[228] Paul J. Hibbard, et al, Analysis Group, The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States (2011) at 2.
[229] *Id.* at 3-4.
[230] *Id.* at 7.

and others) saved nearly $1.1 billion overall because investments in energy efficiency lowered prices, outweighing some near-tern increases in electricity prices.[231]

RGGI also demonstrates that systems-based approaches to reducing power sector emissions can boost local economies—even in states that heavily rely on coal-fired generation. In the first three years of the RGGI cap-and-trade program, *every* RGGI state experienced net positive benefits from RGGI and job growth.[232] The states in the more coal-reliant PJM region—Delaware, Maryland, and New Jersey—added $341 million in value and 3,676 job years.[233] Consumers also realized significant bill savings in these three states, as longer term savings in electricity and energy bills offset the minor increases (0.7 percent) in electricity bills during 2009–2011.[234] RGGI states may be able to improve upon this impressive track record in the future, as the first three years of the program provided an important opportunity for identifying best practices for using allowance revenue and designing energy efficiency programs.[235]

Another part of RGGI's success has come from shifting from high-emitting to lower-emitting sources of generation. From 2005 to 2012, coal-fired generation declined from 23% of the regional generation mix to 9%.[236] In the same period, the share of natural gas-fired generation rose from 25% to 44%.[237] Between 2005 and 2012, the RGGI states also increased in-region, non-hydroelectric renewable generation by 47 percent.[238] This dramatic growth in renewables is driven by a combination of complementary policies: RPSs, net metering tariffs, long-term contracting, the establishment of "Green Banks," innovative green financing mechanisms, and renewable energy technology grant programs.[239] These shifts in generation were able to occur without any disruption to consumers because the power sector functions as an integrated system.

When utilities have designed GHG reduction programs, they too have adopted successful systems-based approaches. These approaches vary widely, but generally combine a shift toward lower-emitting generation with increased energy efficiency. The following examples illustrate the GHG reduction strategies that have been successfully demonstrated on the ground:

- In 2001, Entergy set a goal of stabilizing GHG emissions for its power plants at 2000 levels through 2005 and, after achieving its initial goal, the company strengthened its goal to stabilize

[231] *Id.* at 4.
[232] *Id.* at 7-8.
[233] *Id.* at 33 (Table 2).
[234] *Id.* at 43.
[235] *Id.* at 49-50.
[236] U.S. Energy Information Administration, Lower emissions cap for Regional Greenhouse Gas Initiative takes effect in 2014 (Feb. 3, 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=14851.
[237] *Id.*
[238] RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830 (June 18, 2014) (Docket No. EPA-HQ-OAR-2013-0602) (Nov. 5, 2014) at 20, available at http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf.
[239] *Id.* at 20-21.

emissions at 20 percent below 2000 levels.[240] Entergy was successful, in part, due to upgrades and efficiency improvements at existing facilities.[241]

- Public Service Enterprise Group (PSEG) set a goal of reducing its GHG emissions by twenty-five percent and achieved its goal in 2011—14 years ahead of schedule.[242] PSEG's multi-pronged efforts include deploying energy efficiency, increasing nuclear power output, building efficient natural gas plants, and investing in renewable energy production.[243] From 2000-2011, PSEG increased electricity generation by 37 percent while simultaneously reducing its CO_2 emissions rate 24 percent.[244]

- From 2000-2011, NextEra Energy's CO_2 emissions rate declined by approximately 40 percent while its power generation increased by almost 90 percent.[245] This achievement has been mainly driven by greater energy efficiency in its generation facilities and its large renewable portfolio.[246] One of NextEra Energy's subsidiaries is also a leader in demand-side management.[247]

- In 2008, Exelon set a goal of abating 15.7 million metric tons of GHG emissions by 2020 (the equivalent of its total GHG emissions in 2001 and then increased) and increased its abatement goal to 17.5 million metric tons after its 2012 merger with Constellation Energy.[248] Exelon has already exceeded its revised goal through a combination of measures.[249] Exelon achieved more than half of its goal by increasing production at existing nuclear plants through updates and other operation efficiency, reducing the need for fossil-fired generation.[250] The second most

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[240] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes (December 2013) at 24-25.
[241] *Id.* ("Since 2001, Entergy has spent $14.7 million on 61 energy efficiency improvements that have resulted in nearly 5.3 million metric tons of CO_2 savings and $30 million in annual fuel savings. For example, the company has added nearly 4,000 MW from efficient natural gas-fired combined cycle gas turbine (CCGT) generation resources. It estimates that this upgrade saves 850,000 metric tons of CO_2 per year and $55 million in annual fuel savings. Over the past decade, Entergy has also increased the capacity of its nuclear fleet by over 700 MW, the equivalent of a new reactor, through power upgrades, turbine replacements and cooling tower modifications. Entergy estimates that maintaining and expanding its nuclear energy production avoids 50 million metric tons of CO_2 emissions per year.") (footnotes omitted).
[242] *Id.* at 31-32.
[243] *Id.*
[244] *Id.*
[245] *Id.* at 27.
[246] *Id.* ("For instance, in 2012, the company's wind generation avoided over 20 million tons of CO_2, and its nuclear generation avoided about 26 million tons of CO_2.").
[247] *Id.* ("FPL's programs to encourage customers to use energy more efficiently have saved the company from having to build 14 medium-sized power plants since 1981, avoiding more than 25 million MWh of electricity and an associated 13 million tons of CO_2since 2007.").
[248] Exelon, Exelon 2013 Sustainability Report (2014) at 25, available at http://www.exeloncorp.com/assets/newsroom/downloads/docs/dwnld_Exelon_CSR.pdf.
[249] *Id.*
[250] *Id.*

> significant source of Exelon's reductions were programs that helped its customers use electricity more efficiently.[251]

Municipal utilities have also had proven success with systems-based approaches to reducing power sector GHG emissions. CPS Energy, the nation's largest municipally owned electric and gas utility, has reduced its CO emissions rate by seven percent from 2000-2011, as power generation increased 36 percent.[252] While CPS Energy maintains a diverse electricity mix that includes wind, solar, natural gas, coal, and nuclear, it has achieved substantial emissions reductions by deactivating two older coal units, increasing renewable generation, and implementing energy efficiency programs.[253] The utility is also on track to reach its ambitious energy-saving goal—771 MW of electricity by 2020—through a program that includes rebates for rooftop solar power, commercial lighting and HVAC retrofits, free energy efficiency measures for low-income households, and new home construction.[254] Austin Energy, the eighth largest public power utility in the United States, has implemented demand-side management (DSM) programs since 1982.[255] In total, Austin Energy's energy efficiency programs have saved about 1.8 billion kWh since 1982.[256] Austin Energy's combination of DSM and increased renewable generation has allowed it to serve a rapidly growing population without increasing its CO_2-emitting generating capacity over the past 20 years.[257]

One of the most common ways that electric utilities structure their analysis of options for reducing GHG emissions is by considering a carbon price in an Integrated Resource Plan (IRP). A 2011 study of best practices in integrated resource planning that examined the IRPs of fifteen utilities operating across the United States found that carbon costs were among the variables most commonly considered in assessing available portfolio strategies.[258] Accordingly, the study determined that one of the "key components" of integrated resource planning was "[a] Portfolio Strategy Assessment evaluat[ing] the cost / risk tradeoff of potential strategies as natural gas prices and carbon costs varied."[259] This component was present, for example when an IRP identified alternative mixes of supply-side resources with comparable reliability and then "[c]onducted Monte Carlo analysis assessing total supply cost for each portfolio over the twenty

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[251] *Id.*
[252] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes (December 2013) at 22-23.
[253] *Id. See also* CPS Energy, CPS Energy leading on greenhouse gas reductions, available at http://newsroom.cpsenergy.com/blog/energy-efficiency/leading-on-greenhouse-gas-reductions/ (CPS Energy "has already begun to diversify and reduce the carbon intensity of its power plant fleet, increase customers' energy efficiency and upgrade its electrical grid. . . . Through all of its strategies, [President and CEO] Beneby said, CPS Energy is reducing its carbon emissions by 5.3 million tons by 2020, a 29 percent decrease since 2011.").
[254] CPS Energy, CPS Energy leading on greenhouse gas reductions.
[255] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 20-21.
[256] Austin Energy, Annual Performance Report: Year End September 2013 (2014) at 13, available at http://austinenergy.com/wps/wcm/connect/0b60b1fd-47f6-4256-9c4d-f0e37c38becc/2013AnnualPerformanceReport.pdf?MOD=AJPERES.
[257] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 20-21.
[258] SPO Planning Analysis, IRP Tools & Techniques: Review of a Sample of Recent IRPs by US. Utilities Best Practices Supplement to the 2012 ENO IRP (Oct. 2011) at 2, available at http://www.entergy-neworleans.com/content/IRP/Best_Practices_Supplement.pdf.
[259] *Id.* at 8.

year planning horizon with varying gas and carbon prices."[260] An in-depth 2008 study of the IRPs of fifteen utilities in the Western United States (accounting for about 60% of retail electricity sales in the West) illustrates the varying methodology for considering carbon costs.[261] All but one of the fifteen utilities in the sample incorporated a future carbon tax or cap-and-trade system into their portfolio analysis,[262] confirming that consideration of carbon costs in IRPs is common practice. But crucially, "[e]leven of fifteen utilities included carbon emission prices in their base-case scenario, thereby affecting their choice of preferred portfolio, to the extent that the choice was based on a comparison of candidate portfolios' expected costs."[263] Analyzing scenarios with different carbon prices allows the utilities to reduce risk by shifting from high-emitting sources to lower-generating sources: "Based on the results under its high carbon price scenario, PSCo selected a preferred portfolio that replaces four existing coal-fired units (~200 MW nameplate capacity) with a new CCGT."[264] For a variety of economic and compliance reasons, utilities are shifting toward renewable generation and energy efficiency to meet consumer needs.[265] In addition to IRPs, utilities can consider carbon costs in any investment decision framework. National Grid factors a social cost of carbon of about $50 per ton of CO into all capital project decisions.[266]

Regardless of what factors are driving power company choices, their decisions to shift from high-emitting generation to lower-emitting generation demonstrate the availability of this GHG-reduction option. Power companies that once met a majority of customer demand with coal-fired generation have drastically reduced their reliance on coal. For instance, in 2005, Southern Power and its affiliates generated over 60 percent of their electricity from coal and 10 percent from natural gas.[267] In 2013, Southern Power generated about 40 percent of its power from coal and 34 percent from natural gas.[268]

In addition, there are numerous demonstrated systems-based approaches for reducing criteria pollutant emissions from EGUs. Perhaps most notably, Title IV of the Clean Air Act established a successful market-based program to control EGU emissions that contribute to acid rain, setting a permanent cap on the total amount of $S0_2$ that may be emitted by EGUs nationwide.[269] States and local governments also implement energy efficiency programs to improve local air quality as part of the SIP process.[270] These

[260] *Id.* at 9.
[261] Galen Barbose, Ryan Wiser, Amol Phadke, and Charles Goldman, Lawrence Berkeley National Laboratory, Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans (March 2008), available at http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-44e_0.pdf. *See also id.* at 11, Table 2 (summarizing the utilities' carbon price projections).
[262] *Id.* at 9.
[263] *Id.* at 33.
[264] *Id.* at 40.
[265] *Id.* at 51 ("All utilities selected preferred portfolios with energy efficiency and new renewables, and half selected portfolios in which energy efficiency and renewables together constitute 50% or more of all new resources.").
[266] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 26.
[267] Bianco, Seeing is Believing at 14.
[268] *Id.*
[269] EPA, Cap and Trade: Acid Rain Program Results, available at http://www.epa.gov/capandtrade/documents/ctresults.pdf.
[270] EPA, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix K: State, Tribal and Local Examples and Opportunities" at K-8 to K-9 (July

programs are effective because decreases in electricity demand reduce EGU emissions through the interconnected electricity system. Further, since 1998, each of EPA's rules to address the interstate transport of pollution from EGUs has incorporated energy efficiency compliance options; of these, the NO_x SIP Call also provided a renewable energy compliance option.[271] Taken together, these EPA and state programs have long demonstrated the ability of systems-based approaches to reduce power sector emissions, while providing flexibility and reducing compliance costs.

J. EPA Has Properly Interpreted the "Remaining Useful Life" Provision of Section 111(d).

EPA has appropriately interpreted the "remaining useful life" provision of section 111(d) in a way that is consistent with the statutory text and purpose, and that avoids creating a loophole that could erode the environmental integrity of the standards.

Section 111(d)(1) provides, in part:

> Regulations of the Administrator under this paragraph [section 111(d)(1)] shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

Essentially, this "remaining useful life provision" requires EPA to allow states to consider certain source-specific factors when the states apply section 111(d) standards of performance to particular existing sources. But the "remaining useful life" provision does not specify how or when states shall be permitted to consider source-specific factors in applying standards of performance. Consequently, the statute leaves EPA discretion regarding how it will permit states to consider these factors when they apply standards of performance to particular sources that are regulated under the states' 111(d) plans. EPA must permit

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2012), available at http://epa.gov/airquality/eere/pdfs/appendixK.pdf (To meet federal ambient air quality standards, Texas reduces NOx emissions "through reduced demand for fossil-fuel generation at power plants, as a result of EE measures implemented in new construction for single and multi-family residences in 2003."); id. at K-9 (Louisiana's plan for achieving federal ambient air quality standards included energy conservation measures at City buildings in Shreveport, which were "estimated to have saved 9,121 megawatt-hours (mWhs) of electricity per year with NOx emission reductions of 0.041 tons per ozone season-day").

[271] NO_x SIP Call, 63 Federal Register 57356, 57438 ("The EPA believes that, with respect to EGUs, there is a large potential for energy efficiency and renewables in the NO_x SIP call region that reduce demand and provide for more environmentally-friendly energy resources. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_x emissions proportionately, while the associated generator would produce the same amount of electricity."); Clean Air Interstate Rule, 70 Federal Register 25162, 25279 (explaining that state decision regarding allowance allocation, including whether to use set-asides for energy efficiency, would not change environmental outcome of the cap-and-trade program); Cross State Air Pollution Rule, 76 Federal Register 48208, 48319 ("By reducing electricity demand, energy efficiency avoids emissions of all pollutants associated with electricity generation, including emissions of NO_x and SO_2 targeted by this final rule, and reduces the need for investments in EGU emission control technologies in order to meet emission reduction requirements.").

states to consider remaining useful life and other factors in a manner that is reasonable in any given rulemaking. This does not require a one-size-fits-all approach.

EPA has properly interpreted the "remaining useful life" provision in this rulemaking. EPA has proposed state-wide emission performance goals that can be met using a wide variety of compliance approaches. Each state has the enormous flexibility to consider affected facilities' source-specific characteristics throughout the entire process of designing a plan to meet its goal, including the application of standards of performance to particular sources.[272] As such, EPA's proposal allows states to refrain from requiring specific plants nearing retirement to install specific pollution controls. For instance, states may allow aging facilities to comply by deploying renewable energy or energy efficiency to secure emission reductions in the interim before retirement. Indeed, this rule provides the states with greater opportunity to take source-specific factors into account than any prior 111(d) guidelines.

EPA's approach promotes the apparent purpose of the "remaining useful life" provision, i.e., to avoid mandating major investments in facilities that are near retirement. EPA's proposal achieves this purpose by giving states a variety of options for how to design their standards of performance and implementation plans, including the option to set standards that facilities can meet without undergoing any retrofits whatsoever. Under the proposed guidelines, states apply standards of performance based on whatever considerations they deem appropriate, and can deploy renewable energy and energy efficiency as well as shifts in utilization towards lower-emitting units rather than retrofits to secure the required emission reductions. A state could choose to apply a standard that is satisfied through source emissions combined with the purchase of credits representing emissions reduced from renewable energy or energy efficiency (or allowances)—which would allow a source nearing retirement to purchase sufficient credits (or allowances) to achieved compliance until it retires.[273] Moreover, a state might apply a less stringent standard to older facilities than to newer facilities. By empowering states to consider cases where large expenditures would yield only relatively few emissions reductions due to the short remaining life of a source, the provision ensures that states need not require major expenditures by uniquely situated sources.

In this particular rulemaking, it is also appropriate for states' consideration of remaining useful life and other factors to occur as they design their plans because states must consider the achievability of performance standards during plan development. Specifically, state plan submissions must include "a demonstration that the plan is projected to achieve each of the state's emission performance levels for affected entities" and "[m]aterials supporting the projected emissions performance level that will be achieved by affected entities under the plan." 79 Fed. Reg. 34952. The analysis of the affected entities' projected emissions performance level will necessarily encompass each sources remaining useful life and

[272] Section 111(d)(1) requires EPA to permit states to consider a particular source's remaining useful life and other factors "in applying" standards of performance to that source. EPA's proposal does this; the proposed emission guideline permits states to consider any source-specific factors when the states choose the standard of performance that will apply to their existing sources. Plainly, a state is "applying a standard of performance" when it establishes the standards in its state plan. *See, e.g.*, Merriam-Webster Dictionary (defining "apply" to mean "to put into operation or effect <*apply* a law>"), available at http://www.merriam-webster.com/dictionary/apply. The proposal permits states to consider whatever factors they choose during that process.

[273] EPA has previously concluded that a cap-and-trade system satisfies the requirements of section 111(d)(1), including the "remaining useful life" provision. 70 Fed. Reg. 28,606 at 28,616-17.

other factors. This process is properly designed to ensure that states will not subject sources to standards of performance that they cannot achieve (whether due to a limited remaining useful life or other factors). Further, this process enables states to take into consideration the remaining useful life of sources as that will facilitate compliance, as the retirement of sources will reduce emissions and move states closer to compliance.

Nowhere does the statute require that states must have discretion to relax the state emission goal. The statute simply allows a state to consider "remaining useful life" when the state is "applying a standard of performance" to a source, and that is exactly what the state is doing as it establishes the standards in its state plan to meet its overall state emission goal. In prior instances, EPA has established generally applicable default standards to be applied to all sources, and in some circumstances authorized tailoring of the standards as states applied them to sources with specific difficulties in compliance or nearing the end of their useful life. Under the proposed Clean Power Plan, however, the situation is entirely different. The provision of average state emission targets—and flexible compliance options that do not require investments at specific sources to secure compliance either with the state target or with an individual source's standard—enable states to adjust to source-specific circumstances as they design their compliance plans and the standards that apply to specific sources.

The "remaining useful life" provision does not disrupt the basic structure of section 111(d), in which states must submit plans with standards of performance that reflect the EPA-determined BSER. EPA's proposal properly ensures that state standards of performance (taken together) reflect the emission reductions achievable through the application of the statewide BSER even if the state adjusts its application of a standard to a particular source due to remaining useful life or other factors. We agree with EPA's interpretation that the components of state plans, taken together, must be "at least as stringent as necessary to achieve the required emissions performance level for the state's affected EGUs." *See* 79 Fed. Reg. at 34891. Here, where EPA has applied BSER on a statewide basis, and provided for flexible compliance mechanisms that do not require infrastructure investments at specific sources, EPA has reasonably proposed permitting states to consider source-specific factors when they design their plans and apply standards of performance to those sources. In this manner, EPA's proposal fulfills the requirements of the "remaining useful life" provision in a manner consistent with its "best system of emission reduction" analysis of emission reduction potential and without undermining the environmental integrity of its emissions guidelines.

Previous 111(d) guidelines have generally not given states such an extensive opportunity to consider their sources' remaining useful life (and other site-specific factors) when they established performance standards for particular sources. Most of EPA's prior 111(d) guidelines for health-harming pollutants have specified presumptive standards of performance for all sources in a particular category. EPA's application of the "remaining useful life" provision in this rulemaking reasonably reflects the uncommon opportunities and incentives for states to consider their sources' remaining useful life and other factors as they craft flexible compliance plans and standards for their particular sources.

Currently, the following EPA implementing regulation generally applies to rulemaking under section 111(d):

> Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities, States may provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required by [40 CFR § 60.24(c)] provided that the State demonstrates with respect to each such facility (or class of facilities):
>
> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility of installing necessary control equipment; or
>
> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

40 CFR § 60.24(f). This "variance" provision is not required by section 111(d)(1), but reflects a reasonable approach to implementing section 111(d)(1) where emissions guidelines establish default source-specific standards. These general rules only apply "[u]nless otherwise specified in the applicable" emission guideline. *Id.* In several emissions guidelines, EPA has provided that section 60.24(f) does not apply. *See, e.g.*, 40 C.F.R. § 60.30b; § 60.5040.

EPA properly concluded that 40 C.F.R. § 60.24(f) should not apply to proposed subpart UUUU. Given the extensive compliance flexibilities provided to states (and which states can provide to sources) in the proposal, it is appropriate for EPA to interpret the terms "remaining useful life" and "other factors" for the purposes of this particular rulemaking, rather than apply the general provisions of 40 CFR § 60.24(f). Application of 60.24(f) is not necessary to achieve the apparent purpose of the "remaining useful life" provision—that is, avoiding stranded investments in control technologies—because EPA's proposed guidelines require nothing of any particular facility and certainly do not require expensive investment in controls at a facility nearing retirement. As explained above, EPA's proposal satisfies the requirements of the "remaining useful life" provision in a way that is well-tailored to the specific context of the Clean Power Plan.

K. State plans can be implemented using traditional environmental regulatory tools and frameworks

Contrary to assertions made by some critics of the Clean Power Plan, state air quality regulators are fully capable of implementing EPA's proposed state goals using traditional legal frameworks and environmental regulatory tools.

There are at a minimum two mechanisms by which state air quality regulators could utilize traditional regulatory tools to ensure compliance with the state goals. In both cases, these mechanisms would take the form of traditional requirements that apply directly to affected EGUs, and could be readily incorporated into operating permits for individual existing sources. These mechanisms include:

Allowance holding requirement consistent with mass-based state goal. A number of states have expressed interest in adopting a mass-based compliance framework. Section 111(d) compliance could be achieved by implementing a traditional mass-based emissions trading program, similar to those established by many states for carbon dioxide as well as SO_2 and NO_x. Under this approach, air quality regulators could adopt a mass-based state goal (providing a "budget" for overall emissions in the state), and then create a stock of allowances – each representing one ton of carbon dioxide — in an amount equivalent to the state budget. Each affected EGU in the state would be subject to an individual requirement to hold allowances in an amount equivalent to its emissions, either on an annual basis or some other compliance period defined by the state and in accordance with EPA's emission guidelines. Affected EGUs could be allocated allowances by the state through an administrative formula or a market-based mechanism (such as an auction), and could be allowed to trade allowances as needed to meet their holding requirements. This flexible and straightforward system would ensure that the state meets its emission goals over time, and would not rely upon any additional action by the public utilities commission or other authorities. PUCs would, of course, play their traditional oversight role in evaluating the plans of regulated companies to make changes to generation infrastructure and obtain allowances in order to meet their permit requirements. Many states adopted similar emissions budgets and allowance holding requirements under state implementation plans submitted pursuant to the Clean Air Interstate Rule and the NO_x SIP Call.[274] Other states, such as Utah, have also adopted emissions trading programs for electric generating units to meet federal regional haze requirements, acting under standing legal frameworks to protect air quality.[275] And as discussed elsewhere, states taking this approach could also facilitate even more cost-effective compliance by providing that they would accept credits from a specified set of states, or from any state taking a mass-based approach with a plan approved by EPA.

Rate-based emission standard with well-defined compliance crediting. An alternative approach would be to require individual EGUs within each state to comply with that state's rate-based state goal, and to allow individual EGUs to demonstrate compliance with that emission standard using the same kinds of instruments described in the proposed emission guidelines. To illustrate, a coal-fired EGU in a state with an emission target of 1,000 lbs/MWh would be subject to that emission standard in its operating permit. However, the operating permit would also provide that the EGU could demonstrate compliance with that

[274] Prior to the adoption of CSAPR, EPA approved SIP submittals for Alabama, Arkansas, Connecticut, Georgia, Indiana, Illinoi, Iowa, Kentucky, Louisiana Massachusetts, Michigan, Maryland, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas (NO_x only), Virginia, West Virginia, Wisconsin. To our knowledge, all of these SIPs adopted the respective state-wide emission budgets established in CAIR, authorized emissions trading by regulated EGUs, and provided the necessary administrative and reporting requirements to ensure compliance. *See* collected Federal Register notices at EPA, "EPA Rulemaking Actions on States' CAIR SIP Submissions: Federal Register Notices," http://www.epa.gov/cleanairinterstaterule/rulemakingactions.html (last visited Nov. 12, 2014).

[275] *See* Utah Admin. Code r.307-250 (2014) (establishing sulfur dioxide trading program to comply with regional haze requirements of the Clean Air Act, and invoking general rulemaking authority of the Utah Department of Environmental Quality). EPA has approved similar programs in at least three states. *See* Final Rule, Approval and Promulgation of State Implementation Plans; Wyoming, 77 Fed. Reg. 73,926, 73,926 (Dec. 12, 2012); Final Rule, Approval, Disapproval and Promulgation of State Implementation Plans; Utah, 77 Fed. Reg. 74,355, 74,355 (Dec. 14, 2012); Final Rule, Approval and Promulgation of State Implementation Plans; New Mexico, 77 Fed. Reg. 70,693, 70,693 (Nov. 27, 2012); Final Rule, Approval and Promulgation of State Implementation Plans; City of Albuquerque-Bernalillo County, 77 Fed. Reg. 71,119, 71,119 (Nov. 29, 2012).

emission standard by any combination of the following: a) averaging its emissions with a lower-emitting fossil fuel-fired EGU, either via a tradable credit or a contractual averaging arrangement; b) reducing its emissions rate by procuring and holding verified credits representing emission reductions from renewable energy, either generated within the state or by another state; or c) reducing its emissions rate using credits representing emission reductions from properly documented end-use energy efficiency savings (which could either take the form of a tradable credit created or recognized by the air quality regulator, or could be "allocated" by the air quality regulator to the EGU based on verified savings reported by the public utilities commission). The implementation of this regulatory approach would be greatly facilitated were the air regulator or EPA to create a system for registering and tracking credits related to renewable energy and energy efficiency projects. As discussed elsewhere, the air regulator in a state taking this approach could also ensure greater cost-effectiveness by also providing that it will accept credits generated within the state, within a specified set of states, or within any state taking a parallel rate-based approach with a plan approved by EPA. The creation of a tracking system for credits by EPA would greatly facilitate interstate coordination, and ensure that credits are not double counted towards compliance. However, such a system should not require new legislation or additional action by a public utility commission. This approach is broadly similar to an August 2014 proposal by Western Resource Advocates, describing a "carbon reduction credit" program that would allow affected EGUs to comply with state-wide emission standards by reducing their emissions using credits generated by lower-emitting EGUs, clean energy resources, and providers of verified energy efficiency savings.[276]

Both of these approaches establish enforceable emission limitations for existing EGUs based on traditional tools of air quality regulation, and should be well within the authority of state environmental protection agencies. Although complementary actions by a public utilities commission, state energy office, or other body could certainly be helpful in ensuring predictable and cost-effective implementation of the rules, a state plan adopting one of the two approaches above would not *necessitate* such action.

As discussed in section VIII, a state taking a portfolio or a state commitment approach would need to ensure that the emission reductions in the plan are federally enforceable to meet the requirements of the Clean Air Act. In the context of a portfolio approach, either the individual compliance measures would become federally enforceable (as is the case for typical control measures in the context of State Implementation Plans under Section 110 of the Clean Air Act) or plans must include a backstop mechanism that applies directly to the regulated sources that would ensure that any shortfall in emission reductions was remedied.[277] States adopting state commitment approaches would similarly require

[276] *See* Steven Michel & John Nielsen, Carbon Reduction Credit Program: A State Compliance Tool for EPA's Clean Power Plan Proposal (Western Resource Advocates Aug. 25, 2014).

[277] EPA should require states proposing to meet state goals through assigning RE and demand-side EE measures to entities other than regulated sources to include those measures in state plans as "plan elements." EPA has properly proposed "to interpret CAA section 111 as allowing state CAA section 111(d) plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources." *Id.* at 34903. Requiring that these measures be included in state plans as "other plan elements" would ensure that the state plan as a whole, including both the standards of performance applicable to EGUs and the "other plan elements" applicable to entities other than EGUs, achieves emission reductions consistent with the BSER identified in EPA's emission guidelines.

source-based backstops to ensure enforceability and that any shortfalls would be remedied. Such backstop mechanisms would be implemented through the operating permits of regulated sources. Again, in these contexts, PUCs would play their important and traditional role of evaluating companies' plans to achieve compliance with the emission standards and backstops that would be a part of these types of plans. But the traditional (and traditionally linked) roles of air regulators and PUCs would be undisturbed, and the enforceability mandated by Section 111(d) ensured.

To be sure, the Clean Power Plan will affect the planning and investment decisions made by power companies around the country. In states with regulated utilities, some of these resource planning and investment decisions will require review and approval by a public utilities commission. However, this is the norm for environmental regulations affecting the power sector and does not in any way call into question EPA's authority to require reductions in carbon pollution under the Clean Power Plan. For example, following the enactment of Title IV of the Clean Air Act in 1990, many state PUCs took action to approve compliance actions by regulated utilities, including the establishment of rules governing cost recovery for sulfur dioxide allowance transactions; integrated resource plans demonstrating capital investments or changes in generation and fuel mix that would be required to cost-effectively comply; and approval of investments in individual pollution control projects.[278] Similarly, state PUCs undertook extensive proceedings to ensure that regulated utilities comply with the Clean Air Interstate Rule and install pollution controls needed to meet National Ambient Air Quality Standards.[279] And most recently, state PUCs around the country have been actively engaging with utilities to ensure smooth implementation of the Mercury and Air Toxics Standards, Cross State Air Pollution Rule, and other

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In order to provide the requisite specificity for judicial enforcement, EPA should require RE and demand-side EE measures imposed on non-EGUs to be expressed explicitly in the approved state plan as an objective and measurable requirement related to a specific action. This is generally consistent with the standard that courts have applied when determining whether requirements contained in state implementation plans for criteria pollutants are judicially enforceable. *See, e.g., McEvoy v. IEI Barge Servs*., 622 F.3d 671, 680 (7th Cir. 2010) (state code provision in approved SIP barring all unpermitted visible fugitive particle emissions was not enforceable through citizen suit because it failed to provide an objective standard for visibility threshold triggering the prohibition); *Wilder v. Thomas*, 854 F.2d 605, 613-614 (2d Cir. 1988) (citizen suit must allege violations of "specific provisions of an applicable [state] implementation plan."); *see also Action for Rational Transit v. West Side Highway*, 699 F.2d 614, 616 (2d Cir. 1983) ("the aims and goals of the SIP are not enforceable apart from the specific measures designed to achieve them").

[278] *See* Ron Lile & Dallas Burtraw, *State-Level Policies and Regulatory Guidance for Compliance in the Early Years of the SO_2 Emission Allowance Trading Program* 13-52 (May 1998) (summarizing orders and regulations issued by PUCs in response to the Clean Air Act Amendments of 1990, as well as some instances in which states passed new legislation to ensure timely and well-coordinated compliance. Examples include the establishment of new ratemaking rules requiring utilities to pass on to ratepayers certain profits from allowance transactions, or utilize those profits for demand-side management or other programs benefiting ratepayers; integrated resource planning processes requiring utilities to identify optimal combinations of shifts in generation, pollution control investments, fuel-switching, and other strategies to reduce sulfur dioxide; and approval of cost recovery for investments in flue gas desulfurization projects).

[279] *See* M.J. Bradley & Associates, Public Utility Commission Study, EPA Contract No. EP-W-07-064 (Mar. 31, 2011) (providing detailed case studies of the Indiana Utility Regulatory Commission's response to the Clean Air Interstate Rule and the Clean Air Mercury Rule; the Georgia Public Service Commission's efforts to implement a "Multipollutant Rule" adopted by the state air quality regulators to comply with the Clean Air Interstate Rule and the ozone and particulate matter NAAQS; and the West Virginia Public Service Commission's development of innovative financing mechanisms to ensure its regulated utilities complied with CAIR and CAMR).

environmental requirements through long-term planning and ratemaking proceedings.[280] We expect that state PUCs will similarly exercise prudent review and oversight of utility resource planning and economic decisions associated with investments to comply with the Clean Power Plan while protecting the interests of ratepayers in reliable, affordable electricity.

L. The proposed rule does not conflict with the Federal Power Act

The proposed Clean Power Plan does not conflict with the Federal Power Act (FPA), as some opponents of EPA action to regulate carbon pollution have argued. The FPA vests the Federal Energy Regulatory Commission (FERC) with exclusive jurisdiction to approve "just and reasonable" rates for the transmission of electric energy in interstate commerce and for wholesale sales of electric energy.[281] However, no provision of the FPA limits the authority of EPA under the Clean Air Act to establish emission guidelines (or other emission standards or limitations) for EGUs. Nor should such a limitation be implied, as the D.C. Circuit has ruled in dismissing past claims that the FPA exempts or displaces the nation's federal environmental laws.[282] In addition, no aspect of the Clean Power Plan requires EPA or the states to interfere with rates established by FERC. EPA's emission guidelines simply establish an emissions performance target for existing EGUs within each state, which can be implemented by the states in a manner parallel to other Clean Air Act emissions standards.

EPA's proposed guidelines — once implemented by the states — may have the effect of altering the generating costs of fossil fuel EGUs, with indirect or incidental impacts on wholesale sales or transmission rates that are subject to FERC jurisdiction. This is true of most pollution limitations placed on power plants, and such effects do not present conflicts with FERC's authority under the FPA. For example, FERC has noted that sulfur dioxide allowances created under Title IV of the Clean Air Act may affect wholesale rates under the FPA, and has ruled that the costs of these emission allowances may be

[280] *See* Matthew Bandyk, *State regulators approve Minnesota Power plan for coal retrofit, retirements,* SNL Sept.25, 2013 (reporting on Minnesota PUC's approval of a plan by Minnesota Power to install emission controls needed to comply with MATS at a 585 MW power plant); Matthew Bandyk, *We Energies coal-to-gas conversion gets approval from Wis. Regulators,* SNL Feb. 3, 2014 (describing Wisconsin PUC's approval of a Wisconsin Electric Power proposal to comply with MATS by converting an existing 256 MW coal-fired power plant to natural gas); Matthew Bandyk, *Kentucky Power gets approval to convert coal unit at Big Sandy to gas,* SNL Aug. 1, 2014 (describing Kentucky PUC's approval of a plan to convert a 268 MW coal-fired power plant to gas, also for purposes of complying with MATS).

[281] Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354, 108 S. Ct. 2428, 2439, 101 L. Ed. 2d 322 (1988) (exclusive federal jurisdiction over wholesale electric rates under § 201 of the Federal Power Act, 16 U.S.C. § 824); id. at 2442 (Scalia, J., concurring in the judgment) ("if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject")

[282] *See Monongahela Power Co. v. Marsh,* 809 F.2d 41, 50 (D.C. Cir. 1987) (holding that hydroelectric facilities licensed by FERC are still subject to Clean Water Act permitting requirements, because ". . . the Power Act does not provide adequate justification for ignoring the express and unambiguous directive of the subsequently-adopted Pollution Control Act Amendments."); *cf. PUD No. 1 v. Wash. Dep't of Ecology,* 511 U.S. 700, 723 (1994) (refusing to limit applicability of Clean Water Act requirements to hydroelectric projects licensed by FERC on the basis of "hypothetical" conflicts between the Clean Water Act and FERC's authority under the FPA).

incorporated into rates approved by FERC.[283] FERC's recent Order No. 1000 also expressly recognizes that state and federal public policy requirements, such as renewable portfolio standards and emission limitations, can impact jurisdictional transmission rates — and requires that the impacts of those policies be taken into account in regional transmission planning processes.[284] And FERC has provided in individual ratemaking proceedings that utilities may allocate and recover costs associated with meeting federal and state "documented energy policy mandates or laws," such as state renewable portfolio standards.[285] Simply put, the FPA does not displace or preclude emission limitations established by EPA under the Clean Air Act – and nothing about the proposed Clean Power Plan suggests a different result would arise in this context.

Likewise, state plans submitted under the proposed Clean Power Plan can incorporate a variety of policies – including traditional rate or mass-based emission limitations, policies to promote renewable energy or energy efficiency, or integrated resource plans — which lie securely within the traditional authority reserved to the states under the FPA. Indeed, such policies have already been implemented in many states over the last several years, as EPA recognizes in the preamble to the proposed emission guidelines. There is no doubt that such policies are fully consistent with the FPA, given the high standard that the Supreme Court has articulated for preemption under the FPA and the Natural Gas Act (NGA). Specifically, the Supreme Court has held that state regulations are only preempted by these statutes if "it is impossible to comply with both state and federal law; [a] state regulation prevents attainment of FERC's goals; or [] a state regulation's impact on matters within federal control is not an incident of efforts to achieve a proper state purpose."[286] The Supreme Court has also recognized that "every state statute that has some indirect effect on rates and facilities of natural gas companies is not preempted."[287] Consistent with these principles, the lower courts have found that states retain broad authority to, among other things, regulate the type, quantity, and location of electricity generating resources within their borders.[288] FERC itself has repeatedly affirmed that "states have the authority to dictate the generation resources from which utilities may procure electric energy."[289] And, FERC's own administrative precedents have recognized that states

[283] *Edison Electric Institute,* 69 FERC ¶ 61,344 at 62,289 (1994) (holding also that sales of emission allowances that take place independent of a wholesale sale of electricity are not within FERC's jurisdiction).
[284] *See* Order No. 1000-A, ¶¶ 205-06, 336, 77 Fed. Reg. at 32,217-18, 32,236. The D.C. Circuit upheld this provision of Order No. 1000 in *South Carolina Pub. Serv. Auth. v. FERC,* No. 12-1232 (Aug. 15, 2014).
[285] *See Midwest Independent Transmission System Operator, Inc.,* 137 FERC ¶ 61,074 at P 20 (Oct. 21, 2011)
[286] *Northwest Cent. Pipeline Corp. v. State Corp. Comm'n,* 109 S.Ct. 1262, 1277 (1989). Although the holding in this case pertains to the Natural Gas Act, the federal courts typically interpret and apply the Natural Gas Act and the Federal Power Act in identical fashion. *See Ark. La. Gas Co. v. Hall,* 453 U.S. 571.
[287] *Schneidewind v. ANR Pipeline Co.,* 485 U.S. 293, 309 (1988).
[288] *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, (3d Cir. 2014) ("The states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility. Or states may elect to build no electric generation facilities at all….The states' regulatory choices accumulate into the available supply transacted through the interstate market. The Federal Power Act grants FERC exclusive control over whether interstate rates are "just and reasonable," but FERC's authority over interstate rates does not carry with it exclusive control over any and every force that influences interstate rates.") (citing *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481, 386 U.S. App. D.C. 320 (D.C. Cir. 2009)).
[289] *See California Pub. Utilities Comm'n*, 134 FERC ¶ 61044, 61160 (Jan. 20, 2011); see also, e.g., *In re Midwest Power Systems, Inc.,* 78 FERC ¶ 61,067, 61,246 (1997) ("We find that the Iowa [law] [is] consistent with federal law to the extent that [it] requires electric utilities located in Iowa to purchase from certain types of generating facilities."); *In re S. Cal. Edison Co.*, 70 FERC ¶ 61,215, 61,676 (1995) (because "resource planning and resource

retain authority to use a variety of regulatory tools, including taxes and subsidies for particular fuels or generating types, to meet their electricity needs.[290] Congress intended the FPA "to supplement, not limit, the reach of state regulation."[291]

Nothing about EPA's proposed emission guidelines - or the state plans that would be submitted pursuant to those guidelines – infringe on FERC's authority under the FPA. Like every other emission standard that EPA and the states have implemented under the Clean Air Act, the proposed emission guidelines are fully consistent with the FPA.

M. EPA's BSER Determination Does Not "Redefine" Any Sources, a Concept from a Different Clean Air Act Program Inapplicable Here

Some stakeholders have suggested that EPA's BSER determination is too aggressive because it would inappropriately "redefine" or "redesign" the regulated entities.[292] In particular, some may try to use this claim to criticize EPA's proposal in the Notice of Data Availability that the Agency consider the potential for coal-fired boilers to co-fire with or convert to natural gas in assessing emission reduction potential in each state. Such an argument would fail because (a) the CPP does not redefine or redesign any particular source, and (b) the argument depends on a concept from a different program under the Clean Air Act (CAA) that is not relevant to the system-based approach of section 111(d).

As noted above, the CPP offers states and the power sector tremendous flexibility in deciding how to reduce greenhouse gas emissions and meet the state target. The rule sets state-specific goals for emissions reductions, based on a review of measures already being implemented throughout the country, but each state will choose how to meet its goal through whatever combination of measures reflects its particular circumstances and policy objectives. So some states may choose to require natural gas co-firing at some facilities and other states may not, depending on what is most effective, technically and economically, for the sources in each state. States also have the option to put in place market-based programs providing even greater flexibility, and in such states sources might choose to implement natural gas co-firing or conversion or not, depending upon what is most cost-effective for those sources. In no

decisions are the prerogative of state commissions[,]" a state "may choose to require a utility to construct generation capacity of a preferred technology or to purchase power from the supplier of a particular type of resource").

[290] *See ISO New England and New England Power Pool,* 120 FERC ¶ 61,234 (2007) ("Nothing in the [minimum capacity] requirement prevents a state from requiring its LSEs to meet capacity requirements through demand response, or through contracts to purchase power…or through more environmentally friendly generation, or, generally speaking, through resources that meet state health or environmental or land-use planning goals…how those resources are provided is up to LSEs and the states."); *Southern California Edison,* 71 FERC ¶ 61,269 (1995) ("A state may, through state action, influence what costs are incurred by the utility . . . [as] part of a state's approach to encouraging renewable generation. For example, a state may impose a tax or other charge on all generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use that fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.q., tax credits.").

[291] Kentucky West Virginia Gas Co. v. Pennsylvania Pub. Util. Com'n, 837 F.2d 600, 606 (3rd Cir. 1988).

[292] *See, e.g.*, North American Coal Corporation, Comments on Proposed Carbon Pollution Emission Guidelines For Existing Stationary Sources: Electric Utility Generating Units, EPA-HQ-OAR-2013-0602 (June 18, 2014) at 24-25.

sense, then, does the CPP force any particular source to fundamentally alter its operations. Instead, if a state finds that a source could co-fire, that regulatory option would be available to the state, but for those sources that would have significant challenges doing so, other options remain available under the CPP.

Moreover, any industry argument about "redefining" or "redesigning" would erroneously be trying to pull into section 111(d) a concept that arises in the very different "Prevention of Significant Deterioration" (PSD) program of section 165 of the CAA. The PSD program requires, among other things, a "new" or "modified" source in certain areas of the country to obtain a preconstruction permit that specifies emission limits reflecting the "best available control technology" (BACT) for regulated pollutants.[293] BACT is determined by EPA or the state permitting authority "on a case-by-case basis" for each individual facility that triggers PSD, taking into account the "energy, environmental, and economic impacts and other costs . . . for such facility."[294]

In the past, EPA as a matter of policy has taken the position that when determining BACT for any particular applicant, the agency will not require the source to fundamentally alter its design as a means of reducing emissions.[295] The policy stems from a concern that it might be disruptive for the facility seeking a permit if EPA were to second-guess some of the operator's fundamental choices.

There is nothing in the statute that compels that policy against "redesigning" or "redefining" a source (the two terms are often used interchangeably). Instead, as the Environmental Appeals Board (EAB) noted, "the policy is really an agency interpretation of ambiguous statutory provisions."[296] Likewise, in the key federal judicial decision on this issue, the court cited no CAA provisions directly on point when agreeing with EPA that it could choose not to redefine a source in the facility-specific BACT determination.[297] In fact, because the policy is not compelled by the statute, historically EPA has allowed state permitting authorities to take a different approach in their BACT determinations than set out in the policy, taking the position that "this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire."[298] Accordingly, EPA has explained that the BACT analysis for a coal-fired EGU does not always need to consider natural gas firing under its redefining-the-source policy,

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[293] 42 U.S.C. § 7475(a)(1) (regulating "major emitting facility on which construction is commenced after August 7, 1977"); id. § 7479(a)(1) and (2)(C) (defining "major emitting facility" and "construction" to include modifications).
[294] Id. § 7479(3).
[295] *In re Pennsauken Cnty., N.J. Resource Recovery Facility*, 1988 EPA App. LEXIS 27, 13-14 (EPA App. 1988) (in a challenge to a permit issued under federal PSD permitting regulations, the Administrator of EPA held that "the conditions themselves [of such a PSD permit] are not intended to redefine the source").
[296] In re City of Palmdale (Palmdale Hybrid Power Project), PSD Appeal No. 11-07, 2012 EPA App. LEXIS 29, at *75 n.25 (EAB Sept. 17, 2012) (citations and internal quotation marks omitted). *See also* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) at 27 ("EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire.").
[297] *Sierra Club v. EPA*, 499 F.3d 653, 654-55 (7th Cir. 2007) Sierra Club v. U.S. EPA, 499 F.3d 653, 655 (7th Cir. 2007) (noting that the policy is a refinement of "the statutory definition of 'control technology'" and "the kind of judgment by an administrative agency [of ambiguous statutory terms] to which a reviewing court should defer.").
[298] EPA Guidance on PSD and Nonattainment Area Permitting at B.13-B.14 (Draft, 1990).

but states retain discretion to consider changes in primary fuel type in Step 1 of the BACT analysis.[299] And because it is always appropriate to consider changes that do not "disrupt[] the applicant's basic business purpose for the proposed facility," states may often analyze fuel-switching in an economic environment where both coal- and natural gas-fired units can serve the fundamental business purposes of providing base-load and peaking power.[300]

Even if that limited approach makes sense in the context of the highly fact-specific, facility-by-facility inquiry of BACT, any limit on "redesigning" a source is not relevant to the system-wide determination of BSER under section 111(d) that looks at the potential for emission reduction at regulated sources given the unified nature of the electric grid. The PSD program and the section 111(d) program are substantially different, making any analogies between the two with respect to the redefining the source policy inappropriate. BACT is a case-by-case inquiry in which it may be appropriate to be concerned about "redefining the source" since, with only one project at issue, it might be disruptive if EPA were to push for substantial alterations to the project.

In contrast, an emission guideline under section 111(d) governs a source category on a nationwide basis. Such nationwide standards are designed to level the playing field throughout the regulated industrial sector, and as a result some facilities might be required to make fairly extensive changes to bring their operations up to par with other members of the source category.[301] Thus, the notion of not "redefining a source" is less relevant to nationwide standards for entire source categories, and those standards may sometimes be more intrusive for a particular facility than the BACT inquiry which specifically takes into account technical and economic feasibility for each individual facility seeking a PSD permit. In fact, though, the reality here is that the nationwide, system-based approach of the CPP actually offers considerably *more* flexibility to individual sources than a facility-only inquiry might allow, because, as noted above, the states have significant discretion to choose how to regulate sources within their state to meet the state-specific emissions goals, and state plans can provide sources with flexible compliance options to meet their standards.

In addition, the statutory language on BACT is distinctly different from the statutory language on BSER. The definition of BACT includes the term "system" within a much longer list of other possible descriptions of the scope of the BACT inquiry ("production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques"), and EPA has chosen to interpret its authority under that provision to preclude redefining the

[299] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 27-28; *see also id.* at 27, n.76 (noting that the Environmental Appeals Board has found consideration of repowering reasonable for a coal-fired unit that was equipped to burn natural gas).
[300] *See id.* at 26-27.
[301] Indeed, under some nationwide standards under the Clean Air Act and Clean Water Act, Congress contemplated that some members of the regulated category might not be able to survive. *See, e.g.*, 91 Cong. Senate Debates 1970, debating Conference Report on H.R. 17255 (Dec. 18, 1970), reprinted in CAA70 Leg. Hist. 13 at 42383 (exhibit introduced by S. Muskie summarizing provisions of the conference report by explaining that regulations promulgated under section 112 of the Clean Air Act "could mean, effectively, that a plant would be required to close because of the absence of control techniques."); S. Rep. 91-1196 (explaining that under the proposed national standards for hazardous air pollutants "[s]ome facilities will need altered operating procedures or a change of fuels. Some facilities may be closed.").

source. By contrast, section 111(a)(1) simply calls for standards of performance to be based on the best "system" of emission reduction, and there is no list of possible pollution reduction mechanisms that corresponds to BSER. In fact, BSER is not further defined by the statute. Hence, EPA is within its discretion here – in light of the different statutory text, structure, practical and policy considerations between the two programs – to interpret the scope of the BSER inquiry to be broader than the BACT inquiry.

To be sure, the statute provides that a BACT standard should not be less stringent (allowing greater emissions) than "any applicable standard established pursuant to section 7411 or 7412 of this title".[302] This provision is sometimes referred to as the "BACT floor", as the section 111 standards serve as a "floor" for the BACT limit. Opponents of the CPP proposal may try to suggest that this means that if EPA has chosen not to "redefine the source" for BACT, it also should not do so in the section 111(d) standards. That argument, however, would reverse the normal order of operations under the CAA. Section 111 initially requires EPA to identify pollution that endangers public health and welfare, to promulgate standards of performance for categories that it finds contribute significantly to that pollution with one year of its finding, and to revise those standards every eight years thereafter.[303] The purpose of the PSD program—and BACT more specifically—is to build upon those standards in the interval, as innovative technologies become available and are deemed ready for use on a case-by-case basis.[304] It would be perverse for a narrow policy interpretation of BACT to influence EPA's BSER determination, when the latter determination periodically is supposed to elevate the BACT floor, and when there is a reasonable basis, as here, for taking a different policy approach given the different goals and scope of the two programs.

Finally, evidence that the BSER determination is not limited by any notion of "redefining the source" is found in the regulations implementing section 111(d). 40 C.F.R. Pt. 60, Subpt. B (40 C.F.R. §§ 60.20-60.31). Nowhere do those regulations prohibit EPA, when establishing emission guidelines for the states to implement BSER, from considering alterations of the operations of the regulated facilities. At most, in section 60.24(f), EPA's regulations allow states to grant variances from the emission guidelines to account for differences in "basic process design" (an undefined phrase), but not always – only if the differences in basic process design make compliance with the emission guidelines "unreasonable". 40 C.F.R. § 60.24(f)(1).

In sum, EPA's Notice of Data Availability, which contemplates considering the potential for coal-fired boilers to co-fire with or convert to natural gas in assessing emission reduction potential in each state, is entirely consistent with EPA's authority under section 111(d) and does not run afoul of any concern about

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[302] 42 U.S.C. § 7479(3).
[303] *See id.* § 7411(b)(1)(A), 7411(b)(1)(B).
[304] *See, e.g.*, S. Rep. 95-127 (1977) at 18 ("This procedure to prevent significant deterioration requires a case-by-case determination by the States of best available control technology for any new major emitting facility that will be built in a clean-air region. Thus, each State is free to -- and encouraged to -- examine and impose requirements for the use of the latest technological developments as a requirement in granting the permit. This approach should lead to rapid adoption of improvements in technology as new sources are built, not the stagnation that occurs when everyone works against a single national standard for new sources.").

"redefining" sources, as that concept from the PSD program is inapplicable in the CPP's flexible, nationwide emission guidelines for a broad category of sources.[305]

N. Section 111(d) requires action on greenhouse gas emissions from EGUs, regardless of whether EGUs are subject to Hazardous Air Pollutant ("HAP") regulations.

Section 111(d)(1) sets out a mandatory command that EPA "shall" prescribe regulations providing for state plans for "any air pollutant" that is not in three enumerated categories. 42 U.S.C. § 7411(d)(1). The first two of these excluded categories of pollutants consist of criteria pollutants. *See id.* § 7411(d)(1)(i) (requiring regulation of pollutants "for which air quality criteria have not been listed or which is not included upon a list published under section 108(a)"). Because CO_2 is not a criteria pollutant, it is undisputed that this exclusion does not apply here.

The final category of pollutants excluded from the mandatory duty to promulgate section 111(d) regulations is defined by reference to section 112 of the Act. In the 1990 Clean Air Act Amendments, Congress enacted, and the President signed into law, two provisions containing different language effectuating this cross-reference. Each struck some of the same language in the preexisting section 111(d) (which was itself a reference to a specific provision in section 112 that was eliminated in the 1990 amendments). The two provisions—one originating in the House and one in the Senate—did not refer to one another.

The two 1990 cross-references have been the source of debate concerning the proper scope of regulation under sections 111(d) and 112. In litigation seeking to block the instant rulemaking and prohibit regulation of CO_2 emissions from existing sources, some parties have argued that the amendments must be read to deny EPA the authority to promulgate section 111(d) guidelines for CO_2 emissions from power plants, given that EGUs are listed and regulated under section 112(b).[306]

Contrary to these claims, EPA's authority and obligation to proceed under section 111(d) with respect to power plants is clear. Despite the unusual circumstance of two separate and simultaneously enacted changes to the same statutory text, nothing in the 1990 amendments can be fairly read to call into question EPA's authority to promulgate emissions guidelines for CO_2 emissions from EGUs.

Whatever uncertainties and interpretive challenges the two differing 1990 amendments may pose, it would not even be reasonable—let alone *mandatory* —to read either amendment, or both together, to

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[305] As shown above [cross-reference], reduced utilization of high-emitting sources is a well-established regulatory tool that EPA rightly should consider in its BSER determination. Nevertheless, opponents of the CPP may try to suggest that such curtailments in operations inappropriately "redefine" the regulated entities. To the extent such an inaccurate claim is made about curtailments (or any other aspect of the CPP), the responses would be similar to those presented here on cofiring: The CPP does not redefine any particular source, and in any event the limit on "redefining" sources from the PSD program is not relevant to the system-based approach of section 111(d).
[306] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341); Brief of Amici Curiae West Virginia, et al., 2, *Murray Energy Corp. v. EPA*, No. 14-1112 (D.C. Cir. June 25, 2014) (Doc. 1499435).

preclude regulation of pollutants such as CO_2, that are *neither* listed under section 112(b) *nor* actually regulated under that provision as to any source category.

While the 1990 House and the Senate amendments differ in wording, and arguably to some extent in legal effect, they are similar in that both were intended to provide an updated cross-reference to newly amended section 112 and that Congress, in each amendment, wanted to make sure that section 111(d) guidelines would not be redundant with amended section 112. But there is absolutely no sign that Congress intended to place large categories of harmful pollution beyond the scope of any Clean Air Act regulation, as the litigants and other commenters' theories would posit. Congress surely did not want to prohibit regulation under section 111(d) of pollution that is not regulated under section 112, *i.e.*, emissions of dangerous non-HAP pollutants such as CO_2.

Under no *reasonable* reading of section 111(d) as amended in 1990 can EPA's authority to address non-HAP emissions from existing sources be doubted. The agency need not resolve in this rulemaking every conceivable issue that may arise from the peculiar interpretive issues presented by the dual 1990 amendments; it need not decide here, for example, whether and when HAPs from source categories that are not regulated under section 112 may be regulated under section 111(d). But EPA should clarify here, in the strongest terms, that the text, structure, legislative history, and policy logic of the Clean Air Act all confirm that the dangerous but non-"hazardous" emissions from a category of existing sources are not otherwise immunized from such regulation merely because *other* pollutants emitted by those sources are either listed or regulated under section 112(b).

1. **In CAA sections 110, 111(d), and 112, Congress established a comprehensive framework for controlling pollution from existing sources, in which each section addressed a separate class of pollutants.**

Since Congress first enacted the Clean Air Act in 1970, sections 110, 111(d) and 112 have fit together to ensure that *all* air pollution from existing sources is adequately controlled. Congress crafted these sections to focus on different pollution, forming an interlinked and complementary structure. Section 110 establishes a process for controlling pollutants that are subject to ambient air-quality standards. EPA determines the air-quality standards that will be sufficient to protect human health and the environment, while states are responsible for devising plans that ensure the air-quality standards are met. Because these "criteria pollutants" are emitted by a variety of sources and public health can usually be protected by limiting aggregate emissions in a particular area, states have significant discretion in setting standards under section 110.

Section 112 requires controls on emissions of hazardous air pollutants. In the Clean Air Act of 1970, Congress defined a "hazardous air pollutant" as a pollutant that is not subject to air-quality standards and that "may cause, or contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness."[307] The Act originally required EPA to publish a list of hazardous air pollutants and establish standards that "provide[] an ample margin of safety to protect the public health

[307] Clean Air Amendments of 1970, Pub. Law 91-604, § 112(a)(1), 84 Stat. 1676, 1685 (1970).

from such hazardous air pollutant[s],"[308] but EPA failed to carry out this mandate. Frustrated by EPA's inaction, Congress overhauled section 112 in 1990 by establishing its own list of nearly 200 hazardous air pollutants and requiring EPA to set stringent technology-based standards for all major sources and many non-major ("area") sources of hazardous air pollutants, as discussed below.

Section 111(d) requires controls for source categories that "cause[] or contribute[] significantly to" air pollution which "may reasonably be anticipated to endanger public health or welfare," if the pollution is not regulated under either section 110 or 112. Thus, section 111(d) functions as a backstop for sections 110 and 112, preventing dangerous existing-source pollution from being left unregulated.

Congress' systematic approach allows these sections to sections to form an orderly framework. Sections 110 and 112 focus on specific classes of pollutants and section 111(d) acts as a gap-filler, addressing dangerous pollution not regulated under the sections tailored to address hazardous and ambient air pollution problems. The legislative history of the 1970 Clean Air Act confirms that this complementary framework was deliberate:

> It should be noted that emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [the precursor to section 112]) could be established under section 114 [the precursor to section 111(d)]. Thus there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.[309]

2. The 1990 Clean Air Act amendments strengthened section 112's hazardous air pollution program while maintaining the basic relationship among the Act's stationary source provisions.

In 1990, Congress responded to the fact that few sources of hazardous air pollutants had been addressed under section 112 by revising section 112 in a manner that forced EPA to regulate multitudinous source categories.[310] Specifically, Congress amended section 112 to list nearly 200 toxic air pollutants and

[308] *Id.* § 112(b)(1)(A)-(B).
[309] Sen. Rep. No. 91-1196, at 20 (1970).
[310] The legislative history emphasizes Congress' goal of ensuring that EPA would promulgate stringent regulations for hazardous air pollutants. For instance, during the debate on the conference bill, Senator Cohen expressed his support for the amendments by stating:

> One of the most health-threatening forms of air pollution comes in the form of toxic air emissions from a wide variety of sources. Some emissions occur on an everyday basis, while some are a result of accidents that often have drastic consequences. The EPA has done a woefully inadequate job of establishing emissions standards for the hundreds of toxic pollutants that exist. In 18 years, the agency has regulated only some sources of seven chemical pollutants. Several hundred chemicals remain unregulated, to the detriment of human health. The bill requires the EPA to set standards for approximately 200 hazardous air pollutants, and then define sources of those pollutants for the purpose of implementing the standards. All sources must install the strongest technology available. After this occurs, the EPA must then review emission levels to determine whether a significant health risk continues to exist despite the application of the best technology. If that health risk does exist, the source must achieve further reductions so that the risk to human health is reduced. This new air toxics control program

require EPA to regulate all major sources of these hazardous air pollutants.[311] In addition, Congress required EPA to regulate many area sources of hazardous air pollutants (those "representing 90 percent of the area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas").[312] Congress understood that dozens of source categories would be subject to regulation under section 112, as confirmed by section 112's implementation schedule.[313] Congress successfully catalyzed EPA action. EPA has promulgated hazardous air pollutant regulations for nearly 200 source categories and subcategories.[314] The source categories regulated under section 112 include all of the most significant sources of this nation's dangerous air pollution.

At the same time, Congress took pains to ensure that its strengthening of section 112 would not inadvertently impair any of the Clean Air Act's other vital protections. Congress explicitly provided in section 112 that "No emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section [111] of this title, part C or D of this subchapter, or other authority of this chapter or a standard issued under State authority."[315] Consequently, EPA retains its obligation to—for example—regulate non-HAPs as well as HAPs from new stationary sources under section 111(b), regardless of whether those sources are also regulated under section 112. Similarly, states and EPA are required to ensure that state implementation plans under section 110 achieve attainment with National Ambient Air Quality Standards for criteria pollutants, even if those plans include requirements for existing sources that are also subject to section 112 standards. Congress unambiguously intended for the requirements of section 110, 111 and 112 to continue operating in careful coordination to protect the public from all harmful pollutants emitted by stationary sources.

In the 1990 amendments, Congress also carved out one categorical exception from the seamless threefold framework for controlling stationary source emissions. By enacting section 129, Congress crafted a unique regime for one type of source: solid waste incineration units. Congress decided to exclude these units from regulation under section 112 and instead subject them to tailored regulation under sections 129 and 111.[316] Thus, in the only case where Congress excluded a class of sources from regulation under sections 110, 111(d), or 112 because other CAA controls were sufficient, it provided for rigorous, source

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> is a very significant step forward in the effort to control air pollution. I believe it will result in significant improvements in the protection of human health from cancer risks and other threats.

Senate Debate on the Clean Air Act Amendments of 1990 Conference Report (Oct. 26, 1990), *reprinted in* U.S. Senate Comm. on Envt. & Pub. Works, Legislative History of the Clean Air Act Amendments of 1990, at 1105 (1993) (herinafter 1990 CAA Leg. Hist).

[311] 42 U.S.C. §§ 7412(b)(1), (d)(1).

[312] *Id.* §§ 7412(d)(1), (c)(3).

[313] *Id.* § 7412(e)(1). Congress required EPA to regulate at least 40 source categories and subcategories within two years of the 1990 amendments, and at least 25% of the source categories listed for regulation within four years. This indicates an assumption that the first 40 source categories regulated would be less than a quarter of the total number of regulated source categories (*i.e.*, that EPA would regulate no less than 160 source categories).

[314] EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP), http://www.epa.gov/ttn/atw/mactfnlalph.html.

[315] 42 U.S.C. § 7412(d)(7).

[316] Clean Air Act Amendments, Pub. L. 101-549, § 305, 104 Stat. 2399, 2583 (1990) (codified at 42 U.S.C. § 7429(h)(2)).

category-specific regulation elsewhere in the CAA.

The treatment of EGUs is entirely different. Congress authorized regulation of EGUs under section 112 if EPA "finds such regulation is appropriate and necessary after considering the results of" a study of the health risks of EGU HAP emissions after the implementation of other CAA requirements. 42 U.S.C. § 7411(n)(1)(A). Congress did not remove EGUs from the tripartite framework for stationary source regulation, but allowed EPA to forego regulation of EGU HAP emissions if incidental control of HAPs through other CAA programs (such as the CAA cap-and-trade program to reduce acid rain, which only affects EGUs) rendered that regulation unnecessary. In deciding whether to regulate EGUs' HAP emissions, EPA was required to consider its study of the public health impacts of those HAP emissions;[317] Congress did not require this study to analyze the public health impacts of non-HAP pollution from EGUs because the Act does not force EPA to choose between regulating non-HAP emissions from EGUs under 111(d) or regulating HAP emissions under 112.

The 1990 Clean Air Act Amendments also revised the Act to more effectively protect human health and the environment in several other important ways. For instance, Congress amended section 110 to authorize EPA to require SIP revisions that are necessary to adequately mitigate interstate pollution transport,[318] and authorized EPA to apply certain sanctions if a state submits an inadequate SIP.[319] The legislation introduced new landmark programs and strengthened existing programs, prompting President George H.W. Bush to declare: "This legislation isn't just the centerpiece of our environmental agenda. It is simply the most significant air pollution legislation in our nation's history, and it restores America's place as the global leader in environmental protection."[320]

3. In 1990, Congress enacted two amendments to section 111(d) that maintained the provision's historic role in preventing dangerous pollution from existing industrial sources from going uncontrolled.

a. The 1990 Clean Air Act Amendments contained two different amendments providing for changes to the same statutory language in section 111(d)(1).

Prior to 1990, section 111(d) clearly mandated action to control dangerous air pollutants from existing sources if those emissions were not already regulated under section 108 or section 112, for source categories regulated under section 111(b):

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[317] 42 U.S.C. § 7412(n)(1)(A). Section 112(n) mandates three studies: EPA's study of the hazards EGU HAP emissions pose to public health after the imposition of other Clean Air Act requirements, which the agency must consider in its "appropriate and necessary" finding, § 7412(n)(1)(A); an EPA study of EGU mercury emissions and technologies for controlling such emissions, § 7412(n)(1)(B); and a National Institute of Environmental Health Sciences study on the threshold level of mercury exposure below which adverse human health effects are not expected, § 7412(n)(1)(C). None of these studies non-HAP emissions.

[318] *Id.*, § 101, 104 Stat. at 2407 (codified at 42 U.S.C. § 7410(k)(5)).

[319] *Id.*, § 101, 104 Stat. at 2407-08 (codified at 42 U.S.C. § 7410(m)).

[320] Remarks of President George H.W. Bush Upon Signing S. 1630, 26 Weekly Comp. Pres. Doc. 1824 (Nov. 19, 1990) (reprinting the President's signing statement of Nov. 15, 1990).

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[321]

In 1990, Congress enacted two amendments to section 111(d)(1)(A)(i) addressing the same issue—when regulation under section 112 would supplant regulation under section 111(d). Some amendment to section 111(d) was necessary because the 1990 amendments deleted section 112(b)(1)(A), which was the subsection of section 112 that section 111(d) had cross-referenced since 1970. Bills originating in each chamber amended section 111(d)'s cross-reference to section 112(b)(1)(A) in different ways, and Congress ultimately enacted, and the President signed, a conference bill containing both amendments.

The amendment originating in the House revised section 111(d)(1)(A)(i) by striking the words "or 112(b)(1)(A)" and inserting in their place the following phrase: "or emitted from a source category which is regulated under section 112."[322] Congress also enacted an amendment originating in the Senate that revised the same subsection by striking the reference to "112(b)(1)(A)" and inserting in its place "112(b)."[323] The House amendment is located in section 108 of the Statutes at Large (under "Miscellaneous Guidance"); the Senate amendment is found in section 302 (under "Conforming Amendments"). The text and structure of the Act in the Statutes at Large (104 Stat. 2399) are the same as in the public law passed by both chambers and signed by President George H.W. Bush (101 P.L. 549).

The Office of the Law Revision Counsel[324] codified only the House amendment in the United States

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[321] 42 U.S.C. § 7411(d)(1) (West 1977).
[322] Pub. L. 101-549, § 108, 104 Stat. at 2467.
[323] *Id.*, § 302, 104 Stat. at 2574.
[324] Some commentators have suggested that codification decisions of the House Office of the Law Revision Counsel are entitled to some form of deference. However, the Office is not the expert agency charged with administering the CAA, and therefore not entitled to *Chevron* deference regarding the interpretation of that statute. *Chevron*, 467 U.S. at 844 ("We have long recognized that considerable weight should be accorded to an executive department's construction of a statutory scheme it is entrusted to administer, and the principle of deference to administrative interpretations has been consistently followed by this Court whenever decision as to the meaning or reach of a statute has involved reconciling conflicting policies, and a full understanding of the force of the statutory policy in the given situation has depended upon more than ordinary knowledge respecting the matters subjected to agency regulations.") (footnote and quotation omitted).

Accordingly, the Office does not even purport to interpret or amend the law in the codification process: "The translations and editorial changes made to sections of non-positive law titles are purely technical and do not change the meaning of the law." Office of the Law Revision Counsel, Detailed Guide to the United States Code Content and Features, *available at* http://uscode.house.gov/detailed_guide.xhtml. Even where there are plain errors in grammar, punctuation, or spelling, the Office does not correct them in the text of the code, but merely inserts a footnote indicating the probable error. *Id.*

The Office of the Law Revision Counsel could not purport to determine the text of section 111(d) without running afoul of the Supreme Court's jurisprudence on the separation of powers. Expunging the text of the Senate amendment from section 111(d) is a legislative act that can only be accomplished through the legislative process. *See INS v. Chadha*, 462 U.S. 919, 952-54 (1983) ("Amendment and repeal of statutes . . . must conform with [the

Code, 42 U.S.C. § 7411(d)(1)(A)(i). The codifier's notes to this section state that the Senate amendment ''could not be executed.'' Regardless, the Statutes at Large—not the United States Code—controls here. The Statutes at Large constitute the legal evidence of the laws for code titles that have not been enacted into positive law.[325] Because Title 42 of the United States Code has not been enacted into positive law,[326] the legal evidence of the relevant law is the statutes at large, which contains both amendments.[327]

b. The Senate amendment clearly requires 111(d) regulation of CO_2 from EGUs.

The Senate amendment is clear and consistent with the historic role of section 111(d) as a "backstop" to ensure protection of public health from existing-source emissions not regulated under section 112 or section 110. Read with the rest of section 111(d), the Senate amendment continues the longstanding policy of covering all non-HAP, non-criteria pollutants under section 111(d). The amendment was necessary to conform to the conference committee's amendments to section 112(b). Previously, section 112(b)(1)(A) required EPA to publish a list of HAPs it intended to regulate under section 112. The 1990 amendments removed subsection 112(b)(1)(A) entirely. The new section 112(b)(1) establishes an initial list of over 180 HAPs and section 112(b)(2)-(3) gives EPA authority to both add new HAPs to the list and to de-list certain HAPs. The Senate amendment simply updated EPA's section 111(d) authority to reflect the amended list of HAPs regulated under section 112.

While some have argued that EPA should disregard the text of the Senate amendment because its status as a "conforming amendment" renders it a poor indication of congressional intent and a likely scrivener's error, the Senate amendment cannot be disregarded. The D.C. Circuit has looked to conforming amendments in other statutes and given full effect to "the plain meaning of the statutory language in which Congress has directly expressed its intentions." *Washington Hospital Center v. Bowen*, 795 F.2d 139, 149 (D.C. Cir. 1986); *see also CBS v. FCC*, 453 U.S. 367, 381 ("Perhaps the most telling evidence of congressional intent, however, is the contemporaneous [conforming] amendment"). Further, the Senate amendment does not resemble a scrivener's error at all. A scrivener's error is "a mistake made by someone unfamiliar with the law's object and design," *United States Nat'l Bank v. Independent Ins. Agents of Am.*, 508 U.S. 439, 462 (1993), and produces language with "no plausible interpretation," *Williams Cos. v. FERC*, 345 F.3d 910, 913 n.1 (D.C. Cir. 2003). The Senate amendment is plainly not a scrivener's error. In keeping with the same protective statutory structure that Congress first crafted in the 1970 Clean Air Act, the Senate amendment has the entirely coherent purpose and effect of updating the section 111(d) cross-reference in light of amendments to section 112 that rendered the previous cross-reference meaningless by deleting previous subparagraph 112(b)(1)(A). Furthermore, because the text of the Senate amendment is unambiguous, EPA "can remain agnostic on the question whether Congress intentionally left [that] particular language in [the] statute or simply forgot to take it out. The suggestion that Congress may have 'dropped a stitch,' is not enough to permit [EPA] to ignore the statutory text."

bicameralism and presentment requirements of] Art. I.") "Congress must abide by its delegation of authority until that delegation is legislatively altered or revoked." *Id.* at 955.

[325] 1 U.S.C. §§ 112, 204(a); *U.S. Nat. Bank of Oregon v. Indep. Ins. Agents of Am., Inc.*, 508 U.S. 439, 448 (1993); *United States* v. *Welden,* 377 U.S. 95, 98 n.4 (1964). *Stephan v. United States*, 319 U.S. 423, 426, (1943).

[326] *See* Office of Law Revision Counsel, United States Code, listing titles that have been enacted into positive law with an asterisk, http://uscode.house.gov/browse.xhtml.

[327] *See, supra*, note 325; Clean Air Act Amendments, 104 Stat. 2399, 2467, 2474 (1990).

See United States ex rel. Totten v. Bombardier Corp., 380 F.3d 488, 496 (D.C. Cir. 2004) (quotations and citation omitted).[328] There is no exception here to the rule requiring EPA "to give effect, if possible, to every word Congress used." *See Reiter v. Sonotone Corp.*, 442 U.S. 330, 339 (1979).

c. The House amendment is most reasonably read to require regulation of CO_2 emissions from EGUs.

In contrast to the Senate amendment, the House amendment is subject to multiple interpretations. The ambiguous House amendment would require EPA's expert interpretation even if Congress had not also amended identical language in section 111(d) through the Senate amendment. *See Chevron, U.S.C., Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 843 (1984). Because the Senate amendment unambiguously commands regulation of non-HAP pollutants such as CO_2, and because the House amendment is reasonably interpreted (even without reference to the Senate Amendment) to permit such regulation, EPA plainly has authority to regulate CO_2 emissions under section 111(d), and the agency need not resolve here whether there are scenarios in which some pollutant or source might be regulable under one amendment but not the other, and how to resolve that problem.

i. The House amendment provides for regulation of emissions that are not controlled under the hazardous air pollution program.

The House amendment is subject to multiple readings that would require regulation of CO_2 from sources like EGUs. As changed by the House Amendment, section 111(d) requires EPA to prescribe existing source regulations "for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or emitted from a source category which is regulated under section 112 of this title." (emphasis added). The most reasonable interpretation of the House amendment is to construe it to not authorize regulation under 111(d) as to particular pollutants that are actually regulated under Section 112(n) as to the source category in question. On this interpretation, Congress intended to safeguard section 111(d)'s gap-filling role by expanding the scope of the section to cover HAP emissions that would otherwise be unregulated under sections 112 or section 111(d).

Readings of the House amendment offered by parties seeking to block regulation of CO_2 under Section 111(d) have asserted that the provision necessarily bars regulation of any and all pollutants emitted by any source that is regulated under Section 112, even if it the specific *pollutant* in question is not a HAP and is therefore not regulated under 112.[329]

[328] *See also Owner-Operator Indep. Drivers Ass'n v. Landstar Sys.*, 622 F.3d 1307, 1327 (11th Cir. 2010) ("There is no reason for this Court to rewrite a statute because of an alleged scrivener error unless a literal interpretation would lead to an absurd result."); *Lewis v. Alexander*, 685 F.3d 325, 351-51 (3d Cir. 2012) (regardless of whether statutory text was the result of a drafting error, it was not a mere scrivener's error fit for judicial correction because Congress could have rationally chosen to enact the text at issue); *Nijjar v. Holder*, 689 F.3d 1077, 1084 (9th Cir. 2012) (same).

[329] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341); Brief of Amici Curiae West Virginia, et al., 2, *Murray Energy Corp. v. EPA*, No. 14-1112 (D.C. Cir. June 25, 2014) (Doc. 1499435).

But the text of section 112 is readily susceptible to reasonable interpretations under which the section 112-related exclusion from section 111(d) regulation is pollutant-specific. EPA may interpret the House amendment by resolving ambiguity in the phrase "emitted from a source category *which is regulated under section 112*." A source category is "regulated" under section 112 not in the abstract, but with respect to particular pollutants. The term "regulated" can therefore be read to mean "regulated with respect to that pollutant under section 112," rather than "regulated as to any pollutant under section 112."

In other words, the House text could reasonably be understood to mean either (1) that EPA may not use section 111(d) when the source category is "regulated under section 112 for *the pollutant in question,*" *i.e.,* the same pollutant that is the candidate for regulation under section 111(d), or (2) that EPA may not use section 111(d) when the source category is "regulated under section 112 for *any* pollutant." The former is a sensible interpretation of the ambiguous term "regulated," and one that fits with a context that includes pollutant-specific phrasing of section 111(d) and a reference to a statutory provision, section 112, that "regulates" only hazardous pollutants. While the latter interpretation is plausible as a matter of ordinary understanding, it is not inevitable—and, as explained below, its practical consequences are starkly discordant with the statutory structure and purpose. Furthermore, it is common and proper under the Clean Air Act to construe potentially broad statutory language in light of the context in which the language appears, in order to produce a result that fits with the purpose and mechanics of the particular program in question. *See Utility Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2440 (2014) ("*UARG*") (citing numerous instances in which EPA has narrowed term "any air pollutant" to fit with context). A pollutant-specific reading of the Section 111(d) exclusion is easily permissible given the context here.

The House language may also be read to authorize EPA to regulate any air pollutant which is not a criteria pollutant and "any air pollutant [which is regulated under section 112] . . . which is not . . . emitted from a source category which is regulated under section 112." Under *Young v. Community Nutrition Institute*, an agency has discretion under *Chevron* to determine which terms are the object of a dangling modifier. 476 U.S. 974, 891 (1986) (granting *Chevron* deference to FDA's interpretation concerning which term was modified by a dangling participle in the Federal Food, Drug, and Cosmetic Act, even though a contrary "reading of the statute may seem to some to be the more natural interpretation"). Here, EPA can effectuate legislative intent by reading "which is regulated under section 112" to modify both "any air pollutant" and "source category."

Alternatively, the language "any air pollutant . . . emitted from a source category which is regulated under section 112" could be read to refer to hazardous air pollutants. This reading derives from the statutory context, in which hazardous air pollutants are the only pollutants regulated under section 112. As noted above, the Supreme Court has recently emphasized that the broad term "any air pollutant" as used in the Clean Air Act can take meaning from the context in which it is used. *See UARG*, 134 S. Ct. at 2440 (citing instances in which EPA has narrowed term "any air pollutant" to fit with context, such as EPA's having construed various provisions of section 111 that reference "any air pollutant" as limited to pollutants "*for which EPA has promulgated new source performance standards*"). Here, it is logical to understand Congress to have wanted to preclude section 111(d) regulation based on section 112 regulation only as to pollutants that are actually (or at least potentially) regulated under section 112. Moreover, under this interpretation, the House amendment would have essentially the same meaning as the Senate amendment and continue Congress' longstanding policy of using section 111(d) to control dangerous pollution that is not controlled under the criteria pollution provisions or section 112.

ii. The legislative history of the House amendment supports a narrow reading of the section 111(d) exclusion.

Reading the House version of the section 111(d) exclusion in a pollutant-specific way is not only consistent with the language of the statute, but also promotes the purpose that EPA has reasonably attributed to the House amendment, namely, "expand[ing] EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112,"[330]—thereby protecting against a regulatory gap that would provide no controls against HAP emissions from certain sources not regulated under section 112.

The version of the 1990 Clean Air Act Amendments that initially passed the House clarifies the purpose of the House amendment to section 111(d). As EPA has explained, the House amendment first passed the House in a bill that included several new opportunities for EPA to exercise discretion in whether to regulate HAP emissions under section 112.[331] That bill would have provided EPA significant additional discretion regarding when to promulgate regulations under section 112. Perhaps most importantly, the House bill would have allowed EPA to decline to regulate source categories under section 112 if EPA determined they were "already adequately controlled under this Act or any other Federal statute or regulation."[332] Furthermore, the House bill would have made regulation of non-major sources under section 112 entirely discretionary.[333] In this context, EPA reasonably noted the likelihood that "the House did not want to preclude EPA from regulating under section 111(d) those pollutants emitted from source categories which were not actually being regulated under section 112."[334] Even under the conference bill that became law, the prospect of certain HAP emissions not being regulated under section 112 may have motivated the expansion of section 111(d) to cover certain dangerous HAP emissions that might otherwise escape regulation, and that would not have been subject to section 111(d) standards as it was framed prior to 1990.[335]

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[330] Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, 70 Fed. Reg. 1594, 16031 (Mar. 29, 2005).
[331] *Id.*
[332] HR 3030, § 301, reprinted in 1990 CAA Leg. Hist. 3737 at 3933.
[333] "The Administrator may designate a category or subcategory of area sources that he finds, based on actual or estimated agregate [sic] emissions of a listed pollutant or pollutants in an area, warrants regulation under this section." *Id.*, 1990 CAA Leg. Hist. 3737 at 3933. In contrast, the conference bill required EPA to regulate certain "area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas." Pub. L. 101-549, § 301, 104 Stat. at 2537 (codified at 42 U.S.C. § 7412(c)(3).
[334] 70 Fed. Reg. at 16031.
[335] Section 112 does not mandate controls for all source categories that emit HAPs. For instance, section 112 does not provide for the regulation of HAPs from oil and gas wells outside of certain metropolitan areas, unless those sources meet the statutory definition for "major sources." 42 U.S.C. § 7412(n)(4)(B). Also, section 112 requires EPA to regulate non-major sources "representing 90 percent of the [non-major] source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas," but otherwise only provides for regulation of non-major sources of HAPs if EPA determines they "present[] a threat of adverse effects to human health or the environment (by such sources individually or in the aggregate) warranting

The purpose of the House amendment is further illuminated by its context in the House bill *as introduced*. The House had initially proposed an overhaul of section 112 under which EPA would only be required to promulgate regulations for half the source categories it determines to be major and area sources of HAPs.[336] EPA would have been required to review the remaining fifty percent of listed source categories, and "designate the additional categories and subcategories [the EPA Administrator] finds, in his discretion, warrant regulation under this section."[337] This proposed system clearly entailed the potential for major sources of HAPs to escape regulation under section 112. Aware of this looming gap, the House proposed expanding section 111(d) to avoid leaving HAP emissions from numerous major sources unregulated.[338]

Interpretations that allow section 111(d) to continue providing for non-HAP regulation where needed to protect public health and welfare are true to the Clean Air Act's overarching structure for existing-source regulation. In addition to precluding any gaps in the regulatory framework for dangerous pollution from existing sources, these readings of the House amendment effectuate Congress' desire to make the CAA more protective through each revision. If EPA interprets the House amendment in this fashion, there will be no conflict in how the House and Senate amendments apply to the present rulemaking.

These readings have the benefit of not creating a bizarre and harmful gap in coverage of harmful pollutants that is entirely out of step with the tenor of the Act's regime and of the 1990 amendments. These interpretations are true to the Clean Air Act's overarching structure for existing-source regulation, as they allow section 111(d) to continue providing for coverage of non-HAP emissions where needed to protect public health and welfare.

These pollutant-specific readings of the House amendment are also consistent with the Supreme Court's observations about section 111(d) in *American Electric Power Company v. Connecticut*, 131 S. Ct. 2527 (2011). The Court described section 111(d)'s exclusions by stating: "There is an exception: EPA may not employ §[111(d)] if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§[108–110], or the "hazardous air pollutants" program, §[112]." *Id.* at 2537, n.7. This statement reflects the understanding that the exclusion for emissions regulated under section 112 works in parallel with the exclusion for emissions regulated under the NAAQS program. Indeed, the Court indicated that these exclusions comprise a single exception to section 111(d). There is no question that sources subject to regulation for criteria pollutant emissions

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regulation under this section." *Id.* § 7412(c)(3). Major sources are generally stationary sources with the potential to emit "10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." *Id.* § 7412(a)(1).

[336] H.R. 3030, § 301 (introduced July 27, 1989, and referred to the Committee on Energy and Commerce), reprinted in 1990 CAA Leg. Hist. at 3936-37.

[337] *Id.* at 1990 CAA Leg. Hist. at 3937.

[338] It may also be noteworthy that neither the House bill nor conference bill posed any equivalent need to expand section 111(d) to cover criteria pollutants. This is likely due to the different nature of HAPs and criteria pollutants. Very small doses of HAPs can cause adverse impacts on public health and sources of HAPs impose the greatest burdens on nearby communities. Consequently, addressing HAP impacts requires controlling all major sources of HAPs. In contrast, the NAAQS program gives states discretion over which sources of criteria pollutants should be subject to regulation because states can adequately protect public health so long as they ensure ambient concentrations do not exceed the NAAQS.

under the NAAQS program are also subject to regulation for other emissions under section 111(d). Similarly, there should be no question that sources are subject to regulation for pollution that is not controlled by the HAPs program, even where sources are also regulated under section 112.

iii. In context, the House amendment cannot plausibly be read to end section 111(d)'s application to dangerous pollution that happens to be emitted by source categories regulated under section 112.

Although the House amendment might be read—acontextually—to diminish the scope of section 111(d), such a reading is inconsistent with the structure, purpose, and legislative history of the Clean Air Act.

Although, as demonstrated above, there are multiple ways to read the House amendment to continue 111(d)'s role as a backstop against unregulated, dangerous pollution, other readings of this ambiguous amendment have been proposed that would fundamentally alter the role of section 111(d). The most expansive reading of the House amendment would exclude from section 111(d) all pollutants emitted by sources that are regulated by section 112—even when those pollutants are emitted by a source *not* regulated under section 112. This reading would effectively nullify section 111(d) because there are few (if any) non-HAP pollutants that are *not* emitted by sources in one of the dozens of source categories regulated under section 112.[339] More vitally, this would leave a host of dangerous air pollutants wholly unaddressed by the Clean Air Act. This is made clear by the fact that none of EPA's pre-1990 emission guidelines could now be promulgated under such a regime, leaving communities vulnerable to pollutants such as sulfuric acid mist, reduced sulfur compounds, and fluoride.[340]

Some have argued that the House amendment must be read to exclude any regulation of all source categories regulated under section 112.[341] Even EPA has opined that "a literal" reading of the House amendment would exclude non-HAPs from regulation under section 111(d).[342] But no party has offered a plausible explanation for how Congress could have intended to obliterate the scope of section 111(d) through the House amendment.

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[339] *See* EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP), http://www.epa.gov/ttn/atw/mactfnlalph.html (listing the nearly 200 source categories and subcategories affected by standards set under section 112).

[340] When Congress enacted the 1990 Clean Air Act Amendments, EPA had only issued four 111(d) emission guidelines, addressing total reduced sulfur from kraft paper mills, fluoride emissions from aluminum reduction plants, fluoride emissions from phosphate fertilizer plants, and sulfuric acid mist from sulfuric acid production units. Each of these source categories is now regulated under section 112 except for sulfuric acid production units. Yet sulfuric acid mist is emitted by other sources regulated under section 112, such as EGUs. *See* 76 Fed. Reg. 24976, 25,064 (May 3, 2011).

[341] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341)..

[342] Proposed National Emissions Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 69 Fed. Reg. 4652, 4685 (Jan. 30, 2004). In fact, however, a "literal" reading of section 111(d), both before and after the 1990 amendments would require section 111(d) regulation even for HAPs. That is because the exclusions for criteria pollutants and HAPs are structured as a mandate to regulate various classes of pollutants separated by an "or" in the alternative for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title.

There is no evidence that it was Congress' intent to drastically roll back the protections in section 111(d). If Congress had intended such a radical departure from the statutory structure of the CAA, Congress would have made it explicit in the statute or some member would have at least mentioned it in the extensive legislative history of the 1990 amendments to the CAA. *See Chisom v. Roemer*, 501 U.S. 380, 396 n.23 (statutory interpretation that would work a "sweeping" and "unorthodox" change warrants skepticism). There is simply no evidence in the face of the statute or its legislative history that Congress intended such a major change in policy. Since Congress gave no indication regarding its intention to repeal the protections it established in 1970, reading such a repeal into an ambiguous statute would be strongly disfavored.[343] Here, as noted above, there are other provisions of the 1990 amendments—including section 112(d)(7)—that affirmatively indicate that Congress did *not* intend for section 112 regulations to displace or alter section 111 standards and Clean Air Act permitting programs.

A broad reading of the exclusion in the House amendment would create a hole in the Clean Air Act that is not only sweeping, but also highly anomalous. First, it is fanciful to believe Congress silently worked a major rollback of section 111(d) that is so jarringly discordant with the protective thrust of the 1990 Clean Air Act Amendments. It is simply not credible that Congress purposefully opened a major loophole—completely counter to the historic role of section 111(d)—that would leave dangerous air pollutants entirely unregulated, even as it strengthened environmental controls and systematically limited EPA's discretion to leave air pollution unregulated, purposely opened an unprecedented gap in the Clean Air Act's framework for stationary-source regulation. This reading also assumes that Congress created this unprecedented loophole surreptitiously, leaving major categories of pollutants wholly unregulated for the first time since 1970, at the same time that the supporters of the 1990 amendments uniformly praised the bill for *strengthening* the Clean Air Act.[344]

Second, this reading of the House amendment would insert an exclusion into section 111(d) that is unlike any other in the Clean Air Act. Congress has never allowed sources to release unlimited quantities of some pollutants simply because they must control *other* pollutants. *Cf. Desert Citizens Against Pollution v. EPA*, 699 F.3d 524, 527-28 (D.C. Cir. 2012) (holding that EPA reasonably rejected petitioners' interpretation of the Clean Air Act, which "would have the anomalous effect of changing the required stringency" for certain hazardous air pollutants at a given source "simply on the fortuity" of the source's other emissions).

Third, any attempt to actually implement the broad exclusion reveals additional anomalies. Even under the most expansive reading of the House amendment, pollutants are only excluded from regulation under 111(d) if EPA happens to regulate a source under section 112 first. If EPA first regulates a source

[343] The canon disfavoring implied repeals is discussed in section I.N.4.b.

[344] *See, e.g.*, Remarks of Rep. Dingell during the House Debate on the Conference Report, reprinted in 1990 CAA Leg. Hist. at 1187 ("America already has the toughest air quality laws in the world. With this act, we will be raising our standards even higher. We will also be fulfilling our responsibility to the American people who have told us that they are willing to make some sacrifices in pursuit of a cleaner environment."); Remarks of Rep. Green during House Debate on the Conference Report, reprinted in 1990 CAA Leg. Hist. at 1180 ("Mr. Speaker, the conference report before us today will help us to fulfill our promise to the American people of a clean, safe environment. Although some . . . may argue that the costs of enacting this bill are too great, I contend that the costs of not enacting clean air legislation this year are greater still.").

category under section 111(d) and then regulates the same source category under section 112, section 112(d)(7) provides that the HAP regulation does not diminish or replace the existing 111(d) standards. It is inconceivable that Congress would prohibit section 111(d) standards "simply on the fortuity" of EPA's timing for promulgating standards under section 112. *Accord Desert Citizens Against Pollution*, 699 F.3d at 527-28.

One company has developed a theory that attempts to explain how Congress could have intended to weaken section 111(d) in 1990: that Congress sought to strengthen section 112 without imposing "double regulation" on any source category.[345] This account is entirely unfounded. First of all, the Clean Air Act is full of examples of instances in which Congress, in the interest of protecting public health and welfare, subject pollution sources to multiple, overlapping requirements for the *same* pollutants. *See, e.g.*, 42 U.S.C. § 7475(a) (noting that sources subject to stationary source permitting requirements (and "best available control technology" requirement) also must comply with applicable increments and air standards under, as well as any applicable performance standards under section 111); *Id.* § 7416 (expressly preserving state regulation of stationary sources except where less stringent that Clean Air Act requirements). The 1990 legislative history makes clear that House members were aware that, under the House bill, stationary sources would continue to be regulated under multiple sections of the Clean Air Act.[346]

Most important, it is not "double regulation" for *different* pollutants from a single source category to be regulated under different regulatory programs. The notion that subjecting a source to regulation for some pollutant should immunize it from regulation as to other pollutants is odd and altogether alien to the CAA's protective design. The CAA framework often provides separate but complementary regulatory frameworks to address different types of pollution emitted by the same sources. Criteria pollutant standards also apply to the same sources whose emissions of hazardous air pollution are addressed by Section 112. For instance, the CAA's Prevention of Significant Deterioration program requires new major emitting facilities to use the "best available control technology" for criteria pollutants,[347] in addition to any standards promulgated under section 111(b) or 112. Nor do any of the CAA's stationary source provisions exclude sources from regulation because they are regulated under other federal environmental laws.[348]

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[345] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341).

[346] "Under H.R. 3030, states would be required to submit to EPA comprehensive permit programs for regulating stationary sources. The permitting requirements would extend to sources that are subject to new source performance standards, emission standards for hazardous air pollutants, requirements for preventing significant deterioration (PSD) of air quality, nonattainment new and existing source review, and acid deposition controls under Title V. They also apply to all sources of air pollution emitting over 100 tons a year." House Debate on H.R. 3030 (May 21, 1990), reprinted in 1990 CAA Leg. Hist. at 2566.

[347] 42 U.S.C. § 7475(a)(4).

[348] For certain sources regulated under other acts, the 1990 amendments required EPA to consider the efficacy of those regulations before issuing regulations under section 112. As amended in 1990, section 112 does not require EPA to regulate sources and substances regulated by the Nuclear Regulatory Commission if "the regulatory program established by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act for such category or subcategory provides an ample margin of safety to protect the public health." 104 Stat. at 2542 (codified at 42

In summary, there is no reason to believe that the House amendment should be read to eviscerate section 111(d) and the House amendment can easily be read to preserve the gap-filling role of section 111(d) in the Clean Air Act's regulatory framework.

4. EPA can reasonably harmonize the two amendments to section 111(d) by adopting one of several reasonable interpretations of section 111(d), all of which require EPA to regulate non-HAP pollutants like CO_2.

a. Where one amendment clearly requires regulation of CO_2 emissions from EGUs and another amendment's treatment of such emissions is ambiguous, EPA must interpret the two amendments harmoniously.

The two amendments to section 111(d)(1)(A)(i) created a statutory ambiguity regarding the pollutants regulated under section 111(d). This ambiguity requires EPA's expert interpretation. *See Chevron,* 467 U.S. at 837.[349] EPA's expert interpretation of section 111(d) must be guided by the rule that "[t]he provisions of a text should be interpreted in a way that renders them, compatible, not contradictory."[350] EPA can reconcile the two amendments and interpret section 111(d) to require standards to address CO_2 emissions from EGUs.

b. Any conflict in the section 111(d) can be resolved by reasonably harmonizing the House and Senate amendments.

In the proposed rule, EPA has reasonably harmonized the text of the House and Senate amendments, through the following interpretation: "Where a source category is regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category."[351] This interpretation follows the case law

U.S.C. § 7412(d)(9)). In addition, Congress provided that "In the case of any category or subcategory of sources the air emissions of which are regulated under subtitle C of the Solid Waste Disposal Act, the Administrator shall take into account any regulations of such emissions which are promulgated under such subtitle and shall, to the maximum extent practicable and consistent with the provisions of this section, ensure that the requirements of such subtitle and this section are consistent." 104 Stat. at 2560 (codified at 42 U.S.C. § 7412(n)(7)).

[349] *See also Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2203 (2014) (plurality opinion); *Id.* at 2219 n. 3 (Sotomayor, J., joined by Breyer, J., dissenting).

[350] Antonin Scalia and Bryan A. Garner, Reading Law: The Interpretation of Legal Texts (2012) at 180; *id.* ("The imperative of harmony among provisions is more categorical than most other canons of construction because it is invariably true that intelligent drafters do not contradict themselves (in the absence of duress). Hence there can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously."); s*ee also Ricci v. DeStefano*, 557 U.S. 557, 579-83 (2009) (where provisions of Title VII "could be in conflict absent a rule to reconcile them," Court adopted construction that "allows the [provision at issue] to work in a manner that is consistent with other provisions of Title VII"); *Watt v. Alaska*, 451 U.S. 259, 267 (1981) (construing potentially discordant statutory provisions "to give effect to each if [it] can do so while preserving their sense and purpose").

[351] EPA, "Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units" (2014) at 26. Over the span of a decade, EPA has interpreted the House and Senate amendments to section 111(d) consistently in each of the two rulemakings where they were at issue. Courts should give significant weight to EPA's unwavering interpretation of section 111(d). *See Good Samaritan Hospital v. Shalala*, 508 U.S. 402, 417 (1993) ("[T]he consistency of an agency's position is a factor in assessing the weight that position is due.").

regarding when and how to harmonize conflicting statutory provisions.

The D.C. Circuit has given EPA detailed instructions on "its responsibility to harmonize the statutory provisions" of the Clean Air Act when two provisions conflict and the statute does not plainly indicate which provision shall prevail. *See generally Citizens to Save Spencer Cnty v. EPA*, 600 F.2d 844 (D.C. Cir. 1979) (upholding EPA's harmonization of sections 165 and 168 of the 1977 Clean Air Act, which were drawn from "two bills originating in different Houses and containing provisions that, when combined, were inconsistent in respects never reconciled in conference"); *explained in NRDC v. Thomas*, 805 F.2d 410, 436 n.39 (D.C. Cir. 1986) ("[T]his court held that the agency had broad latitude to harmonize two Clean Air Act provisions that facially dealt with the same issue differently."); *see also Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1043-44 (D.C. Cir. 2001) ("Lest it obtain a license to rewrite the statute" an agency alleging a scrivener's error "may deviate no further from the statute than is needed to protect congressional intent.") (quotations and citation omitted).

The court explained that "the maximum possible effect should be afforded to all statutory provisions . . . if the inconsistent provisions point generally in a common direction." *Spencer Cnty*, 600 F.2d at 870-71; *cf. United States v. Colon-Ortiz*, 866 F.2d 6 (1st Cir. 1989) (reading language out of a statute, where language inserted through a drafting error directly required the opposite outcome from what Congress had mandated elsewhere in the text). Harmonization of the House and Senate amendments to section 111(d) is appropriate because the two amendments point in a common direction. EPA has previously interpreted the House amendment to reflect the "House's apparent desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of HAP for a particular source category."[352] As EPA explained in its proposal for the Clean Air Mercury Rule, the House amendment can be reasonably interpreted to reflect a desire to expand the pollutants that EPA could regulate under section 111(d) so that EPA had authority to regulate HAPs emitted from source categories that were not actually being regulated under section 112 (such as existing area sources of HAPs that did not meet the statutory criterion in section 112(c)(3)). Similarly, the Senate amendment serves the general purposes of preserving EPA's authority to regulate non-HAPs under section 111(d) and avoiding duplicative regulation of HAPs. That is, the Senate's conforming amendment was necessary to give EPA authority to regulate any de-listed HAP under section 111(d). In addition, the Senate amendment avoids duplicative regulation of HAPs because it prevents EPA from regulating any HAP that is listed for regulation under section 112.

In harmonizing the House and Senate amendments to section 111(d), "it is appropriate for the agency . . . to look for guidance to the statute as a whole and to consider the underlying goals and purposes of the legislature in enacting the statute, while avoiding unnecessary hardship or surprise to affected parties." *Spencer County,* 600 F.2d at 871 (footnote omitted).

In the proposed rule, EPA has properly adhered to these principles in interpreting section 111(d). First, EPA concluded that it would be unreasonable to allow an expansive reading of the House amendment to prevail over the Senate amendment because such an interpretation would be inconsistent with "Congress' desire in the 1990 CAA Amendments to require the EPA to regulate more substances, and not to

[352] 69 Fed. Reg. at 4685.

eliminate the EPA's ability to regulate large categories of air pollutants."[353] Further, prohibiting the regulation of non-hazardous but dangerous pollutants from existing sources because hazardous emissions from those sources is appropriately regulated under Section 112 would expose American communities to health- and welfare-harming pollutants—clearly in conflict with Congress' effort in the Clean Air Act to protect Americans from harmful pollution. Thus, EPA has properly effectuated Congress' underlying goals and purposes in the Clean Air Act and subsequent amendments. Second, EPA reasoned that reading section 111(d) to exclude any air pollutant from a source category regulated under section 112 would be inconsistent with "the fact that the EPA has historically regulated non-hazardous air pollutants under section 111(d), even where those air pollutants were emitted from a source category actually regulated under section 112."[354] EPA's interpretation ensures the agency's continued ability to effectively protect public health and the environment, whereas interpreting the 1990 amendments to drastically curtail the agency's longstanding authority under section 111(d) would cause unexpected harm.

EPA's interpretation of section 111(d) is sound for several additional reasons. First, in accord with the interpretative canons against implied amendments and repeals, EPA has not read the 1990 amendments to repeal section 111(d)'s application to non-HAP emissions from sources regulated under section 112.

Reading the House amendment as certain court challengers have urged would deprive section 111(d) of most, if not all, of its traditional effect as a backstop that allows regulation of harmful pollution not covered under section 110 and 112. In the context of CO_2 emissions, this interpretation would not only preclude regulation of CO_2 emissions from the power sector; it would similarly bar any regulation in all other sectors of the nation's most significant sources of CO_2, because, like power plants, these categories too are regulated under section 112. EPA data confirms that—even outside the power sector—the chief emitters of CO_2 among stationary sources are subject to HAP regulation under section 112. According to EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT), the non-power subsectors of the economy that emitted more than 10 million metric tons of CO_2 in 2013 were: Petroleum refineries; natural gas processing; natural gas transmission/compression; other petroleum and natural gas systems; petrochemical production; hydrogen production; ammonia production; other chemicals; iron and steel production, other metals; cement production; lime manufacturing; pulp and paper; other paper products; food processing; manufacturing; ethanol production; and other.[355] All of the major CO_2-emitting source categories in the defined subsectors on this list are regulated under section 112.[356] (The "other" category

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[353] EPA, "Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units" at 26-27.

[354] *Id.*

[355] *See* EPA FLIGHT, available at http://ghgdata.epa.gov/ghgp/main.do.

[356] 40 CFR §§ 63.640 et seq & 63.1560 et seq (NESHAPs for petroleum refineries, including units used for hydrogen production); §§ 63.760 et seq (NESHAP for oil and natural gas production facilities, including facilities that process natural gas and certain compressors); §§ 63.1270 et seq (NESHAP for natural gas transmission and storage facilities); subparts F, G, H & I (NESHAPs for the synthetic organic chemical manufacturing industry, including manufacturing of certain petrochemical products); §§ 63.11400 et seq (NESHAP for carbon black production area sources, which manufacture "petrochemical products"); §§ 63.2430 et seq (NESHAP for miscellaneous organic chemical manufacturing, which includes units classified under 1997 NAICS code 325, such as ammonia manufacturing); §§ 63.11494 et seq (NESHAP for chemical manufacturing area sources, which includes units classified under 1997 NAICS code 325); §§ 63.7680 et seq (NESHAP for iron and steel foundries); §§ 63.7780 et seq (NESHAP for integrated iron and steel foundries); §§ 63.10880 et seq (NESHAP for iron and steel

likely includes many source categories regulated under section 112).[357] Because of the sheer number of section 112-listed source categories, and the fact that they include most of the largest pollution sources, the suggested readings would likely have similarly dramatic effects on section 111(d)'s coverage as to other dangerous, but not hazardous, pollutants.

"[I]t is well settled that amendments by implication (like repeals by implication) are disfavored." *Natural Resources Defense Council, Inc. v. Hodel*, 865 F.2d 288, 318 (D.C. Cir. 1988). "[A]bsent a clearly expressed congressional intention, repeals by implication are not favored." *See Branch v. Smith*, 538 U.S. 254, 273 (2003); *see also Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 664 n.8 (2007) ("It does not matter whether this alteration is characterized as an amendment or a partial repeal."). Congress expressed no clear intention to drastically narrow the scope of section 111(d), given the plain text of the Senate amendment, the categorization of the House amendment as "Miscellaneous Guidance,"[358] the legislative history's silence on such a repeal, and the general thrust of the 1990 amendments to broaden regulation of air pollutants. EPA has properly refrained from interpreting the House amendment to require such a change because Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes." *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001).

Guided by the canon against implied repeals, the Supreme Court has held that an agency may read a later-enacted provision to not override an existing, express statutory mandate. *See Nat'l Ass'n of Home Builders*, 551 U.S. at 666 (approving a harmonizing interpretation of the Endangered Species Act, where one of the act's provisions directly conflicted with a clear mandate in the Clean Water Act). If there is any conflict between the pre-1990 text of the CAA and the 1990 amendments, EPA cannot assume Congress' intended to repeal longstanding mandates in the Act unless that intention is clearly expressed. In the 1990 amendments, Congress did not clearly signal its intent to repeal section 111(d)'s application to non-HAPs emitted by sources regulated under section 112, as the Senate amendment directs EPA to continue applying section 111(d) to these pollutants. EPA's interpretation of section 111(d) appropriately harmonizes the House and Senate amendments because it does not allow the House amendment to override the existing, express statutory mandate to regulate under section 111(d) any air pollutant that is not regulated under the NAAQS program or section 112.

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foundries area sources); §§ 63.1340 et seq (NESHAP for the Portland cement manufacturing industry); §§ 63.7080 et seq (NESHAP for lime manufacturing plants); §§ 63.440 et seq (NESHAP for the pulp and paper industry); §§ 63.7480 et seq (NESHAP for industrial, commercial, and institutional boilers and process heaters that are major sources of HAPs); §§ 63.11193 et seq (NESHAP for industrial, commercial, and institutional boilers and process heaters that are area sources of HAPs); §§ 63.6080 et seq (NESHAP for stationary combustion turbines); §§ 63.6580 et seq (NESHAP for reciprocating internal combustion engines). Boilers, turbines, engines, and process heaters are the main sources of CO_2 emissions from the food processing, manufacturing, and ethanol subsectors. *See* EPA, Who Reports?, http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=93290546 (explaining that facilities in the food processing, manufacturing, and ethanol subsectors are required to report emissions from stationary combustion if they meet an emissions threshold); 40 CFR § 98.30 ("Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.").

[357] For instance sources in the "other chemicals" category may be regulated under section 112 as part of the Chemical manufacturing Industry (area sources) source category, subpart VVVVVV or Miscellaneous Organic Chemical Production and Processing source category, subpart FFFF.

[358] Public Law 101–549, § 4108(g), 104 Stat. at 2467 (Nov. 15, 1990).

Similarly, *Watt v. Alaska* illustrates how the canon against implied repeals can guide EPA in its duty "to give effect to each [amendment] if [it] can do so while preserving their sense and purpose." *See* 451 U.S. 259, 267 (1981). That case examined two statutory provisions that, by their plain terms, gave conflicting instructions regarding the distribution of mineral revenue from all federal wildlife refuges.[359] The Court examined the later-enacted statute (the 1964 amendments to the Wildlife Refuge Revenue Sharing Act) for "clearly expressed congressional intention" to repeal the prior law, and found none. 451 U.S. at 273. The Court harmonized the conflicting provisions by reading the latter-enacted law to apply only to mineral revenues from the class of wildlife refuges that motivated congressional action in 1964. That is, the Court read the latter-enacted provision to establish the revenue-distribution formula for mineral revenues from lands acquired for wildlife refuges, reasoning that the purpose of the 1964 amendments was to facilitate acquisition of lands for wildlife refuges. 451 U.S. at 272.[360]

EPA's proposed interpretation of section 111(d) is entirely consistent with the Court's approach in *Watts.* EPA has interpreted the House amendment to refer to the class of pollutants that motivated the amendment: pollutants that were actually regulated under section 112. EPA has previously concluded that "the House's amendment to section 111(d) could reasonably reflect its effort to expand EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112."[361] This conclusion is supported by reading the House amendments to section 111(d) together with the House's proposed amendments to section 112. As discussed above, the House bill proposed giving EPA discretion to not regulate sources under section 112 in specific circumstances. While the House's proposed amendment to section 112 might have diminished the scope of regulation under that section, the House expanded the scope of section 111(d) and avoided creating a gap in the statutory framework for existing-source regulation. In this rulemaking, EPA has harmonized the House and Senate amendments to ensure the section 111(d) exclusion only applies to pollution that is actually regulated under section 112, thus giving an effect to both the House and Senate amendments that serves their respective purposes.

Second, EPA's proposed interpretation of section 111(d) is consistent with that section's role in the structure of the Clean Air Act. Section 111(d) provides for controlling dangerous existing-source pollution that would otherwise escape regulation, where EPA has regulated a source category under section 111(b) after finding that the category of sources "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." In short, the section fills gaps in the Act's framework for existing stationary sources that cause or contribute significantly to

[359] Under the Mineral Leasing Act of 1920, ninety percent of federal oil and gas revenue goes to the states and ten percent to the U.S. Treasury, whereas 1964 amendments to the Wildlife Refuge Revenue Sharing Act require twenty-five percent of the revenue from refuge resources (including "minerals") to goes to counties and seventy-five percent to the Department of Interior.

[360] The Court explained that the purpose of the 1964 amendments was to distribute more revenue to counties "as compensation for loss of taxable properties that have been acquired by the Federal wildlife refuge system." 451 U.S. at 270. The Court observed that "Congress might be expected to have mentioned a change" that would have increased federal revenues, especially when "Congress was concerned that the Department have sufficient funds to make the increased payments mandated by the amendments." 451 U.S. at 271.

[361] 70 Fed. Reg. at 16031.

harmful air pollution. Because section 112 does not require EPA to regulate HAPs from all sources,[362] some sources may emit dangerous amounts of hazardous pollutants even after EPA fully implements section 112. EPA's harmonization of the conflicting amendments would allow section 111(d) to play its gap-filling role for uncontrolled sources of hazardous air pollution (as well as for non-hazardous but dangerous pollutants emitted by sources that are regulated under Section 112).

Third, EPA's proposed approach is consistent with the canon that exemptions from regulation should be construed narrowly. See *Comm'r v. Clark*, 489 U.S. 726 (U.S. 1989). ("In construing provisions . . . in which a general statement of policy is qualified by an exception, we usually read the exception narrowly in order to preserve the primary operation of the provision"); *see Phillips, Inc.* v. *Walling*, 324 U.S. 490, 493 (1945) ("To extend an exemption to other than those plainly and unmistakably within its terms and spirit is to abuse the interpretative process and to frustrate the announced will of the people."). Here, because the amendments exempt certain pollutants from regulation, any ambiguity in the amendments should be construed in favor of limiting the range of pollutants that are exempted.

As the expert agency responsible for implementing the Clean Air Act, EPA is uniquely aware that narrowing the scope of section 111(d) would significantly harm public health and welfare, and that these harms are contrary to the purposes of the Act. *See* 42 U.S.C. § 7401(b)(1). A court would properly defer to EPA's regulatory expertise in determining whether EPA has reasonably harmonized the differing 1990 amendments to section 111(d). *See Nat'l Ass'n of Home Builders*, 551 U.S.at 666 (upholding EPA's expert harmonization of conflicting statutes, where the agency could not "simultaneously obey the differing mandates set forth in [the two provisions]" and "the statutory language . . . does not itself provide clear guidance as to which command must give way").

c. There are additional ways to harmonize the amendments that are consistent with the language and purpose of 111(d).

The most straightforward way of harmonizing the two amendments is to interpret the ambiguous House amendment to be consistent with the crystal-clear Senate amendment with respect to the question presented here—*i.e.*, EPA may, under section 111(d), regulate a non-HAP pollutant that is emitted from source category whose HAP emissions are regulated under section 112(d). As demonstrated above, there are multiple reasonable readings of section 111(d) as amended by the 1990 House language that would allow EPA to proceed with regulating CO_2 emissions from EGUs.

An alternative means of doing so would be to interpret the 1990 amendments as having included two different versions of 111(d), one reflecting the direction provided by House amendment and one the Senate amendment. Under this approach, the statute contains, with the Senate amendment, a separate, affirmative command to regulate all non-NAAQS, non-112(b)-listed pollutants. Each amendment mandates that EPA "*shall* prescribe regulations" for a set of air pollutants. 42 U.S.C. § 7411(d)(1) (emphasis added). Neither purports to *negate* regulatory obligations required by other provisions of the

[362] As discussed above, section 112 does not provide for regulation of certain area sources in the oil and gas sector and regulation of HAPs from many area sources is discretionary under section 112.

statute.[363] Thus, even if the House amendment is read to exclude EGUs (and to direct regulation of sources not regulated under 112), the two amendments set out compatible and additive commands to regulate (EPA must issue guidelines for all non-NAAQS pollutants not on a 112 pollutant list, and for sources of all non-NAAQS pollutants not regulated under 112). This reading allows EPA to "give effect to both" provisions, *see Morton v. Mancari*, 417 U.S. 535, 551 (1974), by doing what is required by either of the amendments.

Some commentators have suggested that the two 1990 amendments should both be given effect and that, if both are incorporated into the statute, the resulting language can be read to deny EPA authority to act here.[364] The premise that both amendments can be combined together and read as a single statutory command is problematic, since both provisions direct that the same language in the preexisting legislation be stricken; and neither amendment refers to or purports to take account of the other. There is no evidence that either house of Congress, in fact, legislated with the expectation that its change to section 111(d) would be combined with another change. The statute does not provide any definitive guidance for how to incorporate the different chambers' instructions; efforts to combine the language of the two amendments into a workable whole have a kind of artificiality in light of the strong indications that Congress did not actually make any decision that the two amendments were meant to operate together. But, contrary to the premise of the some supporters of this approach, the proper way to combine the amendments yields an approach that is grammatical, that attempts to heed Congress's instructions closely as possible; and that yields a result that is consonant with the statute.

The House and Senate amendments can be effectuated together as follows: First, both amendments would strike out the preexisting reference to "112(b)(1)(A)." The House amendment would then insert "or emitted from a source category" at the point in the text where "or 112(b)(1)(A)" was removed. The Senate amendment would require "112(b)" to be inserted at the point in the text where "112(b)(1)(A)" was removed, immediately after the original "or" that the House Amendment replaced. The combined section would read:

> The Administrator shall [establish emission guidelines] for any existing source for any air pollutant . . . which is not included on a list published under section . . . 112(b) emitted from a source category which is regulated under section 112 of this title.

The resulting amended statute would direct EPA to regulate all pollutants that are not criteria pollutants or emitted by source categories listed under section 112 and actually regulated under that section. Thus,

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363 Indeed, the savings clause enacted as part of the 1990 amendments indicates that Congress recognized the importance of section 111(d) in controlling dangerous pollutants and did not want such regulation to be ousted lightly or by mere implication. That savings provision provides that "[n]o emission standard or other requirement promulgated under this section [112] shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to Section 111 [and other programs]." 42 U.S.C. § 7412(d)(7).
364 See William J. Haun, The Clean Air Act As an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants 10-11 (Federalist Society 2013), available at http://www.fed-soc.org/library/doclib/20130311_HaunEPAWP.pdf.

reading the language added by the House and Senate amendments together yields a meaning that is coherent and maintains section 111(d)'s role in protecting human health and the environment.[365]

Any permissible harmonization of the House and Senate amendments must achieve the purpose of section 111(d), which is ensuring that dangerous pollution from existing industrial sources does not escape regulation. EPA cannot adopt an interpretation of section 111(d) that creates a gaping, inexplicable hole in the CAA's framework for regulating existing industrial sources. The commentators' alternative "harmonization" fails this basic requirement.

5. If harmonizing the amendments were not possible, any reasonable interpretation of section 111(d) would still allow EPA to regulate CO_2 emissions from EGUs.

If harmonizing the amendments were impossible, EPA could rely on several canons of statutory interpretation to resolve any conflict in section 111(d). Under any available rule of construction, section 111(d) controls dangerous non-HAP emissions regardless of whether they come from source categories that are subject to regulation under section 112. EPA's application of these canons to interpret conflicting provisions would be entitled to deference.[366]

First, as EPA observed, "[t]he ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments."[367] If conflicting language in section 111(d) is a result of a mistake, that mistake must have been the House amendment's exclusion of "sources" regulated under section 112 instead of "emissions" regulated under section 112. As described above, the apparent purpose of the House amendment to section 111(d) was to *avoid* creating a gap in the statutory structure for controlling emissions from existing sources; if the conference committee had adopted the House's amendments to section 112, an amendment to section 111(d) would have been necessary to ensure that EPA had authority to regulate existing-source HAP emissions that EPA chose to not regulate under section 112.

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365 In contrast, the approach urged by Haun, supra, results in a formulation that would restrict section 111(d) to "any air pollutant . . . which is not included on a list published under section 7408(a) or 112(b) [Senate amendment] *or emitted from a source category which is regulated under section 112* [House amendment] of this title[.]" Haun at 10 (emphasis added by Haun). However such an interpretation would be properly interpreted, it clearly does not faithfully implement the amendments, since it results in smuggling in an extra "or" that Congress did not enact. The House Amendment struck one "or" (by striking "or section 112(b)(1)(A)"), and the Senate Amendment did not add any "or's." Yet the Haun approach manages to yield a new "or," by disregarding the instruction in the House amendment to strike the preexisting "or".

This purported harmonizing reading is also impermissible because it simply declines to give effect to the Senate amendment in this rulemaking. As discussed above, each amendment contains an exception to a regulatory mandate. But none of the exceptions in section 111(d) prohibit EPA action or otherwise detract from mandates to protect human health and the environment. This attempt at harmonization fails to give full effect to both amendments, as illustrated by its application to this rulemaking. Failure to issue guidelines for CO_2 emissions from EGUs would be a blatant violation of the Senate amendment's mandate to control all dangerous non-HAP, non-criteria pollutant emissions that are subject to standards under section 111(b).

366 *See Scialabba*, 134 S. Ct. at 2203 (plurality opinion); *Id.*. at 2219 n. 3 (Sotomayor, J., joined by Breyer, J., dissenting) (agreeing with plurality that where agency cannot "simultaneously obey" two statutory commands, "it is appropriate to defer to the agency's choice as to 'which command must give way'" (quotation marks omitted)).

367 79 Fed. Reg. at 34853.

Giving effect to the narrow interpretation of the House amendment does not promote the House's (and Congress') manifest intention to control all dangerous air pollution from existing sources. In contrast, the Senate amendment clearly retains EPA's authority to ensure effective regulation of dangerous non-HAP pollutants from existing sources under section 111(d) as a complement to regulation of HAPs under section 112. Accordingly, if EPA's attempts at harmonizing the amendments had failed, EPA could have shown that "Congress did not mean what it appears to have said" in the House amendment and that "as a matter of logic and statutory structure, it almost surely could not have meant it." *See Engine Mfrs. Ass'n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996). In such situations, EPA can interpret section 111(d) "by disregarding an obvious mistake." *See Bohac v. Dep't of Agric.*, 239 F.3d 1334, 1338 (Fed. Cir. 2001); *see also Am. Petroleum Inst. v. SEC,* 714 F.3d 1329, 1336-37 (D.C. Cir. 2013) (refusing to interpret a scrivener's error as indication that Congress intended to depart from a longstanding statutory scheme).[368]

If the two amendments were deemed incompatible, EPA could then choose which amendment is controlling, the agency has discretion in reading section 111(d) to effectuate congressional intent. *See Appalachian Power Co.*, 249 F.3d at 1044 n.3 ("[W]hen there are multiple ways of avoiding a statutory anomaly, all equally consistent with the intentions of the statute's drafters (and equally inconsistent with the statute's text), we accord standard *Chevron* step two deference to an agency's choice between such alternatives.") (quotation omitted); *see also Abdelqadar v. Gonzales*, 413 F.3d 668, 673 (7th Cir. 2005) (noting that judges cannot generally engage in "repair work" to rescue Congress from its drafting errors, "but agencies charged with superintending a comprehensive scheme traditionally have been afforded additional latitude"). In the context of the CAA's carefully crafted framework for controlling all dangerous emissions from existing sources, it would be implausible to read section 111(d) to let certain dangerous pollution go unregulated simply because EPA controlled *other* pollution from the same sources.

Second, if one of the amendments must prevail over the other, the canons against implied repeal and amendment hold that the Senate amendment must control.[369] EPA cannot presume that Congress intended to repeal its authority to regulate non-HAPs from sources regulated under section 112 unless Congress' intention to do so is "clear and manifest." *See Watt*, 451 U.S. at 267. Where there are two amendments to the same language, and those two amendments point in different directions, there is no "clear and manifest" intention. The Senate amendment is substantively similar to prior law and, therefore, should be given effect if EPA cannot discern Congress' clear and manifest intent to substantively change section

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[368] If the inclusion of the House amendment did not create ambiguity in the statutory text, the plain language of the statute would control despite any errors in the drafting process. *See Lamie v. United States Trustee*, 540 U.S. 526, 542 (2004) ("If Congress enacted into law something different from what it intended, then it should amend the statute to conform it to its intent. It is beyond our province to rescue Congress from its drafting errors, and to provide for what we might think . . . is the preferred result.") (quotation omitted). But here, it is impossible for EPA to give effect to the House amendment without violating the mandate in the Senate amendment. As explained above, EPA may also respond to this scrivener's error by interpreting the House amendment in a way that gives it some effect but avoids an absurd result. *See United States ex rel. Holmes v. Consumer Ins. Group*, 318 F.3d 1199, 1209 (10th Cir. 2003) ("Under the doctrine of scrivener's error, a court may give an unusual (though not unheard-of) meaning to a word which, if given its normal meaning, would produce an absurd and arguably unconstitutional result.") (quotations omitted).

[369] These canons are discussed supra, section I.N.4.b, because they demonstrate that—if harmonization is possible—EPA's harmonization is reasonable.

111(d).[370]

Third, "[t]he established rule is that if there exists a conflict in the provisions of the same act, the last provision in point of arrangement must control." *Lodge 1858, American Fed. of Gov't Employees v. Webb*, 580 F.2d 496 (D.C. Cir. 1978). This rule applies regardless of whether the conflicting provisions are in the same statutory section. *See, e.g.*, *Merchants' Nat'l Bank v. United States*, 214 F. 200, 205 (2d Cir. 1914); *Mobile v. GSF Properties, Inc.*, 531 So. 2d 833, 837-38 (Ala. 1988).[371] Under this rule, the Senate amendment controls over the House amendment because it appears later in the Statutes at Large.

Finally, giving effect to the Senate amendment would allow EPA to avoid an absurd result. *See American Water Works Ass'n v. EPA*, 40 F.3d 1266, 1271 (D.C. Cir. 1994) ("where a literal reading of a statutory term would lead to absurd results, the term simply 'has no plain meaning … and is the proper subject of construction by the EPA and the courts'") (quoting *Chemical Mfrs. Assoc. v. Natural Resources Defense Council*, 470 U.S. 116, 126 (1985)). Reading section 111(d) to exclude from control the dangerous (though not hazardous) emissions from all sources regulated under section 112 would exclude myriad of the country's most significant sources of air pollution and profoundly undermine one of the Clean Air Act's basic mechanisms for protecting human health and the environment. Regardless of whether this broad exclusion is a "more natural reading" of the House amendment, EPA cannot give 111(d) a meaning that is at odds with Congressional intent. *See id.* (citing *Young v. Community Nutrition Inst.,* 476 U.S. 974, 980 (1986)). EPA cannot give effect to a reading of the House amendment that would render the Senate amendment ineffective in nearly any situation. *See United States v. Coatoam*, 245 F.3d 553, 557-58 (6th Cir. 2001) (refusing to adopt a defendant's literal reading of a statutory provision, which would have rendered another subsection surplusage in the vast majority of cases, where the government asserted that Congress made a drafting error when it amended the statute).

[370] Both the Senate amendment and then-effective law excluded the current list of HAPs from regulation under section 111(d).

[371] The rationale for giving effect to the last provision in order of arrangement is that the last expression of the legislative will must prevail:

> [O]ne, for being earlier or later in position, must be deemed to render the other nugatory, or repeal it. The decisions are to the effect that the provision which is latest in position repeals the other. Being later in position, the prevailing provision is deemed a later expression of the legislative will. This rule and the reason for it have been criticized, because, all the provisions of an act being adopted at the same time, there is no priority in point of time on account of their relative positions in the statute. This is strictly true; but, in the reading of a bill, matter near the close may be presumed to revive the last consideration, and, if assented to, is a later conclusion.

Sutherland, Statutes and Statutory Construction (2d ed. 1904) vol. 2, § 349. This rationale applies despite the fact that the two relevant sections of the Statutes at Large amend the same statutory provision.

O. The Section 111(b) Standard for Modified and Reconstructed Sources is a Sufficient Predicate for the 111(d) Rule

Below, we demonstrate that the text, structure, and purpose of Section 111 unambiguously require state plans to cover any existing EGU that would be subject to a section 111(b) standard if it were to be newly built, modified, *or* reconstructed. Industry commenters' misguided view that EPA is barred from issuing emission guidelines for existing EGUs until it promulgates standards for *all* new sources is inconsistent with the statute and would frustrate the core purposes of section 111.

1. Section 111(d) Requires EPA to Regulate Carbon Emissions from any Existing EGU that Would be Subject to a Standard of Performance for Carbon Emissions if that Source Undertook Modification or Reconstruction.

Section 111(b) directs EPA to "list . . . categories of stationary sources" if a category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[372] It further directs EPA to establish "Federal standards of performance for new sources within such category."[373] Section 111(a) defines a "new source" as "any stationary source" that undertakes "construction *or* modification" after the proposal date of a standard of performance applicable to that source.[374] EPA's long-established interpretation of the statutory term "construction" includes the "reconstruction" of an existing source that is so extensive that the cost of the replaced components exceeds 50% of the fixed capital cost to construct a comparable new facility.[375] Section 111(d), in turn, directs EPA to ensure that state plans establish standards of performance for "any existing source . . . to which a standard of performance . . . would apply if [that] existing source were a new source." The statutory language is clear and unambiguous. Section 111(b) standards for any source fitting the statutory definition of "new"—which expressly includes modified sources and includes reconstructions through EPA's long-standing interpretation of the term "construction"—establish the category of sources for which Section 111(d) standards must be established for existing sources. Section 111(b) standards for newly constructed, modified, or reconstructed sources all equally fulfill this category-defining role for Section 111(d) standards.

EPA correctly concludes that section 111(d) requires the regulation of carbon pollution from any existing EGU that would, if it were "new", be covered by *any* 111(b) rulemaking establishing carbon pollution standards for EGUs.[376] Notwithstanding the unambiguous statutory language supporting EPA's conclusion, some industry commenters question whether the section 111(b) standards for modified and

[372] 42 U.S.C. § 7411(b)(1)(A).
[373] 42 U.S.C. § 7411(b)(1)(B).
[374] 42 U.S.C § 7411(a)(2) (defining "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.") (emphasis added).
[375] *See* 40 C.F.R. § 60.15; Part 60-Standards of Performance for New Stationary Sources Modification, Notification, and Reconstruction, 40 Fed. Reg. 58,416 (Dec. 16, 1975).
[376] *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,852 (June 18, 2014).

reconstructed EGUs would independently require regulation of carbon pollution from existing EGUs under section 111(d). In a joint comment filed in this docket,[377] a number of trade and business associations[378] claim that the structure of section 111 demonstrates that Congress intended that existing sources would not be regulated unless EPA first established standards of performance for *all* new sources (newly constructed, modified, and reconstructed).[379] These commenters further assert that such an interpretation of the statute is necessary to avoid the "nonsensical outcome" where existing sources become subject to regulation before EPA finalizes standards for newly constructed sources.[380]

Such arguments ignore the text of section 111(d), which compels EPA to regulate existing sources that would be covered by a section 111(b) standard if they were "new sources"— a term that expressly encompasses modified *or* newly constructed sources, and encompasses "reconstructed" sources under EPA's well-settled interpretation of the term "construction" in the statutory definition of "new source."[381] Nothing in the text of section 111(d) states or implies that EPA must defer regulation of existing sources that would be subject to a section 111(b) standard if they undertook modification or reconstruction until such time as EPA has established a section 111(b) standard for newly constructed sources in the same category. On the contrary, the text and structure of section 111 demonstrate that Congress was urgently concerned with identifying and regulating categories of sources contributing significantly to air pollution reasonably "anticipated to endanger public health or welfare."[382] Delaying regulation of existing sources until after the promulgation of standards for all possible forms of "new" sources within a category would be inconsistent with ensuring that all sources of dangerous pollution—even existing sources— are controlled once identified. Finally, the regulation of existing sources under 111(d) while 111(b) standards for newly constructed sources are pending does not produce a "nonsensical outcome."

The text and structure of section 111 demonstrate that a category of sources must be subject to 111(d) regulation if the category would be subject to *any* 111(b) standard. As noted above, section 111(a) explicitly provides that a "new source" includes "any stationary source" that undertakes "construction *or* modification" after the proposal date of a standard of performance applicable to that source.[383] Section 111(d), in turn, directs EPA to ensure that state plans establish standards of performance for "any existing source . . . to which a standard of performance . . . would apply if [that] existing source were a new source." This structure clearly contemplates that the regulation of existing sources in a category is

[377] Docket ID No. EPA–HQ–OAR–2013–0603; 79 Fed. Reg. 34,960 (June 18, 2014).
[378] The organizations include The American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, the NationalAssociation of Manufacturers, National Lime Association, National Oilseed Processors Association, Portland Cement Association, The Fertilizer Institute, and the U.S. Chamber of Commerce.
[379] *See* Comment submitted by Greg Bertelsen, National Association of Manufacturers (NAM), Docket ID. No. EPA-HQ-OAR-2013-0603-0192 (Oct. 16, 2014), at 11-12.
[380] *See id.*
[381] *See* 42 U.S.C. § 7411(a)(2); 40 C.F.R. § 60.15; Part 60-Standards of Performance for New Stationary Sources Modification, Notification, and Reconstruction, 40 Fed. Reg. 58,416 (Dec. 16, 1975).
[382] *See* 42 U.S.C. 7411(b)(1)(A).
[383] 42 U.S.C § 7411(a)(2) (defining "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.") (emphasis added).

triggered by the potential applicability of section 111(b) standards to *either* newly constructed *or* modified sources in that same category. Although Congress did not expressly include reconstructions in the definition of "new source," it is nonetheless clear that Congress contemplated more than one type of "new" source would be subject to 111(b) standards, and therefore that 111(d) standards for a category could be required as a result of EPA establishing 111(b) standards for any of the multiple possible types of "new source." Consequently, now that EPA has proposed standards of performance for modified and reconstructed EGUs, existing EGUs would satisfy the statutory and regulatory definitions of a "new source" if they were to undertake modification or reconstruction. The modified and reconstructed source standards thus serve as a separate and wholly sufficient predicate for the 111(d) standards for existing sources.

By contrast, the statutory text provides no support for the alternative view advanced by some industry commenters, which is that state plans may only regulate existing EGUs after promulgation of standards for new, modified, *and* reconstructed sources of the same type. If Congress had intended that section 111(d) requirements only apply to sources for which *all* possible section 111(b) standards have been promulgated, it would have so stated. Instead, Congress provided that a "new source" is one that undertakes "construction *or* modification" after the proposal of an applicable standard of performance, and did not require that EPA establish a single standard of performance for the different contemplated forms of "new" sources. On the contrary, the statute expressly provides EPA with discretion to establish different standards under section 111(b) for the multiple possible types of "new" sources, by authorizing EPA to distinguish between different types and classes of sources within a category.[384] Thus, because Congress clearly established that there are multiple avenues through which a source may be "new" for the purpose of applicability of a 111(b) standard, the mandate in section 111(d) to regulate existing sources that would be subject to 111(b) standards if they are "new" is triggered by an applicable standard of performance for either newly constructed, reconstructed, or modified sources.

EPA's position is also fully consistent with the purpose of section 111, whereas the position advanced by industry commenters would undermine the statutory purpose. The purpose of section 111, as demonstrated by its text and structure, is curbing the emission of harmful pollutants from *categories* of stationary sources identified as significantly contributing to dangerous pollution; this purpose is fulfilled through a statutory structure that ensures that air pollution emitted by both new and existing sources in those categories are regulated. To address pollution from the category effectively, and to fulfill Section 111's technology-forcing mandate, EPA *must* promptly establish standards under section 111(b) for newly constructed, reconstructed, and modified sources in each listed category.[385] Yet where existing sources are responsible for the vast majority of the pollution generated by the category, as is the case with respect to carbon pollution from power plants (and many other source types), establishing section 111(d) regulation is an even more urgent task to fulfill the Act's fundamental purpose of protecting human health and welfare. For this reason, section 111(d) requires EPA to ensure that standards of performance under section 111(d) are established for existing sources, which are defined as "any stationary source other than

[384] *See* 42 U.S.C. § 111(b)(2)("The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [111(b)] standards.")
[385] 42 U.S.C. § 7411(b)(1)(B).

a new source."[386] Because the goal of this statutory framework is ultimately to ensure that Americans are protected from dangerous air pollution through standards addressing the entire category, it would frustrate that purpose to delay the regulation of existing sources until standards of performance have been established for *all* forms of new sources. Conversely, interpreting section 111(d) as requiring the regulation of existing sources that would be subject to a 111(b) standard of performance if they were *any* form of "new source" is consistent with section 111's clear purpose of ensuring that emissions from the entire category become subject to pollution standards.

Contrary to industry assertions, the regulation of existing sources under 111(d) while 111(b) standards for newly constructed sources are pending does not produce a "nonsensical outcome." EPA's approach ensures that existing sources, responsible for the vast majority of the carbon pollution generated by this category of sources, would be subject to standards requiring the abatement of that pollution once there is a section 111(b) standard for any "new source" of the same type. This approach is wholly consistent with the unambiguous text of section 111(d) and comports with the Act's fundamental purpose of protecting Americans from dangerous air pollution.

2. EPA's Duty to Establish Emission Guidelines for Existing Sources is Not Altered By the Continuing Applicability of 111(d) Requirements to Sources that Subsequently Elect to Modify or Reconstruct

EPA has properly recognized that its duty to issue emission guidelines for existing sources now that the Agency has proposed standards of performance for reconstructed or modified sources is not affected by the clarification that 111(d) requirements continue to apply to sources that modify or reconstruct after becoming subject to 111(d) state plan requirements. Contrary to industry arguments,[387] the modified and reconstructed standard of performance is a sufficient predicate for the regulation of existing sources under 111(d) regardless of the continued applicability of 111(d) plan requirements to sources that modify or reconstruct because the statutory definitions of "new" and "existing" sources are relevant only to the *initial applicability* of the respective standards. Consequently, a source can be subject to ongoing 111(d) requirements because it was *formerly* an existing source, even though the source has also become subject to a 111(b) standard by meeting the section 111(a)(2) definition of a "new" source.

Industry comments rely on the flawed assumption that the ongoing applicability of 111(d) requirements to modified or reconstructed sources rests on the modified or reconstructed sources *continuing* to be "existing" sources as defined in section 111(a)(6). Specifically, the National Mining Association commented that "[i]f EPA intends to continue to subject sources that modify or reconstruct to the CAA section 111(d) plan, it must be because EPA considers modified and reconstructed sources to be existing sources for some reason."[388] Based on this conclusion, NMA asserted that if the modified and reconstructed sources are actually existing sources, the proposed rule cannot be a predicate for regulation

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[387] *See* Comment submitted by National Mining Association, Docket ID. No. EPA-HQ-OAR-2013-0603-0272 (Oct. 15, 2014) at 5-7.
[388] *Id*. at 7.

under the command of section 111(d)(1)(A).[389] As EDF has explained in its comment on the proposed 111(b) standards for modified and reconstructed EGUs, section 111 is ambiguous as to whether 111(d) requirements continue to apply to a source that modifies or reconstructs. A reasonable interpretation of this ambiguity is that the definitions of "new" and "existing" source are relevant to the question of what type of standard of performance initially applies to a source, but do not constrain whether that standard continues to apply once the same source meets the requirements for applicability of another standard under section 111. Consequently, the question of whether a source *continues* to be subject to a standard is separate from whether that source initially meets the statutory definition of "new source" or "existing source."

Under EPA's interpretation of the statutory ambiguity, sources that modify or reconstruct continue to be subject to the 111(d) standard not because they are *still* "existing" sources, but rather because the statute does not relieve sources of requirements that were imposed on them at an earlier time, when they *were* "existing" sources. Indeed, in the specific context of the Clean Power Plan, excluding modified or reconstructed sources from a section 111(d) state plan would not ensure that the standards for such sources reflect the "best system of emission reduction," as section 111(a)(1) requires. As EDF explained in our comments on this proposed rule, the BSER for modified and reconstructed EGUs necessarily encompasses not just systems such as heat rate improvements, considered in the proposed standards here, but also the potential to reduce carbon pollution through shifts in utilization towards lower- or zero-emitting generation and demand-side energy efficiency. This is the system that EPA has identified as the "best system of emission reduction" in the proposed emission guidelines for all existing plants because it achieves the greatest pollution reductions considering cost, energy requirements, and other health and environmental outcomes. The modification or reconstruction of an existing fossil fuel-fired EGU does not alter the fact that the flexible, cost-effective system of emission reduction identified by EPA remains the best system for that plant, achieving the greatest emission reductions considering cost and the other statutory factors. Rather, the modification or reconstruction means that there is an additional component of the best system for that source to ensure that the section 111(b) standard serves its technology-forcing, emission-reducing role when significant investments are being made in these plants.

Because EPA's interpretation that 111(d) requirements continue to apply to sources that later modify or reconstruct does not rely on defining those sources as continuing to be "existing" sources, the proposed 111(b) standards of performance for modified and reconstructed EGUs are in no way standards for "existing" sources. Thus, because the proposed standards are clearly standards of performance for "new" sources, fitting the definition of section 111(a)(2), the standards for modified and reconstructed EGUs are a sufficient predicate for the regulation of existing sources under section 111(d).

[389] *Id*. at 7.

II. EPA Must Ensure that Modified and Reconstructed EGUs Achieve Emission Reductions that Reflect the BSER and Do Not Compromise the Integrity of Section 111(d) State Plans.

A critical issue raised in the proposed rule is whether fossil fuel-fired EGUs covered by state plans issued under section 111(d) must continue to comply with those state plans after undertaking a modification or reconstruction. EDF strongly believes that section 111(d) requirements must apply to all fossil fuel-fired EGUs that were "existing sources" as of the date the emission guidelines were proposed (June 18, 2014), regardless of whether those fossil fuel-fired EGUs subsequently modify or reconstruct. Allowing EGUs to exempt themselves from section 111(d) by modifying or reconstructing would not assure that these units are subject to a "standard for emissions of air pollutants which reflects . . . the best system of emission reduction," as required by sections 111(a) and (b) of the Clean Air Act.[390] For modified and reconstructed EGUs, the "best system of emission reduction" necessarily encompasses not just systems such as heat rate improvements, considered in the proposed standards here, but also the potential for shifts in utilization away from higher-emitting and towards lower- or zero- emitting generation and demand-side energy efficiency to reduce carbon pollution from these plants. This is the system that EPA has identified as the "best" system of emission reduction in the proposed emission guidelines for all existing plants because it achieves the greatest pollution reductions considering cost, energy requirements, and other health and environmental outcomes. The modification or reconstruction of an existing fossil fuel-fired EGU does not alter the fact that the flexible, cost-effective system of emission reduction identified by EPA remains the best system for that plant, achieving the greatest emission reductions considering cost and the other statutory factors—in combination with the additional BSER components described in these comments to ensure that the section 111(b) standard serves its technology-forcing, emission-reducing role when significant investments are being made in these plants.

Moreover, as EPA recognizes in the proposed emission guidelines,[391] an approach under which modified or reconstructed EGUs are no longer subject to section 111(d) would create perverse economic incentives for units to undertake modifications with the objective of avoiding emission reductions that would be

[390] Section 111(b) of the Clean Air Act requires that EPA establish "standards of performance" for "new sources," which are defined under section 111(a) to include sources that undertake modifications after the proposed date of an applicable standard of performance. Under section 111(a)(1) of the Clean Air Act, such standards of performance *must* "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." For modified and reconstructed EGUs, this "best system" includes not just the technology-based standards that EPA has included in the proposed rule, but also the same system-based "building blocks" that EPA determined to be the BSER for existing sources in its proposed Clean Power Plan.
[391] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,904 (proposed June 18, 2014) ("The EPA is concerned that owners or operators or units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d).").

required under their state plans. And as EPA also acknowledges, it would be highly disruptive for state plans—which in many cases will be based on the state-wide average performance of currently existing EGUs—if EGUs that were "existing" sources when the plan was designed were suddenly excluded from the plan upon modifying or reconstructing.

Maintaining the applicability of section 111(d) state plans to modified and reconstructed EGUs is not only supported by these compelling policy considerations, it is also consistent with the text of the Clean Air Act—as we describe in further detail below. For these reasons, we strongly support EPA's determination that fossil fuel-fired EGUs already subject to a section 111(d) state plan must continue to comply with those plans in the event those facilities later modify or reconstruct. In addition, we recommend that EPA extend this interpretation to ensure that *all* fossil fuel EGUs that are currently "existing sources" remain covered by section 111(d) state plans, regardless of whether or when they modify or reconstruct. Lastly, as a supplement to EPA's proposed approach, we also suggest two alternative mechanisms by which EPA could assure that modified and reconstructed EGUs achieve emission reductions consistent with the flexible, system-based BSER identified in the proposed Clean Power Plan: 1) committing to review the New Source Performance Standards (NSPS) for new, modified, and reconstructed EGUs at intervals shorter than the eight-year review period prescribed by the statute, such that all such units would promptly become "existing sources" subject to section 111(d); 2) including emissions from modified and reconstructed EGUs when determining compliance with the state goals under section 111(d).

A. EPA Has Reasonably Interpreted Section 111 as Requiring Sources to Continue to Comply with Section 111(d) State Plan Requirements Following a Modification or Reconstruction.

EPA's proposed rule correctly notes that section 111(d) is ambiguous as to whether state plan requirements must continue to apply to a source that modifies or reconstructs. In the preamble to the proposed emission guidelines for existing power plants, EPA explains that section 111 defines "new" and "existing" sources, and that section 111(d) clearly contemplates the submission of state plans that "establish[]" standards of performance for existing sources. However, the statute "does not say whether, once the EPA has approved a state plan that establishes a standard of performance for a given source, that standard is lifted if the source ceases to be an existing source."[392] EPA proposes to resolve this ambiguity by specifying that section 111(d) requires existing sources covered in a state plan to remain subject to the requirements of CAA section 111(d) plan after modifying or reconstructing.[393] EPA provides two reasons for this determination: (1) to avoid disruption and uncertainty as to which units will be part of state programs under a 111(d) plan; and (2) to avoid creating perverse incentives for sources to modify or reconstruct to escape 111(d) plan requirements, which could potentially be more stringent than 111(b) obligations.[394]

[392] 79 Fed. Reg. at 34,903-04.
[393] *Id.* at 34,904.
[394] *Id.*

EPA's position is a reasonable resolution of the ambiguous language of section 111(d), and is therefore due deference under *Chevron v. Natural Resources Defense Council*.[395] As EPA notes, the plain language of section 111(d) requires only that EPA create a procedure for states to submit plans that "establish[] standards of performance" for any "existing source." This language does not clearly state *when* a source is to be considered "existing" for purposes of defining the scope of the state plan. A requirement that a state plan must "establish[]" performance standards for any source that is "existing" *at the time emission guidelines are proposed or at the time of plan submittal* is consistent with the text of the statute, and reasonable given the particular structure of the Clean Power Plan. Under this interpretation, the function of the section 111(d) reference to existing sources is to specify the group of existing sources that become subject to state plans pursuant to EPA emission guidelines, but is silent on whether the later triggering of a section 111(b) standard affects the on-going applicability of the 111(d) standards to which that source is subject under the state plan.

EPA's determination on this issue is also consistent with past practice. On at least two occasions, EPA addressed the applicability of state plans to modified and reconstructed sources when it finalized revisions to NSPS and emission guidelines. In these rulemaking actions, EPA provided that new sources—including modified and reconstructed sources—are simultaneously subject to both state plans adopted under section 111(d) and EPA-issued performance standards under section 111(b).[396] In both of these rules, EPA promulgated a revised NSPS at the same time that it promulgated revised emission guidelines; although sources subject to the earlier NSPS were not "new" units for the purpose of the revised NSPS, the sources continued to be "new" for the purpose of the earlier NSPS, while simultaneously being "existing" sources with respect to the revised emission standards. For example, in 2009, EPA issued a final rule amending the NSPS and emission guidelines for hazardous, medical, and infectious waste incinerators (HMIWI), which were both initially promulgated in 1997. In that rule, EPA noted that the 2009 revised emission guidelines were, for some pollutants, more stringent than the NSPS that applied to sources constructed or modified between 1997 and 2009. Accordingly, EPA amended the 1997 NSPS to require that those units comply with the more stringent of the pollutant specific limitations in either the emission guideline or the 1997 NSPS, thereby simultaneously subjecting some sources to both the revised emission guideline and the 1997 NSPS.[397] EPA adopted a similar approach in 1995, when it amended the

[395] 467 U.S. 837, 842–844 (1984); *See also EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1604 (U.S. 2014) ("Under *Chevron*, we read Congress' silence as a delegation of authority to EPA to select from among reasonable options.").

[396] *See, e.g.*, 74 Fed. Reg. 51,368, 51,374 (Oct. 6, 2009) (hazardous, medical, and infectious waste incinerators subject to 1997 NSPS must continue to comply with 1997 NSPS requirements that are more stringent than 2009 emission guidelines for sources existing as of 2009); 60 Fed. Reg. 65,382, 65382 (Dec. 19, 1995) (municipal waste combustors remain subject to 1991 NSPS and must also comply with 1995 emission guidelines for units existing as of 1995). Although both of these examples are in the context of joint section 129/111 rulemaking, that context does not diminish their relevance to section 111 rulemakings. Under joint 129/111 standard-setting, the effect of the section 111(a) definitions on the applicability of NSPS to modified units is the same as for rulemakings under section 111. *See Davis County Solid Waste Mgmt. v. United States EPA*, 108 F.3d 1454 (D.C. Cir. 1997) ("Although section 129 does not specifically state that the NSPS applies to modified units, it excludes modified units from the definition of existing units and provides that the NSPS shall be issued pursuant to 42 U.S.C. § 7411, which defines new sources as those sources modification or construction of which occurs after publication or proposal of regulations, whichever is earlier."); 42 U.S.C. §§ 129(a)(1), 129(g)(3); *see also* 42 U.S.C. § 7411(a)(2).

[397] *See* 74 Fed. Reg. at 51,374.

NSPS and emission guidelines for municipal waste combustors.[398] These examples both demonstrate that "new sources" can simultaneously be subject to section 111(b) performance standards and section 111(d) state plans, as well as EPA's practice of requiring that sources comply with the most stringent of overlapping section 111(b) and 111(d) standards.

It is also worth noting that under prior standards of performance for reconstructed sources, those sources would remain existing sources (despite undertaking a modification and becoming a (b) source) if the required feasibility review demonstrated that the source could not meet the reconstructed source standard.[399] This reinforces the interlinked and complementary roles of the section 111(d) and (b) standards for reconstructed units. When undertaking a reconstruction and making major investments in infrastructure, the reconstructed source standard ensures that the most rigorous emission reduction outcomes are achieved if they are feasible—but the existing source standard applies as a backstop in cases where meeting the reconstructed standard is not feasible. In the context of the carbon pollution standards, the situation is analogous—the section 111(b) standard for reconstructed units must ensure that sources are deploying the best technologies available as these major infrastructure investments are being made, while at the same time the continued participation in the section 111(d) program ensures that the sources remain subject to the emission reduction framework that can meet the statutory requirements of maximizing emission reductions considering cost, energy requirements, and impacts on other health and environmental outcomes. In both cases the applicability of the section 111(b) and (d) standards works to ensure that sources are subject to performance standards reflecting the best system of emission reduction that has been adequately demonstrated, maximizing emission reductions considering the other statutory factors.

As noted above, this interpretation of the ambiguity in section 111(d) is also necessary to ensure that modified and reconstructed sources continue to remain subject to standards that reflect the "best system of emission reduction," as required for all standards of performance under section 111. EPA's proposed emission guidelines for existing EGUs rest on the determination that a flexible, broad emission reduction system—including efficiency improvements at existing EGUs, shifts to low and zero-emitting resources, and demand-side energy efficiency improvements—constitute the "best system of emission reduction." That determination remains no less true for existing EGUs that subsequently modify or reconstruct. To allow existing EGUs to avoid requirements under a section 111(d) state plan by modifying or reconstructing would potentially lead to higher emissions from those EGUs – a result that is completely inconsistent with the proper identification of the "best system of emission reduction" for those sources. The existence of a standard for sources undergoing major changes reflects Congressional recognition of the fact that such changes and investments create an opening for emissions performance to be improved. Indeed, the courts have understood that the purpose of standards under section 111(b) is to ensure that the

[398] *See* 60 Fed. Reg. at 65,382 ("Subpart Ea is applicable to MWC units . . . for which construction, modification, or reconstruction was commenced after December 20, 1989 . . . It should be noted that plants that are subject to subpart Ea will also be subject to the emission guidelines contained in subpart Cb, which apply to plants constructed on or before September 20, 1994."). The 1995 regulation provided that MWCs subject to the 1991 NSPS would also be subject to the new 1995 rules governing existing sources, which superseded the 1991 guidelines for existing sources. *See* 40 C.F.R. part 60, subparts Cb and Ea.
[399] 40 C.F.R. § 60.15(b).

emission performance of sources is improved when major investments are being made in infrastructure.[400] Because EPA's proposed interpretation provides that modified sources will be subject to emission controls that are *additional* to the level of control already imposed under the 111(d) plan, it is consistent with the pollution-mitigating framework of section 111 recognized by courts.

Lastly, as EPA recognizes, its determination that state plans continue to apply to modified and reconstructed EGUs is necessary to avoid disrupting state plans submitted under the proposed emission guidelines. The proposed emission guidelines establish average performance standards for existing EGUs in each state, which are premised on the performance of EGUs that were "existing" as of January 8, 2014. If certain existing EGUs were to exit this system by modifying or reconstructing, states and utilities could potentially have difficulty complying with these goals. Indeed, state goals would potentially need to be recalculated or constantly adjusted as EGUs leave the "pool" of existing sources by modifying. Furthermore, the creation of a group of existing fossil-fired EGUs that are not subject to the same carbon reduction signal as EGUs governed by the state plan would potentially lead to market distortions and result in "leakage" of emissions, as generation from EGUs governed by the state plan is displaced by increased generation at modified/reconstructed units rather than low or zero-emission generation. By clarifying that sources subject to section 111(d) plan requirements must continue to comply with those requirements after becoming subject to the 111(b) standard, EPA has avoided creating a perverse incentive that would undermine the effectiveness of the existing source carbon pollution standards.

In summary, section 111 is ambiguous as to whether existing sources continue to be subject to 111(d) requirements after modification or reconstruction makes that source subject to section 111(b) standards. EPA has reasonably resolved this ambiguity by concluding that state plans must continue to apply section 111(d) carbon pollution standards to those sources regardless of a later modification or reconstruction. This interpretation is consistent with the statutory text, EPA's past practice, and judicial interpretations of the framework of section 111, and is necessary to avoid perverse incentives that could undermine the regulatory scheme and weaken limits on carbon pollution.

B. EPA Should Provide that Sources that Modify Prior to 111(d) State Plan Submission Are Subject to the 111(d) State Plan Requirements.

Whereas EPA has clearly stated that sources that modify or reconstruct *after* becoming subject to a section 111(d) state plan remain subject to the state plan requirements,[401] the Agency has not made it clear that sources modifying or reconstructing *prior* to submission of a state plan are subject to section 111(d) state plan requirements. Although one part of the proposal suggests that all modifications and reconstructions are subject to section 111(d),[402] another portion of the proposal asserts that sources that modify or reconstruct after plan submission will continue to be subject to the plan.[403] EPA should

[400] *See Sierra Club v. Costle*, 657 F.2d 298, 325 (D.C. Cir. 1981) ("[Section 111(b)] standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install, thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth.").
[401] *See* 79 Fed. Reg. at 34,903-04.
[402] *See* 79 Fed. Reg. at 34,965/1.
[403] *See* 79 Fed. Reg. at 34,963/1.

expressly provide that sources modifying or reconstructing after the proposal of its emission guidelines and prior to state plan submission are still sources for which state plans must establish performance standards under section 111(d).

Sources that modify or reconstruct prior to submission of a section 111(d) plan should be subject to section 111(d) plan requirements for the same policy reasons described in the preceding section of these comments—most significantly, because the existing source "best system of emission reduction" remains the system that will ensure the greatest pollution reductions from these EGUs considering cost and other statutory factors. Further, as noted above, allowing such modified or reconstructed EGUs to exempt themselves from section 111(d) would potentially undermine the stringency of state plans by allowing "leakage" to modified or reconstructed sources. Moreover, such an approach would potentially require the recalculation of state goals and disrupt the development of state plans, all of which are premised on securing reductions from EGUs that were "existing" as of January 8, 2014.

Requiring, in the finalization of these standards, that state plans apply to all sources that were "existing" as of the date the emission guidelines were proposed is also consistent with the statutory text. As described above, section 111(d) vests EPA with broad authority to establish procedures governing the submission and content of state plans that "establish[]" performance standards for "any existing source." Also as noted above, the statute does not clearly delineate the point in time at which a source should be considered to be "existing" and therefore within the scope of a state plan. However, EPA's proposed emission guidelines set state-wide goals that are based on the "best system of emission reduction" for all EGUs that were under construction or in operation as of January 8, 2014. Accordingly, it is reasonable and consistent with the statute for EPA —acting under its authority to establish minimum requirements for state plans, including determining the scope of those plans—to require that state plans establish performance standards for the same set of existing sources addressed in the emission guidelines.

C. EPA Can Consider Additional Measures to Ensure that Modifications and Reconstructions Do Not Undermine State Goals Under Section 111(d).

Although EDF strongly supports EPA's proposal that section 111(d) standards remain applicable to sources that modify or reconstruct, we note that there are at least two additional mechanisms EPA can consider to ensure that the proposed emission guidelines for existing EGUs are coordinated effectively with the proposed standards for modified and reconstructed EGUs.

1. EPA Could Undertake Frequent Review of the NSPS.

Although section 111(b) of the Clean Air Act clearly requires that carbon pollution standards for new sources be reviewed at least once every eight years,[404] EPA could establish a more frequent schedule for revision (such as once every five years) in recognition of the rapid evolution of methods to reduce carbon pollution from the power sector. A more frequent schedule for revision of the carbon pollution standards for new, modified, and reconstructed EGUs would ensure that sources that modify or reconstruct quickly come into compliance with section 111(d), consistent with EPA's past practice of

[404] 42 U.S.C. § 7411(b)(1)(B).

subjecting modified and reconstructed sources to state plans upon revision of an applicable NSPS.[405] In so doing, EPA would also reduce potential incentives for EGUs to modify or reconstruct for the purpose of avoiding state plan requirements under section 111(d).

2. EPA Could Require that Emissions from Modified and Reconstructed Units "Count" When Determining State Compliance with Section 111(d).

Alternatively, in the event that modified or reconstructed EGUs are excluded from state plans under section 111(d), EPA could require that emissions from those units continue to be "counted" when determining whether states have complied with the goals promulgated in the emission guidelines. Such a requirement would not impose any section 111(d) obligations on the modified or reconstructed EGUs, but would ensure that limits on carbon pollution under section 111(d) are not undermined by "leakage" resulting from increased emissions at those modified or reconstructed EGUs. In practice, state regulators would have a strong incentive to ensure that modified and reconstructed units are subject to either state plans or to additional emission limitations in order to ensure compliance with the section 111(d) goals.

This approach is not precluded by the broad language of section 111(d), which affords EPA significant discretion to determine *how* states demonstrate compliance with an emission guideline. Moreover, EPA could justify this approach as necessary to ensure an accurate accounting of emissions from affected EGUs. This is because generation from any EGU that modifies or reconstructs would effectively be substituting for generation from the same EGU prior to its modification or reconstruction. If generation and emissions from modified and reconstructed EGUs were not counted in the state's emission rate under section 111(d), emissions from existing EGUs could *appear* to decrease solely because some of those units had become modified or reconstructed sources subject to section 111(b). EPA could reasonably conclude that to protect against such "over-crediting," emissions from modified and reconstructed EGUs must be included in a state's average emission rate.

This approach would also have the effect of treating modified or reconstructed EGUs in a way that is comparable to incremental nuclear, renewable energy and energy efficiency—all of which are considered as resources that displace affected EGUs and therefore enter into the compliance determination for each state as zero-emitting resources. Further, because the emissions from the units in question were taken into account when EPA established the state goals, it would be appropriate to find that those emissions must continue to count in determining compliance with that target. In other words, because the proposed state goals reflect the emissions from those units, the state's compliance demonstration must also include the emissions from those units.

[405] As described in section I.a of our comments, *supra*, this practice was reflected in the 1995 revision of the NSPS for both municipal waste combustors and the 2009 revision of the NSPS for HMIWI.

III. Environmental Justice

We urge EPA to ensure that the communities long afflicted by power plant pollution are protected under the Clean Power Plan consistent with our nation's clean air laws and Executive Order 12898, *Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations*. Executive Order 12898 mandates that each Federal agency make achieving environmental justice part of its mission. Section 110(l) of the Clean Air Act has long prohibited state implementation plans that interfere with timely attainment or reasonable further progress in protecting human health from air pollution. EPA should apply this core tenet of protection to its administration of section 111 of the Clean Air Act and the Clean Power Plan. The bedrock protective intent of the Clean Air Act is established in its foundational statutory purpose—to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare" (Section 101(b)(1))—and reflected throughout the fabric of the law. This can be effectuated by ensuring that the Mercury and Air Toxics Standards and health-based air quality standards are rigorously implemented alongside the Clean Power Plan, and by creating a strong framework for coordinated air quality planning so that emissions reductions are secured in areas with unhealthy air pollution concentrations.

We urge EPA to include in the final rule a robust discussion of how states can perform analyses to identify air pollution burdens disproportionately burdening disadvantaged communities and of the ways in which state plans can be designed to ensure that communities bearing a disproportionate share of air pollution burdens have those burdens reduced. These communities might be, in different states, geographically-defined communities, low-income communities, or communities of color.

This will be particularly important in the context of state planning to achieve the revised ambient air quality standards for particulate and ground-level ozone (the main component of smog), as fossil fuel-fired power plants, particularly coal-fired power plants, are both large sources of carbon pollution and of SO_2 and NO_x, which are key ingredients of particulate pollution and smog. Scientific evidence clearly indicates that exposure to these contaminants can reduce lung function and irritate airways, increasing respiratory problems and aggravating asthma and other lung diseases, leading to increased vulnerability to respiratory infections and increases in doctor visits, emergency room visits, hospital admissions, and school absences. Exposure also increases the risk of premature death from heart and lung disease. Children are at increased risk because their lungs are still developing and they are more likely to be active outdoors, increasing their exposure—and African American and Latino children are particularly at risk of asthma[406] and asthma-related hospitalizations.[407]

As states develop plans to address ozone, particulate and carbon pollution—and as sources prepare to meet Clean Air Act restrictions on emissions of mercury and other toxic air pollutants--the potential to reduce burdens on disadvantaged communities can and must be realized.

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[406] *See* http://www.lung.org/assets/documents/publications/solddc-chapters/asthma.pdf.
[407] *See* http://www.epa.gov/epahome/sciencenb/asthma/HD_Hispanic_Asthma.pdf; see also http://lulac.org/programs/health/asthma/.

The Clean Power Plan also creates an increased opportunity to deploy distributed renewable energy generation and demand-side energy efficiency to make American homes and businesses more efficient and energy independent, lowering utility bills, and stimulating local economies as bill savings are rededicated to other goods and services. EPA should urge states to ensure that communities that have borne heavy burdens from fossil fuel-fired power plant emissions—and low-income communities more broadly--have full access to opportunities to develop renewable generation (including distributed renewable generation) and opportunities to benefit from investments in demand-side energy efficiency improvements. Full access will likely mean ensuring that traditional barriers to accessing these types of cost-saving and energy-saving programs are overcome, including by encouraging innovative financing arrangements and addressing problems that arise when landlords are not paying energy bills and thus lack a sufficient incentive to invest in demand-side energy efficiency improvements. Further, in developing guidance for evaluation, measurement and verification of the energy savings that result from energy efficiency programs, EPA should prioritize developing guidance that will facilitate investments in energy efficiency in low-income communities and communities of color, and make it clear to states that these types of programs can be deployed, and verified, as part of a compliance strategy.

Under the newly proposed Clean Power Plan, EPA projects that by investing in energy efficiency household and business energy bills can decrease by about 8% by 2030.[408] As noted in our comments on the potential for demand side energy efficiency to provide more extensive direct bill savings for low income Americans, *through well designed state programs the bill savings to families could be significantly greater with greater deployment of energy efficiency —securing a 15% improvement in energy efficiency by 2030 could generate annual average household savings of $157. State deployment of demand side energy efficiency solutions to mitigate carbon pollution can provide both multipollutant reductions while providing direct bill savings for communities suffering from high pollution levels.*

[408] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, at 3-43 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

IV. Support and Recommendations for Strengthening the BSER and Building Block Formula

A. Best System of Emissions Reduction and Building Block Formula

We strongly support EPA's proposed "best system of emission reduction" (BSER), which sets targets for each state's CO2-emitting power plants by looking at the real-world potential to reduce their carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-polluting and less on the highest-emitting power plants.

Under the Clean Air Act, EPA is required to identify the "best" system of emission reduction that has been "adequately demonstrated" considering cost, energy requirements, and other health and environmental outcomes. We know that the system of emission reduction proposed by EPA is adequately demonstrated because power companies and states across the country are effectively using each of the building blocks to cut emissions of carbon pollution and other dangerous air pollutants from fossil fuel-fired power plants. We agree with EPA that it is the "best" system as defined by the Clean Air Act because it has the potential to secure large reductions in carbon pollution at reasonable cost, and will provide companies and states with flexibility to manage energy requirements and identify the emission reduction pathways that make the most sense for them. (See our legal discussion in Section I for more detail on the legal justification for BSER)

This system of emission reduction reflects the real-world reality of the electricity system, within which different power generation sources and demand-side energy efficiency resources are managed dynamically to ensure that energy demand is met at each moment in time. Companies and states have long been relying on the interconnected nature of the electric grid to reduce harmful pollution from power plants. Adding renewable electricity backs down generation at fossil fuel-fired plants—and reduces emissions accordingly. Likewise, improving energy efficiency lowers demand for electricity, reducing power generation and thus emissions. States and power companies have been increasing use of natural gas plants which has reduced emissions from coal-fired power plants. Coal-fired power plants can (and many already do) co-fire with natural gas, which reduces combustion emissions. Coal plants can also be converted to burn natural gas which reduces combustion emissions, which has occurred at many facilities. These techniques—switching to lower carbon fuels, non-emitting generation resources, and improving energy efficiency—are traditional methods of addressing air pollution under the Clean Air Act.

As discussed *supra*, EPA's proposed system of emission reduction — an emission limit that power plants can achieve through compliance measures including efficiency improvements at power plants, shifts from coal to gas-fired power generation, deployment of renewable energy, and harvesting energy efficiency — meets the requirements of the Clean Air Act. The emission reduction techniques included in the targets are "adequately demonstrated" and enable sources to achieve the greatest emission reductions considering cost, impacts on energy, and other health and environmental outcomes (note comments below on expanding and strengthening the BSER). The flexibility of this system enables states to secure emission reductions cost effectively, to manage impacts on energy and ensure that there are no effects on reliability, and to reduce carbon emissions by building on existing state clean energy and efficiency programs. This system allows states to secure all of the co-benefits of transitioning to cleaner energy and harvesting energy efficiency, reducing not only carbon pollution but also the burden of other health-harming air pollution on their communities. Investment in renewable generation and energy efficiency will drive job creation. The fuel savings of renewable resources and energy efficiency improvements will lower utility bills for families and businesses. Those savings will then be spent on other goods and services, stimulating the economy, as states with strong energy efficiency programs are already experiencing.

1. Support for a Stronger BSER

The system of emission reduction identified by EPA can achieve even greater emission reductions than is reflected in EPA's analysis. In the comments and sections that follow we describe the opportunity to strengthen each of EPA's BSER Building Blocks and how to do so at reasonable cost.

The BSER building blocks proposed by EPA include:

Block 1: Making existing coal plants more efficient

Block 2: Using existing natural gas plants more effectively

Block 3: Increasing renewable and nuclear generation

Block 4: Increasing end-use energy efficiency

A careful analysis of the emission reduction opportunities in each of the four blocks identified by EPA demonstrates that even greater savings are available from each of the four blocks. As discussed in detail below and in EPA's Notice of Data Availability Released on October 27, 2014, in order to reflect the role of renewable energy and energy efficiency in displacing fossil generation emissions, EPA must also fix the formula for calculating state targets.

a. Implementation of BSER Goal-Setting Equation and Treatment of Incremental Renewables and Energy Efficiency

In its October 27, 2014 Notice of Data Availability (NODA), EPA explains that the original formula used in its proposed rule does not fully account for the emission reductions generated by renewables and energy efficiency. As EPA explains, the formula used in the proposed rule failed to account for the reduction in generation at coal and gas power plants that will occur when renewables are added to the grid and when we improve energy efficiency. When EPA sets final state targets, it should use the corrected formula proposed in the Notice of Data Availability. This is necessary to ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

i. The Formula Must Be Adjusted to Conform to the Preamble Explanation for Why Renewables and Energy Efficiency Are Included in the BSER

In the preamble, EPA explains that renewable energy and energy efficiency are part of BSER is because they all decrease the amount of generation at (and therefore emissions from) affected power plants.[409]

In the goal-setting equation, EPA correctly accounted for the emission-reducing effect of coal to gas shifts in utilization (by accounting for reductions in emissions from coal-fired power plants and increases in emissions at gas-fired power plants as the shift occurs) but failed to correctly account for the effect of renewable energy and demand-side energy efficiency in blocks 3 and 4 in displacing fossil emissions. The original proposal's state target calculation formula simply adds additional renewable energy and energy efficiency megawatts to the denominator of the state emission rate without commensurately reducing generation or emissions at fossil-fuel fired plants. As a result, increasing block 3 and 4 resources *dilutes* rather than *replaces* megawatts generated by block 1 and block 2 resources. This is inconsistent with the premise that these resources will "reduce, or avoid, generation from all affected EGUs on a state-wide basis."

The defect in the original formula is significant because the mathematical effect of subtracting fossil generation emissions more accurately reflects what actually happens when renewable power substitutes for, and energy efficiency obviates the need for, an equivalent quantity of fossil generation. EPA must correct the formula as described in the Notice of Data Availability in order to properly reflect the emission reductions achievable based on the best system of reduction identified by EPA.

ii. Recommendations for How to Implement the Corrected Formula

EPA has proposed two alternative approaches that would apply incremental renewable energy and energy efficiency to replace existing fossil generation. Under the first alternative approach, incremental RE and EE would displace historical fossil generation and emissions on a pro rata basis across all fossil generation types, including fossil steam and natural gas. Under the second alternative approach, the adjustment to the historical levels of fossil generation corresponding to the addition of zero-emitting generation would replace highest-emitting generation before replacing lower-emitting generation.

EDF supports both of these approaches, and believes both are valid for BSER state goal setting. EDF encourages EPA to adopt the first approach, revising the target-setting formula so that incremental RE and EE (beyond 2012 levels) directly replace fossil generation and the corresponding emissions in proportion to the 2012 fossil generation mix, which could be seen as reflecting the potential for states to substitute zero carbon resources and energy efficiency for the highest-polluting generation. However, we also support the alternative approach, noting thatit acknowledges that the addition of incremental RE and

[409] 79 Fed. Reg. at 34891 ("the measures in building blocks 3 and 4 . . . reduce, or avoid, generation from all affected EGUs on a state-wide basis."); *see also id.* at 34852 (identifying BSER to include blocks two, three and four because "increases in . . . zero or low-emitting generation, as well as measures to reduce demand for generation . . . taken together, displace or avoid the need for, generation from affected EGUS").

EE could replace various fossil resource types without strictly replacing fossil in order of decreasing carbon intensity.

If EPA adopts a formula in which renewables and energy efficiency displace NGCC and coal-fired generation on a pro rata basis, it must also ensure that it corrects the potential emission reductions from building block 2. When renewables and energy efficiency displace NGCC generation, this will lower the capacity factor of NGCC plants and create additional potential reductions from building block 2. These additional reductions can be achieved either by displacing fossil generation from blocks 3 and 4 before calculating block 2 or by doing a true-up to block two to ensure that NGCC plants remain at a 70 percent capacity.

The formula adjustment will ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

B. Recommendations Regarding the 2012 Baseline & 3 year Average

EPA proposed using 2012 as the generation and emissions year from which to assess the opportunity to reduce emissions. EPA asked for comment on using 2010, 2011 or some average or combination of the three years. EPA also included all existing fossil generation in their calculation and formula, but the agency did not include total generation (all nuclear and hydro). The agency included non-hydro renewables and a portion of nuclear. In this section we address the baseline years and what should be factored in to the formula.

Baseline or Comparable Year

EDF strongly supports using the most up-to-date data and most recent baseline year to develop the emission reduction target for each state. The goal of this exercise is to reduce emissions from existing power plants, and the most recent data available on the sources and utilization of electric generation in each state is the best starting point for such an analysis. Data on the level and composition of generation from several years ago is less relevant to a forward-looking assessment of emission reduction opportunities in each state. Accordingly, EPA is right to start examining the potential to reduce emissions from where we are today and assessing the potential for states to reduce emissions based on that one common starting point.

However, some stakeholders have noted that any one year can have anomalies for one or more plants in a given state. While we do not think this issue is very significant, EPA could reasonably consider using a multi-year average as the starting point in their evaluation and formula for states with such anomalies. A relatively short averaging period, consisting of the most recent years of operating data, could help resolve concerns over unique operational circumstances that may have occurred in 2012.

EDF does not believe states should be allowed to pick from the three years, as this will inevitable create an incentive to pick only the highest emission year (s) in order to set the emissions standard at the highest point possible, reducing the requirement on generation in the state to change their emissions profile over time. Allowing states to choose years will undermine the environmental outcome of the CPP.

Inclusion of Renewables and Nuclear

EPA has included non-hydro renewables and a portion of nuclear power in calculating the 2012 state emission rates. We encourage EPA to examine the benefits of removing all the non-fossil generation from the BSER baseline year starting point in the formula given the following considerations.

1) Current State Renewables Policies and In-state vs. Out of State Considerations:

   In many states, the state policies that have delivered the most development and generation from new renewable energy have been state renewable energy or portfolio standards (RES/RPS). These standards have been increasing over time and have led to the development of significant new renewable resources, particularly wind and solar. However, while these state policies require an increasing percentage of the electricity delivered in the state to be from renewables, most of these state policies do not require the generating resource to be located in the state. Many states have developed or purchased large quantities of wind generation to satisfy the RES/RPS requirements in other states. Reflecting this market reality, EPA has proposed that credit for the emission reductions driven by renewable energy deployment be assigned to the purchaser of the renewable energy credit (REC), which we support.

   State 2012 emission rates under the proposal reflect in-state renewable energy—although the entities holding the RECs associated with that renewable energy may be out of state. EPA should address consistency between the BSER formula structure, current state renewables tracking, and planned compliance tracking. While there are other ways this could be done, we suggest the simplest way would be to consider only new renewables generation and not include existing generation in the BSER baseline. This allows EPA to avoid allocating generation from existing renewables in the BSER formula. Looking forward there would be no concern about using RECs for tracking generation whether from in-state or out of state generation.

2) Consistency of State Targets:

   Inclusion of non-fossil resources in the BSER formula leads to state targets that diverge more than when an average fossil rate is used as the starting point. If states develop a flexible rate-based policy approach and their neighboring state has a very different target level, there is a possibility that generators of the same type on either side of a state border would face different compliance costs. This kind of competitiveness issue could lead to environmental leakage, but it would be reduced if the starting point for developing the state standards was a fossil rate.

C. Comments on the Length of the Compliance Period

1. EPA Should Not Adopt the Alternative Option of a Single 5-year Compliance Period in Combination with Weaker CO_2 Emission Performance Goals

EPA should not adopt the alternative option imposing weaker CO_2 limits over a 5-yr time span. EPA's own data and analysis shows that the best system of emission reduction deployed over this time period would achieve significantly greater emission reductions than are reflected in the proposed alternative state goals. *See* 79 Fed. Reg. at 34,898.

EPA has not justified the assumptions underlying the reduced stringency of the alternative goals associated with the 5-year compliance plan alternative. In setting the interim and final goals for this alternative option, EPA made several adjustments to the set of assumptions used to generate the proposed goals associated with the 10-year compliance period. *See id.* at 34,898. First, with respect to the anticipated heat rate improvement from coal-fired EGUs under Block 1, EPA used a value of four percent instead of six percent. *Id.* Second, under Block 2, EPA assumed that the potential annual utilization rate for NGCC units would increase to 65 percent instead of 70 percent. *Id.* Third, under Block 4, EPA assumed that annual incremental electricity savings achievable through a portfolio of demand-side energy efficiency programs would be one percent instead of 1.5 percent. *Id.* As EPA has noted, these assumptions may be "overly conservative," and "underestimate the extent to which the key elements of the four building blocks . . . can be achieved." *Id.*

EPA has provided no analysis to support the adjusted assumptions aside from the assertion that "the time period for implementation relates directly to the emission reductions that are achievable[.]" *Id.* If EPA were to establish only a single 5-year compliance period, the state targets should reflect the full emission reduction potential available during that 5-year period, commensurate with potential shown during the initial five years of the proposed 10-year compliance period as strengthened through the recommendations discussed in these comments.

2. The Interim Standard is Amply Achievable and, As EPA Itself Finds, More Rigorous Emission Reductions are Achievable in 2025. Further, Consistent with the Statutory Requirements to Periodically Modernize BSER, EPA Must Establish a Legally Enforceable Mechanism that Requires a BSER Determination in 2025 to Secure Additional Deeper Reductions Beginning No Later Than 2030.

The Interim Standard that takes effect beginning in 2020 is amply achievable. The extensive analysis of the building blocks, set out above, addresses important and cost-effective ways the building blocks can be strengthened by achieving deeper emissions reductions and securing the emissions reductions more swiftly than assumed. This includes, for example, the availability of deeper reductions at the source through cost-effective co-firing and repowering with lower emitting fuels that is being widely deployed at coal plants today, the demonstrated potential to

deploy more extensive and cost-effective renewable energy resources, and the rapid mobilization of demand side energy efficiency including a broader array of efficiency solutions than considered by EPA. Further, as discussed in part XIII there is extensive flexibility integrated into the compliance design of the interim standards. In sum, there is a strong – more than amply achievable – basis for meeting the proposed interim standard.
Moreover, EPA expressly recognized that a more rigorous standard could be achieved by 2025, finding that it is achievable for power sector emissions to be 29 percent below 2005 levels in 2025 based on the changes reflected in the four building blocks:

> EPA's analysis shows that under the proposed goals described in Section VII.C above, power sector emissions will be 29 percent below 2005 levels in 2025, suggesting that the kinds of changes contemplated in the four building blocks, even as early as 2025, will be yielding reductions far greater than the 23 percent projected for the alternate goals as set forth above in this subsection.

79 Fed. Reg. at 34,899.

EPA's finding that a deeper reduction in 2025 is achievable based on solutions adequately demonstrated meets the pertinent statutory criteria for determining the best system of emission reduction and thereby requires EPA to establish such a standard in 2025 that "reflects the degree of emission limitation achievable." As such, EPA must establish a five year compliance requirement beginning in 2025 and continuing through 2029 that is far more rigorous than the 2020-2029 10-year average interim standard.

Finally, EPA requests public comment on whether to require maintenance of the 2030 standard beyond that date or, alternatively, to review and revise its BSER determination post 2030:

> The EPA also requests comment on whether we should establish BSER based state emission performance goals for affected EGUs that extend further into the future (e.g., beyond the proposed planning period), and if so, what those levels of improved performance should be. Under this alternative, the EPA would apply its goal-setting methodology based on application of the BSER in 2030 and beyond to a specified time period and final date. The agency requests comment on the appropriate time period(s) and final year for the EPA's calculation of state goals that reflect application of the BSER under this approach.
>
> The EPA notes that CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources. This requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The agency requests comment on the implications of this concept, if any, for CAA section 111(d).

79 Fed Reg. at 34899.

As EPA recognizes, Congress has woven an updating mechanism into the fabric of section 111 that commands the Agency to refresh the BSER analysis for new sources "at least every eight years" and is inextricably connected with updating the existing source standards through the expansive statutory definition of the term "new source," the terms of section 111(d), and the long-standing EPA regulations implementing section 111(d) in parallel with section 111(b).

The availability of clean low carbon solutions is advancing at a rapidly accelerating pace as clean technologies are being drive to scale and meeting our nation's power needs at briskly diminishing costs. See WRI, *Seeing is Believing*. There is every indication that like other modern clean air solutions for the power sector, including scrubbers and SCR, as well as for other major source sectors, that emissions reductions in the near future will be achievable more swiftly, more deeply and at a fraction of the costs currently expected. See U.S. EPA, "The Clean Air Act Amendments: Spurring Innovation and Growth While Cleaning the Air" (prepared by ICF Consulting, 2005).

EPA must hew to the facts in determining BSER and carry out its legal responsibility to commit to determine in 2025 through a legally enforceable mechanism the BSER that applies over time – and that is not stagnant in maintaining in 2030 the standard of performance established a decade earlier. Rather, the BSER analysis must be, as Congress intended, a is vibrant, rigorous, and dynamic tool in securing for our nation's public health, environmental quality, and prosperity--no later than the 2030 timeframe--the additional far deeper "degree of emission reductions achievable."

D. EPA Should Not Adopt a BSER Based Only on Building Blocks 1 & 2

Across the country, states and power companies are reducing carbon pollution through increased deployment of low/zero-emission generation and demand side energy efficiency programs on the integrated power grid. EPA has documented these on-going initiatives to reduce CO_2 emissions from the power sector. *See* 79 Fed. Reg. at 34,848-50; *see also* Section I.I., *supra*. These systems of emission reduction are adequately demonstrated and are producing very significant reductions in carbon pollution at reasonable cost. As such, EPA has properly determined that the BSER includes these approaches to achieving emissions reductions.

EPA nonetheless solicits comment on whether to apply "only the first two building blocks as the basis for the BSER, while noting that application of only the first two building blocks achieves fewer CO_2 reductions at a higher cost." 79 Fed. Reg. at 34836. Applying only the first two building blocks as the basis for the BSER would needlessly exclude key demonstrated available emission reduction measures that, as EPA recognizes, will allow states to achieve greater emission reductions more flexibly, and to achieve those reductions more cost effectively while generating greater co-benefits in reductions of harmful co-pollutant emissions, utility bill savings, and economic stimulus.

As outlined in detail in these comments at section I.E, the statutory term "best system of emission reduction" is broad enough to encompass consideration of measures that have the effect of preferring lower polluting means of producing a product—in this case, energy services. Consequently, EPA has the authority (and indeed, the obligation) to consider the measures in building blocks three and four in determining the combination of measures that constitutes the BSER. Further, EPA's analysis demonstrates that a system of emissions reduction that combines these measures with the measures encompassed by Building Blocks 1 & 2 will achieve greater emissions reductions more cost effectively than a system relying only on Building Blocks 1 & 2. Because the proposed system of emission reduction is thus superior to a system relying on Building Blocks 1 & 2 only, EPA cannot adopt a BSER that disregards the use of key measures that states and companies are already undertaking to reduce emissions.

E. Net Generation Should Be the Basis for State Goals and Emission Reporting

EDF supports EPA's proposal to express the rate-based state goals in terms of emissions per unit of net generation, as opposed to gross generation, and believes that this approach should be extended to all of the pending proposed standards for fossil-fired EGUs.[410] As EPA acknowledged in the preamble to the proposed NSPS for new EGUs, the "net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer."[411] Using net generation as the basis for rate-based standards appropriately incentivizes owners and operators of EGUs to optimize the efficiency of their plants by reducing parasitic loads associated with auxiliary equipment and emission controls. Such improvements in efficiency increase the *useful* output of the plant while avoiding increases in fuel consumption and emissions. Under a standard based on net generation, these improvements in efficiency would lower the emission rate and contribute towards bringing a fossil EGU into compliance. By contrast, a rate-based standard based on gross generation does not recognize any differences in efficiency of auxiliary equipment and pollution control systems among EGUs – and as such fails to fully incentivize the efficient generation of electricity. For this reason, a gross generation-based standard is inconsistent with the overall technology-forcing purpose of performance standards under section 111, as well as EPA's recognition in building block 1 that improvements in fossil plant efficiency – yielding greater useful output while maintaining or reducing emissions — are an important part of the BSER.

Establishing state goals in terms of net generation is also eminently feasible both for EPA and for the states. EPA recognizes in the preamble to the proposed rule that "[n]early all EGUs already have in place the equipment necessary to determine and report hourly net generation," indicating that monitoring and reporting net generation would not be burdensome.[412] Indeed, although net generation is currently not reported to EPA under 40 CFR Part 75, affected EGUs are generally required to report gross and net generation on a monthly basis to the Energy Information Administration (EIA) through Form 923

[410] *See* Comments of Sierra Club et al. on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0495-9514, at 106 (May 9, 2014).
[411] 79 Fed. Reg. at 1448.
[412] *See* 79 Fed. Reg. at 34,894.

submittals.[413] Recent PSD permits for new and modified EGUs also include emission standards based on net generation, providing further support for the feasibility and reasonableness of this approach.[414] Accordingly, EDF strongly supports expressing all emission standards for fossil fuel-fired EGUs in terms of net generation – including the emission guidelines in the Clean Power Plan as well as the performance standards for new, modified, and reconstructed EGUs.

F. EPA Should Consider Combining the Source Categories for Affected EGUs

EDF supports consolidating the two source categories of affected EGUs covered by the emission guidelines – electric steam generating units and combustion turbines – into one regulated source category for purposes of establishing carbon pollution standards for all EGUs, including the emission guidelines for existing EGUs as well as the performance standards for new, modified, and reconstructed EGUs. As we explain below, a consolidated source category would reflect the identical market functions served by all of the affected EGUs covered by EPA's proposed carbon pollution standards. A single source category would also be consistent with the system-based approach EPA has proposed, which has important elements that reduce emissions from existing EGUs as a whole rather than solely from EGUs utilizing particular fuels or generating technologies.

In the proposed emission guidelines, EPA observes that the proposed emission guidelines apply to affected EGUs that EPA has separately listed in two source categories under section 111 — steam electric generating units (listed in 1971) and stationary fossil fuel-fired combustion turbines (listed in 1979). EPA also notes that it proposed to combine these two source categories in its January 8, 2014 proposed rule to establish carbon pollution standards for new fossil fuel-fired EGUs (alongside a "co-proposal" to retain the current source category listings), and solicits comment on that approach again here. EPA suggests that combining both source categories would, among other things, potentially facilitate emissions trading among the EGUs in the two currently-listed source categories, or simplify the implementation of certain system-wide emission reduction measures.[415]

As a threshold matter, EPA correctly states that it has clear legal authority to consolidate or reorganize an already-listed source category without making new regulatory findings that would be required for the listing of an entirely new source category under section 111(b)(1). Section 111(b)(1)(A) directs EPA to publish, "and from time to time thereafter…revise," a list of stationary source categories that in the Administrator's judgment cause or significantly contribute to pollution that endangers public health and welfare. Apart from the finding of endangerment required for the listing of a *new*, not previously-listed

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[413] *See* EIA, Form EIA-923: Power Plant Operations Report Instructions, OMB No. 1905-0129 (Exp. Dec. 31, 2015).
[414] *See* EPA, Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions, Port Everglades Plant, Permit PSD-EPA-R4010 (Nov. 2013), *available at* http://www.epa.gov/region04/air/permits/ghgpermits/porteverglades/PortEverglades_FinalPermit_112513.pdf; *see also* EPA, Prevention of Significant Deterioration Permit for Pioneer Valley Energy Center, Final PSD Permit Number 052-042-MA15 (Apr. 2012) (Requiring that new 431 MW NGCC facility meet a CO2 emission standard of 825 lb/MWh on a net output basis).
[415] 79 Fed. Reg. at 1,455.

source category, the statute places no particular limits on EPA's authority to "revise" the list of stationary sources over time. EPA's proposed consolidation of the source categories for steam electric generating units and fossil fuel-fired combustion turbines would neither expand nor otherwise alter in any way the universe of sources comprising those source categories, and would therefore not constitute the listing of a new source category. Nor would it somehow alter the predicate endangerment finding that EPA made when it originally listed both source categories in the 1970's.[416] EPA is therefore free to make reasonable revisions to the source category listings, including the consolidation of already-listed source categories, without significant new findings.

Here, the proposed consolidation of the source categories would be reasonable for at least three reasons. First, steam electric generating units and fossil fuel-fired combustion turbines broadly serve the same market functions. Not only do units in these source categories all generate electricity for wholesale, they also increasingly provide similar *types* of generating service. In a climate of competitive natural gas prices and relatively high coal prices, coal-fired steam electric generating units now commonly provide intermediate or even peaking generation service rather than playing their traditional role as baseload resources. And as coal generation has declined, gas-fired combustion turbines – especially NGCC facilities – have become intermediate or baseload resources rather than providing primarily peaking service. Combining these two source categories to reflect their converging market functions, as we recommend, would be consistent with the categorization contemplated by Congress when it originally enacted section 111 in 1970.[417] It would also be consistent with the history of these *particular* source categories; for example, in 2005, EPA transferred integrated gasification combined cycle (IGCC) facilities to the steam electric generating unit source category on the grounds that IGCC facilities serve the same function.[418] And it would be consistent with various other instances in which EPA has established broad categories encompassing multiple types of sources that serve the same function, even though those source categories may encompass facilities using disparate fuels and industrial processes.[419]

Second, the consolidation of these two source categories would be consistent with the system-based nature of the BSER that EPA has proposed in these emission guidelines. Importantly, the four building blocks in EPA's BSER are intended to function in concert to reduce emissions from *all* EGUs across the two source categories. The effects of any individual building block on any one type of EGU, however,

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[416] Although the statute does not require that EPA make a *new* finding of endangerment when regulating additional pollutants from an already-listed source category, EPA has provided more than ample evidence to support such a finding in its pending proposals to regulate carbon pollution from new and existing EGUs.

[417] The legislative history of the 1970 Clean Air Act indicates that Congress expected EPA would establish standards within broad functional categories of facilities. One representative, for example, stated that EPA "could establish uniform pollution control standards for the chemical, oil refining, foundries, food processing, and cement-making industry, and other industries. . . . Every plant within the same group could be required to maintain the same high standards." 116 Cong. Rec. 19,218 (1970) (statement of Rep. Vanik).

[418] *See* 77 Fed. Reg. 22392, 22,411/1 (April 13, 2012).

[419] For example, EPA designated a single NSPS for multiple copper smelting production methods as early as 1976. *See* 41 Fed. Reg. 2332-2333 (Jan. 15, 1976). Similarly, EPA's rotary lime kiln source category includes units fueled by coal, natural gas, and oil. *See* 47 Fed. Reg. 38832, 38843 (Sept. 2, 1982); *see also* 40 C.F.R. §§ 60.340(a), 60.342. And most recently, EPA included all Portland cement plants (*e.g.* "long wet," "long dry," "preheater," and "preheater with precalciner") in a single source category. 75 Fed Reg. 54970, 55,010-55,012, 55,015 (Sept. 9, 2010). This decision was ultimately held by the D.C. Circuit. *See Portland Cement Ass'n v. EPA,* 665 F.3d 177, 190-93 (D.C. Cir. 2011).

will depend upon power market dynamics. For example, building blocks 3 and 4 – which involve shifting generation to zero-carbon resources such as renewable energy and energy efficiency – displace the need for *both* generation from fossil fuel-fired combustion turbines and steam electric generating units. The extent to which these building blocks reduce generation from one or both types of EGUs, however, can vary by region of the country and even by season of the year. Establishing a single source category for both steam electric generating units and fossil fuel-fired combustion turbines would be consistent with the broad nature of the BSER that EPA has proposed, and simplify EPA's analysis by ensuring that all emission reductions from that BSER are attributed to one source category.

A single source category would also be consistent with the nature of the power sector. Utilities and independent system operators make dispatch decisions for the entire fleet of power plants without regard to whether those power plants are fueled by coal, natural gas, nuclear energy, or renewable resources. Operating the grid in this way allows utilities to dispatch the least expensive available generating resources. States and utilities may choose to consider compliance options for EPA's forthcoming 111(d) standards that follow similar principles, just as EPA's proposed system-based BSER reflects the capability of the electric system to achieve overall reductions in carbon pollution by increasing output from lower and zero-emitting resources.

Lastly, we note that the adoption of a broad source category encompassing all affected EGUs would not preclude EPA from recognizing appropriate subcategories where needed to establish performance standards for new sources. (Nor, conversely, would the retention of separate source categories preclude the flexible system of emission reduction EPA has proposed for the two categories here, where emission reduction opportunities are assessed and compliance allowed to be achieved comprehensively across the two categories.) Section 111(b), of course, gives EPA broad discretion to "distinguish among classes, types, and sizes within categories of new sources" by establishing subcategories when prescribing standards for new sources.[420] The courts have held that this discretion gives EPA the ability to reasonably subcategorize, or *not* subcategorize, depending on the characteristics of the source category and pollutant at hand.[421] This discretion should logically extend to the establishment of emission guidelines under section 111(d). Indeed, nothing in the text of section 111(d) requires that standards for existing sources replicate the category framework into which EPA organizes new sources, so long as the sources covered by section 111(d) would be subject to "a standard of performance under this section [111]" if they were new sources.[422] Further, EPA's 1975 Federal Register notice implementing section 111(d) also explicitly recognized that the categorization systems adopted under section 111(b) and (d) need not be identical.[423] Thus, combining steam electric generating units and fossil fuel-fired combustion turbines into one source category under section 111 would not limit EPA's authority to establish separate performance standards for distinct *subcategories* of new and modified coal and natural gas-fired EGUs. EDF supported this

[420] 42 USC § 7411(b)(2).
[421] *See Lignite Energy Council,* 198 F.3d 930, 933 (D.C. Cir. 1999) (deferring to EPA's judgment that it was feasible and cost-effective to require all new utility boilers to meet the same NOx emission standards regardless of fuel type, despite past practice establishing varying NOx standards for different subcategories of units).
[422] 42 USC § 7411(d)(1)(A)(ii).
[423] *See* 40 Fed. Reg. at 53,341 ("…while there may be only one standard of performance for new sources of designated pollutants, there may be several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.").

subcategorization approach in the rulemaking proposing standards for new EGUs, as well as the June 18, 2014 proposal for modified and reconstructed EGUs.

G. Comments on Building Block 1: Onsite Emission Reductions

EPA's analysis demonstrates that the existing fleet of power plants is capable of reducing emissions considerably through onsite efficiency improvements resulting from cost-effective equipment upgrades and increased deployment of best operating practices. There are myriad ways in which plants can achieve such efficiency improvements, including many measures not specifically evaluated by EPA in its analysis. Among other things, heat rate improvements can be achieved through:[424]

- increased efficiency of motors and variable frequency drives for coal-handling equipment;
- replacement of inefficient economizers with more efficient ones;
- deployment of more advanced coal pulverizers that provide more consistent size and finer coal particles;
- switching from water-sluicing bottom ash system to a dry drag chain system,
- deployment of neural network systems to enhance plant control and evaluation;
- use of intelligent sootblowers;
- improvements to reduce air heater and duct leakage;
- lower air heater outlet temperature by injecting sorbents such as Trona or hydrated lime that can lower the dew point for acid gases;
- replace or overhaul steam turbines with advanced turbine designs;
- improving heat transfer surface area for feedwater heaters;
- condenser upgrades and maintenance;
- overhaul of boiler feed pumps
- upgrades or replacements to induced draft fans;
- upgrading variable frequency drives in flue gas systems;
- use of co-current spray tower quencher in flue gas desulfurization;
- use of turning vanes and perforated gas distribution palate to improve gas distribution in flue gas desulfurization systems;
- electrostatic precipitator energy management system upgrades;
- reducing pressure drop and using secondary air as dilution for ammonia vaporizer to reduce auxiliary power needs for selective catalytic reduction;
- better maintenance of water quality flowing into the boiler; and,
- better maintenance of cooling water systems to improve water quality

As EPA's analysis and other industry and academic studies find, there is significant variation in the heat rate of existing steam EGUs with similar characteristics — strongly indicating that many existing steam EGUs have failed to implement all cost-effective heat rate improvement measures and that significant opportunities remain to enhance onsite efficiency. In some cases, these opportunities exist because plants in rate regulated markets are allowed to pass fuel costs on to consumers, reducing the financial incentive

[424] GHG Abatement Measures TSD at 2-6 to 2-11.

for onsite efficiency improvements.[425] Coal plants in competitive markets seldom set the clearing price for electricity, and so may face reduced competitive pressure to look internally for all cost saving measures. Many plants may have failed to undertake such improvements in the past because of institutional barriers or lack of onsite engineering personnel focused on the issue.[426] In addition, many plants are old, with more than 30 percent of plants over 50 years of age.[427] There is reason to believe that a number of these plants and younger plants as well have waited to undergo significant upgrades until there was more clarity about the future regulatory environment for a range of air pollutants, including mercury and carbon dioxide.

While robust, EPA's Building Block 1 analysis omits considerable opportunities for additional reductions through the employment of overly conservative discount factors when evaluating opportunities for improvements through use of best practices and equipment upgrades. In addition, EPA excludes from the BSER conversion of utility boilers to natural gas, and co-firing with natural gas, based on an inappropriately narrow assessment of net benefits associated with such systems. As we describe below, there are many opportunities for plants to increase onsite combustion of lower carbon fuels through minimal equipment changes. In addition, we find numerous examples of coal-fired power plants already co-firing with lower carbon fuels and of plants being repowered to run entirely on lower carbon fuels as a result of the cost effectiveness of those conversions. This leads us to conclude that EPA has considerably understated the opportunities for onsite reductions in emissions at existing coal-fired electric generators. In the final rule, EPA should strengthen building block 1 to reflect the full range of opportunities for onsite emission reductions at steam EGUs, including use of lower-carbon fuels.

Opportunities for onsite efficiency improvements

Opportunities to reduce a plant's GHG emissions through onsite efficiency improvements are readily available and have been documented in numerous studies by Sargent and Lundy, the National Energy Technology Laboratories, Resources for the Future, and others. Some of these previous analyses have demonstrated a potential to achieve efficiency improvements that significantly exceed EPA's target of a six percent reduction in average heat rate. For example, as EPA notes in the GHG Abatement Measures TSD, the Department of Energy (DOE) and the National Energy Technology Laboratory (NETL) have undertaken extensive analysis on the performance of the existing fleet of coal-fired steam EGUs, informed by multiple workshops and consultations with industry experts. NETL's analysis identified 13 different subgroups of power plants based on characteristics that determine overall efficiency, and calculated best-in-class efficiency within each subgroup. Based on this analysis, NETL determined that a ten percent improvement in fleet-wide efficiency is a "reasonable average efficiency target" based on "a

[425] *See* DOE/NETL, *Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants: Workshop Report* 2 (July 2009).
[426] *See id.* at 2-3; Joshua Linn, Erin Mastrangelo, & Dallas Burtraw, *Regulating Greenhouse Gases From Coal Power Plants Under the Clean Air Act* 7-8 (Feb. 2013).
[427] http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states

combination of aggressive refurbishment and improved operation maintenance."[428] NETL's consultations with industry experts validated this conclusion, identifying over 50 opportunities to improve thermal efficiency[429] and finding that "there is 'headroom' for efficiency improvements among all plants including those that currently operate at below average, average, and above average efficiency levels."[430] The consultations also identified multiple institutional, regulatory, and market barriers that help explain why many coal-fired EGUs have failed to implement all cost-effective options for improving efficiency.[431]

EPA's own analysis takes a far more conservative approach to quantifying the average efficiency improvement that can reasonably be achieved by existing coal-fired generating units. For example, when examining opportunities to improve efficiency through best operating practices, EPA assumes that power plants can reduce only 30% of the difference between their own hourly heat rate and the heat rate of the top 10% of comparable power plants.[432] This results in substantially lower heat rate improvements than NETL's own analysis, which concluded that existing coal-fired power plants could achieve or exceed the performance of the top 10% of their peers through upgrades or operational improvements.[433] EPA's approach leaves potentially cost effective emissions reduction opportunities on the table. NETL, for example, undertook an alternative analysis in which it assumed that each existing coal-fired EGU simply returned to its own best level of performance over the period from 1998 to 2008 – without considering any potential for refurbishments or equipment upgrades. Even this narrower assessment resulted in an average fleet-wide improvement in efficiency of over six percent, more than fifty percent higher than the level EPA proposes for operational improvements under Building Block 1.[434] As EPA notes, its projected four percent improvement in heat rate from best operating practices is equivalent to requiring only that each existing coal-fired power plant return to its best three-year average performance during the period from 2002 to 2012.[435]

EPA's analysis of the potential for heat rate improvements from equipment upgrades is also highly conservative. Building block 1 only includes one half of the opportunity identified by EPA for equipment upgrades — reducing the potential improvement in heat rate from an average of 4 percent to just 2 percent. In addition, EPA's assessment of equipment upgrades examined only the four most cost-effective types of equipment upgrades identified in the 2009 Sargent and Lundy report. As noted above, NETL's own technical workshops with industry experts identified over 50 different heat rate improvement measures which would afford opportunities for greater efficiency not captured in EPA's analysis.

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[428] Phil DiPietro & Katrina Krulla, *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions* 5 (DOE/NETL-2010/1411, 2010).
[429] DOE/NETL, *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States* v (Feb. 2010).
[430] DOE/NETL 2009 at 2.
[431] DOE/NETL 2010 at vi.
[432] GHG Abatement Measures TSD at 2-32.
[433] DiPietro & Krulla, *supra* at 4-5.
[434] *Id.* at 6.
[435] GHG Abatement Measures TSD at 2-34.

Lastly, EPA's analysis of heat rate improvements only considers potential for improving *gross* heat rates. As EPA notes, "the HRI potential on a net output basis is somewhat greater than on a gross output basis, primarily through upgrades that result in reductions in auxiliary loads."[436] Since the state goals are expressed in terms of net output, the calculation of heat rate improvements on a gross basis is a further dimension of EPA's analysis that leads to a conservative result. We also encourage EPA to look more carefully at opportunities to improve the efficiency of auxiliary or parasitic loads, such as pumps, fans, motors, and pollution controls. As EPA notes, these loads represent from 4 to 12 percent of gross generation at a coal-fired steam EGU, and could present a key untapped opportunity for additional onsite improvements.[437]

It is also reasonable for EPA to base Building Block 1 on the *average* expected improvement in heat rate at existing coal-fired power plants, rather than demonstrate the feasibility of achieving this target at each individual plant. The case law under section 111 specifically recognizes that a standard of performance may be based on reliable data about the average performance of a control technology, so long as EPA grants sufficient flexibility in demonstrating compliance to account for the variability in performance of the control technology.[438] Here, there is ample evidence and multiple lines of analysis to support EPA's determination that a six percent average improvement in heat rate is feasible. Moreover, the flexible structure of the Clean Power Plan – which allows states to average the emissions rates of existing fossil fuel-fired EGUs, and comply using many combinations of emission reduction strategies, more than takes into account potential variability in heat rate improvement across units. The record demonstrates, for example, that there are many opportunities for heat-rate improvements at affected facilities beyond the thirteen measures that were the focus of EPA's analysis. Existing coal-fired power plants that are unable to achieve the six percent reduction in heat rate could also easily meet the anticipated reduction in emissions through modest co-firing with natural gas. Thus, EPA's target for average heat rate improvements is "achievable" under section 111 even in the speculative event that some facilities may need to employ additional heat-rate improvement strategies (or choose to comply through other flexible mechanisms) in certain circumstances. Even if EGUs incurred additional costs in implementing such measures, these costs would certainly be within the relevant limits that courts have placed on the costs of performance standards under section 111.[439]

Repowering with natural gas

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[436] GHG Abatement Measures TSD at 2-37.
[437] 79 Fed. Reg. at 34,860.
[438] *Sierra Club*, 657 F.2d at 372-73 (where EPA had based an NSPS on its estimation of the "average" amount of sulfur that could be removed through coal washing, the D.C. Circuit upheld the standard because utilities had several options for how to comply even when they purchased lots of washed coal that had not been washed to the desired level).
[439] Courts have determined that costs of performance standards under section 111 must not be "exorbitant," *see Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive", *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").

EPA considered conversion to natural gas as a potential BSER, but concluded that coal-to-gas conversion is not BSER due to the allegedly high costs of the resulting emission reductions.[440] However, as explained below, EPA's analysis does not appropriately characterize the costs of gas conversion or reflect full consideration of the BSER factors. Indeed, such measures are already commonplace in the industry, suggesting that they are cost-effective and adequately demonstrated even in the absence of carbon pollution standards for the power sector. In a white paper submitted with our comments as Attachment C, Andover Technology Partners verified that there are at least 24 such conversions in 19 states expected to be completed by 2020, when the Clean Power Plan goes into effect. Some studies have suggested that there could be more than 50 such conversions in 26 states at various stages of planning and development.[441] And recent reports indicate that almost 11 GW of coal generation is currently slated for conversion to natural gas.[442] As the Andover report indicates, many such conversion projects that are currently under way were undertaken for the purposes of pollution control and are being completed at plants of greatly varying size and capacity factor, including large intermediate load plants. Based on the Andover white paper and EPA's own analysis, we find that careful examination of BSER factors demonstrates that coal-to-gas conversion fits the statutory criteria for BSER for fossil fuel-fired utility boilers. Accordingly, we urge EPA to take into account the availability of coal-to-gas conversions when assessing the potential for emission reductions in each state and setting state targets.

[440] 79 Fed. Reg. at 34,982.
[441] http://www.sourcewatch.org/index.php/Coal_plant_conversion_projects
[442] : See http://www.mining.com/web/snl-energy-coal-unit-retirements-conversions-continue-to-sweep-through-power-sector/

Table 1. List of announced coal to gas conversions or co-firing projects verified by Andover Technology Partners

State	Plant Name	Unit	MW	Status or completion date
AL	E C Gaston	1	254	Complete by 2015[17] ~30 mile pipeline
AL	E C Gaston	2	256	
AL	E C Gaston	3	254	
AL	E C Gaston	4	256	
AL	Greene County	1	254	Complete by 2016[18]
AL	Greene County	2	243	
AZ	Cholla	1	116	Convert in 2025[19]
AZ	Cholla	3	271	
AZ	Sundt, Irvington	4	156	Complete by 2018[20]
CO	Cherokee	4	352	Complete 2017[21] 34 mi. pipeline
DE	Edge Moor	3	86	Completed
DE	Edge Moor	4	174	Completed
GA	Yates	Y6BR	352	Complete by 2015[17]
GA	Yates	Y7BR	355	
IL	Joliet	71	250	Complete by 2016[22]
IL	Joliet	72	251	
IL	Joliet	81	252	
IL	Joliet	82	253	
IL	Joliet	9	590	
IN	IPL - Harding Street Station (EW Stout)	5	106	Complete by 2016[23]
IN	IPL - Harding Street Station (EW Stout)	6	106	
IN	IPL - Harding Street Station (EW Stout)	7	435	
IA	Riverside	9	128	Complete by 2016[24]
MS	Watson	4	232	Complete by April 2015[18]
MS	Watson	5	474	
MN	Hoot Lake	2	58	Complete by 2020[25]
MN	Hoot Lake	3	80	
MN	Laskin Energy Center	1	55	Complete in 2015[26]
MN	Laskin Energy Center	2	51	
MO	Meramec	1	119	Units 1 & 2 to be converted in 2016[27]
MO	Meramec	2	120	

State	Plant Name	Unit	MW	Status or completion date
NJ	Deepwater	1	82	Completed
NJ	Deepwater	8	73	Completed
NY	Dunkirk	1	75	Requires construction of 9 or 11 mile pipeline. To be complete 2015[28]
NY	Dunkirk	2	75	
NY	Dunkirk	3	185	
NY	Dunkirk	4	185	
OH	Avon Lake	7	96	To be complete 2016, ~20 mile pipeline to be built.[29]
OH	Avon Lake	9	640	
OK	Muskogee	4	505	Complete by 2017[30]
OK	Muskogee	5	517	
PA	Brunner Island	1	312	Pipeline being added, unclear which units to be converted or use of cofiring [31, 32]
PA	Brunner Island	2	371	
PA	Brunner Island	3	744	
PA	New Castle	3	93	Complete by 2016[33]
PA	New Castle	4	95	
PA	New Castle	5	132	
VA	Clinch River	1	230	Two of three to be converted by September 2015, third to shutdown[34]
VA	Clinch River	2	230	
VA	Clinch River	3	230	
WI	Blount Street	8	51	Completed[35]
WI	Blount Street	9	50	
WI	Valley (WEPCO)	1	67	Complete in 2015/16
WI	Valley (WEPCO)	2	67	
WI	Valley (WEPCO)	3	67	
WI	Valley (WEPCO)	4	67	
WY	Naughton	3	330	By 2017[36]

Notes: This table is likely to be an incomplete list of all announced projects. Also, an effort was made to verify that the units on this table were not subsequently retired or are not being converted to combustion turbines or combined cycle.

Andover Technology Partners Findings in Brief.

The accompanying white paper by Andover Technology Partners provides general background on the economic, logistical, and engineering dimensions of converting utility boilers to gas. In addition, Andover provides sixteen in-depth case studies of conversion projects that have either been recently concluded or are currently planned. It concludes that:

> *In recent years the economics of converting to natural gas has changed for many facilities. First, natural gas prices fell rapidly a few years ago – reaching a historic low in real (inflation adjusted) cost in 2012 - and although gas prices have risen from that low, natural gas prices have – for most locations in the US - been much more stable than in the past. Second, increased stringency of environmental regulations have increased the cost of burning coal. As such, utilities have become reluctant to expend capital on aging coal units that are less economically viable than in the past. As will be demonstrated in the case studies in this report, avoiding the costs associated with complying with US EPA's Mercury and Air Toxic Standards (MATS) or the Regional Haze Rule (RHR, and the need to install Best Available Retrofit Technology, or BART) have been important motivators in the conversion of some of these facilities to natural gas. There are other factors as well. Some of these facilities have low capacity factors in part due to increased renewable generation and natural gas combined cycle that have displaced coal from base load use to cycling duty. In some of these cases it was more economical to convert the now cycling coal boiler to natural gas than to build new simple cycle combustion turbines for peaking conditions that have*

similar heat rates as the boiler..For the most part, where cost information was available, the cost of the boiler modifications were usually lower than anticipated by EPA in the Technical Support Document for the proposed Clean Power Plan. This is because EPA's cost estimates for natural gas conversion include several elements that are not necessary in many cases.

BSER Factor Analysis – Technical feasibility. The technology to convert a coal-fired utility boiler to burn natural gas is well-demonstrated and commercially available, as EPA acknowledges. Utilities have been converting coal-fired units to burn natural gas for at least a decade.[443] As demonstrated by Andover Technology Partners and others, industry is undertaking conversions at a wide variety of units, including very old EGUs,[444] baseload power plants,[445] and facilities that are over thirty miles from natural gas pipelines.[446] As further evidence of the technical feasibility of coal-to-gas conversion, several engineering firms have developed literature outlining economic and technical considerations for utilities that are considering such projects.[447] A recent Black & Veatch paper describes the well-understood process for converting a coal-fired unit to run entirely on natural gas.[448]

Although conversion of a boiler to operate on natural gas involves some physical modifications to the facility, these modifications are often relatively modest. Coal-to-gas conversion projects can usually be accomplished without replacing the existing boiler, and often entail only the construction of natural gas delivery infrastructure (where not already available) and modifications to burners and ducts.[449] Indeed, the Andover report indicates that many such projects can be completed during periods when a plant would otherwise need to be offline for maintenance, and in most cases take only a few months to complete (excluding any pipeline construction). We are unaware of any existing sources for which conversion to natural gas is technologically infeasible.

[443] *See, e.g.*, Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp (Possum Point Power Station "Units 3 & 4 are fired using natural gas but were converted from coal in May of 2003. Unit 3 generates 96 MW and Unit 4 generates 220 MW.").

[444] The Blount Street power plant was first built in 1903 and converted to burn natural gas in 2010. Thomas Content, "MG&E stops burning coal in Madison plant," Milwaukee Journal Sun (March 18, 2010), available at http://www.jsonline.com/business/88508257.html.

[445] Darren Epps, "Alabama Power switching to natural gas from coal at 4 Gaston plant units," SNL (Jan. 17, 2014) (reporting Alabama Power's application to convert 4 units, each with a capacity of about 250 MW, to burn natural gas); Colorado Department of Regulatory Agencies, "Colorado's electric grid and the role of base load and "peaker" electric generating units" (classifying the 352-Mw Cherokee unit 4 as a baseload plant).

[446] Xcel Energy, Cherokee Repowering & Natural Gas Pipeline Projects, available at http://www.xcelenergycherokeepipeline.com ("The Cherokee Natural Gas Pipeline Project has been completed."); Thomas Spencer, "Alabama Power to connect Shelby plant to natural gas line," The Birmingham News, available at http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html (citing an Alabama Power spokesperson for information that the coal-to-gas conversion project at the Gaston Steam Plant will involve building a gas pipeline to tie into the Transcontinental pipeline, which runs across Alabama about 30 miles south of the plant).

[447] *See generally* Babcock & Wilcox, Natural Gas Conversions of Existing Coal-Fired Boilers (2010) ("This paper will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision."); Black & Veatch, Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch (2012) ("This paper explores several technically feasible options available on the current market" for retrofitting coal-fired units, including full conversion to natural gas).

[448] Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch.

[449] *See* Babcock & Wilcox at 2.

BSER Factor Analysis - Emission reductions. Switching to natural gas fuel has very significant potential for reducing the combustion carbon emissions from fossil fuel-fired utility boilers and IGCC units—a critical factor in the BSER analysis. EPA's analysis of conversions for the proposed emission guidelines concluded that a converted utility boiler firing 100% natural gas would have an emissions rate of 1,239 lb CO_2/MWh_{net}, representing a 41% reduction in CO_2 emissions rate from 100% coal firing.[450] The case studies in the Andover report confirm that coal-to-gas conversions can achieve significant reductions in CO_2; the five units covered in the report that have already completed conversions have reported an average 38% reduction in CO_2 emission rates.[451]

EPA should also consider the benefits of co-pollutant emission reductions that would result from converting a unit to burn natural gas. EPA reasonably estimated that converting to 100% natural gas would significantly reduce a unit's emissions of SO_2, NO_x, and $PM_{2.5}$.[452] The five completed conversion projects documented in the Andover report reported average reductions in SO_2 emission rates of 99% and average reductions in NO_x emission rates of 48%. These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between $67/$MWh_{net}$ and $150/$MWh_{net}$—a factor of at least two times the costs associated with conversion, as noted below.[453] By promulgating an appropriately stringent standard for CO_2 emissions from existing sources, EPA can greatly reduce the health burdens on the communities living near these sources.

BSER Factor Analysis – Costs. EPA rejected coal-to-gas conversions as BSER because it found that unit conversions were "an inefficient way to generate electricity compared to use of an NGCC" and that CO_2 reductions from this option were "relatively expensive."[454] However, even where up-front costs are substantial, some utilities have projected net savings for electricity consumers, as the result of reductions in a unit's fixed and variable operating costs.[455] As the Andover report notes, coal-to-gas conversions are currently being undertaken by many utilities because they sometimes represent the most economical option for meeting emission reduction requirements at units that have low to intermediate capacity factors.

EPA estimates the costs of CO_2 avoided from a conversion project to be $83 per metric ton in a representative case, and as low as $75 per metric ton where fuel-switching would not require capital investment or impact on unit performance.[456] In terms of generation, EPA estimated that conversion to

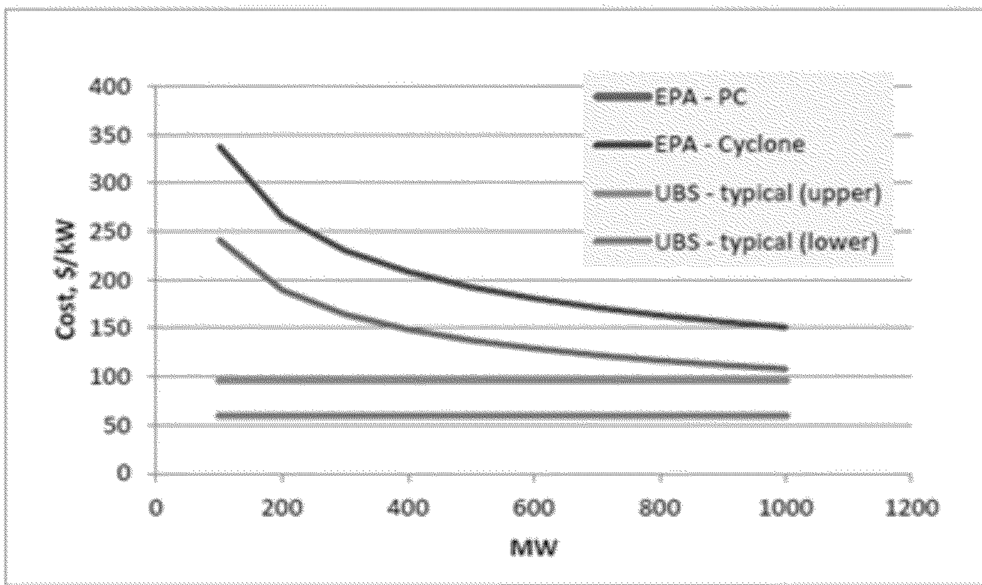
[450] EPA Office of Air and Radiation, GHG Abatement Measures at 6-6, Table 6-1 (June 2014) ("TSD").
[451] Andover report at 3.
[452] TSD at 6-6, Table 6-2. EPA reasonably estimated that 100% gas conversion would reduce emissions of SO_2 by 3.1 lb/MWh_{net}, reduced NO_x by 2.04 lb/MWh_{net}, and reduced $PM_{2.5}$ by .2 lb/MWh_{net}.
[453] TSD at 6-7, Table 6-3. Even given a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through natural gas conversion to be between $61/$MWh_{net}$ and $140/$MWh_{net}$. *Id.*
[454] 79 Fed. Reg. at 34982.
[455] *See* Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be $62 million and "rates for electric customers will go down by .31%, for a net savings of $10.2 million in 2016").
[456] 79 Fed. Reg. at 34982.

natural gas would increase the fuel costs of an EGU by approximately \$30/MWh (three cents per kWh), increase capital costs by \$5/MWh, and *reduce* fixed operating costs by 33% and variable operating costs by 25%.[457] These net costs may be higher than other options EPA has considered, but they are significantly lower than the benefits associated with criteria pollutant reductions from conversion—which as noted above, are approximately \$67-150/MWh_{net}. Adding in the benefits of reduced carbon pollution would only increase the net benefits of conversion as a BSER. The net costs of conversion to gas are certainly within the relevant limits that courts have placed on the costs of performance standards under section 111.[458] Indeed, the fact that many conversion projects have been recently completed or are currently underway shows that the costs are reasonable, and in no way approach the legal standard for a BSER.

Moreover, there is evidence to suggest that EPA's cost estimates are unrealistically high. Andover's white paper concludes that EPA's capital cost estimates are too high because they include all possible modifications that might be necessary as a result of a coal-to-gas conversion, rather than the more modest modifications that are typically required at the average plant. Andover's survey of coal to gas conversions found that the typical capital costs are closer to \$3/MWh, or 40% lower than EPA's estimate. In addition, it appears that EPA has significantly underestimated the costs of coal for many utility boilers by citing national averages instead of specific coal types. In the Technical Support Document, EPA states " base case projections for delivered gas prices…are about double projected delivered coal prices on average (\$2.62/MMBTU for coal and \$5.36/MMBTU for gas). As a result, the fuel cost for a typical converted boiler burning 100% gas is expected to be at least double its prior fuel cost on an output basis as well."[459] However, according to EIA data, in November 2014 spot prices were about \$4.50 per mmBtu of Central Appalachian coal, \$4.89 per mmBtu of Northern Appalachian coal, \$3.79 per mmBtu of Illinois Basin Coal, \$3.23 per mmBtu of Uinta Basin coal, but only \$1.31 per mmBtu of Powder River Basin coal.[460] In the Annual Energy Outlook, EIA projects that mine mouth prices for coal will increase approximately 17 and 33 percent by 2020 and 2030, respectively. This suggests that natural gas may be cheaper than some sources of coal by 2020, and that the price gap for many sources of coal could narrow considerably.

[457] TSD at 6-4. According to EIA's most recent estimates of generation costs, fixed O&M costs for an advanced pulverized coal EGU are approximately \$31-38/kW-yr (equivalent to approximately \$5/MWh) and variable O&M costs are approximately \$4.50/MWh. *See* EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants at 6 (Apr. 2013).
[458] Courts have determined that costs of performance standards under section 111 must not be "exorbitant", *see Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive", *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").
[459] GHG Abatement Measures TSD at 6-5.
[460] *See* EIA, *Coal News and Markets,* http://www.eia.gov/coal/news_markets/ (last visited Nov. 26, 2014).

Figure 2. Estimated cost for boiler modifications associated with gas conversion



Coal-to-gas conversion has emerged as a means of complying with emission standards precisely because it is sometimes the most cost-effective strategy.[461] Several coal-fired units are being converted to burn natural gas because it is the units' most economical option for complying with other emission limitations.[462] The cost of converting to natural gas fuel depends on whether the unit was originally designed to be capable of burning natural gas. The cost of fuel-switching boilers is minimal for units that are already designed to burn gas, but the cost of more extensive retrofits is still moderate (and well below the legal standard for BSER) in the context of carbon pollution standards for existing power plants.[463]

[461] Michael Niven and Neil Powell, "Coal unit retirements, conversions continue to sweep through power sector," SNL Data Dispatch (Oct. 14, 2014).
[462] Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6 at 1-18 ("Finally, for the remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost- effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel, with coal used as a backup fuel."); *see also id.* at 1-11 (requesting favorable amortization of "approximately $14 million of Plant Yates Units 6 and 7 environmental construction work in progress"). Conversion to natural gas is likely to be a cost-effective compliance option for any facility with limited planned service hours. Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch at 7, Table 7.
[463] Ameren Missouri, 2014 Integrated Resource Plan at 4-18:

> Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired

Even where retrofit costs are significant, the conversion to natural gas is cost-effective and can be achieved in a manner that enables electricity consumers to save money.[464]

For some units, building a pipeline is one cost associated with conversion to natural gas. EPA's cost estimates assumed that a unit converting to natural gas would need to build a 50-mile pipeline at a cost of $50 million.[465] EPA estimated pipeline construction would contribute $100/kW to the capital costs of a 500 MW unit, while capital costs as a whole represented only one-seventh of the cost impact of natural gas conversion.[466] EPA's analysis shows that building a long pipeline is generally a relatively small part of the cost of converting a unit to burn natural gas. Consequently, units can undergo conversion at reasonable cost even when they are located at a significant distance from existing pipeline infrastructure. For most units, however, the cost of building a pipeline is likely to be less than EPA assumed. This is because the median distance of a coal-fired unit from a pipeline is 28.3 miles—just over half the length of the pipeline in EPA's calculations.[467]

BSER Factor Analysis – Non-air health and environmental impacts. EPA did not consider the non-air quality health and environmental impacts of the systems it identified as potentially representing the BSER.[468] If EPA had performed the "mandated consideration of the factors enumerated in section 111(a),"[469] the agency would have recognized that switching to natural gas firing at existing units has substantial non-air health and environmental benefits. For example, coal-to-gas conversion eliminates an existing EGU's production of coal combustion residuals (also known as coal ash), which is an industrial waste that contains a range of toxic substances, including arsenic, selenium, and cadmium. Carcinogens and toxic chemicals from coal ash can leach into drinking water supplies and accumulate in the fish we eat.[470] Conversion to natural gas firing also reduces on-site water quality impacts.[471]

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operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

[464] See e.g. Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be $62 million and "rates for electric customers will go down by .31%, for a net savings of $10.2 million in 2016")

[465] TSD at 6-4.

[466] TSD at 6-4 to 6-5. In EPA's estimation, increased fuel costs were responsible for most of the cost of natural gas conversion. *Id.*

[467] See EPA, Table 522 Cost of Building Pipelines to Coal Plants. The average length of pipeline that would need to be built to hook up a coal-fired unit is 61.6 miles. The average is greater than the median because there are a few outliers that are very far from a pipeline hookup. The most isolated coal-fired unit is 713.3 miles from a hookup.

[468] 79 Fed. Reg. at 34981-85. *Sierra Club*, 657 F.2d at 323 ("the agency must consider all of the relevant factors and demonstrate a reasonable connection between the facts on the record and the resulting policy choice").

[469] *Sierra Club*, 657 F.2d at 346, n.175.

[470] EPA, Human and Ecological Risk Assessment of Coal Combustion Wastes (draft) (April 2010). One of the study's conclusions was that managing coal ash in unlined or clay-lined waste management units results in up to 1 in 50 excess cancer risks.

[471] As the Wisconsin Public Service Commission observed in approving the conversion of Valley Power Plant, "Converting the plant from coal to natural gas would eliminate some discharge sources and reduce wastewater treatment requirements. Conversion would eliminate coal pile runoff, yard runoff, ash transport water, and equipment wash wastewaters that convey coal or ash, thereby removing a potential source of mercury." Public Service Commission of Wisconsin, Final Decision, Application of Wisconsin Electric Power Company for

EPA should consider the energy benefits of a standard based on coal-to-gas unit conversion. Conversion to natural gas would likely reduce the energy requirements of the unit because natural gas units have lower parasitic loads. Unit conversion also reduces electricity demand for fuel preparation (including coal transport, crushing, pulverizers).[472] The reduction in parasitic load results in an increase in net output.

Conclusion. A careful weighing of the statutory criteria leads to the conclusion that conversions to natural gas fuel are part of the BSER for existing fossil fuel-fired utility boilers and IGCC units. This system will achieve greater reductions than EPA's current proposal for Building Block 1, and can do so at a cost that is well below the legal standard. Moreover, a standard based on natural gas conversion will have important non-air health and environmental benefits and reduce dangerous co-pollutant emissions.

Co-firing with natural gas

EPA considered co-firing with natural gas as a potential BSER, but concluded that it was not BSER due to the allegedly high costs of the resulting emission reductions.[473] However, as with natural gas repowering, EPA's analysis does not appropriately characterize the costs of co-firing or reflect full consideration of the BSER factors. Natural gas co-firing is already commonplace in the industry. Natural gas can be used to assist with startup or shutdown, to make up for the low Btu values in Western coals in boilers originally designed to combust eastern coals, and it has been used historically as a NOx emissions controls through a process known as reburning. Although EPA's analysis indicates that the net benefits of conversion to gas are greater than those associated with co-firing, EPA should consider significant levels of co-firing with gas as part of the BSER under Building Block 1 in the event that it determines conversion to gas does not meet the BSER criteria, or does not meet those criteria for all coal-fired plants.

BSER Factor Analysis – Technical feasibility and cost. The technology to co-fire that natural gas co-firing in coal-fired utility boiler is well-demonstrated and commercially available, being used for a variety of different reasons, including startup, emissions control, and to make up for the low Btu value of western coals. According to the Andover white paper,

> *Modifying a boiler for natural gas cofiring can sometimes be done with fairly minimal modifications, depending upon the intent and how much gas will be co-fired. Facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters. In this case gas cofiring up to the capacity of the gas igniters can be performed at no additional capital cost. In some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications.*

Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility (March 17, 2014) at 19, available at http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=200566.

[472] Richard Vesel, "Utilities Can Improve Power Plant Efficiency, Become Emission-compliant in Short Term" Electric Light & Power (Nov. 1, 2012), available at http://www.elp.com/articles/print/volume-90/issue-6/sections/utilities-can-improve-power-plant-efficiency-become-emission-compliant-in-short-term.html.

[473] 79 Fed. Reg. at 34,982.

Furthermore, Andover found that natural gas reburning has been used commercially and was demonstrated commercially as early as the 1990s as a means of NOx control. They found that the cost of natural gas reburning was approximately \$15/kW when including the cost of gas injectors, overfire air, and associated controls. Adjusting for today's costs, they estimate that similar retrofits would cost \$23/kW today. However, they determined that actual costs may be less today because many boilers have installed overfire air systems and other modifications that were typically performed then but may be unnecessary today.

Natural gas is frequently co-fired in coal-fired boilers during start-up as gas igniters heat up the furnace in order to allow ignition of the coal. According to analysis by Andover Technology Partners, facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters at no additional capital cost. They also found that in some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications.

Gas cofiring is also common at facilities that have converted from Eastern to Western coal due to its lower Btu value. The number of facilities that have done so may be significant, particularly when one considers the significant expansion of Western coal since the 1990s and even since the 1990s, after which relatively few new coal plants were built.

BSER Factor Analysis – Emission reductions. Co-firing with natural gas fuel has very significant potential for reducing the carbon emissions from fossil fuel-fired utility boilers and IGCC units—a critical factor in the BSER analysis. EPA's analysis for the proposed emission guidelines concluded that a utility boiler firing 10% natural gas would have an emissions rate of 2,021 lbs CO_2/MWh_{net}, representing a 4% reduction in CO_2 emissions rate from 100% coal firing.[474] Supplying 50% of the boiler's heat input with natural gas would lower the emission rate to 1,673 lbs CO_2/MWh_{net}, a 21% reduction in emissions rate from 100% coal firing.

EPA should also consider the benefits of co-pollutant emission reductions that would result from converting a unit to burn natural gas. EPA reasonably estimated that converting to 10% natural gas would reduce a unit's emissions of SO_2, NO_x, and $PM_{2.5}$.[475] These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between \$6.5/MWh_{net} and \$15/MWh_{net}.[476] The benefits of co-firing at 50% would likely be proportionally greater – or approximately \$30 to \$75/MWh.

Conclusion. A careful weighing of the BSER criteria leads to the conclusion that significant co-firing of natural gas can be part of the best system for emissions reduction for existing coal-fired utility boilers and IGCC units, in the event that EPA determines full coal-to-gas conversion does not meet the BSER criteria (or does not meet the criteria at certain plants). This will achieve far greater reductions than the current

[474] EPA Office of Air and Radiation, GHG Abatement Measures at 6-6, Table 6-1 (June 2014) ("TSD").
[475] TSD at 6-6, Table 6-2. EPA reasonably estimated that 100% gas conversion would reduce emissions of SO_2 by 3.1 lb/MWh_{net}, reduced NO_x by 2.04 lb/MWh_{net}, and reduced $PM_{2.5}$ by .2 lb/MWh_{net}.
[476] TSD at 6-7, Table 6-3. Even given a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through natural gas conversion to be between \$61/MWh_{net} and \$140/MWh_{net}. *Id.*

proposal for Building Block 1, and can do so at a cost that is well below the legal standard. Furthermore, this system can yield significant co-pollutant reduction and health benefits.

Onsite redeployment.

Additional CO2 emissions reductions could be achieved by switching the deployment order of different units at a single power plant based on the efficiency of the unit and/or the CO_2 intensity of the fuel deployed. We encourage EPA to evaluate the opportunities for such reductions in the final rule.

H. Comments on Building Block 2: Increase Dispatch of Lower-Carbon Generation

In Building Block 2, EPA considers the potential to reduce emissions by redispatching generation from coal-fired steam generation to existing natural gas combined cycle (NGCC) plants, which emit roughly half as much carbon dioxide per megawatt hour of generation. EPA's June 2, 2014 proposal focused on redispatch from coal-fired steam generation to existing NGCC plants operating at less than 70 percent capacity. EPA also requested comment on whether it should allow new NGCC plants to be a source of compliance credits even if those plants were not considered in setting the targets. As described below, EPA must maintain symmetry between the target setting and compliance.

On October 30, 2014, EPA published a Notice of Data Availability evaluating the potential to reduce emissions by switching dispatch to new NGCC units and by using natural gas at existing coal plants through co-firing or conversion of those plants. 79 Fed. Reg. 64543 (Oct. 30, 2014). EPA also requests comment on an approach that would treat the increased use of natural gas "comprehensively" rather than considering separately the potential to redispatch generation to: 1) existing NGCC, 2) new NGCC, and 3) co-fire natural gas at coal plants or to convert coal plants to run on natural gas. *Id.* at 64546.

EPA should take such a comprehensive approach. We recommend that EPA adopt as a component of BSER a minimum level of generation shift from higher-emitting to lower-emitting fossil sources that can be met by any of these methods. This minimum level should be based on what is cost-effective and reasonable based on historic trends and electric and natural gas sector modeling. As discussed below, EDF believes EPA should assume that at least two percent of a state's coal use shifts to natural gas per year from 2020 to 2029 (at least 20% over a ten year period) through a combination of these three means. This would be a minimum value. If the amount of underutilized existing NGCC capacity in a state (or other pathways of coal to gas transition) would allow for a greater redispatch between coal and gas, that higher level should be used to set the state's target.

These comments address the question of what carbon reduction techniques EPA should use to set state targets in the BSER Guideline. State compliance plan development will involve different considerations. We believe that even if EPA follows all our recommendations for strengthening the targets deemed BSER, EPA will not have exhausted the scope of cost-effective reductions achievable through the various building blocks. In other words, even the analysis we present is likely to conservatively underrepresent the true volume of cost-effective reductions available to EGUs. Thus, states (and likely sources) will have significant flexibility in choosing which combination of measures to employ to meet their applicable targets. We will urge states to rely as much as possible on efficiency and renewables to achieve compliance, in order to avoid or limit expanded reliance on natural gas. This is because investments in energy efficiency and renewable energy provide the soundest long-term investment in our clean energy future.

1. Treatment of New NGCC for Target Setting and Compliance Must be Symmetrical

The definitions of "standard of performance" and "emissions guideline" both provide, in substance, that standards must achieve as much emission reduction as is technically achievable by the sources subject to them considering cost. EPA must determine that the emission limit achieves the emission reductions that are "achievable" using measures that are "adequately demonstrated"— a test of feasibility. The agency also must "tak[e] into account the cost" as well as energy and non-air environmental impacts. The result is "the best system of emission reduction."

The technical and economic feasibility of an emission limit is linked to the methods available for demonstrating compliance.[477] If a guideline allows compliance through a given method of reducing emissions, and that method is a superior system of emission reduction or would be part of a superior system of emission reduction, then EPA must consider that compliance method when determining the level of reductions that the standard of performance or target requires. The statute requires symmetry. It *would be a deviation from the statute* for EPA to set a target based on a reasonably foreseeable emission reduction technique but not allow that technique to be used for compliance purposes. Likewise, it would be a deviation from the statute to allow the use of a reasonably foreseeable emission reduction technique for compliance purposes but exclude it from consideration when setting the target—particularly when that emission reduction technique is expected under the Agency's own analysis (79 Fed. Reg. at 34,876) to play a significant role in compliance.

In this instance, given existing market trends and the Agency's own analysis of possible compliance scenarios, it is reasonable to project the construction of certain amounts of new NGCC capacity; such capacity must reasonably be considered adequately demonstrated at a reasonable cost. The emissions limit in the guideline must reflect the emission reductions that can be achieved through the use of such new NGCC plants.

EPA's initial proposed rule suggested that it might consider excluding new NGCC plants from the determination of the targets but would allow them to be used to generate credits. This asymmetry is not permitted. If EPA were to exclude a new NGCC capacity from target-setting but allow it to be used for compliance, the standard would under-represent the degree of reduction achievable at reasonable cost.

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[477] *See,* e.g., *Portland Cement Association v. Ruckelshaus.* 486 F.2d 375. 396 (D.C. Cir. 1973) (measurements relied on to demonstrate achievability may have "deviate[d] from procedures, outlined by regulation, for ascertaining compliance with prescribed standards").

2. Redispatching generation from coal to natural gas, co-firing, and conversion of coal plants to operate on natural gas are all adequately demonstrated and cost-effective.

The potential to reduce carbon pollution at the point of combustion by using natural gas in lieu of coal is fully demonstrated. The power sector has been constructing and generating electricity with natural gas in combined cycle natural gas plants for many decades. After a long period during which coal-fired steam generation dominated baseload generation in the United States, a significant switch of baseload capacity from coal-fired steam generation to NGCC has occurred. EIA data indicate that from 2003 to 2012, coal generation fell from about 2 million GWh to 1.5 million GWh.[478] During the same period, natural gas capacity increased from 165 GW to 242 GW and generation climbed from about 650 thousand GWh to over 1.2 million GWh, as a result of both increased capacity factors at existing plants and new facility construction. Today, natural gas plants are commonly operating as baseload plants, providing 27 percent of U.S. net power generation in 2013,[479] compared to only 10 percent in 1994.[480]

According to EIA, annual changes in natural gas capacity and generation have been significant. Over the ten year period from 2003 to 2012:

- Annual natural gas capacity increases have averaged 12 GW per year with 41 GW added in 2003 (and in 2002), which is an average annual increase of 6% and a maximum of 25%.

- Annual natural gas generation increases have averaged 5% per year with a maximum of 17%.

Likewise, the use of natural gas to co-fire alongside coal in steam generating plants and the conversion of coal-fired power plants to operate on natural gas is well established.

The potential carbon pollution reductions are well established. Burning coal to generate a given unit of energy generates nearly twice the carbon at the stack as does burning natural gas to generate the same unit of energy.[481] (As we note in more detail below, in order for these emission reductions to mitigate rising atmospheric levels of greenhouse gases it is also critical that EPA act to reduce the methane leakage that occurs during the production and distribution of natural gas and during the mining of coal.)

a. Redispatch to Existing NGCC

The capacity to operate NGCC plants at a 70 percent capacity factor is well established. As EPA notes, more than ten percent of existing NGCC plants have operated at a seventy percent capacity factors in recent years.[482] Similarly, IPM modeling demonstrates that operating each state's NGCC fleet at such a

[478] EIA, Electric Power Monthly (Apr. 2014), at Table 1.1, *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01.
[479] *Id.*
[480] EIA, Electric Power Monthly (July 1996), *available at* http://205.254.135.7/electricity/monthly/archive/pdf/02269607.pdf.
[481] http://www.eia.gov/environment/emissions/co2_vol_mass.cfm
[482] *See* Greenhouse Gas Abatement Technical Support Document at 3-9.

capacity factor (on average) is technically feasible.[483] The costs of such redispatch are also reasonable. EPA reports that the IPM model shows the cost of such redispatch to be 30 or 33 dollars per metric ton of avoided carbon, depending on whether a regional or state-specific approach was taken. 79 Fed. Reg. at 34865. As EPA notes, these costs are reasonable even without considering the additional public health and climate benefits that such a shift in dispatch would create.

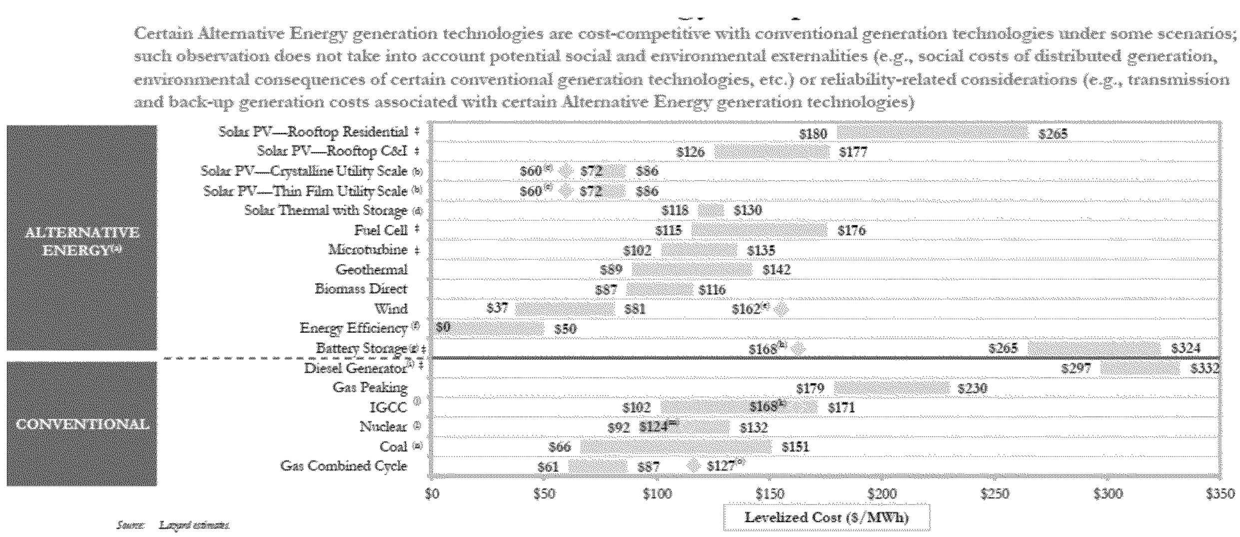
b. New NGCC Plants

The 119 GW of new NGCC plants that have been constructed over the ten year period from 2003 to 2012 (EIA) confirm that it is reasonable to anticipate a continued rate of expansion of this well-understood technology.[484] This conclusion is affirmed by the IPM compliance modeling of the Clean Power Plan conducted by EPA, which showed that "construction and operation of new NGCC capacity will be undertaken as a method of responding to the proposal's requirements." 79 Fed. Reg. at 34,876.

The IPM model results also affirm that the costs of new NGCC are reasonable. The IPM model seeks to satisfy each state's target rate through the least expensive methods. Thus, the fact that the model selected new NGCC (even though NGCC was not included to set the targets) demonstrates that the costs of such plants are reasonable. (We note, however, that neither the renewable energy nor the energy efficiency costs were accurately represented in these modeling runs, as discussed further below.)

In addition, financial analysts such as Lazard have determined that new NGCC is one of the lower cost generation resources available to power companies today, as shown in the figure below (energy efficiency, wind, and utility scale solar are also competitive with natural gas).[485]

Figure 3. Comparison of Unsubsidized Levelized Costs of Energy Generation



[483] *See* 79 Fed. Reg. at 34,865.
[484] http://www.eia.gov/todayinenergy/detail.cfm?id=1690.
[485] Lazard's Levelized Cost of Energy Analysis – version 8.0, http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

In recent years, a number of utilities have retired coal-fired power plants and replaced the generation capacity with new NGCC units. For example, in 2007 Xcel Energy retired the coal-fired plant at its High Bridge Generating Station in St. Paul, Mississippi and replaced it with generation from new NGCC that came on-line in May 2008.[486] In 2011, the Tennessee Valley Authority (TVA) replaced the coal-fired generation at its John Sevier plant in Tennessee with new NGCC generation, and is in the midst of replacing coal-fired units at the Paradise Fossil Plant in Kentucky with new NGCC.[487] In October 2012, Georgia Power completed construction on three new combined-cycle units at its Plant McDonough-Atkinson in Smyrna, Georgia to replace two coal-fired steam turbines that were retired in September 2011 and February 2012.[488] In 2012, Duke Energy accelerated the retirement of its Cape Fear coal-fired power plant in North Carolina and its H.B. Robinson coal plant in South Carolina by replacing the generation from those plants with power from a new 920-MW NGCC plant at the site of the H.F. Lee plant near Goldsboro, North Carolina.[489] Following the proposal of the Clean Power Plan, additional coal-to-new-NGCC replacement plans have been announced.[490]

c. Co-firing with or Conversion to Natural Gas

The third method of using natural gas to reduce emissions at coal-fired power plants — co-firing or conversion — is similarly well-demonstrated and of reasonable cost. As discussed in more detail in section G of these comments, a number of coal-fired steam generating units have already converted, or are planning to convert, to natural gas. Some utilities converted steam generating units to natural gas more than a decade ago.[491] Conversions—including Alabama Power's conversion of four units at the Gaston

[486] Xcel Energy, High Bridge Generating Station, http://www.xcelenergy.com/About_Us/Our_Company/Power_Generation/High_Bridge_Generating_Station (last visited Nov. 13, 2014).
[487] Dave Flessner, *TVA's power shift spurs debate over wind, gas*, Times Free Press on-line (Aug. 12, 2014) *available at* http://www.timesfreepress.com/news/2014/aug/12/tvas-power-shift-spurs-debate-over-wind/.
[488] Matthew Bandyk, *Georgia Power finishes major coal-to-gas generation conversion*, SNL (Oct. 29, 2012) *available at* https://www.snl.com/InteractiveX/articleabstract.aspx?ID=16152278&KPLT=2.
[489] Duke Energy, *Progress Energy Carolinas to retire two coal-fired power plants Oct. 1*, Press Release (Sept. 28, 2012), http://www.duke-energy.com/news/releases/2012092801.asp;
John Crawford, *Duke speeds retirement of Cape Fear coal units, unveils Robinson closure*, SNL (Jul. 27, 2012) available at https://www.snl.com/InteractiveX/articleabstract.aspx?ID=15413584&KPLT=2.
[490] For instance, the TVA announced that it will replace aging coal-fired units at the Thomas H. Allen plant in Memphis, Tenn., with a new 2-on-1 combined-cycle natural gas power plant by December 2018, and Ameren Missouri recently announced that it plans to retire 984 MW of coal-fired units Sioux Energy Center, with the generation to be partially replaced by construction of a 600 MW new NGCC plant to be built by 2034. Anna Lee Grant, *TVA approves replacing Tenn. coal plant with 1,000-MW gas unit*, SNL (Aug. 21, 2014) *available at* https://www.snl.com/Cache/snlpdf_4d94da97-70d7-4420-8cc9-1e35e8ad4b1b.pdf; Eric Wolff, *Ameren Missouri to add renewables, cut coal power in 20-year plan*, SNL (Oct. 1, 2014) *available at* https://www.snl.com/InteractiveX/article.aspx?ID=29378157; *see also* Matthew Bandyk, *TVA proposes retiring Allen coal-fired plant, replacing it with gas generation*, SNL (Jul. 2, 2014) *available at* http://www.snl.com/InteractiveX/article.aspx?ID=28537041; Darren Epps, *Even as it cuts coal, TVA sees difficult road to meet Clean Power Plan rule*, SNL (Aug. 7, 2014) *available at* http://www.snl.com/interactivex/article.aspx?id=28848062&KPLT=6.
[491] In 2003, Dominion Energy converted two units at its Possum Point Power Station from coal to gas. Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp.

Electric Generating Plant—have occurred at baseload generating units.[492] Utilities have even found it economical to convert to gas even when this required the construction of more than thirty miles of pipeline.[493] The cost of conversion is minimal for units that are already designed to burn gas,[494] but even where up-front costs are substantial, some utilities have projected net savings for electricity consumers, as the result of reductions in a unit's fixed and variable operating costs.[495] Recent reports indicate that 10,894 Mwh of coal generation are currently slated for conversion to natural gas.[496]

As EPA notes in the NODA, co-firing also results in significant operational advantages. These include significant reductions of criteria air pollutants including nitrogen oxides, sulfur dioxide, particulate matter, and of hazardous air pollutants, including mercury. 79 Fed. Reg. at 64550. These reductions could allow co-firing power plants to reduce the pollution control equipment operating costs. *Id.* Co-firing could also allow for faster ramp-up and down, allowing for more cost-effective operation of the plants. *Id.* Finally, co-firing is generally not capital intensive.

The cost of co-firing or conversion is within an acceptable range. EPA may select any system that satisfies the other requirements of BSER as long as the system's costs are not "exorbitant."[497] The costs of conversion meet this standard easily. The number of existing and planned conversion projects taken absent any regulatory carbon pollution mandate is strong evidence that the costs are reasonable. Moreover, EPA's own data demonstrate that conversion to natural gas generates substantial net benefits. EPA estimated that the capital costs of conversion (including new pipeline) are $5 per MWh and the increased fuel cost is $30 per MWh, but the health benefits alone of conversion are between $60 and $140 per MWh.[498] EPA observes that the cost per ton of CO_2 avoided is "relatively expensive," but it is certainly not "exorbitant," especially when the full range of benefits associated with conversion are taken into account.

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[492] *See* Scott Disavino, *Southern to Repower Three Alabama Coal Power Plants with Natgas*, REUTERS (Jan. 16, 2014), http://www.reuters.com/article/2014/01/16/utilities-southern-alabama-idUSL2N0KP1WA20140116

[493] *See* Thomas Spencer, *Alabama Power to Connect Shelby Plant to Natural Gas Line*, BIRMINGHAM NEWS (May 12, 2012), http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html.

[494] *See* Ameren Missouri, 2014 Integrated Resource Plan at 4-18, http://www.ameren.com/sitecore/content/Missouri%20Site/Home/environment/renewables/ameren-missouri-irp (noting that the cost to convert Units 1 & 2 at Meramec Energy Center Units 1–4 from coal to natural gas was less than $2 million, because these units were designed with the capability to operate on natural gas).

[495] *See* Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be $62 million and "rates for electric customers will go down by .31%, for a net savings of $10.2 million in 2016").

[496] : See http://www.mining.com/web/snl-energy-coal-unit-retirements-conversions-continue-to-sweep-through-power-sector/

[497] Essex Chem. Corp. v. Ruckelshaus, 486 F.2d 427, 433-34 (D.C. Cir. 1973); Lignite Energy Council v. EPA, 198 F.3d 930, 933 (D.C. Cir. 1999).

[498] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants, GHG Abatement Measures, Chapter 6, Docket ID No. EPA-HQ-OAR-2013-0602, at 6-4 to 6–8 (Jun. 10, 2014).

3. Pipeline Capacity

While some additions to today's natural gas delivery infrastructure may be necessary before 2030, the current natural gas delivery infrastructure is robust and is capable of delivering significantly more natural gas to the power fleet than it does today. This is particularly true on an annual basis, but is also true even during peak periods of demand. Even during extreme cold weather conditions when aggregate natural gas demand for both heating and electric generation is highest (such as during the January 2014 polar vortex), many pipelines have available and unused capacity to deliver more gas. This is not to suggest that there are not periods when some pipelines deliver gas at or near full capacity; it is simply untrue, however, that current pipeline infrastructure is insufficient to deliver substantially more gas to support increased capacity factors for natural gas-fired power plants.

We also note that the Federal Energy Regulatory Commission (FERC) is in the midst of efforts to refine the standards and rules governing interstate gas transportation to among other things, ensure that the market design better serves natural gas-fired electricity generators. These actions should allow utilities to more fully utilize the natural gas delivery infrastructure of today and tomorrow, which will allow the electric power sector to reduce emissions at an even lower cost than would otherwise be possible.

On March 20, 2014 FERC issued a Notice of Proposed Rulemaking ("NOPR") regarding proposed revisions to the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation services.[499] FERC proposed, as part of a series of orders, to revise its regulations to better coordinate the scheduling of natural gas and electricity markets "in light of increased reliance on natural gas for electric generation. . . ." As noted by the Commission, "this trend is expected to continue, resulting in greater interdependence between the natural gas and electric industries."[500] Beginning in 2012, FERC hosted a series of meetings to engage natural gas pipelines, electric transmission operators, and other market participants and stakeholders in both industries regarding natural gas and electric industry coordination. In its April 2013 technical conference, market participants and FERC staff considered natural gas and electric scheduling practices including whether and how natural gas and electric industry schedules could be harmonized in order to achieve the most efficient scheduling systems for both industries.[501] The NOPR was issued in response to an interest in updating market design to enhance the ability of natural gas-fired generators to acquire natural gas, and to augment the means by which the pipelines schedule and deliver natural gas to power plants.

In brief, the NOPR proposes to align the timing for gas pipeline scheduling and delivery to the timetables and utilization patterns prevalent in the electricity markets (e.g., the morning ramp up). It also proposes to increase flexibility for gas-fired generators by requiring pipelines to provide additional delivery scheduling opportunities so that power grid operators and power plants can better adjust to contemporaneous market and operational conditions. In the NOPR, the Commission presented specific

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[499] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities,* 79 Fed. Reg. 18, 223 (April 1, 2014) ("NOPR").
[500] 79 Fed. Reg. 18, 224 (April 1, 2014).
[501] See, *Staff Report on Gas-Electric Coordination Technical Conferences*, Docket No. AD12-12-000, *available at* http://elibrary.ferc.gov/idmws/File_List.asp.

proposed reforms to existing natural gas industry scheduling practices and also provided market participants within the natural gas and electricity industries an opportunity to collaboratively develop alternatives for changes in scheduling practices, through a consensus standards-development process at NAESB. After a series of meetings and votes over the summer 2014, representatives of the two industries reached a series of agreements to enhance coordination and NAESB subsequently filed a series of consensus standards with the Commission on September 29, 2014. While there remains an open issue regarding the start of the gas day, it is highly likely that FERC's final order, when issued, will include a series of new scheduling and delivery standards which will enhance the operational capabilities of natural gas-fired power plants and the deliverability of natural gas.

Importantly, improvements to gas market design such as those currently being considered by FERC will considerably enhance gas supply and deliverability to power generators from the existing infrastructure. This would allow the electric power sector to reduce emissions at an even lower cost than would otherwise be possible.

4. EPA Should Adopt a Minimum Level of Generation Shift from Higher-emitting to Lower-emitting Sources.

In the NODA, EPA sought comment on an alternative approach that would comprehensively consider generation shift from coal to gas through the three vehicles discussed above – redispatch to existing NGCC, to New NGCC and use of natural gas at coal-fired steam generating units. EPA suggests that a minimum level of generation shift could be adopted for each state. We strongly support this approach for several reasons. First, it is important to take advantage of the potential reductions in point-of-combustion emissions that can be achieved through new NGCC as well as co-firing. Treating different methods of switching from coal to gas comprehensively also makes sense given that these methods can be considered variations of the same basic shift toward cleaner fuels. Second, the minimum shift approach ensures that the potential to shift from coal-to-gas will contribute to the targets in all states with coal-generation, not just those states that happen to have underutilized existing NGCC capacity.

Based on trends in increases in natural gas generation and declines in coal generation over the past ten years, we believe it would be reasonable to expect that natural gas generation to increase at an annual rate of 5% per year from the present through 2030. EPA would need to consider the effect of such an expansion rate on natural gas and electricity prices when evaluating the total costs of the BSER targets. The ramp rate should reflect the actual potential for and any infrastructure build-out needed to facilitate increased use of gas through the three respective pathways—and as such may be different for the different pathways. We urge EPA to consider ramp rates up to and including a continuation of a five percent per year shift rate, the historical average over the last 10 years.

5. New NGCC Subject to 111(b) Standards Can Be Considered for Purposes of Setting 111(d) Targets.

The fact that new NGCC plants are subject to standards of performance under section 111(b) does not prevent EPA from considering their emission reduction potential when establishing targets under section 111(d). New NGCC capacity would not be regulated under section 111(d) any more than new renewable capacity. Rather, EPA would simply consider the potential for existing coal-fired EGUs to cost-effectively acquire credits derived from either source (new NGCC or new renewables) in determining the target appropriate for such EGUs. EPA's proposal to consider new NGCC plants simply requires that new combined cycle gas (NGCC) plants be treated like new renewables or new efficiency: all three are sources of megawatt hours with emissions rates lower than coal plants (or old gas plants) that they would displace. This does not mean that a 111(b) source is placed under a 111(d) obligation. Under EPA's proposal, the agency considers generation created (or avoided) by new renewables, efficiency, and nuclear in its BSER determination but does not propose to make them regulated facilities under 111(d). EPA can apply the same approach to new NGCC plants, which would remain subject only to section 111(b).

6. EPA Must Promptly Limit Methane Emissions from the Oil and Gas Sector

As noted above, carbon dioxide emissions due to coal combustion are roughly twice as high per megawatt hour as carbon emissions from natural gas at existing natural gas combined cycle plants. Exploration, production, and delivery of natural gas, however, results in significant methane emissions—which is a potent climate pollutant, and, if left unaddressed, could undermine the relative climate benefits of replacing coal-fired generation with natural gas combined cycle plants. President Obama committed to taking action on methane as part of the Climate Action Plan, and it is vital for EPA to follow through on this pledge by promptly commencing and completing a rulemaking to set standards limiting emissions of methane from new and existing sources in this sector.

There is an urgent need to reduce emissions of methane and other harmful pollutants from the U.S. oil and natural gas sector. Recently, the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) concluded that methane is a much more potent driver of climate change than was understood just a few years ago—with a global warming potential as much as 34 times greater than carbon dioxide (CO_2) over a 100-year time frame, and 84 times greater than CO_2 over a 20-year time frame.[502] Approximately one-third of the anthropogenic climate change we are experiencing today is attributable to methane and other short-lived climate pollutants, and about 30 percent of the warming we will experience over the next two decades as a result of this year's greenhouse gas emissions will come from methane.[503] Climate scientists are now recognizing that avoiding catastrophic climate change will

[502] Working Group I, Intergovernmental Panel on Climate Change (IPCC), *Climate Change 2013: The Physical Science Basis, Fifth Assessment Report* 714, tbl.8.7 (2013), *available at* http://www.climatechange2013.org/images/report/WG1AR5_ALL_FINAL.pdf.

[503] *Id.*

require *both* a long-term strategy to reduce carbon dioxide emissions *and* near-term action to mitigate methane and similar "accelerants" of climate change. As a recent article in the journal *Science* stated, "The only way to permanently slow warming is through lowering emissions of CO_2. The only way to minimize the peak warming this century is to reduce emissions of CO_2 and [short-lived climate pollutants, including methane]."[504]

Reducing emissions from the U.S. oil and gas sector is an indispensable part of such a comprehensive climate strategy. Oil and gas facilities are the largest industrial source of methane in the United States, accounting for approximately thirty percent of the nation's total methane emissions.[505] Estimates of methane emissions in EPA's Annual Inventory of Greenhouse Gas Emissions and Sinks are based on bottom-up assessments. In addition to these, there have been numerous, recent top-down studies uniformly suggesting that oil and gas methane emissions are substantially greater than bottom-up inventories would predict,[506] further underscoring the urgency of action.

Moreover, methane from oil and gas facilities is frequently co-emitted together with other harmful pollutants, including ozone precursors such as VOCs and carcinogenic substances such as benzene and other hazardous air pollutants (HAPs).[507] And because methane is a valuable commodity, reductions in methane emissions often pay for themselves due to increased resource recovery—making methane emission mitigation a low-cost (and sometimes *negative* cost) proposition.

The President has committed to addressing methane emissions—first in the Climate Action Plan[508] and then in a more detailed Strategy to Reduce Methane Emissions.[509] Pursuant to the Methane Strategy, EPA issued a series of five white papers examining available, low-cost technologies that could substantially reduce methane emissions from the oil and natural gas sector. EDF provided peer review comments on these technical white papers, and the Methane Strategy includes a commitment for EPA to determine appropriate additional measures to reduce methane emissions by this fall.

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[504] J.K. Shoemaker et al., What Role for Short-Lived Climate Pollutants in Mitigation Policy? 342 Science 1323, 1324 (2013).

[505] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012* (2012).

[506] A.R. Brandt et al., *Methane Leaks from North American Natural Gas Systems*, 343 Science 33-34 (2014) (reviewing 20 years of technical literature on natural gas emissions in the U.S. finding that "measurements at all scales show that official inventories consistently underestimate actual [methane] emissions").

[507] Petron *et al.*, 2014 A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin, Journal of Geophysical Research: Atmospheres, online: 3 JUN 2014 DOI: 10.1002/2013JD021272.

[508] Executive Office of the President, The President's Climate Action Plan (June 2013), *available at* http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[509] Executive Office of the President, Strategy to Reduce Methane Emissions (March 2014), *available at* http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.

In this proposal, EPA concludes that net upstream methane emissions impacts will likely be small, attributing this finding to reductions in coal mine methane emissions due to decreased coal utilization.[510] This finding, however, does not adequately address upstream methane emissions from the oil and natural gas sector in light of the current methane emissions from this sector and the potential for increased utilization of natural gas.

EPA must address these methane emissions from the oil and natural gas sector directly—establishing standards for both new and existing sources that are based on the highly cost-effective technologies EPA evaluated as part of the white paper process and ICF concluded could reduce methane emissions by 40% in 2018 for a cost of just one penny per thousand cubic feet of natural gas produced.[511] Indeed, states like Colorado[512] and Wyoming[513] have already adopted measures to reduce methane emissions from these key sources and organizations from labor unions[514] to the investment community[515] support rigorous action to reduce methane emissions.

It is critical that the President and EPA promptly follow through on this commitment to address methane emissions, and we urge EPA to establish rigorous emissions standards for new and existing sources in the oil and natural gas sector.

7. The Emission Guidelines Should Apply to Emissions From Simple Cycle Combustion Turbines

In comments on the Section 111(b) proposed standards for carbon pollution for new EGUs, we urged EPA to set a standard of 1,100 lbs CO_2/MWh_{net} for simple cycle combustion turbines operating less than 1,200 hours per year (i.e., combustion turbines providing "peaking" service). In comments on the Section 111(b) proposed standards for modified and reconstructed units, we urged EPA to require a rigorous initial performance test for all sources subject to standards under Section 111(b). These two approaches,

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[510] 79 Fed. Reg. 34,862; *see also* EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants at Appendix 3A (June 2014).
[511] ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries* (March 2014), *available at* http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.
[512] Co. Dep't of Pub. Health & Env't Reg. No. 7 (5 CCR 1001-9) (adopted Feb. 23, 2014).
[513] Wyo. Dep't of Envtl. Quality, Proposed Nonattainment Area Regulations, Ch. 8, Sec. 6 (proposed Oct. 31, 2014), *available at* http://deq.state.wy.us/aqd/Resources-Division/Proposed%20Rules%20and%20Regs/Chapter%208%20-%20NAA-Existing%20Source,%20IBR%20draft%2010-24-14_REDLINE.pdf.
[514] BlueGreen Alliance, *Letter: BlueGreen Alliance Urges the Administration to Adopt a National Methane Reduction Strategy* (Oct. 10, 2014), *available at* http://www.bluegreenalliance.org/news/publications/document/100914-BGA-methane-letter-vFINAL.pdf.
[515] Letter from NYC Comptroller Scott Stringer and Investors to EPA Administrator Gina McCarthy, *Re: National Oil and Gas Methane Regulation* (Oct. 9, 2012), *available at* http://www.trilliuminvest.com/wp-content/uploads/2014/10/EPA-Methane-Regulation-Letter-10.09.14.pdf. Also, on the June 9, 2014 edition of the Charlie Rose show, Goldman Sachs CEO Lloyd Blankfein made clear that investors need strong and stable rules for methane emissions in order to make long-term investments in sectors that use natural gas. *See* http://www.charlierose.com/watch/60403647.

taken together, can ensure that new, modified, and reconstructed power generation infrastructure utilizes the best available technologies currently available.

For simple cycle combustion turbines, the initial performance test should reflect the emission rate achievable using the best system of emission reduction when a plant is operating at optimal conditions to ensure that these facilities are built, reconstructed, or modified using the lowest-emitting technologies and operating systems available, fulfilling the technology-forcing and pollution-minimizing purposes of Section 111. A rigorous initial performance test, combined with an emission standard that recognizes the peaking and load-following services that many simple cycle combustion turbines provide, will enable these units to continue to provide that role while also ensuring that they incorporate the most efficient and lowest polluting technologies available, ensuring that the standards fulfill the Section 111 statutory requirements and case law.

Applying section 111(b) standards to simple cycle combustion turbines will require the inclusion of these sources in Section 111(d) plans. As EPA noted, peaking plants play an important role in the power generation system, and often are used to "balance" intermittent renewable generation. These units emit significant quantities of carbon pollution, however, and as such it is important for the environmental integrity of the standards and for efficient operation of power markets that they are incorporated within the standards for existing fossil fuel-fired power plants and state plans to reduce carbon pollution from the power sector. Incorporating these plants will avoid the creation of perverse incentives to run peaker plants more (and inefficiently) were they not subject to carbon pollution standards. Incorporating existing peaker plants in state plans to address carbon pollution will ensure that plans can secure carbon pollution reductions cost-effectively and efficiently (as all existing fossil fuel-fired power plants would be subject to the plans, and the carbon reduction obligations) and avoid power market distortions that could have the effect of increasing carbon emissions from these plants.

I. Comments on Building Block 3: Zero Carbon Energy Generation

1. Renewable Energy

EDF commends EPA on the Clean Power Plan's adoption of a system-based approach, which includes the full range of technologies available to reduce carbon pollution from existing power plants. Zero-emission, renewable energy technologies are currently reducing overall emissions from a state's generation fleet, and expanding renewable energy should be included in the Best System of Emissions Reduction. EDF's comments on building block 3 address three primary points. First, EDF addresses why EPA properly included renewable energy in setting the BSER.

Second, EDF explains how EPA's analysis relied on outdated renewables cost data that fails to capture the significant cost reductions that have occurred in recent years. EPA must update its analysis to incorporate current renewable cost information. Because of its use of outdated cost data, EPA has significantly underestimated the potential for renewable energy to reduce power sector emissions.

Third, EDF addresses the method EPA should use to determine the amount of renewable energy available in each state. We recommend that EPA adopt a modified version of the Alternative Proposal.

a. EPA Properly Included the Addition of Renewable Energy in the BSER

Electricity generation from renewable resources – such as wind, solar, or geothermal – has been demonstrated to be a cost-effective means of displacing emissions from fossil fuel generation. Given the nature of the electricity grid, the addition of renewable energy will directly result in reduction in other generation. And there is ample evidence that it is fossil-fuel fired generation that is reduced as additional renewables are brought on-line. For instance, the New York State Department of Public Service conducted extensive modeling of the economic and environmental effects of that state's renewable portfolio standard and concluded that increased renewable energy generation would displace generation from higher-emitting sources, primarily natural gas-, coal-, and oil-fired units.[516] Likewise, a recent white paper concluded that in the RGGI region the addition of renewable energy sources have almost entirely displaced coal-fired generation.[517]

Renewable energy also meets EPA's cost criteria. Recent analysis by Lazard suggests that the costs of carbon abatement from building a new wind or solar project, relative to building a new coal or gas plant, are within EPA's range of $10-$40/ton and, particularly in areas with strong wind resources, can result in net savings to electricity customers.[518] A recent LBNL survey of state renewable generation cost assessments found that most states that assessed benefits of RPS policies determined that the policy resulted in net benefits due to, among other things, pollution reductions, economic development, and natural gas price suppression.[519]

b. EPA Must Update the Cost Data it Relies on to Assess Potential Growth in Renewable Energy

Renewable energy costs have fallen dramatically and renewable energy performance has improved in recent years. These changes are well recognized and consistent with the price declines expected as an industry experiences the kind of growth that the renewables industry has seen in the U.S. and abroad.[520] But EPA's analysis fails to account for either the cost reductions that have already occurred or the cost

[516] New York Department of Public Service, Final Generic Environmental Impact Statement (2004) at 111 (Table 6.4-1), available at http://www.dps.ny.gov/NY_RPS_FEIS_8-26-04.pdf. The potential for clean energy to displace fossil-fuel-fired generation also has important benefits for public health. *See id.* at 2ES ("Modeling reveals that the addition of new renewable energy sources at the 25 percent target level could annually reduce NOX emissions by 4000 tons (6.8%), SO2 emissions by 10,000 tons (5.9%), and carbon dioxide (CO2) emissions by 4,129,000 tons (7.7%).").

[517] Brian C. Murray, Peter T. Maniloff, Evan M. Murray, "Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors" at 18, available at http://sites.nicholasinstitute.duke.edu/environmentaleconomics/files/2014/05/RGGI_final.pdf (quantitatively attributed emissions effects to policy and market factors in the RGGI region).

[520] Electric Power Research Institute, "Modeling Technology Learning for Electricity Supply Technologies",

reductions that can reasonably be expected to continue. EPA must properly account for these cost reductions and re-analyze the quantity of renewable energy that is available.

In EPA's analysis of renewable energy (conducted through its Integrated Planning Model IPM®) Base Case v5.13,4), EPA adopts load forecasts and new technology costs from the Energy Information Administration's (EIA) Annual Energy Outlook 2013 (AEO2013).[521] More recent industry data demonstrate that modeling assumptions used for the cost and performance characteristics of new generating technologies are significantly out of date. These cost estimates are especially important because, as discussed below, the costs for new generation technologies constrain the amount of renewable energy available to reduce carbon pollution under the Clean Power Plan.

AEO2013's assumptions are outdated and do not reflect the dramatic cost declines seen in recent years. In fact, we find that AEO2013's cost assumptions for renewables are 46% above current averages for wind and solar technologies. This is not surprising, given that the AEO2013 cost assumptions were based on projects completed in 2012 and reflect pricing contracts that may have been signed several years prior to project completion.[522]

Since 2010, the cost of building utility-scale solar projects has declined by about 50 percent from \$3400/kW to \$1500–1800/kW in 2014.[523] These declines are consistent with NREL's modeled prices using its bottom-up modeling methodology – NREL estimates that the price of solar declined to \$1800/kW_{dc} in Q4 2013.[524] The declines are also reflected in average PPAs for utility-scale solar which, in the past year alone, have dropped from \$123/MWh to \$86/MWh, with several projects reporting prices (including incentives) below \$70/MWh – competitive with new NGCC plants.[525]

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[521] The projections in EIA's Annual Energy Outlook focus on long term trends in the U.S. energy system. The AEO 2013 Reference Case assumes that current non–expiring laws and regulations remain unchanged through 2040, the end of the forecast period. The Production Tax Credit (PTC) and 30% Investment Tax Credit (ITC) for renewables are not extended past their current end date. AEO 2013 is available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf.

[522] EIA reports and other government-issued reports typically have an 18-month or greater time lag due to the comprehensive nature of acquiring, reviewing and reporting on energy data from contributing energy generation, delivery and consumption for the entire country. LBNL has emphasized that reported installed price data "may reflect transactions that occurred several or more years prior to project completion" and therefore are often unable to accurately reflect current prices in such a rapidly changing industry. (LBNL, Tracking the Sun VII).

[523] This range is based on data from the following sources: U.S. DOE Sunshot, "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections." October 2014; "Bloomberg New Energy Finance. "H1 2014 Levelized Cost of Electricity – PV." February 2014; Lazard. "Levelized Cost of Energy – v. 8.0; Bloomberg New Energy Finance/World Energy Council. "World Energy Perspective: Cost of Energy Technologies." 2013; Solar Energy Industries Association. Personal Communications. August 14, 2014. The above sources are available at: http://www.nrel.gov/docs/fy14osti/62558.pdf; https://www.iea.org/media/workshops/2014/solarelectricity/bnef2lcoeofpv.pdf; http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf; http://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf.

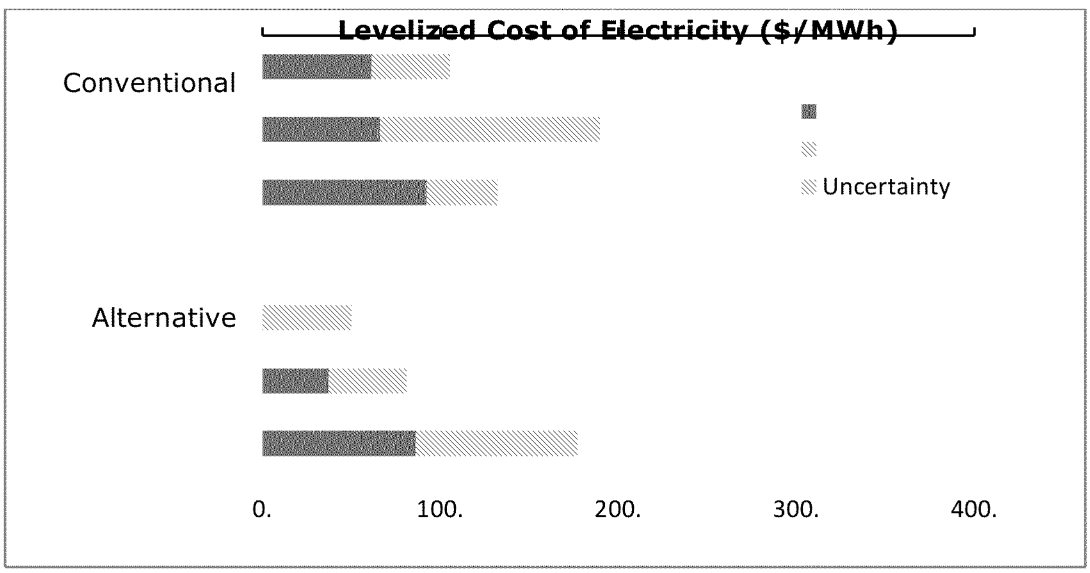
[524] DOE/NREL, "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections." October 2014.

[525] Lawrence Berkeley National Laboratory, "Utility-scale Solar 2012", September 2013, available at:

Wind prices have experienced similar declines since 2010. The capital cost of developing onshore wind turbines has also declined, from $2260/kW to $1750/kW on average.[526] LBNL reports that PPAs for wind projects (including incentives) fell, after peaking briefly at $70/MWh in 2009, to a national average of $25/MWh in 2013.[527] Moreover, technology improvements have allowed for taller wind turbines, enhancing performance through faster and steadier wind speeds at higher elevation. As a result of these advances, Lawrence Berkeley National Laboratory (LBNL) researchers have indicated that average capacity factor has increased by 10 percent across all wind classes since 2012.[528] Taller wind turbines significantly expand the geographic area suitable for wind turbines.

Lazard estimates that the current range of LCOEs for onshore wind, *without* any subsidies, is between $37/MWh and $81/MWh. In contrast, EIA's out-of-date estimate projects that the LCOE in 2019 will be between $70/MWh and $90/MWh.

Figure 4: Levelized Cost of Electricity for Conventional vs. Alternative Technologies[529]



*Low end of uncertainty range represents utility-scale system at $1500/kW; high end represents commercial system at $3000/kW.

There is no basis for EPA to rely on AEO2013's out of date data when it has before it recent government and credible industry analysts' cost data, e.g. NREL, LBNL, BNEF and Lazard. AEO2013's use of

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http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends

[526] Lawrence Berkeley National Laboratory. "2013 Wind Technologies Market Report". August 2014, available at: http://emp.lbl.gov/publications/2013-wind-technologies-market-report.

[527] *id.*

[528] Trabish, H. "Experts: The Cost Gap Between Renewables and Natural Gas 'Is Closing'." Greentech Media. May 6, 2014, available at: http://www.greentechmedia.com/articles/read/The-Price-Gap-Is-Closing-BetweenRenewables-and-Natural-Gas.

[529] All cost estimates and corresponding assumptions from Lazard, Levelized Cost of Electricity v. 8.0, 2014.

installed costs means that the data presented will have an 18-month or greater time lag. As LBNL has noted installed cost data "may reflect transactions that occurred several or more years prior to project completion" and therefore are often unable to accurately reflect current prices in such a rapidly changing industry.[530] In this case, the delay causes the analysis to miss key data showing major price declines, and therefore significantly overestimate current costs and underestimate recent performance. EPA can also check the monthly FERC-issued grid interconnection report, which shows the utility-scale projects that have both been approved for interconnection or commissioned as a new generating resource for the regional transmission authorities that lie under FERC jurisdiction.

Importantly, there is no reason to believe that the declines in cost will not continue. DOE/NREL Sunshot Vision study, which constructs a detailed roadmap for continued cost declines in solar PV technologies, projects that solar system prices can drop 75% between 2010 and 2020.[531] In its 2014 update on Solar PV pricing trends, NREL also predicted that solar prices are still on track to meet the Sunshot goal of $\$1/W_{dc}$ by 2020 for utility-scale systems.[532] This would place utility-scale solar projects in direct competition with NGCC plants, without any incentives or carbon policy. Likewise, many industry analysts predict that wind and solar will become increasingly competitive with new NGCC plants and will make up a major market share of new U.S. demand. [533,,,534535] As noted, average PPAs for utility-scale solar in the past year alone have dropped to levels (including incentives) competitive with new NGCC plants.[536] Meanwhile, a new Deutsche Bank report predicts that distributed solar power will be cheaper than average retail electricity prices in 36 states by 2016 (47 states if the 30% ITC is extended).[537]

Recent analysis also shows that higher penetrations of renewable energy are feasible. Detailed analyses performed on the PJM grid, the Eastern Interconnect, and Western Interconnect have all found that renewables can provide up to 10% of generation on major ISOs with little to no additional costs, and can provide up to 30% of total generation with only minor adjustments to the existing grid and proper system planning.[538,539, 540]The findings of these studies demonstrate that it is technically achievable to incorporate higher levels of renewable energy into the existing grid than what has been proposed in EPA's target-setting.

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530 LBNL Tracking the Sun VII Report (p. 39)
531 DOE/NREL, Sunshot Vision Study, February 2012, available at: http://energy.gov/eere/sunshot/sunshot-vision-study
532 *Ibid.*
533 Credit Suisse. "The Transformational Impact of Renewables." 2013.
534 Bloomberg New Energy Finance, "2030 Market Outlook: Focus on Americas", 2013, available at: http://bnef.folioshack.com/document/v71ve0nkrs8e0/106y4o
535 Greentech Media, "Experts: The Cost Gap Between Renewables and Natural Gas 'Is Closing'", May 2014
536 Lawrence Berkeley National Laboratory, "Utility-scale Solar 2012", September 2013, available at: http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends
537 Bloomberg, "While You Were Getting Worked Up Over Oil Prices, This Just Happened to Solar" , October 2014, available at: http://www.bloomberg.com/news/2014-10-29/while-you-were-getting-worked-up-over-oil-prices-this-just-happened-to-solar.html
538 PJM Integration Study
539 NREL Western Wind and Solar Integration Study
540 NREL Eastern Wind Integration Study

There is no basis for EPA to rely on outdated cost information in its analysis when it has more recent data available showing that current costs are lower. This is particularly true because the cost differential is dramatic. Based on NRDC's analysis of recent data, the costs EPA relied on are 46 percent above current average costs for, respectively, wind and solar energy.[541] As explained in detail below, the lower costs mean that substantially more renewable energy can and should be included in the state targets.

c. EPA Should Strengthen the Alternative Approach To Determining the Amount of Renewable Energy Available at Reasonable Cost in Each State

EDF recommends that EPA adopt the Alternative Approach presented in the proposed rule, which reflects state and regional technical and economic potential. But EPA should strengthen this approach by using updated cost and performance data for renewable energy technologies and removing the benchmark utilization rate.

Update Cost and Performance Assumptions

Under the alternative approach, EPA uses economic modeling of renewable energy using IPM to determine the amount of renewable energy available at reasonable cost in each state. For the reasons describe above, the costs used by EPA are significantly higher than current solar or wind prices. EPA must update these costs with and re-run its IPM economic modeling. This modeling should use the most reliable and up-to-date cost and performance assumptions available, which will provide a more accurate representation of the cost competitiveness of renewables and lead to increased deployment.

Updated installed capacity and generation data

If EPA continues to utilize its benchmark rate methodology within the Alternative Approach, EPA should use updated data on installed capacity and generation – there has been significant growth in wind and solar capacity and generation since 2012, and this capacity will continue to grow between now when the standards take effect. Recent growth in both wind and solar capacity, shown in Table 2 below, highlights the need to use the most up-to-date data available in markets growing at unprecedented rates.

[541] See http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf

Table 2: Growth in Installed Capacity[542]

Cumulative Installed Capacity (MW)							
	2008	2009	2010	2011	2012	2013	Jul-14
Onshore Wind	25,068	35,064	40,298	46,919	60,007	61,091	61,322
Total Solar PV	485	920	1,772	3,691	7,060	11,811	15,900

Refine the Alternative Approach

We support using a state's technical and economic renewable energy potential to determine its potential to reduce carbon pollution from fossil generation by deploying renewable energy; however, the benchmark development rate does not capture the rapid growth of renewable energy. As described in more detail *supra*, both wind and solar capacity have grown at remarkable rates over the past 5-10 years – taking a snapshot of 2012 capacity to set a benchmark development rate simply does not fully capture this progress. Installed capacity has grown significantly even between 2012 and today, and even those states that have deployed significant renewable resources can and should be expected to continue to grow their renewable energy portfolio into the next decade. As discussed below, the benchmark rates not only fail to capture current growth in renewable energy, but it is also redundant and unnecessary when combined with IPM, which already contains technical constraints.

Eliminate benchmark rate, rely solely on technical and economic potential within IPM

IPM results already reflect both constraints through detailed resource supply curves. For example, as stated in the IPM documentation, "EPA worked with the U.S. Department of Energy's National Renewable Energy Laboratory, to conduct a complete update…of the potential onshore, offshore (shallow and deep) wind generating capacity."[543] However, IPM is capable of modeling technical potential in an even more granular fashion than NREL's technical potential, as it details the amount of resources available by cost class. Therefore, IPM has the potential to not only model technical potential limits, but also place economic limitations on resource availability within the overall technical potential — a more accurate representation of market dynamics than EPA's proposed use of benchmark development rates. While this more granular data was not used by EPA in their analysis, we recommend that EPA consider using it when determining technical and economic potential for each state and region.

Another problem with the benchmark development rate is that it places an unnecessary constraint on states that are currently leaders in renewable energy development. If IPM results demonstrate that these states can continue to develop their renewable resources at a reasonable cost, then these states' targets should be set accordingly. Cost-effective renewable resources should not be arbitrarily excluded from the

[542] EIA Form 860 Data; LBNL Tracking the Sun VII, AWEA annual reports
[543] Page 4-31, EPA IPM Documentation, ch. 4

BSER determination based on artificial constraints such as the benchmark development rates described in the Alternative Proposal.

Implement grid integration constraints or costs that supplement and strengthen IPM's capabilities

Instead of using the benchmark rate, EPA should consider implementing constraints that more closely simulate real-world grid operations. There is a growing body of research on grid integration of renewables, and several studies have suggested that at least 30% of renewables can be handled by the existing grid, providing that there is adequate transmission expansion and proper system planning.[6,7] While higher levels could be integrated with some management and investment changes,[544, 545] 30% represents a clearly achievable near-term limit. EPA modeling should reflect this.

Distributed Generation

Distributed solar and other forms of distributed generation are distinctive in their ownership, operation, significance of siting, and relationship to the existing grid. These systems provide quantifiable benefits such as grid support, lower transmission losses, and reduced need for additional capacity, as well as less monetized benefits such as hedging against fuel prices and reduced security risk. As PV module costs continue to decline, rooftop solar is becoming and will continue to become an economic option for an increasing number of residential and commercial customers. [5, 546] Omitting DG from the RE block paints an unrealistic picture of the current and future RE generation mix. In fact, net metered capacity now makes up about half of total U.S. solar PV capacity.[547] NREL's Open PV Project Database provides up-to-date capacity and price data by state, based on a sample of installations,[548] which should be used to incorporate rooftop PV generation into the alternative approach.

Although there are methods in which distributed PV can be implemented into IPM as a resource available to utilities, it may be more accurate to rely on separate modeling that fully accounts for market dynamics at the customer level. As one example, NREL has developed the Solar Deployment System (SolarDS) model, a modeling complement to ReEDS which projects distributed solar installations by state based on system prices, retail rates, and consumer economics.[549] Outputs of SolarDS or similar modeling can then be hard-wired into IPM to ensure that the effects on the grid and other generation options are captured.

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[544] Energy and Environmental Economics (E3). "Investigating a Higher Renewable Portfolio Standard in California." January 2014, available at: https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

[545] NREL, GE Energy Consulting, and JBS Energy. "California 2030 Low Carbon Grid Study", August 2014, available at: http://www.lowcarbongrid2030.org/wp-content/uploads/2014/08/LCGS-Factsheet.pdf

[546] NREL Residential Grid Parity Report, 2013

[547] http://www.eia.gov/electricity/monthly/update/archive/april2014/; SEIA data (from EIA)

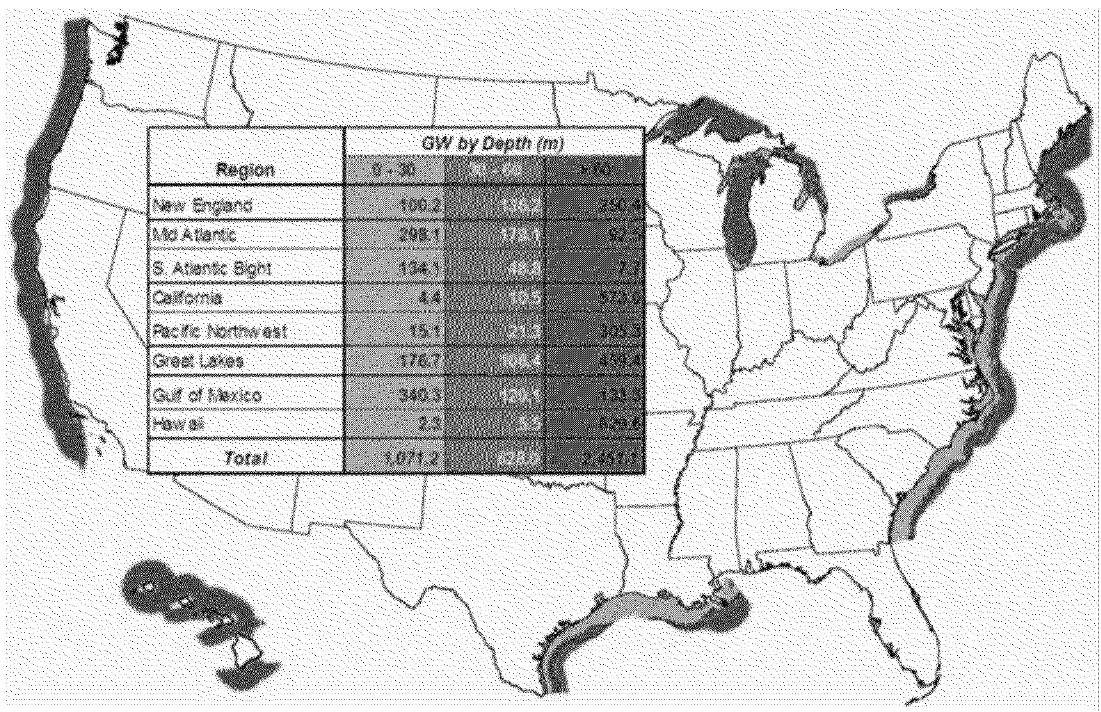
[548] https://openpv.nrel.gov/

[549] NREL, "The Solar Deployment System (SolarDS) Model: Documentation and Sample Results", September 2009, available at: http://www.nrel.gov/docs/fy10osti/45832.pdf

Offshore Wind

The resource potential for offshore wind in the United States is vast, and adjacent to many metropolitan areas with high electricity demand. According to the Bureau of Ocean Energy Management, over 1,000 GWs are available in 0-30 foot depth waters, 628 GW in 30-60 feet, and over 2,400 GW over 60 feet deep. This power is spread across a diverse geography, as shown in the figure below.

Figure 5: Map of Offshore Wind Potential[550]



Region	GW by Depth (m) 0 - 30	30 - 60	> 60
New England	100.2	136.2	250.4
Mid Atlantic	298.1	179.1	92.5
S. Atlantic Bight	134.1	48.8	7.7
California	4.4	10.5	573.0
Pacific Northwest	15.1	21.3	305.3
Great Lakes	176.7	106.4	459.4
Gulf of Mexico	340.3	120.1	133.3
Hawaii	2.3	5.5	629.6
Total	*1,071.2*	628.0	2,451.1

As a less mature technology and industry, offshore wind is at a higher cost point on the development and deployment curve. However, if it follows the historical trajectories of onshore wind and solar power, increasingly higher deployment levels will likely bring substantial cost and performance improvements. These gains come about from a number of factors, including economy of scale; learning by doing; development of needed supply chains; development of transportation infrastructure; streamlining of permitting, financing, and other "soft costs"; and continued research, development, and innovation. Several studies suggest costs could even fall more quickly than they did for onshore wind energy.[551]

[550] NREL, *Dynamic Maps, GIS Data, and Analysis Tools: Wind Maps*, U.S. 90 m Offshore Wind Map, *available at* http://www.nrel.gov/gis/wind.html.
[551] https://www.ieawind.org/index_page_postings/WP2_task26.pdf

Currently there are 14 commercial scale projects in advanced development that would constitute almost 5 GW of capacity.[552] America's first offshore wind project, Cape Wind, is set to produce 75% of the electricity used on Cape Cod and the Islands of Martha's Vineyard and Nantucket with zero pollution emissions.[553] Furthermore, this project is expected to lead to a net reduction in the wholesale cost of power in the region.[554] This phenomenon is not unique to Cape Wind – a recent comprehensive study by DOE details the numerous benefits that development of offshore wind can have for the U.S. electric grid.[555]

The potential to capture the nation's large off-shore wind resources is further evidence of the conservative nature of EPA's assessment of renewable energy potential. Regardless of whether this resource is considered in assessing state emission reduction potential in the current proposal, EPA should revise its best system of emission reduction analysis and state targets as the availability of such resources is demonstrated.

Supporting Analysis

Independent modeling studies have also determined that higher penetrations of renewable energy are both technically feasible and economically achievable. Such studies should serve as further confirmation that much higher levels of renewable energy can and should be considered part of the BSER.

For example, rigorous analyses have been done using NREL's Renewable Energy Deployment System (ReEDS) model. Like IPM, ReEDS is a long-term capacity-expansion model for the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States. Additionally, ReEDS features the following capabilities to model renewable energy:

> "[ReEDS] addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal load and generation profiles, variability and uncertainty of wind and solar power, and the influence of variability on the reliability of electric power provision. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary service requirements and costs."[556]

[552]Navigant, "Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment", *prepared for the Department of Energy,* available at: http://energy.gov/sites/prod/files/2014/09/f18/2014%20Navigant%20Offshore%20Wind%20Market%20%26%20Economic%20Analysis.pdf
[553] http://www.capewind.org/what/benefits
[554] Charles River Associates. "Analysis of the Impact of Cape Wind on New England Energy Prices." February 2010.
[555] Department of Energy. "National Offshore Wind Energy Grid Interconnection Study." July 2014
[556] For more on NREL's ReEDS model, see http://www.nrel.gov/analysis/reeds/documentation.html.

NREL RE Futures Study. Recent analyses by the National Renewable Energy Lab (NREL) and U.S. Department of Energy (DOE) demonstrate the potential for much higher renewables penetration than EPA's proposed targets, even under restrictive sensitivity cases. NREL/DOE used the Regional Energy Deployment System (ReEDS) to model an aggressive target of 80 percent renewable energy by 2050 under several sets of assumptions.

NREL modeled four cases – three assumed a 0.17% annual growth in electricity demand; the fourth specified a high-demand scenario of 0.84% per year annual growth. We focus here on the first three scenarios, which are much closer to specified demand levels in the proposed Clean Power Plan. One case assumed partial achievement of future technology performance and cost advancements, or "incremental technology improvements"(ITI); a second used the same ITI assumptions, but added significant restrictions on transmission, policy flexibility, and reliability ("ITI-Constrained"); the third assumed "advanced technology improvements" (ATI), characterized by aggressive cost reductions for solar and onshore wind technologies.

The ReEDS modeling suggests that states could achieve significantly higher renewables deployment without a significant impact on electricity prices. Depending upon the scenario and year, solar and wind generation levels are two to three times higher in ReEDS than EPA's targets and, in many cases, electricity price projections are lower than EPA's. In 2020, all three scenarios project lower retail electricity prices than EPA (11.1 cents/kWh for EPA, and 10.5, 10.7, and 10.3 cents/kWh for the ITI, ITI-Constrained, and ATI scenarios, respectively). In 2030, retail electricity prices are roughly the same in the ITI and ATI scenarios as EPA's (11.5 and 10.7 cents/kWh vs. 11.2 cents/kWh, respectively), and slightly higher under the ITI-Constrained case (12.1 cents/kWh).

UCS Analysis of Proposed RE Targets. In its comments to EPA, the Union of Concerned Scientists (UCS) has proposed a "Demonstrated Growth" approach to target-setting, which results in 995 TWh of renewable energy deployment.[557] UCS has assessed the technical and economic feasibility of reaching these targets using NREL's ReEDS model, and has reached similar conclusions as NRDC regarding the achievability of these targets.

UCS has also found that the incremental cost of high levels of RE deployment under their proposal was at or below $30/MWh, assuming national trading of RECs. Additionally, UCS examined the impacts on natural gas prices, because diversifying the electricity mix with renewable energy would help reduce the economic risks associated with an overreliance on natural gas.[558] Reducing the demand for natural gas would also lead to lower and more stable natural gas and electricity prices.

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[557] For more on UCS's proposal, see http://www.ucsusa.org/sites/default/files/attach/2014/10/Strengthening-the-EPA-Clean-Power-Plan.pdf.

[558] Bolinger, M. 2013. *Revisiting the long-term hedge value of wind power in an era of low natural gas prices*. Golden, CO: Lawrence Berkeley National Laboratory (March 2013) *available at* http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf (last accessed on October 2, 2014); Fagan, B., P. Lucklow, D. White, and R. Wilson. 2013. *The net benefits of increased wind power in PJM*. Cambridge, MA:

The UCS analysis found that national average consumer electricity prices are a maximum of 0.3% higher per year than BAU through 2030. As a result, a typical household (using 600 kWh per month) would see a maximum increase of 18 cents on their monthly electricity bill on average at the national level. In the UCS analysis, the national average price of natural gas delivered to the electricity sector would be 9% lower than business as usual by 2030. At the regional level, consumer electricity prices would range from a 3.7% reduction to a 3.4% increase, while power sector natural gas price reductions would range from 8 percent to 17%.

Preliminary Results from DOE's Wind Vision Report. While the full Wind Vision report is not scheduled to be released until early next year, DOE issued an early release of the Executive Summary and Roadmap chapter on November 19, 2014.[559] The early release shows that increasing wind power from 4.5% of U.S. electricity use in 2013 to 10% in 2020, 20 percent in 2030, and 35% in 2050 is technically and economically feasible. Achieving these targets would require less than 5 percent of the country's available wind resource potential and would result in a less than 1% (0.1 cents/kWh) increase in electricity costs by 2030, and a 2% reduction in electricity costs by 2050. In addition, the study found that achieving the Wind Vision (compared to a baseline scenario) would result in cumulative (2013-2050) savings of:

- $400 billion in avoided global climate change damages from reducing power plant carbon emissions by 12.3 Gt of CO_2-equivalent (a 14% reduction)

- $108 billion in avoided health and economic damages from reducing particulate matter, nitrous oxide, and sulfur dioxide emissions and

- $280 billion in lower consumer natural gas bills and total electric system costs that are 20% less sensitive to natural gas price fluctuations.[560]

Final Recommendations

EDF commends EPA on the Clean Power Plan's system-based approach, which includes the full range of technologies available to reduce carbon pollution from existing power plants. We fully agree that zero-emission, renewable energy technologies are currently reducing overall emissions from a state's generation fleet, and expanding renewable energy should be included in the Best System of Emissions Reduction. EPA proposed two different approaches to determining how much renewable energy should be included in establishing state targets. Both approaches to Building Block 3 are well-supported but EDF

Synapse Energy Economics, Inc. Mercurio, A. 2013. *Natural gas and renewables are complements, not competitors*. Washington, DC: Energy Solutions Forum, Inc.

[559] U.S. Department of Energy, *Wind Vision: A New Era for Wind Power in the United States (Industry Preview)*. DOE/GO-102014-4557 (2014) *available at* http://energy.gov/eere/wind/downloads/draft-industry-preview-wind-vision-brochure.

[560] Cumulative figures from the study are calculated based on the present value of costs and savings between 2013 and 2050, using a 3 percent discount rate.

recommends that EPA adopt a strengthened Alternative Approach, which better reflects state and regional technical and economic potential, and strengthen the approach by using updated cost and performance data for renewable energy technologies. In the above comments, we have cited research and data to support an overall strengthening of the Renewable Energy building block, as summarized by the recommendations below.

The alternative approach's strengths lie in its use of technical and economic data to calculate the state renewable energy potential, but EPA has relied on outdated data. EPA uses EIA AEO 2013, which contains several-year old cost and performance data and results in levelized costs for wind and solar which are 46% above current averages for each technology. EPA's modeling should use the most reliable and up-to-date cost and performance assumptions available, which will provide a more accurate representation of the cost competitiveness of renewables and demonstrate that more renewables can be deployed at reasonable cost. EDF recommends the following changes to the Alternative Approach (as detailed in previous sections):

- Update cost and performance assumptions for renewable energy technologies, based on recent government or industry data
- Eliminate the benchmark development rate constraint
- Include distributed solar generation through separate modeling (e.g. NREL's Solar Deployment System (SolarDS) model)

Appendix 1: Distributed Solar Projections from NREL's Sunshot Vision Study

Distributed solar PV is a distinctive, customer-sited generation resource, and therefore it may be difficult to represent in a wholesale power model such as IPM. Instead, it is appropriate to rely on NREL's modeling using the SolarDS model, which takes into account various factors that affect the decision-making of homeowners and businesses.

In its 2012 Sunshot report, NREL modeled solar PV penetration across the country for several sensitivity scenarios, based on expected price declines. NREL's October 2014 Sunshot pricing update indicates that system prices are in fact on track to meet a 75% price reduction by 2020.

Table 3. DOE/NREL Sunshot, Distributed solar capacity projections for -62.5% price case[561]

Distributed Solar Projections (GWdc)				
	2014	2020	2025	2030

[561] NREL, "Sunshot Vision Study", February 2012 (Table A3).

AL	0.00	0.04	0.11	0.18
AZ	0.58	0.95	2.86	4.76
AR	0.00	0.01	0.04	0.07
CA	2.55	3.96	11.87	19.78
CO	0.27	0.52	1.57	2.62
CT	0.09	0.23	0.69	1.14
DE	0.03	0.06	0.18	0.30
FL	0.07	0.94	2.82	4.70
GA	0.04	0.20	0.59	0.98
ID	0.00	0.00	0.01	0.02
IL	0.01	0.15	0.44	0.73
IN	0.00	0.08	0.25	0.42
IA	0.02	0.12	0.37	0.62
KS	0.00	0.13	0.39	0.65
KY	0.00	0.02	0.07	0.12
LA	0.07	0.16	0.49	0.81
ME	0.01	0.05	0.14	0.23
MD	0.12	0.16	0.47	0.78
MA	0.42	0.42	0.68	0.95

MI	0.01	0.13	0.40	0.67
MN	0.02	0.12	0.37	0.61
MS	0.00	0.01	0.04	0.06
MO	0.07	0.20	0.59	0.99
MT	0.01	0.03	0.08	0.14
NE	0.00	0.06	0.19	0.32
NV	0.06	0.42	1.27	2.12
NH	0.01	0.02	0.05	0.09
NJ	1.05	1.05	1.13	1.21
NM	0.07	0.14	0.43	0.71
NY	0.17	0.79	2.37	3.95
NC	0.03	0.25	0.75	1.25
ND	0.00	0.01	0.03	0.05
OH	0.07	0.07	0.19	0.30
OK	0.00	0.15	0.45	0.75
OR	0.07	0.07	0.20	0.32
PA	0.20	0.32	0.95	1.59
RI	0.01	0.07	0.22	0.37
SC	0.00	0.06	0.17	0.28

SD	0.00	0.03	0.10	0.16
TN	0.00	0.07	0.21	0.35
TX	0.07	1.54	4.63	7.71
UT	0.02	0.08	0.24	0.40
VT	0.11	0.11	0.11	0.11
VA	0.02	0.16	0.48	0.79
WA	0.03	0.32	0.95	1.58
WV	0.00	0.02	0.05	0.09
WI	0.01	0.10	0.30	0.50
WY	0.00	0.02	0.05	0.09
Total	6.4	14.6	41.0	67.44

Appendix 2: Comments on Proposed Approach

Although the bulk of our comments on the renewable energy building block focus on improvements to the Alternative Approach based on cost and performance data, we note also that the Proposed Approach succeeds in recognizing the regional nature of renewable energy markets, as well as the value of existing RPS requirements as an indicator of feasibility. However, this approach can be improved in several ways.

If EPA decides to use the Proposed Approach to determine the renewable energy component of the emissions reduction target, we recommend the following improvements to EPA's methodology to more accurately reflect best practices and existing trends of renewable energy growth.

Update RPS Requirement. Many of the state RPS goals extend beyond 2020, yet EPA used 2020 targets only in determining average regional RPS levels for the states for a 2030 emissions reduction target. EPA should reassess regional targets based on the last target year in state law: whether it be 2015, 2020, 2025 or another year, in setting the 2030 renewable target.

Some states have multiple RPS targets for different load serving entities (for example, one target for investor-owned utilities and another for coops or municipal utilities; or one target for larger utilities and another for smaller utilities). In any state with multiple targets, EPA should use the larger of the targets in formulating the regional average. Since EPA seeks the best system of emissions reductions, it should use the highest renewables targets being adequately demonstrated by states. While some states may have determined that lower targets are acceptable for some classes of utilities, they did not do so in the context of seeking the best system of emissions reductions. The higher targets, which have been demonstrated to be economically and technically achievable, clearly demonstrate a better system of emissions reductions.

Eliminate growth rate constraint, and choose best of: existing generation, existing state RPS requirement, and state goal based on the regional RPS average . We agree that Renewable Portfolio Standards are instructive in evaluating the best available emissions reductions opportunities. Some states have achieved higher renewable energy generation and integration than is required by their RPS, indicating that an RPS should not be a cap on renewable generation. However, in EPA's target-setting methodology, some state targets fall below existing generation and existing state RPS requirements. We believe that a state's existing generation and, if applicable, its existing state RPS requirement, should both serve as a floor to set the minimum level of emissions reductions available for that state. Using a level lower than the state has already demonstrated (either through generation or a state RPS target) would indicate a lower level of emissions reductions than the state has found to be available.

Further, in establishing a regional growth rate, EPA used unnecessary constraints that limited the pace of renewable energy growth. EPA's approach generated growth rates well below what has been demonstrated in the last several years and below what is achieved in most projections for the next decade. For example, the top 16 states in solar deployment all grew at growth rates higher than 40%, with 11 states growing at rates above 100%, between 2009 and 2013. According to EIA data, the top 16 states in wind development have all experienced growth at rates higher than 15%, with a national growth rate of 30%, sustained over a longer period between 2006 and 2013. In contrast, only one region in EPA's Proposed Approach is expected to meet a growth rate above 15% (East Central, 17%) in EPA's target-setting. Furthermore, when setting a growth rate EPA should rely on the most recent available capacity data, and should not ignore new and under-construction capacity. Renewable generation is quickly growing to meet and exceed state RPS requirements, and states with those standards have demonstrated that the levels required by these standards are both feasible and economic.[562] As such, assumed growth rates should more closely resemble the impressive growth from leading states during the last decade.

[562] NREL/LBNL, "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards", May 2014

Tables 4 and 5. Recent growth rates in solar PV and wind generation by state.

Solar PV Generation (GWh)						
State	2009	2010	2011	2012	2013	AAGR
CA	647	769	889	1,382	3,865	56%
AZ	14	16	83	955	2,041	247%
NV	174	217	291	473	749	44%
NJ	11	21	69	304	546	165%
NM	0	9	128	334	414	258%
NC	5	11	17	139	379	195%
FL	9	80	126	194	240	127%
CO	26	42	105	165	199	66%
TX	0	8	29	118	176	180%
MA	0	1	5	30	109	378%
PA	4	8	23	32	82	113%
MD	0	0	3	22	80	416%
IL	0	14	14	31	64	66%
OH	0	13	15	37	64	70%
DE	0	0	8	23	57	167%
NY	0	0	6	53	53	197%
U.S.	157	423	1,012	3,451	8,327	170%

Net Generation from Wind (GWh)									
State	2006	2007	2008	2009	2010	2011	2012	2013	AAGR
TX	6,671	9,006	16,225	20,026	26,251	30,548	32,214	35,937	27%
IA	2,318	2,757	4,084	7,421	9,170	10,709	14,032	15,571	31%

CA	4,883	5,585	5,385	5,840	6,079	7,752	9,754	13,230	15%
OK	1,712	1,849	2,358	2,698	3,808	5,605	8,158	10,881	30%
IL	255	664	2,337	2,820	4,454	6,213	7,727	9,607	68%
KS	992	1,153	1,759	2,863	3,405	3,720	5,195	9,430	38%
MN	2,055	2,639	4,355	5,053	4,792	6,726	7,615	8,065	22%
OR	931	1,247	2,575	3,470	3,920	4,775	6,343	7,452	35%
CO	866	1,292	3,221	3,164	3,452	5,200	5,969	7,382	36%
WA	1,038	2,438	3,657	3,572	4,745	6,262	6,600	7,008	31%
ND	369	621	1,693	2,998	4,096	5,236	5,275	5,530	47%
WY	759	755	963	2,226	3,247	4,612	4,369	4,415	29%
NY	655	833	1,251	2,266	2,596	2,828	2,992	3,548	27%
IN	0	0	238	1,403	2,934	3,285	3,210	3,483	71%
PA	361	470	729	1,075	1,854	1,794	2,129	3,339	37%
SD	149	150	145	421	1,372	2,668	2,915	2,688	51%
U.S.	26,589	34,450	55,363	73,886	94,652	120,177	140,822	167,665	30%

J. Comments on Building Block 4: Demand-Side Energy Efficiency

1. Overview

EDF strongly supports EPA's determination that demand-side reductions in carbon pollution from the power sector through increased energy efficiency measures are an integral part of the BSER for existing power plants. Energy efficiency has long been recognized as the most cost-effective way to meet our electricity needs,[563] and a variety of recent studies — as well as the experience of states and utilities that have been implementing energy efficiency programs for many years — confirm that there remains vast potential to achieve significant further reductions in electricity demand. As EPA recognizes, every megawatt-hour saved through energy efficiency translates into reduced generation from units operating

[563] *See, e.g.,* Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* 52 (World Resources Institute, Oct. 2014) ("Over the past decade, efficiency has remained the least-cost option for utilities, with levelized costs to utilities ranging from 2 to 5 cents per kilowatt hour, about one-half to one-third the cost of new electricity generation options.").

"at the margin," which in almost all cases will be an affected EGU utilizing fossil fuel.[564] As a result, energy efficiency is a highly economical and effective mechanism for reducing emissions from the power sector. Underscoring this conclusion, various federal and state regulatory programs have already sought to reduce emissions of carbon dioxide and other pollutants from the power sector by incentivizing energy efficiency.[565] EPA's inclusion of energy efficiency as part of the BSER under section 111(d) is a well-justified part of its system-wide approach to determining the level of emission reductions that state plans should achieve.

Many states and utilities have already taken action to realize this enormous opportunity for consumer savings and climate protection, providing further support for EPA's conclusion that energy efficiency is an "adequately demonstrated" and cost-effective element of the BSER. Indeed, twenty-six states around the country – including states in the Midwest, Southwest, West Coast, and the Northeast – have adopted energy efficiency standards or targets for their utilities that, in many cases, require investments matching or exceeding the level EPA has assumed in its BSER analysis. In recent years, state investments in consumer-funded EE programs increased to nearly $6 billion in 2012, representing a 28% increase in just three years. And incremental electricity savings reported by the states have increased by approximately 120% over the same period, reaching 22 million MWh in 2011 — equivalent to about 0.6% of retail sales – with 14 states reporting savings of more than 1% of retail sales.[566] A recent report by the Georgetown Climate Center contains numerous case studies of states and utilities that have successfully implemented energy efficiency programs to reduce greenhouse gas emissions and save customers money.[567] And a 2013 report by LBNL indicates that, under trends in existing programs, utility investments in energy efficiency are likely to increase to $9.5 billion by 2025 — with a corresponding increase of nearly 60% in

[564] The impacts of energy efficiency (and renewable energy) on the emissions of marginal EGUs is vividly illustrated in EPA's recently-released AVERT model, which draws from historical data on EGU operations to calculate the marginal emission reductions associated with energy efficiency and renewables deployment on an hour-to-hour basis. Other analyses carried out by grid operators confirm that the effect of energy efficiency and renewable energy is to displace generation – and emissions – from fossil fuel-fired EGUs on a continuous basis. For a more detailed explanation of the impacts of energy efficiency and renewable energy on emissions from fossil fuel-fired EGUs, please see section I.F of our comments.

[565] For example, in Title IV of the Clean Air Act Congress directed EPA to create an incentive program awarding allowances to utilities that reduce sulfur dioxide emissions through energy efficiency. For over a decade, EPA has also encouraged states to consider energy efficiency in developing state implementation plans (SIPs) to achieve National Ambient Air Quality Standards under section 110 of the Clean Air Act. *See generally* EPA, *Guidance on State Implementation Plan (SIP) Credits for Emission Reductions From Electric-Sector Energy Efficiency and Renewable Energy Measures* (Aug. 2004); EPA, *Roadmap for Incorporating Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans* (July 2012). And EPA has approved at least three SIPs that incorporate emission reductions from energy efficiency and renewable energy as compliance measures for achieving air quality standards. *See* EPA Roadmap, Appendix K at K-8 to K-10.

[566] American Council for an Energy Efficient Economy (ACEEE), *2013 State Energy Efficiency Scorecard* 19, 27, 30-31 (Nov. 2013).

[567] *See* Georgetown Climate Center, *Reducing Carbon Emissions in the Power Sector* 12, 15, 17, 26 (2013) (citing, among other examples, energy efficiency programs implemented by Xcel Energy and Black Hills Energy that reduced CO2 emissions by 1 million tons over 2009-2011; Minnesota's Conservation Improvement Program, which achieved CO2 reductions of 800,000 tons in 2010; an EE program by National Grid that benefits 1.8 million customers and saves 660,000 tons of CO_2 per year; and an energy efficiency initiative in Kentucky that is designed to reduce energy consumption by 18% by 2025).

total electricity savings.[568] EPA's recognition of energy efficiency as part of the BSER builds on the widespread — and rapidly increasing — deployment of energy efficiency around the country to benefit ratepayers and reduce emissions.

EPA's technical analysis of energy efficiency in "Building Block Four" contains two major components, both of which we support and reinforce in our comments below. First, EPA concludes – on the basis of recent potential studies as well as the experience of states that have succeeded in developing energy efficiency programs — that all states can eventually achieve annual incremental energy savings of at least 1.5% of retail sales each year. As we discuss below and as documented in a white paper separately filed in this docket by Analysis Group,[569] this assessment is amply supported by individual energy efficiency potential studies that have been performed around the country, as well as by broader national and regional studies. Moreover, EPA's assessment is conservative because it is based largely on efficiency opportunities that have historically been captured through ratepayer-funded energy efficiency programs. Importantly, these are programs where the cost effectiveness of energy efficiency investments are typically evaluated in the absence of carbon dioxide emissions standards for the power sector. Factoring in those avoided compliance costs will inherently increase the amount of cost effective energy efficiency investments. As such, EPA's analysis does not fully account for many *existing* energy efficiency technologies and practices – such as whole-building retrofits, commercial building commissioning, upgrades to transmission and distribution infrastructure, voltage/VAR optimization, and combined heat and power – that are typically not included in achievable potential studies but are nonetheless available to states and utilities. Nor does EPA's analysis fully reflect the many emerging energy efficiency technologies that will increase future technical and economic potential for energy savings. And EPA's assessment does not capture the many innovative mechanisms now being developed by states, utilities, and the private sector to streamline the financing and delivery of cost-effective energy efficiency solutions, all of which will have the effect of increasing achievable potential. In light of these considerations, EPA's 1.5% target likely understates the actual magnitude of savings that states can and will achieve as they implement state plans.

The second major component of EPA's analysis concerns the pace and timing of energy efficiency savings. Based on current energy efficiency targets adopted by states around the country, and historical rates of increase in energy efficiency savings, EPA concludes that each state can reasonably increase its energy efficiency savings by 0.2% of retail sales per year. Like EPA's assessment of ultimate savings potential, this projected "ramp-up" rate is conservative based on the actual experiences of states and utilities. Below, we discuss a second white paper filed in this docket by Analysis Group that examines ramp-up rates achieved by utilities in various states and concludes that EPA's projected rate has been met or exceeded in numerous instances over the last seven years.[570] Based on this analysis we conclude that EPA should increase the ramp rate to no less than 0.3%, and consider increasing it to 0.5% per year or more. In addition, we find that the experience of leading states and utilities — coupled with the vast

[568] Galen L. Barbose et al., *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025* at 5 (LBNL, Jan. 2013)
[569] *See* Paul J. Hibbard, Katherine Franklin, & Andrea M. Okie, *The Economic Potential of Energy Efficiency: A Resource Potentially Unlocked by the Clean Power Plan* (Dec. 1, 2014) ("AG Potential Analysis").
[570] Paul J. Hibbard, Andrea M. Okie & Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels* (Dec. 1, 2014) ("AG Ramp Rate Anaylsis").

additional potential for energy savings not included in EPA's 1.5% target — provides ample support for EPA's expectation that a savings rate of up to 1.5% can be sustained through 2030.

Our comments also show that EPA's assumed costs for energy efficiency measures greatly exceed the most recent assessments in the literature, and recommend that EPA adopt lower and more realistic cost estimates that better reflect the opportunities for cost-effective pollution reductions available under the proposed Clean Power Plan. Lastly, our comments recognize that rigorous evaluation, measurement and verification (EM&V) for energy efficiency savings is a critical issue for state plans that rely on reported savings as an important part of demonstrating compliance. EDF looks forward to EPA's eventual guidance on EM&V. To assist EPA in preparing such guidance, we provide a brief review of the recommendations of Analysis Group on EM&V in section 111(d) state plans – which were included in a white paper published in March 2014, and which we have previously filed in this docket.[571]

2. EPA's Assessment of Energy Efficiency Potential is Conservative and Readily Achievable

EPA's proposed annual energy savings target of 1.5% of retail sales is readily achievable and, indeed, likely underestimates the full potential for cost-effective energy savings. As EPA notes in the TSD accompanying the proposed rule, the 1.5% target is consistent with average achievable energy savings in twelve recently-conducted potential studies from around the country, and with an ACEEE analysis from April 2014.[572] In addition, three states were already achieving this level of energy savings as of 2012, and an additional nine states will be required to achieve this level by 2020 under existing energy efficiency policies.[573, 574] These considerations all indicate that the 1.5% target is adequately demonstrated.

States have made these investments because these programs are good for consumers, even absent limits on carbon pollution. According to analysis by the World Resources Institute, these programs "regularly save customers over $2 for every $1 invested, and in some cases up to $5."[575] According to ACEEE, ramping up every start target to 1.5 percent would increase GDP by over $17 billion by 2030 while creating over 600,000 new jobs.[576]

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[571] *See* Paul J. Hibbard & Andrea Okie, *Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments,* Document ID No. EPA-HQ-OAR-2013-0602-6120 (Mar. 2014).
[572] *See* GHG Abatement Measures TSD at 5-24 (citing ACEEE, *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution* (Report E1401, Apr. 2014).
[573] *See* GHG Abatement Measures TSD at 5-32 to 5-33.
[574] Among all states with energy efficiency targets, ACEEE found that "In 2011, 13 states exceeded their electricity savings targets, and 6 others came within 90% of them. Only two states achieved less than 80% of their targeted electricity savings. In 2012, 15 states met or exceeded their electricity savings targets, and 6 others came within 90% of their savings targets for the year. Only one state met less than 80% of its target." See Annie Downs and Celia Cui, Energy Efficiency Resource Standards: A New Progress Report on State Experience. ACEEE. April 2014. Available at http://aceee.org/sites/default/files/publications/researchreports/u1403.pdf
[575] Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014)
[576] H.Hayes, G. Herndon, J. P. Barrett, J. Mauer, M. Molina, M. Neubauer, D. Trombley, and L. Ungar, 2014, "Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution," April, Report E1401, American Council for an Energy-Efficient Economy (ACEEE), Washington, DC, accessible at http://www.aceee.org/sites/default/files/publications/researchreports/e1401.pdf.

Further support for EPA's proposal appears in two recent white papers prepared by the Analysis Group and submitted separately to this docket. The AG Potential Analysis focuses specifically on the 1.5% target, evaluating both EPA's meta-analysis and a recent comprehensive study by ACEEE (2014), as well as other literature. The Analysis Group's review confirms that the studies considered by EPA and ACEEE are thorough, geographically diverse, and represent sound methodologies for evaluating energy efficiency potential. Further, the Analysis Group review finds that energy efficiency potential studies have found economic and achievable energy savings potential well in excess of 1.5% per year in all major regions of the country, and over varying forecast periods ranging up to 20 years. The Analysis Group report also includes a critical evaluation of the EPRI (2009) analysis reported in the TSD, which found significantly lower energy savings potential than other studies reported in the literature; the Analysis Group notes that, among other flaws, the EPRI analysis excluded savings from a wide range of efficiency measures and did not take into account the potential to reduce energy consumption through accelerated replacement of equipment.

As the Analysis Group report also explains, the methodology used by EPA (and other similar analyses) to quantify achievable potential is likely to lead to a conservative result that understates the full scale of energy savings that can be achieved by states and utilities. This is because "achievable" potential is typically defined to represent only a fraction of cost-effective energy efficiency potential, and is often intentionally restricted to reflect current energy efficiency program budgets and limitations. As the National Academy of Sciences described it in a 2010 review of potential studies, "The risk of overestimating efficiency potential *is minimal*, owing to the methodologies that are used in the studies…the studies openly and intentionally make assumptions that lead to 'conservatively' low estimates of the efficiency resource."[577] These are considerations that are not binding in the context of an emission reduction program such as the Clean Power Plan.

There are at least four additional reasons why EPA's analysis likely underestimates the full potential for energy savings in each state:

- **Alternative EE measures**. First, the potential studies reviewed in the EPA, ACEEE, and similar analyses are typically prepared for state PUCs or utilities interested in determining potential savings from ratepayer-funded programs; as such, only a minority of those studies include savings that can be achieved through measures that are typically not included in such programs, such as through improvements in building codes and appliance standards or through investments in CHP.[578] These measures can make significant contributions to total energy savings. For example, a 2011 study by the Edison Foundation's Institute for Electric Efficiency indicated approximately 8.6-13.6% of total electricity demand in 2025 (approximately 351-556 TWh) could be achieved by adopting "moderate" to "aggressive" new energy codes for buildings and appliances at the state level.[579] These savings are comparable in magnitude to the *total* savings

[577] AG Potential Analysis at 17 (citing National Academy of Sciences, *Real Prospects for Energy Efficiency in the United States* 59 (2010)).
[578] *See* Max Neubauer, Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies 38 (Aug. 2014).
[579] According to the Department of Energy, only one-quarter of states have adopted the most up-to-date codes for residential and commercial buildings. This is notable as these codes can reduce energy use in new residential and commercial buildings by 20 and 25 percent, respectively. Importantly, building codes have shown themselves to be

EPA projects from ratepayer-funded programs alone in 2030 under building block 4 (approximately 500 TWh).[580] Another example of a demonstrated technology not included in EPA's analysis is Voltage/VAR optimization, which was recently highlighted in a report documenting new strategies being used by utilities to achieve higher levels of energy efficiency savings.[581] As described more fully in Table 7, VVO is a cost-effective resource that states can use to generate significant additional savings and that is not typically considered in potential studies. For example, Xcel Energy is projecting energy savings equivalent to approximately 1.8% of its retail load by 2020 as a result of a proposed voltage optimization project throughout its system.[582]

- **Emerging technologies**. Potential studies also have difficulty capturing changes in technical and economic potential that may result over time due to technological innovation and declining costs of new technologies. This is likely one reason why potential studies with longer time horizons tend to report lower annualized savings than studies that assess short term potential.[583] Yet, the history of energy efficiency deployment shows that savings potential has remained steady or increased over time due to the introduction of new technologies.[584] For example, the Northwest Power and Conservation Council's most recent regional energy plan, issued in 2010, reported a 136% increase in energy efficiency potential relative to 2005 – primarily because of "changing technology that has created new efficiency opportunities and reduced costs."[585] If history has shown anything is that change is norm for this industry. As the World Resources Institute notes, "Major household appliances—including refrigerators, dishwashers, and clothes washers—have become 50 to 80 percent more energy efficient over the last two decades." For example, new refrigerators, clothes washers, dishwashers, and air conditioners use 75, 70, 40, and 50 percent

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cost effective, with codes adopted between 1992 and 2012 expected to save consumers more than $40 billion from buildings constructed during these 20 years alone. See U.S. Department of Energy (DOE), 2014, Building Energy Codes Program: "Status of State Energy Code Adoption," July, U.S. DOE Office of Energy Efficiency and Renewable Energy, accessible at http://www.energycodes.gov/adoption/states. See also U.S. Department of Energy (DOE), Building Technologies Office, "Building Energy Codes Program," DOE Office of Energy Efficiency & Renewable Energy, accessible at https://www.energycodes.gov/.

[580] *See* RIA at 3-27. Although there is likely to be overlap between savings that could be achieved through ratepayer-funded programs and savings that would result from building codes and appliance standards, this comparison nonetheless demonstrates that there are viable alternative pathways for achieving significant savings that are not considered in EPA's core analysis.

[581] Howard Geller, Jeff Schlegel & Ellen Zuckerman, *Maintaining High Levels of Energy Savings from Utility Energy Efficiency Programs: Strategies From the Southwest* 5-152 (ACEEE Summer Study on Energy Efficiency in Buildings, 2014)

[582] *Id.*

[583] National Academy of Sciences, Real Prospects for Energy Efficiency in the United States at 57.

[584] *See id.* at 58 (Comparing potential studies conducted in New York State in 1989 and 2003, which found very similar levels of economic potential, and stating "Studies of technical and economic energy-savings potential generally capture energy efficiency potential at a single point in time based on technologies that are available at the time a study is conducted. But new efficiency measures continue to be developed and to add to the long-term efficiency potential.")

[585] Sixth Northwest Conservation and Electric Power Plan," Northwest Power and Conservation Council, February 2010, p. 10-4.

less energy, respectively, than they did in 1990.[586] Meanwhile, lighting continues to improve by leaps and bounds. LED lighting has fallen in cost by approximately 75% over the last several years and achieves significant energy savings even relative to compact fluorescent bulbs.[587] One recent report notes that Southwestern utilities have increasingly begun incentivizing customers to switch to LED bulbs in order to meet more stringent energy savings targets, as the cost and performance of this technology has improved.[588] Table 7 highlights other emerging technologies, such as high-efficiency HVAC units and intelligent energy monitoring instruments, that demonstrate the potential to maintain or increase technical and economic potential for energy efficiency over time.

- **Innovation in program design and financing**. EPA's analysis is based on studies of "achievable" potential, which is a term of art that refers to the most conservative assessment of energy savings potential taking into account current budgetary and administrative constraints facing utilities or PUCs in a specific policy context. Achievable potential *can* be increased by utilities and state agencies — even without improvements in the cost or effectiveness of energy efficiency technologies — through concerted investment and improvement in program design and financing. And indeed, there are many examples of such innovations taking place just in the last few years. For example, at least twenty states now have utilities that offer "on-bill" loan programs that allow ratepayers to finance energy efficiency projects at competitive rates, and repay the cost of the loans through monthly energy bills.[589] Since 2009, over two dozen states have authorized local governments to implement Property Assessed Clean Energy (PACE) programs to provide competitive financing for energy efficiency projects by allowing property owners to repay the costs of energy efficiency investments gradually through their property taxes.[590] And individual utilities are increasingly devising other creative customer outreach and

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586 Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014)
587 Neabauer, *supra* at 14 n.13.
588 Howard Geller, Jeff Schlegel & Ellen Zuckerman, *Maintaining High Levels of Energy Savings from Utility Energy Efficiency Programs: Strategies From the Southwest* 5-151 to 5-152 (ACEEE Summer Study on Energy Efficiency in Buildings, 2014) (describing new programs being implemented by Southwestern utilities to increase deployment of LEDs, and noting that these savings are more than offsetting other reductions in energy savings from lighting that were occurring as a result of new federal efficiency standards).
589 *See* Catherine Bell, Steven Nadel, & Sara Hayes, *On-Bill Financing for Energy Efficiency Improvements: A Review of Current Program Challenges, Opportunities, and Best Practices* (Dec. 2011) (identifying twenty states with on-bill financing programs, and providing 19 case studies of such programs).
590 Although a 2010 administrative decision by the Federal Housing Finance Administration (FHA) hindered the development of residential PACE programs, PACE programs for commercial buildings continue to be developed and had financed approximately 71 projects in four counties as of early 2011. In addition, we note that some states have managed to find a way to continue operating their residential PACE programs. According to the World Resources Institute, these states are "insuring mortgage holders against losses they may incur because of PACE financing, subordinating the status of residential PACE liens, or maintaining the senior status of PACE liens and providing disclaimers to homeowners interested in enrolling." LBNL, Renewable Funding & Clinton Climate Initiative, *Policy Brief: Property Assessed Clean Energy (PACE) Financing: Update on Commercial Programs* 1 (Mar. 2011); *see also* Katrina Managan & Kristina Klimovich, *Setting the PACE: Financing Commercial Retrofits* 6-7 (Feb. 2013) (indicating that 26 states and DC have enabling legislation, and that sixteen active PACE programs in seven states are financing commercial PACE projects as of early 2013). Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014)

financial incentive programs that enhance participation in energy efficiency initiatives and help achieve greater levels of energy savings.[591] A recent systematic analysis of innovative energy efficiency program designs estimated that such programs could achieve total savings of almost 1,200 TWh in 2030, or approximately 27% of baseline electricity demand – well in excess of EPA's target.[592]

- **Private investments in EE**. Because many studies of achievable potential are designed to take into account the limitations of ratepayer-funded programs, it is unclear whether or how these studies take into account the potential for private actors to deliver energy savings additional to those that would be captured through programs administered by utilities or states. Nevertheless, there is a significant opportunity for private sector investment in cost-effective energy efficiency projects. The private energy services performance contracting industry, for example, has been growing at a rapid pace in recent years, and achieved average annual savings of approximately 26-40 TWh (including both electricity and gas savings) over the period 2003-2012.[593] It is reasonable to expect that this industry and others like it will see significant new growth if energy efficiency investments are incentivized through section 111(d).

As noted above, it is critical to understand that analyses of "achievable" potential are limited by the policy context in which they are developed. The Clean Power Plan creates a fundamental change in the portion of economic energy efficiency that is "achievable" by making energy efficiency a means of achieving compliance with federal carbon pollution standards.

In addition to the conservative assessments of achievable potential reflected in EPA's analysis, several national and regional studies have found technical, economic, and achievable efficiency potential that significantly exceeds EPA's target.[594] These corroborating studies provide further confirmation that EPA's target is eminently reasonable and, in fact, conservative:

- A February 2014 study by LBNL estimated energy efficiency potential in the Western Interconnection in both 2021 and 2032. For 2021, LBNL estimated that aggressive deployment of economically cost-effective energy efficiency measures could reduce annual energy demand in the Western Interconnection by 18% relative to a business as usual scenario. For 2032, LBNL found technical potential for a 22% decrease in demand *above and beyond* savings that would

[591] *See* Seth Nowak et al., *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs* (June 2013) (Reviewing leading energy efficiency programs being implemented by states and utilities, and noting several emerging trends in successful program design including more sophisticated and segmented marketing, adoption of "one stop shopping" and other customer-friendly delivery approaches, and adoption of new financing programs); Geller et al., *supra*, at 5-149, 5-153 to 5-154 (describing utility programs providing financial incentives to builders and developers for constructing or retrofitting buildings that exceed minimum energy code requirements; incentivizing homeowners for undertaking whole-home energy savings; and adopting innovative marketing strategies to encourage greater participation in energy saving programs).

[592] *See* Dan York et al., *Frontiers of Energy Efficiency: Next Generation Programs Reach for High Efficiency Savings* (ACEEE, Jan. 2013).

[593] *See* Elizabeth Stuart et al., *Current Size and Remaining Market Potential of the U.S. Energy Service Company Industry* 1, A-6 (LBNL, 2013).

[594] As discussed below, because these studies report aggregate reductions in energy demand, they tend to support the *combination* of EPA's 1.5% annual energy savings target and the assumed "ramp-up" rate at which savings can be increased to the target level.

already occur as a result of energy efficiency programs that are already in place – many of which could be counted by states towards compliance with their state goals.[595] Both of these estimates greatly exceed EPA's proposed targets, which imply a 3% decrease in overall electricity demand in 2020 and a 11% decrease in electricity demand by 2030.[596]

- A January 2013 study published by Oak Ridge National Laboratory and conducted by researchers at Georgia Tech considered energy efficiency potential in the Eastern Interconnection. Like the LBNL study, the ORNL report found very high potential for energy savings. Moreover, ORNL's study was arguably more conservative than the LBNL study, in that it examined *achievable potential* for savings using a limited suite of 12 selected policies to incentivize or require greater efficiency in residential, commercial, and industrial buildings. These policies do not even come close to representing the full range of measures that states and utilities could implement to increase energy efficiency savings. Even so, the study found that the combination of examined policies would reduce total electricity use in the Eastern Interconnection by almost 7% in 2020 and approximately 10.2% in 2035, which is more than double the level of demand savings implied by EPA's target for 2020 and is very comparable to EPA's target for 2030.[597]

- A 2012 report by the Southwest Energy Efficiency Project (SWEEP) reviewed the historical performance of "best practice" energy efficiency programs for both residential and commercial buildings, and estimated the energy savings that could be achieved in six Southwestern states (Arizona, Colorado, Nevada, New Mexica, Utah, and Wyoming) if similar best practice programs were adopted in the region. Because this analysis is based on savings and participation rates achieved by actual energy efficiency programs being implemented around the country, it is best characterized as an assessment of achievable potential. SWEEP projected that these best practice energy efficiency programs could achieve savings equivalent to over 20% of retail sales by 2020 – reducing electricity demand to approximately 18% below the reference case.[598] The SWEEP study suggests that Southwestern states could achieve a level of energy savings by 2020 that significantly exceeds even EPA's long-term targets for 2030.

- An exhaustive 2009 analysis by McKinsey & Company analyzed the economic potential to deploy hundreds of already-available technologies in buildings and industrial processes. This study found that the country's total end-use energy consumption could be reduced by 23% by 2020 relative to a business-as-usual scenario, relying only on measures that pay for themselves over time.[599] This vastly exceeds the level of energy savings expected by EPA for 2030, albeit using an economic potential metric rather than achievable potential.

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[595] *See* Galen Barbose et al., *Incorporating Energy Efficiency into Western Interconnection Transmission Planning,* 19, 36 (LBNL Feb. 2014).
[596] RIA at 3-17.
[597] *See* Marilyn Brown & Yu Wang, *Estimating the Energy-Efficiency Potential in the Eastern Interconnection* (ORNL Jan. 2013).
[598] Howard Geller, *The $20 Billion Bonanza: Best Practice Utility Energy Efficiency Programs and Their Benefits for the Southwest* xi (2012).
[599] Hannah Choi Granade et al., *Unlocking Energy Efficiency in the U.S. Economy* v (2009).

- A 2010 report by the National Academy of Sciences reviewed a number of studies of EE in residential and commercial buildings, and similarly found that a 25-30% energy savings for the building sector as a whole could be achieved between 2030 and 2035, at a cost of just 2.7 cents per kWh saved. The NAS report also reviewed studies finding that approximately 14-22% of industrial electricity demand could be cost-effectively reduced by 2020. [600] These estimates significantly exceed the levels of energy savings EPA's target implies for 2030.

Lastly, the individual experiences of large energy users that have voluntarily implemented energy efficiency measures are consistent with the findings from these forward-looking studies, and suggest that there is significant, untapped potential to achieve energy savings well in excess of the levels EPA has assumed. Over the last several years, for example, over 190 organizations that collectively own or operate approximately 3.3 billion square feet of building space and over 600 manufacturing facilities have partnered with the U.S. Department of Energy to monitor and improve their energy efficiency through a program called the Better Buildings Challenge.[601] This partnership has furnished a wealth of information about the potential to significantly reduce energy use in commercial, residential, and industrial buildings, and yielded a number of best practices and implementation models that can be adopted by both private and public sector institutions.[602] Since 2011, the Better Buildings Challenge partners have reduced the energy intensity of their buildings by an average of 2.5% each year. More than 2,100 of the 9,000 participating facilities have improved their performance by 20% or more, and more than 4,500 have improved their performance by at least 10%.[603] Many of the large companies and municipal entities that are taking part in the Challenge have reported reductions in building energy use as great as 40%, through the adoption of leading energy efficiency technologies as well as careful energy management practices.[604] These achievements further corroborate the results of the energy efficiency potential studies reviewed above, and suggest that even deeper savings can be achieved through well-coordinated investments in efficiency.

Taken together, both the evidence that EPA cites in the proposed rule and the additional studies and reports highlighted above indicate that the target of 1.5% of savings per year is conservative and readily achievable.

3. EPA's Projected Rate of Increase in Energy Savings is Conservative and Should be Increased

EPA's projection that states can increase energy savings at a rate of 0.2% of retail sales per year is conservative according to recent experiences at the state level, as Analysis Group concludes in a second white paper filed separately in this docket. According to work by the Analysis Group, it is very common for states to achieve a ramp rate in excess of 0.3 percent per year, and most of those states were able to

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[600] America's Energy Future Panel on Energy Efficiency Technologies, *Real Prospects for Energy Efficiency in the United States* 7-8, 15-16 (2010).
[601] *See* U.S. Department of Energy, *Better Buildings Challenge: Progress Update Spring 2014* 1 (May 2014).
[602] *See* U.S. Department of Energy, *Better Buildings Challenge: Three Ways to Find a Solution for You*, *http://www4.eere.energy.gov/challenge/browse-market* (last visited November 24, 2014) (gathering implementation models used by Better Buildings Challenge partners).
[603] BBC Spring 2014 Progress Update, *supra* at 2.
[604] *Id.* at 9.

sustain this high rate of savings growth over multiple years. However, the Analysis Group also documents many cases where states recorded an annual rate of energy savings growth from 0.5%-0.9% at various times from 2006-2013, including California, Massachusetts, Ohio, Oregon, Rhode Island, and Vermont. In addition, we note that EPA's own analysis of past rates of energy savings shows that states achieving moderate levels of savings recorded an average rate of improvement of incremental annual savings of 0.30% per year, and that the high performers achieved an increase in incremental annual savings of 0.38% per year.[605] Because the actual performance of programs so regularly exceeds the ramp rates from EERS targets, EPA should use historical data when determining what energy efficiency ramp rate constitutes the best system of emissions reductions. Based on these analyses, we recommend that EPA increase the ramp rate to no less than 0.3%, and consider increasing it to 0.5% per year or more.

As the Analysis Group also demonstrates through in-depth case studies, these periods of high energy savings growth often followed changes in state-level policies that were specifically intended to spur investment in energy efficiency. Thus, the experience of these states suggests that state-level decisions – such as programs and regulatory policies that will be adopted as part of state plans under section 111(d) — can have a decisive impact on the pace and performance of energy efficiency investments. To take one example, the state of Arizona has rapidly become a national leader in energy efficiency over the last seven years, increasing its state-wide energy savings by 1.57% of retail sales between 2006 and 2013 (reflecting an annual average rate of increase of over 0.2% per year). As the Analysis Group report demonstrates, this increase in energy savings directly followed the adoption of an expanded system benefits charge in 2006 that significantly expanded the resources available for utility-sponsored energy efficiency programs. In 2010, Arizona took the further step of enacting a rigorous energy efficiency resource standard (EERS) that requires cumulative energy savings to reach 22% of sales by 2020. These two policies combined have helped Arizona sustain a rapid upward trajectory of energy savings growth – helping Arizona exceed EPA's 1.5% target in both 2012 and 2013.[606]

In addition to supporting EPA's conclusions regarding feasible rates for increasing energy efficiency savings, the Analysis Group also documents the ability of states and utilities to *sustain* high savings levels over time. As noted above, the existence of massive technical and economic potential for energy savings – including savings from measures and programs that are not explicitly included in EPA's analysis – strongly suggests that states will be able to achieve high levels of energy savings over an extended period of time. However, Analysis Group also provides many examples of leading states and utilities that have demonstrated this ability in recent years. For example, the Analysis Group notes that San Diego Gas & Electric, one of California's "big three" large investor-owned utilities, has reported energy savings well in excess of 1.5% of sales every year since 2007. In 2009 alone, SDG&E reported energy savings of over 2.5% of sales. Similarly, the state of Massachusetts achieved energy savings exceeding 1.5% of sales in each year from 2011 to 2013, with savings exceeding 2% of sales in both 2012 and 2013. And Vermont has exceeded the 1.5% target every year from 2007 to 2012, with energy savings in three of those years at or exceeding 2% of sales. These and other examples in the Analysis Group report demonstrate that high

[605] GHG
[606] AG Ramp Rates Analysis at 23-25.

savings rates can not only be reached at the rate that EPA projects in building block 4, but can also be met over extended periods.[607]

In addition to the Analysis Group white paper, many of the regional and national studies cited above in the context of EPA's 1.5% target also lend support EPA's assumptions regarding ramp-up rates and sustained savings. These regional and national studies report aggregate reductions in demand in future years, which can be compared to EPA's projected demand savings in 2020 and 2030. And EPA's projected energy savings, in turn, are based on *both* the 1.5% savings target and the ramp-up rate. The fact that the demand reductions in these regional and national studies either meet or significantly exceed EPA's projections therefore indicates that the combination of savings target and ramp-up rate is reasonable and achievable.

4. Other Elements of EPA's Goal-Setting Approach Contribute to a Conservative Assessment of Potential

There are two other aspects of EPA's goal-setting approach that lead to an overall conservative assessment of potential energy savings, and that further indicate EPA's proposed energy savings levels in Building Block 4 are readily achievable.

First, EPA assumes that each year's energy efficiency investments have a limited measure lifetime of 20 years, and that the energy savings resulting from any given measure decline at a rate of 5% per year starting the year after the measure is installed. This means that cumulative savings in the year 2030 reflect only 50% of the first-year energy savings achieved by energy efficiency measures installed in the year 2020, and just 35% of the first-year energy savings from measures installed in 2017. This is a highly conservative assumption, given data from LBNL indicating that minimum lifetimes for energy efficiency measures are at least 5 years.[608] Moreover, the practical effect of this assumption is to reduce the cumulative savings that are used to calculate each state's goal. EPA's TSD, for example, shows that for South Carolina the "expiring" savings reduced the state's cumulative savings by approximately 5% in 2025.

Second, EPA applies the 1.5% goal in a way that results in *annual average* reductions of slightly less than 1.5%. As noted above and in the TSD, the 1.5% goal was drawn from analyses of annual average energy efficiency savings – defined as cumulative savings divided by the total time period over which those savings can be achieved. However, when calculating state goals, EPA does not determine annual savings by applying the 1.5% goal to a fixed baseline, as the potential studies do; rather, EPA applies the 1.5% goal to the prior year's sales in each year (after the state has ramped up to that level). As a result, EPA's target-setting approach results in annual average savings that are slightly *less* than 1.5% over the 13-year period in the proposed emission guidelines. This effect is illustrated in Table 6 below, which shows the cumulative savings that would result from a 1.5% per year energy savings in a state with business as usual (BAU) demand growth of 0.8%. As the table shows, the 1.5% target results in annual average savings of

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[607] *Id.* at 33-35, 38-40, 50.

[608] Megan A. Billingsley et al., *The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs* 17 (LBNL Mar. 2014) (reporting range of measure lifetimes for twelve different categories of energy efficiency measures; no measure had a lifetime of less than five years).

approximately 1.37% by 2013. This only underscores that EPA's goal is readily achievable and well within the range of savings reported in energy efficiency potential studies.

Table 6. Annual Average Savings for a Hypothetical State Experiencing Incremental Annual Savings of 1.5% and Business as Usual Demand Growth of 0.8%

Year	BAU Demand	Demand Net of EE Savings	Cumulative Savings Relative to BAU	Annual Average Savings (Cumulative Savings/Time Period)
2017	100	100	0	0
2018	100.8	99.3	1.5	1.5%
2019	101.6	98.6	3.0	1.49%
2020	102.4	97.9	4.5	1.48%
2021	103.2	97.2	6.1	1.47%
2022	104.1	96.5	7.6	1.46%
2023	104.9	95.8	9.1	1.45%
2024	105.7	95.1	10.6	1.43%
2025	106.6	94.4	12.1	1.42%
2026	107.4	93.8	13.7	1.41%
2027	108.3	93.1	15.2	1.40%
2028	109.2	92.4	16.7	1.39%
2029	110.0	91.8	18.3	1.38%
2030	110.9	91.1	19.8	1.37%

5. The RIA Significantly Overestimates the Projected Costs of Energy Efficiency Measures

EPA has significantly overestimated the costs of implementing energy efficiency measures at the pace and level contemplated in building block four. A more realistic assessment of these costs, based on the long track record of energy efficiency programs that have been deployed over the last few decades, would significantly lower the overall compliance costs anticipated for the Clean Power Plan and perhaps alter the overall balance of carbon pollution reduction measures that EPA would consider cost-effective in its BSER analysis.

According to the RIA, EPA assumed that the total levelized cost of energy efficiency projects would be approximately 8.5 cents per kWh saved in 2020, 8.9 cents/kWh in 2025, and 9 cents/kWh in 2030, assuming a 3% discount rate. In projecting these costs, EPA assumed that the first-year cost of saved energy would increase by 20% once a state reached a savings level of 0.5% per year, and by 40% once a state reaches savings of 1.0% per year.[609]

[609] RIA at 3-18.

These cost estimates are much higher than the recent literature and the historical record indicate. As noted above, states frequently find that such programs make sense even in the absence of policies to reduce CO_2 emissions because they save customers money.[610]

In March 2014, LBNL published a comprehensive survey of energy efficiency program costs in March 2014 that collected data from more than 1,700 energy efficiency programs in 31 states – the most recent, rigorous, and expansive review of energy efficiency program costs that we have encountered. LBNL found that on a savings-weighted basis, the average levelized cost of saved energy across the programs sampled was just 2.1 cents per kWh.[611] Although this figure only includes costs incurred by program administrators, LBNL also estimated (based on more limited data) that *total* resource costs, including both program and participant costs, would be about twice the program costs. This suggests that total levelized costs for the programs surveyed by LBNL would be about 4.2 cents per kWh saved — less than half the cost that EPA estimated for 2020. Given that the GHG Abatement Measures TSD references the LBNL study, it is not clear why EPA adopted a much higher cost estimate from a much older and less comprehensive 2009 analysis.[612]

Even taking into account EPA's assumption that the costs of energy efficiency will escalate by 40% for states that exceed a savings rate of 1% per year, LBNL's levelized cost figure would still be much lower than the values EPA derived. Nevertheless, the evidence simply does not support EPA's assumption that states will experience increasing costs at energy savings levels below 1.5% per year. The Analysis Group white paper on ramp-up rates, for example, highlights an empirical study of energy efficiency program costs for a variety of jurisdictions reflecting a wide range of energy savings levels.[613] Based on a regression analysis of this historic cost data, the study found that the first-year cost of saved energy *declines* as a state increases its savings level to 2.5%. Only once savings levels reach 2.5% did the study find that diminishing returns cause the cost of saved energy to increase. These results are consistent with a 2008 study by economists at Synapse Energy Economics, which also found that the unit cost of saved energy for a cross-section of high-performing utilities declined with increasing levels of savings, even at savings levels of 2% of annual sales.[614] The Synapse researchers concluded that their results likely reflected economies of scale and learning effects, and stated that "While there exists a possibility that unit

[610] *See* Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014) (finding that energy efficiency programs regularly save customers over two dollars for every dollar invested, and sometimes yield savings as great as five dollars for every dollar of investment); H.Hayeset al., *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution*, (ACEEE Report E1401, April 2014), accessible at http://www.aceee.org/sites/default/files/publications/researchreports/e1401.pdf (ramping up every state target to 1.5 percent would increase GDP by over $17 billion by 2030 while creating over 600,000 new jobs).
[611] Megan A. Billingsley et al., *The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs* xi (LBNL Mar. 2014).
[612] GHG Abatement Measures TSD at 5-50 to 5-51.
[613] *See* AG Ramp Rates Analysis, *supra* nat 53 (citing John Plunkett, Theodore Love, & Francis Wyatt, *An Empirical Model for Predicting Electric Energy Efficiency Resource Acquisition Costs in North America: Analysis and Application* 5-347 (ACEEE Summer Study on Energy Efficiency in Buildings, 2012)).
[614] Kenji Takahashi & David Nichols, *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence From Experience to Date* 8-369 (ACEEE Summer Study on Energy Efficiency in Buildings, 2008).

costs might begin to increase at much higher levels of EE program savings, this evidence suggests that current program savings levels have not yet approached any such point."[615]

Accordingly, EPA should revise its cost assumptions for energy efficiency to better reflect the results of the LBNL analysis and other credible studies, as well as the literature finding little to no relationship between total energy savings and costs at levels of 1.5% per year or less. We believe that more realistic cost projections for energy efficiency would significantly reduce the overall anticipated cost of the Clean Power Plan, and indicate that increased levels of pollution reduction are cost-effective to achieve.

6. Comments on Evaluation, Measurement & Verification (EM&V)

Credible and workable plans for evaluating, measuring and verifying energy efficiency savings will be a critical part of state plans under the proposed emission guidelines, especially in states with rate-based goals where reported savings will be directly used to demonstrate compliance. As EPA recognizes in the TSD,[616] EM&V approaches to quantify energy savings from energy efficiency measures have been demonstrated for several decades and have grown increasingly rigorous. Over the last two decades, at least fourteen states and several regional transmission organizations (RTOs) and regional partnerships have developed M&V protocols for quantifying energy savings.[617] Reflecting growing confidence in these techniques, verified energy savings are now widely used as the basis for critical regulatory proceedings and market functions, including utility ratemaking[618] and regional forward capacity markets.[619] And although M&V practices continue to vary widely among states and utilities,[620] serious efforts have been undertaken to develop consensus as to best practices and standardized protocols. These initiatives include the Department of Energy's Uniform Methods Project; the International Performance Measurement and Verification Protocol and associated professional certification program; regional technical initiatives such as the Northeast Energy Efficiency Partnership and Pacific Northwest Regional Technical Forum; and the evaluation guides and studies produced by the State and Local Energy Efficiency Action Network (SEE Action).

EDF believes these initiatives provide a sound foundation for EM&V frameworks that could be integrated into state plans, and looks forward to further guidance from EPA regarding satisfactory state plan

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615 *Id.* at 8-371.
616 State Plan Considerations TSD at 37.
617 *See* Steven Schiller et al., *National Energy Efficiency Evaluation, Measurement and Verification (EM&V) Standard: Scoping Study of Issues and Implementation Requirements* 51 (State & Local Energy Efficiency Action Network, Apr. 2011).
618 Thirty states currently have or are implementing a performance incentive rewarding utilities for EE investments. ACEEE, *2013 State Energy Efficiency Scorecard* at 37.
619 Two major federally-regulated regional transmission organizations (RTOs), PJM Interconnection and the New England Independent System Operator (ISO-NE), allow EE resources to bid on a level playing field with traditional generating resources in specialized markets that ensure the long-term ability of the power grid to meet demand. Moreover, both organizations have adopted manuals for measuring and verifying EE resources with sufficient reliability to be counted as a capacity resource. *See* State & Local Energy Efficiency Action Network, *Energy Efficiency Program Impact Evaluation Guide* 7-5 (Dec. 2012).
620 *See generally* Mike Messenger et al., *Review of Evaluation, Measurement and Verification Approaches Used to Estimate the Load Impacts and Effectiveness of Energy Efficiency Programs* (Lawrence Berkeley National Laboratory, Apr. 2010); Martin Kushler et al., *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs* (ACEEE, Feb. 2012).

provisions on EM&V. To support the development of this guidance, EDF has commissioned a white paper from the Analysis Group (filed previously in this docket) that suggests possible frameworks for integrating EM&V into state plans. Broadly speaking, the Analysis Group framework seeks to balance the following policy priorities:

- Environmental rigor, which in this context means utilizing EM&V approaches that account for uncertainty by yielding conservative quantifications of energy savings;
- Flexibility with respect to the types of energy savings measures that can be certified and the types of EM&V approaches that can be approved;
- Compatibility with well-established and rigorous existing approaches to EM&V;
- Providing a cost-effective and administratively efficient process for states, utilities, and energy efficiency providers.

The report describes suggested guidance to the states on a number of issues, including documentation and reporting requirements for entities seeking to certify energy savings; assumed lifetimes of energy efficiency measures; the determination of baselines against which energy savings are to be measured; and consensus-based processes for reviewing and improving EM&V methods over time. The report also identifies three broad categories of EM&V approaches that EPA could recognize in guidance to the states, including 1) deemed savings values and algorithms; 2) measurement-based (or "tailored") EM&V approaches; and 3) PUC-approved EM&V programs, which often reflect combinations of deemed savings and measurement-based evaluations. For each pathway, the report recommends minimum quality assurance elements that would be included in a state plan, as well as potential existing protocols that a state could adopt "off the shelf" to minimize the administrative burdens of developing an EM&V plan. State plans could adopt one pathway or any combination of these pathways, and would include a reasonable basis for adjusting reported energy savings for uncertainty. Although EDF believes that EM&V guidance could take a number of reasonable forms, the Analysis Group report presents one possible framework EPA could consider.

EDF has also reviewed the joint comments on EM&V filed by the Northeast Energy Efficiency Partnership (NEEP) and other organizations, and believes these comments provide many useful recommendations for the development of EPA's EM&V guidance. Among other things, the comments identify credible EM&V protocols that have been established by national and regional partnerships, recommend the development of cross-cutting protocols to assure the rigor of EM&V, and provide recommendations as to the process for establishing and improving EM&V guidance over time. EPA should give careful consideration to these comments as it considers guidance on EM&V.

Table 7. Existing and Emerging Energy Efficiency Technologies With Significant Potential for Additional Energy Savings

Volt/VAR Optimization. VVO involves the management of various electric distribution system assets and advanced control technologies to "right-size" the voltage delivered to end-use electric customers. Reductions in distribution system voltage have been demonstrated to result in reductions in energy consumption across the electric circuits on which these are applied.

Electric customers across circuits with active VVO management and lower voltage levels typically consume less energy without needing to make changes to their individual consumption behavior. Investments in VVO technology and grid modernization can result not only in energy reductions, but also may provide additional service and operational benefits for the customers and the electric system in general.

The magnitude of the energy reductions can vary by location given different system configurations, the nature of customer consumption (including the types of appliances used), and what the voltage levels were before VVO was deployed, among other factors. Various studies, however, have demonstrated the significant energy conservation potential of VVO. In its final report of its "gridSMART" demonstration project, American Electric Power (AEP) estimated based on project results that "a 3 percent reduction in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on those circuits on which VVO technology is deployed."[621]

In a separate report, the Pacific Northwest National Laboratory concluded that Conservation Voltage Reduction (CVR) provides peak load reduction and annual energy reduction of approximately 0.5%-3% depending on the specific feeder". Additionally, "when extrapolated to a national level it can be seen that a complete deployment of CVR, 100% of distribution feeders, provides a 3.04% reduction in annual energy consumption."[622]

Designing appropriate Evaluation, Measurement and Verification (EM&V) protocols are critical in creating an effective compliance mechanism with the Clean Power Plan goals. The AEP gridSMART final report additionally identified one method to translate the energy savings from VVO deployment to carbon emissions avoided over its entire system area, using regional emissions data already collected by the EPA. [623] Whole-Building Energy Retrofits. There is widespread recognition that building energy efficiency can be dramatically improved by carefully integrating improvements to multiple building systems at once, rather than incrementally improving individual systems such as insulation, lighting, or appliances. One high-profile example of this "deep retrofit" strategy is the Empire State Building, which

[621] https://www.smartgrid.gov/sites/default/files/doc/files/AEP%20Ohio_DE-OE-0000193_Final%20Technical%20Report_06-23-2014.pdf
AEP Ohio – Final Technical Report – gridSMART Demonstration Project, June 2014

[622] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf
Schneider, K., Tuffner, T., Fuller, J., & Singh, R. (2010). Evaluation of Conservation Voltage Reduction on a National Level. Pacific Northwest National Laboratory.

[623] https://www.smartgrid.gov/sites/default/files/doc/files/AEP%20Ohio_DE-OE-0000193_Final%20Technical%20Report_06-23-2014.pdf
AEP Ohio – Final Technical Report – gridSMART Demonstration Project, June 2014

undertook extensive renovations in 2009 that were anticipated to yield a 38% reduction in energy use and annual utility savings of approximately $4.4 million. The building's performance has succeeded beyond expectations, exceeding the energy reduction projections by 4-16% in each of the last three years.[624] Similar deep retrofits, yielding energy savings as high as 30 to 50% of baseline energy consumption, have been demonstrated in many other buildings over the last two decades.[625]

Intelligent Energy Management. Advancements in sensors and control systems are now enabling building owners and operators to optimize their energy use in real-time, achieving reductions in building electricity use of as much as 30%.[626] Using the modest 1.5% annual improvement in energy efficiency proposed by EPA, it would take more than 20 years for such opportunities to be exhausted – twice as many years as covered by the Clean Power Plan.

High-Performance Rooftop HVAC. As a result of an initiative by the Department of Energy to improve the efficiency of large rooftop HVAC systems used in approximately half of U.S. commercial buildings, two manufacturers are now producing rooftop HVAC systems that can help reduce energy consumption for cooling by as much as 50% relative to current industry standards. If all existing rooftop units were replaced with systems meeting DOE's new specifications, businesses around the country would realize approximately $1 billion in energy savings each year.[627]

Dynamic Windows. New "dynamic" windows that change opacity automatically in response to electronic controls or thermal conditions can significantly limit heat gain and improve comfort in buildings with significant light exposure. These windows are now commercially available, and a recent pilot test by the General Services Administration (GSA) at a federal building in Denver, Colorado found that the technology could reduce heating and cooling electricity consumption by about 9-10% compared to modern high-efficiency windows.[628] This technology is likely to see increasing use in the future as it comes down in price and as architects and builders gain familiarity with it.

[624] C40 et al., *Innovative Empire State Building Program Cuts $7.5M in Energy Costs Over Past Three Years* (Aug. 14, 2014).
[625] *See* Sameer Kwatra & Chiara Essig, *The Promise and Potential of Comprehensive Commercial Building Retrofit Programs* 1-3 (ACEEE, May 2014) (citing Pacific Northwest National Laboratory, *Advanced Energy Retrofit Guide* (2011); J. Amann & E. Mendelsohn, *Comprehensive Commercial Retrofit Programs: A Review of Activity and Opportunities* (ACEEE, 2005)).
[626] WRI, *Seeing is Believing* at 60 (citing Mary Ann Piette et al., *Intelligent Building Energy Information and Control Systems for Low-Energy Operations and Optimal Demand Response* (LBNL, 2012)).
[627] U.S. Department of Energy, *DOE and Private Sector Partners Introduce a New Money-Saving Specification for Commercial Air Conditioners* 1 (Apr. 2012).
[628] General Services Administration, *Electrochromic and Thermochromic Windows* (Mar. 2014), available at http://www.gsa.gov/portal/mediaId/188003/fileName/Smart-Windows-Findings-508.action (last visited Nov. 24, 2014)

V. Early Action

Under the Clean Power Plan, the United States will finally have Clean Air Act standards to address carbon pollution from existing power plants. During the long wait for these standards, a diverse group of states and companies have acted—have led the way in reducing carbon pollution. They have done so by deploying renewable energy, harvesting demand-side energy efficiency, and by shifting utilization away from high emitting and towards lower emitting power plants.

State and private sector leadership in addressing pollution is something that should be recognized, and supported. Action at the federal level to address climate-destabilizing pollution is lagging perilously far behind the scope and pace of action that scientists tell us is necessary to mitigate harmful climate impacts and reduce the risk of catastrophic climate change. We have for these reasons long supported the recognition of early action in the context of the Clean Power Plan. Yet the question of how to do so in the context of the proposed framework is complex.

Under Section 111(d), EPA identifies the best system of emission reduction available to address dangerous air pollution from stationary sources, and sets emission performance targets achievable using that best system. This framework—like other frameworks under the Clean Air Act—looks at existing pollution problems and how they can be addressed going forward. It does not provide for an assessment of past emission reduction performance by those sources (or that state).

Of course, under the Clean Power Plan, states and companies that have already transitioned towards lower carbon and zero carbon energy and energy efficiency are closer to the full deployment of the best system of emission reduction than others—and EPA should consider clarifying that states that go beyond their targets under the Clean Power Plan would receive credit for those actions under future updating of the carbon pollution standards for power plants. In addition, the standard only applies to fossil generators, so those states with less fossil generation in their system mix will bear less cost.

The years between 2012 and 2020 present a distinct challenge. EPA uses 2012 data on power sector infrastructure in assessing the potential for emission reductions to be secured under the best system of emission reduction during the 2020-2029 compliance period. Crediting emission reductions secured between 2012 and 2020 would encourage states and companies to act earlier, moving emission reductions forward in time. All else being equal, earlier action to reduce emissions is certainly better than later action. But the potential to reduce carbon pollution during 2012 to 2020 was not taken into account in setting the state targets. As such, giving compliance credit to those actions taken during this time that would have happened regardless of the Clean Power Plan—take, for example, renewable energy deployed by a renewable energy standard in a state strongly committed to clean energy—creates a bank of compliance credits that will be used by that state during the compliance period in the place of other, beyond business-as-usual emission reducing actions—and the overall emission reductions achieved by the Clean Power Plan will be reduced by the same amount.

There are, of course, highly compelling reasons to begin to take action now to reduce carbon pollution. States and companies can take advantage of the 5 years between the finalization of the standards and the beginning of the compliance period to gradually build out renewable generation and build up energy efficiency programs so that these resources are ready to deliver carbon reductions. The reductions in co-pollutants that will result will help states deliver cleaner air for their citizens and meet other clean air standards. Companies can develop business models built on a foundation of clean energy and efficiency, and investments in cleaner energy and efficiency will create jobs. Improvements in energy efficiency will cut utility bills for homes and businesses, and spending those savings in their communities will stimulate the local economy. These are simply common sense actions, with tremendous co-benefits—and the existence of an initial compliance date for the long-awaited carbon pollution standards does not alter that common sense.

If EPA does decide to provide early action credit, we urge the Agency to ensure that such crediting does not erode the environmental integrity of the Clean Power Plan by crediting business-as-usual actions. Further, crediting for early action should take place in the context of strengthened state targets that better reflect the full potential for emission reductions under the best system of emission reduction, as discussed above with respect to each of the building blocks and the formula change.

It is naturally difficult to determine what generation is avoided as a result of early actions that commence before the start of the interim compliance period. Therefore, we recommend that EPA credit such actions in a manner that does not over-reward such actions and undermine the benefits of the Clean Power Plan. One possible approach that EPA may wish to consider is comparing early action in states employing rate or mass based programs against the emissions standard for new natural gas plants under section 111(b), or the state's GHG emissions rate for the interim control period, whichever is lower. Another possible approach that could be used in conjunction with or in place of the first approach would be to credit states adopting mass-based programs based on how much they reduce emissions below their approved cap for the interim compliance period.

VI. Renewables and Energy Efficiency Crediting and Tracking

We recommend that EPA establish clear guidelines for the crediting and tracking of energy efficiency and renewable generation. Guidelines may differ depending on whether a state employs a mass-based program or a rate-based program.

A. Tracking

States employing rate-based compliance programs should credit renewable energy and energy efficiency in the form of tons of CO_2 as opposed to trading credits of MWh through RECs or some other mechanism. So doing will simplify compliance across regulated entities and avoid creating significant administrative challenges for state renewable portfolio standards, which in many states will have a different compliance entity than the state's compliance program for 111(d). As a result, RECs will continue to be used by load serving entities for compliance with state renewable standards, while CO_2 emissions credits will be used by electric generators for compliance under section 111(d).

Credit should be provided at the time of generation or at the time energy efficiency projects are verified. This should be done in whatever system is used to track CO_2 credits and compliance. EPA should allow states to determine the frequency with which credits are created in this system, though we would recommend that such credits are created no less frequently than quarterly in order to ensure that projects can quickly capitalize on the value they create.

To ensure that the system can be properly reviewed and problems corrected if they arise, each allowance should be labeled in a manner that indicates its point of origination. For renewable projects this would require that a CO_2 credit could be connected with a particular REC and its associated MWh and generating facility in one of the mandatory or voluntary tracking systems.

In order to facilitate inter-state trading and to simplify state implementation, we recommend that EPA design and operate a tracking system that states can opt to use if they choose.

B. Crediting

Due to the interconnected nature of the electric grid, it is not possible to determine which power plants reduce their generation as a result of each and every MWh of electricity avoided due to efficiency measures, or generated from new carbon free projects such as wind, solar, hydro, or nuclear uprates. In order to ensure that crediting does not overestimate the emission reductions secured by these projects, we recommend that such projects are credited in an amount based on the emissions standard for new natural gas plants established under section 111(b), or the state's GHG emissions rate for the interim control period, whichever is lower. Another approach could be to credit the projects in an amount based on the state's GHG emissions rate for the interim control period or the average emissions rate in their market region (consistent with the regions used to establish the requirements for the renewables building block), whichever is lower.

C. Tracking and Crediting for States Employing a Mass-based Program

Regardless of how states convert EPA's rate-based standard to a mass-based standard, they should not increase their cap each time new generation comes online or new efficiency projects are deployed, as so doing would compromise the emissions benefits of the program. However, a state that has adopted a mass-based standard could incentivize such projects by providing them with free allowance allocations or allowance auction revenue, without modifying its cap. This approach would preserve the environmental integrity of the state goal while promoting the development of projects that contribute to emission reductions from existing power plants.

VII. State Plan Submission Deadline Extensions and the Proposed Compliance Period

EPA has proposed allowing states to apply for a one-year extension beyond the state plan submission deadline if it is not possible to complete a state plan in one year and for a two-year extension if the state is pursuing a multi-state approach. This goes well beyond general EPA requirements. EPA's long-standing regulations implementing section 111(d) generally require state plan submittal within 9 months of EPA's final Emissions Guidelines. 40 CFR § 60.23(a)(1). And with only one exception, EPA has set the deadline for submitting state plans within 12 months of its final guidelines.[629]

While we appreciate EPA's efforts to balance the importance of timely state plan submittal with other considerations, we are quite concerned about delays in carrying out these important emission reductions. And, as noted, states have ample authority to carry out the Emission Guidelines through long established emission reduction measures that apply to the regulated sources, such as Title V operating permits implementing, for example, intrastate emissions averaging across regulated sources.

While we also recognize the dual environmental and economic benefits of regional collaboration, these benefits can be fully realized through timely submittal of state plans developed under existing authority that rely on informal MOUs or agreed upon consistencies across state plans to harness efficiencies in existing cross state markets and platforms within the plan development period provided. For example, states can adopt state programs under existing law and effectuate MOUs for crediting the emission reductions associated with RECs or energy efficiency "white tags" across states to smooth compliance across jurisdictions. Further, states could develop stand-alone state plans initially and subsequently submit revised plans to enable multi-state collaboration.

EPA seems to erroneously presuppose that well designed and efficient regional collaboration must necessarily take the form of formalistic and complex regional programs that impose new burdens on long established, time tested state authorities and prerogatives. This is not the case. There are an extensive suite of opportunities and approaches that states can deploy to mobilize and optimize the synergies of cross border coordination that are thoroughly anchored in existing law. And states can always develop more formal inter-state frameworks over time.

We recommend that any enlargement of time for state plan submittal beyond the extension of time from 9 months to 13 months that EPA has proposed for all states be based on documented exigencies stemming from state laws that preceded the *proposed* Clean Power Plan. Those exigencies should be limited to democratic process requirements—a legislative calendar that is demonstrably not within the state plan development window in a state where legislative action is required for state plan submittal, or a regulatory process that must, by its express terms, take more than 13 months to complete.

[629] EPA, Final Guideline Document: Control of Flouride Emissions from Existing Phosphate Fertilizer Plants (1977) (OAQPS No. 1.2-070) at 1-2 ("After publication of a final guideline document for the pollutant in question, the States will have nine months to develop and submit plans for control of that pollutant from designated facilities."); EPA, Final Guideline Document: Control of Sulfuric Acid Mist Emissions from Existing Sulfuric Acid Production Units (1977) (OAQPS No. 1.2-078) at 1-2 (same); EPA, Kraft Pulping: Control of TRS Emissions from Existing Mills (1979) (EPA-460/2-78-003b) at 1-2 (same); EPA, Primary Aluminum: Guidelines for Control of Flouride Emissions from Existing Primary Aluminum Plants (1979) (EPA-450/2-78-049b) at 1-2 (same); 40 CFR part 60, subpart Cc (establishing emission guidelines for municipal solid waste landfills without setting out exception to the general rule that state plans are due within 9 months of EPA emission guidelines). *But see* 70 Fed. Reg. 28,606, 28,650 (requiring states to submit state plans within 18 months of the finalization of the Clean Air Mercury Rule). Under section 129, state plans must be submitted within 12 months of promulgation of joint section 129/111(d) emission guidelines. 42 U.S.C. § 7429(b)(2). Accordingly, all joint 129/111(d) guidelines have required the submittal of state plans within 12 months of promulgation. 40 CFR § 60.39b (setting 12-month submission deadline for plan submittal); § 60.39e (same); § 60.1505 (same); § 60.2505 (same); § 60.2981 (same); § 60.5005 (same).

Further, there is no justification for providing extensions for actions or steps beyond those in a state's plan development process that make the extension necessary. As such, EPA should require all steps that can be completed during the provided time period should be completed.

To effectuate these central principles, we make the following recommendations. Any initial plan submittal that requests an enlargement of time for plan submittal beyond 13 months must include, at a minimum:

- A complete regulatory framework (with regulatory text) and a demonstration that the plan will meet the state targets, understanding that the plan might change while undergoing pre-existing mandated regulatory or legislative processes that would manifestly take longer than a year. As suggested by EPA, it is also reasonable to require that a state must document that it has at least proposed any necessary regulations and introduced any necessary legislation within the first 13 months to qualify for additional time to complete a state plan.

- A demonstration that completion of the plan during one year is, in fact, not possible given pre-existing regulatory requirements or legislative processes that cannot be completed within one year. If legislative processes are cited, the submittal must also demonstrate that the plan cannot be put in place through regulatory processes standing alone. Neither technical work nor coordination with third parties should be a sufficient predicate for a one-year extension.

- Documentation of notification provided to the owners and operators of all regulated sources that their operating permits will come up for review at a specified date to enable eventual state plan requirements to be incorporated (sufficiently prior to 2020 to enable compliance with the interim targets to be achieved). This is important as some states may not have an existing framework in place to ensure that state plan requirements can be incorporated into regulated source operating permits in a timely fashion.

- For all operating permits of regulated sources, a requirement that the source not increase its CO_2 emissions, measured on an annual basis, to be in place until replaced by requirements incorporated in the final state plan.

- A comprehensive roadmap for completing the plan expeditiously with clear and concrete milestones and timetables that would become the basis for plan disapproval if not achieved.

- For formal, joint multi-state plans, a demonstration that the specific extension requested is necessary and documentation that all plan development steps that can be completed without formal multi-state agreements have been carried out. For multi-state plans that could function initially as state-only plans (e.g. plans that establish intra-state trading mechanisms but allow for inter-state trading of credits or allowances), complete state plans should be submitted by the deadline with the multi-state components to follow within the extension period. States seeking an extension for development of a multi-state plan should also be required to develop a "backup" stand-alone, compliant state plan by the June 2016 deadline to be put in place should the multi-state process not be completed in the allotted time.

VIII. Enforceability of the Portfolio and State Commitment Approaches

To ensure environmental integrity and to fulfill the requirements of Section 111, EPA should ensure that "portfolio" and "state commitment" plans are either composed of specific federally enforceable components or contain backstops that are federally enforceable.

Enforceability is key to the environmental integrity of the Clean Power Plan, and is explicitly provided for in Section 111(d). *See* 42 U.S.C. § 7411(d)(1)(B) (requiring state plans to "provide[] for the implementation and enforcement of . . . standards of performance" established under section 111(d)). State plans composed of an emission rate trading program, an allowance trading program, or other requirements that apply directly to sources will provide a clear and traditional enforcement pathway. The proposed portfolio and state commitment approaches, however, propose to take a different approach in which third parties other than emitting EGUs (including the state itself) could be responsible for securing emission reductions under a state plan. The preamble for the proposed rule describes the "portfolio approach" as one in which:

> *[T]he [state] plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures, that reduce CO_2 emissions from affected EGUs. Under this approach, it would be all of the measures combined that would be designed to achieve the required emission performance level for affected EGUs as expressed in the state goal. Under this approach, the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level.* ***Rather, the state plan would include measures enforceable against other entities that support reduced generation by, and therefore CO2 emission reductions from, the affected EGUs. As noted, these other measures would be federally enforceable because they would be included in the state plan.***

79 Fed. Reg. at 34901 (emphasis added).

In describing the "state commitment" approach to RE and demand-side EE measures, the preamble for the proposed rule states:

> *As another vehicle for approving CAA section 111(d) plans for states that wish to rely on state RE and demand-side EE programs but do not wish to include those programs in their state plans, the EPA requests comment on what we refer to as a "state commitment approach." This approach differs from the proposed portfolio approach, described above, in one major way:* ***Under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally***

> ***enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures*** *that would achieve a specified portion of the required emission performance level on behalf of affected EGUs. . .* ***if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges—including by citizen groups—for violating CAA requirements and, as a result, could be held liable for CAA penalties.***

79 Fed. Reg. at 34902 (emphasis added).

Under either a portfolio or a state commitment approach, in order to satisfy the enforceability requirements of the statute and to ensure the environmental integrity of the standards, either:

(1) specific measures must be federally enforceable (e.g. the state's renewable portfolio standard becomes federally enforceable, or the delivery of a specific quantity of demand-side energy efficiency [kW of demand reduced] by an energy efficiency program becomes federally enforceable); or

(2) the state plan must include federally enforceable, backstop policy measures that will be automatically triggered and take effect without further action by the state or EPA should the state fail to achieve its required emission budget or rate by more than a de minimis percentage at any required reporting deadline.[630] The backstop must be designed by the state to secure at minimum the "missed" emission reductions, and apply directly to the regulated sources. A backstop could, for example, require regulated sources to secure renewable energy credits (or some other type of credit allowed to be submitted for compliance) sufficient to make up the shortfall within a year and a half of the compliance failure. The obligation to make up the shortfall could be allocated among sources in any manner acceptable to the state (for example, the credit obligation above could be distributed among EGUs in a manner proportional to the sources' emissions in the year of the shortfall). The backstop would be included in the operating permits of the regulated entities as part of the section 111(d) standard of performance, and would be federally enforceable by EPA and through citizen suits under sections 113 and 304 of the Act, respectively.

This backstop approach would allow states to satisfy the requirement that state plans contain enforceable measures, while also preserving flexibility for states to adopt state commitments or portfolio approaches that are not themselves federally enforceable. The backstop would also give states the flexibility to design the backstop that best suits local circumstances, with input from their stakeholders. It would provide regulated sources with certainty about the implications of any failure of the state to meet its compliance obligations. However, it would also be important for states to—as proposed—take "corrective measures" to ensure that the compliance failure was not repeated.

IX. Enforcement Guidance for Non-EGUs

[630] See, e.g., section 172(c)(9) of the CAA.

Because existing EPA guidance on the enforceability of RE and EE measures does not provide clear examples of how such measures would be *federally* enforceable against non-EGU entities, EPA should develop new guidance specifically addressing the enforceability of such measures for non-EGUs in the 111(d) context. EPA seeks comment on "the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan." 79 Fed. Reg. at 34,909. Existing EPA guidance addressing RE and EE measures is tailored specifically to the section 110 State Implementation Plan context.[631] EPA's 2004 Guidance on SIP Credits for Emission Reductions from Electric Sector Energy Efficiency Measures specifies that EPA considers RE/EE requirements imposed on non-source entities to be enforceable, such that emissions reductions resulting from those measures "count" toward compliance with emission reduction requirements, where:

> (a) The activity or measure is independently verifiable;
>
> (b) Violations are defined;
>
> (c) Those liable for violations can be identified;
>
> (d) [The State] and EPA maintain the ability to apply penalties and secure appropriate corrective actions where applicable;
>
> (e) Citizens have access to all the required activity information from the responsible party;
>
> (f) Citizens can file suits against the responsible party for violations; and
>
> (g) The activity or measure is practicably enforceable in accordance with EPA guidance on practicable enforceability.[632]

Current EPA guidance discusses how states have actually used RE and demand-side EE measures in SIPs, but provides only one example where such measures were directly enforceable against non-EGU entities.[633] Furthermore, that example does not make it clear how the measure in question would be

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[631] *See, e.g.*, U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012; U.S. EPA, Office of Air and Radiation, Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP), September 2004; U.S. EPA, Office of Air and Radiation, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric Sector Energy Efficiency and Renewable Energy Measures, August 2004.

[632] U.S. EPA, Office of Air and Radiation, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric Sector Energy Efficiency and Renewable Energy Measures, August 2004, at 6.

[633] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-8-K-9 (discussing the inclusion of EE measures aimed at reducing NOx emissions for Dallas-Fort Worth into the Texas SIP).

federally enforceable.[634] Instead, the current guidance relevant to RE and EE measures focuses largely on the use of voluntary measures that are supported by an "enforceable commitment" by the state.[635] Because of the absence of clear examples specifically making measures federally enforceable against non-source entities, EPA should provide new guidance specifically addressing this issue.

The need for guidance tailored to the section 111(d) context is especially important because EPA's current guidance on enforceability relies on the federalization of state law requirements that are included in an EPA-approved section 110 SIP to conclude that any SIP component, whether imposed on sources or non-source entities, will be *federally* enforceable by both EPA and citizens. For example, in advising Connecticut on incorporating its state law RPS and energy efficiency programs into its section 110 SIP, EPA Region 1 noted that federal enforceability would be ensured merely by the inclusion of the mandatory state law requirements into the text of the SIP.[636] Consequently, EPA should provide specific guidance that addresses how such requirements should be structured to ensure that they will be enforceable by both EPA and citizens.

Furthermore, as discussed above, to ensure federal enforceability, EPA should require that state plans taking a "state commitment" approach include a backstop that ensures ultimate responsibility for remedying any shortfall in emission reductions rests with the regulated sources. In the context of section 110 SIPs, present EPA guidance does address the enforceability of RPS and EE requirements imposed on EGUs, but provides no example of states that have actually federalized such requirements by inclusion in a SIP.[637] EPA should provide guidance to states on how to structure RE and EE programs to ensure that specific backstop requirements applied to EGUs to remedy any emissions shortfall will be enforceable by the state, EPA, citizens.

X. Rate to Mass Conversion

[634] The Texas SIP revision mandated the statewide adoption of the International Residential Code (IRC) and the International Energy Conservation Code (IECC), and directed counties to develop ordinances to impose EE requirements on the construction of new homes to reduce electricity consumption in those counties by at least 5% each year for 5 yrs. *See* 73 Fed.Reg. 47835, 47836 (Aug. 15, 2008); Texas Commission on Environmental Quality, Revisions to the State Implementation Plan (SIP) for the Control of Ozone Air Pollution, Apr. 27, 2005, at ES-5, 5-2, 5-3. The enforceability of the EE measures in the Texas SIP appears to stem from the enforceability of the new building codes *under state law and local ordinances*. EPA does not specifically address how the requirements would be enforceable either by EPA under section 113 or by citizens bringing suit under section 304 of the Act.

[635] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.

[636] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at K-36.

[637] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at K-9-K-10, K-12-K-14.

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In the proposed rule, EPA established a rate-based emission target, under which state goals were measured in pounds of CO_2 per megawatt-hour of electricity generated. EPA recently issued a supplemental notice regarding potential approaches for translating the emission rate-based goals to an equivalent mass-based metric.[638] EDF agrees that states should have the option of taking a mass-based approach to compliance. EDF also urges EPA to conduct this conversion for states or, at a minimum, establish a presumptive methodology and minimum standards to ensure that the rate-to-mass conversion does not become a vehicle for weakening standards. In particular, EPA must define a uniform electricity demand growth projection that can be used in a rate-to-mass conversion. EDF recommends that the energy information agency projections provide the maximum demand growth that can be included.

In its rate-to-mass conversion Notice, EPA provides two options for conversion of an emission rate-based goal to a mass-based form.[639] The two approaches include one that provides "mass-based equivalent metrics that apply to existing affected EGUs only."[640] The second provides for a mass-based equivalent that applies to both existing and any new power plants.

The first approach – a mass-based target applicable only to existing power plants – is a viable option only if EPA requires mechanisms to ensure that the mass-based emissions limit is not achieved simply by reducing generation from covered sources and increasing generation at new plants built in the state, an outcome through which the targets could ostensibly be met without achieving actual emission reductions equivalent to those that would be achieved under a rate-based system. (As we discuss in section XII, similar protections must be established to ensure that interstate changes in dispatch do not compromise the actual emission reductions.)

The second approach – a mass-based target that is "*inclusive* of new fossil fuel-fired sources"[641] – is a preferable option and should be the default approach. This approach avoids the complication of tracking excess new fossil generation. The critically important aspect of this approach is the determination of the level of demand growth. This determination must be subject to a uniform methodology established by EPA. An excessive projection of demand growth will weaken the target and void the required equivalency between the rate-based and mass-based targets. Even states that are not attempting to weaken their target will inevitably face pressure to adopt an overly optimistic demand growth projection consistent with the state's aspirations for future economic development. In its TSD accompanying the supplemental notice of the rate-to-mass conversion, EPA bases its annual average growth rate on regional demand projections from the 2013 Annual Energy Outlook published by the Energy Information Administration.[642] EPA must adopt a consistent and unbiased demand growth projection and we suggest that EPA use of the EIA projection.

[638] Notice: Additional information regarding the translation of emission rate-based CO2 goals to mass-based equivalents. 79 Fed. Reg. 67406 (November 13, 2014).
[639] 79 Fed. Reg. 67406, 67408.
[640] 79 Fed. Reg. 67406, 67408 (emphasis added).
[641] 79 Fed. Reg. 67406, 67408 (emphasis added).
[642] Technical Support Document: *Translation of the Clean Power Plan Emission Rate-based CO2 Goals to Mass-based Equivalents,* page 6 (November, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-11/documents/20141106tsd-rate-to-mass.pdf.

In sum, EDF supports the EPA's continued flexibility in the state emission reduction planning process under section 111(d). But EPA must clearly define the acceptable methods for converting rate-based targets and requirements for existing-only mass-based caps in order to ensure that equivalent emission reductions will be achieved.

XI. State and Regional Plan Policy Options and Criteria

While we support EPA providing states with significant flexibility in the development of state plans, it will also be helpful to provide guidance that assists states with the planning process and describes minimum criteria for state plans to ensure environmental integrity and achievement of the state standards of performance. There will inevitably be new ideas developed by states – state innovation is desired – but there are four categories of policies that EPA should consider providing guidance on and must develop minimum criteria for.

The four policy approaches we hear states and stakeholders discussing most are:

1) Flexible Intensity-based Standards
2) Mass-based Standards
3) Carbon Fees
4) Resource Standards or Portfolio Approaches

EPA, the states, and other jurisdictions have experience with all of these policy approaches and EPA should look to those existing programs as guidance and minimum criteria are developed.

Table 8, below, describes the four policy approaches, provides ideas on how EPA could establish minimum criteria, and provides background on how they impact different resource types and stakeholders.

There is also discussion of how the different approaches could work regionally and how interstate problems could develop with different policy approaches existing on either side of a state line. The interstate and market issues that will develop if EPA does not proactively address them in their guidance and minimum criteria are significant – these include environmental leakage[643] and market distortions and associated competitiveness issues for generators of a similar type one either side of a state border. Many of these issues are minimized or not a concern if market regions can agree on consistent policy approaches, but it is important for EPA to proactively consider and address these issues. See also our comments in Section XII on leakage.

[643] Environmental leakage is a transfer of emissions from one region to another. For example one state could set a mass-based cap and a neighboring state a flexible rate based standard, leading to a competitive advantage for natural gas generators in the rate-based state and emissions rising significantly in that state even though they meet the rate-based standard.

The following are minimum criteria by policy type EPA should work with and add to as further guidance on state plans is developed. We are suggesting this as additional criteria by policy approach, on top of the proposed components of state plans EPA presented in the CPP proposal.

1. Flexible Intensity-based Standards
   a. Requirement on the regulated fossil generator to meet the emissions standard on an annual or multi-year basis, with the opportunity to offset emissions with credits from non- and low-emitting sources;
   b. Normal reporting, compliance, and enforcement provisions:
   c. Energy efficiency evaluation, monitoring and verification requirements in order to certify units of energy savings that can be converted to credits;
   d. Renewable energy certificate (REC) tracking system to avoid double counting and allow tracking of units of energy that can be converted to credits;
   e. System and methodology to convert efficiency and renewable MWhs to emissions credits and a platform to track and trade those credits;
   f. Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports;
   g. Prohibition on conversion of RECs and efficiency savings to emissions credits from mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state could still be used for RPS compliance)
2. Mass-based Standards
   a. Requirement on the regulated fossil generator to meet the emissions standard by holding emissions allowances equal to their emissions;
   b. Normal reporting, compliance, and enforcement provisions
   c. Note: we do not think a leakage requirement is needed in mass-based or carbon fee states, as the potential for leakage and increased generation exists primarily in the states that adopt a rate-based approach that allows generation and total emissions to increase.
3. Carbon Fees
   a. Requirement on the regulated fossil generator to pay a fee based on their emissions over a given period of time;
   b. Normal reporting, compliance, and enforcement provisions;
   c. Backstop requirement to track and regularly adjust fees (not longer than annually) if emissions rise above levels allowed by the state standard of performance and have an adjustment made to ensure the standard is being met if emissions rise above allowed levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d))
4. Resource Standards or Portfolio Approaches
   a. Requirement on the regulated load serving entity (LSE) or distribution company providing services to consumers to procure a set amount of efficiency or renewables based on percentages of sales or what is cost-effective (note, there could be other state policy approaches that regulate other entities beyond fossil generators or the LSE);
   b. Normal reporting, compliance, and enforcement provisions:
   c. Energy efficiency evaluation, monitoring and verification requirements;
   d. Renewable energy certificate (REC) tracking system to avoid double counting;

e. Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports;
f. Prohibition on claiming an emissions benefit from RECs generated in mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state could still be used for RPS compliance)
g. Backstop requirement to track emissions in relation to the state standard of performance and have an immediate adjustment made to ensure the standard is being met if emissions rise above allowed levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d))

Table 8. Primary Policy Options for State and Regional Plans

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Examples:	Phase-out of lead in gasoline; NRDC 111(d) proposal	EPA acid rain and ozone trading programs; RGGI, CA and EU carbon trading programs	Great River/Brattle proposal; British Columbia carbon tax	Renewable and clean energy standards in many states; energy efficiency procurement and EERS requirements in many states
Regulated Entity:	Fossil power plants (could be all fossil or just existing - all fossil ensures a level playing field among generators)	Fossil power plants (could be all fossil or just existing - all fossil ensures a level playing field among generators)	Fossil power plants (could be all fossil or just existing - all fossil ensures a level playing field among generators)	Load serving entity (those that deliver energy to customers, not necessarily the generator owners); also EGUs under Clean Power Plan performance standards
Environmental Goal, Units & Outcome:	Each state has an intensity or rate goal (lbs/MWh) that all generators have to meet and declines over time to meet the reduction goal established by EPA; the total emissions outcome is tied to energy production/use; potential for environmental leakage due to increased generation/exports	Each state has a goal expressed in tons, which is fixed and certain and declines over time to meet the reduction goal established by EPA; potential for environmental leakage due to decreased generation/imports; the emissions limit could also be set at the operating company rather than state or regional level for large utilities that want to meet their target internally	A carbon fee would be established at a price estimated to deliver the environmental goal established by EPA (including a decline over time); the price is known but the environmental outcome is uncertain; adjustments may be needed to meet the goal (backstop needed); possible leakage issues if next to intensity-based approaches	Minimum requirements would be set for procurement of non-emitting resources (efficiency and renewables) at levels estimated to deliver the environmental goal established by EPA (backstop needed), with procurement tracked in MWh of energy delivered/saved; possible tracking and crediting issues if buying from mass-based states unless a hybrid approach is adopted that provides for compliance on a mass-basis

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Market Structure & Trading:	Fossil power plants that emit above the intensity standard have to buy credits from other resource types that operate below the standard and generate credits for every unit of energy (MWh) they produce; the credits (denominated in tons) are issued by the environmental agency and then traded; the credit price will float and depend on supply and demand in the market; high emitting fossil plants have to pay for credits and become less competitive in the market in comparison to low- or non-emitting resources; credits could be banked (held) for future compliance periods	The environmental agency issues allowances (tons) equal to the emissions limit; allowances can be auctioned or allocated and fossil power plants have to hold an allowance for every ton of emissions; allowances are tradable and the price will float and depend on supply and demand in the market; high emitting fossil plants have to buy or hold more allowances and become less competitive in the market in comparison to low- or non-emitting resources; allowances are usually allowed to be banked (held) for future compliance periods	The environmental agency estimates the carbon price needed to achieve the emissions goal and then they, another state agency, or the ISO/RTO collect the fee based on emissions rates from power plants; high emitting fossil plants have to pay a higher fee and become less competitive in the market in comparison to low- or non-emitting resources; revenue from the fee could be returned to utility customers through investments in energy efficiency programs, rebates or used for other state policy goals ; there is no trading although the cost flows through the power markets	For generation, eligible resources are identified (i.e. renewables) and the energy (MWh) are tracked using generator certificate/attribute tracking systems; the LSEs need a certain number of certificates in comparison to the energy they are providing customers (i.e. 20%) and the certificate price will float and depend on supply and demand in the market; non-emitting resources will become more attractive investments compared to high emitting resources; certificates could be banked (held) for future compliance periods. Energy efficiency could similarly receive credits and satisfy LSE holding requirements. All EGUs also subject to a performance standard.

<table>
<tr><th>Policy Approach</th><th>Flexible Intensity-based</th><th>Mass-based with Trading</th><th>Carbon Fee</th><th>Portfolio / Resource Standards</th></tr>
<tr><td>Crediting Non-emitting Resources:</td><td>Each unit of energy generated from a low- or non-emitting resource will need to be tracked (likely using a generator certificate/attribute system); the environmental agency would issue an appropriate emissions credit (in tons) associated with the MWh and the difference between its emissions rate and the emissions goal in the state or an average emissions rate; energy efficiency will also be credited based (in tons) based on units of energy saved (MWh); the emissions credits are then sold to the fossil generators who use them to offset emissions.</td><td>In a mass-based approach, all fossil generators in the program have their costs rise based on their emissions rate (allowance price driven); higher emitting generators become less competitive than low or non-emitting resources over time; non-emitting resources are not directly credited but become more competitive because they do not need to submit allowances to cover their generation; there is also an opportunity to auction the allowances and use the revenue to benefit consumers, with energy efficiency being a preferred investment, as it reduces consumers' bills and lowers the cost of the program as a whole.</td><td>In a fee-based approach, all fossil generators in the program have their costs rise based on their emissions rate (driven by the fee level); higher emitting generators become less competitive than low or non-emitting resources over time; non-emitting resources are not directly credited but become more competitive because they do not need to pay fees to cover their generation ; there is also an opportunity to use revenue from the fee to benefit consumers, with energy efficiency being a preferred investment, as it reduces bills and lowers the cost of the program as a whole.</td><td>Resource standards directly require increased investment in the qualified technologies, such as renewables and energy efficiency; depending on the structure, there can either be a floating price for delivery of energy from the technology type or procurement through a planning process; there is a clear incentive and known increase in production from the technologies in the standard, but only up to the requirement level; for example, once the percentage requirement for renewables is reached, demand or incentives above the wholesale energy price go to zero unless additional investments can be sold to assist other entities with compliance such as through a hybrid approach.</td></tr>
<tr><td>Electric System Reliability:</td><td colspan="4">All of these market-based approaches provide significant flexibility for plant operators, ISO/RTOs, and regulators to ensure reliability requirements are met. If a plant is needed in the short-term it can keep operating by buying allowances, credits or paying a fee. In any of the approaches a unit could be designated as "must-run" for reliability reasons until the reliability constraint is addressed, as long as other facilities could adjust their performance to accommodate the output from that plant.</td></tr>
<tr><td>New vs. Existing Sources:</td><td colspan="4">A key issue across all of the program types is what resources are included or not. This is primarily associated with designating facilities as regulated entities or as eligible for crediting. This decision can have a significant impact on generators of the same type who happen to be constructed or become operation on either side of a date. In general, EPA and states should examine the market impacts of a decision to include or exclude resource types and be sure that it: 1) maximizes the development of new non-emitting resources and the degree to which emissions decline, and 2) minimizes unequal treatment of resources with the same or similar emissions characteristics in a way that could cause older resources to retire in favor of new units with identical emissions characteristics (note that many non-emitting resources have low marginal costs and markets and operators will choose to run them regardless of their treatment).</td></tr>
</table>

<table>
<tr><th>Policy Approach</th><th>Flexible Intensity-based</th><th>Mass-based with Trading</th><th>Carbon Fee</th><th>Portfolio / Resource Standards</th></tr>
<tr><td>Regional Approache s:</td><td colspan="4">There are significant benefits associated with states pursuing consistent regional approaches to compliance. The primary benefits are:
1) LOWER COST - a larger market should be more efficient and reduce costs;
2) EQUAL TREATMENT - generators, market participants, and consumers should face consistent market signals, costs and benefits;
3) IMPROVED ENVIRONMENTAL OUTCOME - regional approaches avoid different price signals across a market region and on either side of state boundaries could lead to emissions leakage and higher national emissions than anticipated; and
4) ENHANCE RELIABILITY PROTECTIONS - a larger market and additional flexibility enhances reliability</td></tr>
</table>

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Minimum Requirements for State Plans:	1) Requirement on the regulated fossil generator to meet the emissions standard on an annual or multi-year basis, with the opportunity to offset emissions with credits from non-emitting sources; 2) Normal reporting, compliance, and enforcement provisions: 3) Energy efficiency evaluation, monitoring and verification requirements in order to certify units of energy savings that can be converted to credits; 4) Renewable energy certificate (REC) tracking system to avoid double counting and allow tracking of units of energy that can be converted to credits; 5) System and methodology to convert EE & RE MWhs to emissions credits and a platform to track and trade those credits; 6) Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports; 7) Prohibition on conversion of RECs to emissions credits from mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state	1) Requirement on the regulated fossil generator to meet the emissions standard on an annual or multi-year basis by holding emissions allowances equal to their emissions; 2) Normal reporting, compliance, and enforcement provisions 3) Note: we do not think a leakage requirement is needed in mass-based or carbon fee states, as the potential for leakage and increased generation exists primarily in the states that adopt a rate-based approach that allows generation and total emissions to increase.	1) Requirement on the regulated fossil generator to pay a fee based on their emissions over a given period of time; 2) Backstop requirement to track emissions in relation to the state standard of performance and have an immediate adjustment made to ensure the standard is being met if emissions rise above allowed levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d)) 3) Normal reporting, compliance, and enforcement provisions;	1) Requirement on the regulated load serving entity or distribution company providing services to consumers to procure a set amount of efficiency or renewables based on percentages of sales or what is cost-effective; 2) Normal reporting, compliance, and enforcement provisions: 3) Energy efficiency evaluation, monitoring and verification requirements; 4) Renewable energy certificate (REC) tracking system to avoid double counting; 5) Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports; 6) Prohibition on claiming an emissions benefit from RECs generated in mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state could still be used for RPS compliance); 7) Backstop requirement to track emissions in relation to the state standard of performance and have an adjustment to ensure the standard is being met if emissions rise above allowed

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Legislative Requirements:	Most state environmental statutes provide the environmental or air agency with broad authority to develop regulations under the Clean Air Act that limit emissions from stationary sources like power plants. These agencies can in most cases develop this kind of program without additional state legislation. Energy efficiency and renewables crediting would likely be improved if the utility regulator in the state collaborated with the environmental agency.	Most state environmental statutes provide the environmental or air agency with broad authority to develop regulations under the Clean Air Act that limit emissions from stationary sources like power plants. These agencies can in most cases develop this kind of program without additional state legislation. Auctioning of allowances and distribution of revenue would require legislation in most states.	Legislation would be required in most states to collect revenue and distribute or appropriate it.	Legislation may necessary in many states to require load serving entities or distribution companies to procure specific resources over time. However, if such plans were implemented via permit requirements on EGUs, most state environmental statutes provide the environmental or air agency with broad authority to develop regulations to secure compliance with Clean Air Act standards.
Complimentary Programs / Policies Needed:	State and utility energy efficiency programs would likely remain an essential source of efficiency credits and should be expanded by the utility regulator as long as it is cost-effective. Renewable portfolio standards also contribute credits and are complementary and could be expanded in parallel.	While energy efficiency and renewables will be more competitive and cost-effective under this policy approach, market barriers will still remain. Energy efficiency and renewables programs and policies should remain and be expanded, which will reduce the cost of achieving the carbon goal and can be funded through the auction of allowances. Low income and worker transition assistance can also be funded with auction revenue.	While energy efficiency and renewables will be more competitive and cost-effective under this policy approach, market barriers will still remain. Energy efficiency and renewables programs and policies should remain and be expanded, which will reduce the cost of achieving the carbon goal and can be funded through the revenue raised through the application of a carbon fee. Low income and worker transition assistance can also be funded with revenue raised by the carbon fee.	NA

XII. Environmental Leakage

A. Addressing Challenges for Rate-based Trading Programs

Whenever a shift in the deployment of generation assets is treated as delivering greater GHG emissions reductions than actually occur, emissions "leakage" can be said to have occurred. Environmental leakage is a transfer of emissions from one region to another. For example one state could set a mass-based cap and a neighboring state a flexible rate based standard, leading to increased generation by the natural gas generators in the rate-based state and emissions rising significantly in that state even though they meet the rate-based standard. Some analysis has suggested that the threat of leakage could significantly reduce the CO_2 emissions benefits of the program. Under the Clean Power Plan, leakage can occur in two basic ways:

1. Rate to Rate Leakage – Leakage can occur as a result of electric generation moving from a state with a lower emissions rate standard to a state with a higher emissions rate standard.

2. Rate to Mass Leakage – Leakage can occur as a result of shifts in electric generation from states with a fixed mass-based cap to states with a rate-based program. Under this scenario there is an increase in emissions in the rate-based state that allows the state implementing a mass-based program to avoid actions that result in real emission reductions.

Note there is no threat of mass to mass leakage. There is no impact on emissions as a result of electric generation shifting from one state implementing a mass-based program to another state implementing a mass-based program. This is because the cap is fixed in both states.

1. Rate to Rate Leakage

A wide variation in rate-based targets could lead to significant discrepancies in incentives for generators in different states. For example, Minnesota and North Dakota share a common border, and both are in the MISO region, but have very different emissions targets in 2030 under EPA's proposed rule – 873 lbs CO_2/MWh and 1783 lbs CO_2/MWh, respectively. Because of this differential in targets, shifting 20 MWhs of coal-based generation (assuming 2,200 lbs CO_2/MWh) from Minnesota to North Dakota would generate a credit equal to 18,200 lbs of CO2 (about 9 tons of CO2), even though the atmosphere would have not seen any reduction in actual CO_2 emissions.

Any action EPA takes to reduce the variation in state targets by increasing the GHG emissions reductions required in states that currently have higher emissions rate standards will help reduce the level of emissions leakage that could be expected. This is one of the reasons we recommend that EPA exclude existing renewables from its calculations of a state's initial emissions level. If EPA does this, and expands building block 1 to include opportunities for co-firing natural gas at coal plants, as we discuss supra, or new natural gas plants in building block 2, then the risk of leakage will decrease. However, some risk of leakage will remain unless EPA standardizes state emissions targets across grid regions or takes other steps to address it, as discussed below.

2. Rate to Mass Leakage

Mass-based programs are superior to rate based programs for a number of reasons, including: 1) they guarantee emissions reductions, 2) they significantly minimize reporting and verification needs for energy efficiency programs, which are a critical cost saving opportunity for state plans, 3) they provide a clear and consistent carbon signal to the power markets, enhancing the efficiency and cost-effectiveness of emission reductions, and 4) there is no threat of leakage between the borders of two adjacent states that are employing mass-based compliance programs no matter how different their target are. However, there are boundary challenges between a state employing a rate-based program and a state employing a mass-based program.

For example, consider West Virginia, which has a proposed interim target of 1,748 lbs CO_2/MWh. It borders Maryland, which participates in the Regional Greenhouse Gas Initiative (RGGI). Under the Clean Power Plan, shifting 10 MWh of natural gas generation from Maryland to West Virginia would generate a credit equal to approximately 7,480 lbs CO_2 in West Virginia without resulting in a commensurate decrease in the RGGI cap (assuming the natural gas plant has an emissions rate of 1,000 lbs CO_2/MWh).

B. Options for Addressing Leakage

Pressures for emissions leakage will depend both on the final form of the 111(d) regulations as well as state plans, making it is difficult to assess at this time just how significant the risk is. But the risk is great enough that EPA must ensure that it is addressed in EPA's final guideline and in state plans. Therefore, we recommend that EPA describe a methodology for how they will measure and evaluate leakage over time. In addition, EPA must address leakage in order to ensure the equivalency of state-established standards of performance with the emission reductions achievable under the best system of emission reduction identified by EPA, as required by the statute (standards of performance, which states establish in their plans, are defined by Section 111(a) as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.") We recommend that the responsibility to address leakage be placed on the states that increased electricity production as that is the source of the environmental leakage. States employing a rate-based approach or a portfolio approach should be required to include a policy fix in their state plan to address leakage. Several approaches to address leakage are outlined below.

OPTION 1: First jurisdictional deliver approach

Under this approach, an entity that exports power out of a given state is required to submit credits to the state equal to the emissions leakage that would otherwise occur (note that this approach was first developed for California where the obligation could only be placed on the importer, while we are recommending the rate-based state or exporter be given the obligation). The advantage to this approach is that it imposes the burden on the importer and not the state. The disadvantage is that given the interconnected nature of the electric grid, it may be challenging to determine where exported power comes from in some regions. The Western Climate Initiative, the Regulatory Assistance Project (www.raponline.org/document/download/id/6509), and NextGen have done considerable research into the practical implementation questions surrounding these approaches.

OPTION 2: Ex post evaluation and adjustment of state-level emissions reductions

Leakage is caused by a shift in the net balance of imports and exports between states with disparate rate standards or at the border of states employing rate and mass-based programs. Therefore, EPA could require states to evaluate shifts in their balance of electricity supply and demand on an annual or bi-annual basis and account for it through automatic ex-post adjustment of their GHG programs. This approach can address the threat of leakage over time through adjustments, but potentially in some circumstances could increase uncertainty for power companies. NextGen has done considerable work into practical implementation questions surrounding ex post evaluation approaches.

OPTION 3: Require all states to evaluate state-wide power sector performance against mass-based targets

As detailed there is no threat of leakage between states implementing mass-based compliance programs. Because the cap is fixed in both states, shifts in generation between those states will not impact total emissions of CO2 to the atmosphere. Therefore, EPA could eliminate the threat of leakage by requiring all states, including those that adopt a rate-based approach, to evaluate whether the state's actual emissions exceeded the mass-based target that the state would have been subject to had it adopted a mass-based approach. States that exceeded their mass-based target would be required to adjust for excess emissions.

OPTION 4: Ex ante adjustment to level the playing field for generation.

Under this approach all new generation would be compared to the emissions rate for new units established under 111(b) or the state rate standard, whichever is lower, in order to prevent sources from taking advantage of higher state emissions targets. This rate would apply to new fossil-based generation, new renewable generation, increased deployment of energy efficiency resources, as well as significant increases in generation at existing power plants. .

Again, this approach is based on the observation that leakage is caused by a shift in the net balance of imports and exports between states with disparate standards. However, instead of applying an ex post adjustment at the state level, it applies an up-front adjustment at the plant level, which provides greater certainty for project developers. These obligations could either be placed on plants whose generation is increasing, or plants whose generation is decreasing. In addition, the approach simultaneously addresses the question of how much to credit increased deployment of energy efficiency resources and renewables.

By creating a more level playing field, this approach would reduce but not completely eliminate the risk of leakage.

C. Complementary State-Level Measures

Mass-based programs get the benefit of added efficiency and renewables, with the additional generation or energy efficiency allowing fossil plants to run less and making it easier to achieve the cap level. If rate-based states were allowed to use generation from neighboring mass-based states as emissions credit generators, they would effectively be double counting the emissions benefit. EPA's approach for addressing leakage should address this challenge.

One effective approach for doing so would be to establish a clear prohibition on rate-based states converting RECs and efficiency savings from mass-based states to emissions credits. Under this approach, rate-based states could still be allowed to purchase RECs from mass-based states for other renewables requirements like RES/RPSs, but not claim a Section 111(d) emissions benefit from those purchases.

XIII. Reliability

EDF appreciates the crucial importance of maintaining the reliability of the electric grid while securing urgently-needed reductions in carbon pollution, and believes that the proposed emission guidelines provide a sound framework for meeting both goals.

There are at least three critical design features of the proposed Clean Power Plan that will enable states, system operators, utilities and other entities to preserve electric system reliability and achieve the required carbon pollution reductions. First, the proposed Clean Power Plan allows states unparalleled flexibility to meet their carbon pollution goals through a wide variety of low-carbon resources – including highly efficient fossil resources, energy efficiency, renewable energy, and other clean energy sources. This flexibility opens the door for each state, working together with utilities, regional entities, and other stakeholders, to develop a tailored compliance plan that reflects its own resource mix and reliability needs. Second, the proposed Clean Power Plan also provides great flexibility as to how states may demonstrate compliance — allowing states, among other things, to average their emissions over the period from 2020 to 2029; average the emissions of multiple EGUs when determining fleet-wide emission rates; and utilize market-based mechanisms, including credit trading systems that build on frameworks already in place in many states, to show that carbon pollution goals are being met. Third, the proposed Clean Power Plan provides a long, multi-year period for developing state plans as well as for demonstrating compliance. The relatively extended period for implementing these guidelines allows sufficient time for stakeholders to plan for future resource needs, and develop and deploy any infrastructure that may be needed to maintain reliability while reducing emissions from existing EGUs. All three of these features contribute to reliability by allowing states considerable latitude to determine the optimal timing, manner, and distribution of emission reductions across their fleet of existing EGUs.

In addition to these inherently reliability-preserving aspects of the Clean Power Plan itself, there are many existing federal, state, and regional tools and processes that are currently in place to ensure that our electricity needs are met while satisfying a number of other public policy goals – including environmental requirements, resource diversity, and affordability. Some examples of the tools that state, federal, and regional entities use to uphold their shared responsibilities for reliability include:

- Mandatory reliability standards for the bulk power system that are approved by FERC, and developed by the North American Electric Reliability Corporation (NERC) and regional reliability entities;

- Long-term regional transmission planning processes, overseen by FERC under Order 1000, that require public utilities to consider resource and transmission needs in light of both federal and state public policy requirements, and develop coordinated plans for meeting those needs;

- Wholesale market instruments, such as forward capacity markets, day-ahead markets, and ancillary services markets, that provide both short-term and long-term incentives to develop adequate supply resources;

- "Reliability must run" contracts to ensure that generating resources are on-call to meet electricity needs on an emergency basis, as needed; and

- Annual updates on short and long-term reliability issues produced by NERC and regional reliability entities;

These mechanisms have proven highly effective, and in the last decade have successfully preserved reliability during a period of significant changes in the power sector – including large-scale shifts of generation from coal to natural gas; integration of new resources such as renewables and demand response; and implementation of major pollution control projects to reduce emissions of air toxics, ozone precursors, and other pollutants. The Clean Power Plan builds on these ongoing trends, and will lead to changes in the power sector of a kind and scale that existing reliability entities and processes are fully capable of managing.

In light of these reliability safeguards and the ample flexibility provided in the Clean Power Plan — as well as EPA's own rigorous modeling showing that the Clean Power Plan is consistent with reliability needs — we do not believe it is necessary for EPA to provide less stringent standards or compliance schedules specifically for purposes of preserving reliability, as some stakeholders have suggested. Such measures would undermine the environmental and public health benefits of the Clean Power Plan while making no meaningful contribution to reliability.

XIV. EPA should facilitate multi-state compliance by enabling credits and allowances from approved programs to be used for compliance in multiple states, and should provide a tracking system for these credits to prevent double-counting.

EPA has proposed that states could jointly submit plans providing for multi-state compliance with state targets. We strongly support facilitating multi-state compliance, as states working together can secure reductions in carbon pollution more cost-effectively and with greater flexibility. However, we urge EPA to enable a less structured form of multi-state compliance as well. States may comply with their emission targets by putting in place source-based trading programs, under which a regulated unit is required under its permit to hold enough allowances to match its emissions (under a mass-based approach) or enough credits to meet a specified emission rate (under a rate-based approach). In the emission guidelines, EPA should provide that states designing such state-based plans with credits or allowances can specify that they will accept for compliance credits or allowances originating in their state or originating in another state taking the same type of target (mass or rate-based) with an approved plan. EPA should also provide a centralized tracking system for credits and allowances that cross state borders in order to facilitate multi-state compliance and to ensure that these credits and allowances are not double counted.

XV. EPA should provide templates for different plan designs and components.

In order to support states in their efforts to design plans to meet their carbon emission reduction targets, EPA should provide templates for different plan designs (e.g. a mass-based trading framework, a rate-based trading framework, multi-state compliance, and a utility-based portfolio approach) and for specific plan components (e.g. how to incorporate a state renewable energy standard and an energy efficiency program into a state plan; how to assess the emission reductions delivered by renewable energy and energy efficiency). One or more of the state plan templates could take the form of the federal implementation plan that will become the default framework for any states that choose not to submit a compliant implementation plan.

To: Schmidt, Lorie[Schmidt.Lorie@epa.gov]
From: Vickie Patton
Sent: Wed 9/17/2014 6:22:12 PM
Subject: FW: Protecting Human Health and the Environment from Oil and Gas Emissions
A - Methane Standards for New - Existing Sources Under Section 111 Protective Emissions Pathway - Final.pdf
A - EPA re Endangerment and Delineated Scope of Section 111 - Final.pdf

Dear Ms. Schmidt, Environmental Defense Fund respectfully submitted these two analyses to the U.S. Environmental Protection Agency. Sincerely yours, Vickie Patton

From: Vickie Patton
Sent: Sunday, September 07, 2014 7:03 PM
To: McCabe, Janet (McCabe.Janet@epa.gov); goffman.joseph@epa.gov; Dunham, Sarah (Dunham.Sarah@epa.gov); Page.Steve@epa.gov; tsirigotis.peter@epa.gov
Cc: Peter Zalzal; Tomas Carbonell
Subject: Protecting Human Health and the Environment from Oil and Gas Emissions

Dear Acting Assistant Administrator McCabe, Mr. Goffman, Ms. Dunham, Mr. Page and Mr. Tsirigotis,

Environmental Defense Fund respectfully provides two analyses attached here:

(1) The first analysis examines the geographic distribution of oil and gas emissions activity in light of ICF's highly cost-effective emissions abatement potential for the oil and gas sector, and finds that protective common sense mitigation requires methane standards under section 111 that address new and existing sources and that secure vital co-pollutant benefits in reducing VOCs and HAPs. ICF estimates that 90 percent of emissions in 2018 will come from existing sources. A dual ozone and HAP pathway, due to its limitations, would achieve at most an estimated six percent reduction in the overall 2018 emissions from this sector and such approach is inadequate alone to protect human health and the environment from deleterious emissions.

(2) This brief analysis demonstrates that EPA need not make a separate endangerment finding to regulate methane from the oil and gas sector under section 111 and that these statutory provisions are well suited to carefully delineate implementation of methane emission limits for this sector (a long listed source category). It examines the plain text of the statute and the regulation of the oil and gas sector under section 111, the Agency's time tested regulatory history and practice in implementing section 111 over numerous administrations, EPA's 2009 endangerment finding for methane, and the recent science documenting the warming effects of methane and its increasing warming potential that only bolsters the reasonableness, and the urgency, of regulating methane under section 111.

Sincerely yours,

Vickie Patton

Protective Mitigation of Oil & Gas Emissions Requires Methane Standards Under Section 111 that Address Emissions from Both New and Existing Sources:
Ozone and HAP Pathways Would Achieve an Estimated 6 Percent Emission Reduction and Are Inadequate Alone to Protect Human Health and the Environment

This memo analyzes emissions abatement potential for the oil and natural gas production sector achievable through three different Clean Air Act pathways:

(1) Section 111(b)/(d) direct regulation of methane (CH_4);
(2) Section 182 abatement of emissions in ozone nonattainment areas; and
(3) Section 112(n)(4) abatement of emissions in major metropolitan statistical areas ("MSAs").

The analysis proceeds in two steps. First, it examines the percentage of wells located in geographic areas that would be covered under each of these pathways. The memo then analyzes emissions abatement potential for each pathway.

ICF estimates that 90% of methane emissions in 2018 will be discharged by existing sources. Meaningful emissions protections must address existing sources.

The ozone and HAPs pathways would achieve an estimated 6 percent emission reduction and are inadequate to protect human health and the environment. Section 111 standards directly regulating methane -- including the extensive methane emissions from existing sources -- are the only way to protectively mitigate emissions from the production sector. Further, methane standards under section 111 are the only pathway capable of securing protective emissions reductions from the extensive volume of oil and gas sector emissions that occur from new and existing sources downstream of the production segment and that occur upstream of the local distribution segment. Finally, methane emissions standard for new and existing sources under section 111 would secure vital co-benefits in protecting human health and the environment from VOCs and HAPs.

At the same time, section 112 standards could complement section 111 standards by directly limiting HAPs from production wells in MSAs, and the standards could be designed to be entirely complementary and synergistic, rather than overlapping.

I. Total Production Well Coverage Associated with Clean Air Act Pathways

As ICF's economic analysis of highly cost-effective emission reduction opportunities underscores that 90% of emissions in 2018 will come from existing sources.[1] We have used total active wells as a proxy for emissions (including volatile organic compounds ("VOCs"), CH_4, hazardous air pollutants ("HAPs")) from existing sources in the production sector, because well count allows for disaggregation across geographies. This is critical because the section

[1] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries, at 6-1 (Mar. 2014) ("methane cost curve report").

112(n)(4) HAPs-focused pathway and the section 182 VOC-focused pathway are both limited to sources in specific geographic areas, while section 111 provides for far more protective coverage.

In particular:

- Section 112(n)(4) provides that the Administrator may only address "oil and gas production wells located in any metropolitan statistical area or consolidated metropolitan statistical area with a population in excess of 1 million."

- Section 182 control techniques guidelines could apply only to areas that are designated as nonattainment for the 2008 ozone national ambient air quality standard ("NAAQS"). These guidelines are also non-binding and would achieve far less emissions protections in practice than estimated here.

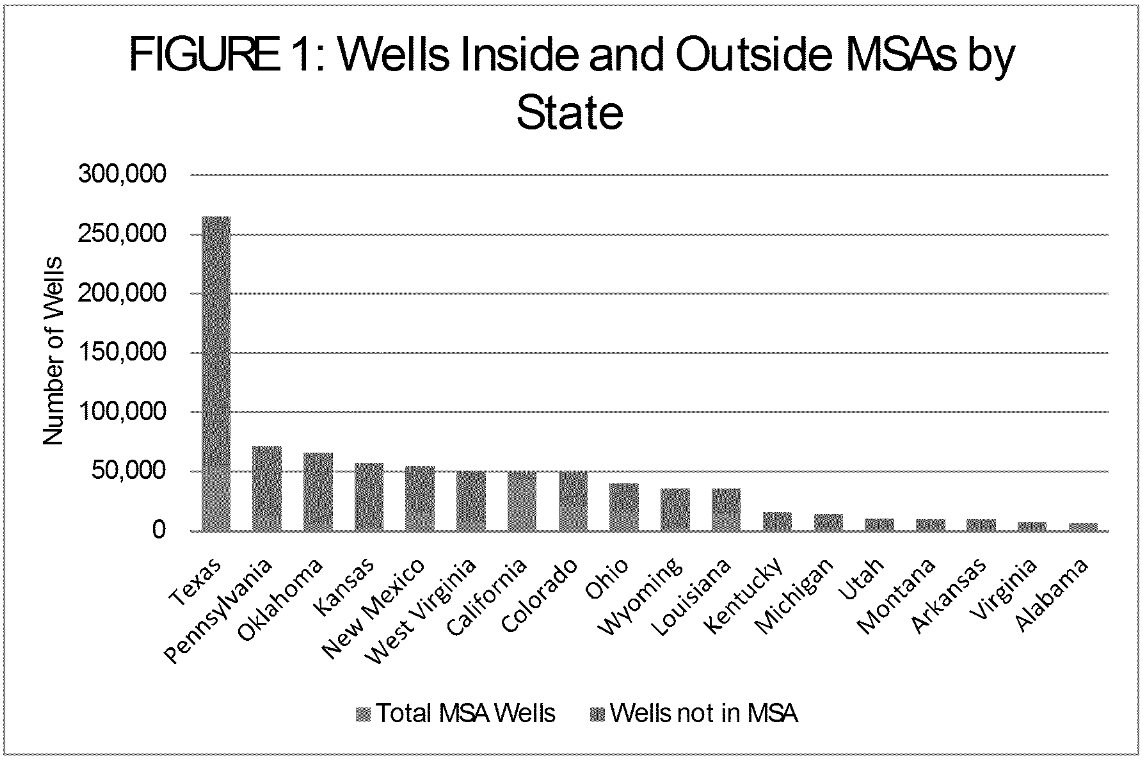
In contrast, section 111 provides for uniform, national emissions standards that would be far more protective in addressing emissions from new and existing sources in the production sector. While more protective, section 111 standards would also be tailored in addressing major emissions in the limited number of states where production activities in fact occur:

- 89% of onshore total energy production comes from just 10 states; and

- 21 states have no production whatsoever.

Of the total active national wells, an estimated 15% are located in ozone nonattainment areas and 23% in MSAs. Further, because of the substantial overlap between ozone nonattainment areas and MSAs, an estimated 24% of active national wells are within either an ozone nonattainment area or a MSA.

Figure 1 below shows active wells within and outside of MSAs by state. California, Colorado and Wyoming are deploying or in the process of developing more rigorous emission limits for the oil and gas sector including Leak Detection and Repair for existing sources; the Wyoming LDAR standards for existing infrastructure are focused on the ozone nonattainment area in the Upper Green River Basin.



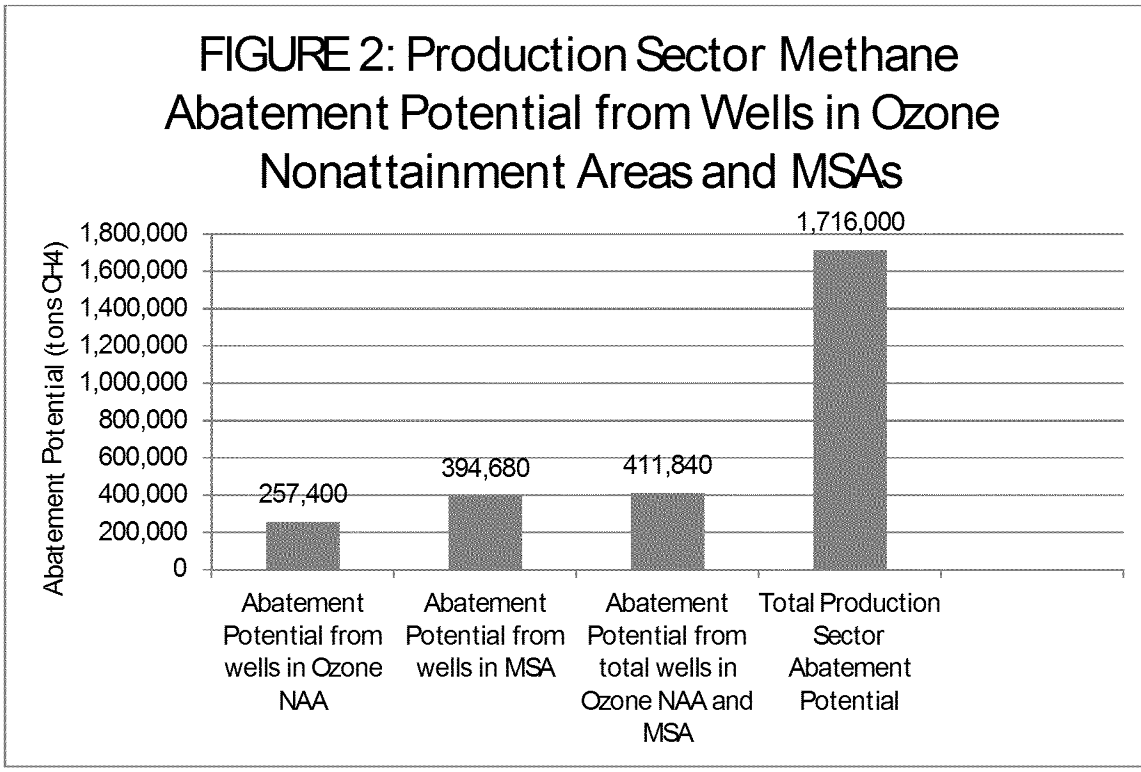
II. Examination of Abatement Achievable of ICF's Highly Cost-Effective Emissions Abatement Opportunities

As noted, section 182 and section 112(n)(4) of the Clean Air Act have limited geographic scopes compared with the regulation of methane from new and existing sources under section 111. This analysis examines production segment abatement potential and sector-wide abatement potential for each one of these pathways relative to ICF's highly cost-effective emissions abatement opportunities.

A. Production Segment

As described above, both sections 112(n)(4) and 182 are geographically limited in terms of the production sector sources they cover. Section 182 applies only in ozone nonattainment areas, and section 112(n)(4) allows only for regulation in highly populated MSAs. Even utilizing section 182 and section 112(n)(4) in tandem would not alleviate these geographic constraints, because current ozone nonattainment areas largely overlap with highly-populated areas covered by section 112(n)(4).

To determine the production segment abatement potential for a combined section 182 + section 112(n)(4) pathway, we began with ICF's methane cost curve report and identified the reductions attributable to the production segment, which were approximately 55% of ICF's total cost curve or about 1,716,000 metric tons CH_4. Because approximately 24% of the nation's oil and natural gas wells are located in either ozone nonattainment areas or MSAs covered by section 112(n)(4), we assume that 24% of these reductions (or about 412,000 metric tons) could be achieved through a combination of section 182 and 112(n)(4). We assume that methane standards for new and existing sources under section 111, because of their protective coverage, would achieve comprehensive production segment reductions (1,716,000 metric tons CH_4). Figure 2 depicts these methane reductions.[2]



B. <u>Overall Oil and Natural Gas Abatement Potential Including Processing and Transmission/Storage</u>

The sections 182 and 112(n)(4) pathways are further limited in addressing the large volume of emissions in the processing, and transmission/storage segments.

- Processing. An additional 12% of the emission reductions identified by ICF, or 370,000 metric tons CH_4, arise in the processing segment. Processing has not historically been considered part of the limited scope of coverage for section 112(n)(4) but could potentially be regulated in ozone nonattainment areas under section 182. Because approximately 15% of all oil and gas wells are located in areas designated nonattainment for the 2008 ozone NAAQS, we assume that 15% of the ICF emission reductions from processing (56,000 metric tons) could be achieved through section 182. This would very modestly increase the abatement potential

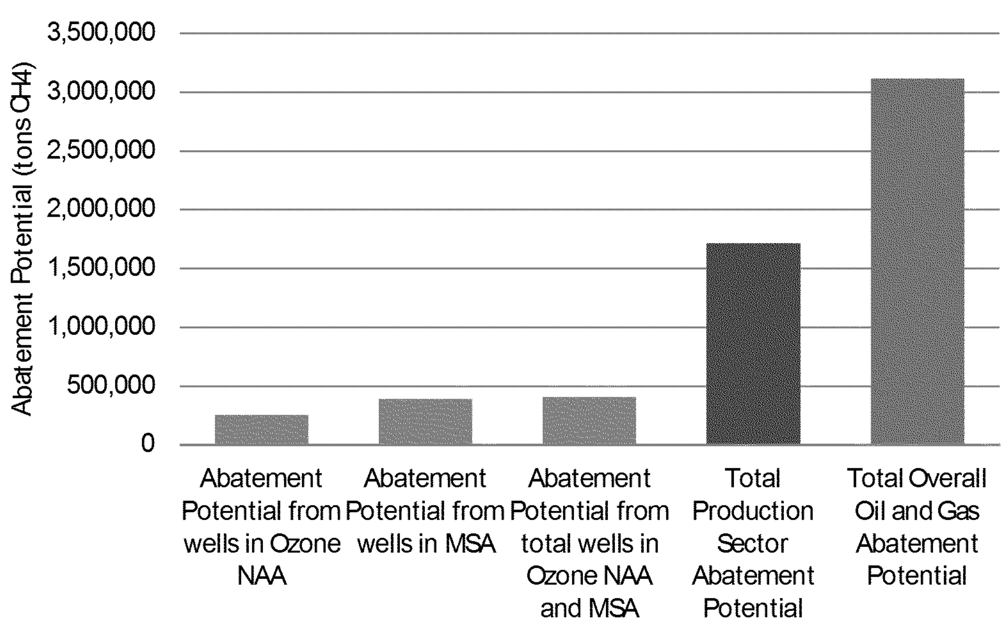
[2] We used the same approach to determine abatement potential for approaches focused separately on nonattainment areas (15% of total reductions) and MSAs (23% of total reductions).

from wells in ozone nonattainment areas and the dual abatement potential from MSAs + ozone NAAs depicted in Figure 3 below.

- Transmission/storage. Approximately one-third of ICF's total cost curve, or 1,120,000 metric tons CH_4, are attributable to segments downstream of processing. This segment has low VOC and HAP emissions. Only section 111 is well suited to address the extensive volume of emissions from this segment, which are largely comprised of deleterious methane emissions.

The ICF report identified total cost-effective emission reductions of approximately 3,120,000 metric tons CH_4 in 2018 (approximately 40% of projected emissions from onshore oil and gas facilities; the abatement potential is about 3 million metric tons CH_4 when local distribution is excluded). We have estimated that a combination of section 182 and section 112(n)(4) could achieve only total abatement of 470,000 metric tons CH_4,[3] or approximately 6% of ICF's projected total onshore emissions inventory for 2018. By comparison, section 111 emissions standards and guidelines for new and existing sources could be well designed to achieve virtually all of ICF's highly cost-effective abatement potential while securing vital co-benefits in reducing VOCs and HAPs and applying to a limited number of states, and could operate synergistically with section 112 standards.

FIGURE 3: Methane Abatement Potential in Ozone NAAs and in MSAs Relative to ICF's Highly Cost-Effective Oil and Gas Abatement Potential for the Production Sector and Overall



[3] 412,000 metric tons in production + 56,000 metric tons in processing.

Under section 111, EPA does not need to make a separate endangerment finding to address methane emissions from the oil and natural gas sector. Further, section 111 authorizes standards of performance for listed source categories and is well suited to carefully delineate the implementation of methane emission limitations for this sector.

A. EPA has already made an endangerment finding for the oil and natural gas sector under section 111 and does not need to make additional, separate findings to regulate each pollutant from that sector.

The plain text of the Clean Air Act does not require a pollutant-specific endangerment determination as a prerequisite to establishing standards for an already-listed source category under § 111. See 42 U.S.C. § 7411(b)(1)(A) (requiring the Administrator to list "a category of sources if in [her] judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare"). Once listed as a source category, EPA has authority to issue standards of performance for emissions of any air pollutants from that sector. *Id.* § 7411(b)(1)(B). The agency's interpretation of § 111, recently articulated in EPA's proposed carbon pollution standards, confirms this approach. 79 Fed. Reg. 1,430, 1,454 (Jan. 8, 2014) (concluding that, once a source category is listed, EPA must show only a rational basis for controlling the emissions of a particular pollutant). Moreover, in practice, EPA has never issued a new or revised endangerment finding when revising new source performance standards ("NSPS") under § 111, even when revising the NSPS to add a new pollutant to those regulated in the category or adding a new source to the category.

Examples of this practice abound over the course of EPA's time tested experience administering section 111 across Republican and Democratic Administrations. *See, e.g.*, 74 Fed. Reg. 51,950, 51,957 (Oct. 8, 2009) ("The plain language of section 111(b)(1)(A) provides that such findings are to be made for source categories, not for specific pollutants emitted by the source category. . . . Determinations regarding the specific pollutants to be regulated are made, not in the initial endangerment finding, but at the time the performance standards are promulgated.") (amending subpart Y, which had set PM standards since 1976); 41 Fed. Reg. 3826 (Jan. 26, 1975) (relying on an endangerment finding for one pollutant when setting standards for two pollutants); 77 Fed. Reg. 9304 (Feb. 16, 2012) (amending 71 Fed. Reg. 9866 (Feb. 27, 2006) regarding HAPs emissions from fossil fuel-fired EGUs); 75 Fed. Reg. 54,970 (Sept. 9, 2010) (amending 36 Fed. Reg. 24,876 (Dec. 23, 1971) regarding HAPs emissions from Portland cement plants); 73 Fed. Reg. 35,838 (June 24, 2008) (amending 39 Fed Reg. 9308 (Mar. 8, 1974) regarding petroleum refineries); 70 Fed. Reg. 28,606 (May 18, 2005) (amending 36 Fed.Reg. 24,876 (Dec. 23, 1971) regarding steam-generating EGUs); 54 Fed. Reg. 34,008 (Aug. 17, 1989) (amending 39 Fed. Reg. 9308 (Mar. 8, 1974) regarding fluid catalytic cracking unit regenerators); 52 Fed. Reg. 47,826 (Dec. 16, 1987) (amending 51 Fed. Reg. 42,768 (Nov. 25, 1986) regarding commercial-industrial steam generators).

EPA has determined that the oil and natural gas sector contributes to air pollution that may reasonably be anticipated to endanger public health or welfare, listed the source category at 40 C.F.R. § 60.16, and has established standards of performance codified at subpart KKK, subpart LLL and subpart OOOO of 40 C.F.R. part 60.* Having already made an endangerment determination for the sector, the agency

* The resulting source category listed at 40 C.F.R. § 60.16 was "Crude Oil and Natural Gas Production." EPA has taken the position, in its 2012 NSPS for the oil and gas sector, that the listing should be interpreted "very broadly" and that it clearly covers sources regulated in the NSPS – including VOC-emitting sources in the oil and gas production, natural gas gathering and processing, and transmission segments of the industry. 77 Fed. Reg. 49,490, 49,514 (Aug. 16, 2012). EPA emphasized that its initial listing explicitly " 'encompass[es] the operations of exploring for crude oil and natural gas

can establish methane standards under § 111 for sources in the listed source category without issuing a methane-specific endangerment finding.

B. EPA's 2009 endangerment finding for greenhouse gases provides a more than ample foundation for regulating methane emissions from the oil and natural gas sector under section 111.

EPA has already determined that methane emissions endanger human health and welfare. 74 Fed. Reg. 66,498, 66,497 (Dec. 15, 2009) (finding that six well-mixed greenhouse gases, including methane, "may reasonably be anticipated both to endanger public health and to endanger public welfare").

That determination amply provides a rational basis for EPA's regulation of methane emissions from an already-listed source category under section 111. *See* 79 Fed. Reg. at 1,454 (explaining that rational basis "may be based on information concerning the health and welfare impacts of the air pollution at issue, and the amount of contribution that the source category's emissions make to that air pollution").

In the alternative, EPA's 2009 determination about the human health and welfare threats of methane can serve as an endangerment finding if such a finding is necessary notwithstanding the text of the Act and EPA's long-standing interpretation of section 111, or in the event EPA concluded the delineation of the listed source category under section 111 warrants expansion to address any remaining questions about the legal and scientific foundation for source category coverage. In its proposed rulemakings under § 111(b) and (d) for carbon pollution standards from new and existing power plants, EPA similarly concluded that its 2009 endangerment finding provided the necessary basis for regulating greenhouse gas emissions from that sector. 79 Fed. Reg. at 1,455-56; 79 Fed. Reg. 34,830, 34,841-43 (June 18, 2014).

C. Finally, in a rulemaking to mitigate methane emissions from the oil and natural gas sector, EPA can bolster its 2009 determination concerning methane without issuing a new endangerment finding. Indeed, recent scientific findings indicate that the warming effects of methane are even more potent.

In its 2009 endangerment finding, EPA discussed the commonalities of the six greenhouse gases—that they have lifetimes long enough to become well mixed in the global atmosphere and all exert warming effects on climate. 74 Fed. Reg. at 66,517. EPA noted, in its June 2014 proposed rule for existing power plants, that since the agency denied administrative petitions for reconsideration of its endangerment finding in 2010, a number of scientific assessments have been released that improve our understanding of the climate system and strengthen the case that these greenhouse gases endanger public health and welfare. 79 Fed. Reg. at 34,842.

EPA could similarly bolster the 2009 finding in any future regulation of methane emissions from the oil and gas sector by providing additional analysis of the impacts of methane as a potent warming gas. Indeed, the science on the increased warming effects of methane over 100 years alone further strengthens the technical basis for EPA action.

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products, drilling for these products, removing them from beneath the earth's surface, and processing these products from oil and gas fields for distribution to petroleum refineries and gas pipelines.' " *Id.* (emphasis omitted) (quoting 49 Fed. Reg. at 2,637). See also 49 Fed. Reg. 2,636, 2,636 (Jan. 20, 1984).

To: Kris Barney[barney@eli.org]
Cc: John Cruden[cruden@eli.org]; Nancy Oliver[oliver@eli.org]; Robert R. Nordhaus (rrn@vnf.com)[rrn@vnf.com]; Ilan W. Gutherz (iwg@vnf.com)[iwg@vnf.com]; Scott Schang[schang@eli.org]; Schmidt, Lorie[Schmidt.Lorie@epa.gov]; Jim Fores (jim.fores@hq.doe.gov)[jim.fores@hq.doe.gov]; Bryan Mignone (Bryan.Mignone@hq.doe.gov)[Bryan.Mignone@hq.doe.gov]; Schramm, Daniel[Schramm.Daniel@epa.gov]; Dallas Burtraw (burtraw@rff.org)[burtraw@rff.org]; Megan Ceronsky (mceronsky@edf.org)[mceronsky@edf.org]; Allison D. Wood (awood@hunton.com)[awood@hunton.com]; Lance, Carol[clance@hunton.com]; Jeremy M. Tarr[jeremy.tarr@duke.edu]; bbecker@4cleanair.org[bbecker@4cleanair.org]; Stephanie Steigman (scooper@4cleanair.org)[scooper@4cleanair.org]; Tom Curry (tcurry@mjbradley.com)[tcurry@mjbradley.com]; Tim Profeta (tim.profeta@duke.edu)[tim.profeta@duke.edu]; Jessica Bunnel Sheffield (Jessica.Sheffield@duke.edu)[Jessica.Sheffield@duke.edu]; Goffman, Joseph[Goffman.Joseph@epa.gov]; Browne, Cynthia[Browne.Cynthia@epa.gov]; Drinkard, Andrea[Drinkard.Andrea@epa.gov]; Gabriel S Pacyniak (Pacyniak@law.georgetown.edu)[Pacyniak@law.georgetown.edu]; Kathy Bishop (kathy.bishop@maryland.gov)[kathy.bishop@maryland.gov]; Kathy Kinsey -MDE- (kathy.kinsey@maryland.gov)[kathy.kinsey@maryland.gov]; Franz T. Litz (franz@litzstrategies.com)[franz@litzstrategies.com]; Paul M. Sotkiewicz, Ph.D. (paul.sotkiewicz@pjm.com)[paul.sotkiewicz@pjm.com]; Thomas A. Lorenzen (lorenzen.thomas@dorsey.com)[lorenzen.thomas@dorsey.com]; Roadfeldt.Christi@dorsey.com[Roadfeldt.Christi@dorsey.com]; Michael B. Gerrard (michael.gerrard@law.columbia.edu)[michael.gerrard@law.columbia.edu]; Roger Martella, Jr. (rmartella@sidley.com)[rmartella@sidley.com]; Jing Shi Moreno (JMoreno@Sidley.com)[JMoreno@Sidley.com]; Shenkman, Ethan[Shenkman.Ethan@epa.gov]; Jonas Monast (jonas.monast@duke.edu)[jonas.monast@duke.edu]; Emily Fisher (efisher@eei.org)[efisher@eei.org]; Judith M. Greenwald (Judi.Greenwald@Hq.Doe.Gov)[Judi.Greenwald@Hq.Doe.Gov]; Boyd, Erin (FELLOW)[Erin.Boyd@Hq.Doe.Gov]; Kevin Kennedy (kkennedy@wri.org)[kkennedy@wri.org]; Sheila Slocum Hollis (Sshollis@duanemorris.com)[Sshollis@duanemorris.com]; Joanne R. Jewell (JRJewell@duanemorris.com)[JRJewell@duanemorris.com]; Matilda Mitchell (MMitchell@duanemorris.com)[MMitchell@duanemorris.com]; Chandra Middleton[middleton@eli.org]; Marcia McMurrin[mcmurrin@eli.org]; Colin Gipson-Tansil[gipson-tansil@eli.org]; William Conroy[conroy@eli.org]; Elaine Swiedler[swiedler@eli.org]; Daphne Chang[chang@eli.org]; Eric Falquero[falquero@eli.org]; Brett Kitchen[kitchen@eli.org]
From: Kris Barney
Sent: Wed 7/9/2014 11:49:27 PM
Subject: logistical details for SPEAKERS for July 14 111(d) Workshop + call for papers
07-14 ELI Workshop on EPA's Proposed 111(d) Rules 07 09 2014.pdf

Dear 111(d) Workshop Speaker:

Thank you so much for agreeing to speak at ELI's Workshop on EPA's Proposed Clean Power/CAA Section 111(d) Rules on July 14, cosponsored by the Nicholas Institute for Environmental Policy Solutions at Duke University.

This email contains:

•□□□□□□□□ Arrival/Logistical Information for Speakers

•□□□□□□□□ An Invitation to Submit a 111(d) Paper for the *Environmental Law Reporter*

(submission deadline August 8)

Aside from how to get to the conference center (see below), perhaps the most important thing to know is where to meet before your panel begins. Inside the conference room, please come to the table marked "RESERVED" at the front of the room near the podium. There you can meet up with Scott, me, and the other panelists, and listen to the panel prior to yours, if you wish.

Also, see my note below about special dietary needs.

Attached please find the latest agenda.

Please let me know if you have any questions.

Thank you!

Kris

Arrival/Logistical Information for Speakers
Your Point of Contact

On the day of the conference please contact Kristen Barney at (703) 966-2995 (cell) or barney@eli.org.

Location/Directions/Parking

Please come to the Pew DC Conference Center, 901 E Street, NW, Washington DC 20004.

Closest Metro Station: Gallery Place / Chinatown (Red Line). Directions: Exit station at 9th Street NW & G St NW. Walk approx. 2 blocks south on 9th Street NW to 901.

The closest parking garage is across the street from the Pew DC Conference Center at

505 9th St NW, Washington, DC 20004.

Arriving

Invitation to Submit a 111(d) Paper for the *Environmental Law Reporter*
Extending the Workshop's Impact

We want to be sure the workshop's impact reaches far beyond Monday's event. To that end, you're invited to submit a paper for publication in the October issue of the *Environmental Law Reporter* that encapsulates your ideas and perspectives.

Details

Articles for ELR need not be law review size or style. Perspective pieces that are a few pages (at least 750 words) in length are fine as are longer pieces. You do not need extensive footnotes, although we do ask that you provide citations to allow researchers to access resources on which you rely.

Submission Guidelines

Submission guidelines are easy: send your drafts to Scott Schang (schang@eli.org) by August 8, 2014. We promise a fairly fast turnaround time in editing with a minimum

In the main lobby there will be a registration desk where you can pick up your name tag and an agenda.

You will be given access to the second floor via the elevators. Bathrooms are located near the elevators. Follow signs to the event. There is a coat closet / luggage room where you can store things during the event.

Breakfast

We will have a continental breakfast available from 8:30 to 9:00, and beverages and snacks will be available through the morning (and afternoon).

Keynote Lunch

Lunch will begin at 12:30, and the keynote will begin at 12:45 or 12:50. Lunch will end at 1:30.

Dietary Needs

We will have a limited number of meals that meet the following dietary needs: vegan, vegetarian, gluten free, and dairy free. If you have one of these special needs, please pick up your lunch ASAP at 12:30 for the best chance of getting your choice. We will also have boxed sandwiches and wraps for omnivores.

Webcast + Phone Audience

Please note that the event will be broadcast via WebEx to a phone audience. In your remarks and interaction with the audience, please think of the phone audience first! (You will not forget the in person audience, and it is easy to forget those participating remotely.) Questions from the remote audience will amount of edits from our professional attorney-editors. The issue of *ELR* will come out in late September 2014.

Contact

Please let Scott know if you will submit or plan on submitting a paper:

Scott Schang, Executive Vice President, Editor-in-Chief, Environmental Law Reporter, Environmental Law Institute. 2000 L St., NW Ste. 620, Washington, DC 20036. (202) 939-3865. schang@eli.org.

come in via email.

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Kristen Barney

Manager, Professional Education Programs

Environmental Law Institute

(202) 939-3867 + barney@eli.org
~~~~~~

ENVIRONMENTAL LAW • INSTITUTE®

Workshop on EPA's Proposed Clean Power/CAA Section 111(d) Rules

Cosponsored by Duke University's Nicholas Institute for Environmental Policy Solutions

EPA has just released arguably the most important set of proposed rules in its efforts to restrain greenhouse gas emissions from stationary sources: regulation of existing and modified fossil fuel power plants under Clean Air Act Section 111(d).

The proposals have broad implications for the economy and the environment, pose challenges for harmonizing federal and state action on both environmental and energy fronts, and set the stage for regulation of other sectors under Section 111(d). As a result, it is critical to understand the scope, implications, and nuances of the proposed rules.

Timed to take place during EPA's comment period, the Workshop features top experts from government, industry, nonprofits, and academia who will explore practical and legal implications of this significant regulatory undertaking. Join us for this interactive event that takes a "deep dive" into these rules.

8:30-9:00 am	**Registration and Breakfast**
9:00-9:05	**Welcome** John C. Cruden, Environmental Law Institute
9:05-9:30	**Section 111(d): A Historical Perspective** Robert R. Nordhaus, Van Ness Feldman LLP
9:30-11:15	**Defining the "Best System of Emission Reduction" under Section 111(d)** Scott E. Schang, Environmental Law Institute *(moderator)* Lorie J. Schmidt, Office of the General Counsel, U.S. Environmental Protection Agency Dallas Burtraw, Resources for the Future Megan Ceronsky, Environmental Defense Fund Allison Wood, Hunton & Williams LLP
11:15-11:30	**Break**
11:30 am-12:30 pm	**State Choices: Flexibility and Limits** Jeremy M. Tarr, Nicholas Institute for Environmental Policy Solutions, Duke University *(moderator)* S. William Becker, National Association of Clean Air Agencies Tom Curry, M.J. Bradley & Associates LLC Tim Profeta, Nicholas Institute for Environmental Policy Solutions, Duke University
12:30-1:30	**Luncheon Keynote** Joseph Goffman, Office of Air and Radiation, U.S. Environmental Protection Agency

Continued...

When:

Monday, July 14, 2014
Breakfast 8:30 - 9:00 AM ET
Seminar: 9:00 AM - 4:45 PM ET

Where:
DC Conference Center
The Pew Charitable Trusts
901 E Street, NW
Washington, DC 20004
(and via teleconference)

RSVP:
To register visit:
http://www.eli.org/events/workshop-epas-proposed-caa-section-111d-rules.

Teleconference information will be emailed one business day prior to the event.

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1:30-2:30 **Regional Coordination: Considering the Alternatives**

- Gabe Pacyniak, Georgetown Climate Center, Georgetown Law (moderator)
- Kathy M. Kinsey, Maryland Department of the Environment
- Franz Litz, Great Plains Institute
- Paul M. Sotkiewicz, PJM Interconnection

2:30 - 2:45 **Break**

2:45 - 3:45 **Legal Ramifications and Litigation**

- Thomas A. Lorenzen, Dorsey & Whitney, LLP *(moderator)*
- Michael B. Gerrard, Columbia Law School
- Roger R. Martella, Jr., Sidley Austin LLP
- Ethan Shenkman, U.S. Environmental Protection Agency

3:45 - 4:45 **111(d) in Context: Broader Energy and Policy Implications**

- Jonas Monast, Nicholas Institute for Environmental Policy Solutions, Duke University *(moderator)*
- Emily Fisher, Edison Electric Institute
- Judith M. Greenwald, U.S. Department of Energy
- Kevin Kennedy, World Resources Institute
- Sheila Slocum Hollis, Duane Morris LLP

4:45 pm **Wrap Up**

To: Scott Schang[schang@eli.org]; Schmidt, Lorie[Schmidt.Lorie@epa.gov]; Dallas Burtraw (burtraw@rff.org)[burtraw@rff.org]; Megan Ceronsky (mceronsky@edf.org)[mceronsky@edf.org]; Allison D. Wood (awood@hunton.com)[awood@hunton.com]
Cc: Lance, Carol[clance@hunton.com]; Hooks, Samantha[hooks.samantha@epa.gov]; Schramm, Daniel[Schramm.Daniel@epa.gov]
From: Kris Barney
Sent: Wed 7/9/2014 3:21:27 PM
Subject: update + logistical questions
07-14 ELI Workshop on EPA's Proposed 111(d) Rules 07 09 2014.pdf

Hello Scott, Lorie, Dallas, Megan, and Allison

Our panel is complete, and we are so excited you will be speaking.

As you may recall from Scott's earlier communication, he will be playing moderator. Here is what our panel looks like:

Defining the "Best System of Emission Reduction" under Section 111(d)

Scott E. Schang, Environmental Law Institute *(moderator)*

Lorie J. Schmidt, Office of the General Counsel, U.S. Environmental Protection Agency

Dallas Burtraw, Resources for the Future

Megan Ceronsky, Environmental Defense Fund

Allison Wood, Hunton & Williams LLP

Would you each kindly answer these questions? (Scott, you don't need to reply.)

1. Will you be present for the full day?
2. If you will not be present the full day, approximately what time will you arrive?

3. I have not received PPTs from you and am not expecting any. Please let me know if you understand otherwise.

4. Please provide your cell number in case we need to reach you.

Attached for your reference is the latest agenda.

Thanks,

Kris

From: lorenzen.thomas@dorsey.com [mailto:lorenzen.thomas@dorsey.com]
Sent: Wednesday, July 09, 2014 10:20 AM
To: Kris Barney
Cc: Roadfeldt.Christi@dorsey.com
Subject: RE: Jody Freeman for "Legal" panel on 7/14

Just had an email from Jody. She has inconveniently fled to Australia. So, no luck.

Thomas A. Lorenzen

Partner

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DORSEY & WHITNEY LLP
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Suite 750
Washington, DC 20006
P: 202.442.3525 **F:** 202.315.3478 **C:** 202.304.7675

. . . .

From: Kris Barney [mailto:barney@eli.org]
Sent: Wednesday, July 09, 2014 10:19 AM
To: Lorenzen, Thomas
Cc: Roadfeldt, Christi
Subject: Jody Freeman for "Legal" panel on 7/14

Hi Tom,

Just wondering if you had any response from Jody Freeman. I can follow up with a formal invitation.

Please let me know.

Thanks,

Kris

From: lorenzen.thomas@dorsey.com [mailto:lorenzen.thomas@dorsey.com]
Sent: Monday, July 07, 2014 10:33 AM
To: Scott Schang; Kris Barney
Subject: RE: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)

Lisa Heinzerling cannot make the panel. I've reached out to Jody Freeman to see if she might be available. I'll let you know. Otherwise, I'll plan on offering the NGO/EPA rebuttal to the industry arguments unless you've had luck with Ann Weeks or others.

Thomas A. Lorenzen

Partner

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DORSEY & WHITNEY LLP
1801 K Street NW
Suite 750
Washington, DC 20006
P: 202.442.3525 **F:** 202.315.3478 **C:** 202.304.7675

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From: Scott Schang [mailto:schang@eli.org]
Sent: Monday, July 07, 2014 7:48 AM
To: Gerrard, Michael B.
Cc: Kris Barney; Lorenzen, Thomas
Subject: RE: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)

The panel, at the moment, is you, Roger Martella, Ethan Shenkman from EPA. Lisa Heinzerling is invited, and Tom Lorenzen is moderator.

The panel will focus on two aspects of legal ramifications and litigation: 1) litigation strategy around the 111(d) rule and 2) implications of the rule. Most of the panel will focus on 1, with the second issue coming up in Q&A.

The tentative plan was for you to present the “objective assessment” you offered regarding where the rule stands legally and how the legal challenges are likely to shape up. Then Roger will give his assessment, Lisa (or other NGO), and EPA. We’ll then have Q&A with the panel and the audience on that topic and ramifications/implications.

I don't believe we put out time limits on the presentations, but I think 10 minutes is about right, given that the panel is only an hour. It's a strong panel, so the more Q&A the better.

I'm copying Tom because as of the planning call, we didn't have an EPA person confirmed. He may want to reconvene via email or phone once all the panelists are confirmed.

Thanks for doing this, and happy travels.

From: Gerrard, Michael B. [mailto:Michael.Gerrard@APORTER.COM]
Sent: Monday, July 07, 2014 6:29 AM
To: Scott Schang
Cc: Kris Barney
Subject: RE: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)

Thanks. I'm still in Madrid; I fly back tomorrow.

I don't think I received a summary from Kris. Kris-- please re-send.

Thanks.

From: Scott Schang [mailto:schang@eli.org]
Sent: Sunday, July 06, 2014 7:54 PM
To: Gerrard, Michael B.
Cc: Kris Barney
Subject: Re: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)

Hi Mike,

They took you up on your offer to offer the neutral assessment of where things are at. I think Kris sent around a summary of the call and the general lineup. I'll confirm tomorrow.

Welcome back, assuming you're home.

Sent from my iPad

On Jul 6, 2014, at 4:47 PM, "Gerrard, Michael B." <Michael.Gerrard@APORTER.COM> wrote:

> **Sorry I couldn't join the planning call from Barcelona. Can you give me any guidance on what I should talk about on the panel, and at what length? Thanks.**
>
> **From:** Kris Barney [mailto:barney@eli.org]
> **Sent:** Tuesday, July 01, 2014 5:00 PM
> **To:** Gerrard, Michael B.; Thomas A. Lorenzen (lorenzen.thomas@dorsey.com); Scott Schang; Jonas Monast (jonas.monast@duke.edu); Jeremy M. Tarr
> **Cc:** Roger Martella, Jr. (rmartella@sidley.com); Jing Shi Moreno (JMoreno@Sidley.com); Roadfeldt.Christi@dorsey.com
> **Subject:** RE: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)
>
> Hello Michael,
>
> Thank you for writing in with your acceptance. We are so delighted! It is fine for you to arrive around noon.
>
> I will send you call in information for tomorrow as soon as I have it.
>
> Thank you also for thoughts on your presentation.

Kris

From: Gerrard, Michael B. [mailto:Michael.Gerrard@APORTER.COM]
Sent: Tuesday, July 01, 2014 4:51 PM
To: Kris Barney; Thomas A. Lorenzen (lorenzen.thomas@dorsey.com); Scott Schang; Jonas Monast (jonas.monast@duke.edu); Jeremy M. Tarr
Cc: Roger Martella, Jr. (rmartella@sidley.com); Jing Shi Moreno (JMoreno@Sidley.com); Roadfeldt.Christi@dorsey.com
Subject: RE: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)

Thanks. I am confirming that I will come to the program and speak on this panel. For various logistical reasons I won't be able to arrive until around noon.

I don't think I'll be able to call in to tomorrow's call. I am in Barcelona for the IUCN conference (in nearby Tarragona) and expect to be on a train at the time of the call. However, please send me the call-in number in case that changes.

As to the topic of my presentation -- one option is that I could give a neutral overview of the various litigation theories and defenses that have been kicking around in connection with the 111(d) proposal. But I am open to other topics if the rest of you would prefer that I cover something else.

Michael B. Gerrard

Andrew Sabin Professor of Professional Practice

Director, Center for Climate Change Law

Columbia Law School

435 West 116th Street

New York, New York 10027

Telephone: (212) 854-3287

Facsimile: (212) 854-7946

michael.gerrard@law.columbia.edu

From: Kris Barney [mailto:barney@eli.org]
Sent: Tuesday, July 01, 2014 4:27 PM
To: Thomas A. Lorenzen (lorenzen.thomas@dorsey.com); Scott Schang; Jonas Monast (jonas.monast@duke.edu); Jeremy M. Tarr; Michael B. Gerrard (michael.gerrard@law.columbia.edu)
Cc: Roger Martella, Jr. (rmartella@sidley.com); Jing Shi Moreno (JMoreno@Sidley.com); Roadfeldt.Christi@dorsey.com
Subject: CONFIRMED: planning call on 7/2 at 1:30 pm ET: "Legal Ramifications and Litigation" panel (7/14)

Dear Tom, Scott, Jonas, and Jeremy, (and Michael if you can confirm and participate),

We will hold a planning call for the "Legal Ramifications and Litigation" panel for the July 14 Workshop on EPA's Clean Power/CAA Section Section 111(d) Rules on:

Wednesday, July 2, 2014 from 1:30 to 2:00 pm ET (7:30 to 8 pm Barcelona time for Michael).

The conference call information will be provided tomorrow. (Our conference bridge is booked, so I am making alternate arrangements.)

The purpose of the call is to begin mapping out the substance and flow of the session. Roger Martella will be speaking with Scott earlier on Wednesday to provide input. Michael, if you will be able to speak on July 14 and can join us on the call Wednesday, please do.

Scott opened an extra panel slot to invite Anne Isdal of Texas CEQ. Anne regrets she is not available.

We still hope Avi Garbow will be able to send someone.

Attached is the lastest agenda, and I will send you an outlook invitation.

Thank you!

Kris

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Kristen Barney

Manager, Professional Education Programs

Environmental Law Institute

(202) 939-3867 + barney@eli.org

Spam
Not spam
Forget previous vote

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9:00-9:05 **Welcome**
John C. Cruden, Environmental Law Institute

9:05-9:30 **Section 111(d): A Historical Perspective**
Robert R. Nordhaus, Van Ness Feldman LLP

9:30-11:15 **Defining the "Best System of Emission Reduction" under Section 111(d)**
Scott E. Schang, Environmental Law Institute *(moderator)*
Lorie J. Schmidt, Office of the General Counsel, U.S. Environmental Protection Agency
Dallas Burtraw, Resources for the Future
Megan Ceronsky, Environmental Defense Fund
Allison Wood, Hunton & Williams LLP

11:15-11:30 **Break**

11:30 am-12:30 pm **State Choices: Flexibility and Limits**
Jeremy Tarr, Nicholas Institute for Environmental Policy Solutions, Duke University *(moderator)*
S. William Becker, National Association of Clean Air Agencies
Tom Curry, M.J. Bradley & Associates LLC
Tim Profeta, Nicholas Institute for Environmental Policy Solutions, Duke University

12:30-1:30 **Luncheon Keynote**
Joseph Goffman, Office of Air and Radiation, U.S. Environmental Protection Agency

Continued...

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1:30-2:30	**Regional Coordination: Considering the Alternatives**	
		Gabe Pacyniak, Georgetown Climate Center, Georgetown Law (moderator)
		Kathy M. Kinsey, Maryland Department of the Environment
		Franz Litz, Great Plains Institute
		Paul M. Sotkiewicz, PJM Interconnection
2:30 - 2:45	**Break**	
2:45 - 3:45	**Legal Ramifications and Litigation**	
		Thomas A. Lorenzen, Dorsey & Whitney, LLP *(moderator)*
		Michael B. Gerrard, Columbia Law School
		Roger R. Martella, Jr., Sidley Austin LLP
		Ethan Shenkman, U.S. Environmental Protection Agency
3:45 - 4:45	**111(d) in Context: Broader Energy and Policy Implications**	
		Jonas Monast, Nicholas Institute for Environmental Policy Solutions, Duke University *(moderator)*
		Emily Fisher, Edison Electric Institute
		Judith M. Greenwald, U.S. Department of Energy
		Kevin Kennedy, World Resources Institute
		Sheila Slocum Hollis, Duane Morris LLP
4:45 pm	**Wrap Up**	

To: Kris Barney[barney@eli.org]; Lance, Carol[clance@hunton.com]; Hooks, Samantha[hooks.samantha@epa.gov]; Schmidt, Lorie[Schmidt.Lorie@epa.gov]; Jeremy M. Tarr[jeremy.tarr@duke.edu]; Dallas Burtraw (burtraw@rff.org)[burtraw@rff.org]; Allison D. Wood (awood@hunton.com)[awood@hunton.com]; Franz T. Litz (franz@litzstrategies.com)[franz@litzstrategies.com]; Jonas Monast (jonas.monast@duke.edu)[jonas.monast@duke.edu]; Megan Ceronsky (mceronsky@edf.org)[mceronsky@edf.org]
From: Scott Schang
Sent: Tue 7/1/2014 8:44:51 PM
Subject: Planning call cancelled. Summary to follow

-----Original Appointment-----
From: Kris Barney
Sent: Monday, June 30, 2014 12:13 PM
To: Scott Schang; Lance, Carol; Hooks, Samantha; Lorie Schmidt (Schmidt.Lorie@epa.gov); Jeremy M. Tarr; Dallas Burtraw (burtraw@rff.org); Allison D. Wood (awood@hunton.com); Franz T. Litz (franz@litzstrategies.com); Jonas Monast (jonas.monast@duke.edu); Megan Ceronsky (mceronsky@edf.org)
Subject: ELI Planning call for "Defining the 'BESR' under Section 111(d)"
When: Tuesday, July 01, 2014 4:30 PM-5:00 PM (GMT-05:00) Eastern Time (US & Canada).
Where: teleconference

The purpose of this call is to discuss the roles and topics for each panelist, and clarify the timetable.

<< Message: CONFIRMED: planning call 7/1 4:30 PM: "Defining the 'Best System of Emission Reduction' under Section 111(d)" (7/14) >> << File: 07-14 ELI Workshop on EPA's Proposed 111(d) Rules 06 30 2014.pdf >>

From: Kris Barney
Location: teleconference
Importance: Normal
Subject: ELI Planning call for "Defining the 'BESR' under Section 111(d)"
Start Date/Time: Tue 7/1/2014 8:30:00 PM
End Date/Time: Tue 7/1/2014 9:00:00 PM
CONFIRMED: planning call 7/1 4:30 PM: "Defining the 'Best System of Emission Reduction' under Section 111(d)" (7/14)
07-14 ELI Workshop on EPA's Proposed 111(d) Rules 06 30 2014.pdf

;
The purpose of this call is to discuss the roles and topics for each panelist, and clarify the timetable.

To: Dallas Burtraw (burtraw@rff.org)[burtraw@rff.org]; Megan Ceronsky (mceronsky@edf.org)[mceronsky@edf.org]; Franz T. Litz (franz@litzstrategies.com)[franz@litzstrategies.com]; Allison D. Wood (awood@hunton.com)[awood@hunton.com]; Jeremy M. Tarr[jeremy.tarr@duke.edu]; Jonas Monast (jonas.monast@duke.edu)[jonas.monast@duke.edu]; Scott Schang[schang@eli.org]
Cc: Lance, Carol[clance@hunton.com]
From: Kris Barney
Sent: Mon 6/30/2014 4:33:31 PM
Subject: CONFIRMED: planning call 7/1 4:30 PM: "Defining the 'Best System of Emission Reduction' under Section 111(d)" (7/14)
07-14 ELI Workshop on EPA's Proposed 111(d) Rules 06 27 2014.pdf

Dear Dallas, Megan, Franz, Allison, Jeremy (and Jonas), and Scott,

Thank you for taking the doodle poll. We will hold the planning call at 4:30 pm on Tuesday, July 1, for the "Defining the 'Best System of Emission Reduction' under Section 111(d)" panel on 7/14.

Allison, I hope you can join. Dallas, we will catch up with you after your travels.

Teleconference Information:

Dial-In Number: Non Responsive

Session Number: Non Responsive

PIN: Non Responsive

The purposes of this call are to frame the panel's overall focus, to discuss who will speak about which topic, and to clarify the timetable.

I will send you an Outlook invitation.

I look forward to talking with you soon.

Kris

From: Kris Barney
Sent: Friday, June 27, 2014 5:17 PM
To: Dallas Burtraw (burtraw@rff.org); Megan Ceronsky (mceronsky@edf.org); Franz T. Litz (franz@litzstrategies.com); Allison D. Wood (awood@hunton.com)
Subject: SCHEDULING planning call 7/1: "Defining the 'Best System of Emission Reduction' under Section 111(d)" (7/14)
Importance: High

Dear Dallas, Megan, Franz, and Allison,

Thank you for agreeing to speak at ELI's Workshop on EPA's Proposed Clean Power/CAA Section 111(d) Rules on July 14, cosponsored by the Nicholas Institute! We are so excited you will be on the panel!

I would like to schedule a planning call for Tuesday, July 1. Kindly take this doodle poll to indicate all times you are available.

The purpose of this call is to discuss the roles and topics for each panelist, and clarify the timetable.

Lorie Schmidt has not yet confirmed, so we will loop her (or her alternate) in ASAP.

If you have any questions, please let me know.

Thank you,

Kris

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Kristen Barney

Manager, Professional Education Programs

Environmental Law Institute

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1:30-2:30 **Regional Coordination:**
Considering the Alternatives

- Gabe Pacyniak, Georgetown Climate Center, Georgetown Law
- Kathy M. Kinsey, Maryland Department of the Environment *(invited)*
- Myra Reece, Bureau Chief at South Carolina Department of Health & Environmental Control *(invited)*
- Paul M. Sotkiewicz, PJM Interconnection

2:30 - 2:45 **Break**

2:45 - 3:45 **Legal Ramifications and Litigation**

- Thomas A. Lorenzen, Dorsey & Whitney, LLP
- Avi Garbow, U.S. Environmental Protection Agency *(invited)*
- David G. Hawkins, Natural Resources Defense Council *(invited)*
- Roger R. Martella, Jr., Sidley Austin LLP

3:45 - 4:45 **111(d) in Context:**
Broader Energy and Policy Implications

- Jonas Monast, Nicholas Institute for Environmental Policy Solutions, Duke University
- Emily Fisher, Edison Electric Institute
- Nathaniel Keohane, Environmental Defense Fund *(invited)*
- Jonathan C. Pershing, Office of International Affairs, U.S. Department of Energy *(invited)*
- Sheila Slocum Hollis, Partner, Duane Morris LLP

4:45 pm **Wrap Up**

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Continued...

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Monday, July 14, 2014
Breakfast 8:30 - 9:00 AM ET
Seminar: 9:00 AM - 4:45 PM ET

Where:
DC Conference Center
The Pew Charitable Trusts
901 E Street, NW
Washington, DC 20004
(and via teleconference)

RSVP:
To register visit:
http://www.eli.org/events/workshop-epas-proposed-caa-section-111d-rules.

Teleconference information will be emailedone business day prior to the event.

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1:30-2:30 **Regional Coordination: Considering the Alternatives**

- Gabe Pacyniak, Georgetown Climate Center, Georgetown Law
- Kathy M. Kinsey, Maryland Department of the Environment *(invited)*
- Myra Reece, Bureau Chief at South Carolina Department of Health & Environmental Control *(invited)*
- Paul M. Sotkiewicz, PJM Interconnection

2:30 - 2:45 **Break**

2:45 - 3:45 **Legal Ramifications and Litigation**

- Thomas A. Lorenzen, Dorsey & Whitney, LLP
- Avi Garbow, U.S. Environmental Protection Agency *(invited)*
- Michael B. Gerrard, Columbia Law School *(invited)*
- Roger R. Martella, Jr., Sidley Austin LLP

3:45 - 4:45 **111(d) in Context: Broader Energy and Policy Implications**

- Jonas Monast, Nicholas Institute for Environmental Policy Solutions, Duke University
- Emily Fisher, Edison Electric Institute
- Nathaniel Keohane, Environmental Defense Fund *(invited)*
- Trigg Talley, U.S. Department of State *(invited)*
- Sheila Slocum Hollis, Partner, Duane Morris LLP

4:45 pm **Wrap Up**

To: MICHAEL.GERGEN@LW.com[MICHAEL.GERGEN@LW.com]; kbilas@misoenergy.org[kbilas@misoenergy.org]; hmblinderman@daypitney.com[hmblinderman@daypitney.com]; mceronsky@edf.org[mceronsky@edf.org]; ann.w.loomis@dom.com[ann.w.loomis@dom.com]; Schmidt, Lorie[Schmidt.Lorie@epa.gov]; SimonD@ballardspahr.com[SimonD@ballardspahr.com]
From: Jeschke, Diana
Sent: Thur 3/27/2014 2:26:24 PM
Subject: RE: EBA Environmental Regulatory Update Panel

Good morning,

This is just a reminder for those planning to use slides, would you please send us your deck by no later than noon tomorrow?

Diana

From: MICHAEL.GERGEN@LW.com [mailto:MICHAEL.GERGEN@LW.com]
Sent: Monday, March 24, 2014 10:22 AM
To: Jeschke, Diana; kbilas@misoenergy.org; hmblinderman@daypitney.com; mceronsky@edf.org; ann.w.loomis@dom.com; Schmidt.Lorie@epa.gov; SimonD@ballardspahr.com
Subject: RE: EBA Environmental Regulatory Update Panel

All,

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Our session will last 1:15 (75 minutes). Each panelist should plan on speaking for 8-10 minutes (hopefully leaving us with approximately 25 minutes for Q&As). Speaker who want to use PowerPoint slides should use no more than 7 slides. Slides should be sent to Diana and Harold no later than mid-week this week.

The order of speakers and topics are:

Michael Gergen (moderator): Opening remarks and introduction and brief background on CWA s 316(b) and Coal Combustion Residuals (RCRA) [Comment: Ann, I understand that you also want to include "waters of the U.S." under the CWA. I can include this in my presentation if you can provide some context that is relevant to Dominion and other electric utilities.]

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Ann Loomis (Dominion): Background and update on compliance planning and implementation actions by Dominion (with a focus on MATS)

Kurt Bilas (MISO): Background and update on compliance planning actions by MISO

-----Original Appointment-----
From: Jeschke, Diana [mailto:DJeschke@crowell.com]
Sent: Wednesday, March 19, 2014 3:06 PM
To: Kurt W. Bilas; Blinderman, Harold M.; Megan Ceronsky; Gergen, Michael (DC); ann.w.loomis@dom.com; Schmidt.Lorie@epa.gov; Simon, Daniel R. (DC)
Subject: EBA Environmental Regulatory Update Panel
When: Friday, March 21, 2014 11:00 AM-11:30 AM (UTC-05:00) Eastern Time (US & Canada).
Where: Dial-In: 877-211-3621 // Passcode: 202 624 2619

Please find attached some potential discussion topics for the Environmental Regulatory Update panel. Feedback and other ideas are welcomed.

<< File: EBA Environmental Panel Discussion.docx >>

To: Blinderman, Harold M.[hmblinderman@daypitney.com]
Cc: MICHAEL.GERGEN@LW.com[MICHAEL.GERGEN@LW.com]; DJeschke@crowell.com[DJeschke@crowell.com]; kbilas@misoenergy.org[kbilas@misoenergy.org]; mceronsky@edf.org[mceronsky@edf.org]; Schmidt, Lorie[Schmidt.Lorie@epa.gov]; SimonD@ballardspahr.com[SimonD@ballardspahr.com]
From: Ann W Loomis (Services - 6)
Sent: Tue 3/25/2014 12:24:00 AM
Subject: Re: EBA Environmental Regulatory Update Panel

Harold,
I will briefly discuss the potential impact of 316(b) compliance for coal, gas and nuclear plants, particularly coal plants that are retrofitting for MATS and nuclear plants that are important for CO2 reductions.
Ann

Sent from my iPad

On Mar 24, 2014, at 10:50 AM, "Blinderman, Harold M." <hmblinderman@daypitney.com> wrote:

Ann: Can you touch on 316b in addition to MATS? Thanks. Harold.

From: MICHAEL.GERGEN@LW.com [mailto:MICHAEL.GERGEN@LW.com]
Sent: Monday, March 24, 2014 10:22 AM
To: DJeschke@crowell.com; kbilas@misoenergy.org; Blinderman, Harold M.; mceronsky@edf.org; ann.w.loomis@dom.com; Schmidt.Lorie@epa.gov; SimonD@ballardspahr.com
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From: MICHAEL.GERGEN@LW.com
Sent: Mon 3/24/2014 2:22:29 PM
Subject: RE: EBA Environmental Regulatory Update Panel

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Subject: EBA Environmental Regulatory Update Panel
When: Friday, March 21, 2014 11:00 AM-11:30 AM (UTC-05:00) Eastern Time (US & Canada).
Where: Dial-In: Non Responsive // Passcode: Non Responsive

Please find attached some potential discussion topics for the Environmental Regulatory Update panel. Feedback and other ideas are welcomed.

<< File: EBA Environmental Panel Discussion.docx >>

From: Jeschke, Diana
Location: Dial-In: Non Responsive // Passcode: Non Responsive
Importance: Normal
Subject: EBA Environmental Regulatory Update Panel
Start Date/Time: Fri 3/21/2014 6:30:00 PM
End Date/Time: Fri 3/21/2014 7:00:00 PM
EBA Environmental Panel Discussion.docx

;
UPDATE: Time changed from 11 AM to 2:30 PM.
Please find attached some potential discussion topics for the Environmental Regulatory Update panel.
Feedback and other ideas are welcomed.

U.S. Environmental Regulatory Update

The past year witnessed numerous environmental developments affecting the energy sector. Air issues include the President's Climate Action Plan, issuance of proposed new standards of performance for new affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, consideration by the United States Supreme Court regarding whether EPA's Transport Rule should stand and whether EPA has the authority to regulate greenhouse gases from stationary sources, With respect to the Clean Water Act, EPA continues to wrestle with the development of a final cooling water intake rule and a proposed rule that would potentially expand the scope of waters that can be regulated by EPA and the Army Corps. This panel will discuss these and other developments, as well as how new and evolving environmental requirements will affect the nation's electric generation and reliability.

- Overview of EPA rules having the potential to impact electric generation facilities and the current status: MATS, CSAPR, GHG Regulation under CAA § 111, CCR and CWA § 316(b).
- If the rules are upheld and implemented as the schedule exists today, how would the schedule play out for implementation and required compliance with the new rules?
- Is there enough lead time? Many of these rules have been in development for some time, have they been incorporated into corporate and market planning for owners and operators of generation facilities and resource adequacy and transmission planning for grid operators? What rules and improvements do you see as most challenging to resource adequacy?
- While unit retirements have been discussed, can the new standards under these rules be met through retrofits or other inside the fence line measures? How often are retrofits economic? How effective can inside the fence line measures be in reducing GHG emissions at existing fossil fuel generation units?
- Do planned retirements (or extended outage for retrofits) of coal and oil-fired generation facilities present a reliability issue? Has there been an increase in retirements or retrofits even though the rules are still not final? Under current projections, how serious of an issue will this be and when?
- How should reliability aspects of EPA's proposed and final regulations be addressed? What federal, regional or local processes are used to plan for emerging issues such as the potential reliability and market impacts of EPA regulations?
- Is there sufficient existing or new generation capacity coming online to offset planned

retirements or reduced generation by some fossil fuel generation facilities? Should greater diversity of fuel sources such as renewable, nuclear "clean coal", and oil be encouraged.

- What market structures and tariff rules are used to address regional and local reliability issues that may arise from retirements or reduced generation of some fossil fuel generation facilities potentially triggered by EPA regulations?

To: Schmidt, Lorie[Schmidt.Lorie@epa.gov]
From: Vickie Patton
Sent: Fri 9/20/2013 3:16:44 PM
Subject: Setting the record straight: EPA has ample authority to protect us from carbon pollution

http://www.edf.org/blog/2013/09/20/setting-record-straight-epa-has-ample-authority-protect-us-carbon-pollution?utm_source=twitter&utm_medium=social-media&utm_campaign=main

Setting the record straight: EPA has ample authority to protect us from carbon pollution

Megan Ceronsky / Published September 20, 2013 in Legal

SHARE on Twitter

evanbrennan/flickr

(This post was co-authored by Tomas Carbonell and Peter Heisler.)

Even though they account for 40 percent of U.S. emissions of harmful carbon pollution, fossil fuel-fired power plants are currently subject to no national limits on the amount of such pollution they emit. Drawing on the same Clean Air Act tools it has previously used to regulate other pollutants, the U.S. Environmental Protection Agency (EPA) is working to put in place common-sense standards for carbon pollution from new and existing power plants.

Recently, a group of state attorneys general[1] issued a White Paper challenging EPA's authority to establish minimum emission performance standards for carbon pollution from existing power plants under Section 111(d) of the Clean Air Act, and to issue rigorous standards for new power plants that are based on advanced technologies such as carbon capture and storage. This attack on EPA's well-established authority to administer the Clean Air Act is legally unfounded and a misguided attempt to obstruct urgently-needed and long-delayed limits on carbon pollution from our nation's largest source.

Background

On June 25, 2013, President Obama called on EPA to exercise well-established authority under Section 111 of the Clean Air Act to establish common-sense limits on carbon pollution from both new and existing power plants. A proposed rule that would implement the nation's first limits on carbon pollution for new plants under Section 111(b) is due to be released for public comment by September 20th. At the same time, EPA has been reaching out to a diverse group of stakeholders—including state policy makers and energy regulators, industry, and the environmental community—to seek input as they begin to develop proposed emission guidelines for existing power plants under Section 111(d). These emission guidelines will set out the environmental performance criteria that state plans to implement Carbon Pollution Standards for existing power plants must meet to satisfy the Clean Air Act.

EPA's authority to establish environmental performance criteria for state plans under Section 111(d) is firmly grounded in the statute and no longer open to legal attack.

The argument that Section 111(d) authorizes EPA to issue only procedural requirements for state plans to implement emission standards for existing pollution sources is not new; it revives an industry interpretation of the Act that EPA considered and rejected in 1975, when the Agency first undertook a rulemaking to implement Section 111(d). There, EPA carefully analyzed the language, purpose and legislative history of Section 111(d),[2]and concluded that all of these authorities supported its responsibility to ensure that states plans meet environmental performance targets. The Agency has consistently adhered to this interpretation for almost 40 years while putting in place Section 111(d) emission guidelines for a number of major sources of harmful air pollution including municipal solid waste landfills, municipal waste combustors, and sulfuric acid plants.[3] EPA's authority to issue environmental performance requirements for state plans is no longer open to question or legal attack.[4]

EPA's longstanding interpretation of Section 111(d) as providing for EPA to establish substantive criteria for state plans is firmly anchored in the statutory language and the structure of Section 111. The White Paper's assertion that States select the "best system of emission reduction" misreads the plain language of section 111(a)(1) of the statute, which specifically directs the EPA Administrator to identify the most effective ("best") system of emission reduction that has been "adequately demonstrated," considering cost, effects on energy, and other environmental effects. The Act further provides that the standards of performance for existing sources must "reflect[] the degree of emission limitation achievable" under that best system.[5]

Under Section 111(d), EPA is directed to review state plans to determine whether or not the plans are"satisfactory." EPA's assessment during this review is based on whether the state plans meet the statutory criteria of establishing a "standard for emissions" that "reflects the degree of emission limitation achievable" under the "best system of emission reduction" that "the Administrator determines has been adequately demonstrated."[6] The emission guidelines issued by EPA lay out the information States will need to establish plans and standards of performance that will satisfy the statutory criteria, identifying the "best system of emission reduction" and the emission reductions achievable through application of that system. Although states have the flexibility to use other systems, they must achieve equal or greater emission reductions as the "best"system would achieve. Section 111(d) sets up a carefully balanced framework of cooperative federalism, in which EPA establishes emission guidelines and works with states to achieve emission reductions consistent with those guidelines. As the Supreme Court recently explained, States issue Section 111(d) standards "in compliance with [EPA] guidelines and subject to federal oversight."[7]

Section 111(d)'s direction that EPA put in place a process like that in Section 110 for the submittal and review of state plans likewise confirms EPA's role in setting emission reduction performance requirements. Under Section 110, States submit state implementation plans to achieve National Ambient Air Quality Standards for specified pollutants. The safe level of ambient pollution is an expert, science-based determination made by EPA, and the efficacy of state plans in achieving that safe level of air quality is the critical basis for EPA review and approval of state implementation plans.[8] EPA's long-standing role under Section 111(d) in establishing the environmental performance criteria for state plans parallels the structure of Section 110, consistent with the statutory cross-reference to that provision. And under both of these provisions, States are granted considerable flexibility to determine how best to meet those criteria.[9]

EPA has broad flexibility in assessing systems of emission reduction, including cutting-edge technologies that Section 111 was designed to stimulate.

The White Paper asserts that carbon capture and storage (CCS) is not yet widely deployed and that it therefore cannot be the "best system of emission reduction" for new coal-fired power plants. But as the Senate committee that voted on Section 111 stated, Section 111 was designed to promote "constant improvement in techniques for preventing and controlling emissions from stationary sources,[10]and an emerging technology used as the basis for standards of performance need not "be in actual routine use somewhere."[11] In the 1970's, Section 111 standards for sulfur dioxide emissions from power plants played a key role in driving the development and deployment of flue gas "scrubbers" — which was a novel technology installed at only three power plants at the time those standards were established.[12] Projects such as Southern Company's Plant Barry, Plant Daniel, and Kemper County facilities,[13]as well as AEP's Mountaineer plant,[14] have shown that CCS is a viable control technology in the power sector. Indeed, the core technologies involved in CCS have been applied in other industries for decades.

Furthermore, contrary to the assertions of the White Paper, a "best system of emission reduction" for new power plants need not be identical to that for existing power plants – and EPA has flexibility to consider a variety of "systems," not just technological end-of-pipe solutions, in crafting emission guidelines under section 111(d). Although EPA was at one time limited to considering "technological" systems when setting standards for new sources, Congress has consistently used broad, flexible language in describing systems of emission reduction for existing sources. It is consistent with this flexible language for EPA to consider cost-effective systems that reflect the unified nature of the electric grid by treating all fossil fuel fired power plants as an interconnected group, averaging emissions across plants, and recognizing changes in plant utilization that reduce emissions. These strategies are not only valid "systems of emission reduction" under Section 111, they are also "adequately demonstrated" by the tremendous success that states and companies across the country have already shown in reducing carbon pollution through investing in low-carbon generation, harvesting demand-side energy efficiency, and utilizing lower-emitting fossil fuel-fired units.

Conclusion

We agree with the attorneys general that the States have a vital role in achieving emissions reductions under Section 111. So does the Environmental Protection Agency. Indeed, the leadership of both EPA and the states will be essential in cutting carbon pollution from existing fossil fuel power plants, EPA in establishing protective emission reduction requirements for carbon pollution and the States in deploying innovative solutions to secure these emission reductions. EPA's fulfillment of its long-overdue statutory responsibilities will establish the foundation for a vibrant partnership between EPA and the states, consistent with the Clean Air Act's time-tested model of cooperative federalism, to finally place limits on the carbon pollution emitted by power plants and support the transition to cleaner, safer power for our nation, our states and our communities.

To: Schmidt, Lorie[Schmidt.Lorie@epa.gov]; Rodman, Sonja[Rodman.Sonja@epa.gov]; Schneeberg, Sara[schneeberg.sara@epa.gov]
Cc: Vickie Patton[vpatton@edf.org]
From: Graham McCahan
Sent: Thur 9/12/2013 4:41:35 PM
Subject: CSAPR - amicus briefs
12-1182 12-1183 ATS in support of petitioners.pdf
12-1182, 12-1183 tsac Inst. for Policy Integrity.pdf
12-1182, -1183 tsac Atmospheric Scientists.pdf
EMEHomerCity--LawProfsAmicus.pdf
12-1182 12-1183 tsac Energy Mkts-Grid amicus.pdf
12-1182 and 12-1183tsacConstitutionalAccountability Center.pdf
12-1182 and 12-1183 ac APA Watch.pdf

Hello all,

In case you didn't already receive these from DOJ, Vickie asked me to pass along the amicus briefs filed yesterday in the CSAPR case.

Best regards,

Graham

Graham McCahan
Attorney

Climate & Air Program

Environmental Defense Fund
2060 Broadway, Suite 300
Boulder, CO 80302
303-447-7228
gmccahan@edf.org
edf.org

Nos. 12-1182, 12-1183

IN THE

Supreme Court of the United States

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *ET AL.*,

Petitioners,

and

AMERICAN LUNG ASSOCIATION, *ET AL.*,

Petitioners,

v.

EME HOMER CITY GENERATION, L.P., *ET AL.*,

Respondents.

On Writs of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

BRIEF OF *AMICUS CURIAE* AMERICAN THORACIC SOCIETY IN SUPPORT OF PETITIONERS

HOPE M. BABCOCK*
JUSTIN M. GUNDLACH
Institute for Public Representation
Georgetown University Law Center
600 New Jersey Avenue, NW
Washington, D.C. 20001
(202) 662-9535
babcock@law.georgetown.edu
**Counsel of Record*

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RULES

OTHER SOURCES

INTEREST OF THE *AMICUS CURIAE*[1]

The American Thoracic Society (ATS) is an international educational and scientific organization founded in 1905 that represents more than 15,000 health care professionals. ATS works to prevent and fight respiratory disease around the globe through research, education, patient care, and advocacy. ATS publishes three peer-reviewed scientific journals that disseminate groundbreaking research, including studies on air pollution and health.

Amicus curiae ATS supports Petitioners' position because cross-border air pollution harms public health in downwind states. In light of this case's vital importance to the millions of citizens living in downwind states, *amicus* urges that this Court reverse the decision of the U.S. Court of Appeals for the D.C. Circuit and reinstate the U.S. Environmental Protection Agency's Cross State Air Pollution Rule, referred to below as the Transport Rule.

---

[1] Pursuant to this Court's Rule 37.2(a), all parties were timely notified of *amicus'* intention to file this brief. Counsel for petitioners and respondents have consented to the filing of this brief and their written consent has been lodged with the Court. Pursuant to this Court's Rule 37.6, *amicus* states that this brief was not authored in whole or in part by counsel for any party and that no person or entity other than *amicus* or her counsel made a monetary contribution intended to fund the preparation or submission of this brief.

SUMMARY OF ARGUMENT

Amicus curiae submits this brief to assist the Court in understanding the importance of the public health impacts of the air pollution at issue in this case. Air pollution measurably and substantially shortens lives. Vacating EPA's Transport Rule prevents the U.S. Environmental Protection Agency (EPA) from enforcing protections against such pollution. Should the decision of the U.S. Court of Appeals for the D.C. Circuit stand, it would condemn millions of American citizens to suffer preventable harm in violation of the Clean Air Act (CAA).

The Transport Rule addresses air pollution emitted by various sources, chiefly by electricity-generating facilities. Exposure to the pollutants emitted by these sources can have serious impacts on human health, including premature death, asthma exacerbations, and increased hospitalizations for cardiovascular and respiratory illnesses. These pollutants are especially harmful to children, whose respiratory systems are developing, to the elderly, whose respiratory systems are compromised by age, and to those whose respiratory systems are compromised by disease or disability.

The D.C. Circuit grounded its decision to vacate the Transport Rule upon a concern for "unnecessary over-control" of air pollution. In so doing, the D.C. Circuit cast aside EPA's carefully calibrated rule, which rationally took into account the benefits to human health available from reducing interstate air pollution. Numerous scientific studies demonstrate that improving air quality—in this instance, by preventing upwind states from polluting the air downwind—benefits public health.

Amicus curiae ATS supports EPA's efforts to protect citizens of downwind states from the needless health risks caused by air pollution from upwind states. Ensuring that emissions from upwind states do not push air quality in downwind states out of compliance with national ambient air quality standards (NAAQS) is a crucial aspect of protecting Americans' air quality more generally. Accordingly, *amicus* ATS urges this Court to reverse the D.C. Circuit's decision.

ARGUMENT

I. AIR POLLUTION THAT CROSSES STATE LINES ENDANGERS THE LIVES AND HARMS THE HEALTH OF CITIZENS IN DOWNWIND STATES

This case presents issues of extraordinary importance because interstate air pollution threatens the lives and health of millions of Americans. Nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions react in the atmosphere to form other dangerous pollutants, such as fine particulate matter (PM) and ground-level ozone. Plumes from electricity-generating facilities and other sources spread emissions great distances and affect PM and ozone levels in areas well beyond their place of origin, compromising public health in downwind regions. Exposure to these pollutants has long been understood to have significant and severe health impacts, see STAFF OF S. COMM. ON THE ENV'T AND PUB. WORKS, 95TH CONG., A LEGISLATIVE HISTORY OF THE CLEAN AIR ACT AMENDMENTS OF 1977, 6634-55 (1978).[2]

An extensive body of scientific and medical research documents the link between these emissions and human health.[3] PM emissions are especially dangerous because they can bypass the body's defensive mechanisms and become lodged deep in the smaller airways of the human lung; the smallest "ultrafine" particles can enter the blood

[2] *See also* Ephraim Thaller et al., *Moderate Increases in Ambient $PM_{2.5}$ and Ozone are Associated with Lung Function Decreases in Beach Lifeguards*, 50 J. OCCUPATIONAL & ENVTL. MED. 202, 202 (2008) (reporting adverse effects of air pollution even at low levels); Morton Lippmann, *Health Effects of Airborne Particulate Matter*, 357 NEW ENG. J. MED. 2395, 2396 (2007); Edward S. Schelegle et al., *6.6-Hour Inhalation of Ozone Concentrations from 60 to 87 Parts Per Billion in Healthy Humans*, 180 AM. J. RESPIRATORY & CRITICAL CARE MED. 265, 265 (2009).

[3] *See generally* U.S. ENVTL. PROT. AGENCY, INTEGRATED SCIENCE ASSESSMENT FOR PARTICULATE MATTER, EPA/600/R-08/139F (2009) [hereinafter INTEGRATED SCIENCE ASSESSMENT FOR PM] (reviewing and summarizing scientific literature on impacts of PM on human health); U.S. ENVTL. PROT. AGENCY, INTEGRATED SCIENCE ASSESSMENT FOR OZONE AND RELATED PHOTOCHEMICAL OXIDANTS, EPA 600/R-10/076F (2013) [hereinafter INTEGRATED SCIENCE ASSESSMENT FOR OZONE] (reviewing and summarizing scientific literature on impacts of ozone on human health).

stream and travel throughout the body.[4] These interactions increase the risk of premature death and cause or contribute to a host of respiratory and cardiopulmonary ailments, including asthma. Children, the elderly, and patients with cardiopulmonary disease are particularly susceptible to the adverse health effects of air pollution.

a. Air Pollution Shortens Lives

Exposure to air pollution kills.[5] In 2008, EPA elicited an assessment from twelve of the world's leading experts on the health effects of air pollution, which revealed substantial agreement on the likelihood of a causal connection between exposure and premature death.[6]

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[4] Günter Oberdörster et al., *Nanotoxicology: An Emerging Discipline Evolving from Studies of Ultrafine Particles*, 113 ENVTL. HEALTH PERSPS. 823, 823 (2005).

[5] U.S. ENVTL. PROT. AGENCY, EXPANDED EXPERT JUDGMENT ASSESSMENT OF THE CONCENTRATION-RESPONSE RELATIONSHIP BETWEEN $PM_{2.5}$ AND MORTALITY: FINAL REPORT, vii, 3-20 through 3-24 (2006); C. Arden Pope III et al., *Fine Particulate Air Pollution and Life Expectancies in the United States: the Role of Influential Observations*, 63 J. AIR WASTE MGMT. ASS'N 129, 131-32 (2013); Johanna Lepeule et al., *Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009,* 120 ENVTL. HEALTH PERSPS. 965, 968 (2012).

[6] INTEGRATED SCIENCE ASSESSMENT FOR PM at 1-14 through 1-24; *see also* Henry A. Roman et al., *Expert Judgment Assessment of the Mortality Impact of Changes in Ambient Fine Particulate Matter in the U.S.*, 42 ENVTL. SCI. TECH. 2268, 2270 (2008).

When air pollution levels are high, deaths can occur immediately, or within months, by inducing heart attacks or strokes.[7] Daily PM exposure, even at low levels, can lead to premature mortality through multiple pathways.[8] Acute PM exposure increases the risk of death from respiratory and cardiovascular causes;[9] chronic exposure increases the risk of death from lung cancer and cardiovascular disease.[10]

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[7] Yun-Chul Hong et al., *Effects of Air Pollutants on Acute Stroke Mortality*, 110 ENVTL. HEALTH PERSPS. 187, 188 (2002); Shang-Shyue Tsai et al., *Evidence for an Association Between Air Pollution and Daily Stroke Admissions in Kaohsiung, Taiwan*, 34 STROKE 2612, 2615 (2003).

[8] C. Arden Pope III & Douglas W. Dockery, *Health Effects of Fine Particulate Air Pollution: Lines that Connect*, 56 J. AIR WASTE MGMT. ASS'N 709 (2006) (presenting new evidence and noting consistent evidence found by serial prior studies).

[9] Meredith Franklin et al., *Association Between $PM_{2.5}$ and All-Cause and Specific-Cause Mortality in 27 US Communities*, 17 J. EXPOSURE SCI. & ENVTL. EPIDEMIOLOGY 279, 279, 285 (2007); Cathryn Tonne et al., *A Case-Control Analysis of Exposure to Traffic and Acute Myocardial Infarction*, 115 ENVTL. HEALTH PERSPS. 53, 53 (2007).

[10] C. Arden Pope III et al., *Cardiovascular Mortality and Long-Term Exposure to Particulate Air Pollution: Epidemiological Evidence of General Pathophysiological Pathways of Disease*, 109 CIRCULATION 71, 74-76 (2004) (finding 10□g/m3 increase in $PM_{2.5}$ increased mortality risk by 8-18%); C. Arden Pope III et al., *Lung Cancer, Cardiopulmonary Mortality, and Long-Term Exposure to Fine Particulate Air Pollution*, 287 J. AM. MED. ASS'N 1132, 1136-37 (2002).

Numerous studies also demonstrate that short-term exposure to ozone can shorten life.[11]

Successive assessments of the risk of premature mortality from air pollution have shown that risk to be greater than previously believed.[12] In 2007, a groundbreaking study of 66,000 women in thirty-six U.S. cities found that an increase in ten micrograms per cubic meter[13] of $PM_{2.5}$ (particulate matter less than 2.5 micrometers in aerodynamic diameter) raised the risk of death from cardiovascular disease by seventy-six percent.[14]

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[11] *See, e.g.*, Michelle L. Bell et al., *A Meta-Analysis of Time-Series Studies of Ozone and Mortality with Comparison to the National Morbidity, Mortality, and Air Pollution Study*, 16 EPIDEMIOLOGY 436, 442 (2005); Jonathan I. Levy et al., *Ozone Exposure and Mortality: An Empiric Bayes Metaregression Analysis*, 16 EPIDEMIOLOGY 458, 466 (2005); Kazuhiko Ito et al., *Associations Between Ozone and Daily Mortality: Analysis and Meta-Analysis*, 16 EPIDEMIOLOGY 446, 455 (2005).

[12] C. Arden Pope III, *Mortality Effects of Longer Term Exposures to Fine Particulate Air Pollution: Review of Recent Epidemiological Evidence*, 19 INHALATION TOXICOLOGY 33 (Supp. 1, 2007) (concluding short-term exposure studies capture only small amount of overall health effects of long-term repeated PM exposure); Michael Jerrett et al., *Spatial Analysis of Air Pollution and Mortality in Los Angeles*, 16 EPIDEMIOLOGY 727, 732 (2005).

[13] Concentrations of chemicals in air are typically measured in units of the mass of chemical (milligrams, micrograms, nanograms, or picograms) per cubic meter or cubic foot of air.

[14] Kristen A. Miller et al., *Long-Term Exposure to Air Pollution and Incidence of Cardiovascular Events in Women*, 356 NEW ENG. J. MED. 447, 456-57 (2007).

These results reflect improved data collection and methodologies and update earlier, less thorough studies that had identified a twelve percent increase in risk for every increase of ten micrograms per cubic meter.[15] A 2009 review of epidemiological studies by the California Environmental Protection Agency's Air Resources Board found a strong relationship between $PM_{2.5}$ exposure and premature death generally, and concluded that the risk of mortality rose by ten percent for every ten micrograms per cubic meter.[16] In addition, several studies have undermined the suggestion that increases in mortality arising from air pollution exposure merely "displace" the demise of the sick or frail by just a few days.[17]

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[15] *See* Douglas W. Dockery & Peter H. Stone, *Cardiovascular Risks from Fine Particulate Air Pollution*, 356 NEW ENG. J. MED. 511, 511 (2007) (noting approvingly updated results and methodological improvements in Miller et al. (2007)).

[16] AIR RES. BD., CAL. ENVTL. PROT. AGENCY, METHODOLOGY FOR ESTIMATING PREMATURE DEATHS ASSOCIATED WITH LONG-TERM EXPOSURES TO FINE AIRBORNE PARTICULATE MATTER IN CALIFORNIA: DRAFT STAFF REPORT 1 (2009) (attributing 18,000 deaths annually to $PM_{2.5}$ in California alone).

[17] Antonella Zanobetti et al., *The Temporal Pattern of Respiratory and Heart Disease Mortality in Response to Air Pollution*, 111 ENVTL. HEALTH PERSPS. 1188, 1192 (2003); Francesca Dominici et al., *Airborne Particulate Matter and Mortality: Timescale Effects in Four US Cities*, 157 AM. J. EPIDEMIOLOGY 1055, 1062 (2003).

Ozone also shortens lives, as demonstrated by several multi-city studies,[18] including two that identified elevated risk of premature death in the northeastern U.S.[19]—the states most directly served by the Transport Rule. The National Research Council confirmed this threat from ozone in a 2008 report, in which the Council also explained that premature death caused by ozone is not restricted to people who are already in poor health.[20]

b. Air Pollution Impairs Cardiovascular and Respiratory Health

Exposure to air pollution can also cause serious illness and disease. Researchers have found a significant association between air pollution and risk

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[18] Michelle. L. Bell et al., *supra* note 10, at 442; Mercedes Medina-Ramón & Joel Schwartz, *Who Is More Vulnerable to Die from Ozone Air Pollution?*, 19 EPIDEMIOLOGY 672 (2008); K. KATSOUYANNI ET AL., HEALTH EFFECTS INST. RESEARCH REP. NO. 142, AIR POLLUTION AND HEALTH: A EUROPEAN AND NORTH AMERICAN APPROACH (APHENA) (2009).

[19] Michelle L. Bell & Francesca Dominici, *Effect Modification by Community Characteristics on the Short-Term Effects of Ozone Exposure and Mortality in 98 US Communities*, 167 AM. J. EPIDEMIOLOGY 986 (2008); Richard L. Smith et al., *Reassessing the Relationship Between Ozone and Short-Term Mortality in US Urban Communities*. 21 INHALATION TOXICOLOGY 37 (2009).

[20] NAT'L RES. COUNCIL, NAT'L ACAD. OF SCIS., ESTIMATING MORTALITY RISK REDUCTION AND ECONOMIC BENEFITS FROM CONTROLLING OZONE AIR POLLUTION 8 (2008).

of heart attacks.[21] Numerous studies link both ozone and PM air pollution to increased hospitalization for cardiovascular disease, strokes, and congestive heart failure.[22] Exposure to PM also increases the risk of blood clots[23] and affects blood vessel reactivity,[24] reducing the amount of blood that reaches the heart

[21] Antonella Zanobetti & Joel Schwartz, *The Effect of Particulate Air Pollution on Emergency Admissions for Myocardial Infarction: A Multicity Case-Crossover Analysis*, 113 ENVTL. HEALTH PERSPS. 978, 980 (2005); Daniela D'Ippoliti et al., *Air Pollution and Myocardial Infarction in Rome: A Case-Crossover Analysis*, 14 EPIDEMIOLOGY 528, 528 (2003).

[22] *See, e.g.*, Francesca Dominici et al., *Fine Particulate Air Pollution and Hospital Admission for Cardiovascular and Respiratory Diseases*, 295 J. AM. MED. ASS'N 1127, 1133 (2006); Kristi B. Metzger et al., *Ambient Air Pollution and Cardiovascular Emergency Department Visits,* 15 EPIDEMIOLOGY 46, 55 (2004); William S. Linn et al., *Air Pollution and Daily Hospital Admissions in Metropolitan Los Angeles*, 108 ENVTL. HEALTH PERSPS. 427, 427 (2000); Tsai et al., *supra* note 6, at 26; Bruce Urch et al., *Relative Contributions of $PM_{2.5}$ Chemical Constituents to Acute Arterial Vasoconstriction in Humans*, 16 INHALATION TOXICOLOGY 345 (2004); Lynda D. Lisabeth, et al., *Ambient Air Pollution and Risk for Ischemic Stroke and Transient Ischemic Attack*, 64 ANNALS NEUROLOGY 53, 53-59 (2008).

[23] Andrea Baccarelli et al., *Exposure to Particulate Air Pollution and Risk of Deep Vein Thrombosis*, 168 ARCHIVES INTERNAL MED. 920, 926 (2008); Andrew J. Ghio et al., *Exposure to Concentrated Ambient Air Particles Alters Hematologic Indices in Humans*, 15 INHALATION TOXICOLOGY 1465, 1476 (2003).

[24] Urch et al., *supra* note 21, at 350-52.

and the brain.[25] Further, PM may inhibit the body's ability to vary its heart rate in response to environmental or situational changes.[26]

Long-term exposure to air pollution can inflict significant damage on the lungs[27] and reduce lung function.[28] Ambient concentrations of ozone and PM are associated with increased hospital admissions for pneumonia and chronic obstructive pulmonary disease.[29] Exposure to PM also increases emergency

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[25] Robert D. Brook et al., *Inhalation of Fine Particulate Air Pollution and Ozone Causes Acute Arterial Vasoconstriction in Healthy Adults*, 105 CIRCULATION 1534, 1535 (2002).

[26] Yuh-Chin T. Huang et al., *The Role of Soluble Components in Ambient Fine Particles-Induced Changes in Human Lungs and Blood*, 15 INHALATION TOXICOLOGY 327, 327 (2003).

[27] Ira B. Tager et al., *Chronic Exposure to Ambient Ozone and Lung Function in Young Adults*, 16 EPIDEMIOLOGY 751, 751 (2005); Andrew Churg et al., *Chronic Exposure to High Levels of Particulate Air Pollution and Small Airway Remodeling*, 111 ENVTL. HEALTH PERSPS. 714, 717-718 (2003); Patrick L. Kinney & Morton Lippmann, *Respiratory Effects of Seasonal Exposures to Ozone and Particles*, 55 ARCHIVES ENVTL. HEALTH 210, 215 (2000).

[28] John M. Peters et al*A Study of Twelve Southern California Communities with Differing Levels and Types of Air Pollution: II. Effects on Pulmonary Function*, 159 AM. J. RESPIRATORY & CRITICAL CARE MED. 759, 765-66 (1999).

[29] Mercedes Medina-Ramón et al., *The Effect of Ozone and PM_{10} on Hospital Admissions for Pneumonia and Chronic Obstructive Pulmonary Disease: A National Multicity Study*, 163 AM. J. EPIDEMIOLOGY 579, 583-84 (2006); *see also* Dominici et al., *supra* note 21, at 1133.

room visits for patients suffering from acute and chronic respiratory ailments.[30]

Scientists observe that the relationship between ozone and respiratory illness is "so well established that emergency admissions have been suggested as a surrogate measure of ozone."[31] Even in healthy adults, short-term exposure can inflame the lungs and cause immediate discomfort.[32] A study of hikers in New Hampshire indicated that healthy individuals were more likely to experience significant declines in lung function on days with higher ambient ozone; the study observed adverse health effects even on days when ozone levels were well below the most recent regulatory standard for ozone.[33] PM can also induce inflammation of lung

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[30] STEPHEN VAN DEN EEDEN ET AL., PARTICULATE AIR POLLUTION AND MORBIDITY IN THE CALIFORNIA CENTRAL VALLEY: A HIGH PARTICULATE POLLUTION REGION 3-4 (2002).

[31] David V. Bates, *Ambient Ozone and Mortality*, 16 EPIDEMIOLOGY 427, 428 (2005).

[32] Ian S. Mudway & Frank J. Kelly, *An Investigation of Inhaled Ozone Dose and the Magnitude of Airway Inflammation in Healthy Adults*, 169 AM. J. RESPIRATORY & CRITICAL CARE MED. 1089, 1093 (2004); W.F. McDonnell et al., *Ozone-Induced Respiratory Symptoms: Exposure-Response Models and Association with Lung Function*, 14 EUROPEAN RESPIRATORY J. 845, 852 (1999).

[33] Susan Korrick et al., *Effects of Ozone and Other Pollutants on the Pulmonary Function of Adult Hikers*, 106 ENVTL. HEALTH PERSPS. 93, 97-99 (1998) (reporting adverse effects from exposure to average ozone levels ranging from 0.021-0.074ppb, well below 0.075ppm level mandated by 8-hour ozone NAAQS in 2008).

tissue in healthy adults.[34] Recent research has also found a strong and consistent correlation between adult diabetes and air pollution, suggesting that PM is a risk factor for diabetes.[35]

c. Air Pollution Exacerbates Asthma

Asthma is a chronic respiratory disease affecting 25.7 million Americans—8.4 percent of the nation.[36] Asthma inflames and narrows the airways of the lungs, making it difficult for an individual to breathe.[37] People with asthma have heightened sensitivity to airway irritants, such as PM and ozone, and airway irritation leads to recurring symptoms, such as wheezing, chest tightness, shortness of breath, and coughing.[38] An asthma attack can be both painful and frightening, as its onset is often sudden. Left untreated, asthma can lead to

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[34] Andrew J. Ghio et al., *Concentrated Ambient Air Particles Induce Mild Pulmonary Inflammation in Healthy Human Volunteers*, 162 AM. J. RESPIRATORY & CRITICAL CARE MED. 981, 986 (2000).

[35] John F. Pearson et al., *Association Between Fine Particulate Matter and Diabetes Prevalence in the U.S.*, 33 DIABETES CARE 2196 (2010).

[36] LARA.J. AKINBAMI ET AL., CTRS. FOR DISEASE CONTROL AND PREVENTION, NHCS DATA BRIEF NO. 94, TRENDS IN ASTHMA PREVALENCE, HEALTH CARE USE, AND MORTALITY IN THE UNITED STATES, 2001-2010, at 1 (2012).

[37] NAT'L HEART, LUNG, AND BLOOD INST., NAT'L INSTS. OF HEALTH, PUB. NO. 09-7429, AT A GLANCE: ASTHMA 1 (2009).

[38] *Id.*

permanent lung damage or fatalities.[39] Exposure to PM and ozone is especially harmful for people with asthma.[40] Indeed, health experts maintain that air pollution is "one of the most under-appreciated contributors to asthma exacerbation."[41] Recurrent asthma exacerbations can cause permanent airway damage, and, as well as being inconvenient, they are dangerous and often expensive.[42]

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[39] Diane E. McLean et al., *Asthma Among Homeless Children: Undercounting and Undertreating the Underserved*, 158 ARCHIVES PEDIATRICS & ADOLESCENT MED. 244, 247 (2004).

[40] Janneane F. Gent et al., *Association of Low-Level Ozone and Fine Particles with Respiratory Symptoms in Children with Asthma*, 290 J. AM. MED. ASS'N 1859, 1859 (2003); Helene Desqueyroux et al., *Short-Term Effects of Low-Level Air Pollution on Respiratory Health of Adults Suffering from Moderate to Severe Asthma*, 89 ENVTL. RES. 29, 29 (2002).

[41] George D. Thurston & David V. Bates, *Air Pollution as an Underappreciated Cause of Asthma Symptoms*, 290 J. AM. MED. ASS'N 1915, 1915 (2003); *see also* Ariel Spira-Cohen et al., *Personal Exposures to Traffic-Related Air Pollution and Acute Respiratory Health among Bronx Schoolchildren with Asthma*, 119 ENVTL. HEALTH PERSPS. 559, 559, 564 (2011) (collecting studies linking PM emissions to asthma exacerbation and identifying key causal factors in relationship).

[42] *See* Susan M. Pollart et al., *Management of Acute Asthma Exacerbations*, 84 AM. FAMILY PHYSICIAN 40, 40-47 (2011) (describing symptoms and treatment strategies).

d. Air Pollution Increases Health Risks for Vulnerable Subpopulations Such as Children

The adverse health effects of air pollution pose greater risks for certain populations, including children (18 years and younger), the elderly (65 years and older), people with chronic cardiovascular and lung disease, and people with diabetes.[43] Children are especially susceptible because their lungs are still developing,[44] and because they breathe more air per pound of body weight than adults, which increases the dose of inhaled pollutants.[45] Children also spend more time outdoors and have higher activity levels than adults, which means they generally inhale greater volumes of polluted air.[46]

Air pollution can affect health even before birth, as PM exposure during pregnancy is linked to

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[43] INTEGRATED SCIENCE ASSESSMENT FOR PM, *supra* note 2, at Ch. 8 ("Populations Susceptible to PM-Related Health Effects").

[44] Comm. on Envtl. Health, Am. Acad. of Pediatrics, *Ambient Air Pollution: Health Hazards to Children*, 114 PEDIATRICS 1699, 1699 (2004) (observing that eighty percent of alveolar function develops post-natally).

[45] *See* Kent E. Pinkerton et al., *Ozone, a Malady for All Ages*, 176 AM. J. RESPIRATORY & CRITICAL CARE MED. 107, 107 (2007) (collecting and summarizing studies that illustrate nature of and reasons for ozone's adverse impact on lungs of children).

[46] *Id.*; *see also* Comm. on Envtl. Health, Am. Acad. of Pediatrics, *supra* note 43 at 1699.

increased risk of premature birth[47] and PM and ozone are linked to increased risk of lower birth weight.[48] One study found that infants faced an increased risk of bronchiolitis for every increase of ten micrograms per cubic meter in $PM_{2.5}$ in the ambient air.[49] In Canada's largest cities, ozone is associated with increased hospitalization for respiratory problems in babies under one month old.[50]

The adverse effects of high ozone exposure can stay with children for life. A five-year study tracking 3,500 students in Southern California found that children who played team sports in areas with high daytime ozone concentrations had a greater risk of

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47 Sharon K. Sagiv et al. *A Time Series Analysis of Air Pollution and Preterm Birth in Pennsylvania, 1997-2001*, 113 ENVTL. HEALTH PERSPS. 602, 605 (2005).

48 Michelle L. Bell, *Prenatal Exposure to Fine Particulate Matter and Birth Weight: Variations by Particulate Constituents and Sources*, 21 EPIDEMIOLOGY 884 (2010); Muhammad T. Salam et al., *Birth Outcomes and Prenatal Exposure to Ozone, Carbon Monoxide, and Particulate Matter: Results from the Children's Health Study*. 113 ENVTL. HEALTH PERSPS. 1638 (2005).

49 Catherine Karr et al., *Effects of Subchronic Exposure to Ambient Air Pollutants on Infant Bronchiolitis*, 165 AM. J. EPIDEMIOLOGY 553, 557 (2007).

50 Robert E. Dales et al., *Gaseous Air Pollutants and Hospitalization for Respiratory Disease in the Neonatal Period*, 114 ENVTL. HEALTH PERSPS. 1751, 1754 (2006); Richard T. Burnett et al., *Association Between Ozone and Hospitalization for Acute Respiratory Diseases in Children Less than 2 Years of Age*, 153 AM. J. EPIDEMIOLOGY 444, 449 (2001).

developing asthma.[51] Asthmatic children also have increased hospitalization rates, more severe asthma attacks, and decreased pulmonary function when exposed to air pollution.[52] A study of 255 college freshmen similarly found that students who grew up in areas with more ambient ozone had decreased lung function, a risk factor for lung disease later in life.[53]

Older adults are susceptible to the adverse health effects of air pollution because they have a higher prevalence of pre-existing illness and the aging process has contributed to their sensitivity.[54] Healthy elderly adults can experience significant decreases in heart rate variability following PM exposure, which may induce adverse cardiovascular events.[55] PM can trigger hospitalization for

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[51] Rob McConnell et al., *Asthma in Exercising Children Exposed to Ozone: A Cohort Study*, 359 LANCET 386, 389-91 (2002).

[52] Leonardo Trasande & George D. Thurston, *The Role of Air Pollution in Asthma and Other Pediatric Morbidities*, 115 J. ALLERGY & CLINICAL IMMUNOLOGY 689, 691-96 (2005); Toby C. Lewis et al., *Air Pollution-Associated Changes in Lung Function Among Asthmatic Children in Detroit*, 113 ENVTL. HEALTH PERSPS. 1068, 1073 (2005); George D. Thurston et al., *Summertime Haze Air Pollution and Children with Asthma*, 155 AM. J. RESPIRATORY & CRITICAL CARE MED. 654, 659-60 (1997).

[53] Tager et al., *supra* note 26 at 756-58.

[54] INTEGRATED SCIENCE ASSESSMENT FOR PM, *supra* note 2, at 8-3.

[55] R.B. Devlin et al., *Elderly Humans Exposed to Concentrated Air Pollution Particles Have Decreased Heart Rate Variability*, 21 EUROPEAN RESPIRATORY J. 76s, 79s (2003).

congestive heart failure among the elderly,[56] and low-level ozone exposure increases emergency room visits for respiratory illnesses among older populations.[57]

Also vulnerable are non-elderly individuals with pre-existing medical conditions. Adults with chronic obstructive pulmonary disease are particularly sensitive to ozone exposure,[58] and patients with cystic fibrosis are at greater risk of pulmonary exacerbations and significant loss in lung function when exposed to air pollution.[59] Individuals with diabetes are especially sensitive to air pollution as well, in particular because of increased risks from pollution-associated cardiovascular events.[60]

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[56] Gregory Wellenius et al., *Particulate Air Pollution and the Rate of Hospitalization for Congestive Heart Failure Among Medicare Beneficiaries in Pittsburgh, Pennsylvania*, 161 AM. J. EPIDEMIOLOGY 1030, 1030 (2005).

[57] Ralph J. Delfino et al., *Emergency Room Visits for Respiratory Illnesses Among the Elderly in Montreal: Association with Low Level Ozone Exposure*, 76 ENVTL. RES. 67, 75 (1998).

[58] Helene Desqueyroux et al., *Effects of Air Pollution on Adults with Chronic Obstructive Pulmonary Disease*, 6 ARCHIVES ENVTL. HEALTH 554, 554 (2002).

[59] Christopher H. Goss et al., *Effect of Ambient Air Pollution on Pulmonary Exacerbations and Lung Function in Cystic Fibrosis*, 169 AM. J. RESPIRATORY & CRITICAL CARE MED. 816, 816 (2004).

[60] Marie S. O'Neill et al., *Air Pollution and Inflammation in Type 2 Diabetes: A Mechanism for Susceptibility*, 64 OCCUPATIONAL & ENVTL. MED. 373, 376 (2007); Marie S. O'Neill et al., *Diabetes Enhances Vulnerability to Particulate Air Pollution-Associated Impairment in Vascular Reactivity and Endothelial Function*, 111 CIRCULATION 2913, 2918 (2005);

II. SIGNIFICANT PUBLIC HEALTH BENEFITS WILL RESULT FROM EPA'S IMPLEMENTATION OF THE TRANSPORT RULE

Imposing the air pollution restrictions embodied in the Transport Rule would reduce precursor emissions substantially, thereby removing a significant amount of PM and ozone from the ambient air downwind. Numerous studies demonstrate that decreases in air pollution, like PM and ozone, improve human health and increase average life expectancy.[61] Reduced exposure is associated with reduced mortality from various causes, including cardiovascular disease and lung cancer.[62] Even incremental reductions at lower

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Antonella Zanobetti & Joel Schwartz, *Are Diabetics More Susceptible to the Health Effects of Airborne Particles?*, 164 AM. J. RESPIRATORY & CRITICAL CARE MED. 831, 832-33 (2001).

[61] *See, e.g.*, Joel Schwartz et al., *The Effect of Dose and Timing of Dose on the Association between Airborne Particles and Survival*, 116 ENVTL. HEALTH PERSPS. 64, 68 (2008) (finding no evidence of a threshold in the association between $PM_{2.5}$ exposure and risk of death, suggesting efforts to reduce PM as low as feasible are most effective way to improve public health); Andrew W. Correia et al., *Effects of Air Pollution Control on Life Expectancy in the United States: An Analysis of 545 U.S. Counties for the Period from 2000 to 2007*, 24 EPIDEMIOLOGY 23, 23 (2013).

[62] Francine Laden et al., *Reduction in Fine Particulate Air Pollution and Mortality: Extended Follow-Up for the Harvard*

concentrations can save lives.[63] In 2009, researchers compared data on PM pollution and life expectancy in fifty-one U.S. cities between 1980 and 2000.[64] After controlling for socioeconomic, demographic, and lifestyle factors like smoking, the study revealed that decreasing $PM_{2.5}$ by ten micrograms per cubic meter could increase life expectancy by between six months and two years. The study also demonstrated that reduced pollution accounted for as much as fifteen percent of the overall increase in life expectancy seen in those cities. Other studies also show that limiting air pollution can produce substantial improvements in public health in a short period of time.[65] Decreases in long-term exposure reduce mortality rates to a

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Six Cities Study, 173 AM. J. RESPIRATORY & CRITICAL CARE MED. 667, 668-69 (2006).

[63] *Id.*

[64] C. Arden Pope III et al., *Fine-Particulate Air Pollution and Life Expectancy in the United States*, 360 NEW ENG. J. MED. 371, 384-85 (2009).

[65] Antonella Zanobetti & Joel Schwartz, *The Effect of Fine and Coarse Particulate Air Pollution on Mortality: A National Analysis*, 117 ENVTL. HEALTH PERSPS. 898, 902 (2009); Robin C. Puett et al., *Chronic Particulate Exposure, Mortality and Coronary Heart Disease in the Nurses' Health Study*, 168 AM. J. EPIDEMIOLOGY 1161, 1167 (2008); Antonella Zanobetti et al., *Particulate Air Pollution and Survival in a COPD Cohort*, 7 ENVTL. HEALTH 48, 55-56 (2008); Sara H. Downs et al., *Reduced Exposure to PM_{10} and Attenuated Age-Related Decline in Lung Function*, 357 NEW ENG. J. MED. 2338, 2346 (2007).

greater extent than previously believed.[66]

EPA has estimated that the Transport Rule would prevent between 13,000 and 34,000 premature deaths annually, measured against a state of affairs in which the Clean Air Interstate Rule (CAIR) does not govern interstate air pollution. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208, 48,309 (Aug. 8, 2011). Measured against the framework established by CAIR, it is estimated that the Transport Rule—a tougher approach than CAIR—would prevent an additional 2,550 to 6,560 premature deaths annually. Response of Intervenors American Lung Ass'n, Clean Air Council, Environmental Defense Fund, Natural Resources Defense Council, & The Sierra Club in Opposition to the Motion of Southwestern Public Service Co. for a Partial Stay of the Transport Rule Ex. 3, at 12-13, *EME Homer City Generation, L.P. v.*

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[66] *See* Roman et al., *supra* note 5, at 2268. EPA has tightened several different NAAQS in recent years, but there is still a positive correlation between better health and reduced air pollution at levels below the NAAQS. EPA even recognized this point in its most recent decision to tighten the standard for 24-hour $PM_{2.5}$. *See* National Ambient Air Quality Standards for Particulate Matter, 78 Fed. Reg. 3,086, 3,098 (Jan. 15, 2013) ("evidence- and risk-based approaches using information from epidemiological studies to inform decisions on $PM_{2.5}$ standards are complicated by the *recognition that no population threshold, below which it can be concluded with confidence that $PM_{2.5}$-related effects do not occur, can be discerned from the available evidence*.") (emphasis added).

EPA, 696 F.3d 7 (D.C. Cir. 2011) (No. 11-1302) (Declaration of David Schoengold) [hereinafter Schoengold Declaration].

III. THE TRANSPORT RULE IS NECESSARY TO IMPROVE AMERICANS' AIR QUALITY AND HEALTH WITHOUT DELAY

Respondents make several spurious points in support of their contention that the Transport Rule is not necessary for achieving reductions in harmful air pollution. Respondents suggest—wrongly—that the CAIR framework currently in place is sufficient to achieve attainment in downwind states as required under the Clean Air Act. Br. in Opp'n of Indust. & Labor Resp'ts at 30-31. Respondents also point out—wrongly again—that EPA "design value" data show that air pollution concentrations are declining even without implementation of the Transport Rule. *Id.* at 31.

a. Without the Transport Rule, EPA Will Have No Workable Regulatory Framework for Implementing the Clean Air Act's Good Neighbor Provision

CAIR was to be a comprehensive regulatory framework for implementing the CAA's requirement that upwind states act as "good neighbors" to downwind states by limiting cross border air pollution. Clean Air Interstate Rule, 70 Fed. Reg. 25,162, 25,170 (May 12, 2005). Its requirements reflect 1997 NAAQS for both PM and ozone, *id.* at 25,168, both of which have since been superseded by more protective standards. *See* National Air Quality Standards for Ozone, 73 Fed. Reg. 16,436, 16,471 (Mar. 27, 2008) ("the current [ozone] standard . . . does not provide sufficient protection"); National Air Quality Standards for Particulate Matter, 71 Fed. Reg. 61,144, 61,155 (Oct. 17, 2006) ("the available information clearly calls into question the adequacy of the current suite of $PM_{2.5}$ standards and provides strong support for revising the current suite of $PM_{2.5}$ standards to provide increased public health protection."). In 2008, the D.C. Circuit found "more than several fatal flaws in [CAIR]." *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C. Cir. 2008). Rather than vacate CAIR, however, the D.C. Circuit limited its life, making it a stopgap that will cease to operate once EPA issues a regulatory replacement. *North Carolina v. EPA*, 550 F.3d 1176, 1178 (D.C. Cir. 2008). EPA has sought to replace CAIR with the Transport Rule, which would reduce air pollution and improve public health to a greater degree than CAIR. Schoengold Declaration at 12-13; 76 Fed. Reg. at 48, 209.

The D.C. Circuit's decision to vacate the Transport Rule effectively guarantees that millions of Americans will spend years needlessly breathing more heavily polluted air and suffering the predictable health consequences. This guarantee takes two forms. First, as EPA has explained, the decision effectively delays those emission reductions that upwind states must undertake in order for downwind states to attain the NAAQS—particularly for ozone and PM. EPA Pet. at 29-30. And second, by instructing EPA to craft yet another novel replacement for CAIR, the decision ensures that the weaker and flawed CAIR will remain in place for the months and years EPA will require to comply with that instruction. Each year that CAIR remains in place will see an estimated 2,550 to 6,560 more premature deaths than would occur under the Transport Rule. Schoengold Declaration at 12-13.

b. Air Pollution Concentrations Are Rising Once Again

EPA regularly publishes air pollution "design values"—data reflecting official concentrations of particular pollutants, such as PM and ozone. These data report concentrations of pollution based on community monitors, and those concentrations, in turn, reflect a host of factors, including emissions from anthropogenic and natural sources and the impact of weather patterns and temperature over each three-year period studied.[67] Design values for most U.S. regions fell from the 2007-2009 period to the 2009-2011 period, but, as evident from EPA's 2010-2012 design values, ozone levels have risen

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[67] *See generally* OFFICE OF AIR QUALITY PLANNING & STANDARDS EMISSIONS, MONITORING, AND ANALYSIS DIVISION, U.S. ENVTL. PROT. AGENCY, GUIDANCE ON THE USE OF MODELS AND OTHER ANALYSES IN ATTAINMENT DEMONSTRATIONS FOR THE 8-HOUR OZONE NAAQS, EPA-454/R-05-002 (2005) (describing EPA's approach to air quality monitoring).

sharply.[68] For example, in Washington, D.C. (a nonattainment area for ozone), concentrations of ozone have increased nine percent since 2009.[69]

These recent EPA data show that air pollution concentrations can rise as well as fall under CAIR and so belie Respondents' contention that EPA has failed to demonstrate why the Transport Rule is necessary. *See* Br. in Opp'n of Indust. & Labor Resp'ts 30-31. Respondents ask this Court to look closely at the EPA data showing an earlier dip in pollution concentrations, but Respondents ignore EPA's more recent data, which show a significant

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[68] U.S. Envtl. Prot. Agency, Design Values—Period Ending 2012, Ozone Detailed Information, tbl. 3a, *available at* http://www.epa.gov/airtrends/values.html (scroll to row "2012" under "Design Value period ending" then click on "Ozone Detailed Information" under "Design Value Reports"). Notably, the higher ambient temperatures that likely contributed to this rise in 2012 are expected to persist—and continue increasing—in future years. Noah S. Diffenbaugh & Martin Scherer, *Likelihood of July 2012 U.S. Temperatures in Preindustrial and Current Forcing Regimes*, at s6, s8-s9, *and* Thomas R. Knutson et al., *The Extreme March-May 2012 Warm Anomaly over the Eastern United States: Global Context and Multimodel Trend Analysis*, at s13, s16, *in Explaining Extreme Events of 2012 from a Climate Perspective*, 94 BULL. AM. METEOROLOGICAL SOC'Y (SPECIAL SUPP.) (Thomas C. Peterson et al. eds., 2013), *available at* http://www.ametsoc.org/2012extremeeventsclimate.pdf. This warming trend, with its promise of higher rates of ozone, makes it all the more pressing to reduce ozone precursors below levels currently set by CAIR.

[69] U.S. Envtl. Prot. Agency, Design Values—Period Ending 2012, Ozone Detailed Information, tbl. 3a.

rise in ozone concentrations.[70] Contrary to Respondents' characterization of air pollution trends, EPA is right to push for implementation of the Transport Rule, because the problem of air pollution that harms and sometimes kills Americans urgently needs the stronger solution the Transport Rule provides.

CONCLUSION

For the foregoing reasons, *amicus* ATS urges this Court to reverse the D.C. Circuit's decision in order to protect the health of millions of Americans.

Respectfully submitted,

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[70] U.S. Envtl. Prot. Agency, Design Values—Period Ending 2012, Ozone Detailed Information, tbl. 3a.

Nos. 12-1182 and 12-1183

In The
Supreme Court of the United States

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, *et al.*,

Petitioners,

v.

EME HOMER CITY GENERATION, L.P., *et al.*,

Respondents.

and

AMERICAN LUNG ASSOCIATION, *et al.*,

Petitioners,

v.

EME HOMER CITY GENERATION, L.P., *et al.*,

Respondents.

On Writs Of Certiorari To The United States Court Of Appeals For The District Of Columbia Circuit

BRIEF OF THE INSTITUTE FOR POLICY INTEGRITY AT NEW YORK UNIVERSITY SCHOOL OF LAW AS AMICUS CURIAE IN SUPPORT OF PETITIONERS

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QUESTION PRESENTED

This amicus brief considers the third of the Questions Presented:

> Whether the EPA permissibly interpreted the statutory term "contribute significantly" so as to define each upwind State's "significant" interstate air pollution contributions in light of the cost-effective emission reductions it can make to improve air quality in polluted downwind areas, or whether the Act instead unambiguously requires the EPA to consider only each upwind State's physically proportionate responsibility for each downwind air quality problem.

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INTEREST OF THE AMICUS CURIAE[1]

The Institute for Policy Integrity at New York University School of Law[2] (Policy Integrity) is dedicated to improving the quality of government decisionmaking through advocacy and scholarship in the fields of administrative law, economics, and public policy. Policy Integrity is a collaborative effort of faculty at New York University School of Law; a full-time staff of attorneys, economists, and policy experts; law students; and a Board of Advisors composed of leaders in public policy, law, and government.

Policy Integrity and its directors have produced extensive scholarship on the economics and regulation of interstate pollution under the Clean Air Act. An area of special concern for Policy Integrity is the promulgation of federal environmental regulations justified by cost-benefit analysis. The question presented, above, directly bears on the use of cost-effectiveness criteria in interpreting and implementing environmental statutes. Policy Integrity has a significant interest in the outcome of the legal issues at stake—particularly in ensuring that federal agencies have the authority and flexibility to promulgate rational and economically efficient regulations.

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[1] The parties have submitted letters to the Clerk granting blanket consent to the filing of amicus briefs. No counsel for any party authored this brief in whole or in part, and no person or entity other than amicus and its counsel made a monetary contribution intended to fund the preparation or submission of this brief.

[2] No part of this brief purports to present New York University School of Law's views, if any.

SUMMARY OF THE ARGUMENT

A central and original justification for the Clean Air Act has been to more effectively address the serious and complex spillover effects that result from interstate air pollution. Congress confronted the difficult problem of interstate air pollution through a series of revisions to the Clean Air Act over several decades, ultimately producing the current version of the so-called Good Neighbor Provision, [3] which defines the obligations upwind states owe to their downwind neighbors. *See* Clean Air Act § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D). Crucially, the Good Neighbor Provision defines the allocation of responsibility between states for implementing air quality standards; it does not alter the level of health and welfare protection required by the statute. At no point has Congress ever prohibited the Environmental Protection Agency (EPA) or states from considering costs when they implement the Good Neighbor Provision. Indeed, the legislative history of this provision and related sections of the Act support the use of cost-minimizing market mechanisms to address interstate air pollution.

For decades, since its earliest interpretations of the Good Neighbor Provision, EPA has consistently determined—during both Republican and Democratic administrations—that the provision

[3] As explained further below, Congress has revised the Good Neighbor Provision several times over the past few decades, and it has been renumbered as well as reworded. This brief uses the phrase "Good Neighbor Provision" to refer to all of the versions of the statutory provision. The brief will specify when it is referring to a particular version of the provision.

authorizes the consideration of costs in crafting a program that effectively mitigates interstate air pollution while minimizing the unnecessary use of resources to achieve that goal. Similarly, for decades and through administrations of both parties, EPA has employed interstate emissions trading systems as a tool to cost-effectively achieve ambient air quality goals.

In accordance with EPA's longstanding interpretation of the Good Neighbor Provision, the Transport Rule at issue in this case considers costs in combination with other factors to determine when upwind states have violated their statutory obligations to downwind states. Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed. Reg. 48,208, 48,248 (Aug. 8, 2011) [hereinafter Transport Rule]. Congress did not prohibit the agency from considering costs under this section through either the text or the statutory structure. Moreover, the text of the statute and policy considerations support the agency's interpretation of the provision. Instead of substituting its own policy judgment for how best to address the complex problem of interstate air pollution—as the D.C. Circuit did—this Court should defer to the agency's reasonable interpretation of the Good Neighbor Provision, allowing the agency to utilize its expertise to cost-effectively mitigate interstate air pollution.

ARGUMENT

I. CONGRESS DESIGNED THE GOOD NEIGHBOR PROVISION AS PART OF A COMPREHENSIVE, FLEXIBLE SOLUTION TO THE ECONOMICALLY AND SCIENTIFICALLY COMPLEX PROBLEM OF INTERSTATE AIR POLLUTION

In the D.C. Circuit's majority opinion below, Judge Kavanaugh belittles the Good Neighbor Provision, calling it a "mousehole"—an "ancillary provision" that contains just one minor obligation among the many requirements for implementing air quality standards, and maintaining that the provision is too "narrow" to possibly authorize EPA to design a comprehensive, cost-effective response to interstate air pollution. *EME Homer City Generation v. EPA*, 696 F.3d 7, 28 (D.C. Circuit 2012) (citing *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001)). Far from being a "mousehole," the Good Neighbor Provision directly serves one of the most central and original rationales for the Clean Air Act: efficiently tackling the challenges of interstate air pollution. The plain language, statutory context, and legislative history of the Good Neighbor Provision all confirm that Congress never prohibited EPA and the states from considering or minimizing costs as they work together to achieve air quality goals.

A. Interstate Externalities Provide a Central Justification for Federal Environmental Protections

Air pollution is a classic negative economic externality: polluting activities impose uncompensated health and welfare costs on third parties. When those third parties cannot efficiently bargain with the polluters to mitigate those negative external costs, the resulting market failure justifies government regulation. *See* U.S. Office of Mgmt. & Budget, *Circular A-4: Regulatory Analysis* 4 (2003).

Additionally, air pollution famously "does not know" or respect state lines. S. Rep. No. 88-638, at 3 (1963). Subject to weather patterns, air pollution emitted from inside an upwind state can drift into and harm third parties in a downwind state. Even assuming that states adequately respond to all intrastate environmental problems, any individual state has little incentive to control the interstate air pollution externalities it generates. After all, the upwind state receives the productive benefits of the polluting activity without having to bear the full costs, which have been opportunistically externalized to a downwind state. Consequently, the upwind state has a powerful motive to allow its industries to exceed the socially optimal level of emissions. *See* Richard L. Revesz, *Federalism and Interstate Environmental Externalities*, 144 U. Pa. L. Rev. 2341, 2343 (1996). The potential for externalization of air pollution costs to other states means that state-level regulation may not sufficiently address air pollution. Indeed, "[t]he presence of interstate externalities is a powerful reason for intervention at the federal level." Richard L. Revesz, *Rehabilitating Interstate Competition: Rethinking the "Race-to-the-Bottom" Rationale for Federal Environmental Regulation*, 67 N.Y.U. L. Rev. 1210, 1222 (1992); *see also* Richard L. Revesz, *Federalism and Environmental Regulation: A Public Choice Analysis*, 115 Harv. L. Rev. 555, 557 n.3 (2001).

The particular case of interstate air pollution presents an important wrinkle on the classic story of externalities. The Clean Air Act separately obligates every state to comply with standards specifying the maximum permissible concentrations of certain "criteria" pollutants, *see* 42 U.S.C. §§ 7409-10, a category that includes some of the pollutants likely to cross borders and cause interstate harms, such as sulfur dioxide, *see, e.g.*, Primary National Ambient Air Quality Standard for Sulfur Dioxide; Final Rule, 75 Fed. Reg. 35,519, 35,522 (June 22, 2010). The fact that an upwind state contributes to a downwind state's ambient concentrations does not relieve the downwind state of any part of its obligation to comply with the federal ambient standards. Therefore, the externality imposed by upwind pollution often is not health and welfare costs, since the downwind state is still charged with achieving the overall target level of health and welfare. Instead, the negative externality is often the additional pollution abatement costs that the downwind state must now impose on itself to offset the upwind pollution. *See* Revesz, 144 U. Pa. L. Rev. at 2352.

Indeed, those very ambient air quality standards create an additional incentive for upwind states to externalize pollution. Not only does the upwind state want to enjoy the productive benefits of the polluting activity without facing the full health and welfare costs, but also it is motivated to try to avoid the regulatory costs by shifting the burden onto downwind states. In the 1970s and 1980s, following the enactment of the Clean Air Act, upwind states began having taller emissions stacks, sending their emissions into downwind states rather than curtailing the polluting activity: in 1970, only two stacks in the United States were higher than 500 feet; by 1985, more than 180 stacks were higher than 500 feet, and twenty-three were higher than 1000 feet. *Id.* at 2352-53. Statutory provisions and EPA regulations have since addressed some, but not all, of the concerns associated with tall stacks. *Id.* at 2354. Moreover, upwind states may be inclined to encourage their polluting sources to locate near their downwind borders to effectively export their uncontrolled pollution out of state. *Id.* at 2350-54.

Theoretically, states or private parties could address these externalities on their own, by negotiating with the polluting state and offering payments in exchange for pollution abatement. *See* R.H. Coase, *The Problem of Social Cost*, 3 J.L. & Econ. 1, 15 (1960) (explaining that, in the absence of transaction costs, parties would bargain to pay polluters in exchange for reducing pollution). History, however, strongly suggests that this approach is not realistic. This Court's 1907 ruling in *Georgia v. Tenn. Copper Co.* offers a good example of the limitations of voluntary interstate bargaining: Georgia went to court only after "a vain application to the State of Tennessee for relief." 206 U.S. 230, 236. In addition to the shortcomings of bargaining, the same case further shows that the common law is similarly unlikely to produce a timely, efficient remedy to interstate air pollution problems. *See id.*, *enforced by* 237 U.S. 474 (1915) (ending nine years of litigation with modest emissions reductions requirements).

The need for federal action on interstate air pollution motivated the original Clean Air Act. In

1963, Congress highlighted the air pollution problems created when growing urban areas and their impacts "cross the boundary lines" between states. Pub. L. No. 88-206, § 1(a), 77 Stat. 392, 392; *see also* Hon. Edmund S. Muskie, *Role of the Federal Government in Air Pollution Control*, 10 Ariz. L. Rev. 17, 18 (1968) ("The philosophy of the Clean Air Act of 1963 was to encourage state, regional, and local programs to control and abate pollution, while spelling out the authority of the national government to step into interstate situations with effective enforcement authority."). In fact, encouraging regional control efforts was listed as an original legislative purpose. Pub. L. No. 88-206, § 1(b)(4), 77 Stat. 392, 393.

Initially, Congress attempted to address interstate air pollution largely by promoting bargaining among the states. To that end, Congress empowered the federal government to convene interstate conferences, *id.* § 5(c), 77 Stat. at 396-97, and to set up interstate planning commissions, Air Quality Act of 1967, Pub. L. No. 90-148, § 106, 81 Stat. 485, 490.

But by 1970, no interstate planning commission had ever been empaneled, S. Rep. No. 91-1196, at 6 (1970), and only eight, largely ineffective conferences had ever been convened on interstate pollution, Bruce M. Kramer, *Transboundary Air Pollution and the Clean Air Act*, 32 U. Kan. L. Rev. 181, 189 (1983). "Disappointed" in these results, S. Rep. No. 91-1196, at 6, in 1970 Congress abandoned its exclusive reliance on the conference procedure and imposed a more regulatory solution by moving interstate air pollution issues under the rubric of section 110's

State Implementation Plans (SIPs). Specifically, this first version of the Good Neighbor Provision required SIPs to provide for "intergovernmental cooperation," including measures to ensure upwind pollution would not "interfere with" downwind air quality standards. *See* Clean Air Amendments of 1970 § 110(a)(2)(E), Pub. L. No. 91-604, 84 Stat. 1676, 1681. In short, the barriers to effective interstate negotiations were simply too intractable, and the market failures created by the interstate air pollution externalities required a more comprehensive federal response. *See* U.S. Office of Mgmt. & Budget, *Circular A-4*, at 5 (explaining that "problems that spill across State lines . . . are probably best addressed by Federal regulation").

Though the initial version of the Good Neighbor Provision created by the 1970 Amendments was later deemed "inadequate," H.R. Rep. No. 95-294, at 330 (1977), Congress remained committed to designing a "better solution" to the "serious" problem of interstate air pollution. *Id.* The 1977 Amendments began to establish the Clean Air Act's modern approach to interstate air pollution. Central to this structure was a stronger Good Neighbor Provision, which replaced the vague call for "intergovernmental cooperation" with a specific mandate for "adequate provisions . . . prohibiting any stationary source within the State from emitting any air pollutant in amounts which will . . . prevent attainment or maintenance by any other State of any such national primary or secondary ambient air quality standard." Clean Air Act Amendments of 1977 § 110(a)(2)(E), Pub. L. No. 95-95, 91 Stat. 685, 693; *see also id.*, 91 Stat. at 721-22, 724-25 (creating section 123 constraining tall stacks and section 126 allowing states to petition EPA to declare violations of the Good Neighbor Provision).

The final elements of the modern approach took shape in 1990, when Congress made two important changes to the language of the Good Neighbor Provision. First, it expanded the scope from individual stationary sources to "any . . . emissions activity"; second, it changed the standard from "prevent attainment or maintenance" to "contribute significantly to nonattainment in, or interfere with maintenance by." [4] Clean Air Act Amendments of 1990 § 110(a)(2)(D), Pub. L. No. 101-549, 104 Stat. 2399, 2404. These modifications gave EPA and the states more flexibility to address cumulative emissions from multiple sources and activities, instead of just regulating individual, stationary sources.

B. The Good Neighbor Provision Is a Key Element of the Clean Air Act's Overall Response to Interstate Externalities

The Good Neighbor Provision, housed within the requirements for State Implementation Plans (SIPs), requires:

> adequate provisions (i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity within the

[4] The statute thus provides two distinct avenues for finding a violation of the Good Neighbor Provision: (1) an upwind state "contribute[s] significantly to nonattainment" of ambient air quality standards in a downwind state, or (2) an upwind state "interfere[s] with" a downwind state's "maintenance" of the ambient air quality standards. This brief will use "contribute significantly" as a shorthand to refer to both provisions.

> State from emitting any air pollutant in amounts which will (I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any such national primary or secondary ambient air quality standards, or (II) interfere with measures required to be included in the applicable implementation plan for any other State under part C of this subchapter to prevent significant deterioration of air quality or to protect visibility.

Clean Air Act § 110(a)(2)(D), 42 U.S.C. § 7410(a)(2)(D). The Act provides multiple mechanisms to ensure the obligation is satisfied. After EPA issues or revises national ambient air quality standards, each state must submit a SIP for EPA's approval that adequately addresses the Good Neighbor Provision. Clean Air Act § 110(a), 42 U.S.C. § 7410(a). If a state fails to submit an adequate SIP, EPA "shall" develop a Federal Implementation Plan to enforce the Good Neighbor Provision. Clean Air Act § 110(c), 42 U.S.C. § 7410(c). If EPA finds an approved SIP is "substantially inadequate" with respect to the Good Neighbor Provision, the agency must call for revisions. Clean Air Act § 110(k)(5), 42 U.S.C. § 7410(k)(5). Finally, a downwind state or local government may petition EPA for a finding that a source in an upwind state is violating the Good Neighbor Provision. Clean Air Act § 126, 42 U.S.C. § 7426. The subject of this case, the Transport Rule, concerns a Federal Implementation Plan under section 110(c), but the content of the substantive standard contained in the Good Neighbor Provision remains the same regardless of how it is enforced.

The Good Neighbor Provision works together with and alongside several other provisions in the Clean Air Act to address interstate pollution. Some of these other provisions, like sections 106 and 176A on interstate commissions, 42 U.S.C. §§ 7406, 7506a, harken back to Congress's first efforts to address the problem. Some, like section 123 on stack heights, 42 U.S.C. § 7423, attempt to mitigate particular perverse incentives that may result in socially inefficient levels of interstate pollution, *see* Revesz, 144 U. Pa. L. Rev. at 2349, 2354-58. Some, like section 184 on interstate ozone pollution, 42 U.S.C. § 7511c, and Title IV on acid rain pollution, 42 U.S.C. §§ 7651-7651o, target specific pollutants and sources. But only the Good Neighbor provision applies more broadly to "any pollutant" emitted by "any source or . . . activity" that interferes with air quality and visibility standards in other states, and creates binding obligations on states while still giving them flexibility in designing a response.

C. From the Clean Air Act's Earliest Approaches to Interstate Pollution, Congress Has Never Prohibited the Consideration of Costs or the Pursuit of Cost-Effective Strategies

Since 1963, the Clean Air Act has listed four fundamental statutory purposes: one is to "protect the Nation's air resources so as to promote the public health and welfare *and the productive capacity*" of the country; another is to assist the development of regional air pollution control programs. Pub. L. No. 88-206, § 1(b), 77 Stat. at 393 (emphasis added). These goals remain key statutory purposes today. 42 U.S.C. § 7401(b) (note that the phrase "and enhance the quality" has been added to the first goal of protecting air resources). As recently as the 1990 Amendments, Congress expressed its intent for EPA to continue to balance these underlying objectives, by "exercis[ing] equally" "both the regulatory tools to accomplish cleaner air and the flexibility to protect our industrial and productive capacity." H.R. Rep. No. 101-490, at 163 (1990).

For example, the now obsolete interstate conference process from 1963 authorized the federal government to recommend "reasonably calculated" abatement strategies, and the Attorney General to initiate litigation in which the court was instructed to weigh "the physical and economic feasibility . . . , [against] public interest and the equities." Pub. L. No. 88-206,§ 5(d)-(g), 77 Stat. at 397-98; *see also* Pub. L. No. 90-148, §§ 108(c)-(h), 81 Stat. at 493-96; S. Rep. No. 90-403, at 3 (1967) (noting that the Clean Air Act's success would depend in part on "the development of plans for air regions, to implement the established ambient air standards giving due consideration of factors of technical and economic feasibility"). Though, as discussed above, the conference process ultimately proved too cumbersome and weak and was replaced, it shows the start of a historical trend of Congress not foreclosing cost considerations from interstate air pollution remedies.

Similarly, when strengthening the Good Neighbor Provision in 1977, Congress noted that the "economic and competitive . . . positions" of emissions sources in different states were one important factor in designing an effective interstate air pollution program. S. Rep. No. 95-127, 41-42 (1977). Even more telling than such occasional references to economic considerations, though, is the complete absence from the legislative histories in 1963, 1967, 1970, 1977, and 1990 of any mention of a congressional intent to prohibit the consideration of costs or the pursuit of cost-effective strategies.

D. Congress Explicitly Authorized EPA and the States to Use Market Mechanisms to Address Interstate Air Pollution in Order to Achieve Environmental Goals Cost-Effectively

In 1990, as part of a broad initiative to harness economic theory to design more efficient air quality regulations, Congress added several provisions to the Clean Air Act authorizing the use of market-based incentives to control emissions.[5] Notably, Congress inserted language explicitly allowing State Implementation Plans to use:

> enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter.

[5] Perhaps the best known is the highly successful program to control interstate acid rain pollution under Title IV of the Clean Air Act. 42 U.S.C. §§ 7651-7651o; *see* Gabriel Chan, Robert Stavins et al., *The SO_2 Allowance Trading System and the Clean Air Act Amendments of 1990* at 31 (Nat'l Bureau of Econ. Research, Working Paper No. 17,845, 2012) (noting the program is "viewed as a success by almost all measures").

42 U.S.C. § 7410(a)(2)(A). Similarly, Federal Implementation Plans—like the one proposed by the Transport Rule—are authorized to use these same market-based tools (except for fees). 42 U.S.C. § 7602(y). Because the Good Neighbor Provision is one of the "applicable requirements" of implementation plans, the plain language of section 110 makes clear that market mechanisms like trading are available to satisfy the requirements of the Good Neighbor Provision. The 1990 Amendments arguably further facilitated trading under the Good Neighbor Provision by giving EPA and the states more flexibility to address cumulative emissions from multiple sources and activities, instead of just regulating individual, stationary sources. *See* Pub. L. No. 101-549, 104 Stat. at 2404.

The purpose of using market mechanisms like trading is to achieve the same environmental goal at a lower cost (or a better environmental outcome at the same cost) by concentrating pollution control efforts on the least-cost abatement opportunities. *See* U.S. Office of Mgmt. & Budget, *Regulatory Impact Analysis: A Primer* 6 (2011) (recommending "trading . . . as an approach that might achieve the same [environmental] gain at a significantly lower cost"). As many of the drafters of the Clean Air Act Amendments of 1990 stated, "the overall goal" of the various trading programs added in 1990 was "to permit an aggregate least-cost solution." *See* 136 Cong. Rec. 35,000, 35,044, 35,759 (Oct. 26, 1990) (identical phrases appearing in statements of Rep. Sharp, Rep. Hall, and Sen. Simpson); *accord* 133 Cong. Rec. 1382 (Jan. 16, 1987) (statement of Sen. Proxmire). In short, Congress explicitly authorized the use of trading to achieve interstate goals like the

Good Neighbor Provision, as a way for EPA and the states to minimize the aggregate costs of achieving these pollution reductions. Therefore, EPA and the states must not be prohibited from considering and minimizing costs under the Good Neighbor Provision, since that is the whole point of authorizing trading.

II. MULTIPLE PRESIDENTIAL ADMINISTRATIONS OVER SEVERAL DECADES HAVE CONSISTENTLY INTERPRETED THE GOOD NEIGHBOR PROVISION TO PERMIT FLEXIBLE INTERSTATE POLLUTION-CONTROL MECHANISMS THAT CONSIDER AND MINIMIZE COSTS

For over three decades, under both Republican and Democratic presidential administrations, EPA has interpreted the Good Neighbor Provision to authorize pursuit of cost-effective, regional strategies to mitigate interstate air pollution externalities. For more than two decades, presidents and their EPA administrators—again from both parties—have similarly interpreted the Clean Air Act to authorize the use of market mechanisms to minimize the costs of achieving goals like those under the interstate air pollution programs. As explained in more detail below, a consistent interpretation by an agency is entitled to additional deference. On this point, EPA's remarkably consistent interpretation of the statutory language in the Good Neighbor Provision is highly relevant.

A. EPA Has Consistently Interpreted the Good Neighbor Provision to Allow for Consideration of Costs When Addressing Interstate Air Pollution

For decades, EPA has interpreted the relevant Clean Air Act provisions to permit it to consider costs when regulating interstate air pollution. For example, under the Carter Administration, EPA believed the Good Neighbor Provision gave it authority to require "generally comparable emission limits for comparable sources" in different states. Interstate Pollution Abatement; Notice of Proceedings under Section 126 of the Clean Air Act and Hearing, 45 Fed. Reg. 17,048, 17,049 (1980). Moreover, in the same notice, EPA asked for comments on whether it should "consider the application of reasonably available control technology (RACT) by the contested sources to be sufficient in and of itself to avoid a finding of impermissible interstate pollution." *Id.* at 17,049. EPA had previously defined RACT to include a consideration of cost factors. State Implementation Plans; General Preamble for Proposed Rulemaking on Approval of Plan Revisions for Nonattainment Areas—Supplement (on Control Technique Guidelines), 44 Fed. Reg. 53,761, 53,762 (Sept. 17, 1979) (defining RACT as "[t]he lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility"). Though the proceeding on interstate violations was not completed during the Carter Administration, it shows that from EPA's earliest statutory interpretations of the Good Neighbor Provision, the agency felt it could consider factors beyond the mere volume of emissions contributions—including economic considerations—when resolving interstate air pollution problems. EPA's present approach under the Transport Rule is consistent with this earliest interpretation, as the cost-effectiveness criterion is one reasonable way of setting "generally comparable emission limits for comparable sources."

The Reagan Administration's EPA went a step further and made costs an explicit factor that could be considered in assessing violations of the Good Neighbor Provision. For example, when the Reagan EPA finalized the above proceeding that the Carter EPA had initiated, it noted that the relative allocation of pollution abatement responsibilities among states "may vary depending on a number of circumstances, possibly including social and economic factors." Interstate Pollution Abatement; Final Determination, 47 Fed. Reg. 6624, 6626 (Feb. 16, 1982). In developing a set of criteria for determining if an upwind state had violated the Good Neighbor Provision, the Reagan EPA listed "the relative costs of pollution abatement between sources that contribute to a violation." Interstate Pollution Abatement; Proposed Determination, 49 Fed. Reg. 34,851, 34,859 (Sept. 4, 1984), *approved in* Final Determination under section 126 of the Clean Air Act (Interstate Pollution Abatement), 49 Fed. Reg. 48,152, 48,156-57 (Dec. 10, 1984) (noting the particular relevance of costs in determining the remedy for a violation of the Good Neighbor Provision).[6]

[6] At the time, the statutory provision in effect was the old section 110(a)(2)(E), which—as discussed above—was worded

When EPA began to take more proactive steps during the Clinton Administration to regulate interstate air pollution directly under the Good Neighbor Provision, it based its criteria for determining which emissions "contribute significantly" to downwind nonattainment on "both air quality factors relating to amounts of upwind emissions and their ambient impact downwind, as well as cost factors relating to the costs of the upwind emissions reductions." Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57,356, 57,376 (Oct. 27, 1998) [hereinafter NO_x SIP Call].

When President George W. Bush's EPA updated and expanded the interstate air pollution rules under the Good Neighbor Provision, it, too, incorporated cost considerations into its criteria for addressing those states that "contribute significantly" to downwind pollution. Under the Clean Air Interstate Rule (CAIR), cost factors were one of EPA's two primary considerations in determining significant contributions to interstate air pollution. Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_x SIP Call, 70 Fed. Reg. 25,162, 25,174 (May 12,

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differently to prohibit upwind emissions that "prevent attainment or maintenance," rather than "contribute significantly to nonattainment . . . or interfere with maintenance." Nonetheless, EPA interpreted the "prevent attainment" language to prohibit "substantial" or "significant" contributions from upwind states, *see, e.g.*, 47 Fed. Reg. at 6628; 49 Fed. Reg. at 34,859.

2005) [hereinafter CAIR]. EPA took costs into account by "mandating emissions reductions in amounts that would result from application of highly cost-effective controls." *Id.* at 25,175.

In the Transport Rule at issue here, in line with longstanding agency practice and recent court rulings, the Obama EPA incorporated a slightly modified consideration of costs into its assessment of whether upwind states' emissions violate the Good Neighbor Provision. Transport Rule, 76 Fed. Reg. at 48,248. The Transport Rule analyzed "both cost and air quality improvement to identify the portion of a state's contribution that constitutes its significant contribution to nonattainment and interference with maintenance." *Id.* The Transport Rule "defines each state's significant contribution to nonattainment and interference with maintenance as the emission reductions available at a particular cost threshold in a specific upwind state which effectively address nonattainment and maintenance of the relevant NAAQS in the linked downwind states of concern." *Id.* Thus, under the Transport Rule, EPA interpreted the Good Neighbor Provision to authorize cost-effective strategies to implement interstate air pollution controls—much as agency actions under four previous presidential administrations had also interpreted the statute.

B. EPA Has Consistently Interpreted the Good Neighbor Provision to Allow for Interstate Emissions Trading Mechanisms as a Way to Achieve Cost-Effective Pollution Reductions

For over twenty years, presidents and their EPA administrators have interpreted the Clean Air Act to authorize the use of emissions trading systems as a way to pursue cost-effective controls of interstate air pollution. Upon signing the 1990 Clean Air Act Amendments, which added new language on market incentives to section 110, President George H.W. Bush directed EPA to use the statute's multiple new provisions on flexibility and trading to "implement this bill in the most cost-effective manner possible." Statement on Signing the Bill Amending the Clean Air Act, 1990 Pub. Papers 1602, 1603 (Nov. 15, 1990). Though George H.W. Bush's EPA focused its attentions on the bill's related provisions creating cost-effective, market incentives to control interstate acid rain pollution, *see* E. Donald Elliott, *Lessons from Implementing the 1990 CAA Amendments*, 40 Envtl. L. Rep. 10,592 (2010), each subsequent administration has utilized the Good Neighbor Provision to institute a cost-minimizing emissions trading system.

The Clinton EPA's signature effort to enforce the Good Neighbor Provision, the NO_x SIP Call, featured an optional trading program. 63 Fed. Reg. at 57,456. EPA "encourage[d] States to consider electric utility and large boiler controls under a cap-and-trade program as a cost-effective strategy." *Id.* at 57,359. It created a model program, which states could opt into. EPA explained in the rule that a regional trading system would allow states to achieve the required emissions reductions at the least cost. *Id.* at 57,400.

Likewise, the George W. Bush EPA crafted an interstate emissions trading mechanism in CAIR. Similar to the 1998 NO_x SIP Call, CAIR allowed states to opt into a model interstate emissions trading program. 70 Fed. Reg. at 25,229. The agency explained, "If States choose to . . . participate in the cap and trade program, allowances could be freely traded, encouraging least-cost compliance over the entire region." *Id.* at 25,231.

Building on the cost-effective trading approach in those two earlier efforts to implement the Good Neighbor Provision, in the Transport Rule, Obama's EPA designed "air quality-assured trading programs" to "ensure that necessary reductions will occur within every covered state." 76 Fed. Reg. at 48,210. EPA explained, "the trading component of the Transport Rule provides flexibility to the power sector and enables industry to comply with the emission reduction requirements in the most cost-effective manner . . . thus minimizing overall costs." *Id.* at 48,347.

In short, EPA has long viewed interstate trading mechanisms as both authorized under the Good Neighbor Provision and as a key tool for pursuing cost-effective approaches to interstate air pollution. Through these trading regimes, EPA maintains the same overall level of air quality in the downwind states while allowing states to prioritize their abatement strategies in a cost-effective manner. If EPA and the states are authorized to use trading to implement the Good Neighbor Provision cost-effectively, the Good Neighbor Provision must also more generally authorize the consideration and minimization of costs.

III. EPA'S USE OF A COST-EFFECTIVENESS FRAMEWORK TO IMPLEMENT THE GOOD NEIGHBOR PROVISION IS A PERMISSIBLE, REASONABLE, AND PRUDENT STATUTORY INTERPRETATION

A. The Court Should Defer to the Agency's Reasonable and Longstanding Statutory Interpretations Since Congress Has Not Unambiguously Addressed the Precise Question

Where, as here, an agency adopts a reasonable interpretation of an ambiguous statutory provision, a court should defer to the agency's interpretation rather than substitute its own policy judgment. *Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-45 (1984). Under *Chevron*, a court reviewing "an agency's construction of the statute which it administers . . . is confronted with two questions." *Id.* at 842. First, the court must examine "whether Congress has directly spoken to the precise question at issue. If the intent of Congress is clear, . . . the court, as well as the agency, must give effect to the unambiguously expressed intent of Congress." *Id.* at 842-43. "If, however, the court determines Congress has not directly addressed the precise question at issue, the court does not simply impose its own construction on the statute." *Id.* at 843. Instead, it moves to the second step of the analysis, wherein, "if the statute is silent or ambiguous with respect to the specific issue, the question for the court is whether the agency's answer is based on a permissible construction of the statute." *Id.*

Here, because EPA has for decades consistently interpreted the Good Neighbor Provision to authorize the consideration and minimization of costs, the Court should afford additional deference to the agency. This Court has repeatedly recognized the importance of "accord[ing] particular deference to an agency interpretation of longstanding duration." *Alaska Dept. of Envtl. Conservation v. EPA*, 540 U.S. 461, 487 (2004) (quoting *Barnhart v. Walton*, 535 U.S. 212, 220 (2002)) (internal quotation omitted). The Court has explained, "While not conclusive, it surely tends to show that the EPA's current practice is a reasonable and hence legitimate exercise of its discretion to weigh benefits against costs that the agency has been proceeding in essentially this fashion for over 30 years." *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 224 (2009) (holding that EPA's use of cost-benefit analysis was permissible under section 1326(b) of the Clean Water Act, an interpretation that EPA had espoused since the late 1970s). The thirty-year history of agency interpretation in this case is remarkably similar, and EPA deserves a similar level of "particular deference" on interpreting the Good Neighbor Provision.

B. The Clean Air Act Does Not Clearly Prohibit EPA's Interpretation of the Good Neighbor Provision and, in Fact, Supports the Agency's Interpretation

The Good Neighbor Provision instructs:

> Each [state implementation] plan shall— . . . (D) contain *adequate provisions*—(i) prohibiting, consistent with the provisions of this subchapter, any source or other type of emissions activity

> within the State from emitting any air pollutant in *amounts* which will—(I) *contribute significantly to nonattainment in, or interfere with maintenance by,* any other State with respect to any such national primary or secondary ambient air quality standard.

42 U.S.C. § 7410(a)(2) (emphasis added). The Clean Air Act nowhere defines such key terms as "adequate," "amounts," "contribute significantly to nonattainment," or "interfere with maintenance." *See, e.g.*, *Michigan v. EPA*, 213 F.3d 663, 674 (D.C. Cir. 2000) ("Nothing in the text of the new section or any other provision of the statute spells out a criterion for classifying 'emissions activity' as 'significant.'"); *id.* at 697 (Sentelle, J., dissenting) ("Neither did it define amount."). The plain language of Good Neighbor Provision does not unambiguously speak to the matter of cost-effectiveness.

At most, the statute is silent on the issue of cost-effectiveness. The question of whether perceived statutory silence indicates a clear congressional prohibition often turns on context. For example, in *Whitman v. American Trucking*, this Court held that EPA was not permitted to consider costs in the unique context of setting the National Ambient Air Quality Standards under section 109(b)(1) of the Clean Air Act. 531 U.S. 457, 471 (2001). However, as the Court later explained in *Entergy*, "*American Trucking* . . . stands for the rather unremarkable proposition that sometimes statutory silence, when viewed in context, is best interpreted as limiting agency discretion." 556 U.S. at 223.

In particular, *American Trucking* draws a sharp contrast between sections of the Clean Air Act that set air quality standards and sections that implement those standards. Section 109 directs EPA to set ambient air quality standards at levels "requisite to protect the public health" with "an adequate margin of safety." 42 U.S.C. § 7409(b)(1). The question before the Court in *American Trucking* was whether that particular language vested EPA with "the power to determine whether implementation costs should moderate national air quality standards." 531 U.S. at 468. Given that the fundamental purpose of the section was to set standards necessary to safeguard public health and welfare, the Court found it "implausible" that Congress would have wanted EPA to also consider costs and yet forgot to mention it in the statute. *Id.* The Court contrasted section 109(b)(1) with other provisions of the Clean Air Act—including section 110—that focused not on setting public health and welfare goals, but instead on implementing them. *Id.* at 469-70. The task of implementation, the Court said, "would be impossible . . . without considering which abatement technologies are most efficient, and most economically feasible." *Id.* at 470. The question before the Court here—how to properly interpret the Good Neighbor Provision—deals with such a task of implementation that necessitates consideration of economic efficiency: indeed, the Good Neighbor Provision appears in section 110, which is entitled "State *Implementation* Plans." 42 U.S.C. § 7410 (emphasis added).

The issue at stake now is not the level at which to set air quality standards to safeguard public health and welfare; those levels have already been independently set under section 109(b)(1), and will not be affected by the Transport Rule. Instead, the

Transport Rule is meant to implement those standards in the most cost-effective manner, by efficiently allocating abatement responsibilities between the states. The choice of a cost-effective trading mechanism will not affect the level of air quality achieved, but only the total cost of achieving it. Especially for such provisions that deal with issues of implementation, EPA should have broad discretion to pursue cost-effective and flexible strategies unless specifically prohibited by the plain text of the statute.

Therefore, to the extent that the Good Neighbor Provision is silent on cost considerations, the case is much more analogous to *Entergy* than to *American Trucking*. In *Entergy*, the Court noted that the relevant section was "silent not only with respect to [cost factors] but with respect to all potentially relevant factors. If silence here implies prohibition, then the EPA could not consider *any* factors in implementing [the relevant section]—an obvious logical impossibility." 556 U.S. at 222. Similarly, the Clean Air Act provides no instructions on the criteria EPA should use to determine which state regulations would be "adequate" to implement the Good Neighbor Provision's prohibition on "amounts" of interstate pollution that "contribute significantly to" violations or "interfere with" air quality standards. As in *Entergy*, statutory context suggests that congressional silence on the criteria for implementing the Good Neighbor Provision does not unambiguously prohibit cost considerations. Rather, EPA has discretion to adopt any reasonable interpretation of the statutory language.

Cost-effectively apportioning the states' obligations to achieve air quality standards is a reasonable interpretation of the Good Neighbor Provision. In fact, the plain language, statutory context, and legislative history of the provision offer strong support for interpreting the language with cost-minimization principles in mind. For example, as explored in depth above, Congress explicitly provided that the "adequate provisions" required by the Good Neighbor Provision may utilize cost-minimizing tools like emissions trading. Similarly, the history of interstate emissions programs under the Clean Air Act reveals a consistent legislative intent to rationally weigh economic considerations and a consistent agency interpretation, going back decades, that has emphasized cost-effectiveness criteria.

Of all the terms in the Good Neighbor Provision that may support a reasonable interpretation with respect to cost-effectiveness, particular attention has been given to the phrase "contribute significantly" and especially the word "significant." In holding that "there is nothing in the text, structure, or history of [the Good Neighbor Provision] that bars EPA from considering cost in its application," *Michigan*, 213 F.3d at 679, the D.C. Circuit noted that, "In some contexts, 'significant' begs a consideration of costs." *Id.* at 677. Much like the term "minimize" in *Entergy*, "significant" is a word that "admits of degree." *Cf.* 556 U.S. at 219. There is no clear numerical threshold or percentage increase at which the tons of emissions contributed suddenly and obviously become "significant." Rather, the word has no singular definition, and this Court has ruled that ambiguous terms, like "best," can reasonably be interpreted to mean the lowest cost. *Cf. id.* at 218. As the D.C. Circuit had repeatedly found in prior cases, where a "mandate directed to some environmental benefits is phrased in general quantitative terms ('ample margin of safety,' 'substantial restoration,' and 'major'), and contains not a word alluding to non-health trade-offs[,] . . . the agency [i]s free to consider the costs of demanding higher levels of environmental benefit." *Michigan*, 213 F.3d at 679 (citing *Natural Res. Def. Council v. EPA*, 824 F.2d 1146, 1163 (D.C. Cir. 1987); *Grand Canyon Air Tour Coal. v. FAA*, 154 F.3d 455, 475 (D.C. Cir. 1998); and *Natural Res. Def. Council v. EPA*, 937 F.2d 641, 643-46 (D.C. Cir. 1991)); *see also George E. Warren Corp. v. EPA*, 159 F.3d 616, 623-24 (D.C. Cir. 1998) (holding that EPA's consideration of factors other than air quality, such as the price and supply of gasoline, was permissible under the anti-dumping provisions of the reformulated gasoline program established by the 1990 Clean Air Act Amendments); *cf. Int'l Bhd. of Teamsters v. United States*, 735 F.2d 1525, 1528-29 (D.C. Cir. 1984) (construing mandate to adopt "reasonable requirements" for safety as allowing consideration of cost).

C. The D.C. Circuit Majority Below Substituted Its Own Policy Judgment to Set Aside the Agency's Reasonable Interpretation

While acknowledging that EPA has "significant discretion to implement the good neighbor provision," the D.C. Circuit majority below contends that the statute's text and previous circuit decisions in the *Michigan* and *North Carolina* cases "establish several red lines" that limit how EPA may reasonably interpret the requirements. *EME Homer*

City Generation, 696 F.3d at 19. However, neither text nor previous circuit precedent (nor, indeed, statutory structure nor history) actually mandates the limitations on implementing the Good Neighbor Provision that the majority below imagines. Even if the majority's readings of the text are permissible, they are not the only legitimate interpretations, and they should not trump the agency's own reasonable views on the statute.

For example, the majority asserts that EPA may not consider the cost-effectiveness of pollution controls in ways that violate the statute's purported "proportionality requirement." *Id.* at 26. Under this supposed statutory requirement, the allocation of emissions allowances between states must be proportional to their contributions to a downwind states' nonattainment. *Id.* at 21. The D.C. Circuit created this interpretation based upon its own policy judgment; proportionality is not required by the statutory text and runs contrary to prior D.C. Circuit precedent. As noted above, the *Michigan* court held, "there is nothing in the text, structure, or history of [the Good Neighbor Provision] that bars EPA from considering cost in its application." *Michigan*, 213 F.3d at 679. Moreover, the court observed that allocating reduction requirements solely on the basis of air quality impacts, without considering costs, would vitiate the efficient emissions trading system and would be a result "as extreme as it sounds." 213 F.3d at 676. It further puzzled over how the statutory text could possibly be interpreted to "exclude cost but admit equity." *Id.* at 678. A cost-blind proportionality requirement is also "at odds with *North Carolina* where the court concluded that EPA's measure of significant contribution need not 'directly correlate with each State's individualized air quality impact on downwind nonattainment *relative to other upwind states*.'" *EME Homer City Generation*, 696 F.3d at 59 (Rogers, J., dissenting) (quoting *North Carolina v. EPA*, 531 F.3d 896, 908 (D.C. Cir. 2008) (emphasis added)).

Moreover, the majority below does not address whether its interpretation is practicable. For instance, it fails to explain how proportionality can be determined when multiple upwind states' emissions intermingle and affect multiple downwind states. An upwind state will contribute different proportions of emissions to different downwind states and, therefore, allocating emissions by proportional impact on downwind states would not be feasible.

In short, neither text nor precedent, nor structure nor history imposes a cost-blind "proportionality requirement" on implementation of the Good Neighbor Provision. Congress never required proportionality. Rather, the D.C. Circuit's preference for proportionality is only one possible interpretation of the text. But another possible—and much more reasonable—interpretation of the text is the cost-effectiveness framework applied by EPA. The majority below should not have substituted its own policy judgment for that of the agency.

D. Best Regulatory Practices Confirm That the Cost-Effectiveness Framework Is Not Just Permissible and Reasonable, but Also a Prudent Interpretation of the Good Neighbor Provision

As explored above, Congress has never prohibited using a cost-effectiveness framework to implement the Good Neighbor Provision. Moreover, in light of statutory context and legislative history supporting the minimization of costs through tools like market mechanisms, the cost-effectiveness framework is a reasonable interpretation of any ambiguity in the Good Neighbor Provision. Under *Chevron*, the Court's inquiry should end there: agencies have discretion to adopt permissible and reasonable interpretations, even if they are not necessarily the best policy choices. Still, it is telling that the cost-effectiveness framework, in addition to being permissible and reasonable, is consistent with the administration's broader regulatory goals and best rulemaking practices.

The pursuit of cost-effective regulatory strategies and the use of market mechanisms to minimize costs are required by executive order where not prohibited by statute. Specifically, executive orders instruct federal agencies to "assess both the costs and the benefits of the intended regulation" and "design its regulations in the most cost-effective manner to achieve the regulatory objective," giving due consideration to the advantages of using "economic incentives" like "marketable permits." Exec. Order No. 12,866 §§ 1(b)(3)-(6) & 9, 58 Fed. Reg. 51,735, 51,736, 51,744 (Oct. 4, 1993); *see also* Exec. Order No. 13,563 § 1(b), 76 Fed. Reg. 3821, 3821 (Jan. 21, 2011). Since the Clean Air Act does not prohibit the consideration of costs in implementing the Good Neighbor Provision, the clear presidential preference for cost-effective, incentive-based regulations makes EPA's interpretation a reasonable and prudent one.

In designing the Transport Rule, EPA drew on its decades of experience implementing such economically and scientifically complex interstate air pollution programs. EPA, in partnership with the states, oversees countless environmental programs that all compete for resources. In such circumstances, it is essential to consider and minimize the costs of achieving the desired targets for environmental quality. Cost-effectiveness is all the more critical "in an age of limited resources available to deal with grave environmental problems, where too much wasteful expenditure devoted to one problem may well mean considerably fewer resources available to deal effectively with other (perhaps more serious) problems." *Entergy*, 556 U.S. at 233 (Breyer, J., concurring and dissenting). Moreover, since the Transport Rule addresses only the allocation of responsibility for emissions reductions, not the ambient air quality standards that must be satisfied, it makes little sense to create a compliance framework that results in paying more to achieve a result that could be achieved more cheaply.

CONCLUSION

For the foregoing reasons, the Court should reverse and remand the D.C. Circuit's decision in this case.

Respectfully submitted,

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Nos. 12-1182 and 12-1183

In The
Supreme Court of the United States

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,

Petitioners,

v.

EME HOMER CITY GENERATION, L.P., et al.,

Respondents.

AMERICAN LUNG ASSOCIATION, et al.,

Petitioners,

v.

EME HOMER CITY GENERATION, L.P., et al.,

Respondents.

On Writ Of Certiorari To The United States Court Of Appeals For The District Of Columbia Circuit

BRIEF FOR *AMICI CURIAE* BENJAMIN F. HOBBS, SHMUEL S. OREN, JAMES SWEENEY, AND FRANK WOLAK IN SUPPORT OF PETITIONERS

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INTRODUCTION AND INTEREST OF *AMICI CURIAE*[1]

The Transport Rule at issue in this case primarily targets the electric generation sector because fossil fuel-fired power plants account for two-thirds of the nation's sulfur dioxide emissions and nearly a quarter of the nitrogen oxide emissions.[2] In the majority opinion below, the court appears to fundamentally misunderstand the structure, operation, and economics of the modern electric generating industry. Today's electric power sector is regionally interconnected and highly dynamic – and becoming more so every day. To be environmentally effective and economically efficient, any interstate air pollution rule must account for these essential attributes of the nation's electric grid and the wholesale electricity markets in which generators and utilities participate. Otherwise, tighter controls on one generating facility, or on one state, will merely shift production to another facility or another state. The rigid state-by-state approach imposed by the court of appeals ignores this reality, making it highly unlikely that the Environmental

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[1] Pursuant to Rule 37.6, counsel for *Amici* state that no counsel for a party authored this brief in whole or in part, and that no person other than *Amici* and its counsel made a monetary contribution to the preparation or submission of this brief. All Petitioners and Respondents have filed letters of consent with the Clerk of the Court.

[2] U.S. Environmental Protection Agency, Clean Energy Website, http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html.

Protection Agency ("EPA") can achieve the congressional objectives of the Clean Air Act's "Good Neighbor" provision, 42 U.S.C. § 7410(a)(2)(D), and at the same time virtually certain that it will needlessly impose much higher costs on the broader economy by its attempt.

Amici curiae are electrical engineers, economists, and physicists specializing in the study of electricity, the operation of electric power systems, and the design of wholesale electricity markets. They have an abiding professional interest in the proper regulation of the ever more important electric energy industry.[3]

Amicus curiae Benjamin F. Hobbs is the Theodore M. and Kay W. Schad Professor in Environmental Management in the Department of Geography and Environmental Engineering at Johns Hopkins University. He holds a joint appointment in the Department of Applied Mathematics and Statistics, and directs the Johns Hopkins University Environment, Energy, Sustainability and Health Institute. Professor Hobbs serves as the chair of the California Independent System Operator Market Surveillance Committee and as a consultant to the Pennsylvania-New Jersey-Maryland Independent System Operator, where he developed the methodology it uses to evaluate the capacity market demand curve. From 1995

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[3] *Amici* appear here in their individual capacities as scholars, scientists and engineers and not as representatives of the institutions with which they are affiliated.

until 2002, he was also a consultant to the Federal Energy Regulatory Commission's Office of the Economic Advisor. His academic research focuses on stochastic electric power planning models, multi-objective and risk analysis, mathematical programming models of imperfect energy markets, and environmental and energy systems analysis and economics. He holds a Ph.D. in Civil and Environmental Engineering from Cornell University and is a Fellow at the Institute of Electrical and Electronics Engineers and the Institute of Operations Research and Management Science.

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Fellow at the Stanford Institute for Economic Policy Research, the Hoover Institution on War, Revolution and Peace, the Freeman Spogli Institute for International Studies, and the Precourt Institute for Energy. His research includes depletable and renewable resource use, electricity market analysis, environmental economics, global climate change policy, gasoline market dynamics, energy demand, energy price dynamics, and housing market dynamics. He was a founding member of the International Association for Energy Economics and is a Senior Fellow at the U.S. Association for Energy Economics and a member of the California Council on Science and Technology. Professor Sweeney has been or is a member of numerous committees of the National Research Council and is a lifetime National Associate of the National Academies. He holds a Ph.D. from Stanford University in Engineering and Economic Systems.

Amicus curiae Frank Wolak is the Holbrook Working Professor of Commodity Price Studies in the Department of Economics at Stanford University. He currently directs the Program on Energy and Sustainable Development in the Freeman-Spogli Institute for International Studies and is a Senior Fellow at the Stanford Institute for Economic Policy Research. Professor Wolak's fields of specialization are industrial organization and econometric theory. His recent work studies methods for introducing competition into infrastructure industries – telecommunications, electricity, water delivery and postal delivery services – and on assessing the impacts of these competition policies on consumer and producer welfare. From January 1998 to March 2011, he was the Chair of the Market Surveillance Committee of the California Independent System Operator. Professor Wolak is a visiting scholar at University of California Energy Institute and a Research Associate at the National Bureau of Economic Research. He is also a member of the Emissions Market Advisory Committee for California's Market for Greenhouse Gas Emissions allowances. This committee advises the California Air Resources Board on the design and monitoring of the state's cap-and-trade market for greenhouse gas emissions allowances. He holds a Ph.D. in Economics from Harvard University.

SUMMARY OF ARGUMENT

American dependence upon electric energy has nearly doubled since a Good Neighbor provision, structurally similar to the current one, was added to the Clean Air Act in 1977.[4] The use of the electricity grid as a conveyance of energy from where it is produced to where it can be put to productive use lies at the heart of the U.S. economy. Electricity's share of U.S primary energy was 41 percent in the year 2011.[5]

[4] Energy Information Administration, Annual Energy Review 2011, 221 (2012), *available at* http://www.eia.gov/totalenergy/data/annual/index.cfm.

[5] *Compare id.* at 219, *with id.* at 3.

The modern integrated system of infrastructure, regulation, and markets that conveys electric energy from power plants to consumers is immensely complex, dynamic, and regional.

Most electricity is derived from the combustion at large central station power plants of fossil fuels, including coal, natural gas, and to a lesser degree, oil.[6] An unfortunate byproduct of the fossil fuel combustion process is the substantial emission of air pollutants. A central objective of the EPA and its state partners in implementing the Clean Air Act has been to reduce the contribution of power plant and other combustion to air pollution and its associated public health impacts.

More than 30 years ago, Congress understood that fully resolving the air pollution problem caused by electric power plants would require taking account of the interstate nature of the harm. The tall smokestacks that are such a familiar sight at power plants were initially constructed to reduce local air pollution impacts. They were largely successful in doing so, but had the unintended consequence of spreading pollutants and consequent pollution impacts into downwind air sheds, often in neighboring states. Congress enacted and later revised the Good Neighbor provision of the Clean Air Act to address these cross-border effects.

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[6] *Id.* at 225.

The court of appeals, in interpreting the Good Neighbor provision, imposes several constraints that limit EPA's flexibility in designing a regional response to the interstate air pollution problem. Underlying this interpretation are assumptions that power plant operations are static and controlled at the state level. Unfortunately, those assumptions fail to appreciate the dramatic developments that have occurred over the past 40 years in the physical and governance structure of the U.S. electric power system.

Today, dynamic, regional, wholesale electric power markets operate via a highly interconnected transmission network that extends seamlessly across state boundaries. Because regional competition between power plants determines which plants operate, and the imposition of pollution controls changes individual power plant operating costs, the rigid state-by-state approach dictated by the court of appeals is destined to create numerous unintended consequences that may well undermine the overall pollution control effort.

Both before and since the last modification of the Good Neighbor provision in 1990, Congress has repeatedly enacted legislation aimed at empowering the Federal Energy Regulatory Commission ("FERC") to foster regional, competitive, wholesale markets for electric energy. Congress must have intended any solution to the regional air pollution problem to take account of the physical, regulatory, and economic structure of the electric power system that is its primary cause. As scholars specializing in the design of the U.S. electric power system, *Amici* respectfully submit this brief to aid the Court in understanding the structure of the modern electricity system and the constraints it places on resolving regional air pollution problems in the United States.

Below, we describe these physical, regulatory, and economic developments in sufficient detail to illustrate the misunderstandings upon which the court of appeals predicated its decision. Then we explain how the interpretation of the Good Neighbor provision articulated by the lower court, when applied to an accurate view of the U.S. electricity system, would most likely prevent EPA from eliminating interstate air pollution harms and would almost certainly result in significant waste of economic resources with no attendant environmental benefits. These additional costs will be imposed not just on electricity generators, but also on the firms and households that consume electricity in the broader U.S. economy.

ARGUMENT

I. The Unique Attributes of Electricity Have Slowly and Inexorably Shaped the Regional Infrastructure and Wholesale Markets that Exist Today.

A. The Fundamental Properties of Electricity Make It Different in Kind from Direct Energy Sources.

Electricity is different from other kinds of energy. To turn on a light, we don't need the source of the energy to be located in the same place. Electricity is the means of conveying energy rather than a source of it; it provides an efficient way to separate the harnessing of energy from its use. This ability to separate the point of generation from the point of end use provides the basis for our complex modern economy as well as the need for the electrical transmission system. It also profoundly affects how energy markets function today.

Thermal power plants are the primary way we convert stored energy into electricity. They consume fossil or nuclear fuel to boil water and use the resulting steam to turn a turbine generator.[7] The spinning generator induces an electrical current in a wire that is then propagated away from the generating plant through transmission lines. In an alternating current

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[7] Other energy sources operate on the same principle. Blowing wind turns the turbine on a windmill and falling water spins the turbine at a hydroelectric plant.

system like the one used in the United States, the direction of the electromagnetic wave reverses 120 times per second. Thus, the electrons do not flow from the power plant to the end user, as commonly believed. Rather, they oscillate more or less in place inside transmission wires, causing a wave of energy – or electric current – to flow through the wire, much like energy is transmitted when one billiard ball strikes another, when sound travels through air, or when a wave crosses the ocean.

The physics of electricity generation make it possible to move energy long distances from power plants to end users, but also pose two important challenges for the operators of electric grids. First, unlike water or fossil fuel, electricity cannot be stored economically for most uses with current technologies. Thus, the generation of electricity at power plants must be continuously balanced against the consumption of electricity drawn out of the system by end users, known as "load." In effect, "[e]lectricity is the ultimate 'just in time' manufacturing process, where supply must be produced to meet demand in real time."[8]

Second, electricity does not necessarily flow from a generator at Point A to a consumer at Point B.

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[8] Paul Joskow, *Creating a Smarter U.S. Electricity Grid*, 26 J. Econ. Perspectives 29, 33 (Winter 2012), *available at* http://pubs.aeaweb.org/doi/pdfplus/10.1257/jep.26.1.29.

Under basic physical laws, electricity distributes itself along the path of least resistance. This means that on an interconnected transmission network or grid, when electricity is consumed at one point in the system (by turning on an electric appliance, for example), power rushes in from surrounding points to reestablish equilibrium across the system.

These unique properties of electricity require careful and constant balancing of the energy load to ensure reliability. When demand increases in one area, the resulting imbalance across the system can cause cascading network failures leading to black-outs. Because there are currently no cost-effective means of storing large quantities of electric energy, grid operators must balance energy supply and demand on a variety of timescales ranging from seconds to decades in order to maintain equilibrium across the network. Different solutions, ranging from second-to-second matching of supply and demand via automatic control of power plants to long-range planning for power plant and transmission adequacy have been developed to address this challenge.

Critical to these load balancing efforts is the ability to coordinate operations between electricity networks. Regional interconnection provides a cost-efficient way to address load and reliability concerns, allowing energy to flow readily to areas of high demand and avoiding system-wide breakdowns.

B. The Need for Reliability and Efficiency of Centralized Electricity Generation Led to Today's Highly Interconnected System.

The basic physical attributes of electricity have, in large part, shaped the electric power system we enjoy today. From an early crazy-quilt of small, local generators powering such urban uses as hotels and stores in downtown business districts, visionary entrepreneurs – most notably, former Edison employee Samuel Insull – developed a business model to centralize electric power generation and transmit electricity over copper wires to end users. That model was built on the development of alternating current, which allowed electricity to be transmitted at higher voltage (or "pressure") with much reduced energy losses, and on the invention of the transformer, which allowed electric current running long distances through high voltage power lines to be "stepped down" to a lower voltage for safe delivery to consumers. With the economies of scale provided by these developments, centralized generators were able to compete against – and eventually out-compete – local distributed generation and gas lamps, forming what we know today as investor-owned utilities.[9]

The rise of centralized power generation in the late 1800's and early 1900's led to "vertically integrated

[9] A full discussion of these developments can be found in Harold L. Platt, *The Electric City* (Univ. of Chicago Press, 1991).

utilities that had constructed their own power plants, transmission lines, and local delivery systems." *New York v. F.E.R.C.* , 535 U.S. 1, 5 (2002). "Although there were some interconnections among utilities, most operated as separate, local monopolies subject to state or local regulation." *Id.* Under this regime, dispatch decisions were made within a single utility's system, which was limited by the Public Utility Holding Company Act to a single state. Formerly codified at 15 U.S.C. § 79 *et seq.*[10]

Fairly early in the development of the electricity industry, however, the state-centered approach began to break down, as utilities sought to enhance reliability and efficiency by interconnecting with adjacent utility networks, raising issues about the reach of state regulatory and rate-setting authority. *See Public Utilities Comm'n of Rhode Island v. Attleboro Steam and Electric Co.*, 273 U.S. 83 (1927) (addressing Rhode Island's ability to regulate prices of electricity generated in-state and delivered over interconnecting transmission lines to a utility in Massachusetts).

In recognition of the growing interconnectivity of electricity transmission, Congress enacted the Federal Power Act of 1935. The Act charged the Federal Power Commission, the predecessor to FERC, with jurisdiction over "the transmission of electric energy in interstate commerce" and "the sale of electric

[10] This statute was ultimately repealed by the 2005 Energy Policy Act.

energy at wholesale in interstate commerce." 16 U.S.C. § 824(b). Over the next several decades, the electricity grid became increasingly interconnected across states, and technological advances both diversified the sources of electricity generation and reduced the cost of long-distance transmission. Thus, more power plants developed and began serving more distant areas. *New York v. F.E.R.C.,* 535 U.S. at 7.

Today, most electricity in the continental United States is delivered over two major grids, the "Eastern Interconnect" and the "Western Interconnect," which are weakly connected to each other.[11] As a result, outside of Texas, "any electricity that enters the grid immediately becomes a part of a vast pool of energy that is constantly moving in interstate commerce." *New York v. F.E.R.C.*, 535 U.S. at 7, 9. A wholesale electricity customer in one state can now purchase electricity from a power producer in a neighboring state without difficulty.

The Court has long recognized the benefits of interconnection:

> The demand upon an electric utility for electric power fluctuates significantly from hour to hour, day to day, and season to season. . . . [T]he utility's generating capacity must be

[11] Most of Texas is covered by a separate grid operated by the Electricity Reliability Council of Texas. This grid maintains limited interconnections with other states in order to avoid Federal Power Act jurisdiction.

> geared to the utility's peak load of demand, and also take into account the fact that generating equipment must occasionally be out of service for overhaul, or because of breakdowns. . . . The major importance of interconnection is that it reduces the need for the "isolated" utility to build and maintain "reserve" generating capacity.

Gainesville Utilities v. Florida Power Corp., 402 U.S. 515, 517 (1971).

The present interstate grids are the result of nearly a century of deepening interconnection. They are massive spider webs of high-voltage transmission lines allowing energy to flow across thousands of miles. Consequently, the electricity that consumers enjoy in their homes and businesses is increasingly generated at distant power plants, sometimes many states away. The regional nature of the transmission system and the fact that power plants do not tend to be sited near urban areas where most consumers live means that dependable electricity for consumers in one place is bound up with decisions about when to run a power plant hundreds of miles away. A large coal-fired power plant in Indiana, for example, can produce electric energy to balance New York City's energy consumption.

In short, the nature of electricity generation, transmission, and distribution changed dramatically over the first century of the sector's development. While consumers once received power from a relatively close source, electricity transmission is no longer characterized by isolated fiefdoms limited in extent to the territory of one state.

C. Recent Legislative and Regulatory Changes Paved the Way for the Modern Regional Wholesale Electricity Markets.

Congress and FERC have responded to these profound structural changes with a regulatory regime intended to facilitate competitive, efficient, and reliable regional electricity markets. Since passage of the Federal Power Act, the federal government has become increasingly involved in shaping wholesale electricity markets. As technological advances led to diversified electric generating sources and long distance transmission across state lines, federal laws and regulations evolved to keep pace, laying the foundation for our contemporary regional electricity dispatch system.

Spurred originally by the energy crises of the 1970's, Congress initiated a series of steps that have led to the dynamic, regional wholesale markets for electric energy that exist today. First, Congress enacted the Public Utility Regulatory Policies Act of 1978 ("PURPA"). 16 U.S.C. § 2601 *et seq.* By requiring utilities to purchase electricity from nontraditional suppliers (qualifying cogeneration and small power production facilities), PURPA created, for the first time, an obligation on the part of vertically integrated utilities to purchase energy at wholesale from non-affiliated entities.[12]

Congress continued to influence energy markets with enactment of the Energy Policy Act of 1992 ("EPAct 1992"), which compelled utilities to provide transmission services to unaffiliated wholesale generators on a case-by-case basis. 16 U.S.C. §§ 824j-824k.[13] Concluding that individual proceedings to enforce EPAact 1992 were too costly and time-consuming, FERC in 1996 promulgated Orders 888 and 889, which require public utilities that own high voltage transmission systems to offer non-discriminatory open access transmission service. *New York v. F.E.R.C.*, 535 U.S. at 10-11.

The structure of the power industry evolved significantly in response to these regulatory changes. Integrated utilities divested their generating assets, and new market participants emerged, including independent and affiliated power marketers, which do not own or operate any electric facilities but buy and sell electricity on the open market, and independent power producers (or "merchant generators"), which sell electricity to utilities but are not themselves regulated as a public utility. Regional

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[12] PURPA did so by directing FERC to promulgate rules requiring these utility purchases.

[13] EPAct 1992 similarly operated by directing FERC to order utilities to provide these transmission services.

Transmission Organizations, Order No. 2000, 89 FERC 61,285 at *7 (Dec. 20, 1999).

To manage the many new entrants and increasingly complex market structure, FERC attempted to organize owners of transmission lines into Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs") as a way to promote grid reliability and to guard against the improper exercise of market power in the provision of transmission services. These independent, non-profit entities are charged with operating a high voltage transmission network owned by utilities in a way that allows open and equal access; they also administer electricity markets that match supply and demand in real time to maintain reliability across the network.[14]

These novel transmission governance structures have given rise, in turn, to the large regional electricity markets that exist today. The Pennsylvania-New Jersey-Maryland Interconnection ("PJM") is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The Midcontinent Independent System Operator ("MISO")

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[14] *See generally*, Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update* (1997), *available at* http://books.google.com/books?id=C5W8uxwMqdUC&printsec=frontcover&source=gbs_ge_summary_r&cad=0#v=onepage&q&f=false.

is an ISO/RTO that provides open access transmission and real-time load balancing services throughout the Midwest, including all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, Illinois, Indiana, Michigan, and parts of Montana, Missouri, Kentucky, and Ohio. ISO New England is an RTO serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. In addition, New York, California and Texas all have ISOs covering multiple utility service territories. Even in areas where ISOs or RTOs have not been established, supply and demand on the high voltage transmission network are balanced via less centrally coordinated organizational structures called power pools.

The crucial operational difference between ISOs or RTOs and power pools is in how power plants are dispatched to meet demand. In ISOs or RTOs, the grid operator manages a series of energy auctions, selecting bids from generators to sell electric energy necessary to meet forecast demand on the system. All accepted bids are paid the price offered by the highest accepted bid. This approach is known as bid-based dispatch. By contrast, in power pools, the grid operator dispatches power plants based upon the estimated operating costs of the power plants on the system. The power plants with lowest operating costs are dispatched first while those with higher operating costs are dispatched only when demand peaks. This approach is known as cost-based dispatch. In either case, underlying power plant economics determine which generators are directed to turn on and which sit idle on any given day.

This regionalization of electricity market structures continues. Recently FERC issued Order No. 1000, which requires regional transmission planning and cost allocation on the part of all utilities, whether or not they are a participant in an organized wholesale market. And several states now require that their utilities be part of an ISO or RTO. At the same time, PJM and MISO, the two largest multi-state RTOs, are in renewed discussions and planning efforts to form a joint and common energy market that would cover all or part of 23 states and the District of Columbia.[15] Similar efforts at greater regional coordination are also ongoing in the Western Interconnect where the California ISO and PacificCorp, a neighboring utility, are forming an "Energy Imbalance Market" aimed at trading excess supply and demand across system interties. Order Accepting Implementation Agreement, 143 FERC 61,298, at *1 (June 28, 2013).

In short, just as the electricity grid has become physically interconnected over the past century, so too has the regulatory structure that controls its operations. This process has transformed the electric

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[15] *See* 2012 PJM-MISO Joint and Common Market Initiative, *available at* http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx.

system from one that is driven by local imperatives to one that can respond quickly to changes in either supply or demand conditions across regions. Because the Transport Rule will create just such an economic change in supply, it is essential that it take account of the modern regulatory setting.

II. Today's Regional Electricity Markets Are Inconsistent with the Constraints Posed by the Court of Appeals Decision.

A. Modern Wholesale Electricity Markets Are Regional In Nature.

Modern wholesale electricity markets reflect the unique nature of electricity, the current physical structure of the U.S. electric system, and the legislative and regulatory history described above. Demand "varies widely from hour to hour," but electricity supply and demand must remain balanced for the grid to operate.[16] In many areas of the country, including many areas affected by the Transport Rule, organized wholesale electricity markets determine, through generator bids, which power plants will generate energy (or "dispatch") to facilitate this supply and demand balance. In less tightly organized power

[16] S. Hunt, *Making Competition Work in Electricity* 32 (John Wiley & Sons, Inc., New York) (2002).

pools, plants are dispatched on an estimated marginal cost basis.[17]

Regardless of whether high voltage transmission is governed by an organized ISO/RTO or through a less centrally coordinated power pool, system operators uniformly rely on economics to determine which power plants to dispatch or turn on.[18] In general, cheaper plants – those with lower marginal operating costs – come on line first. In electricity market terminology, this means that "base load" plants, with high capital costs but the lowest marginal operating costs, are called first, along with renewable energy producers that have no fuel costs; "intermediate load" plants with lower capital costs but higher marginal operating costs are called next; and finally "peaking" capacity plants, with the lowest capital costs but highest marginal operating costs, are called last, when demand peaks.[19]

A simplified example of modern dispatch procedures illustrates how this coordination of dispatch via economics works. On any given day, the PJM system operator could call on a power plant in Ohio, then New Jersey, then Maryland to supply the energy

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[17] *See, e.g.*, United States Department of Energy: Solar Energy Technologies Program, *The Role of Electricity Markets and Market Design in Integrating Solar Generation* 1, Solar Integration Series, May 2011, *available at* http://www1.eere.energy.gov/solar/pdfs/50058.pdf.

[18] Joskow, *Creating a Smarter U.S. Electricity Grid* at 33.

[19] *See, e.g.*, *id*.

needed to meet demand for electricity in the District of Columbia. The operator would make these dispatch decisions based on the generator bids offered in an auction and any binding transmission constraints, also called congestion prices, that exist within the high voltage transmission network. Transmission constraints are generated when a transmission link between two areas of an electricity network is insufficient to allow the lowest cost supply of energy in one to serve demand in the other. Organized wholesale electricity markets produce shadow prices called congestion prices that reflect these physical transmission constraints. Ultimately, dispatch decisions are made based upon the marginal bid for power needed to meet demand plus any congestion price that applies.

At night, the Ohio plant might be called to serve the District of Columbia demand because congestion on the system is low and it is the most economical resource. On a hot summer afternoon, with many air conditioners running at full power, congestion on the network might limit the ability of energy to flow such distances. In response, PJM might instead dispatch nearby resources in Maryland that have higher marginal bids but lower congestion prices to serve demand in the District of Columbia.

In sum, operational decisions in PJM, like other organized wholesale markets and to a lesser degree the power pools, occur through a regional process that is driven by the underlying physics and economics of generation and transmission, combined with the modern scale of electricity market structures. As a consequence, these decisions often do not respect state jurisdictions. Were EPA to craft a Transport Rule that treated state electric systems as isolated and ignored the realities of modern multi-state wholesale electricity markets, these markets would quickly respond to and quite possibly undo many of the Transport Rule's intended outcomes.

B. The Lower Court's Interpretation of the Good Neighbor Provision Is Incompatible with the Physical, Regulatory, and Economic Operation of the U.S. Electric System.

Because the electricity sector is now highly regionalized in both physical structure and operational management, regulatory interventions with significant economic effects cannot be isolated to a single state, just as ripples in a pond spread to its furthest edge. In drawing several "red lines" which EPA cannot cross in implementing the Good Neighbor provision of the Clean Air Act, the court of appeals failed to appreciate these basic facts about the modern U.S. electric system. As a result, the court placed an unnecessary burden upon both EPA and the firms and households that must ultimately bear the economic costs of its regulation.

In concluding that EPA cannot compel an upwind state to eliminate more than its current contribution to a downwind state's nonattainment problem, the court of appeals made a seriously flawed threshold assumption that an upwind state's contribution is fixed. This assumption is simply wrong as a matter of fact. Today's highly interconnected and dynamic regional wholesale electricity markets – markets that adjust "hour by hour" – will alter dispatch as marginal costs change in response to regulatory requirements. This is true irrespective of whether the markets in question utilize a bid-based or cost-based dispatch system. The court's holding would force EPA to ignore these realities and behave as if the dramatic developments in the U.S. electric system over the last half century had not occurred.

In contrast, the Transport Rule that EPA adopted recognizes the realities of the current highly dynamic regional electricity market. It allocates responsibility for emission reductions at the regional level, based upon the availability of cost-effective pollution reduction opportunities at power plants. EPA's approach makes very good sense once one considers how the U.S. electric system operates and how it will respond to the imposition of additional pollution controls at power plants.

Moreover, a regional, market-based allocation of responsibility has the additional benefit of minimizing the costs of resolving the regional air pollution problem. By attempting to allocate the emissions reduction burden to the least-cost providers of reductions, the Transport Rule minimizes costs even if one or more states elects not to join the proposed EPA trading program.

At bottom, a requirement that a state reduce pollutant emissions from electricity production will increase marginal operating costs at power plants within its borders because they will install new pollution controls or burn more expensive, lower sulfur coal, or operate for fewer hours during the year. Changes in marginal operating costs will, in turn, affect regional dispatch decisions, whether that dispatch is bid-based or cost-based.

To take a simple example, suppose a power plant in State A is cheaper to operate than a plant in State B under the present regulatory regime, meaning that power will be dispatched from the plant in State A before the plant in State B, all else being equal. If new pollution controls alter the relative economics such that the plant in State A now becomes more expensive to operate than the plant in State B, the regional grid operator will now call power from the plant in State B, without regard to state boundaries, assuming for purposes of this simple example that there are no constraints that generate congestion prices. In this way, the state in which air pollution is generated, and the relative contribution to downwind nonattainment problems, is shifted due to regional operation of the wholesale electricity market. The lower court forbids EPA to account for these shifts because it mandates a focus on ex-ante upwind state-by-state contributions to downwind state nonattainment.

A state-centric pollution control regime, such as the one directed by the court of appeals, will have serious difficulty adjusting to the dynamics of today's regional markets. This is particularly the case given the specific instructions of the court of appeals that EPA must rely on its static estimates of upwind state contribution to downwind state nonattainment. EPA might get lucky in allocating pollution burdens in a way that did not lead simply to a shift in the location of the pollution burden, or it might opt to overcontrol in all upwind states in order to guarantee elimination of the regional air pollution problem in downwind states, irrespective of any shift in the location of generation and consequent air pollutant emissions. But either solution will be far inferior – from an economic efficiency and pollution control perspective – to the sophisticated regional power plant emissions approach that EPA has crafted.

There are no doubt multiple means for allocating responsibility for the regional air pollution problem created by power plant emissions. But doing so in a way that rigidly adheres to state boundaries and ignores power plant economics makes little sense. As EPA understood,[20] regional markets for wholesale electric energy will adjust to any new costs imposed

[20] EPA investigated this issue by using the Integrated Planning Model ("IPM") to assess its rulemaking. IPM is a complex model of the U.S. electricity system that simulates power plants, transmission constraints, and the regional structure of U.S. electricity markets. *See* EPA, *Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model,* at 2-9 (Aug. 2010), *available at* http://www.regulations.gov/ #!documentDetail;D=EPA-HQOAR-2009-0491-0309.

on power plants in ways that are not constrained by state lines.

The court of appeals spelled out in some detail how it believed that EPA should allocate responsibility for interstate pollution problems using hypotheticals. *EME Homer City,* 696 F.3d 21. These hypotheticals usefully illustrate the court's misunderstanding of power system structure and power market operations. Consider the example the court proprovides of a downwind state that receives significant contributions to its nonattainment from three upwind states. In the court's hypothetical, each upwind state contributes 20 units of pollution to downwind state air, which itself exceeds attainment by 50 units. *Id.* The court believes that the proper procedure for EPA to take in this instance is simply to tell each upwind state to reduce its emissions by 16 2/3 units of pollution, thus resolving the downwind air pollution problem. *Id.*

This "solution" assumes both that the states' grids are not interconnected with each other and that electricity markets are not regional. It ignores the fact that regional electricity markets are likely to redistribute the 50 units of air pollution over the interstate high voltage transmission network in ways that may partially or totally undermine the effectiveness of the strategy.

For example, imposing costs in this simplistic fashion may cause pollution reductions in two of the upwind states, but actively increase pollution in the third as a result of changes in relative bids into the wholesale market by generators. It may also cause emissions to *increase* in the downwind state for similar reasons. It may even cause emissions to shift from the downwind state to one or more of the upwind states. In short, predicting the outcome of a particular regulatory intervention requires EPA to think in terms of the physical and economic structure of the present electric power system, not in the simplistic and anachronistic fashion that animated the court of appeal's hypothetical. Because the court fails to consider that electricity markets will respond dynamically to imposition of new pollution controls, it believes it can substitute its relatively simple solution for the sophisticated modeling supplied by EPA.

In the real world, a power plant's total emissions depend on both the plant's emissions rate and the number of hours the plant operates. The state imposes pollution controls that impact the plant's emissions rate and marginal operating cost, but the state does not directly determine how frequently the plant is dispatched. That operational decision is a wholesale market-driven effect, not one orchestrated by each state. And the wholesale markets in question are almost entirely regional, not state-delimited or state-controlled. Even if a state were to mandate reductions in total emissions at one of its power plants, the effect would be to shift energy production for the regional system to another power plant, either within that state or in a neighboring state. The effect is similar to squeezing a balloon in one's hand. The majority opinion below ignores this reality, much to the detriment of the impacted populations and regional electricity prices.

Further, given that EPA cannot compel state participation in its regional cap-and-trade market, allocation of pollution burdens based upon each upwind state's contribution to downwind state nonattainment is likely to lead to highly inefficient and hence unnecessarily costly outcomes. States that face low marginal abatement costs relative to their neighbors may well opt not to participate in the trading program. This would leave states that face high marginal abatement costs with little flexibility and far higher overall costs. At the national level, this outcome would generate far higher societal costs but identical pollution levels. Thus, utilizing the rigid, state-by-state allocation mandated by the court of appeals creates state-level incentives that are likely to reduce the cost effectiveness of EPA's approach.

By contrast, under EPA's cost-based allocation approach, whether or not states opt to participate in emissions trading, actions taken by power plants within individual states are far more likely to approximate the cost minimizing solution. While *Amici* recognize that cost-effectiveness alone cannot dictate interpretation of the Good Neighbor provision, we urge the Court to consider the difference in economic outcomes between the lower court's and EPA's views of the law. In our opinion, the difference is likely to be substantial.

Without endorsing any particular methodology for selecting states or for allocating pollution reduction burdens across them, *Amici* urge the Court to defer to EPA's expertise in implementing the Good Neighbor provision consistent with the realities of the modern multi-state electric power system. Allowing the agency sufficient flexibility to design a program with a regional focus is the optimal way to ensure that all states act as good neighbors in their implementation of air pollution controls. It is also the most effective way EPA has to minimize the costs of such a program. The decision below, by requiring a static, rigid, state-by-state approach to regional air pollution problems, is very likely to frustrate the statutory objective of the program and virtually certain to result in needless costs to electricity consumers. In contrast, by tailoring regulation to the facts on the ground, EPA's regional approach provides the greatest assurance that interstate causes of nonattainment of air quality standards will be cost effectively eliminated.

CONCLUSION

For the foregoing reasons, *Amici* urge the Court to reverse the misinformed decision below.

Respectfully submitted,

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Nos. 12-1182 and 12-1183

In the Supreme Court of the United States

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, ET AL., PETITIONERS
v.

EME HOMER CITY GENERATION, L.P., ET AL., RESPONDENTS

AMERICAN LUNG ASSOCIATION, ET AL., PETITIONERS
v.

EME HOMER CITY GENERATION, L.P., ET AL., RESPONDENTS

On Writs of Certiorari to the U.S. Court of Appeals for the D.C. Circuit

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BRIEF OF *AMICUS CURIAE* CONSTITUTIONAL ACCOUNTABILITY CENTER IN SUPPORT OF PETITIONERS

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INTEREST OF *AMICUS CURIAE*

Amicus Constitutional Accountability Center (CAC) is a think tank, public interest law firm, and action center dedicated to fulfilling the progressive promise of our Constitution's text and history. CAC works in our courts, through our government, and with legal scholars to improve understanding of the Constitution and preserve the rights and freedoms it guarantees. CAC has a strong interest in preserving the balanced system of government laid out in our nation's charter and accordingly has an interest in this case. *Amicus* submits this brief to demonstrate that the text, history, and structure of the Constitution all strongly support Congress's power to enact laws that address genuinely national problems like interstate air pollution and, in turn, bolster the Environmental Protection Agency's authority to deal with this complex problem, including through its recently enacted Transport Rule.[1]

INTRODUCTION AND SUMMARY OF ARGUMENT

In the early days of the American Republic, the young nation faced a multitude of difficulties—a woefully underfunded army and navy, uncertain day-to-day funding of the federal government, and disa-

[1]Pursuant to Supreme Court Rule 37.6, *amicus curiae* states that no counsel for a party authored this brief in whole or in part, and no party or counsel for a party made a monetary contribution intended to fund the preparation or submission of this brief. No person other than *amicus curiae* or its counsel made a monetary contribution to its preparation or submission. Pursuant to Supreme Court Rule 37.3, *amicus curiae* states that all parties have consented to the filing of this brief; letters of consent have been filed with the Clerk of the Court.

greements among the States on everything from debt to commerce to meeting treaty obligations. Unfortunately, the nation, then bound by the Articles of Confederation and its ineffectual model of central government, also lacked a national government with sufficient power to address these challenges, which transcended State lines and implicated a national interest the federal government was not yet empowered to protect.

Today, our nation faces new problems that spill across State lines and affect the public interest of the country as a whole, including the scourge of air pollution at the heart of this case. Fortunately, our enduring Constitution conveys ample federal power to address these problems.

When the Framers came to Philadelphia, the failures of the Articles were fresh in their minds. In considering the scope of power necessary to establish a national government capable of meeting the task of governing the United States, the Constitutional Convention delegates adopted Resolution VI, which declared that Congress should have authority "to legislate in all Cases for the general Interests of the Union, and also in those to which the States are separately incompetent, or in which the Harmony of the United States may be interrupted by the Exercise of individual legislation." 2 THE RECORDS OF THE FEDERAL CONVENTION OF 1787 at 131-32 (Max Farrand, ed., rev. ed. 1966). The principle of Resolution VI was translated into constitutional provisions—specifically, the powers granted to Congress in Article I—affording the federal government the ability to provide national solutions to national problems.

Interstate air pollution is a quintessential example of the sort of problem that implicates "the general Interests of the Union," in which "the States are separately incompetent," and as to which "the Harmony of the United States may be interrupted by the Exercise of individual legislation." Air pollution does not respect State lines, and emissions from one State may cause harm in another (with little cost to the emitting State). For more than 50 years, the federal government has sought to mitigate interstate air pollution and promote healthy air quality through the Clean Air Act ("CAA"), 42 U.S.C. 7401 *et seq.*, and implementing regulations from the Environmental Protection Agency ("EPA").

The Cross-State Air Pollution Rule at issue here—commonly referred to as the Transport Rule—is the government's most recent attempt to mitigate the spillover effects of air pollution. The EPA promulgated the Transport Rule to address the emission of pollutants in 27 upwind States that significantly contribute to the problem that downwind States have attaining certain air quality standards. As argued persuasively by the Petitioners, the Transport Rule is a reasonable interpretation and application of the CAA.

Nonetheless, the court of appeals threw out the Transport Rule, blatantly interfering with the federal government's attempt to solve the complex interstate problem of air pollution—a challenge that is precisely the sort of national issue the architects of our constitutional system of government intended Congress to solve. Particularly remarkable is the lower court's willingness to, as Judge Rogers explained in her dissent, engage in "a redesign of Congress's vision of cooperative federalism between the States and the federal government in implementing the CAA," Pet. App. at 65a, based on the panel's own policy preferences and without any basis in the factual record, the controlling statute, or relevant precedent.

Quite contrary to the court of appeals' suggestion that the Transport Rule transgresses the "federalism bar," Pet. App. at 56a, the CAA and the Transport Rule are perfect examples of how the federal government can use its constitutionally granted authority to solve complex interstate problems while respecting the role of the States in our federalist system. Under the CAA, the EPA establishes national air quality standards, including requirements aimed at the spillover effects of air pollution, while leaving the States flexibility to implement their own clean air policies that meet these federal standards. It is only *after* individual States fail to satisfy these requirements—as was the case here—that the CAA imposes a duty on the federal government to intervene and design implementation plans of its own, which is exactly what the EPA did when it created the Transport Rule.

Our Constitution establishes a vibrant system of federalism that gives broad power to the federal government to act in circumstances in which a national approach is necessary or preferable, while reserving a significant role for the States to craft innovative policy solutions reflecting the diversity of America's people, places, and ideas. The CAA and the Transport Rule respect the balance of power the Constitution strikes between the federal government and the States. Unfortunately, the court of appeals failed to respect the limits placed on its role in this process, overstepping jurisdictional limitations and reworking Congress' statutory scheme and vision of cooperative federalism in the CAA. *Amicus* urges this Court to reverse the decision below and uphold the EPA's Transport Rule as a reasonable effort to carry out its duties under the CAA.

ARGUMENT

I. The Federal Government Has Ample Authority To Regulate Problems That Implicate The National Interest And Cross State Lines, Such As Air Pollution.

The desire to ensure that the United States' national government was furnished with constitutional authority to address truly national problems was perhaps the most important motivation for our Framers to return to the drawing board in the summer of 1787 and craft our enduring Constitution.

Our Constitution was drafted "in Order to form a more perfect Union" —both more perfect than the British tyranny against which the founding generation had revolted and more perfect than the flawed Articles of Confederation under which Americans had lived for a decade since declaring independence. The result was a vibrant federalist system that empowers the federal government to provide national solutions to national problems —including complicated interstate problems such as air pollution —while preserving a significant role for State and local governments to exercise general police power and craft policies "adapted to local conditions and local tastes." Michael W. McConnell, *Federalism: Evaluating the*

Founders' Design, 54 U. CHI. L. REV. 1484, 1493 (1987).

While some have portrayed the Constitution as a document that is primarily about limiting government, the historical context shows that the Founders were just as, if not more, concerned with creating an empowered, effective national government than with setting stark limits on federal power. *E.g.*, THE FEDERALIST NO. 3, at 36 (John Jay) (Clinton Rossiter, ed. 1999) (noting Americans' agreement on "the importance of their continuing firmly united under one federal government, vested with sufficient powers for all general and national purposes").

By the time our Founders took up the task of drafting the Constitution in 1787, they had lived for nearly a decade under the dysfunctional Articles of Confederation. The Articles, adopted by the Second Continental Congress in 1777 and ratified in 1781, established a confederacy built merely on a "firm league of friendship" among thirteen independent states. ARTICLES OF CONFEDERATION (1781), art. III. Without any serious federal oversight, States often "acted individually when they needed to act collectively." Robert D. Cooter & Neil S. Siegel, *Collective Action Federalism: A General Theory of Article I, Section 8*, 63 STAN. L. REV. 115 (2010). There was only a single branch of the national government, the Congress, which was made up of State delegations. ARTICLES OF CONFEDERATION, art. V. Under the Articles, Congress had some powers, but was given no means to execute those powers.

This created such an ineffectual central government that, according to George Washington, it nearly cost Americans victory in the Revolutionary War. *See*

18 THE WRITINGS OF GEORGE WASHINGTON 453 (John C. Fitzpatrick, ed. 1931) (Letter to Joseph Jones, May 31, 1780). *See also* WASHINGTON: WRITINGS 393 (John Rhodehamel, ed. 1997) (Circular to State Governments, Oct. 18, 1780). Congress was only able to ask the States to send troops and money to the war cause, but the States were often loathe and late to send such support. *See id.* at 488 (Letter to Alexander Hamilton, March 4, 1783) ; AKHIL REED AMAR, AMERICA'S CONSTITUTION: A BIOGRAPHY 45-46 (2005) (noting that, in the United States as it existed under the Articles, "the individual states could not be trusted to provide their fair share of American soldiers and the money to pay them").

The inadequacy of the central government of the Articles was not merely a military problem. The government could not ensure compliance with international treaties; after America's 1783 peace treaty with Britain, individual States failed to honor parts of the treaty. *Id.* at 47. Without the power to impose taxes, Congress could not regulate the currency or control inflation effectively, nor could it secure the country's long-term credit. Larry D. Kramer, *Madison's Audience*, 112 HARV. L. REV. 611, 619 (1999). The nation could not adequately address civil unrest; indeed, the difficulty Massachusetts had in quelling Shay's Rebellion in 1786 further convinced Washington of the great need for improving upon the Articles of Confederation: "What stronger evidence can be given of the want of energy in our governments than these disorders? If there exists not a power to check them, what security has a man of life, liberty, or property?" 4 THE PAPERS OF GEORGE WASHINGTON: CONFEDERATION SERIES 332 (W.W. Abbot et al., eds. 1992) (Letter to James Madison, Nov. 5, 1786).

As Washington explained to Alexander Hamilton, "unless Congress have powers competent to all *general* purposes, that the distresses we have encountered, the expences we have incurred, and the blood we have spilt in the course of an Eight years war, will avail us nothing." *Id.* at 490 (Letter to Alexander Hamilton, March 4, 1783) (emphasis in original). *See also id.* at 519 (Circular to State Governments, June 8, 1783) ("[I]t is indispensible to the happiness of the individual States, that there should be lodged somewhere, a Supreme Power to regulate and govern the general concerns of the Confederated Republic, without which the Union cannot be of long duration.").

Fortunately, when the Framers assembled in Philadelphia for the Constitutional Convention in 1787, they sought to remedy the failures of the Articles and establish a government with sufficient power to govern the United States. In considering how to grant such power to the national government, the delegates adopted Resolution VI, which declared that Congress should have authority "to legislate in all Cases for the general Interests of the Union, and also in those Cases to which the States are separately incompetent, or in which the Harmony of the United States may be interrupted by the Exercise of individual legislation." 2 THE RECORDS OF THE FEDERAL CONVENTION OF 1787 at 131-32 (Max Farrand, ed., rev. ed. 1966). *See also Nat'l Fed'n of Indep. Bus. v. Sebelius*, 132 S. Ct. 2566, 2615 (2012) (Ginsburg, J., concurring in part and dissenting in part); AMAR, AMERICA'S CONSTITUTION, at 108; Jack M. Balkin, *Commerce*, 109 MICH. L. REV. 1, 8-12 (2010). The delegates then passed Resolution VI on to the Committee of Detail, which was responsible for drafting the enumerated powers of Congress in Article I, to transform this general principle into a list of powers enumerated in the Constitution. Balkin, *Commerce*, at 10.

Resolution VI established a structural constitutional principle with "its focus on state competencies and the general interests of the Union." *Id.* Translating this general principle into specific provisions, the Committee of Detail drafted Article I to grant Congress the broad power to, among other things, "regulate Commerce . . . among the several States," U.S. CONST. art I, § 8, cl. 3. These enumerated powers were intended to capture the idea that "whatever object of government extends, in its operation or effects, beyond the bounds of a particular state, should be considered as belonging to the government of the United States." 2 THE DEBATES IN THE SEVERAL STATE CONVENTIONS ON THE ADOPTION OF THE FEDERAL CONSTITUTION 424 (Jonathan Elliot ed., 2d ed. 1836) (Statement of James Wilson). *See also* JACK N. RAKOVE, ORIGINAL MEANINGS: POLITICS AND IDEAS IN THE MAKING OF THE CONSTITUTION 178 (1996) (explaining that Article I was "an effort to identify particular areas of governance where there were 'general interests of the Union,' where the states were 'separately incompetent,' or where state legislation could disrupt the national 'Harmony'"); THE FEDERALIST NO. 80, at 476 (Alexander Hamilton) ("Whatever practices may have a tendency to disturb the harmony between the States, are proper objects of federal superintendence and control.").

This list of enumerated powers was not an attempt to limit the federal government for its own sake, but rather "was designed so that the new federal government would have power to pass laws on subjects and concerning problems that are federal by nature"—those that individual states could not "unilaterally solve by themselves" and that might, in turn, "hamper economic union in the short run and threaten political and social union in the long run." Balkin, *Commerce*, at 12, 13. This included problems where "activity in one state ha[d] spillover effects in other states." *Id.* at 13. *See also* Cooter & Siegel, *Collective Action Federalism*, at 117.

As Chief Justice John Marshall explained:

> The genius and character of the whole government seem to be, that its action is to be applied to all the external concerns of the nation, and to those internal concerns which affect the States generally; but not to those which are completely within a particular State, which do not affect other States, and with which it is not necessary to interfere, for the purpose of executing some of the general powers of the government.

Gibbons v. Ogden, 22 U.S. (9 Wheat.) 1, 195 (1824). Today, the problem of air pollution and unhealthy air quality fits within this paradigm. Phrased in the language of Resolution VI, air pollution that crosses State lines is precisely the sort of problem that implicates "the general Interests of the Union," in which "the States are separately incompetent," and as to which "the Harmony of the United States may be interrupted by the Exercise of individual legislation." 2 FARRAND'S RECORDS at 131-32.

II. Congress Has Used Its Constitutionally Granted Authority, Aided By The EPA's Implementing Regulations, To Address The Genuinely National Problem of Interstate Air Pollution.

Air pollution that crosses State lines has long been of concern in the United States. As Justice Oliver Wendell Holmes wrote in 1907, "[i]t is a fair and reasonable demand on the part of a sovereign" in our federal system "that the air over its territory should not be polluted on a great scale . . . by the act of persons beyond its control" in a neighboring State. *Georgia v. Tennessee Copper Co.*, 206 U.S. 230, 238 (1907). Then, as now, as the Federal Petitioners explain, "[t]he fundamental problem is that the emitting, or upwind, State secures all the benefits of the economic activity causing the pollution without having to absorb all the costs." Br. of Fed. Ptrs. at 2.

Air pollution is a truly national problem. To begin with, it inevitably crosses State borders, with decisions made in one State often affecting the air quality in others. For instance, consider a State's policy to cluster its power plants near its border. Such a policy may protect the welfare of that State's own citizens, but it may also result in the State's export of air pollution from its power plants to its downwind neighbors. Richard L. Revesz, *Federalism and Interstate Environmental Externalities*, 144 U. PA. L. REV. 2341, 2350 (1996). Or, consider a State law requiring taller smoke stacks. Again, this policy may protect nearby citizens by sending polluted air higher into the atmosphere, but it may also increase that pollution's impact further downwind. *Id.* In each case, these policy choices are completely rational. They protect a State's own citizens and send its air pollution elsewhere. At the same time, these decisions also seriously damage the environment in downwind States and, in turn, the health of their citizens. This is federalism run amok, and it demands a national solution.

Without federal intervention, upwind States certainly have an incentive to reduce pollution within their own jurisdiction. At the same time, they have little incentive to protect their downwind neighbors. Even worse, they may actually have an incentive to pollute them, thereby "obtain[ing] the labor and fiscal benefits of the economic activity that generates the pollution" without "suffer[ing] the full costs of the activity." Revesz, *Interstate*, at 2343. Either way, downwind States are helpless before the policy decisions of their upwind neighbors, and often saddled with a degraded environment and less healthy citizens —all through no fault of their own. *See* S. Rep. No. 228, 101st Cong., 1st Sess. 3389 (1989) ("Aggressive controls in downwind areas will do little to improve air quality if the quality of air entering the region is poor.").

This is precisely the sort of problem that the delegates to the Constitutional Convention had in mind when approving Resolution VI, that the Committee of Detail had in mind when translating that general principle into Article I's enumerated powers, and that Chief Justice Marshall had in mind when outlining the reach of federal power in *Gibbons*—a problem that "involve[s] activity in one state that has spillover effects in other states." Balkin, *Commerce*, at 23. *See also* Neil S. Siegel, *Collective Action Federalism and Its Discontents*, 91 TEX. L. REV. 1937, 1958 (2013) (using interstate pollution as an example of the type of spillover effect that our federal government was designed to address).

Beginning in 1970 with major amendments to the Clean Air Act, Congress set the reasonable goal of ensuring that upwind states were held accountable for the pollution that they exported to their downwind neighbors. Since then, Congress has amended the CAA multiple times to both strengthen these interstate responsibilities and increase the federal government's role in policing interstate disputes.

Congress first pursued a national interstate air pollution policy with the 1970 amendments to the CAA. This initial policy gave States great latitude to coordinate with one another to reduce the spillover effects of air pollution—in turn, carving out a very limited role for the federal government. The original provision required the States to address interstate air pollution through "intergovernmental cooperation," 42 U.S.C. § 1857c-5(a)(2)(E) (1970), with the EPA issuing a regulation simply calling for "an exchange of information among States on factors which may significantly affect air quality in any State," 40 C.F.R. § 51.21(c). Neither the statute itself nor the EPA's implementing regulations included any concrete enforcement measures that might hold upwind States accountable for any harm done to their downwind neighbors.

Before long, Congress concluded that stronger medicine was needed. Prior to enacting major revisions to the CAA in 1977, a House Report acknowledged that interstate air pollution had "long been a source of concern." H.R. Rep. No. 294, 95th Cong., 1st Sess. 330 (1977). Nevertheless, it conceded that the 1970 amendments were "an inadequate answer to the problem," adding that a mere "information exchange" was "simply insufficient" and that "a *Federal* mechanism for resolving disputes" was required. *Id.* (emphasis added). Similarly, a Senate Report expressed concern that, without "interstate abatement procedures" or "interstate enforcement actions," the 1970 law "result[ed] in serious inequities among the several States" and put some States "at a distinct economic and competitive disadvantage." S. Rep. No. 127, 95th Cong., 1st Sess. 41-42 (1977).

Tracking these concerns, Congress increased federal oversight of interstate air pollution in its 1977 amendments to the CAA. Rather than relying on mere "cooperation" between the States, Congress amended the Act to require upwind States to curb emissions from "any stationary source" that would "*prevent* attainment or maintenance" of federal air pollution standards in downwind States. 42 U.S.C. § 7410(a)(2)(E) (1980) (emphasis added). In amending the CAA in this manner, Congress acknowledged that the previous law had failed because it depended too much on voluntary actions by upwind States that really had no "incentive and need to act." H.R. Rep. No. 294, 95th Cong., 1st Sess. 330 (1977). The new provisions were "intended to establish an effective mechanism for prevention, control, and abatement of interstate air pollution," *id.*—one that would "equalize the positions of the States with respect to interstate air pollution by making a source at least as responsible for polluting another State as it would be for polluting its own State," S. Rep. No. 127, 95th Cong., 1st Sess. 16 (1977).

By the late 1980s, Congress once again concluded that the current law was too weak,[2] and, in 1990, Congress once again strengthened the federal government's hand. After struggling for years to prove that upwind States had "*prevent[ed]*" them from meeting federal air pollution standards[3]—as required by the 1977 amendments—downwind States finally received even stronger protection in the 1990 amendments. The result was the "good neighbor" provision at issue in this case, a provision that was designed to be more flexible than its predecessor and, in turn, more helpful to downwind States. In relevant part, Congress changed the 1977 law's "prevent attainment or maintenance" prong to a new provision requiring upwind States to "prohibit[] any source or other type of emissions activity . . . from emitting any air pollutant in amounts that will . . . contribute significantly" to nonattainment or maintenance in downwind States—whether or not those emissions could be shown, on their own, to "*prevent*" attainment or maintenance of federal air pollution standards. 42 U.S.C. § 7410(a)(2)(D)(i)(I).

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[2] S. Rep. No. 228, 101st. Cong. 1st Sess. 48-49 (1989) (explaining that "additional efforts must be made" to address the "transport problem").

[3] *See, e.g.*, *State of New York v. EPA*, 852 F.2d 574 (D.C. Cir. 1988); *Air Pollution Control Dist. of Jefferson County v. EPA*, 739 F.2d 1071 (6th Cir. 1984); *State of New York v. EPA*, 716 F.2d 440 (7th Cir. 1983); *State of Connecticut v. EPA*, 696 F.2d 147 (2d Cir. 1982).

From there, the EPA went to work developing regulations to implement this new "good neighbor" provision. In 1998, it established a cap-and-trade program for nitrogen oxide emissions, which, in turn, was largely upheld by the D.C. Circuit in *Michigan v. EPA*, 213 F.3d 663 (2000).

In 2005, the EPA then issued its Clean Air Interstate Rule (CAIR), which attempted to apply its approach to nitrogen oxide to regulations covering fine particulate matter and ozone. 70 Fed. Reg. 25,162 (May 12, 2005). The D.C. Circuit struck down this rule, concluding that it did not go far enough to protect the interests of downwind States like North Carolina. *North Carolina v. EPA*, 531 F.3d 896, 901 (D.C. Cir. 2008) ("*North Carolina I*"). While the court first vacated the rule in its entirety, it later modified its ruling to allow for the EPA to continue to administer CAIR until it could replace it with other (stronger) regulations, *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008) ("*North Carolina II*"). However, the EPA would first have to "redo its analysis from the ground up" as "expeditious[ly] as practicable," *North Carolina I*, 896 F.3d at 929, 930. *See also North Carolina II*, 550 F.3d at 1178 ("[W]e remind the Petitioners that they may bring a mandamus petition to this court in the event that EPA fails to modify CAIR in a manner consistent with [*North Carolina I*].").

Finally, in response to the *North Carolina* decisions, the EPA issued its Transport Rule, which is at issue in this case. This Rule addresses the emissions of 27 upwind States that significantly contribute to the problems downwind States have attaining or maintaining governing air quality standards. None of these upwind States satisfied their "good neighbor" obligations prior to the EPA's challenged actions. For each State subject to the Transport Rule, the agency had previously conducted an administrative proceeding in which it either (1) made a finding that the State failed to submit a plan addressing the good neighbor requirement or (2) disapproved the State's plan as inadequate. Br. of Fed. Ptrs. at 9. In the Transport Rule, the EPA promulgated federal plans for those states, as required under the CAA. *See generally* Br. of Fed. Ptrs. at 10-13 (describing the EPA's analysis in detail).

The CAA and the EPA's implementing Transport Rule are excellent examples of the type of cooperative federalism envisioned by our Founders. While the EPA establishes national air pollution standards in the first instance, the statutory scheme provides States with flexibility to implement their own clean air policies to meet these federal standards. 42 U.S.C. §§ 7408, 7409. It is only *after* individual States fail to establish adequate air policy programs—as was the case here—that the CAA requires the federal government to step in with implementation plans of its own. 42 U.S.C. § 7410(c)(1).

As discussed above, the CAA, through its "good neighbor" provision, requires each State to craft an implementation plan that addresses the spillover effects of air pollution. Indeed, each upwind State must submit a plan that regulates pollutants that "contribute significantly" to its downwind neighbors' difficulties in complying with federal air pollution standards. 42 U.S.C. § 7410(a)(2)(D)(i)(I). In turn, the CAA provides the EPA with great discretion to define the related policy details through regulations like the Transport Rule. And when States fail to fulfill their "good neighbor" responsibilities, the EPA has the power to hold them accountable—as it did in this case.

III. In Rejecting The Transport Rule, The Court Of Appeals Undermined The Federal Government's Ability To Address Interstate Air Pollution, And Engaged In An Unauthorized Redesign Of The Clean Air Act's Vision Of Cooperative Federalism.

As Judge Rogers explained in her dissent, the majority in the court of appeals did "several remarkable things" when it vacated the Transport Rule. Pet. App. at 115a. It ignored congressional limitations on the courts' jurisdiction. It ignored precedent enforcing those jurisdictional limitations. It ignored requirements of administrative exhaustion. It deemed the EPA's clearly reasonable interpretation of the Clean Air Act—an "interpretation" Judge Rogers characterizes as "*reading the actual text of the statute*," Pet. App. at 85a (emphasis in original)—absurd. And, in the process, the majority below rewrote the plain text of a federal statute and "recalibrate[d] Congress's statutory scheme and vision of cooperative federalism in the CAA." Pet. App. at 115a.

Just last Term, this Court reaffirmed its commitment to *Chevron U.S.A. Inc. v. Natural Resources Defense Council*, 467 U.S. 837 (1984). As the Court explained then, "*Chevron* is rooted in a background presumption of congressional intent": "Congress knows to speak in plain terms when it wishes to circumscribe, and in capacious terms when it wishes to enlarge agency discretion." *City of Arlington v. FEC*, 133 S. Ct. 1863, 1868 (2013). The court below deviated from this clearly established principle, "transferring any number of interpretative decisions—archetypal *Chevron* questions, about how best to construe an ambiguous term in light of competing policy interests—from [an] agenc[y] that administer[s] the statute[] to [a] federal court[]" and, in turn, "'substituting [the lower court's] own interstitial lawmaking' for that of an agency." *Id.* at 1873. (quoting *Ford Motor Credit Co. v. Milhollin*, 444 U.S. 555, 568 (1980)). While the Federal Petitioners' brief fully addresses the lower court's substantive and procedural errors, we offer one illustrative example below.

In invalidating the Transport Rule, the lower court concluded, in part, that the EPA erred in issuing a federal implementation plan for noncomplying States, relying on "contextual and structural factors" to support its conclusion, Pet. App. at 54a—over and above the plain text of the CAA. As per the CAA itself, within three years of the EPA issuing new federal air pollution standards, each State "shall" submit a new implementation plan—one that satisfies its "good neighbor" obligations, among other requirements. 42 U.S.C. § 7410(a)(2). The EPA "shall" then "promulgate [a federal plan] at any time within 2 years" after it either "finds that a State has failed to make a required submission" or it "disapproves" of a given State's plan. 42 U.S.C. § 7410(c)(1)(A) & (B).

The Transport Rule covered federal standards first put in place in 1997 (for ozone) and 2006 (for fine particulate matter). 76 Fed. Reg. 48219 (Aug. 8, 2011). Therefore, under the plain text of the CAA, State plans were due three years later—in 2000 and 2009, respectively. In turn, those plans were required to include provisions satisfying each State's good neighbor obligations. In 2010 and 2011, the EPA concluded that many States had failed to satisfy these requirements. 75 Fed. Reg. 32673 (June 9, 2010). Furthermore, the EPA explained that this "create[d] a 2-year deadline" for each noncomplying State to implement a valid plan. 75 Fed. Reg. 32674. Only after these States failed to comply with this deadline did the EPA issue its own plan, as required by the plain text of the CAA—the lower court's "structural and contextual" factors notwithstanding.

The lower court's failure to recognize that the EPA did, in fact, give the States the opportunity to meet their obligations under the CAA before the agency promulgated federal implementation plans for those States, may account for its conclusion that the Transport Rule transgresses the "federalism bar," Pet. App. at 56a. But it certainly should not be accepted by this Court, when it is clear as day that the EPA's implementation of the CAA's system of cooperative federalism was in line with the statute. In reality, the CAA and the Transport Rule are perfect examples of how the federal government can use its constitutionally granted authority to solve complex interstate problems while respecting the role of the States in our federalist system.

* * *

Our Constitution establishes a federal government that is strong enough to act when the national interest requires a national solution, while reserving a crucial role for the States as our "laboratories of democracy." Congress has the power to address the spillover effects of interstate air pollution, and the EPA has the clear authority under the CAA to implement a regulation like the Transport Rule to carry out its statutory duty. Far from offending our Constitution's careful balance of federal-state power, the CAA—and the EPA's attempt to implement it through the Transport Rule—reflect our system of vibrant federalism and allow the federal and State governments to better protect their citizens and resources.

CONCLUSION

Amicus supports the steps toward regulating interstate air pollution undertaken in the CAA and believes that the EPA's Transport Rule is valid. *Amicus* respectfully urges this Court to uphold the EPA's Transport Rule and reverse the lower court's contrary holding.

Respectfully submitted,

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Nos. 12-1182 & 12-1183

In the Supreme Court of the United States

ENVIRONMENTAL PROTECTION AGENCY, *ET AL.*,
Petitioners,
v.
EME HOMER CITY GENERATION, L.P., *ET AL.*

AMERICAN LUNG ASSOCIATION, *ET AL.*,
Petitioners,
v.
EME HOMER CITY GENERATION, L.P., *ET AL.*

On Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

BRIEF *AMICUS CURIAE* OF APA WATCH IN SUPPORT OF NEITHER PARTY

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QUESTIONS PRESENTED

These two consolidated cases present both merits and jurisdictional questions, with the latter hinging on whether review was available, given (a) failure to raise the relevant merits issues during the comment period, and (b) 42 U.S.C. §7607(d)(7)(B)'s limitation on review to issues presented during the rulemaking. This *amicus* brief focuses only on the jurisdictional question, including the implications of §7607(d)(7)(B) on review when after-arising grounds provide a basis for revisiting existing Clean Air Act rules.

No. 12-1182

The Clean Air Act, 42 U.S.C. 7401 *et seq.* (Act or CAA), requires the Environmental Protection Agency (EPA) to establish National Ambient Air Quality Standards (NAAQS) for particular pollutants at levels that will protect the public health and welfare. 42 U.S.C. 7408, 7409. "[W]ithin 3 years" of "promulgation of a [NAAQS]," each State must adopt a state implementation plan (SIP) with "adequate provisions" that will, inter alia, "prohibit[]" pollution that will "contribute significantly " to other States' inability to meet, or maintain compliance with, the NAAQS. 42 U.S.C. 7410(a)(1), (2)(D)(i)(I). If a State fails to submit a SIP or submits an inadequate one, the EPA must enter an order so finding. 42 U.S.C 7410(k). After the EPA does so, it "shall promulgate a [f]ederal implementation plan" for that State within two years. 42 U.S.C. 7410(c)(1).

The questions presented are as follows:

(1) Whether the court of appeals lacked jurisdiction to consider the challenges on which it granted relief.

(2) Whether States are excused from adopting SIPs prohibiting emissions that "contribute significantly" to air pollution problems in other States until after the EPA has adopted a rule quantifying each State's interstate pollution obligations.

(3) Whether the EPA permissibly interpreted the statutory term "contribute significantly" so as to define each upwind State's "significant" interstate air pollution contributions in light of the cost-effective emission reductions it can make to improve air quality in polluted downwind areas, or whether the Act instead unambiguously requires the EPA to consider only each upwind State's physically proportionate responsibility for each downwind air quality problem.

No. 12-1183

The Clean Air Act's "Good Neighbor" provision requires that state implementation plans contain "adequate" provisions prohibiting emissions that will "contribute significantly" to another state's nonattainment of health-based air quality standards. 42 U.S.C. 7410(a)(2) (D)(i). A divided D.C. Circuit panel invalidated, as contrary to statute, a major EPA regulation, the Transport Rule, that gives effect to the provision and requires 27 states to reduce emissions that contribute to downwind states' inability to attain or maintain air quality standards. The questions presented are:

(1) Whether the statutory challenges to EPA's methodology for defining upwind states' "significant contributions" were properly before the court, given the failure of anyone to raise these objections at all,

let alone wit h the requisite "reasonable specificity," "during the period for public comment," 42 U.S.C. 7607(d)(7)(B);

(2) Whether the court's imposition of its own detailed methodology for implementing the Good Neighbor provision violated foundational principles governing judicial review of administrative decision - making;

(3) Whether an upwind state that is polluting a downwind state is free of any obligations under the Good Neighbor provision unless and until EPA has quantified the upwind state's contribution to downwind states' air pollution problems.

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On Writ of Certiorari to the United States Court of Appeals for the District of Columbia Circuit

INTEREST OF *AMICUS CURIAE*

Amicus curiae APA Watch [1] is a nonprofit membership organization headquartered in McLean,

[1] *Amicus* APA Watch files this brief with the consent of all parties; the parties have lodged blanket letters of consent with the Clerk. Pursuant to Rule 37.6, counsel for *amicus curiae* authored this brief in whole, no counsel for a party authored this brief in whole or in part, and no person or entity – other than *amicus*, its members, and its counsel – contributed monetarily to the preparation or submission of this brief.

Virginia. APA Watch has participated as *amicus curiae* before this Court and the Courts of Appeals on both justiciability and the Clean Air Act ("CAA"), including in *Stormans Inc. v. Seleky,* No. 07-36039 (9th Cir.); *Envtl. Defense v. Duke Energy Corp.,* No. 05-848 (U.S.); *Astra USA, Inc. v. Santa Clara County, Cal.,* No. 09-1273 (U.S.); *Douglas v. Independent Living Ctr. of Southern California, Inc.,* Nos. 09-958, 09-1158, 10-283 (U.S.). In addition, APA Watch members seek to compel the Environmental Protection Agency ("EPA") to revisit CAA rules and orders outside CAA §307(b)'s 60-day window for judicial review, 42 U.S.C. §7607(b), which implicates the same statutory text and legislative history on the question of CAA issue-exhaustion that petitioners present here. Accordingly, APA Watch has a direct and vital interest in the issues raised here.

STATEMENT OF THE CASE

As relevant to this *amicus* brief, this case presents the jurisdictional question whether the industry petitioners below ("Industry") and the D.C. Circuit could reach an issue that no party pressed in their comments to EPA. *Amicus* APA Watch takes no position on that issue *per se,* but rather outlines the related issues of whether and when parties can seek renewed review under the CAA for after-arising grounds (*i.e.,* grounds that arise outside §307(b)'s 60-day window for judicial review and outside the comment period. *See* 42 U.S.C. §7607(b)(1), 7607(d)(7)(B). Although these issues may not appear to be conceptually related to the question presented here, Congress enacted §307(d)(7)(B) for the very reason of channeling the process for review of after-arising grounds.

Constitutional Background

Absent a waiver of sovereign immunity, federal agencies are jurisdictionally immune from suit. *FDIC v. Meyer,* 510 U.S. 471, 475 (1994). Statutes that allow judicial review obviously waive sovereign immunity, Louis L. Jaffee, *The Right to Judicial Review I,* 71 HARV. L. REV. 401, 432 (1958) ("If a statute provides for judicial review the consent has, of course, been given"), at least for the scope of review that the statute grants.

Statutory Background

In 1970, Congress applied the precursor of current §307(b) to judicial review of a subset of CAA actions, PUB. L. NO. 91-604, §12(a), 84 Stat. 1676, 1707 (1970), which the 1977 amendments expanded to apply to virtually all final CAA actions. PUB. L. NO. 95-95, §305(c)(1) -(3), 91 Stat. 685, 776 (1977). CAA §307(b)'s central provisions are (a) direct review in the courts of appeal; (b) review of nationally applicable actions exclusively in the D.C. Circuit, with review of regionally applicable actions in the court of appeals for the relevant circuit; and (c) the jurisdictional requirement to petition for review in the relevant court of appeals within 60 days of EPA's publishing notice of its action in the *Federal Register* or within 60 days of after -arising grounds. 42 U.S.C. §7607(b)(1). In addition, §307(b)(2) prohibits courts from reviewing in an enforcement proceeding any EPA action for which review could have been had under §307(b)(1). 42 U.S.C. §7607(b)(2).[2] Subsection 307(d) provides a hybrid judicial-review procedure for many (but not all) EPA rulemakings, 42 U.S.C. §7607(d), which differs in some respects from the more general provisions of the Administrative Procedure Act, 5 U.S.C. §§551-706 ("APA"). Where those CAA-specific revisions apply, judicial review is available only on issues first presented to EPA. 42 U.S.C. §7607(d)(7)(B).

In *Olijato Chapter, Navajo Tribe v. Train,* 515 F.2d 654 (D.C. Cir. 1975) ("*Navajo Tribe*"), the D.C. Circuit addressed the interplay between §307(b)(1) and the APA procedure to address after-arising grounds, 5 U.S.C. §553(e). There, the Tribe sought to challenge an EPA rule outside §307(b)(1)'s window, but based on after-arising information. The Tribe had filed suit in district court and, based on that court's determining it lacked jurisdiction, also filed a belated petition for review in the court of appeals. 515 F.2d at 658-59. *Navajo Tribe* held that – in order to present such information to EPA in a manner that the Court of Appeals could review – one first must petition EPA under §553(e) to present their issues to the Agency and then petition for review under the Clean Air Act on the "grounds" of EPA's denying the administrative petition. 515 F.2d at 666.[3]

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[2] Before 1977, §307(b)(1)'s deadline was 30 days. PUB. L. NO. 91-604, §12(a), 84 Stat. at 1707. For consistency, APA Watch refers to §307(b)(1)'s 60-day window throughout this brief.

[3] In 1970, Congress amended S. 4358 in conference to require suing on after-arising *grounds* (*e.g.,* petition denials), not "whenever … significant new information has become

In broadening §307(b)'s scope in the 1977 amendments, Congress expressly ratified the *Navajo Tribe* approach. H.R. REP. 94-1175, 264 (1976); S. REP. 95-294, 323 (1977). In addition, Congress rejected *dicta* from *Investment Co. Inst. v. Bd. of Governors, Fed'l Reserve Sys.*, 551 F.2d 1270, 1280-81 (D.C. Cir. 1977) ("*Investment Co.*") that might allow escaping §307(b)'s time bar for "an undefined legitimate excuse." S. REP. 95-294, at 322. By negative implication, Congress did not reject the *Investment Co.* holding that such petitions are *required* for a party to challenge a rule that it lacked a ripe claim to challenge within the 60-day window or that seeks to raise an issue that arose after EPA acted on its original rule or order.[4]

SUMMARY OF ARGUMENT

Amicus APA Watch takes no position on either the jurisdictional question presented (whether issue exhaustion under §307(d)(7)(B) is jurisdictional) or on the merits questions presented. Instead, this *amicus* brief explains §307(d)(7)(B)'s legislative history and its relevance to renewed review – *i.e.*,

available." *Navajo Tribe,* 515 F.2d at 660 (*quoting* S. 4358, 91st Cong., 2d Sess., §308(a) (1970)).

4 Notwithstanding *Navajo Tribe* and the 1977 amendment's legislative history, the D.C. Circuit subsequently held that parties cannot seek judicial review of petition denials. *Nat'l Mining Ass'n v. Dep't of Interior,* 70 F.3d 1345 (D.C. Cir. 1995); *Am. Road & Transportation Builders Ass'n v. EPA,* 588 F.3d 1109, 1114 (D.C. Cir. 2009). The circuits are split on that issue, *see, e.g., Union Elec. Co. v. EPA,* 515 F.2d 206, 220 (8th Cir. 1975), and the issue is before this Court on petition for a writ of *certiorari* in *Am. Road & Transportation Builders Ass'n v. EPA,* No. 13-145 (U.S.).

outside §307(b)'s 60-day window – of EPA rules and orders based on after-arising grounds. On that issue, such review predated the 1977 amendments that added §307(d)(7)(B) and were the very reason that Congress added §307(d)(7)(B), which makes clear that the Court should preserve (or at least not foreclose) such review under that congressional intent and the policy against repeals by implication (Section II.A). In addition, denying or foreclosing that review would violate due process and further defeat congressional intent by allowing review *outside the CAA framework* under the APA and in equity (Section II.B). In addition, APA Watch also argues that neither the APA nor other issue-exhaustion statutes provide useful guidelines here for CAA review because of difference between the CAA on the one hand and the APA (Section I.A) and the other issue-exhaustion statutes on the other hand (Section I.B).

ARGUMENT

I. NEITHER THE APA NOR NON-CAA ISSUE-EXHAUSTION STATUTES NECESSARILY RESOLVE THIS ISSUE UNDER THE CAA

Amicus APA Watch respectfully submits that the Court should use care in generalizing principles from the APA and administrative-law generally on the one hand and other statutes with issue-exhaustion provisions on the other hand. In both situations (and particularly the latter), neither non-statutory review under the APA or common law nor statutory review under statutes that differ from the CAA will necessarily provide a rule of decision for judicial review under the CAA.

For example, §307(d) and the APA are similar in many respects, *Whitman v. Am. Trucking Ass'ns,* 531 U.S. 457, 478 (2001) (standard of review), but they also differ. Indeed, Congress wrote §307(d) precisely to override the APA template in those areas where the APA and §307(d) differ. As such, while the APA may guide the Court's understanding of §307(d) in some respects, the APA does not apply here where APA and CAA review do not align:

> The meaning and applicability of [the first statute] are useful guides in construing [the second statute], therefore, only to the extent that the language and history of [the second statute] do not suggest a contrary interpretation.

North Haven Bd. of Educ. v. Bell, 456 U.S. 512, 529-30 (1982). While *amicus* APA Watch will defer to the parties to establish the rule of decision in this case, Section II, *infra,* will discuss issues of CAA review that the Court should consider for the wider impact of its decision here.

A. The APA Does Not Necessarily Resolve the Question Presented Here

Under *Sims v. Apfel,* 530 U.S. 103 (2000), non-adversarial proceedings like most rulemakings would provide a much weaker case for judicially requiring exhaustion than would adversarial proceedings. *Sims* cautions against applying APA principles here, and it also cautions against too readily adopting holdings from adversarial proceedings into litigation that does not involve an adversarial proceeding.

1. <u>If It Arose under the APA, this Case Would Present a Weak Case for Issue Exhaustion</u>

To the extent that issue exhaustion principles apply under the APA and common law, they apply judicially, under general principles of administrative law. This Court's recent decision in *Sims* is the leading authority, and it ties the question to the adversarial nature of the agency proceedings:

> [C]ourts require administrative issue exhaustion "as a general rule" because it is usually "appropriate under [an agency's] practice" for "contestants in an adversary proceeding" before it to develop fully all issues there. … But, as *Hormel* and *L. A. Tucker Truck Lines* suggest, the desirability of a court imposing a requirement of issue exhaustion depends on the degree to which the analogy to normal adversarial litigation applies in a particular administrative proceeding. Where the parties are expected to develop the issues in an adversarial administrative proceeding, it seems to us that the rationale for requiring issue exhaustion is at its greatest. *Hormel, L.A. Tucker Truck Lines,* and *Aragon* each involved an adversarial proceeding. … Where, by contrast, an administrative proceeding is not adversarial, we think the reasons for a court to require issue exhaustion are much weaker.

Sims, 530 U.S. at 110 (second alteration in original, citations omitted). As used in *Sims* and its earlier cited precedents, an "adversarial administrative proceeding" entails elements of due process – *e.g.,* the ability to cross examine witnesses – that are wholly absent from most APA rulemakings. Indeed, even some APA hearings are not adversarial. *See, e.g., Nat'l Ass'n of Psychiatric Treatment Ctrs. for Children v. Mendez,* 857 F. Supp. 85, 89-90 (D.D.C. 1994); *Norwegian Nitrogen Prod. Co. v. U.S.,* 288 U.S. 294, 317 (1933) (because "the word 'hearing' as applied to administrative proceedings has been thought to have a broader meaning," "[a]ll depends upon the context").

Specifically, an "adversary proceeding [includes] the attendant rights to counsel, confrontation, cross-examination, and compulsory process." *Ellis v. District of Columbia,* 84 F.3d 1413, 1422 (D.C. Cir. 1996); *see also U.S. v. Boney,* 68 F.3d 497, 502 (D.C. Cir. 1995); *Communications Satellite Corp. v. Fed'l Communications Comm'n,* 611 F.2d 883, 887 (D.C. Cir. 1977); *Delta Found. v. U.S.,* 303 F.3d 551, 561-62 (5th Cir. 2002); *Coalition for Gov't Procurement v. Fed. Prison Indus.,* 365 F.3d 435, 465-66 (6th Cir. 2004); *Gambill v. Shinseki,* 576 F.3d 1307, 1326 (Fed. Cir. 2009) (Bryson, J., concurring) (collecting cases); *Goldberg v. Kelly,* 397 U.S. 254, 269 (1970). With APA actions that are not adversarial proceedings, the case for *judicially imposing* issue exhaustion is "much weaker" under *Sims.*

Sims undermines EPA's citation to decisions that involved adversarial proceedings because – at least under the APA – the case for issue exhaustion is more forceful with adversarial proceedings than it would be here, with this non-adversarial rulemaking.

See, e.g., EPA Br. at 35 (*citing U.S. v. L.A. Tucker Truck Lines, Inc.,* 344 U.S. 33, 37 (1952)); *cf. Sims,* 530 U.S. at 110 ("*L.A. Tucker Truck Lines* … involved an adversarial proceeding"). This Court cannot necessarily draw inferences from the APA, and particularly not from APA situations in which (unlike here) the agency provided an adversarial proceeding.

2. **If the APA Applied, Industry Could Excuse Exhaustion Based on the Futility of Seeking Review from EPA**

If the Court holds that general administrative-law decisions apply to this dispute, EPA's rejection of the industry position on the merits, EPA Br. at 33-55, would render exhaustion futile:

> [I]n view of Attorney General's submission that the challenged rules of the prison were "validly and correctly applied to petitioner," requiring administrative review through a process culminating with the Attorney General 'would be to demand a futile act."

McCarthy v. Madigan, 503 U.S. 140, 148 (1992) (*quoting Houghton v. Shafer,* 392 U.S. 639, 640 (1968)); *cf. McKart v. U.S.,* 395 U.S. 185, 197-99 (1969) (exhaustion not required if question "solely one of statutory interpretation" where "the proper interpretation [was] certainly not a matter of [agency] discretion"). Here, if EPA indeed decided its merits views, there would be no point to asking that industry raise the issues with EPA.

B. Non-CAA Issue -Exhaustion Statutes Do Not Resolve the Question Presented Here

The argument against relying too heavily on general APA and administrative -law issues is even stronger when it comes to other statutes that provide issue-exhaustion principles as part of their statutory review.[5] Here, Congress is even less likely to have intended courts to interpret different statutory text to mean the *same* thing.

Although it has on occasion strictly enforced issue-exhaustion statutes, *see, e.g., EEOC v. FLRA,* 476 U.S. 19 , 23 -24 (1986), this Court has not yet ruled on the issue -exhaustion criteria presented by §307(d)(7)(B). While the Court perhaps can draw some general principles from its precedents on other issue-exhaustion statutes, *amicus* APA Watch respectfully submits that m any of those decisions do not generalize to this CAA context because the statutes at issue in those other cases differed from the CAA statute at issue here.

For example, the issue -exhaustion statute in *EEOC v. FLRA* was somewhat stricter than §307(d):

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[5] The Court perhaps should distinguish between nonstatutory review and special forms of statutory review, as the enactment of "statutes" such as the APA has rendered the term "nonstatutory" something of a "misnome r." *Air New Zealand Ltd. v. C.A.B.,* 726 F.2d 832, 836 -37 (D.C. Cir. 1984) (Scalia, J.); *cf. generally* Clark Byse & Joseph V. Fiocca, *Section 1361 of the Mandamus and Venue Act of 1962 and "Nonstatutory" Judicial Review of Federal Administrative Action,* 81 HARV. L. REV. 308 (1967).

> "[no] objection that has not been urged before the Authority, or its designee, shall be considered by the court, unless the failure or neglect to urge the objection is excused because of extraordinary circumstances."

EEOC v. FLRA, 476 U.S. at 23 (*quoting* 5 U.S. C. §7123(c)) (alteration in *EEOC v. FLRA*). As the Court noted, this language is identical to §10(e) of the National Labor Relations Act, *id.* (*citing* 29 U.S.C. §160(e)), which jurisdictionally precludes courts from considering issues not raised before the agency. *Id.* (*citing Woelke & Romero Framing, Inc. v. NLRB,* 456 U.S. 645, 665-66 (1982)). If these authorities applied here, they would help EPA greatly.

But Congress did not model §307(d)(7)(B) on §10(e) of the National Labor Relations Act. First, the CAA requires only that it must have been "impracticable to raise [a timely] objection," 42 U.S.C. §7607(d)(7)(B), which is less stringent than "extraordinary circumstances." *EEOC v. FLRA,* 476 U.S. at 23 (*quoting* 5 U.S.C. §7123(c)). Moreover, whereas the latter "speaks to courts, not parties," *EEOC v. FLRA,* 476 U.S. at 23, §307(d)(7)(B) speaks only to what issues "may be raised during judicial review," presumably by "the person raising an objection." 42 U.S.C. §7607(d)(7)(B). Under that less-stringent restriction, courts may feel free to insert issues *sua sponte* that the parties could not themselves raise.

II. CONGRESS INTENDED REVIEW UNDER §307 TO ALLOW REVISITING EPA RULES BASED ON AFTER-ARISING GROUNDS

Although this *amicus* brief expresses no view on whether Industry here can avail itself of §307's provisions for seeking renewed review, *amicus* APA Watch respectfully submits that this Court's decision should recognize – or, at least, not foreclose – the CAA's flexibility for seeking renewed review under §307(b), which was the genesis of §307(d)(7)(B) in the 1977 CAA amendments. Because the jurisdictional question presented is sufficiently close to the question of whether and when parties can seek renewed review, APA Watch respectfully files this *amicus* brief as a protective matter to advise this Court that the integrally related issues of renewed review under §307(b).

A. Congress Intended §307(d)(7)(B) to Preserve and Channel the Ability to Seek Renewed Review Based on After-Arising Grounds

As indicated by both §307(d)(7)(B)'s legislative history and the strong disfavor for repeals by implication, *Nat'l Ass'n of Home Builders v. Defenders of Wildlife,* 551 U.S. 644, 662 (2007), judicial review based on after-arising grounds should *remain* available under §307(b).[6] Indeed, although repeal by implication requires that "the intention of the legislature to repeal [is] clear and manifest," *id.,* the policy against repeals by implication is *even stronger* for judicial review: "this canon of

[6] Under *Navajo Tribe,* 515 F.2d at 666-67, such review was available prior to the 1977 amendments, and nothing in the 1977 amendments repealed that review, except for instances of "an undefined legitimate excuse" under the *Investment Co. dictum.* S. REP. 95-294, at 322; *cf. Investment Co.,* 551 F.2d at 1280-81.

construction applies with particular force when the asserted repealer would remove a remedy otherwise available." *Schlesinger v. Councilman,* 420 U.S. 738, 752 (1975) (internal quotations omitted); *cf.* 5 U.S.C. §559; *Dickinson v. Zurko,* 527 U.S. 150, 154-55 (1999). Thus, assuming *arguendo* that §307(d)(7)(B) is jurisdictional here, this Court must not inadvertently suggest that §307 limits *renewed review,* even if §307(d)(7)(B) limits review here.

With that background, the only two effects of §307(d)(7)(B) on the availability for renewed review are that (1) renewed review is unavailable under the *Investment Co. dictum* about "an undefined legitimate excuse" and instead requires (minimally) that it must have been "impracticable" to have raised the issue within the original 60-day window;[7] and (2) issue exhaustion applies to renewed review, so that parties must first raise their issues administratively with EPA and await a denial of their administrative petition before seeking judicial review. *See* 42 U.S.C. §7607(d)(7)(B); S. REP. 95-294, at 322-23; H.R. REP. 94-1175, at 264. As indicated, *amicus* APA expresses no view on whether Industry here can avail itself of an opportunity for renewed review.

B. Renewed Review Based on After-Arising Grounds Provides a Necessary Safety Valve under the Due Process Clause

Allowing renewed review of after-arising grounds

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[7] As indicated in Section I.B, *supra,* CAA's "impracticable" test is less stringent that the "extraordinary circumstances" that some other issue-exhaustion statutes require.

serves two important goals, one constitutional and one statutory. Both reasons caution against this Court's finding §307 to bar review permanently for any issue on which a party misses – for whatever reason – §307(b)'s original 60-day window.

First, it would deny due process for an agency action taken, for example, when a prospective plaintiff or petitioner lacked an Article III case or controversy to bind entities because their claims ripened or arose more than 60-odd days after EPA acted. This Court has noted without resolving that due-process issues raise by §307(b)(2)'s closing review *in enforcement actions* of EPA rules that could have been had under §307(b)(1). *See* 42 U.S.C. §7607(b)(2); *Adamo Wrec king Co. v. U.S.,* 434 U.S. 275, 307 n.* (1978); *Harrison v. PPG Indus.,* 446 U.S. 578, 607 n.9 (1980). When a party with an Article III case or controversy that is *not an enforcement action* seeks to have EPA revisit a prior rule or order, §307(b)(2) does not apply by its terms, but the same due-process issues still arise. Indeed, the issues are even stronger because §307(b)(2) negatively implies that renewed review *outside enforcement actions* should be available. Were it otherwise, §307(b)(2) would be mere surplusage.

Second, if review is not available under §307 in the D.C. Circuit for nationally applicable rules, review would be available in equity in every district court nationwide, *Leedom v. Kyne,* 358 U.S. 184, 188-90 (1958) (allowing nonstatutory equit able review, notwithstanding that the statute in question impliedly prohibits judicial review[8]); *cf.* 5 U.S.C. §703 (APA review available "in the absence or inadequacy" of "the special statutory review proceeding relevant to the subject matter in a court specified by statute"), thereby defeating the nationwide uniformity that Congress intended §307(b) to provide. *Adamo Wrecking Co.*, 434 U.S. at 283-84 (entrusting CAA review to the D.C. Circuit to "insur[e] that [CAA's] substantive provisions ... would be uniformly applied" nationwide). Renewed review under §307 ensures that parties can seek EPA review administratively and then seek judicial review in the appropriate Court of Appeals in the event that EPA denies the requested relief.

CONCLUSION

Although it takes no position how this Court should resolve the jurisdictional question presented by §307(d)(7)(B), *amicus* APA Watch respectfully submits that this Court's decision should not lightly foreclose renewed judicial review for after-arising grounds if the Court finds §307(d)(7)(B) to be jurisdictional.

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[8] The CAA does not *expressly* limit judicial review to §307, 42 U.S.C. §7607(e) ("[n]othing in this chapter shall be construed to authorize judicial review of [EPA] regulations or orders ... under this chapter, except as provided in this section," which does not restrict review not based "on this chapter" (*i.e.*, the CAA) such as the APA and equity), so *Kyne* jurisdiction would apply in the absence of §307 jurisdiction where the prospective plaintiff or petitioner could not have raised its after-arising grounds during §307(b)'s original 60-day window. *Board of Governor's of the Federal Reserve System v. MCorp Financial*, 502 U.S. 32, 43-44 (1991).

September 11, 2013 Respectfully submitted,

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Counsel for Amicus

To: Schmidt, Lorie[Schmidt.Lorie@epa.gov]
From: Doniger, David
Sent: Tue 8/27/2013 5:39:39 PM
Subject: EPA Readies Presentation on Plans To Regulate Power Plant Greenhouse Gases

Lorie, is this solely going to be a watch-it-on-your-own video, or is there one or more webinars or presentations planned (like one for the states)?

David

EPA Readies Presentation on Plans To Regulate Power Plant Greenhouse Gases

By Andrew Childers | August 26, 2013 04:05PM ET

(BNA) -- The Environmental Protection Agency announced Aug. 26 it will post a video on its YouTube channel Aug. 28 that provides an overview of the agency's plans to regulate carbon dioxide emissions from existing power plants.

The video is intended to provide a basic understanding of the agency's authority under Section 111(d) of the Clean Air Act as it prepares to regulate greenhouse gases from existing plants. The video comes in advance of a series of planned conference calls with states and community groups Sept. 9 and with industry and environmental groups Sept. 12.

As part of President Obama's climate change plan announced June 25, he directed EPA to propose emissions guidelines for existing fossil fuel-fired power plants by June 1, 2014, with a final rule expected by June 1, 2015. They will be administered by the states through a process similar to that used to approve state implementation plans (123 DEN A-9, 6/26/13).

'Best System of Reduction.'

Section 111(d) requires EPA to issue emissions guidelines that set the "best system of emission reduction" for existing industrial facilities whenever it issues a new source performance standard for a pollutant that previously has not been regulated by other provisions of the Clean Air Act, such as carbon dioxide.

Obama has directed the agency to propose new source performance standards for carbon dioxide for new power plants by Sept. 20.

In the United States, the 1,595 power plants that reported their emissions for 2011 accounted for 67 percent of all reported greenhouse gas emissions that year, EPA said when it released its annual emissions reporting data in February.

Power plants emitted 2.2 billion metric tons of the carbon equivalent emitted in 2011, down 4.6 percent from 2010 levels. The reduction was largely due to power plants switching from more carbon-intensive coal to natural gas as well as increased use of renewable energy sources, according to EPA.

Power plants accounted for 72.3 percent of reported emissions in 2010 (25 DEN A-6, 2/6/13).

For More Information

EPA's YouTube channel is available at http://www.youtube.com/user/USEPAgov.

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From: Hawkins, Dave
Location: WJC-N 5400 + Non Responsive ; Participant Code: Non Responsive
Importance: Normal
Subject: Accepted: Conference Call re: 111(d) Proposal (Confirmed)
Start Date/Time: Sun 6/1/2014 11:00:00 PM
End Date/Time: Mon 6/2/2014 12:00:00 AM

To: Hoffman, Howard[hoffman.howard@epa.gov]
From: Nicholas Bianco
Sent: Mon 12/8/2014 2:57:17 PM
Subject: EDF comments on the Clean Power Plan
EDF 111d Comments FINAL.pdf

Dear Howard, I am forwarding along EDF's comments on the proposed Clean Power Plan. I will send a second email with the attachments as they increase the file size considerably, and might interfere with your email filters. We hope that you will find them to be helpful. We are all grateful for the fantastic work you and the rest of the team at EPA are doing on this.

Best.

Nicholas

Nicholas Bianco
Director of Regulatory Analysis and Strategic Partnerships

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BY EMAIL AND ELECTRONIC FILING

The Hon. Gina McCarthy
Administrator, U.S. Environmental Protection Agency
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Mail Code 28221T
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Attn: Docket ID No. EPA-HQ-OAR-2013-0602

Re: Comments of Environmental Defense Fund on EPA's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34, 830 (June 18, 2014); 79 Fed. Reg. 64,543 (Oct. 30, 2014) (Notice of data availability); 79 Fed. Reg. 67,406 (Nov. 13, 2014) (Notice; additional information regarding the translation of emission rate-based CO2 goals to mass-based equivalents)

The Environmental Defense Fund (EDF) appreciates the opportunity to provide the following comments on the Environmental Protection Agency's (EPA) June 18, 2014 proposed rule to establish performance standards for carbon pollution from existing electric utility generating units (EGUs).[1] Representing over 750,000 members nationwide, EDF is a national non-profit, non-partisan organization dedicated to protecting human health and the environment by effectively applying science, economics, and the law. EDF has long recognized the urgent and critical threat that climate change poses to public health and welfare, and it is one of our top priorities to advocate for rigorous measures to secure rapid reductions in emissions of climate-destabilizing pollutants – especially emissions of carbon dioxide from fossil fuel-fired EGUs, which currently account for nearly 40 percent of the United States' carbon pollution. Accordingly, we strongly support EPA's initiative to establish the first nation-wide limits on carbon pollution from fossil fuel-fired EGUs using its existing authorities under section 111(b) and (d) of the Clean Air Act.[2]

EPA's proposed rule for existing EGUs is a vital part of this initiative. Our comments below are directed at ensuring that these pollution standards meet the Clean Air Act's standard—that they deliver the maximum possible emission reductions considering cost and the other statutory factors—and are

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830 (proposed June 18, 2014).
[2] 42 U.S.C. § 7411(b), (d).

coordinated effectively with EPA's standards for newly constructed, modified, and reconstructed fossil fuel-fired EGUs.

All prior written and oral testimony and submissions to the Agency in this matter, including all citations and attachments, as well as all of the documents cited to in these comments and attached hereto are hereby incorporated by reference as part of the administrative record in this EPA action, Docket ID No. EPA–HQ–OAR–2013–0602.

We appreciate the opportunity to provide comments on this important rulemaking. Please direct any inquiries regarding these comments to Megan Ceronsky, Director of Regulatory Policy and Senior Attorney at EDF, or Tomás Carbonell, Senior Attorney at EDF.

Respectfully submitted,

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Attachments:

Attachment A: John A. "Skip" Laitner & Matthew T. McDonnell, *Energy Efficiency as a Pollution Control Technology and a Net Job Creator Under Section 111(d) Carbon Pollution Standards for Existing Power Plants* (Nov. 28, 2014)

Attachment B: Brief Amicus Curiae of Electrical Engineers, Energy Economists and Physicists in Support of Respondents in No. 00-568, *New York v. FERC*, 535 U.S. 1 (2002)

Attachment C: Andover Technology Partners, *Natural Gas Conversion and Cofiring for Coal-Fired Utility Boilers* (Nov. 30, 2014)

TABLE OF CONTENTS

Executive Summary

EDF strongly supports EPA's proposed Clean Power Plan. In these comments we discuss the urgency of acting to address carbon pollution from the largest source in our country and lay out the strong legal foundation upon which the Clean Power Plan is based. We strongly support EPA's approach to identifying the "best system of emission reduction" to address carbon pollution from power plants; EPA's approach fulfills the statutory requirements and appropriately reflects the uniquely unified and interconnected nature of the electric grid and the generation resources that energize it as well as the end-users who use power from it. We describe the consistency of this rulemaking with past federal clean air standards addressing power plant emissions and the distinct roles of the Federal Energy Regulatory Commission and public utility regulators in regulating aspects of the power sector, roles they will play in the context of these standards and have played in the context of all prior power plant emission standards. We explore the conflict between the 1990 House and the Senate amendments to Section 111(d) and EPA's clear authority to address carbon pollution from power plants in that context. We discuss the key role that environmental justice must play in EPA's mission and how environmental justice concerns should be addressed in the context of the Clean Power Plan.

We then examine the technical foundation for EPA's four building blocks, and recommend changes to the proposal that would more accurately reflect the potential to reduce carbon pollution from regulated fossil fuel-fired plants and drive greater pollution reductions. Finally, we recommend adjustments to address the potential for emission "leakage" across state lines, discuss the importance of ensuring that the Act's requirement for enforceability is met through federally enforceable plan components and standards or "backstops" enforceable against regulated sources that ensure state targets are attained, and explain the irreducible components of a state submittal requesting a delay in the deadline for state plan submission.

In summary, the comments make the following recommendations:

A. Summary

We strongly support EPA in moving forward with the proposed Clean Power Plan in a strengthened form. We strongly support EPA's proposed "best system of emission reduction", which looks at the real-world potential to reduce carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-emitting power plants and less on the highest-emitting power plants. We urge EPA to finalize these historic and urgently needed carbon pollution standards by June 1, 2015, as set forth in the Presidential Memorandum on Power Sector Carbon Pollution Standards.

We also urge EPA to strengthen the environmental benefits of the standards by:

- Recognizing the full potential across the electric system and all resource types to reduce emissions and especially utilizing updated cost and performance data for renewables and energy efficiency to ensure we achieve more at lower cost;

- Strengthening the emissions outcome in 2020 – near term emissions reductions are vital for climate security; and

- Significantly strengthening the emissions outcome in the later years – 2030 is far too long to achieve such modest emission reductions.

B. Background

It is imperative that we dramatically reduce carbon pollution. The science is clear: rising concentrations of heat-trapping gases like carbon dioxide in the atmosphere will destabilize our climate and lead to severe impacts on our health and well-being and risk triggering catastrophic climate change.

We are already seeing the impacts of climate change on our communities and facing substantial costs from these impacts. But the costs that our children and grandchildren will face if we fail to act now are simply unacceptable.

The National Climatic Data Center reports that the United States experienced seven climate disasters that each caused more than a billion dollars of damage in 2013, including devastating floods and extreme droughts in a number of western states. These are precisely the type of impacts projected to affect American communities with increasing frequency and severity as climate-destabilizing emissions continue to accumulate in the atmosphere.

The Third National Climate Assessment, released earlier this year, found that if greenhouse gas emissions are not reduced it is likely that American communities will experience:

- increased severity of health-harming smog and particulate pollution in many regions;
- intensified precipitation, hurricanes, and storm surges;
- reduced precipitation and runoff in the arid West;
- reduced crop yields and livestock productivity;
- increases in fires, insect pests, and the prevalence of diseases transmitted by food, water, and insects; and
- increased risk of illness and death due to extreme heat.

We must act now to reduce carbon pollution and mitigate these impacts. Fossil fuel-fired power plants are the largest source of greenhouse gases in our nation, and the solutions are at hand to reduce carbon pollution from the power sector. Reducing carbon pollution will also result in important reductions in health-harming co-pollutants such as mercury, nitrogen oxides, sulfur dioxide, and particulates. Reducing these co-pollutants will reduce asthma attacks, heart attacks, hospital admissions, missed school and work days, and premature deaths.

C. Best System of Emission Reduction

We strongly support EPA's proposed "best system of emission reduction," which sets targets for each state's CO2-emitting power plants by looking at the real-world potential to reduce their carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-emitting power plants and less on the highest-emitting power plants.

Under the Clean Air Act and Supreme Court precedent identifying greenhouse gases as "air pollutants" covered under the Act, EPA is required to identify the "best" system of emission reduction that has been "adequately demonstrated" considering cost, energy requirements, and other health and environmental outcomes. We know that the system of emission reduction proposed by EPA is adequately demonstrated because power companies and states across the country are effectively using each of the building blocks to cut emissions of carbon pollution and other dangerous air pollutants from fossil fuel-fired power plants. We agree with EPA that it is the "best" system as defined by the Clean Air Act because it has the potential to secure large reductions in carbon pollution at reasonable cost, and will provide companies and states with flexibility to manage energy requirements and identify the emission reduction pathways that make the most sense for them.

This system of emission reduction reflects the reality of the electricity system, within which different power generation sources and demand-side energy efficiency resources are managed dynamically to ensure that energy demand is met at each moment in time. Companies and states have long been relying on the interconnected nature of the electric grid to reduce harmful pollution from power plants. Because supply and demand must be continuously balanced on the grid, adding renewable electricity backs down generation at fossil fuel-fired plants—and reduces emissions accordingly. Likewise, improving energy efficiency lowers demand for electricity, reducing power generation and thus emissions. States and power companies have been increasing use of natural gas plants which has reduced emissions from coal-fired power plants. Coal-fired power plants can (and many already do) co-fire with natural gas, which reduces combustion emissions. Coal plants can also be converted to burn natural gas which reduces combustion emissions, which has occurred at many facilities. These techniques—deploying non-emitting generation resources, improving energy efficiency, and switching to lower-polluting fuels—are traditional methods of addressing air pollution issues under the Clean Air Act.

EPA's proposed system of emission reduction — an emission limit that power plants can achieve through compliance measures including efficiency improvements at power plants, shifts from coal to gas-fired power generation, deployment of renewable energy, and harvesting energy efficiency —meets the requirements of the Clean Air Act. The emission reduction techniques included in the targets are "adequately demonstrated" and enable sources to achieve the greatest emission reductions considering cost, impacts on energy, and other health and environmental outcomes (note comments below on expanding and strengthening the BSER). The flexibility of this system enables states to secure emission reductions cost effectively, to manage impacts on energy and ensure that there are no effects on reliability, and to reduce carbon emissions by building on existing state clean energy and efficiency programs. This system allows states to secure all of the co-benefits of transitioning to cleaner energy and harvesting energy efficiency, reducing not only carbon pollution but also the burden of other health-harming air pollution on their communities. Investment in renewable generation and energy efficiency will drive job creation. The fuel savings of renewable resources and energy efficiency improvements will lower utility bills for families and businesses. Those savings will then be spent on other goods and services, stimulating the economy, as states with strong energy efficiency programs are already experiencing.

The system of emission reduction identified by EPA can achieve even greater emission reductions than is reflected in EPA's analysis.

The BSER building blocks proposed by EPA include:

1) Making existing coal plants more efficient
2) Using existing natural gas plants more effectively
3) Increasing renewable and nuclear generation
4) Increasing end-use energy efficiency

A careful analysis of the emission reduction opportunities in each of the four blocks identified by EPA demonstrates that even greater savings are available from each of the four blocks. As discussed in detail below and in EPA's Notice of Data Availability Released on October 27, 2014, EPA must also fix the formula for calculating state targets to properly account for reductions in emissions from renewable energy and energy efficiency.

D. BSER Building Block 1 & 2

EPA's analysis appropriately considered the potential for efficiency improvements at power plants to drive reductions in emissions when combined with the rest of the proposed system of emission reduction. EPA identifies opportunities for improvements that can be made based on specific power plant upgrades and also for operational and maintenance changes. EPA determined that coal-fired power plants can achieve at least a six percent improvement in performance. This is a conservative estimate. Analysis of carbon emissions at coal plants shows that even greater reductions would be available if power plants simply had to match the lowest emission rate actually achieved by the plant over the past decade.

In its Notice of Data Availability, EPA requested comment on whether it should consider, alongside existing NGCC plants, redispatch from coal plants to new NGCC and the potential to co-fire with natural gas or convert to natural gas at existing coal boilers. While we believe that scaling up energy efficiency and renewable energy is the best and least-cost compliance pathway and will urge states to focus their compliance plans on clean energy, we urge EPA to set targets that reflect the opportunities presented by all three coal to natural gas options. Already all three of these pathways are being deployed across the country even without any carbon pollution standards in place—and as such they are clearly adequately demonstrated, and reasonable in cost. All three of these pathways secure significant reductions in combustion carbon emissions, as well as significant reductions in harmful co-pollutants like mercury, NO_X, SO_X, and particulates at the power plant stack. These co-benefits will have enormous near-term benefits to public health. In addition to providing tremendous health benefits, fuel switching will reduce the need for and the costs of pollution controls on coal-fired power plants.

However, given the increase in the use and extraction of natural gas already underway in the country, we strongly urge EPA to address emissions of methane, a potent climate pollutant, from oil and natural gas development under the Clean Air Act. President Obama committed to taking action on methane as part of the Climate Action Plan. It is vital that EPA follow through on this pledge by promptly commencing a rulemaking to set standards limiting emissions of dangerous climate and public health harming pollutants from new and existing sources in this sector.

In its original proposed rule, EPA considered the potential to shift power generation from existing coal-fired power plants to underutilized natural gas combined cycle (NGCC) plants. EPA did not include new NGCC plants in setting state targets but suggested that it was considering whether states should be allowed to use new NGCC plants for compliance purposes. EPA must ensure symmetry between the resources available for compliance purposes and the resources used to determine the targets. Thus, unless a potential compliance option is too costly or not adequately demonstrated, it must be included in setting the target if EPA will allow its use for compliance purposes.

E. BSER Building Block 3

EPA appropriately considered the potential to reduce emissions from coal and gas fired power plants by deploying renewable energy. But EPA has significantly underestimated the amount of renewable energy that can be deployed at reasonable cost. In its proposal, EPA included two frameworks for analyzing the potential for emission reductions via renewable energy deployment—the use of regional averages of renewable energy policies and a technical-economic potential analysis. Both significantly underestimate the actual potential by failing to reflect the dramatic cost reductions that have occurred in recent years. In order to properly assess the potential from renewable energy, EPA must use up-to date data. Current data show that wind and solar costs are each approximately 45 percent less costly than EPA assumed in its analysis. We urge EPA to use current data and any subsequently published data on costs and technical potential in order to evaluate the quantity of renewable energy that can be deployed at reasonable cost in each state. We further urge EPA to ensure that the rate of renewable energy deployment assumed in EPA's analysis is at least as fast as the historical rates of deployment.

F. BSER Building Block 4

EPA's Proposed Standards properly considered the potential to use improved demand-side energy efficiency to drive reductions in carbon pollution, which will also drive reductions in the harmful co-pollutants emitted by fossil fuel-fired power plants. By making investments to increase energy efficiency in our homes, businesses and factories, we can reduce carbon pollution while also lowering utility bills, creating jobs, and stimulating the economy.[3] Based on its analysis, EPA determined that states can eventually achieve incremental annual energy savings of 1.5 percent of retail sales. This level of energy efficiency is readily achievable and, if anything, underestimates the amount of energy efficiency that can be achieved. In reaching its determination that 1.5 percent annual savings are possible from energy

[3] *See generally* John A. "Skip" Laitner and Matthew T. McDonnell, *Energy Efficiency as a Pollution Control Technology and a Net Job Creator Under Section 111(d) Carbon Pollution Standards for Existing Power Plants* (Nov. 2014) (Attachment A).

efficiency, EPA excluded a number of important additional opportunities for energy efficiency such as building codes, transmission and distribution, voltage optimization, and combined heat and power—which indicates how conservative EPA's analysis is. The country's energy efficiency resource is vast, and grows continuously as new technologies are developed. Further, EPA also underestimates the potential for energy efficiency by assuming that states will only be able to ramp up energy efficiency programs extremely slowly. But new energy efficiency programs can be implemented more quickly than EPA assumes, as demonstrated by the faster expansion of efficiency programs achieved in practice by many states. EPA should use a faster ramp up rate, allowing for greater overall emission reductions from energy efficiency.

EPA's analysis also overestimated the cost of improving energy efficiency by using cost assumptions more than fifty percent above the costs observed in practice—including costs observed in the assessments cited by EPA. EPA should use more realistic program cost numbers and data on the true scale of demand-side energy efficiency potential in its analysis of the potential for carbon reductions.

G. Formula Change for Building Block 3 & 4

EPA should ensure that the calculation of state targets fully reflects the role of renewable energy and energy efficiency in reducing carbon pollution.

In its October 27, 2014 Notice of Data Availability, EPA explains that the original formula used in its proposed rule failed to correctly account for the emission reductions generated by renewables and energy efficiency. As EPA explains, the formula used in the proposed rule failed to account for the reduction in generation at coal and gas power plants that will occur when additional renewables are added to the grid and when we improve energy efficiency. When EPA sets final state targets, it should use the corrected formula proposed in the Notice of Data Availability. This is particularly important because it will ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

H. Strengthening the CPP

All of the suggested changes to the CPP proposal noted above have the potential to strengthen the public health and environmental outcome and we believe this can be accomplished at reasonable cost.

The impact of using outdated cost and performance numbers for renewables and energy efficiency in estimating the cost of the Clean Power Plan is substantial. EPA found that under the Clean Power Plan, the power sector could reduce its emissions by 30% in 2030 below 2005 levels, costing between $7.5 billion and $8.8 billion. But because EPA used unreasonably high and out-of-date cost assumptions for renewable energy and energy efficiency, EPA substantially overstates the costs of compliance with the standard and underestimates the potential to make these critical carbon reductions. A study by the Natural Resources Defense Council found that simply by updating the cost and performance parameters for renewable generation and energy efficiency to be consistent with today's technologies, compliance could be achieved at net savings of $1.8 billion in 2020 and $6.6 billion in 2030. In the final rule, EPA should update its cost numbers and strengthen the state targets to reflect the emission reductions available based on current data on availability and cost.

I. Environmental Justice

The Clean Power Plan will result in significant improvements in air quality across the country. EPA estimates that it will result in a twenty-five percent drop in the pollutants that lead to soot and smog. However, we urge EPA to include in the final guidance a robust discussion of the ways in which state plans can be designed to ensure that communities bearing a disproportionate share of ambient air pollution burdens have those burdens reduced. State plans will determine how the carbon pollution reductions required by the state targets are achieved—and with those reductions, reductions in harmful co-pollutants will follow. This will be particularly important in the context of state planning around attainment of ozone ambient air quality standards and other clean air protections, enabling comprehensive planning to ensure that states are ensuring that carbon pollution is reduced and other harmful air pollution problems are addressed.

J. State Plan Flexibility & Minimum Requirements to Ensure Enforceability

We support EPA's proposal to give states flexibility to design tailored plans to meet their carbon pollution reduction targets. States will be able to build their plans on the foundation of existing clean energy and efficiency policies, and shape their plans to capture the emission reduction opportunities that deliver the greatest co-benefits for their citizens—cleaner air, more efficient homes and businesses with lower utility bills, and a vibrant clean energy economy.

In order to satisfy the requirements of the Clean Air Act and EPA's long-standing regulations, the Clean Power Plan must ensure that emission reductions secured under the plan are verifiable and enforceable. State plans taking a source-based approach can do this by requiring that each power plant achieve the target rate by keeping its emissions below the target rate or purchasing necessary credits or, in a "mass-based" system by holding sufficient emission allowances. EPA must define minimum requirements for measurement and verification of energy efficiency and renewable energy that will be used as credits in a rate-based system.

In order to ensure enforceability, a state taking a "state commitment" approach must also incorporate a "backstop" mechanism that will ensure that any shortfall in emission reductions will be remedied and that applies to the regulated emission sources. States can help regulated sources comply by requiring actions such as implementation of energy efficiency or purchase of renewable energy by other entities such as load-serving utilities. But it is important that the state plan ensures, through the backstop, that there is an enforceable mechanism that ensures that the emission reductions will be achieved. The backstop mechanism could be designed by the state and should be incorporated in its plan. In order to ensure that the requirements of the Act are met and protect environmental integrity of the standards, backstops must be triggered automatically by any shortfall and apply directly to the regulated sources.

K. Conversion of State Targets from Rate to Mass

We support the conversion of rate targets to mass-based targets. EPA must ensure that the conversion process provides equivalence between the two targets.

We support EPA's effort to facilitate state adoption of mass-based targets. EPA must provide clear and rigorous guidance to ensure that a state plan adopting a mass-based approach is equivalent to the rate-based target. In addition, in order to fulfill the statutory mandate to address harmful air pollution through limitations on emissions, EPA must ensure that states will achieve the necessary reductions through the actions taken in their plans and that emission reductions are not eroded due to changes in electricity generation between neighboring states that have different plan structures (rate vs. mass) or different target rates.

L. Model State Plans

In order to support state plan development, EPA should provide model plan components that states could utilize (for example flexible, source-permit-based rate-based programs and mass-based programs with trading). EPA should emphasize model components facilitating state deployment of renewable energy and demand-side energy efficiency. EPA should also specify minimum criteria or requirements for each policy approach to ensure enforceability. Further, EPA should provide guidance on the full range of potential multistate approaches—from agreements about renewable energy and energy efficiency, to frameworks allowing emission reduction credits to cross state lines, to joint state plans.

M. Strong Interim Targets, Compliance Periods & Program Review

Strong interim targets are essential to deliver near-term reductions in carbon pollution and begin to transition the power sector towards lower-polluting infrastructure, deploying investments in renewable energy and energy efficiency that will create jobs and stimulate the economy.

The interim standard that takes effect beginning in 2020 is amply achievable. The extensive analysis of the building blocks, set out below, addresses important and cost-effective ways the building blocks can be strengthened by achieving deeper emissions reductions over a more accelerated time frame. These include achieving deeper reductions at the source through cost-effective co-firing and repowering with lower emitting fuels that is being widely deployed at coal plants today, the demonstrated potential to deploy more extensive and cost-effective renewable energy resources, and the rapid mobilization of demand side energy efficiency including a broader array of efficiency solutions than considered by EPA.

EPA expressly recognized that a more rigorous standard could be achieved by 2025, finding that it is achievable for power sector emissions to be 29 percent below 2005 levels in 2025 based on the changes reflected in the four building blocks. EPA's finding that a deeper reduction in 2025 is achievable based on solutions adequately demonstrated meets the pertinent statutory criteria for determining the best system of emission reduction and thereby requires EPA to establish such a standard in 2025 that "reflects the degree of emission limitation achievable." Alternatively, EPA must establish a five year compliance requirement beginning in 2025 and continuing through 2029 that is far more rigorous than the 2020-2029 10-year average interim standard.

EPA must also provide a legally enforceable timeline for securing reductions no later than 2030. As EPA recognizes, Congress has woven an updating mechanism into the fabric of section 111 that commands the Agency refresh the BSER for new sources "at least every eight years" and is inextricably connected with updating the existing source standards. EPA must carry out its legal responsibility by committing to determine in 2025, through a legally enforceable mechanism, the BSER that applies over time – and that is not stagnant in maintaining in 2030 the standard of performance established a decade earlier. Rather, the BSER analysis must be, as Congress intended, a is vibrant, rigorous, and dynamic tool in securing for our nation's public health, environmental quality, and prosperity--no later than the 2030 timeframe--the additional far deeper "degree of emission reductions achievable."

Introduction

The Intergovernmental Panel on Climate Change's recent report, "Climate Change 2013: The Physical Science Basis," includes several grim findings:

- Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, sea level has risen, and the concentrations of greenhouse gases have increased.[4]

- It is *extremely likely* that human influence has been the dominant cause of the observed warming since the mid-20th century.[5]

- Continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. Limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.[6]

Climate impacts are already affecting American communities—and the impacts are projected to intensify. The U.S. Global Change Research Program has determined that if greenhouse gas emissions are not reduced it is likely that American communities will experience:

- increased severity of dangerous smog in cities;[7]

- intensified precipitation events, hurricanes, and storm surges;[8]

- reduced precipitation and runoff in the arid West;[9]

- reduced crop yields and livestock productivity;[10]

- increases in fires, insect pests, and the prevalence of diseases transmitted by food, water, and insects;[11] and

- increased risk of illness and death due to extreme heat.[12]

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[4] Intergovernmental Panel on Climate Change Working Group I, Summary for Policymakers, at 4 (2013), *available at* http://www.climatechange2013.org/images/report/WG1AR5_SPM_FINAL.pdf.
[5] *Id.* at 17.
[6] *Id.* at 19.
[7] U.S. Global Change Research Program, Global Climate Change Impacts in the United States, at 92-93 (2009), *available at* http://downloads.globalchange.gov/usimpacts/pdfs/climate-impacts-report.pdf.
[8] *Id.* at 34-36.
[9] *Id.* at 45.
[10] *Id.* at 74-75, 78.
[11] *Id.* at 82-83.

Extreme weather imposes a high cost on our communities, our livelihoods, and our lives. The National Climatic Data Center reports that the United States experienced seven climate disasters each causing more than a billion dollars of damage in 2013, including the devastating floods in Colorado and extreme droughts in western states.[13] These are precisely the type of impacts projected to affect American communities with increasing frequency and severity as climate-destabilizing emissions continue to accumulate in the atmosphere.

Power plants are far and away the largest source of greenhouse gas emissions in the United States.[14] In 2012, fossil fuel fired power plants emitted more than 2 billion metric tons of CO_2e, or 40% of U.S. carbon pollution and nearly one-third of total U.S. greenhouse gas emissions.[15]

Section 111 of the Clean Air Act provides for the establishment of nationwide emission standards for major stationary sources of dangerous air pollution—including, since 1971, power plants.[16] In response to the Supreme Court's decision in *Massachusetts v. EPA*[17] that the Clean Air Act's protections encompass greenhouse gas emissions and to EPA's science-based determination that these climate-destabilizing emissions endanger public health and welfare,[18] EPA is now developing § 111 Carbon Pollution Standards for power plants.

EPA is developing carbon pollution-reduction standards for new and existing power plants under Clean Air Act § 111(b) and (d) respectively. Emission standards for existing pollution sources are developed and implemented through a dynamic federal-state collaboration, the legal underpinnings of which are described here. Through this collaboration, reflected in the Clean Power Plan proposed by EPA in June under § 111(d), EPA and the states can put in place strong standards that will drive cost-effective reductions in carbon pollution and support our nation's transition to a cleaner, safer, smarter power infrastructure.

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[12] *Id.* at 90-91.
[13] National Climatic Data Center, Billion-Dollar U.S. Weather/Climate Disasters 1980-2013 (2014), *available at* www.ncdc.noaa.gov/billions/events.pdf.
[14] Unless otherwise indicated, this document uses the term "power plants" or "electric generating units" (EGUs) generically to refer to existing EGUs covered by the requirements of the proposed Clean Power Plan.
[15] EPA, DRAFT Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012, at ES-5 to ES-7, tbl. ES-2 (Feb. 2014), *available at* http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf. Of the heat-trapping pollutants emitted by sources in the United States, carbon dioxide is by far the most prevalent. Transportation emissions are the only greenhouse gas emission source that approaches the scale of power plants.
[16] *See, e.g.,* Congressional Research Service, "Climate Change: Potential Regulation of Stationary Greenhouse Gas Sources Under the Clean Air Act," Larry Parker and James E. McCarthy, 7-5700, R40585 (May 14, 2009).
[17] 549 U.S. 497 (2007).
[18] 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).

Background

Section 111(b) directs EPA to identify ("list") categories of stationary sources that significantly contribute to dangerous air pollution, and to establish emission standards for air pollutants emitted by new sources in the listed categories.[19] Power plants were listed in 1971.[20] Section 111(d) directs the development of emission standards for pollutants emitted by existing sources in the listed categories. Emission standards are not established under § 111(d) if a source category's emissions of a specific pollutant are regulated under the provisions of the Clean Air Act addressing hazardous or criteria air pollutants.[21] [22]

The Clean Air Act provides that an emission standard (for new or existing sources) must reflect the emission reductions achievable through application of the "best system of emission reduction" that EPA finds has been adequately demonstrated, taking into account costs and any non-air quality health and environmental impacts and energy requirements.[23] For existing sources, once EPA guidance is issued identifying the best system of emission reduction and the emission reductions achievable under that system, the standards are implemented through state plans submitted to EPA for approval.[24] These plans must provide for the enforcement of the emission standards.[25]

The CPP is Consistent with Longstanding Regulation of Power Plants Under the CAA

EPA has long regulated pollutant emissions from power plants, which the largest single source of most air pollutants in the nation. Soon after Congress enacted the 1970 Clean Air Act amendments that first provided for a strong federal role in addressing air pollution, EPA established national standards for

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[19] 42 U.S.C. § 7411(b)(1).

[20] Air Pollution Prevention and Control: List of Categories of Stationary Sources, 36 Fed. Reg. 5931 (Mar. 31, 1971) (listing "Fossil fuel-fired steam generators of more than 250 million B.t.u. per hour heat input").

[21] 42 U.S.C. § 7411(d). Congress enacted § 111 in the 1970 Clean Air Amendments. Emissions of criteria pollutants from all sources are addressed through the detailed State Implementation Plan process set forth in § 110, *id.* § 7410, and hazardous air pollutants are the subject of a detailed framework of protections set out in § 112, *id.* § 7412. In its 1975 implementing regulations and for the subsequent 15 years EPA treated § 111(d) as a means of 'filling the gap,' and addressing pollutants that were not otherwise covered by § 110 or 112. *See* 40 Fed. Reg. 53,340, 53,340 (Nov. 17, 1975). In 1990, the House and Senate passed conflicting amendments to § 111(d), both of which were included in the Clean Air Act Amendments of 1990. In a 2005 rulemaking, after conducting a thorough analysis of the language and legislative history of the two versions, EPA described one way to reconcile them in a manner that comported with the overall thrust of the Clean Air Act Amendments of 1990. EPA concluded that it has authority under § 111(d) to regulate any air pollutant not listed under § 112(b) (i.e., any non-hazardous air pollutant), even if the source category to be regulated under § 111 is also being regulated under § 112. *See* 70 Fed. Reg. 15,994, 16,030-32 (Mar. 29, 2005). Thus, the only pollutants EPA may *not* regulate under § 111(d) are hazardous air pollutants emitted from a source category that is actually being regulated under § 112 and criteria pollutants.

[22] 42 U.S.C. § 7411(d).

[23] *Id.* § 7411(a)(1).

[24] *Id.* § 7411(d)(1)(A).

[25] *Id.* § 7411(d)(1)(B).

emissions of SO_2 from coal-fired power plants.[26] Reflecting Congressional recognition of the extraordinary impact of energy generation on air pollution and the need to address that pollution while ensuring electricity supply, numerous provisions of the statute authorize, and in many cases require, EPA to consider energy-related impacts of pollution standards. EPA has established pollution standards for fossil fuel-fired power plants to address emissions of, among other things, sulfur dioxide; nitrogen oxides; particulate matter; and mercury, acid gases, and other hazardous air pollutants. As a result, harmful emissions of many of these pollutants have been dramatically reduced or soon will be, without harming the power sector's ability to deliver affordable, reliable electricity. The regulation of CO_2 emissions from power plants under the Clean Power Plan is no different. The flexibility provided in Section 111(d) and the authority delegated to EPA to consider energy impacts has enabled the Agency to propose, in the Clean Power Plan, a flexible framework that empowers states to deploy measures that will cost-effectively reduce CO_2 emissions without any adverse impact on electric reliability. Furthermore, in taking a flexible-systems based approach to CO_2 regulation, EPA has accommodated and recognized state-driven efforts to reduce emissions using this flexible toolkit.

The impact of coal-fired power plants on air quality is very significant. In addition to being major sources of fine particles (PM2.5), coal-fired power plants emit approximately 70% of total U.S. SO_2 emissions, 46% of mercury emissions, 19% of NO_x emissions, and one-third of anthropogenic greenhouse gas emissions, in the form of CO_2.[27]

Cognizant of the relationship between energy generation and air pollution, Congress has specifically authorized, if not required, EPA to consider this relationship in numerous provisions of the Clean Air Act.[28] Throughout the Clean Air Act, Congress expressly compels EPA to consider the "energy impacts"

[26] "Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971," 36 Fed. Reg. 24,876, 24, 879 (Dec. 23, 1971) (codified at 40 C.F.R. § 60.40-46.)
[27] James E. McCarthy, Clean Air Issues in the 113th Congress, Congressional Research Service Report (June 27, 2014) at 5.
[28] *See, e.g.,* 42 U.S.C. §§ 7408(b)(1) (requiring Administrator to issue information on pollution control techniques, including energy requirements for controls); 7408 (f)(2)(C) (requiring Administrator to provide information on energy impact of pollution control measures); 7409(d)(2)(C)(requiring Administrator to appoint a committee to advise EPA on, inter alia, "energy effects" that may result from strategies for NAAQS attainment and maintenance); 7410(f)(providing a process to temporarily suspend SIP requirements in response to "energy emergencies"); 7411(a)(1)(mandating that "energy requirements" must be taken into account in selection of best system of emission reduction); 7411(j)(1)(A)(ii) (authorizing waiver for innovate systems of emission reduction based on inter alia, "lower cost in terms of energy . . . impact"); 7412(d)(2)(compelling consideration of energy requirements in establishing emission standards); 7412(f)(2)(A)(compelling consideration of "energy" as a factor in setting emission standards); 7429(a)(2)(compelling consideration of energy requirements in setting emission standards); 7491(g)(1)(requiring "energy. . . impacts of compliance" to be taken into account in reasonable progress determination) 7491(g)(2)(requiring "energy . . . impacts of compliance" to be taken into account in determining best available retrofit technology); 7511b(e)(1)(A)(compelling consideration of "energy impacts" in determination of best available controls); 7617(c)(5)(requiring economic impact analysis to include "effects of standard or regulation on energy use")7651(b)(stating that the purpose of Title IV is "to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy"); 7651b(f)(stating that nothing in the Title IV allowances trading program shall be construed as modifying the Federal Power Act or affecting FERC authority under that act); 7651c(f)(providing for emissions allowances based on avoided energy generation); 7651f(b)(2)(D)(requiring consideration of energy impacts in establishing NO_X emission limitation for boilers); and 7651(g)(c)(1)(B)(allowing emission limitations to be satisfied by reduced utilization achieved through

of pollution control measures when setting emission standards.[29] Furthermore, with respect to emissions of hazardous pollutants, SO_2, and NO_X, Congress specifically provided for the regulation of fossil-fuel fired power plants.[30]

The long history of EPA's regulation of power plants also demonstrates how some members of the power industry have repeatedly responded to urgently needed, health-protective pollution standards by denying the harms caused by power plant pollution and by making exaggerated claims that clean air standards constituted regulatory overreach into the energy market that would disrupt electric reliability. In 1974, an advertisement by American Electric Power Company, one of the largest sources of power plant pollution in the country, alleged that EPA emission standards for SO_2 would cause: "Literally thousands unemployed. Millions lost in state tax revenues and more millions lost by businesses that supply the coal industry."[31] In 1982, AEP sent mailers to its customers claiming that proposed EPA controls to avoid acid rain would cost the company and its customers $2 billion a year based on a study described by the Congressional Research Service as using "questionable assumptions."[32] In 1990, an AEP official told the Boston Globe that CAA legislation to address acid rain could lead to "the potential destruction of the Midwest economy."[33] In 2004, opposing standards to control hazardous air pollutants emitted by power plants, AEP claimed that "there is a lack of any demonstrated link between power plant emissions and inhalation based health effects risks."[34] In 2011, AEP's sustainability report claimed that "power plant particulate emissions are not a significant risk to public health,"[35] and AEP's chairman and CEO claimed that Clean Air Act pollution standards would cause AEP to "prematurely shut down nearly 25% of [its] current coal-fueled generating capacity, cut hundreds of good power-plant jobs, and invest billions of dollars in capital" and stated that, "The sudden increase in electricity rates and impacts on state economies will be significant."[36]

The reality of Clean Air Act standards for power plants has demonstrated such fear-mongering to be entirely baseless. The federal clean air standards addressing SO_2, NO_x, hazardous air pollutants (including mercury), and particulate matter have without exception achieved pollution reductions without affecting the provision of reliable, affordable power. Since the Clean Air Act was passed in 1970, particulate matter emissions have been cut by 83% and SO_2 emissions by 58%--while our population grew by over

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energy conservation); *see also id.* at 7412(n)(1)(specifically requiring EPA to make determinations regarding the regulation of emissions of hazardous pollutants from electric utility steam generating units).

[29] *See* above.

[30] *See* 42 U.S.C.§§ 7412(n)(1) (requiring EPA to make determinations regarding the regulation of emissions of hazardous pollutants from electric utility steam generating units; 7651b (SO_2 emission limitation and trading program for existing and new power plants); and 7651f (NO_X emission limitation and trading program for existing and new power plants).

[31] The Washington Post, Oct. 25, 1974, AEP Display Ad 32, "Amen!"

[32] Sarasota Herald-Tribune, Sept. 4, 1982, "The dirty politics of clean air."

[33] Boston Globe, Oct.17, 2010, "A clear water revival." *accessible at* http://articles.boston.com/2010-10-17/news/29321038_1_acid-rain-power-plant-global-warming. (viewed 8/18/2011).

[34] AEP Comments on EPA's Proposed National Emissions Standards for Hazardous Air Pollutants, June 29, 2004, EPA Rulemaking Docket, Doc ID: EPA-HQ-OAR-2002-0056-3558.

[35] AEP 2011 Corporate Accountability Report, p. 22. *accessible at* http://www.aepsustainability.com/docs/2011_AEP_CAReport.pdf.

[36] AEP Press Release, June 9, 2011, "AEP shares plan for compliance with proposed EPA regulations." *accessible at* http://www.aep.com/environmental/news/?id=1697 (viewed 8/18/2011).

50% and the economy by over 200%. In 1990, power companies predicted that addressing SO_2 pollution would cost $1000-$1500/ton and electricity prices would increase up to 10% in many states. The actual pollution reduction cost has been between $100-$200/ton for most of the program, and electricity prices fell in most states. As a result of the reductions in pollution achieved, acid rain has been dramatically reduced and the limits on SO_2 were met faster and at a dramatically lower price than expected in 1990.[37] Between 1990 and 2006, when electric utilities were claiming that electricity rates would increase substantially because of EPA regulations, rates actually fell in most states—by 47% in Arkansas, 32% in Georgia, 64% in Illinois, 28% in Indiana, 35% in Michigan, 30% in North Carolina, 18% in Ohio, 36% in Pennsylvania, 40% in Utah, and 36% in Virginia.[38] In the meantime, our nation's preeminent public health organizations—including the American Lung Association and the American Academy of Pediatrics—have documented the serious respiratory, cardiovascular, and development harm—particularly for children and the elderly—caused by power plant pollutants, and the importance of addressing these emissions.[39] Because of the health harms reduced by federal clean air standards, the benefits of the Clean Air Act will have exceeded the costs of pollution reductions by 30:1 between 1990-2020.[40]

More recently, in challenging the Cross-State Air Pollution Rule (CSAPR), energy industry petitioners claimed that meeting the Phase I emission budget requirements of the rule would lead to the idling of generating facilities, threaten electric system reliability, and cause blackouts.[41] Yet emissions data collected by EPA from the years when the Phase I requirements would have been in effect but for the litigation shows that actual emissions were within the rule's budgets—demonstrating conclusively that compliance would not have caused the disastrous consequences predicted by industry challengers.[42] Furthermore, EPA determined that the vast majority of the emissions reductions required by Phase II of the rule could be met by power plants resuming operation of already installed *but unused* pollution control devices.[43] With respect to the Mercury and Air Toxic Standards (MATS), energy industry claims about

[37] *See* U.S. House of Representatives Committee on Energy & Commerce, June 16, 2009, "Industry claims about the costs of the Clean Air Act." accessible at http://democrats.energycommerce.house.gov/Press 111/20090616/dc_industryjobs.pdf (viewed 8/18/2011).
[38] *See* U.S. House of Representatives Committee on Energy & Commerce, June 16, 2009, "Industry claims about the costs of the Clean Air Act." accessible at http://democrats.energycommerce.house.gov/Press 111/20090616/dc_industryjobs.pdf (viewed 8/18/2011); U.S. Environmental Protection Agency, April 2011, "The benefits and costs of the Clean Air Act from 1990 to 2020." accessible at http://www.epa.gov/oar/sect812/prospective2.html (viewed 8/18/2011).
[39] American Lung Association, American Thoracic Society, American Public Health Association, Asthma and Allergy Foundation of America, American Academcy of Pediatrics, Physicians for Social Responsibility, Letter to Representative Joe Barton, May 10, 2011. Accessible at: http://www.lungusa.org/get-involved/advocate/advocacy-documents/doctors-letter-.pdf.
[40] Environmental Protection Agency, April 2011, "The Benefits and Costs of the Clean Air Act from 1990 to 2020." Accessible at http://www.epa.gov/air/sect812/feb11/fullreport.pdf.
[41] *See EME Homer City Generation, L.P. v. U.S. EPA,* No. 11-1302 (D.C. Cir.), Luminant Mot. for Stay (Dkt. No. 1329866) (filed Sept. 15, 2011), at 16-20; Kansas Util.'s Mot. for Stay (Dkt. No. 1337158) (filed Oct. 21, 2011), at 6-14; Wisc. Electric Power Co.'s Mot. for Stay (Dkt No. 1339347) (filed Nov. 1, 2011), at 10; Entergy Corp. Stay Mot. (Dkt. No. 1338085) (filed Oct. 26, 2011), at 12-19; Ohio Mot. for Stay (Dkt. No. 1342027) (filed Nov. 15, 2011), at 18-19.
[42] *See EME Homer City Generation, L.P. v. U.S. EPA*, No. 11-1302 (D.C. Cir.), EPA Motion to Lift the Stay Entered on December 8, 2011 (Dkt. No 1499505.)(filed June 26, 2014), at 17-20.
[43] *See id.* at 19-20.

the extent of compliance costs have also proven to be inflated. First Energy claimed in 2011 that its MATS compliance costs would be $2-3 billion dollars, but by 2013 that estimate fell to $465 million.[44] Southern Company's initial estimates of compliance costs fell by 900 million dollars between the time the rule was proposed and 2012;[45] AEP's estimate of its costs of compliance also dropped by billions of dollars over this period.[46]

The Clean Power Plan is also consistent with EPA's long tradition of working collaboratively with states to foster pioneering state efforts to reduce pollution.

States have led the way in promoting renewable energy and energy-efficiency as pollution reduction measures. EPA has accommodated this state-driven innovation by providing avenues for states to satisfy Clean Air Act requirements through the use of such measures.

The development of the Regional Haze Rule exemplifies how EPA has responded to state-driven efforts to achieve pollution reduction through renewable energy and energy efficiency measures. The Western Governors' Association (WGA) provided recommendations to EPA in the context of the Agency's development of regional haze rules[47] that called for a compliance alternative under which state implementation plans for western states would include renewable energy and energy efficiency as a pollution control strategy.[48] EPA reopened the comment period specifically to address the recommendations of the WGA, and proposed adding a new regulation, 40 C.F.R. § 51.309, that provided the alternative compliance program sought by the WGA's recommendations.[49] EPA ultimately finalized that alternative compliance measure, which fully reflected the WGA's recommendations regarding renewable energy and energy efficiency measures.[50]

The NO_X SIP call also demonstrates how EPA has facilitated the use of renewable energy and energy-efficiency measures by employing a flexible approach that allows states to rely on these measures for cost-effective emission reductions. In that rulemaking, EPA determined state emission budgets by considering the level of NO_X reductions that could be obtained by applying pollution control technologies

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[44] *See* FirstEnergy, 2011 Q3 Earnings Call (Anthony Alexander, CEO) http://seekingalpha.com/article/304211-firstenergys-ceo-discusses-q3-2011-results-earnings-call-transcript; FirstEnergy, 2013 Q3 Earnings Call (Anthony Alexander, CEO) http://seekingalpha.com/article/1808342-firstenergy-management-discusses-q3-2013-results-earnings-call-transcript.
[45] *See* Southern Company, 2012 Q2 Earnings Call (Art Beattie, CFO) http://seekingalpha.com/article/749651-southern-management-discusses-q2-2012-results-earnings-call-transcript.
[46] *See* AEP, 2012 Q4 Earnings Call (Nicholas K. Akins, CEO) http://seekingalpha.com/article/1188551-american-electric-power-management-discusses-q4-2012-results-earnings-call-transcript
[47] 62 Fed. Reg. 41,138 (July 31, 1997).
[48] *See* Notice of Availability of Additional Information Related to Proposed Regional Haze Regulations; Solicitation of Comments, 63 Fed. Reg. 46952 (Sept. 3, 1998); Letter from Western Governors Association to Carol Browner (June 29, 1998), at 16-18, *available at* http://www.epa.gov/ttn/oarpg/t1/fr_notices/wgagclet.pdf.
[49] *See* Notice of Availability of Additional Information Related to Proposed Regional Haze Regulations; Solicitation of Comments, 63 Fed. Reg. 46952 (Sept. 3, 1998).
[50] *See* 64 Fed. Reg. 35,714, 35,754 (stating that section § 51.309 provides "an alternative to the general provisions of section 51.308").

to utility sources, but specifically provided that state SIPs could rely on energy efficiency and renewables as a strategy for meeting the NO_x budgets.[51]

Notably, in 2002 the George W. Bush Administration specifically called for the utilization of renewable energy development and energy-efficiency as pollution reduction measures,[52] and much of EPA's work to facilitate pioneering state efforts to develop renewables and energy efficiency as pollution reduction measures progressed under that Administration. For example, EPA has provided extensive guidance to states on incorporating renewable energy and demand-side energy reduction measures into section 110 State Implementation Plans and demonstrating compliance with NAAQS or attainment goals through the use of those measures.[53] In the last decade, a number of states have incorporated renewable energy requirements and energy-efficiency measures into EPA approved SIPs. For example, in 2005, EPA approved inclusion of county government commitments to purchase 5% of their annual electricity consumption from wind power in Maryland's SIP.[54] This approval allowed the county commitments to be credited toward NO_X reduction goals for NAAQS attainment.[55] In 2006, EPA Region 6 approved a Louisiana SIP revision for attaining the 8-hr ozone standard in Shreveport that included a performance contract whereby the City of Shreveport installed energy-saving equipment in city-owned buildings to reduce energy use by 9121 MWh per year.[56] In 2007, Virginia, Maryland, and the District of Columbia submitted SIP revisions for 8-hr ozone in the Washington non-attainment area that included commitments by municipalities to purchase renewable energy certificates representing 123 million kWh of wind energy each year from 2004 to 2009.[57] The SIP submissions also included commitments by local and state governments to replace conventional traffic lights with LED lights.[58] In 2008, EPA approved the inclusion of energy efficiency measures aimed at reducing NO_X emissions for Dallas-Fort Worth into the Texas SIP.[59] The SIP mandated the statewide adoption of the International Residential Code (IRC) and the International Energy Conservation Code (IECC), and directed counties to develop ordinances to

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[51] *See* 63 Fed. Reg. 57,356, 57,362, 57438 (Oct. 27, 1998).
[52] *See* Fact Sheet: President Bush Announces Clear Skies & Global Climate Change Initiatives (Feb. 12, 2002) *available at* http://georgewbush-whitehouse.archives.gov/news/releases/2002/02/20020214.html.
[53] *See, e.g.*, U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012; U.S. EPA, Office of Air and Radiation, Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP), September 2004; U.S. EPA, Office of Air and Radiation, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric Sector Energy Efficiency and Renewable Energy Measures, August 2004.
[54] 70 Fed. Reg. 24,988 (May 12, 2005).
[55] *Id*. at 24,989.
[56] U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[57] According to EPA guidance, these submittals were approved by EPA Regions in 2007, but there appears to be no record of those approvals in the Federal Register. See U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[58] U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[59] *See* 73 Fed.Reg. 47,835, 47,836 (Aug. 15, 2008).

impose energy efficiency requirements on the construction of new homes to reduce electricity consumption in those counties by at least 5% each year for 5 years.[60]

Under the Obama Administration, EPA has continued to work closely with states engaged in pioneering efforts to reduce power plant pollution through renewable energy and energy efficiency measures. For example, EPA has collaborated with the Connecticut Department of Environmental Protection (CTDEP) to develop pathways for the state to use its renewable portfolio standard (RPS) requirements and extensive energy efficiency programs for CAA planning and compliance under section 110.[61] Having assessed the effect of its EE and RE projects on NO_X emissions during high demand days as part of the weight of evidence analysis in its 2007 8-hr ozone attainment demonstration, CTDEP contacted EPA Region 1 for guidance on additional opportunities for incorporating RE and EE programs into its CAA planning.[62] Region 1 responded by providing CTDEP with a guidance letter outlining key issues and questions for CTDEP to consider in incorporating RE/EE measures into its SIP as federally enforceable control measures.[63]

In addressing interstate air pollution, EPA across Republican and Democratic administrations has also recognized and facilitated state efforts to reduce pollution through renewable energy and energy-efficiency measures. Both CAIR and CSAPR provided states with latitude to achieve required emission reductions through renewable energy utilization or measures to improve energy efficiency.[64] Specifically, CAIR ensured that states would have flexibility in establishing allowance set-asides for both energy efficiency and renewables.[65] CSAPR gave states the option of developing state plans to achieve reductions through alternative measures to those established in FIPs,[66] and provided for state creation of allowance set-asides for energy efficiency and renewables.[67]

In summary, Congress has provided EPA with the authority, and mandate, to address air pollution from power plants. Because power plants emit a large portion of the air pollution in the United States, addressing emissions from this category of sources is of utmost importance to protecting human health and environmental quality. Throughout the Clean Air Act, Congress has recognized the relationship between pollution from power plants and energy generation, and has expressly instructed EPA on the

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[60] *See* Texas Commission on Environmental Quality, Revisions to the State Implementation Plan (SIP) for the Control of Ozone Air Pollution, Apr. 27, 2005, at ES-5, 5-2, 5-3; U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-8-K-9.
[61] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9-K-10, K-12-K-14.
[62] *See id.*
[63] *Id.* at K-14-K-15.
[64] *See* 70 Fed. Reg. 25,162, 25, 165, 25,256, 25, 279 (May 12, 2005) (Clean Air Interstate Rule); 76 Fed. Reg. 48,208, 48,209-11, 48, 319 (Aug. 8, 2011) (Cross-State Air Pollution Rule).
[65] *See* 70 Fed. Reg. at 25, 279 ("NO_X allocation methodology elements for which States will have flexibility include…The use of allowance set-asides . . . for energy efficiency [and, inter alia,] renewables[.]").
[66] 76 Fed. Reg. at 48,209 ("Each state has the option of replacing these federal rules [in the FIP] with state rules to achieve the required amount of emission reductions from sources selected by the state.")
[67] 76 Fed. Reg. at 48,319 (discussing treatment of energy efficiency), 48,327-28 (final rule provides states with option of allocating allowances to renewable energy facilities).

consideration of energy impacts in establishing emissions standards. Since 1971, when first empowered to do so by the Clean Air Act Amendments of 1970, EPA has established standards for dangerous emissions from fossil-fuel fired power plants. These regulations have achieved emissions reductions without affecting electric reliability. Finally, for more than fifteen years, and under three different Administrations, EPA has worked to facilitate state-pioneered efforts to achieve pollution reductions through development of renewables and improved energy-efficiency. For these reasons, it is clear that the CPP is consistent with EPA's long history of addressing harmful emissions from power plants, and constitutes a natural and necessary step forward in protecting the public from carbon pollution.

I. The Legal Foundation for the Clean Power Plan

Section 111(d) provides for dynamic federal-state collaboration in securing emission reductions from existing sources, with state flexibility to identify the optimal systems of emission reduction for their state while achieving the necessary environmental performance. EPA's longstanding § 111(d) implementing regulations[68] provide for EPA to issue "emission guidelines" in which the Agency fulfills its § 111 duty to identify the "best system of emission reduction" for a specific pollutant and listed source category.[69] EPA then identifies the emission reductions achievable using that system. States are given the flexibility to deploy different systems of emission reduction than the "best" system identified by EPA, so long as they achieve equivalent or better emission reductions.[70] The achievement of equivalent emission reductions enables state plans to be deemed "satisfactory" in the statutorily required review.[71] The statute provides that when states do not submit a satisfactory plan, EPA must develop and implement emission standards for the sources in that state.[72]

A. The statute gives EPA ample authority to oversee state compliance with § 111(d).

Although some have posited that the states have the sole authority to determine the stringency of emission standards under § 111(d), this disregards the plain language of § 111. Section 111(a)(1) elucidates that it is EPA—not the states—that identifies the best system of emission reduction considering the statutory factors:

> The term "standard of performance" means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[73]

That definition specifically refers to "the Administrator"[74] as the entity that "determines" what constitutes the best system of emission reduction based on the statutory factors such as optimal environmental performance ("best") and cost. It is the Administrator who "tak[es] into account the cost of achieving

[68] 40 C.F.R pt. 60, subpt. B. EPA's regulations for the general implementation of § 111(d) have not been challenged since they were promulgated in 1975. *See* 40 Fed. Reg. 53,340 (Nov. 17, 1975); *see also* Clean Air Mercury Rule, 70 Fed. Reg. 28,606 (May 18, 2005), *vacated on other grounds by New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008). Any challenge would now be time-barred. 42 U.S.C. § 7607(b); *see also Am. Rd. & Transp. Builders Ass'n v. EPA*, 705 F.3d 453, 457-58 (D.C. Cir. 2013); *Am. Rd. & Transp. Builders Ass'n v. EPA*, 588 F.3d 1109, 1113 (D.C. Cir. 2009).

[69] 40 C.F.R. § 60.22(b)(5) (guidelines will "reflect[] the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved").

[70] *See* 40 C.F.R. § 60.24.

[71] *Id.*; 42 U.S.C. § 7411(a); *id.* § 7411(d)(2).

[72] 42 U.S.C. § 7411(d)(2).

[73] *Id.* § 7411(a)(1) (emphasis added).

[74] *Id.* § 7602(a) (defining "Administrator" to be "the Administrator of the Environmental Protection Agency").

such reduction and any nonair quality health and environmental impact and energy requirements." Significantly, that definition is explicitly made applicable to the entirety of § 111.[75]

Under § 111(d)(1)(A), state plans must impose "standards of performance" on existing sources[76] according to the criteria provided in the "standard of performance" definition quoted above.[77] Section 111(d)(2) directs states to submit "satisfactory" plans, implementing such standards of performance, to EPA for review and approval.[78] EPA's regulations and emission guidelines have long interpreted the Agency's § 111(d) responsibility to determine whether state plans are "satisfactory" as governed by whether the plans implement emission standards that reflect the emission reductions achievable under the best system of emission reduction identified by the Administrator.[79]

EPA's review of state plans is guided by the statutory parameters defining a "standard of performance"—do state plans establish emission standards that achieve emission reductions equivalent to or better than those achievable using the best system of emission reduction? This interpretation of the statute flows inexorably from its plain language and structure, and EPA's interpretation of its substantive role under § 111(d) carries the weight of nearly four decades of Agency statutory interpretation and practice under the 1975 § 111(d) implementing regulations.[80] It is implausible that Congress provided statutory criteria that state plans must meet and further provided for EPA to review state plans, but did not intend for the statutory criteria to direct the review.[81] Indeed, for EPA to approve state plans without regard to whether those plans satisfy the statutory criteria for standards of performance would be arbitrary.

Yet the language of § 111 requires substantive review of state plans by EPA even more directly. A "standard of performance" is defined as "a standard for emissions of air pollutants *which reflects the*

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[75] *See id.* § 7411(a) ("For purposes of this section . . .").
[76] *Id.* § 7411(d)(1)(A).
[77] *Id.* § 7411(a) (all definitions, including "standard of performance," apply "[f]or purposes of this *section*" (emphasis added)).
[78] *Id.* § 7411(d)(2) (discussing results if "the State fails to submit a *satisfactory* plan" (emphasis added)).
[79] *See* State Plans for the Control of Existing Facilities, 39 Fed. Reg. 36,102 (Oct. 7. 1974); *see also* State Plans for the Control of Certain Pollutants from Existing Facilities, 40 Fed. Reg. 53,340, 53,342-44 (Nov. 17, 1975) (rejecting commenters' argument that EPA does not have authority to require states to establish emissions standards that are at least as stringent as EPA's emission guidelines); *id.* at 53,346 (defining "emission guideline" as "a guideline . . . which reflects the degree of emission reduction achievable through the application of the best system of emission reduction which (taking into account the cost of such reduction) the Administrator has determined has been adequately demonstrated for designated facilities.").
[80] *Id.* EPA has issued § 111(d) emission guidelines for a number of source categories. *See* 42 Fed. Reg. 12,022 (Mar. 1, 1977) (phosphate fertilizer plants); 42 Fed. Reg. 55,796 (Oct. 18, 1977) (sulfuric acid plants); 44 Fed. Reg. 29,828 (May 22, 1979) (kraft pulp mills); 45 Fed. Reg. 26,294 (Apr. 17, 1980) (primary aluminum plants); 61 Fed. Reg. 9,905 (Mar. 12, 1996) (municipal solid waste landfills).
[81] EPA noted in its 1975 implementing regulations that § 111(d) is silent on the criteria by which state plans might be judged "satisfactory," and that therefore those criteria must be inferred from the context of § 111. *See* 40 Fed. Reg. at 53,342. The criteria were located in § 111(a)(1)'s definition of "standard of performance," mirrored in EPA's definition of "emission guideline." *Compare* Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1683 (1970), *with* 40 Fed. Reg. at 53,346. Moreover, the agency suggested that the criteria for state plans served the same function as the criteria for standards of performance issued under § 111(b). 40 Fed. Reg. at 53,342 ("it seems clear that some substantive criterion was intended to govern *not only the Administrator's promulgation of standards but also his review of State plans*" (emphasis added)). Thus, EPA's emission guidelines have always been closely tied to the statutory definition of "standard of performance" in § 111(a)(1).

degree of emission limitation achievable through the application of the best system of emission reduction" identified by the Administrator. An emission standard that fails on its face to secure the degree of emission reductions achievable under the best system of emission reduction is outside the statutory definition of standards of performance and does not meet the requirement that the "State establish[] standards of performance" for existing sources. State plans that fail to include a standard of performance cannot be approved as "satisfactory" by EPA under any reading of § 111.

In addition to being inconsistent with the language of § 111, exclusive state authority over the substance of existing source standards would be contrary to the purpose of the 1970 Clean Air Act—"to provide for a more effective program to improve the quality of the Nation's air"[82]—because air quality could *worsen* if state plans were not subject to any enforceable substantive standards. Evidence of the central role for protective federal standard setting is found throughout the Clean Air Act, including in § 116, which prohibits the states from adopting or enforcing emission standards less stringent than those set by EPA.[83]

Preserving that basic role for EPA in protecting the nation's air quality was a central theme of the regulations EPA adopted in 1975 to implement § 111(d). As EPA noted in the rulemaking:

> [I]t would make no sense to interpret section 111(d) as requiring the Administrator to base approval or disapproval of State plans solely on procedural criteria. Under that interpretation, States could set extremely lenient standards— even standards permitting greatly increased emissions—so long as EPA's procedural requirements were met. Given that the pollutants in question are (or may be) harmful to public health and welfare, and that section 111(d) is the only provision of the Act requiring their control, it is difficult to believe that Congress meant to leave such a gaping loophole in a statutory scheme otherwise designed to force meaningful action.[84]

In sum, both the language of § 111 and the overall purpose of the 1970 Clean Air Act amendments require a strong substantive role for EPA in ensuring that standards for existing sources meet the statutory requirements.

B. EPA's responsibility includes establishing binding emission guidelines for states.

Similarly, some stakeholders have questioned EPA's authority to establish binding emission guidelines that identify the "best system of emission reduction" and the resulting emissions reductions that each state plan must achieve. That argument fails in light of the structure of § 111(d) and in light of congressional intent. It is also contrary to EPA's reasonable interpretation of its statutory responsibility, laid out in the long-established regulations implementing § 111.

EPA's interpretation of § 111(d) as authorizing it to adopt emission guidelines makes eminent sense in light of the core delegation of authority to EPA to determine the best system of emission reduction and the statute's overall structure. The guidelines provide states with the parameters a state plan must fit

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82 Clean Air Amendments of 1970, Pub. L. No. 91-604, 84 Stat. 1676, 1676.
83 42 U.S.C. § 7416.
84 40 Fed. Reg. at 53,343.

within in order to be found "satisfactory" by the Administrator.

Moreover, while Congress did not detail the process by which EPA would evaluate and approve state plans, there is considerable evidence that Congress subsequently recognized and approved the guidelines process that EPA established in its 1975 regulations. In 1977, for example, when Congress modified the definition of "standard of performance," the House committee explained that under § 111(d) "[t]he Administrator would establish *guidelines* as to what the best system for each . . . category of existing sources is."[85] Then, in 1990, in § 129 of the Clean Air Act, Congress directed EPA to adopt standards for solid waste combustion that would mirror the § 111 process, expressly referring to the "*guidelines* (under section 7411(d) of this title . . .)."[86]). The 1990 CAA amendments added section 129 to supplement EPA's pre-existing authority (and mandate) under section 111 to regulate emissions from solid waste incinerators. For existing solid waste incinerators to which section 129 is applicable, section 129 explicitly requires EPA to promulgate guidelines "pursuant to section 7411 (d) of this title and this section [that] shall include . . . emissions limitations" and requires the States to submit to EPA within a year following promulgation of the guidelines a plan to implement and enforce those guidelines.[87] Thus, section 129 expressly mandates that EPA's role in undertaking joint 111(d)/129 regulatory action is to establish emission limitations for solid waste incineration units whereas the state's role is to establish a plan to implement those emission limitations. This division of regulatory authority is the same as the division established by EPA's 1975 implementing regulations for 111(d). When Congress enacted section 129 in 1990, it explicitly codified that joint 111(d)/129 standards would be established by the same process EPA had developed in its 1975 implementing regulation to govern 111(d) standards. This demonstrates that Congress was not only aware of the procedures established by EPA's 1975 implementing regulations, but also approved of those procedures. In summary, both the 1977 and 1990 amendments demonstrate that Congress has recognized and legislated in reliance upon EPA's guidelines process under § 111(d).

Congress is not alone in affirming the place of emissions guidelines in the § 111(d) structure. The Supreme Court recently noted that states issue § 111(d) standards "in compliance with [EPA] guidelines and subject to federal oversight."[88]

C. EPA's authority to set quantitative requirements in emission guidelines is well-established and reflects EPA's longstanding interpretation of § 111(d).

It is well-established that EPA has authority to set quantitative requirements in emission guidelines, which states must implement via state plans. The proposed rule reflects EPA's longstanding interpretation of the distinct Federal and State roles under § 111(d), as established in the 1975 implementing regulations.

85 H.R. Rep. No. 95-294, at 195 (1977) (emphasis added).
86 42 U.S.C. § 7429(a)(1)(A) (emphasis added).
87 42 U.S.C. § 7429(b)(1)-(2).
88 *Am. Elec. Power Co. v. Connecticut*, 131 S. Ct. 2527, 2537-38 (2011).

In the 1975 rulemaking to implement § 111(d), EPA received a number of comments questioning the Agency's authority to set those substantive guidelines.[89] In response, EPA demonstrated its authority to do so with a detailed analysis of the language, purpose, and legislative history of § 111(d).[90] EPA's regulations for the general implementation of § 111(d) have not been challenged since they were promulgated in 1975.[91] Any challenge would now be time-barred.[92] Notably, when EPA promulgated the Clean Air Mercury Rule (CAMR) in 2005, which, in accordance with the 1975 implementing regulations, established substantive emission limitations for power plants under § 111(d), EPA's interpretation of its authority in the 1975 implementing regulations was not challenged by any of the parties in the ensuing litigation on CAMR.[93] Thus, because the regulations were neither challenged upon promulgation, nor in the specific and very recent context of their application to regulate emissions from power plants, EPA's authority to issue emission guidelines is settled.[94]

D. States can deploy locally designed solutions to meet EPA's emission guidelines.

Although EPA adopts emission guidelines identifying the best system of emission reduction, § 111(d) (and EPA's implementing regulations) provide for state tailoring and flexibility in meeting those guidelines. The statute does not require states (or sources) to use the exact system of emission reduction identified by EPA. Instead, states simply must achieve the level of emission reductions that would be achieved under that best system, and can deploy the system or systems of emission reduction most appropriate for the emission sources in their state.[95]

With this federal-state collaboration, § 111 is very similar to the process implemented under § 110, under which states put in place plans to achieve National Ambient Air Quality Standards for criteria pollutants. This parallel structure reflects the directive in section 111(d) that EPA establish "a procedure similar to that provided by" § 110, under which states develop their plans and submit them to EPA for review.[96] Under § 110, the safe level of ambient pollution is an expert, science-based determination made by EPA, but states have considerable discretion in determining how to reduce emissions to that level. The state plan submission and review "procedure" under § 110 provides for EPA review of each state plan to ensure that "it meets all the applicable requirements" of § 110—including implementation and enforcement of the National Ambient Air Quality Standards as well as other requirements relevant to ensuring the effectiveness of the plans.[97] Thus, sections 110 and 111(d) have an appropriately parallel

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89 40 Fed. Reg. at 53,342.
90 *Id.* at 53,342-44.
91 *See* 40 Fed. Reg. 53,340 (Nov. 17, 1975); *see also* Clean Air Mercury Rule, 70 Fed. Reg. 28,606 (May 18, 2005), *vacated on other grounds by New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).
92 42 U.S.C. § 7607(b); *see also Am. Rd. & Transp. Builders Ass'n v. EPA*, 705 F.3d 453, 457-58 (D.C. Cir. 2013); *Am. Rd. & Transp. Builders Ass'n v. EPA*, 588 F.3d 1109, 1113 (D.C. Cir. 2009).
93 *See New Jersey v. EPA*, 517 F.3d 574 (D.C. Cir. 2008).
94 *See* 42 U.S.C. § 7607(b) (60-day review period for Clean Air Act rulemakings).
95 *See id.* § 7411(a) (a "standard of performance" must "reflect[]" the emission reductions achievable through use of the best system, but need not actually <u>use</u> the best system).
96 *Id.* § 7411(d)(1).
97 *Id.* § 7410(k)(3). Section 110 requires, *inter alia*, state plans to provide for "implementation, maintenance, and enforcement of" National Ambient Air Quality Standards, *id.* § 7410(a)(1), the use of emissions monitoring equipment as prescribed by EPA, *id.* § 7410(a)(2)(F), and any air quality modeling requirements prescribed by EPA,

structure under EPA's interpretation of the statute — under both provisions, EPA uses its expertise to identify the emission reductions that must be achieved, states use their discretion to develop plans to achieve the emission reductions, and EPA reviews plans to ensure they are meeting the relevant statutory criteria.

In sum, § 111(d) establishes a collaborative federal-state process for regulating existing sources in which EPA establishes quantitative emission guidelines and the states deploy locally tailored and potentially innovative solutions to achieve the required emission reductions.

E. A System of Emission Reduction That Achieves the Rigorous Cuts in Carbon Pollution Demanded by Science and Does so Cost-Effectively is Eminently Consistent with the § 111 Criteria and Is Plainly Authorized by § 111

In the proposed Clean Power Plan, EPA has identified the "best system of emission reduction" as a flexible, system-based framework comprised of four building blocks: (1) heat rate (efficiency) improvements at coal-fired power plants; (2) shifting utilization from higher emitting coal-fired power plants to underutilized natural gas combined cycle power plants; (3) deploying zero carbon energy such as wind and solar; and (4) improving demand-side energy efficiency. This system of emission reduction mirrors what is happening on the ground. Across the country, states and power companies are reducing emissions from fossil fuel fired power plants by making those plants more efficient, increasing the use of lower-carbon generation capacity and zero-emitting energy, and investing in demand-side energy efficiency. At their core, these approaches all have the same result—reducing emissions from existing high-emitting fossil fuel fired power plants and improving the emission performance of the power plant source category. The broad employment of this system across the country indicates that it is demonstrated in practice—and indeed, these approaches have been in use for decades.[98]

When seen through the lens of § 111, the system described above is fundamentally an emissions averaging system, achieving broadly based reductions from the power plant source category. Improving efficiency at plants, deploying zero-emitting energy on the grid, investing in demand-side energy efficiency to reduce demand, and shifting utilization towards lower-emitting generation all reduce

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id. § 7410(a)(2)(K). *See also, e.g.*, *North Dakota v. EPA*, 730 F.3d, 750, 760-61 (8th Cir. 2013) (holding that EPA is charged with "more than the ministerial task of routinely approving SIP submissions" under CAA § 169A) (citing *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461 (2004); *Oklahoma v. EPA*, 723 F.3d 1201 (10th Cir. 2013)).

[98] *See, e.g.*, World Resources Institute, Power Sector Opportunities for Reducing Carbon Dioxide Emissions: Michigan (Sept. 2013), *available at* http://www.wri.org/publication/power-sector-opportunities-for-reducing-carbon-dioxide-emissions-michigan; World Resources Institute, Power Sector Opportunities for Reducing Carbon Dioxide Emissions: North Carolina (Sept. 2013), *available at* http://www.wri.org/publication/power-sector-opportunities-for-reducing-carbon-dioxide-emissions-north-carolina; World Resources Institute, Power Sector Opportunities for Reducing Carbon Dioxide Emissions: Ohio (Aug. 2013), *available at* http://www.wri.org/publication/power-sector-opportunities-for-reducing-carbon-dioxide-emissions-ohio. *See generally* World Resources Institute, GHG Mitigation in the United States: An Overview of the Current Policy Landscape, at 10-12 (2012), *available at* http://www.wri.org/publication/ghg-mitigation-us-policy-landscape; Database of State Incentives for Renewables & Efficiency, http://www.dsireusa.org/ (last visited Feb. 27, 2014).

emissions from fossil fuel fired units as a group. This system of emission reduction is conceptually more expansive than the typical end of the pipe pollution-control technology installed at a plant but satisfies the statutory language and purpose of § 111(d) and is a reasonable interpretation of that provision. This system will employ emissions averaging across the regulated sources in order to recognize the pollution reductions achieved by changes in utilization at plants and among plants.

By incorporating an averaging framework, this system can create flexibility to identify the most cost effective emission reductions across the regulated sources. Because sources are allowed to average emission reductions, the system will give sources flexibility to reduce emissions onsite or secure emission reductions from other sources that can achieve reductions beyond those necessary for their own compliance at lower cost. Each source will be required to comply with the emission standard established but can meet its compliance obligation by securing emission reductions at other units in the source category. By recognizing the emission reductions achieved by the deployment of low-carbon generation, shifts in utilization toward lower- or non-emitting generation, and improvements in demand-side energy efficiency, the system will create flexibility for states and regulated sources and enhance the cost-effectiveness and environmental co-benefits of the emission standards.

As discussed below, the language of § 111 is broad enough to encompass such an emission reduction system. Moreover, under § 111(d), where the goal is maximizing the reduction of carbon pollution from existing power plants considering cost and wider environmental and energy impacts, this emission reduction system best satisfies the statutory factors.

1. Section 111 gives EPA wide discretion to establish a system of emission reduction that achieves rigorous reductions in carbon pollution through locally tailored solutions.

The language and structure of § 111 give EPA expansive authority to determine which system of emission reduction best serves the statutory goals. The marked breadth of the language indicates Congress' broad delegation of authority to EPA. Neither the term "best system of emission reduction" nor its components are given technical definitions in the Act. In common usage, a "system" is defined as "a complex unity formed of many often diverse parts subject to a common plan or serving a common purpose."[99] Clearly the ordinary meaning of the term "system" does not limit EPA to choosing end-of-pipe control technologies or other mechanical interventions at the plant. Rather, EPA may choose to base its standards on a "complex unity . . . serving a common purpose" that is consistent with the other statutory requirements. A system of emission reduction that reflects the unified nature of the electric grid and achieves cost-effective emission reductions from the source category by treating all fossil fuel fired power plants as an interconnected group, averaging emissions across plants and recognizing changes in plant use that reduce emissions, fits securely within this framework.

The history of § 111 demonstrates that Congress deliberately rejected terms that were more restrictive than "best system of emission reduction," and that it was especially important to Congress for EPA to have flexibility in identifying solutions to reduce emissions from existing sources. The original 1970 language provided a definition of the standard applicable to existing sources under § 111 that is rather

[99] Webster's Third New International Dictionary 2322 (1967).

similar to the current definition: "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated."[100] Congress subsequently identified this standard as a "standard of performance"—the same term Congress used to describe the standards applicable to new sources under § 111.[101]

The 1970 legislative history reveals that the terms "standard of performance" and "best system of emission reduction" rely on broad concepts beyond mere add-on technologies. Because the current definition is almost identical to the 1970 definition,[102] we can look to the 1970 legislative history to inform our understanding of the phrase "standard of performance."

Section 111 was first adopted in the Clean Air Act Amendments of 1970.[103] To understand the 1970 legislative history, it is necessary to distinguish between provisions in the precursors to § 111 related to *new* sources and those related to *existing* sources.

In the House bill (H.R. 17255), proposed § 112 would have added a new section to the Clean Air Act titled Emission Standards for New Stationary Sources.[104] That provision used the phrase "emission standards," which was not defined anywhere in the bill. The House bill only focused on these emission standards for new sources; it did not have a provision providing for emission standards for existing sources.

The Senate bill (S. 4358), by contrast, called for federal regulation of both existing sources (proposed § 114[105]) and new sources (proposed section 113).[106] For existing sources, the bill expected "emission

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[100] Clean Air Amendments of 1970, Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1683. The original definition lacks the language directing EPA to consider "any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1).

[101] *See* Pub. L. No. 95-95, § 109(b), 91 Stat. 685, 699 (1977).

[102] Again, the only difference between the current definition of "standard of performance" and the 1970 definition is that now it specifies that EPA must also consider "any nonair quality health and environmental impact and energy requirements." 42 U.S.C. § 7411(a)(1). The language about "non-air quality health and environmental impact and energy requirements" was added in 1977. *See* Pub. L. No. 95-95, § 109(c), 91 Stat. 685, 700 (1977).

[103] Clean Air Act Amendments of 1970, Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1683.

[104] H.R. 17255, 91st Cong., 2d Sess. § 5, 116 Cong. Rec. 19,225 (1970) (proposing a new section 112 for the Clean Air Act).

[105] Proposed section 114 did not expressly refer *just* to existing sources; on its face it made no distinction between new or existing sources. S. 4358, 91st Cong., 2d Sess. § 6(b) (1970). However, the Senate report (S. Rep. 91-1196) plainly said that section 114 "would be applied to existing stationary sources." S. Rep. No. 91-1196, at 19 (1970). Furthermore, Senator Cooper from Kentucky, the ranking Republican member on the main Senate committee considering the bill, also plainly stated that section 114 would apply to existing sources. *See* 116 Cong. Rec. 32,918 (1970) (stating in floor debate that "section 114 requires the Secretary to set emission standards for specific industrial pollutants -- applicable to old plants as well as new. This procedure would apply to the same industries designated for new source standards of performance in section 113.")

[106] S. 4358, 91st Cong., 2d Sess. § 6(b) (1970).

standards"—an undefined term. For new sources, the bill expected "standards of performance" [107] —the phrase later codified in § 111.

The Senate bill included broad language describing what a "standard of performance" would entail. The "standards of performance" called for by proposed § 113 for new sources were to "reflect the greatest degree of emission control which the Secretary determines to be achievable through application of the *latest available control technology, processes, operating methods, or other alternatives*."[108] Thus, it is plain that the Senate contemplated that standards of performance would be based on more than add-on technologies alone.

Moreover, the Senate report accompanying the bill revealed that the standards of performance would not be limited to just reducing pollution but could also *prevent* pollution. From the Senate committee report:

"[P]erformance standards should be met through application of the latest available emission control technology or through other means of *preventing or controlling* air pollution."[109]

The Senate report went on to emphasize how innovative this new concept of a "standard of performance" was. The report noted that this was "a term which has not previously appeared in the Clean Air Act" and that the term "refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods."[110]

That broad, innovative concept from the Senate of a "standard of performance" was incorporated into the version of § 111 proposed by the Conference Committee and ultimately codified. Although the definition of "standard of performance" in section 111(a)(1) of the Conference bill did not define that phrase exactly as the Senate had with reference to "latest available control technology, processes, operating methods, or other alternatives," the Conference bill used an equally broad and equally innovative phrase—"best system of emission reduction."[111]

The Conference bill did not define "best system of emission reduction" and the Conference Committee report did not discuss that phrase, but the Senate deliberations after the Conference Committee confirmed that the final version of the bill reflected the Senate's broad understanding of the basis for the standards. The Senate's summary of the conference bill stated: "The [Conference] agreement authorizes regulations to require new major industry plants . . . [to] achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives," reflecting the language the Senate originally used to describe a "standard of performance."[112] This broad inquiry, well

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[107] S. 4358, 91st Cong. § 6(b) (1970).
[108] S. 4358, 91st Cong. § 6(b) (1970) (emphasis added).
[109] S. Rep. No. 91-1196, at 16 (1970) (emphasis added).
[110] *Id.* at 17.
[111] H.R. 17255 (conf. bill), 91st Cong., 2d Sess. § 4(a) (as reported by Senate-House Conf. Comm., Dec. 17, 1970) (enacted); H.R. Rep. No. 91-1783 (1970).
[112] 116 Cong. Rec. 42,384 (1970) (Senate Agreement to Conference Report on H.R. 17255). That same Senate statement also noted that the "conference agreement, as did the Senate bill, provides for national standards of

beyond mere add-on technology, would be accomplished by the federal government looking to the "best system of emission reduction" as the basis for the § 111 standards.

The Senate also contributed something else very important to the Conference bill—the idea of regulating existing sources. Section 114 of the Senate bill was the only provision in either chamber that required existing source standards. The Conference bill then took that concept and included it as subsection (d) of § 111.[113] Section 111(d) in the final bill is identical to today's version in all pertinent respects except one: In 1970, existing sources were subject to "emission standards," an undefined term, rather than "standards of performance."[114] In 1977, Congress amended section 111(d) to provide specifically that existing sources, like new sources, would be subject to "standards of performance."[115] Thus, the legislative history of the phrase "standard of performance" from 1970—emphasizing a broad inquiry into processes, operating methods, and other alternatives to reduce and prevent pollution—is entirely relevant to interpreting the present version of the existing source standards under section 111(d), and supports the flexible, system-wide approach taken by EPA in the proposed Clean Power Plan.

Furthermore, although Congress made changes to the definition of "standard of performance" in 1977 that introduced additional requirements and distinctions between the standards for new and existing sources, with the 1990 amendments, Congress essentially restored the 1970 version of the term. Changes to the definition made in the 1977 Amendments to the Clean Air Act required § 111 standards for new sources to reflect "the best *technological* system of *continuous* emission reduction."[116] In contrast, the § 111 standards for existing sources were to reflect the "best system of continuous emission reduction,"[117] which, as clarified by the Conference Report, need not be a technological system.[118] In 1990, Congress removed the requirements that standards for new sources be based on "technological" systems and that standards for both new and existing sources achieve "continuous" reductions, restoring use of broad "system" language for both new and existing source standards.[119] Thus, the 1990 version of § 111 that Congress adopted was strikingly similar to the 1970 version, calling for "standards of performance" for both new and existing sources that would reflect the "best system of emission reduction." It is noteworthy that even during the period of time when Congress determined a more specific definition of "standard of

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performance on emission from new stationary sources," again confirming the analogy to the prior Senate version. *Id.* at 42,385.

113 H.R. 17255 (conf. bill), 91st Cong., 2d Sess. § 4(a) (1970) (enacted); H.R. Rep. No. 91-1783 (1970); Pub. L. No. 91-604, § 4(a), 84 Stat. 1676, 1684. The Senate version of the existing source provision (proposed section 114) and the final version differed in this respect: The Senate would have required EPA to set and enforce the standards for existing sources, with the states having an option to take over enforcement. *See* S. 4358, 91st Cong. § 6(b) (1970).The final bill, rather than simply offering an opportunity to the states, required the states to submit plans, along the lines of section 110, for EPA approval. H.R. 17255 (conf. bill), 91st Cong., 2d Sess. § 4(a) (1970)(enacted).

114 42 U.S.C. § 1857c-6(a)(1) (1970).

115 *See* Pub. L. No. 95-95, § 109(b), 91 Stat. 685, 699 (1977).

116 Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 109(c)(1)(A), 91 Stat. 685, 699-700 (emphases added).

117 *Id.*

118 The conference committee explained that the amendments "make[] clear that standards adopted for existing sources under section 111(d) of the act are to be based on available means of emission control (*not necessarily technological*)." H.R. Rep. No. 95-564, at 129 (1977) (Conf. Rep.) (emphasis added).

119 Clean Air Act Amendments of 1990, Pub. L. No. 101-549, § 403(a), 104 Stat. 2399, 2631.

performance" was advisable for new sources, it did not take this approach for existing sources. The current text of the Clean Air Act reflects both Congress' more recent decision to allow EPA to select a non-technological system of emission reduction when promulgating standards for new sources under § 111 as well as Congress' longstanding policy of allowing that approach for existing sources.[120]

Courts have recognized that the identification of the best system of emission reduction is an expansive, flexible endeavor, in the service of securing the maximum emission reductions, finding that EPA may weigh "cost, energy, and environmental impacts in the broadest sense at the national and regional levels and over time as opposed to simply at the plant level in the immediate present."[121] Further, courts have noted that EPA's choice of the best system of emission reduction should encourage the development of systems that achieve greater emission reductions at lower costs and deliver energy and nonair health and environmental benefits.[122]

In short, § 111 gives EPA wide discretion to identify an emission reduction system that relies on solutions such as averaging to maximize environmental performance and enhance cost-effectiveness.

2. The language of § 111 is sufficiently broad to authorize the selection of an averaging system as the best system of emission reduction, thus expressing state goals as average, state-wide performance levels is reasonable and consistent with EPA's authority under the Clean Air Act

Although the term "best system of emission reduction" is broad, it is not unbounded. Section 111 requires the "best" system to be the system adequately demonstrated to achieve the maximum emission reductions from the regulated sources, considering cost and impacts on non-air quality health or environmental impacts and energy requirements. The system must also provide the foundation for state standards of performance to apply a "standard for emissions" to "any existing source" in the listed category. EPA must seek out the system that best serves these clearly enunciated goals of § 111.

[120] Congress' use of the broad term "system" in section 111 of the CAA is also consistent with its use of that term in other sections of the CAA and other federal environmental laws. *See, e.g.*, 42 U.S.C. § 7412(d)(2) (emissions standards for hazardous air pollutants must reflect the maximum degree of reductions achievable "through application of measures, processes, methods, systems or techniques" including pollution reduction through process changes or substitution of materials, operational standards, and other measures); -(r)(7)(A) (EPA's regulations for preventing the accidental release of hazardous air pollutants may make distinctions between various "devices and systems," signaling that devices and systems are not coextensive); 33 U.S.C. § 1292(2)(B) (Clean Water Act's definition of "treatment works" includes any "method or system for preventing, abating, reducing, storing, treating, separating, or disposing of municipal waste").

[121] *Sierra Club v. Costle*, 657 F.2d 298, 321, 330 (D.C. Cir. 1981).

[122] *Id.* at 346-47. Courts have also recognized that standards under the Clean Air Act will often require changes in the methods of production or operation for regulated sources. *Id.* at 364 ("Recognizing that the Clean Air Act is a technology-forcing statute, we believe EPA does have authority to hold the industry to a standard of improved design and operation advances."); *International Harvester Co. v. Ruckelshaus*, 478 F.2d 615, 640 (D.C. Cir. 1973) (under certain mobile source provisions, satisfaction of the CAA "might occasion fewer models and a more limited choice of engine types," as long as consumer demand can "be generally met").

We strongly support EPA's decision to propose state goals in the form of average performance levels that reflect state-wide application of the BSER. As EPA recognizes in the preamble,[123] this approach has clear policy advantages. Because CO_2 is a dispersed pollutant whose effects on the atmosphere are the same regardless of where it is emitted, EPA's averaging approach is as environmentally effective as an alternative approach establishing guidelines specific to particular EGUs. At the same time, the averaging approach allows each state valuable flexibility to determine the most locally appropriate mix of measures to reduce carbon pollution – and to establish standards of performance for individual EGUs that recognize the unique circumstances of specific facilities. For example, the proposed state-wide averaging approach automatically takes into account reductions in carbon intensity associated with shifting generation from high-emitting EGUs to lower-emitting facilities, and allows states to flexibly adjust the amount of dispatch shift that occurs in their generating fleet both geographically and over time. Similarly, the state-wide averaging approach allows states to themselves put in place flexible, averaging compliance frameworks to capture emission reductions attributable to zero-emitting resources, such as renewables. Lastly, the state-wide averaging approach is also compatible with existing state programs, such as renewable portfolio standards and emissions trading programs, which could be incorporated into state plans and used to meet the state goals. Given the interconnected nature of the power sector and the fact that the most cost-effective, well-established techniques for reducing carbon pollution from existing EGUs rely on reducing aggregate emissions from the power sector, EPA's approach is eminently reasonable.

As the proposed emission guidelines recognize, there are many available options for reducing carbon dioxide emissions from existing power plants through modifications or upgrades at these plants. An analysis focused on these "onsite" measures would by necessity be expansive in scope—including not only significant improvements to the efficiency or "heat rate" of the plant, but also other emission reduction measures such as co-firing or re-powering with lower-carbon fuels;[124] utilizing renewable energy sources to provide supplemental steam heating;[125] using available waste heat to remove moisture from coal or switching to higher-rank coal;[126] and implementing combined heat and power (CHP) systems at plants near industrial facilities or district heating systems,[127] among other solutions. For example, engineering firms have estimated that with modest modifications, coal-fired power plants can derive as

[123] 79 Fed Reg at 34,890-92, 34,894.
[124] *See* F.J. Binkiewicz, Jr. et al., Natural Gas Conversions of Existing Coal-Fired Boilers (Babcock & Wilcox White Paper MS-14, 2010), *available at* http://www.babcock.com/library/Documents/MS-14.pdf; Brian Reinhart et al., *A Case Study on Coal to Natural Gas Fuel Switch* (Black & Veatch, 2012), *available at* http://bv.com/Home/news/thought-leadership/energy-issues/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.
[125] *See* Craig Turchi et al., Solar-Augment Potential of U.S. Fossil-Fired Power Plants (National Renewable Energy Laboratory, 2011), *available at* http://www.nrel.gov/docs/fy11osti/50597.pdf. Several projects are currently under way to augment existing coal-fired power plants in Australia and the United States with concentrated solar thermal power systems. *See Hybrid Renewable Energy Systems Case Studies*, Clean Energy Action Project, http://www.cleanenergyactionproject.com/CleanEnergyActionProject/Hybrid_Renewable_Energy_Systems_Case_Studies.html (last visited Feb. 27, 2014).
[126] *See* EPA, Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units, at 31-33 (Oct. 2010), *available at* http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf (describing a commercially-available on-site drying process that can reduce CO_2 emissions from a pulverized coal boiler by approximately 4%).
[127] *See id.* at 34-35.

much as 50% of their heat input from natural gas.[128] Co-firing at this level could yield emission reductions of 20%, and could be combined with heat rate and other improvements to achieve even deeper reductions at a specific plant.

Here, however, EPA has appropriately determined that a more flexible averaging system best satisfies the statutory factors in the unique context of carbon pollution from the power sector.[129] Flexible averaging programs implemented under the Clean Air Act and by states and companies have demonstrated that they can significantly lower the cost of cutting pollution because they facilitate capture of the lowest-cost emission reduction opportunities.[130] In the context of carbon pollution standards for existing power plants, a flexible averaging framework that rigorously quantifies the emission reductions achieved via increased utilization of lower and zero-emitting generation and investments in demand-side energy efficiency can achieve very substantial carbon pollution reductions cost-effectively while enabling proactive management of generation capacity and enhancement of grid reliability. Indeed, a flexible system will facilitate efficient compliance not only with the Clean Power Plan but also with other applicable air quality and energy regulations, allowing states and companies to make sensible investments in multi-pollutant emission reductions and clean, safe, and reliable electricity infrastructure. Such a system will enable states to consider the "remaining useful life" of sources as the Clean Air Act provides[131] and optimize investments in existing and new generation to secure the necessary emission reductions. A flexible system that facilitates a variety of emission reduction pathways is also the system already being deployed by a number of states and companies, mobilizing innovative emission reduction measures and securing significant reductions in carbon pollution.[132]

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[128] *See* Reinhart et al., *supra* note 124.

[129] EPA has allowed averaging or trading programs where they provide greater emissions reductions than source-specific technology standards. *See*, *e.g.*, Regional Haze Regulations, 64 Fed. Reg. 35,714, 35,739 (July 1, 1999) (allowing state plans "to adopt alternative measures in lieu of BART where such measures would achieve even greater reasonable progress toward the national visibility goal").

[130] For example, a recent survey of economic research found that the Clean Air Act's flexible Acid Rain Program has achieved "a range of 15-90 percent savings, compared to counterfactual policies that specified the means of regulation in various ways and for various portions of the program's regulatory period." Gabriel Chan, Robert Stavins, Robert Stowe & Richard Sweeney, The SO_2 Allowance Trading System and the Clean Air Act Amendments of 1990: Reflections on Twenty Years of Policy Innovation, at 5 (2012), *available at* http://belfercenter.ksg.harvard.edu/files/so2-brief_digital4_final.pdf.

[131] 42 U.S.C. § 7411(d)(1).

[132] Some have suggested that the general Clean Air Act definition of "standard of performance" in § 302(l) also applies in the context of § 111, and precludes an averaging approach because it requires "continuous emission reduction." *Id.* § 7602(l). It is unlikely that the § 302(l) definition applies given that Congress provided a specific and different definition of the term "[f]or purposes of" § 111, 42 U.S.C. § 7411(a). *See Reynolds v. United States*, 132 S. Ct. 975, 981 (2012) (specific statutory language supersedes general language); *Fourco Glass Co. v. Transmirra Prods. Corp.*, 353 U.S. 222, 228 (1957) (same). However, even if § 302(l) were found to apply, an averaging approach qualifies as "a requirement of continuous emission reduction" per the § 302(l) definition because covered sources must collectively achieve the emission limitations, which apply continuously. Even in a flexible program each source meets its obligations continuously. Under an averaging framework each source must secure the emission reductions needed, onsite or from other plants, to continuously be in compliance with the standard.

It is also worth noting that the generally applicable definition of "emission standard" in § 302(k) likely does inform the otherwise undefined phrase "standard for emissions" within the definition of "standard of performance" in § 111(a)(1). *See* 42 U.S.C. § 7416 (referring to an "emission standard or limitation . . . under section 7411"). A §

EPA's proposed approach is also fully consistent with the Clean Air Act. First, as the preamble explains,[133] section 111(d) itself does not preclude EPA's emission guidelines from applying the BSER on a state-wide basis or expressing the guidelines as an average performance level for each state. EPA issues emission guidelines as part of its statutory responsibility under section 111(d) to ensure that state plans are "satisfactory," in that they establish, implement, and enforce "standards of performance" that reflect EPA's judgment as to the BSER for existing sources. The statute does not preclude the emission guidelines from specifying an average level of performance that reflects the BSER, and that sets the degree of stringency that will be required for "satisfactory" state plans. EPA's proposed approach is an appropriate application of the broad language of section 111(a)(1) and (d) to the unique circumstances affecting the power sector, which as noted above consists of a diverse population of interconnected sources.

EPA's proposal is consistent with the way EPA (and the courts) have flexibly applied the Clean Air Act to complex source categories, including the power sector. Under section 110(a)(2)(D) of the Clean Air Act, for example, EPA has adopted a series of rulemakings that limit interstate transport of NO_x and SO_2 from the power sector by establishing state-wide emission budgets based on state or regional application of pollution control measures. In the case of the 1998 NO_x SIP Call, these budgets were based on IPM modeling of a multi-state emissions trading system designed to achieve an average emission rate expressed in pounds per unit of heat input – taking into account changes in dispatch and other measures available to reduce aggregate NO_x emissions from the power sector.[134] Similarly, EPA's 2011 Cross State Air Pollution Rule – recently upheld by the Supreme Court as a "permissible, workable, and equitable interpretation" of section 110[135] — established state-wide budgets for NO_x and SO_2 that were based on power sector modeling of emission reductions achievable through "increased dispatch of lower-emitting generation" and fuel-switching, among other compliance options.[136] In both of these major power sector rulemakings, EPA established state-wide emission targets that reflected system-based measures to achieve aggregate emission reductions from the power sector — just as EPA proposes to do here.

In addition, the Clean Air Act provides that the procedure for establishing standards of performance for existing sources under § 111(d) is to be "similar" to that of § 110, and § 110 expressly provides that emission limitations and control measures can include "fees, marketable permits, and auctions of emissions rights." The direct link to § 110 thus further reinforces the appropriateness of such flexible approaches under § 111(d).

302(k) "emission standard" or "emission limitation" is defined as "a requirement . . . which limits the quantity, rate, or concentration of emissions of air pollutants *on a continuous basis*." *Id.* § 7602(k) (emphasis added). An averaging approach qualifies as an "emission standard" or "emission limitation," because covered sources must meet a limitation that applies continuously. Indeed, Congress used the term "emission limitation" in 1990 to describe its Acid Rain Program. *See id.* §§ 7651b(a)(1), 7651c(a).

[133] 79 Fed Reg at 34,891.

[134] *See* Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 Fed. Reg. 57,356, 57,400-401 (Oct. 27, 1998) ("NOx SIP Call") (explaining approach to developing cost curves and state emission budgets).

[135] EPA v. EPE Homer City Generation, L.P., 134 S. Ct. 1584, 1610 (2014).

[136] Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals, 76 Fed Reg. 48,208, 48,252, 279-80 (Aug. 8, 2011).

EPA has also applied averaging approaches extensively in setting emission standards for mobile sources and fuels. Under Title II of the Clean Air Act, EPA has long interpreted its authority to establish "emission standards" for motor vehicles to allow for *average* standards that apply to broad categories of vehicles and engines.[137] In promulgating its first particulate matter and NO_x emission standards for heavy duty vehicles in 1985, EPA defended the averaging concept as "fully consistent with the technology-forcing mandate of the Act" and essential to establishing rigorous standards for a diverse group of sources.[138] The D.C. Circuit specifically upheld EPA's use of averaging in those standards – noting the "absence of any clear evidence that Congress meant to prohibit averaging" and the reasonable policy arguments EPA advanced in favor of the approach.[139] Similarly, EPA's regulations phasing out lead in gasoline took the form of an average standard for the "total pool" of gasoline produced by each refiner; EPA's assumption that refiners would participate in a yet-to-be created inter-refinery credit trading system, which was integral to the stringency of the standard, was likewise upheld by the D.C. Circuit.[140]

Thus, average standards such as those proposed in the Clean Power Plan are a time-tested regulatory approach under the Clean Air Act and a reasonable application of the ambiguous language of section 111. In the context of § 111 and greenhouse gas emissions, a flexible system that enables a wide variety of available solutions to achieve rigorous and cost-effective carbon pollution reductions manifestly fulfills the statutory criteria for the "best" system.

3. Summary

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[137] *See* Control of Air Pollution from New Motor Vehicles and New Motor Vehicle Engines; Gaseous Emission Regulations for 1987 and Later Model Year Light-Duty Vehicles, and for 1988 and Later Model Year Light-Duty Trucks and Heavy-Duty Engines; Particulate Emission Regulations for 1988 and Later Model Year Heavy-Duty Diesel Engines, 50 Fed. Reg. 10,606 (Mar. 15, 1985) (describing averaging system and noting that it is similar to the averaging system established for light-duty vehicles and trucks in 1983).

[138] *Id.* ("Private and state sponsored environmental groups, as well as the Manufacturers of Emission Controls Association (MECA), claimed that averaging as proposed was inconsistent with EPA's responsibility under section 202(a)(3)(A)(iii) of the Act to set standards that require use of the best technology that is expected to be available at the time the standards are implemented…The Agency finds the averaging concept, as applied by the standards promulgated, to be fully consistent with the technology-forcing mandate of the Act. Particulate trap technology is heretofore untried on the fleet level. EPA believes that the 0.25 g/BHP-hr standard which, through averaging, effectively requires use of traps on 70 percent of all heavy-duty vehicles will significantly reduce the risk of widespread noncompliance while allowing manufacturers to gain valuable experience with this new technology. To promulgate this standard without allowing averaging. . . would increase the technological risk associated with the standard because traps would have to be used in even the most difficult design applications.").

[139] *See Natural Resources Defense Council v. Thomas,* 805 F.2d 410, 425 (D.C. Cir. 1986) ("Lacking any clear congressional prohibition of averaging, the EPA's agreement that averaging will allow manufacturers more flexibility in cost allocation while ensuring that a manufacturer's overall fleet still meets the emissions reduction standards makes sense.").

[140] *See Small Refiner Lead Phase-Down Task Force v. EPA,* 705 F.2d 506, 536 (D.C. Cir. 1983). Note that although sec. 211(g) of the Clean Air Act placed numerical limits on average lead standards for small refiners, that section made no mention of inter-refinery trading for purposes of standard-setting or compliance. See Clean Air Act Amendments of 1977, Pub. L. No. 95-95, § 223, 91 Stat. 685, 764 (1977). In addition, EPA's pre-1977 regulations for refiners established "total pool" average lead standards despite the absence of explicit authorization for such standards in the Act. *See* Clean Air Act Amendments of 1970, Pub. L. No. 91-604, § 211, 84 Stat. 1676, 1698 (1970). Those early standards were also upheld by the D.C. Circuit, *see Ethyl Corp. v. EPA,* 541 F.2d 1 (D.C. Cir. 1976), and Congress effectively ratified EPA's approach in 1977 by enacting a special provision for small refiners prescribing maximum levels of stringency for average lead limits.

Across the country, states and power companies are reducing emissions from fossil fuel fired power plants by improving plant efficiency, by increasing the use of lower-carbon generation capacity and zero-emitting energy, and by investing in demand-side energy efficiency and demand management. The widespread and long-established use of this system and its success in achieving cost-effective carbon pollution reductions for diverse states and companies indicate that it satisfies the statutory criteria for the "best system of emission reduction." This system allows states and companies to adjust to locally relevant factors and generation-fleet characteristics, deploying the emission reduction strategies most appropriate and effective. The language of § 111 is sufficiently broad to encompass a system-based approach to securing carbon pollution reductions from existing power plants. Indeed, the constraints provided by § 111—directing EPA to identify the system of emission reduction best able to secure rigorous carbon emission reductions considering cost and impacts on energy and other environmental considerations—strongly suggest that a system-based approach is optimal in satisfying the statutory requirements by securing the vital cuts in carbon pollution that science demands through locally-tailored and innovative solutions.

F. EPA's Alternative BSER is Also Reasonable and Fully Supported by Section 111(d).

EPA has proposed an alternative approach for determining the ''best system of emission reduction . . . adequately demonstrated,'' under which the BSER would be "identified as including, in addition to building block 1, the reduction of affected fossil fuel-fired EGUs' mass emissions achievable through reductions in generation of specified amounts from those EGUs." 79 Fed. Reg. at 34,889. "Under this approach, the measures in building blocks 2, 3, and 4 . . . would serve as bases for quantifying the reduced generation (and therefore emissions) at affected EGUs." *Id.* In addition to supporting EPA's primary BSER approach, we support EPA's alternative approach because it satisfies the statutory requirement to identify the best system of emission reduction that is adequately demonstrated and because this methodology reflects the reality of how the measures in building blocks 2, 3, and 4—in practice—secure reductions.[141]

EPA properly concludes that this alternative BSER meets all applicable statutory requirements. That is, EPA correctly notes that its alternative approach: (1) identifies a "system" of emissions reduction, (2) that is adequately demonstrated, and (3) that EPA could reasonably choose as the "best" among alternatives. As discussed in section I.E, "system of emission reduction" is a markedly broad term that indicates Congress' intention to provide EPA with ample flexibility in identifying the most effective means of controlling emissions. Congress envisioned that "system" would encompass operational changes or other measures to both control and prevent pollution—not just add-on technological devices.[142] This intention is manifest in the statutory text; in common usage, a "system" is defined as "a complex unity formed of

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[141] EPA's proposal to determine that BSER is a combination of building blocks 1, 2, 3 and 4 is also proper for the reasons discussed in this section, as it is based on measures that either improve the carbon intensity of the affected EGUs or reduces emissions from affected sources by decreasing the need for generation by those sources.
[142] *See, e.g.*, 116 Cong. Rec. 42,384 (1970) (Senate Agreement to Conference Report on H.R. 17255) ("The [Conference] agreement authorizes regulations to require new major industry plants . . . [to] achieve a standard of emission performance based on the latest available control technology, processes, operating methods, and other alternatives").

many often diverse parts subject to a common plan or serving a common purpose."[143] As such, the plain meaning of the term "system" includes curtailing generation at high-emitting facilities in concert with replaced generation at lower-emitting sources serving the common purpose of providing a reliable electric supply while reducing emissions. This system is adequately demonstrated. As EPA has explained, the measures in building blocks 2, 3, and 4 are already in widespread use in the industry. 79 Fed. Reg. at 34,890. Numerous states and utilities have used the measures in these building blocks effectively to reduce generation from high-emitting sources, as discussed below in sections IV.H. to IV.J. EPA's proposed finding that certain levels of reduced generation are part of the "best" adequately demonstrated system of emission reduction is based on several appropriate factors: emission reductions can be achieved at reasonable cost, do not jeopardize reliability, result in significant emission reductions, are consistent with current trends in the electricity sector, and promote the development and implementation of technology that is important for continued emissions reductions. 79 Fed. Reg. at 34,889.

At the same time that Congress established the current BSER standard, Congress designed a trading system that would lead some EGUs to shut down or reduce utilization while shifting electricity generation to other cleaner facilities. In the 1990 Clean Air Act Amendments, Congress enacted Title IV of the Clean Air Act to control the EGU emissions that cause acid rain through an emissions trading program. 42 U.S.C. § 7651. Congress intended curtailments to be one of the methods by which EGUs could reduce emissions and meet program requirements. *See, e.g.*, § 7651g(c)(1)(B) (providing for "an affected source . . . for which the owner or operator proposes to meet the requirements of that section by reducing utilization of the unit as compared with its baseline or by shutting down the unit"). Congress also created a specific mechanism by which affected units could receive allowances for "avoided emissions" by paying for renewable energy and energy efficiency measures. § 7651n(f)-(g) (setting aside 300,000 allowances in a "Conservation and Renewable Energy Reserve"). Congress further provided for the reactivation of inoperative "very clean units" through a streamlined permitting process, § 7651n(c), presumably so that these low-emitting units could replace the curtailed generation of dirtier units. Thus, Congress was not just aware that shifting generation from high-emitting to low-emitting resources was an available system for reducing power-sector emissions—Congress took deliberate steps to enable this cost-effective system for protecting human health and the environment.

Title IV clearly illustrates Congress's recognition that the integrated nature of the power system provides unique opportunities for reducing harmful pollution. Section 111(d), in contrast to Title IV, does not require such an approach in every case—which is wholly sensible given the gap-filling role of section 111(d) in addressing diverse source categories and pollutants not addressed elsewhere under the Act. For some pollutants and sources, an emission guideline based on a specific technology would be appropriate. But in using broad language directing EPA to identify the "best system of emission reduction," Congress clearly signaled that the Agency's analysis of systems of emission reduction was to be expansive. And in this circumstance, where reliance on the uniquely integrated nature of the power grid to reduce carbon pollution can provide the greatest emission reductions the most cost-effectively, EPA's approach in the Clean Power Plan fulfills the statutory directive.

[143] Webster's Third New International Dictionary 2322 (1967).

EPA, states, and the courts, too, have long understood that utilization is a key determinant of emissions levels, and that reduced utilization can achieve air quality goals. Since the 1990s, regulators implementing the CAA have routinely relied on mechanisms such as "synthetic minor" permits and "plantwide applicability limits" by which owners of sources may avoid certain permitting requirements if they agree to operate facilities so as to keep pollution levels below stated regulatory annual emissions thresholds, even though their facilities' physical capacity to emit exceeds the thresholds.[144] These mechanisms rest on the recognition that pollution is a function of a source's emissions rate and the time it is in use, and that limiting utilization can be an effective way of limiting pollution. And they demonstrate that, in certain instances at least, reductions in operation (or promises not to increase operations) are appropriate regulatory tools under the Clean Air Act. Indeed, long before the 1990 Clean Air Act Amendments, it was well understood that reduced utilization of a facility was one means of reducing emissions. In 1979, the D.C. Circuit recognized that under the PSD program "EPA has authority to require inclusion in state plans of provision for the correction of any violation of allowable increments or maximum allowable concentrations, and may even require, in appropriate instances, the relatively severe correctives of a rollback in operations . . ." *Alabama Power Co. v. Costle*, 636 F.2d 323, 363 (D.C. Cir. 1979). Section 111's "best system of emission reduction" standard must encompass this basic mechanism for reducing emissions.[145]

EPA's alternative approach to BSER is appropriate because it reflects the reality that the measures in building blocks 2, 3, and 4 reduce emissions precisely because they allow high-emitting sources to reduce generation, and electricity services to be provided through less-polluting means. As EPA properly noted, the "the operation of the electrical grid through integrated generation, transmission, and distribution networks creates fungibility for electricity and electricity services." 79 Fed. Reg. at 34,889-90. That is, the unique nature of the electrical grid gives generators enormous flexibility in how they reduce emissions. The alternative approach to BSER would be a commonsense response to the fact that affected

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[144] A plantwide applicability limit is a voluntary limit or "cap" on a facility's total emissions which is established based on the facility's historical emissions. This limit provides flexibility for a facility to make modifications without triggering major New Source Review requirements as long as the emissions cap is not exceeded. EPA, Fact Sheet, New Source Review: Solicitation of Comments on When New Source Review Applies for a Physical or Operational Change to a Facility (July 16, 1998), available at http://www.epa.gov/ttn/oarpg/t1/fact_sheets/nsrna.pdf. A synthetic minor permit is a permit that includes enforceable permit conditions that ensure that emissions will not exceed the regulatory major source threshold. *See, e.g.*, Virginia DEQ, Types of Air Permits, http://www.deq.virginia.gov/Programs/Air/PermittingCompliance/Permitting/TypesofAirPermits.aspx ("[State Operating Permits] are most often used by stationary sources to establish federally enforceable limits on potential to emit to avoid major New Source Review permitting (PSD and Nonattainment permits), Title V permitting, and/or major source MACT applicability. When a source chooses to use a SOP to limit their emissions below major source permitting thresholds, it is commonly referred to as a "synthetic minor" source.").

[145] Congress sought to encourage reduced utilization in as a tool for protecting and improving air quality in the transportation sector. In the 1977 Clean Air Act Amendments, Congress enacted section 108(f), which required EPA to publish guidance on policies for reducing transportation-sector emissions, including several policies to reduce vehicle-miles travelled. Public Law 95-95, 91 Stat. 685, 689-90 (Aug. 7, 1977) (requiring EPA to provide information on policies such as carpool lanes, park and rides, bike infrastructure, employer-sponsored transit programs, and programs that discourage single-passenger car trips). In 1990, Congress revised section 108(f) by, *inter alia*, requiring EPA to provide current guidance on transportation-sector policies and periodically update its guidance. Pub. Law 101-549, 101 Stat. 2399, 2465-66 (Nov. 15, 1990). Thus, Congress' interest in reduced utilization as a cost-effective emissions-control strategy spans decades.

sources can reduce emissions cost-effectively (through a wide variety of means) by reducing generation as low-emitting sources and energy efficiency satisfy the demand for electricity services.

Many existing programs for reducing electricity-sector GHG emissions work precisely because high-emitting sources reduce generation as low-emitting sources increase their generation. For instance, the New York State Department of Public Service conducted extensive modeling to predict the economic and environmental effects of that state's RPS and concluded that increased renewable energy generation under the policy would displace generation from higher-emitting sources, primarily natural gas-, coal-, and oil-fired units.[146] A recent white paper concluded that renewables introduced in states with RPSs in the RGGI region almost entirely substitute for coal base load.[147] Energy efficiency programs also have a proven track record of reducing electricity demand and, consequently, allowing high-emitting sources to reduce emissions.[148] Freely available tools, such as EPA's AVERT, allow policymakers, utilities, and other stakeholders quantify the CO_2, NO_x, and SO_2 impacts of state and multi-state renewable energy and energy efficiency programs.[149]

States and local governments also implement energy efficiency programs to improve local air quality—again, precisely because such programs lead to reduced generation at emitting facilities.[150] EPA has long encouraged states to take advantage of energy efficiency measures to cost-effectively control EGU emissions. The agency's 1998 NO_x SIP Call Rule allowed states to set aside allowances in their cap-and-trade programs for reductions achieved through renewable energy and energy efficiency measures and, in

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[146] New York Department of Public Service, Final Generic Environmental Impact Statement (2004) at 111 (Table 6.4-1), available at http://www.dps.ny.gov/NY_RPS_FEIS_8-26-04.pdf. The potential for clean energy to displace fossil-fuel-fired generation also has important benefits for public health. *See id.* at 2ES ("Modeling reveals that the addition of new renewable energy sources at the 25 percent target level could annually reduce NOX emissions by 4000 tons (6.8%), SO2 emissions by 10,000 tons (5.9%), and carbon dioxide (CO2) emissions by 4,129,000 tons (7.7%).").

[147] Brian C. Murray, Peter T. Maniloff, Evan M. Murray, "Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors" at 18, available at http://sites.nicholasinstitute.duke.edu/environmentaleconomics/files/2014/05/RGGI_final.pdf (quantitatively attributed emissions effects to policy and market factors in the RGGI region).

[148] Vital reductions are occurring at both the state- and utility- levels. For instance, the Minnesota Department of Commerce estimates that investments required under the state's Conservation Improvement Program saved nearly 900,000 MWh of electricity in 2010, resulting in over 800,000 tons of reduced CO_2 emissions. MDOC, Division of Energy Resources "Minnesota Conservation Improvement Program Energy and Carbon Dioxide Savings Report for 2009-2010" at 3 (Table 1) (2012), available at http://mn.gov/commerce/energy/images/CIPCO2Rpt2012.pdf. *See also* Georgetown Climate Center, "Reducing Carbon Emissions in the Power Sector: State and Company Success" at 24 ("Since 2001, Entergy has spent $14.7 million on 61 energy efficiency improvements that have resulted in nearly 5.3 million metric tons of CO_2 savings and $30 million in annual fuel savings.").

[149] EPA, AVoided Emissions and genRation Tool (AVERT), http://epa.gov/avert/.

[150] EPA, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix K: State, Tribal and Local Examples and Opportunities" at K-8 to K-9 (July 2012), available at http://epa.gov/airquality/eere/pdfs/appendixK.pdf (To meet federal ambient air quality standards, Texas reduces NOx emissions "through reduced demand for fossil-fuel generation at power plants, as a result of EE measures implemented in new construction for single and multi-family residences in 2003."); *id.* at K-9 (Louisiana's plan for achieving federal ambient air quality standards included energy conservation measures at City buildings in Shreveport, which were "estimated to have saved 9,121 megawatt-hours (mWhs) of electricity per year with NOx emission reductions of 0.041 tons per ozone season-day").

2007, seven states had set-asides for these kinds of reductions.[151] Implementing the NO_x SIP Call with set-asides for energy-efficiency reductions, states have noted the economic benefits of achieving reductions in this manner.[152] In CAIR, EPA also enabled states to incorporate renewable energy and energy efficiency into their NO_x trading programs, and several states took advantage of this flexibility.[153] For instance, Connecticut set aside 10% of its summer ozone season allowances for renewable energy and energy efficiency projects.[154] Energy efficiency and renewable energy will likely become even greater components of state ambient air quality planning in the future, as states take advantage of EPA's recent guidance on incorporating such programs into SIPs.[155]

In the marketplace, renewable generation and energy efficiency displace generation at affected units because they can meet electricity demand at lower marginal cost. A recent article succinctly described the mechanism by which low-emitting sources displace higher-emitting sources in electricity capacity markets:

> In comparison to conventional fossil-fired generation, renewables are likely to have a lower running cost. Consequently, renewable generators can often bid much lower than conventional generation. This will lead to renewable generation being dispatched ahead of conventional plants. Thus, renewable generation displaces conventional generation in bid-based markets. This displacement lowers the capacity factor of conventional generators and reduces the time conventional generators are selling in the market.[156]

Similarly, where energy efficiency resources are available on forward capacity markets they compete directly and successfully against higher-emitting sources to meet the capacity needs of the electricity grid.[157]

The particular generation that a low- or zero-emitting resource will replace—and, consequently, the resultant emissions reductions on the grid—depend on the resource's location. Specifically, the units that

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[151] U.S. Department of Energy, Eastern States Harness Clean Energy to Promote Air Quality (2007) at 4, available at http://www.nrel.gov/docs/fy08osti/42143.pdf.
[152] *See, e.g.*, Ohio EPA, Guidance Manual: Energy Efficiency/Renewable Energy and Innovative Technology Projects at 1, available at http://www.epa.ohio.gov/portals/27/files/OhioGuidanceFINAL.pdf ("A more energy efficient process results in not only less NOx emissions but also cost savings. Cost savings is the catalyst that will keep successful energy efficient processes operating long after the set-asides cease.").
[153] U.S. Department of Energy, Eastern States Harness Clean Energy to Promote Air Quality (2007) at 4-6.
[154] *Id.* at 5.
[155] *See* EPA, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans (July 2012), available at http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf.
[156] Peter H. Griffes, "Renewable Generation and Capacity Markets", International Association for Energy Economics Newsletter (Third Quarter 2014) at 27-28, available at www.iaee.org/en/publications/newsletterdl.aspx?id=242.
[157] World Resources Institute, "Seeing is Believing: Creating a New Climate Economy in the United States" (Working Paper October 2014) at 53 ("In the Independent System Operator (ISO) New England grid region, the electric efficiency resources clearing the forward capacity market more than doubled between the first auction held in 2008 and 2013, accounting for nearly 30 percent of new capacity in the 2013 auction (to be provided in the 2016–17 time- frame). Electric energy efficiency resources clearing the market also nearly doubled in the PJM interconnection grid region during auctions held between 2009 and 2013, accounting for 20 percent of new capacity in the 2013 auction (also for the 2016–17 timeframe)." (footnotes omitted)).

set a transmission region's marginal price have historically been a primary driver of how low- or zero-emitting resources reduced generation at affected units. Historical data on these "locational marginal units" demonstrates the ability of clean energy and energy efficiency to displace generation from high-emitting sources. Models for estimating the GHG emission reductions from energy efficiency programs incorporate data about the hourly marginal emissions rates for local electricity, even when the programs do not place energy efficiency resources on the electricity capacity market.[158]

EPA has also correctly observed that "[r]eduction of, or limitation on, the amount of generation is already a well- established means of reducing emissions of pollutants in the electric sector." 79 Fed. Reg. at 34,889 (listing several emission control programs under which reduced generation is an available compliance option). Reduced generation is already a prominent consideration in compliance planning for EGUs, and ICF's Integrated Planning Model's optimization process incorporates "reduce running regime" as one of the main compliance options for policies that set an emissions cap.[159]

G. The Unique Characteristics of the Power Sector and Associated Carbon Pollution

As EPA effectively describes in the preamble and legal TSD,[160] the unique features of the Clean Power Plan arise from – indeed, are driven by – the distinctive characteristics of carbon pollution from the power sector. Other source categories for which EPA has issued performance standards under section 111, including the five source categories which are subject to section 111(d) standards, are characterized by functionally independent facilities that emit pollutants with primarily local or regional effects. For such source categories, EPA has appropriately issued performance standards that reflect the application of cleaner processes, technologies, or techniques to emissions from individual sources. This approach responds to the need to protect local and regional air quality from emissions associated with such sources, and is well-suited to sectors in which standardized technologies and practices are available to reduce pollution from individual sources.

The characteristics of carbon pollution from the power sector, by contrast, call for the distinctive regulatory approach reflected in the Clean Power Plan – an approach that, as we argue elsewhere in these comments, also fits comfortably within the broad language of section 111; comports with other Clean Air Act regulatory programs affecting the power sector; and reflects policies that utilities and states around the country are already employing to reduce carbon pollution. Unlike other industrial sectors regulated under section 111(b) and (d), the power sector does not consist of functionally independent facilities –

[158] *See, e.g.*, Energy and Environmental Economics, Inc. Report to the California Energy Commission PIER, Developing a Greenhouse Gas Tool for Buildings in California: Methodology and User's Manual v.2 (2009) at 8, available at https://ethree.com/GHG/GHG%20Tool%20for%20Buildings%20in%20CA%20v2%20April09.pdf ("The greenhouse gas (GHG) emissions of a building's electricity consumption are calculated by multiplying the hourly, or time of use, load profile of the building with an estimated hourly GHG emissions profile of California's electricity generation.").
[159] ICF International, Edison Electric Institute, "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet" at 8 (2011), available at http://www.psc.utah.gov/utilities/electric/12docs/1203592/239801Exhibit%20G%20to%20Fisher%20Testimony%2012-3-2012.pdf.
[160] *See* 79 Fed. Reg. at 34,880-881; Legal TSD at 43-45.

rather, it consists of an interconnected network of facilities that operate as a continuously-balanced and centrally-coordinated machine, or system.[161] Key distinguishing features of this system include:

- **Real-time balancing of supply and demand via centralized dispatch**. Due to the lack of large-scale electricity storage facilities, the electric grid has always required continuous matching of electricity supply and demand – a process that is carried out in practice by balancing authorities or system operators that centrally manage the resources on the grid.[162] Depending on the region, these functions can be carried out by vertically integrated utilities, RTOs/ISOs, transmission operators, or other entities. These entities continuously "dispatch" available generating resources (and in many cases, demand-side resources as well) to meet demand in a cost-effective way and ensure reliability, either through a real-time energy market or other centralized method of ordering and coordinating power supply from the various resources on the grid.[163] Through these mechanisms, the portfolio of generating resources that serves the grid changes from hour to hour in response to changes in cost, reliability considerations, environmental constraints, and other dynamic factors. Producing electricity on the interconnected grid also means that other basic aspects of a generator's operations are determined by the needs of the grid; for instance, generators must produce electricity at the same nominal frequency in synchronization.[164]

- **Fungible and commingled product**. Although electric generating resources do have diverse operating characteristics that influence the rate and timing of their output, the generation from any given EGU can be seamlessly substituted with that of any other — and is thoroughly commingled with generation from all other sources connected to the grid. This makes electricity one of the most thoroughly fungible of industrial products. From a supply standpoint, this fungibility is reflected in the fact that utilities and grid operators routinely and continuously coordinate output from different resources to optimize the availability and cost of power. Another unique result is that utilities whose transmission networks are connected

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[161] A useful primer on the structure of the nation's electric system appears in *The Future of the Electric Grid,* at 2-7, 243-249 (Massachusetts Institute of Technology, 2011). *See also* PHILLIP F. SCHEWE, THE GRID: A JOURNEY THROUGH THE HEART OF OUR ELECTRIFIED WORLD 1 (2007) ("Taken in its entirety, the grid is a machine, the most complex machine ever made.")

[162] *The Future of the Electric Grid* at 4, 6.

[163] *See id.* at 34 ("Power systems require a level of centralized planning and operation to ensure system reliability. System operators at control centers carry out many of these centralized functions. . . .In areas with traditional vertically integrated utilities, economic dispatch and unit commitment are calculated based on known start-up and fuel costs for generators; in restructured areas, a similar result is obtained through bidding in wholesale markets. Control centers then refine these day-ahead estimates as often as every 5-15 minutes, dispatching each generator to minimize total system costs given the load level, generator availability, and transmission constraints."). *See also* Paul L. Joskow, Creating a Smarter U.S. Electricity Grid, 26 J. ECON. PERSP. 29, 33 (2012) ("Electricity is the ultimate 'just-in-time' manufacturing process, where supply must be produced to meet demand in real time.").

[164] Brief of Amici Curiae Electrical Engineers, Energy Economists and Physicists (May 31, 2001) at 9, *New York v. FERC*, 535 U.S. 1 (2002) (Nos. 00-568 and 00-809) (signed by 21 amici and two supporters after filing date, including seven professors of electrical engineering, seven professional electrical engineers, five economists and management consultants with expertise in the power sector, and four professors who study the power sector in the fields of industrial engineering, planning and public policy, economics, and applied economics and management) (excerpts included as an appendix to these comments).

by "tie lines" buy power from one another to satisfy demand; for instance, companies buy electricity when it is cheaper to procure than generate or when their generation resources cannot satisfy demand alone.[165] (And is described further below, the vast majority of the power generation sources in the country are interconnected on two massive grids.) Moreover, due to the commingling of power on the grid, minute-to-minute changes in the composition of the electric generating portfolio take place in a way that is largely invisible to the consumer. Indeed, even if a consumer preferred power from a particular source, it would be impossible for the generator or power system operators to direct the energy from a particular generator to a particular user.[166] Energy flowing onto the power grid energizes the entire grid, and consumers draw undifferentiated energy from the grid.[167]

- **Substitutability of demand and supply**. Related to the fungibility of electricity is the extent to which reduction in electricity demand serves as a substitute for supply.[168] Thanks to an array of cost-effective energy efficiency and demand response technologies, there are a large number of ways in which consumers can use *less* electricity while maintaining the *same* (or greater) level of utility or "electricity services." From the standpoint of the interconnected power system, which is continuously balanced at every moment in time, such demand-side measures are effectively equivalent to supply resources: every megawatt in demand reduction translates automatically and immediately into a megawatt reduction in needed supply. This phenomenon is most vividly illustrated in the energy and capacity markets operated by regional transmission operators and independent system operators, many of which allow demand response and/or energy efficiency to compete directly with generation to meet energy and capacity needs.[169] It is also illustrated in the extensive modeling that EPA and others have undertaken to quantify the effects of energy efficiency programs and measures on hourly dispatch and overall emissions from the power sector.[170] There are few, if any other products where a reduction in demand leads automatically to changes in output and supply; a refinery, for example, might respond to local changes in demand for gasoline by exporting a

[165] *Id.* at 14.
[166] *Id.* at 10 (quoting Florida Power & Light Co., 404 U.S. 453, 460 (1972)).
[167] *Id.* at 9.
[168] *See, e.g.,* Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 at P 20-21, 49 (2012) (reviewing comments and expert testimony supporting the substitutability of supply-side and demand-side resources in organized wholesale energy markets, and concluding that ". . . . a power system must be operated so that there is real-time balance of generation and load, supply and demand. An RTO or ISO dispatches just the amount of generation needed to match expected load at any given moment in time. The system can also be balanced through the reduction of demand. Both can have the same effect of balancing supply and demand at the margin either by increasing supply or by decreasing demand."); North American Electric Reliability Corporation (NERC), Summer Reliability Report, May 2014, at 25 (noting that "Energy Efficiency/Conservation programs . . . are counted as [either] a resource or as a load modifier, depending on the type of the program offered" in reliability analyses) *available at* http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014SRA.pdf.
[169] *See, e.g,* Although the authority of FERC to establish compensation level for demand response resources in wholesale energy markets is currently being litigated, *see Electric Power Supply Ass'n v. FERC,* No. 11-1486 et al. (D.C. Cir. May 23, 2014), this legal dispute does not affect the reality of how demand and supply interact on wholesale markets.
[170] *See, e.g.,* EPA, "Avoided Emissions and Generation Tool: A Tool that Estimates the Emissions Benefits of Energy Efficiency and Renewable Energy Policies and Programs," http://epa.gov/avert/ (last visited Nov. 10, 2014).

greater share of its products or storing product in anticipation of future demand. Such responses are generally unavailable to electric generating units.

- **Dispersed nature of carbon pollution**. Carbon dioxide is a globally dispersed pollutant whose harmful effects on our atmosphere are virtually identical regardless of where it is emitted. Accordingly, the climate benefits of mitigating carbon pollution depend entirely on the *aggregate* level of reductions from the power sector, rather than the distribution of those reductions.

- **Lack of source-specific control technologies**. Due to the limited readily-available technologies that can be implemented at individual fossil fuel-fired EGUs to mitigate carbon pollution, states and power companies that have sought to decrease carbon pollution in recent years have almost exclusively relied on system-based approaches that leverage the capacity of the power system to reduce aggregate emissions through flexible changes in the generating portfolio and cost-effective efficiency measures. As described elsewhere, these states and companies have successfully reduced carbon pollution cost-effectively, without creating any reliability problems, and while securing concomitant reductions in other harmful air pollutants emitted by fossil fuel-fired power plants.

The proposed Clean Power Plan responds to these distinctive aspects of the power sector by establishing state-wide performance targets that will ensure aggregate reductions in carbon pollution over time, and that give states flexibility to leverage the dynamic nature of the power system in various ways to achieve these aggregate targets. The level of aggregate reductions required are based on a system-wide analysis that recognizes that all existing fossil fuel-fired EGUs are part of a large, coordinated system for generating and delivering electricity. For this reason, EPA appropriately considers the various mechanisms that are available to states to reduce emissions as a whole from existing EGUs — including shifts in dispatch from high-emitting units to low or zero-emitting units, or to demand-side efficiency. Indeed, as EPA recognizes, an approach that failed to account for the actual behavior of the interconnected power system could undermine the emission reduction goals of section 111 by increasing the economic competitiveness of higher-emitting EGUs relative to other resources.

As we note elsewhere in these comments, this is a time-tested approach to reducing emissions from the power sector under the Clean Air Act, and one that states and utilities themselves have recognized and demonstrated. The Acid Rain Program created as part of the 1990 Clean Air Act amendments, for example, explicitly reflected a system-wide approach whose purpose was "to encourage energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of [Title IV], for reducing air pollution and other adverse impacts of energy production and use."[171] System-wide approaches were also inherent to the design of the NO_x SIP Call and the Cross-State Air Pollution Rule, both of which have been upheld by the courts as appropriate exercises of EPA's authority to protect public health against harmful ozone and particulate

[171] 42 U.S.C. § 7651(b); *see also* 42 U.S.C. § 7651c(f), (g) (establishing a reserve of allowances and requiring EPA to issue allowances "for each ton of sulfur dioxide emissions avoided by an electric utility . . . through the use of qualified energy conservation measures or qualified renewable energy").

pollution that crosses state lines.[172] And at least three jurisdictions have adopted state implementation plans (SIP) — approved by EPA — that rely on renewable energy and energy efficiency programs to achieve needed reductions in emissions of harmful power sector pollution.[173] These examples show that, in practice, the interconnected nature of the power sector has been recognized and harnessed by Congress, EPA, and individual states when designing pollution control programs under the Clean Air Act. The proposed Clean Power Plan is consonant with this long tradition.

H. EPA Should Find that Partial CCS is an Alternative Adequately Demonstrated System of Emission Reduction

Although EPA has properly identified the CPP's flexible Building Block system as the "best" system of emission reduction, partial carbon capture and storage (CCS) is an adequately demonstrated alternative that would be the BSER *in the absence of* the Building Block system. A partial CCS standard similar to the standard proposed for new EGUs would reduce CO_2 emissions from super critical pulverized coal plants by 33 percent and from IGCC plants by18 percent[174]—far exceeding the reductions that could be achieved by the 6% heat rate improvement under Building Block 1—and would also achieve significantly greater reductions of co-pollutants.[175] In the final rule, EPA should provide a more detailed assessment of partial CCS as an alternative BSER. Partial CCS is a statutorily satisfactory system of emissions reduction that achieves far greater emissions reductions than Building Block 1 (heat rate improvements) alone.

As explained below, partial CCS satisfies the statutory criteria for BSER:

CCS is adequately demonstrated for retrofit to existing EGUs.

As EPA documented at length in the TSD for the proposed carbon pollution standards for new EGUs, the individual technologies used in CCS systems have been available for decades and have been applied at a

[172] *See Michigan v. EPA*, 213 F.3d 663 (D.C. Cir. 2000)(upholding NO_x SIP call rulemaking); *EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584 (2014)(upholding Cross-State Air Pollution Rule).
[173] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9 (describing EPA approval of SIPs for Texas, Maryland, Virginia, the District of Columbia, and Louisiana incorporating renewable energy or energy efficiency measures); *see, e.g.*, Approval and Promulgation of Air Quality Implementation Plans; Texas; Revisions to Chapter 117 and Emission Inventories for the Dallas/Fort Worth 8-Hour Ozone Nonattainment Area, 73 Fed.Reg. 47835, 47836 (Aug. 15, 2008) (EPA approval of the inclusion of EE measures aimed at reducing NOx emissions for Dallas-Fort Worth into the Texas SIP); Approval and Promulgation of Air Quality Implementation Plans; Maryland and Virginia; Non-Regulatory Voluntary Emission Reduction Program Measures, 70 Fed. Reg. 24,987 (May 12, 2005) (EPA approval of inclusion of county government commitments to purchase 5% of their annual electricity consumption from wind power in Maryland's SIP).
[174] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-452/R-13-003 (Sept. 2013) at 5-35, Table 5-10.214, *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf.
[175] *Id.* at 5-39.

commercial scale in other industrial sectors. Utilities have made significant progress towards applying this technology to coal-fired EGUs, including several successful demonstration-scale projects at existing facilities. And in October 2014, the Canadian utility SaskPower activated the first commercial-scale CCS project for the power sector: a rebuilt 139 MW unit at its Boundary Dam plant, equipped with CCS technology capable of capturing 90 percent of the unit's CO_2 emissions.

Coal-fired power plants designed for demonstration-scale CCS application include AES's coal-fired Warrior Run (Cumberland, MD) (capturing 110,000 metric tons CO_2 /year) and Shady Point (Panama, OK) (capturing 66,000 metric tons CO_2 /year), both equipped with amine scrubbers designed to process a slip stream of the plant's flue gas.[176] SaskPower's Boundary Dam plant in Canada, a coal-fired power plant retro-fitted for CCS at commercial scale, in the testing stage at the time of the proposed rule, came online in October 2014.[177] Mississippi Power's Kemper County Energy Facility, a second coal-fired power plant designed to employ CCS at a commercial scale, is expected to begin operation in 2016.[178] In July 2014, retrofit construction began on the Petra Nova Carbon Capture Project at the existing 240 MW W.A. Parish coal-fired power plant near Houston, Texas; capture at a rate of 1.6 million tons CO_2 per year will begin by the end of 2016.[179]

The Boundary Dan project will result in the capture of over one million metric tons of CO_2 per year, and was undertaken in part to comply with Canadian emission standards for existing EGUs[180] Although SaskPower has yet to release official data since operations began, SaskPower CEO Robert Watson has stated that the carbon capture equipment is performing as expected with respect to the amount of power required for operation of the equipment, and noted that SaskPower anticipates achieving the full 90% capture rate "in not too long at all."[181]

SaskPower's currently operational, commercial scale Boundary Dam plant project – along with other evidence in the record for the proposed NSPS for new EGUs — shows that partial carbon capture is adequately demonstrated for existing coal-fired power plants. "Adequately demonstrated" does not mean that all existing sources are able to meet the requirement, *see Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785-86, nor does it require the available technology to be in "actual routine use" at the time of the rulemaking. *See Portland Cement Ass'n v. Ruckleshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) ("*Portland Cement I*"). Rather,

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[176] *See* 79 Fed. Reg. at 1474-75 (citing J.J Dooley et al., An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009. U.S. DOE, Pacific Northwest National Laboratory, under Contract DE-AC05-76RL01830).
[177] Laverty, Gene, SaskPower launches C$1.4B carbon capture project, SNL (Oct. 1, 2014), *available at* https://www.snl.com/Cache/snlpdf_d204175b-8901-454b-85ed-2b4f93463194.pdf.
[178] *See* Southern Co. and Mississippi Power Co., SEC Form 8-K (Oct. 27, 2014) at 3., *available at* http://www.sec.gov/Archives/edgar/data/66904/000009212214000064/msmonthlyreport8-k10x14.htm.
[179] *See* WA Parish Carbon Capture Project, http://www.nrg.com/sustainability/strategy/enhance-generation/carbon-capture/wa-parish-ccs-project/.
[180] Stéphenne, Karl, Start-Up of World's First Commercial Post-Combustion Coal Fired CCS Project: Contribution of Shell Cansolv to SaskPower Boundary Dam ICCS Project, Energy Procedia (to be published in 2014/2015) at 2, *available at* https://sequestration.mit.edu/tools/projects/GHGT-12%20paper/boundary_dam_update_2014.pdf.
[181] Marshall, Christa, World's first coal carbon capture project set for startup this week, E&E Reporter (Sept. 30, 2014).

> [t]he Administrator may make a projection based on existing technology, though that projection is subject to the restraints of reasonableness and cannot be based on 'crystal ball' inquiry.
> . . .
> [T]he question of availability is partially dependent on 'lead time', the time in which the technology will have to be available.
> . . .
> If actual tests are not relied on, but instead a prediction is made, 'its validity . . . rests on the reliability of [the] prediction and the nature of [the] assumption.

Portland Cement I, 486 F.2d at 391-92 (citing and quoting *Int'l Harvester v. Ruckelshaus*, 478 F.2d 615, 629 (D.C. Cir. 1973)). Moreover, EPA can "extrapolat[e] . . . a technology's performance in other industries", and look beyond domestic facilities to those used abroad. *Lignite Energy Council,* 198 F.3d 930, 934 n.3 (D.C. Cir. 1999). The *Portland Cement I* court found that the term "adequately demonstrated" required a showing by EPA "that there *will be* 'available technology' *during the regulated future*." *Portland Cement I*, 486 F.2d at 391 (emphasis added). Thus the question is whether the technology will be available at the time that implementation is required.

EPA can and must encourage new and less-polluting technologies through the standards it sets under section 111. The legislative history of section 111 and the relevant case law affirm the technology-forcing nature of the statute. For instance, the 1977 Senate Report discusses the need "to assure the use of available technology and to stimulate the development of new technology." S. Rep. No. 95-127 at 171. To that end, "[t]he statutory factors which EPA must weigh [when setting performance standards] are broadly defined and include within their ambit subfactors such as technological innovation." *Sierra Club*, 657 F.2d 298, 346 (D.C. Cir. 1981). In *Sierra Club*, the court explained: "Recognizing that the Clean Air Act is a technology-forcing statute, we believe EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard.... As a result, we uphold EPA's judgment that the standard can be set at a level that is higher than has been actually demonstrated over the long term by currently operating lime scrubbers at plants burning high sulfur coal."[182] *see also Portland Cement Ass'n v. EPA* (*"Portland Cement III"*), 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology). These standards should reflect the use of the "best" control options, including those achieving the deepest reductions, consistent with Congress's intent to encourage technological advancement in controls.

The operational status of the Boundary Dam project demonstrates the viability of large scale CO_2 capture and shows that CCS can be accomplished on a commercial scale, including as a retro-fit to an existing

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[182] 657 F.2d 298, 364 (D.C. Cir. 1981) (footnote omitted). *See also Portland Cement Ass'n v. EPA* (*"Portland Cement III"*), 665 F.3d 177, 190 (D.C. Cir. 2011) (EPA properly based the NSPS for new cement kilns on a recent and more efficient model, even though many older kilns still existed that did not utilize the same technology).

plant. Furthermore, the current status of the Boundary Dam project and the development rate of CCS technology evinced by the record support the conclusion that retrofitted CCS technology will be more widely available for commercial use by 2020, when the rule's requirements must be implemented.

With respect to the CO_2 transportation required to facilitate storage where nearby geologic sequestration is not feasible, EPA has properly concluded that the necessary technology is adequately demonstrated and feasible. *See* 79 Fed. Reg at 1472. As EPA notes, CO_2 has been transported via pipelines in the U.S. for almost 40 years, and approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. *See id.* EPA has determined that 95 percent of the 500 largest CO_2 point sources are within 50 miles of a possible geologic sequestration site. *See id.*

Similarly, with respect to the storage component of CCS, as EPA properly identified in the proposal for NSPS for GHG emissions from new EGUs, geologic sequestration of CO_2 is available and adequately demonstrated. EPA has cited to numerous CO_2 commercial storage projects as well as field studies that demonstrate the feasibility of geologic sequestration. *See* 79 Fed. Reg. at 1472-74. For example, since 1996 the Sleipner natural gas processing project in the North Sea has separated CO_2 from natural gas and sequestered .9 Mtpa of CO_2 in an offshore deep saline reservoir.[183] Additionally, the oil and natural gas industry in the United States and abroad has five decades of experience in injecting captured CO_2 into geologic formations. Department of Energy ("DOE") studies indicate that the U.S. has ample CO_2 storage potential. *See* 79 Fed. Reg. at 1473. As mentioned above, the majority of existing coal-fired power plants are located in regions where there is a high likelihood of nearby geologic storage availability.[184]

The costs of CCS do not preclude its identification as the best system of emission reduction.

In the proposed rule, EPA asserts that it will not propose partial CCS as the BSER because the costs would be "substantial" and affect electricity prices.[185] Yet even if the costs of retro-fitting the existing EGU fleet for partial CCS would be "substantial" and affect electricity prices, those costs will be within EPA's discretion under section 111 as long as they are not "exorbitant" or "more than the industry can bear." *See Portland Cement I*, 486 F.2d at 391; *Essex Chemical Corp.*, 486 F.2d 427, 433 (D.C. Cir. 1973); *Sierra Club*, 657 F.2d 298, 383 (D.C. Cir. 1981); *Lignite Energy Council*, 198 F.3d at 933. Consequently, EPA is not foreclosed from determining that CCS is the BSER. Furthermore, CCS costs may be defrayed by the use of captured CO_2 for enhanced oil recovery, or reduced by implementation of partial CCS at lower proportions of capture.

Section 111(a)(1) of the CAA directs EPA to include costs among the factors it considers when determining the BSER. In a line of cases spanning several decades, the D.C. Circuit held that the statute is

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[183] Pacific Northeast Nat'l Laboratory, *An Assessment of the Commercial Availability of Carbon Dioxide Capture and Storage Technologies as of June 2009* (June 2009), n. 203, at 5-6; Global CCS Inst., *Sleipner CO2 Injection* (project data current as of Sept. 7, 2014), *available at* http://www.globalccsinstitute.com/project/sleipner%C2%A0co2-injection.

[184] MIT, The Future of Coal, at 58-59 (2007) ("The majority of coal-fired power plants are situated in regions where there are high expectations of having CO2 sequestration sites nearby. In these cases, the cost of transport and injection of CO_2 should be less than 20% of total cost for capture, compression, transport, and injection.").

[185] *See* 79 Fed. Reg. at 34,856-57, 34,876.

satisfied as long as the costs of the BSER are not "excessive" or "exorbitant." *See Portland Cement I*, 486 F.2d at 391; *Essex Chemical Corp.*, 486 F.2d at 433; *Sierra Club*, 657 F.2d at 383; *Lignite Energy Council*, 198 F.3d at 933. Section 111 allows EPA to take a broad view of the costs of the proposed standard at the national and regional level, which includes consideration of the pollution benefits that would be achieved, the avoided costs of carbon pollution on society as well as the co-benefits of reducing harmful $PM_{2.5}$ and ozone pollution. *See Sierra Club*, 657 F.2d at 330. When setting a standard of performance under section 111, "EPA has authority to weigh cost, energy, and environmental impacts *in the broadest sense at the national and regional levels* and over time as opposed to simply at the plant level in the immediate present." *Sierra Club*, 657 F.2d at 330. Notably, the D.C. Circuit has never upheld a challenge to a section 111 standard based on cost. 79 Fed. Reg. at 1464. For example, in *Portland Cement I*, the court upheld an NSPS for particulate matter emissions, even though control technologies amounted to roughly 12 percent of the capital investment for an entire new plant and consumed five to seven percent of a plant's total operating costs. 486 F.2d 375, 387-88. Likewise, the court upheld particulate matter ("PM") standards that were anticipated to increase the cost of cement by one to seven percent, with little projected decrease in demand. *Portland Cement Ass'n v. EPA*, 665 F.3d 177, 191 (D.C. Cir. 2011); *see also* 73 Fed. Reg. 34,072, 34,077, 34,086 (June 16, 2008). With respect to the electricity generating industry, the *Lignite Energy Council* court held that a two percent increase in the cost of producing electricity was not exorbitant, and upheld the 1997 nitrogen oxides ("NO_x") NSPS for EGUs and industrial boilers. *See* 198 F.3d at 933 (citing 62 Fed. Reg. 36, 948, 36,958 (July 9, 1997)).

In the CPP proposal, EPA explains that the costs of CCS may be "substantial" and potentially affect electricity prices:

> [T]he cost of integrating a retrofit CCS system into an existing facility would be expected to be substantial, and some existing EGUs might have space limitations and thus might not be able to accommodate the expansion needed to install CCS. Further, the aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. For these reasons, although some individual facilities may find implementation of CCS to be a viable CO2 mitigation option . . . EPA is not proposing . . . CCS as a component of the BSER[.]

See 79 Fed. Reg. at 34,857.[186] Yet such cost impacts—in the absence of an alternative system of emission reduction that is less costly and achieves very significant emission reductions—may well not be outside of the appropriate bounds of a best system of emission reduction analysis.

Furthermore, in evaluating the costs of partial CCS, EPA has discretion to include a consideration of revenue generated as a result of injection of CO_2 for enhanced oil recovery (EOR) operations. Section 111 allows a broad consideration of costs, including the sale of byproducts, and EPA may properly take the possibility of EOR sales into account when evaluating the costs of the proposed performance standard. *See Sierra Club v. Costle*, 657 F.2d at 330 ("[S]ection 111 . . . gives EPA authority when determining the best technological system to weigh cost, energy, and environmental impacts in the broadest sense…over

[186] *See also*, EPA, GHG Abatement Measures TSD (June 18, 2014) at 7-5 to 7-6 (concluding that the costs of CCS would be unreasonable, significantly affect nationwide electricity prices and could affect reliability).

time."). We note, however, that ensuring permanent sequestration of CO_2 injected for EOR would be essential to implementing CCS as the BSER, as EOR operations have not been designed for this purpose historically. Nonetheless, because EPA's assessment of the costs of CCS may properly include the potential for EOR at some subset of the fleet, the costs of CCS would, in some locations, be reduced by this source of revenue generation.

The D.C. Circuit has held that the agency has authority to evaluate all of the statutory factors in a BSER determination "in the broadest possible sense," and to consider costs "at the national and regional levels and over time as opposed to simply at the plant level in the immediate present." *Sierra Club*, 657 F.2d at 331. Given that, it is appropriate for EPA to consider revenue streams from the co-production of CO_2 in its determination that carbon capture and storage ("CCS") is BSER for coal-fired EGUs. Furthermore, as EPA asserts, if costs of *disposal* of byproducts must be taken into account during cost analysis, *revenue* from the sale of economically valuable products as a co-benefit of achieving a particular performance standard should also be taken into account. *See* 79 Fed. Reg. at 1,464. To the extent that the sale of captured CO_2 may generate revenues for plant operators, those revenues should be factored into a determination of the proposed rule's costs.

EPA's prior actions are consistent with the notion that byproduct revenue may be considered when the agency sets a performance standard. For example, in 2012, EPA and the National Highway Traffic Safety Administration finalized new fuel economy standards for lightduty vehicles. *See* 77 Fed. Reg. 62,624 (Oct. 15, 2012). In its cost analysis, the agencies determined that the benefits that would result from more stringent standards would "far outweigh higher vehicle costs" to consumers, largely due to the 170 billion gallons of fuel that would be saved throughout the lives of vehicles sold over an eight-year period. *Id.* at 62,629, 62,631. From a macroeconomic standpoint, these savings are functionally indistinguishable from the revenue that would accrue if those 170 billion gallons of fuel were a direct byproduct of the new technology, rather than the amount saved due to reduced demand. That same year, EPA analyzed revenues from the sale of natural gas and condensate recovered through the installation of pollution controls when describing costs associated with the NSPS for oil and natural gas production. *See* 77 Fed. Reg. 49,490, 49,534 (Aug. 16, 2012) (estimating that the proposed standards would save approximately $11 million annually if revenues from additional recovery were considered).

Finally, EPA could employ flexibility measures that would reduce the cost of CCS. For example, to reduce overall costs in the initial years following CCS technology installation, EPA could incorporate a gradual ramp-up rate in the percentage of capture that would allow for lower operational costs. A gradual introduction of CCS would also allow the industry to realize reductions in cost and improvements in performance that are likely to result from increasing familiarity with and development of CCS technology. For example, SaskPower executives have stated that they expect to retrofit additional coal-fired EGUs with CCS, and that the next such project will likely have 20-30% lower capital costs than Boundary Dam.[187] Studies of CCS technology development have also estimated that the cost of

[187] Matthew Bandyk, *SaskPower Looking to Spur More CCS with Boundary Dam Project*, SNL (Nov. 7, 2013 5:26 PM ET), http://www.snl.com/interactivex/article.aspx?id=25792864&KPLT=6.

electricity from CCS-equipped plants would likely decrease by 10-18% after approximately 100 GW of CCS capacity has been installed.[188]

In summary, EPA may ultimately determine that the costs of CCS, though significant, are nonetheless within the appropriate bounds, particularly in light of opportunities to defray costs through EOR, and to adjust the proportion of capture assumed in setting the standard.

EPA's technical feasibility concerns should be addressed through the analysis of cost.

Although the preamble to the proposed rule appears to reject partial CCS on the ground of cost alone, the GHG Abatement Measures TSD makes it clear that EPA also based its decision on the conclusion that CCS "may not be technically or logistically feasible in a number of cases."[189] Whereas the preamble appears to treat the spatial requirements and geographic factors relevant to CCS as considerations that will inflate the cost of CCS, the TSD addresses these concerns as part of an analysis of feasibility.[190]

In the TSD, EPA explains that:

> Some existing facilities are located in areas where CO2 storage is not geologically favorable and are not near an existing CO2 pipeline.
> . . .
> Integrating a retrofit CCS system into an existing facility is much more challenging. Some existing sources have a limited footprint and may not have the land available to add partial CCS system. Integration of the existing steam system with a retrofit CCS system can be particularly challenging.[191]

Although EPA states that CCS may not be feasible "in a number of cases," such a consideration does not bar the Agency from selecting CCS as the BSER because section 111 does not require EPA to find that *all* existing sources be able to meet the requirement. *See Nat'l Asphalt Pavement Ass'n*, 539 F.2d at 785-86. To the extent that EPA is asserting that these site-specific concerns show that CCS is not adequately demonstrated for any retrofit applications, such a conclusion would be unwarranted because it is well established that an emission reductions system can be "adequately demonstrated" even though some existing units may not be able to meet the resultant standard. *See id.*

Furthermore the difficulty that some existing sources might have in adopting CCS due to site-specific spatial constraints or distance from CO_2 pipelines or geologic units appropriate for sequestration are properly assessed as part of the projected cost of CCS rather than as technical feasibility. *Cf. Honeywell Int'l, Inc. v. EPA, 374 F.3d 1363, 1372 (D.C. Cir. 2004)* (finding that EPA decision to allow certain businesses to continue to use certain chemical agents on "technical feasibility" ground that it might be

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[188] Congressional Budget Office, *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide 8* (June 2012).
[189] *Id.* at 7-6; *see also id.* at 7-4 to 7-5 (discussing technical feasibility).
[190] *See id.* at 7-4 to 7-5; 79 Fed. Reg. at 34,857.
[191] GHG Abatement Measures TSD at 7-4.

burdensome to those businesses to switch to another agent was actually a decision based on cost.) As the D.C. Circuit has stated, "it is often possible to fit a round peg in a square hole if enough money is spent to make the round peg fit. In other words, a given change in manufacturing technique may be 'technically infeasible' only as compared to some baseline of what it would cost to change the technique." *Id*. For example, though the *current* footprint of a particular plant might not be large enough to accommodate CCS, it might nonetheless be feasible for the plant to expand its footprint by acquiring adjacent land at a cost that would not be exorbitant. Thus, rather than speculating that some number of plants may have spatial and geographic factors that would make CCS "infeasible," EPA should assess how widespread such constraints are and factor that information into its determination regarding the cost of CCS.

In summary, because the case law makes clear that the BSER need not be feasibly applied at *every* source, EPA is not required to base its evaluation of the feasibility or cost of CCS on some subset of facilities where source-specific spatial or geographic constraints would prohibit its use. Although spatial and geographic factors may generally increase the average cost of CCS, those costs will not necessarily be "exorbitant" or "more than the industry can bear." Consequently, EPA could ultimately conclude that CCS is a potential BSER (though inferior to the flexible, system-based BSER currently proposed).

In addition, EPA can and should take into account likely reductions in the cost of CCS that will accompany increasing deployment of the technology. As noted above, utilities such as SaskPower and researchers in the field of pollution control have predicted that the costs of CCS will decline significantly as the industry gains experience with the technology – just as has occurred with well-established technologies for power plants, such as flue gas desulfurization and selective catalytic reduction.[192]

Finally, it is noteworthy that because EPA has discretion to sub-categorize sources,[193] the Agency could distinguish between sources based on proximity to EOR or other spatial or geographic factors. By sub-categorizing in this way, EPA could find that partial CCS is the BSER for the sub-category of plants where physical constraints would not impose excessive costs.

EPA may reasonably evaluate the costs associated with a standard by looking at the degree of pollution control it achieves

Section 111 makes clear that EPA must consider the degree of emission limitation achieved, as well as the costs of achieving it, when formulating a performance standard. 42 U.S.C. § 7411(a)(1). This does not require the application of a strict cost-benefit test; rather, reviewing courts have upheld performance standards so long as the costs are not exorbitant (i.e., too high for the industry to bear) in light of the pollution reduction benefits they will yield. For example, in Sierra Club, the court upheld sulfur dioxide ("SO2") standards that would cost industry tens of billions of dollars between 1987 and 1995, but would provide significant benefits, including 100,000–200,000 tons of SO2 emission reductions per year, cost

[192] *See* Congressional Budget Office, *supra; see also* Edward S. Rubin, *Reducing the Cost of CCS Through "Learning by Doing,"* Presentation to the Clearwater Coal Conference (June 2, 2014), *available at* http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2014/Reducing%20the%20Cost%20of%20CCS%20through%20Learning%20by%20Doing.pdf
[193] 42 U.S.C. § 7411(b)(2).

savings of over \$1 billion per year, and a 200,000 barrel-per-day reduction in oil consumption. 657 F.2d at 314, 327-28.

While there exists no dollars-per-ton-removed cost-effectiveness level to serve as a "rule of thumb," the Portland Cement III court upheld PM standards for Portland cement plants that EPA had determined were "well within the range of cost-effectiveness" at about \$3,969 per ton of PM emissions removed. 665 F.3d 191; see also 73 Fed. Reg. 34,072, 34,076-077 (June 16, 2008) (discussing costs per ton removed by EPA's BSER for PM, and noting that the agency had previously deemed PM regulations for EGUs to be reasonably cost-effective at \$8,400 per ton of PM removed). Similarly, in Lignite, the court upheld NOx performance standards that would cost \$1,770 per ton removed, despite the availability of cheaper but less protective alternatives advocated by industry petitioners. 198 F.3d at 933; 62 Fed. Reg. 36,948, 36,953 (July 9, 1997).

Partial CCS would achieve significant emission reductions directly from EGUs.

Partial CCS can achieve emission reductions that are far greater than reductions generated by other alternative standards, such as a standard based on heat rate improvements alone. In the absence of a flexible Building Block scheme that can provide comparable CO_2 reductions more cost effectively, EPA could conclude that partial CCS would be the BSER because those reductions are considerable, the technology is adequately demonstrated for existing coal-fired power plants, and the costs have not been shown to be outside the range allowable under statute as elucidated by the case law. In evaluating alternative systems of emission reductions, EPA must consider the degree of the pollution reduction benefits that a proposed standard would achieve along with the costs of achieving it. *See Sierra Club*, 657 F.2d at 314, 327-28 (upholding costly SO_2 standards that would provide significant pollution benefits); *Essex Chem. Corp.*, 486 F.2d at 437 (acid mist standards were reasoned and cost benefit analysis was not required). A partial CCS standard would achieve significant reductions in CO_2 emissions that are urgently needed in the power sector. A partial CCS standard similar to the standard proposed for new EGUs would reduce CO_2 emissions from super critical pulverized coal plants by 33 percent (600 lb CO_2/MWh net) and from IGCC plants by18 percent (300 lb CO_2/MWh net).[194] Such a partial CCS standard would also result in additional co-benefits of reducing NO_x, SO_2, and $PM_{2.5}$.[195] These emissions reductions far exceed those anticipated to result from, for example, the 6% heat rate improvement under Building Block 1. Consequently, partial CCS is a superior system of emission reduction compared to alternative systems of emission reduction, and would be the BSER if the building block approach proposed by EPA were not available.

[194] EPA, *Regulatory Impact Analysis for the Proposed Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units*, EPA-452/R-13-003 (Sept. 2013) at 5-35, Table 5-10.214, *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposalria.pdf.
[195] *Id.* at 5-39.

I. The Best System of Emission Reduction Identified in the Clean Power Plan Reflects the Approach Taken by States and Power Companies Across the Country to Reduce Carbon and Other Harmful Air Pollutants Using Mechanisms that Reflect the Integrated Nature of the Power Sector

Across the country, states and companies are taking system-based approaches to achieve carbon pollution reductions, with a long track record of successful implementation. These programs are cost-effective and enable significant reductions because they take advantage of the unique opportunities for emission reductions provided by the interconnected electric grid. In fact, proven techniques for controlling GHGs that approach EGUs as part of an integrated system are the dominant approach for controlling EGU emissions of GHGs.

One of the most widespread and oldest approaches for states to reduce power sector emissions is the Renewable Portfolio Standard (RPS). As captured in the following chart, twenty-nine states and the District of Columbia have enacted RPSs, beginning in 1983. In many of these states, RPS requirements have been in force for ten or more years. There is also significant variation in program design among the RPS; states have made different decisions about key RPS features, such as resource eligibility, the program target, set-asides, and flexibility mechanisms.[196] The long experience with different kinds of RPS has allowed policymakers to understand best practices for RPS design.[197] In particular, the best practices guide states in developing programs that are enforceable, consistent with the structure of the electricity market, socially beneficial, cost-effective, flexible, and predictable.[198] RPS have had a significant impact on GHG emissions from the power sector. Several RPSs are slated to become even more stringent in coming years, leading to even greater reductions.[199]

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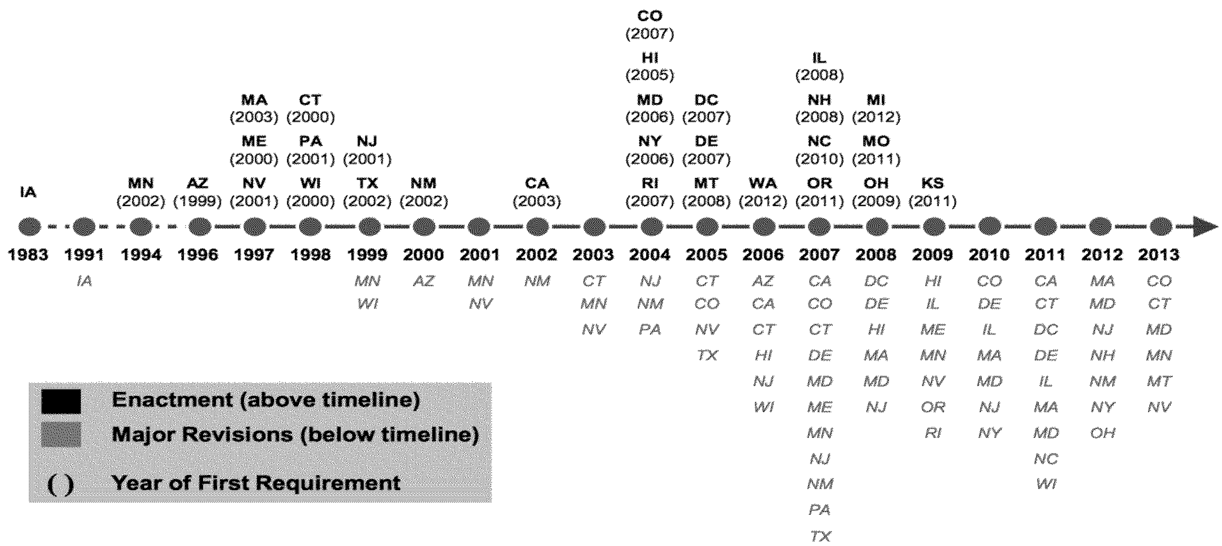
[196] *See generally* R. Wiser, K. Porter, and R. Grace, Lawrence Berkeley National Laboratory, Evaluating Experience with Renewables Portfolio Standards in the United States (2004), available at http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2054439.pdf; Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standard Policies (September 2014), available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

[197] *See, e.g.*, State/Federal RPS Collaborative, Recommended Principles and Best Practices for State Renewable Portfolio Standards (2009), available at http://www.cesa.org/assets/Uploads/Resources-post-8-16/Principles-Best-Practices-RPS-2.pdf; Clean Energy States Alliance, The State of State Renewable Portfolio Standards (2013), available at http://www.cesa.org/assets/2013-Files/RPS/State-of-State-RPSs-Report-Final-June-2013.pdf.

[198] Wiser et al, Evaluating Experience with Renewables Portfolio Standards in the United States at 25-30.

[199] Database of State Incentives for Renewables & Efficiency, Renewable Portfolio Standard Policies (September 2014), available at http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

Figure 1. Timeline of RPS Enactment and Initial Requirements



Source: Lawrence Berkeley National Laboratory (2013), http://emp.lbl.gov/sites/all/files/rps_summit_nov_2013.pdf

Several studies have documented the ability to expand on these historical successes by integrating much more renewable energy on the grid. A recent study of the PJM system found that it will not have any significant issues operating with wind and solar generation providing up to 30% of its energy.[200] In every scenario examined, integrating renewables into the PJM system would lead to lower operation & maintenance costs and a lower locational marginal price of electricity (which reflects the cost of generation and transmission), while reduction in CO_2 emissions relative to business as usual would range from 12% to 41%.[201] A study commissioned by the Minnesota Department of Commerce and conducted in coordination with the Midcontinent Independent System Operator (MISO) has found the state of Minnesota could obtain 40% or more of its electricity from wind and solar energy without suffering any grid reliability issues.[202] Accordingly, grid operators around the country are poised to duplicate the

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[200] GE Energy Consulting, PJM Renewable Integration Study, Executive Summary Report (March 2014) at 6-7, available at http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx.
[201] *Id.* at 7.
[202] GE Energy Consulting, Minnesota Renewable Energy Integration and Transmission Study (October 2014) (modeling the ability of the MISO grid to accommodate the renewable energy required by RPSs in the MISO region).

success of the RGGI region, which demonstrated the ability to dramatically increase its use of renewable generation while maintaining grid reliability.[203]

Another well-demonstrated state policy for reducing GHG emissions from the power sector as a whole is the energy efficiency resource standard (EERS). Currently, twenty states have an EERS and an additional seven states have energy efficiency goals.[204] As with RPSs, states have taken a variety of approaches in designing EERSs that meet specific state needs.[205] Key policy-design elements include the stringency of the standard, flexibility mechanisms, and methodology for measuring savings.[206] Almost all the current EERSs were enacted five or more years ago.[207] Over this time, these policies have proven to be an achievable means of reducing emissions from the power sector.[208] And the diversity of EERS design has allowed stakeholders to analyze best practices.[209] The Institute for Electric Innovation recently found that if rate-payer funded energy efficiency programs continue to grow at trend, they will reduce total U.S. electricity use by 5.9% by 2025.[210]

Energy efficiency programs are especially suitable for wide-scale deployment because they present an enormous opportunity for cost-savings. Investments made to meet state energy efficiency targets regularly save customers over $2 for every $1 invested, and in some cases up to $5.[211] For example, the largest utility in Minnesota, Xcel energy, reported that its energy efficiency programs in 2012 alone would provide a net benefit of $376 million to its electricity customers.[212] Across the country, there are many money-saving energy-efficiency opportunities that are yet to be realized. In 2010, National Academy of Science reported that full deployment of cost-effective energy-efficiency technologies in buildings would eliminate the need to add new generation capacity.[213] This study identified opportunities to reduce power consumption in residential and commercial buildings that (together) would save over

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[203] RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830 (June 18, 2014) (Docket No. EPA-HQ-OAR-2013-0602) (Nov. 5, 2014) at 3, 20, available at http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf.
[204] Database of State Incentives for Renewables & Efficiency, Energy Efficiency Resource Standards (February 2013), available at http://www.dsireusa.org/documents/summarymaps/EERS_map.pdf.
[205] *See id.*
[206] See generally Karen L. Palmer, Samuel Grausz, Blair Beasley, and Timothy J. Brennan, Putting a floor on energy savings: Comparing state energy efficiency resource standards, 25 Utilities Policy 43 (2013).
[207] *See id.* at 45, Table 1.
[208] *See* ACEE, EERS: A Progress Report on State Experience (2011) at 9-10 (Thirteen of the twenty states with EERS policies in place for over two years are achieving 100% or more of their goals, three states are achieving over 90% of their goals, and only three states are realizing savings below 80% of their goals.").
[209] *See generally* Steven Nadel, ACEE, Energy Efficiency Resource Standards: Experience and Recommendations (2006), available at http://www.epatechforum.org/documents/2005-2006/2006-05-16/2006-05-16-ACEEE%20Report%20on%20EE%20Portfolio%20Standards.pdf.
[210] IEE Report, Factors Affecting Electricity Consumption in the U.S. (2010 - 2035) (March 2013) at 1, available at http://www.edisonfoundation.net/iei/documents/IEE_FactorsAffectinguSElecconsumption_Final.pdf.
[211] Bianco, et al, Seeing is Believing: Creating a New Climate Economy in the United States, World Resources Institute Working Paper, at (2014) at 52, available at http://www.wri.org/sites/default/files/seeingisbelieving_working_paper.pdf (hereinafter "Seeing is Believing").
[212] Xcel Energy, 2012 Status Report & Associated Compliance Filings: Minnesota Electric and Natural Gas Conservation Improvement Program Docket No. E,G002/CIP-09-198 (2013) at 2, available at http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/MN-DSM-CIP-2012-Status-Report.pdf. These savings dwarf the $98.1 million spend on electric energy efficiency programs. *Id.*
[213] National Academy of Sciences, et al, Real Prospects for Energy Efficiency in the United States (2010) at 5.

1,200 TWh in 2030 and yield a return on investment in less than three years.[214] Another recent report identified building retrofit opportunities with the potential to mitigate more than 600 million metric tons of CO_2 per year, returning more than one trillion dollars in energy saving over ten years on a $279 billion dollar investment.[215] The many opportunities for reducing power-sector emissions through energy efficiency give states a range of well-demonstrated options for inclusion in their state plans.[216]

Where energy efficiency resources compete on the market, it is clear that they are a cost-effective way to meet consumer needs while reducing power-sector GHG emissions. Over the past decade, efficiency has remained the least-cost electricity option; with an average cost of 2.8 cents per kilowatt hour, energy efficiency programs are about one-half to one-third the cost of new electricity generation options.[217] In some regions, efficiency is beginning to feature in forward capacity markets directly competing for the right to meet the capacity needs of the electric grid.[218] Comparing the cost of energy efficiency and affected-source generation in this context clarifies the interconnected nature of the electric system and the appropriateness of taking a system-based approach to reducing GHG emissions from EGUs.

Individual states have crafted strategies for reducing power-sector emissions that combine several tailored policies. In Colorado, emissions reductions are being driven by the Clean Air - Clean Jobs Act, an energy efficiency standard, and a renewable energy standard. The Clean Air - Clean Jobs Act required Colorado's utilities to propose plans for achieving integrated multipollutant reductions from coal-fired power plants, prompting utilities like Xcel Energy design systems-based plans that shift generation to cleaner sources.[219] The Act has enormous public health benefits and is expected to create about 1,500 jobs during the construction of cleaner facilities.[220] Illinois also has a unique suite of policies with proven results; Illinois has an energy efficiency standard that requires utilities to save two percent of electricity

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[214] *Id.* at 69-70, 78. *See also* Granade, et a., McKinsey Global Energy and Materials, Unlocking Energy Efficiency in the U.S. Economy (2009) at iv-v ("Our research indicates that by 2020, the United States could reduce annual energy consumption by 23 percent from a business-as-usual (BAU) projection by deploying an array of NPV-positive efficiency measures, saving 9.1 quadrillion BTUs of end-use energy . . . . If captured at full potential, energy efficiency would abate approximately 1.1 gigatons of CO_{2e} of greenhouse gas emissions per year in 2020 relative to BAU projections.").
[215] The Rockefeller Foundation and DB Climate Change Advisors, United States Building Energy Efficiency Retrofits (2012) at 7, available at http://www.rockefellerfoundation.org/uploads/files/791d15ac-90e1-4998-8932-5379bcd654c9-building.pdf.
[216] *See generally* National Academy of Sciences, Real Prospects for Energy Efficiency in the United States, chapter 2 (quantifying the opportunities for electricity savings from different building energy efficiency measures).
[217] Maggie Molina, ACEE, The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (2014) at iii, available at http://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf.
[218] Bianco, Seeing is Believing at 53.
[219] Xcel Energy, Colorado Clean Air - Clean Jobs Plan, available at http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air_-_Clean_Jobs_Plan (explaining that Xcel's plan calls for the retirement of certain coal-fired units, the replacement of a retired unit with a modern natural gas plant, fuel-switching at one plant, and retrofits).
[220] *Id.* ("We expect to reduce nitrogen oxides by about 86 percent, sulfur dioxide emissions by 83 percent and mercury emissions by 82 percent from the plants included in the plan. The project will contribute to a projected system-wide reduction in carbon dioxide emissions since 2005 of 35 percent by 2020. The University of Colorado Leeds School of Business forecasts the project will have a total economic impact of about $590 million on the state of Colorado between 2010 and 2026, resulting in about 1,500 jobs at the peak of construction.").

annually by 2015 and reduce rate-payer spending,[221] an RPS that requires 25 percent of electricity to come from renewables by 2025 and drives a booming local economy in wind energy,[222] and has required any new coal-fired power plants to capture and store some of their carbon emissions.[223]

The nine states participating in the Regional Greenhouse Gas Initiative (RGGI) have already demonstrated that a systems-based approach to reducing power sector GHG emissions can achieve vast reductions with economic benefits. Since 2005, the RGGI states have reduced their power sector CO_2 emissions by 40 percent, while the regional economy has grown 7 percent.[224] The RGGI states now have nearly six years of experience with a fully operational carbon market.[225] Even during the first three years of the RGGI cap-and-trade program, the mandatory system had been functioning properly and seamlessly introducing a carbon price into the electricity market.[226] Experience with RGGI demonstrated that not only that the initial system-wide targets were achievable, but that even more ambitious targets were within reach: in 2013, the RGGI states lowered the program's emissions cap by 45 percent, starting in 2014.[227]

RGGI's enormous economic benefits demonstrate that integrating energy efficiency into power-sector GHG-reduction is not just available, but an economic boon. During the first three years of its cap-and-trade program, RGGI added $1.6 billion in economic value to the ten-state region.[228] In general, this positive impact results from the injection of carbon-allowance revenue into the economy and consumer savings on energy.[229] During this three-year period, RGGI state investments in energy efficiency created about 16,000 "job years."[230] Electricity consumers (including households, businesses, government users,

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[221] 220 Ill. Comp. Stat. 5/8-103(b) (2013). *See also* Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 14 ("in the first year (2008-2009) of the Illinois Public Utilities Act, Ameren Illinois Utilities (AIU) customers saved almost 90,000 MWh, far exceeding AIU's goal for that year. In Plan Year 3 (June 2010-May 2011), another major utility, Commonwealth Edison Company (ComEd), achieved about 662,000 MWh net energy savings through its energy-efficiency and demand-response programs.) (footnote omitted).
[222] Ill. Pub. Act 095-0481 (2007). *See also* Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 14 ("The state has experienced significant growth in wind power development as a result—electricity generation from wind increased by more than six million MWh from 2005-2011. Growth in wind energy from 2003 to 2010 alone created almost 10,000 new local jobs during construction and a lifetime economic benefit of $3.2 billion, according to one analysis. In 2011, Illinois avoided about five million tons of CO_2 emissions from renewable resource integration, along with four million tons of NO_X.") (footnotes omitted).
[223] Ill. Clean Coal Portfolio Standard, Public Act 095-1027 (2009).
[224] Kelly Speakes-Backman, Testimony on Questions Concerning EPA's Proposed Clean Power Plan, House Committee on Energy and Commerce (Sept. 9, 2014) at 4, available at http://docs.house.gov/meetings/IF/IF03/20140909/102623/HHRG-113-IF03-Wstate-Speakes-BackmanK-20140909.pdf.
[225] *Id.*
[226] Paul J. Hibbard, et al, Analysis Group, The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States (2011) at 43.
[227] U.S. Energy Information Administration, Lower emissions cap for Regional Greenhouse Gas Initiative takes effect in 2014 (Feb. 3, 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=14851.
[228] Paul J. Hibbard, et al, Analysis Group, The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States (2011) at 2.
[229] *Id.* at 3-4.
[230] *Id.* at 7.

and others) saved nearly $1.1 billion overall because investments in energy efficiency lowered prices, outweighing some near-tern increases in electricity prices.[231]

RGGI also demonstrates that systems-based approaches to reducing power sector emissions can boost local economies—even in states that heavily rely on coal-fired generation. In the first three years of the RGGI cap-and-trade program, *every* RGGI state experienced net positive benefits from RGGI and job growth.[232] The states in the more coal-reliant PJM region—Delaware, Maryland, and New Jersey—added $341 million in value and 3,676 job years.[233] Consumers also realized significant bill savings in these three states, as longer term savings in electricity and energy bills offset the minor increases (0.7 percent) in electricity bills during 2009–2011.[234] RGGI states may be able to improve upon this impressive track record in the future, as the first three years of the program provided an important opportunity for identifying best practices for using allowance revenue and designing energy efficiency programs.[235]

Another part of RGGI's success has come from shifting from high-emitting to lower-emitting sources of generation. From 2005 to 2012, coal-fired generation declined from 23% of the regional generation mix to 9%.[236] In the same period, the share of natural gas-fired generation rose from 25% to 44%.[237] Between 2005 and 2012, the RGGI states also increased in-region, non-hydroelectric renewable generation by 47 percent.[238] This dramatic growth in renewables is driven by a combination of complementary policies: RPSs, net metering tariffs, long-term contracting, the establishment of "Green Banks," innovative green financing mechanisms, and renewable energy technology grant programs.[239] These shifts in generation were able to occur without any disruption to consumers because the power sector functions as an integrated system.

When utilities have designed GHG reduction programs, they too have adopted successful systems-based approaches. These approaches vary widely, but generally combine a shift toward lower-emitting generation with increased energy efficiency. The following examples illustrate the GHG reduction strategies that have been successfully demonstrated on the ground:

- In 2001, Entergy set a goal of stabilizing GHG emissions for its power plants at 2000 levels through 2005 and, after achieving its initial goal, the company strengthened its goal to stabilize

[231] *Id.* at 4.
[232] *Id.* at 7-8.
[233] *Id.* at 33 (Table 2).
[234] *Id.* at 43.
[235] *Id.* at 49-50.
[236] U.S. Energy Information Administration, Lower emissions cap for Regional Greenhouse Gas Initiative takes effect in 2014 (Feb. 3, 2014), available at http://www.eia.gov/todayinenergy/detail.cfm?id=14851.
[237] *Id.*
[238] RGGI States' Comments on Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 FR 34830 (June 18, 2014) (Docket No. EPA-HQ-OAR-2013-0602) (Nov. 5, 2014) at 20, available at http://www.rggi.org/docs/PressReleases/PR110714_CPP_Joint_Comments.pdf.
[239] *Id.* at 20-21.

emissions at 20 percent below 2000 levels.[240] Entergy was successful, in part, due to upgrades and efficiency improvements at existing facilities.[241]

- Public Service Enterprise Group (PSEG) set a goal of reducing its GHG emissions by twenty-five percent and achieved its goal in 2011—14 years ahead of schedule.[242] PSEG's multi-pronged efforts include deploying energy efficiency, increasing nuclear power output, building efficient natural gas plants, and investing in renewable energy production.[243] From 2000-2011, PSEG increased electricity generation by 37 percent while simultaneously reducing its CO_2 emissions rate 24 percent.[244]

- From 2000-2011, NextEra Energy's CO_2 emissions rate declined by approximately 40 percent while its power generation increased by almost 90 percent.[245] This achievement has been mainly driven by greater energy efficiency in its generation facilities and its large renewable portfolio.[246] One of NextEra Energy's subsidiaries is also a leader in demand-side management.[247]

- In 2008, Exelon set a goal of abating 15.7 million metric tons of GHG emissions by 2020 (the equivalent of its total GHG emissions in 2001 and then increased) and increased its abatement goal to 17.5 million metric tons after its 2012 merger with Constellation Energy.[248] Exelon has already exceeded its revised goal through a combination of measures.[249] Exelon achieved more than half of its goal by increasing production at existing nuclear plants through updates and other operation efficiency, reducing the need for fossil-fired generation.[250] The second most

[240] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes (December 2013) at 24-25.
[241] *Id.* ("Since 2001, Entergy has spent $14.7 million on 61 energy efficiency improvements that have resulted in nearly 5.3 million metric tons of CO_2 savings and $30 million in annual fuel savings. For example, the company has added nearly 4,000 MW from efficient natural gas-fired combined cycle gas turbine (CCGT) generation resources. It estimates that this upgrade saves 850,000 metric tons of CO_2 per year and $55 million in annual fuel savings. Over the past decade, Entergy has also increased the capacity of its nuclear fleet by over 700 MW, the equivalent of a new reactor, through power upgrades, turbine replacements and cooling tower modifications. Entergy estimates that maintaining and expanding its nuclear energy production avoids 50 million metric tons of CO_2 emissions per year.") (footnotes omitted).
[242] *Id.* at 31-32.
[243] *Id.*
[244] *Id.*
[245] *Id.* at 27.
[246] *Id.* ("For instance, in 2012, the company's wind generation avoided over 20 million tons of CO_2, and its nuclear generation avoided about 26 million tons of CO_2.").
[247] *Id.* ("FPL's programs to encourage customers to use energy more efficiently have saved the company from having to build 14 medium-sized power plants since 1981, avoiding more than 25 million MWh of electricity and an associated 13 million tons of CO_2since 2007.").
[248] Exelon, Exelon 2013 Sustainability Report (2014) at 25, available at http://www.exeloncorp.com/assets/newsroom/downloads/docs/dwnld_Exelon_CSR.pdf.
[249] *Id.*
[250] *Id.*

significant source of Exelon's reductions were programs that helped its customers use electricity more efficiently.[251]

Municipal utilities have also had proven success with systems-based approaches to reducing power sector GHG emissions. CPS Energy, the nation's largest municipally owned electric and gas utility, has reduced its CO emissions rate by seven percent from 2000-2011, as power generation increased 36 percent.[252] While CPS Energy maintains a diverse electricity mix that includes wind, solar, natural gas, coal, and nuclear, it has achieved substantial emissions reductions by deactivating two older coal units, increasing renewable generation, and implementing energy efficiency programs.[253] The utility is also on track to reach its ambitious energy-saving goal—771 MW of electricity by 2020—through a program that includes rebates for rooftop solar power, commercial lighting and HVAC retrofits, free energy efficiency measures for low-income households, and new home construction.[254] Austin Energy, the eighth largest public power utility in the United States, has implemented demand-side management (DSM) programs since 1982.[255] In total, Austin Energy's energy efficiency programs have saved about 1.8 billion kWh since 1982.[256] Austin Energy's combination of DSM and increased renewable generation has allowed it to serve a rapidly growing population without increasing its CO_2-emitting generating capacity over the past 20 years.[257]

One of the most common ways that electric utilities structure their analysis of options for reducing GHG emissions is by considering a carbon price in an Integrated Resource Plan (IRP). A 2011 study of best practices in integrated resource planning that examined the IRPs of fifteen utilities operating across the United States found that carbon costs were among the variables most commonly considered in assessing available portfolio strategies.[258] Accordingly, the study determined that one of the "key components" of integrated resource planning was "[a] Portfolio Strategy Assessment evaluat[ing] the cost / risk tradeoff of potential strategies as natural gas prices and carbon costs varied."[259] This component was present, for example when an IRP identified alternative mixes of supply-side resources with comparable reliability and then "[c]onducted Monte Carlo analysis assessing total supply cost for each portfolio over the twenty

[251] *Id.*
[252] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes (December 2013) at 22-23.
[253] *Id. See also* CPS Energy, CPS Energy leading on greenhouse gas reductions, available at http://newsroom.cpsenergy.com/blog/energy-efficiency/leading-on-greenhouse-gas-reductions/ (CPS Energy "has already begun to diversify and reduce the carbon intensity of its power plant fleet, increase customers' energy efficiency and upgrade its electrical grid. . . . Through all of its strategies, [President and CEO] Beneby said, CPS Energy is reducing its carbon emissions by 5.3 million tons by 2020, a 29 percent decrease since 2011.").
[254] CPS Energy, CPS Energy leading on greenhouse gas reductions.
[255] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 20-21.
[256] Austin Energy, Annual Performance Report: Year End September 2013 (2014) at 13, available at http://austinenergy.com/wps/wcm/connect/0b60b1fd-47f6-4256-9c4d-f0e37c38becc/2013AnnualPerformanceReport.pdf?MOD=AJPERES.
[257] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 20-21.
[258] SPO Planning Analysis, IRP Tools & Techniques: Review of a Sample of Recent IRPs by US. Utilities Best Practices Supplement to the 2012 ENO IRP (Oct. 2011) at 2, available at http://www.entergy-neworleans.com/content/IRP/Best_Practices_Supplement.pdf.
[259] *Id.* at 8.

year planning horizon with varying gas and carbon prices."[260] An in-depth 2008 study of the IRPs of fifteen utilities in the Western United States (accounting for about 60% of retail electricity sales in the West) illustrates the varying methodology for considering carbon costs.[261] All but one of the fifteen utilities in the sample incorporated a future carbon tax or cap-and-trade system into their portfolio analysis,[262] confirming that consideration of carbon costs in IRPs is common practice. But crucially, "[e]leven of fifteen utilities included carbon emission prices in their base-case scenario, thereby affecting their choice of preferred portfolio, to the extent that the choice was based on a comparison of candidate portfolios' expected costs."[263] Analyzing scenarios with different carbon prices allows the utilities to reduce risk by shifting from high-emitting sources to lower-generating sources: "Based on the results under its high carbon price scenario, PSCo selected a preferred portfolio that replaces four existing coal-fired units (~200 MW nameplate capacity) with a new CCGT."[264] For a variety of economic and compliance reasons, utilities are shifting toward renewable generation and energy efficiency to meet consumer needs.[265] In addition to IRPs, utilities can consider carbon costs in any investment decision framework. National Grid factors a social cost of carbon of about $50 per ton of CO into all capital project decisions.[266]

Regardless of what factors are driving power company choices, their decisions to shift from high-emitting generation to lower-emitting generation demonstrate the availability of this GHG-reduction option. Power companies that once met a majority of customer demand with coal-fired generation have drastically reduced their reliance on coal. For instance, in 2005, Southern Power and its affiliates generated over 60 percent of their electricity from coal and 10 percent from natural gas.[267] In 2013, Southern Power generated about 40 percent of its power from coal and 34 percent from natural gas.[268]

In addition, there are numerous demonstrated systems-based approaches for reducing criteria pollutant emissions from EGUs. Perhaps most notably, Title IV of the Clean Air Act established a successful market-based program to control EGU emissions that contribute to acid rain, setting a permanent cap on the total amount of $S0_2$ that may be emitted by EGUs nationwide.[269] States and local governments also implement energy efficiency programs to improve local air quality as part of the SIP process.[270] These

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[260] *Id.* at 9.
[261] Galen Barbose, Ryan Wiser, Amol Phadke, and Charles Goldman, Lawrence Berkeley National Laboratory, Reading the Tea Leaves: How Utilities in the West Are Managing Carbon Regulatory Risk in their Resource Plans (March 2008), available at http://emp.lbl.gov/sites/all/files/REPORT%20lbnl-44e_0.pdf. *See also id.* at 11, Table 2 (summarizing the utilities' carbon price projections).
[262] *Id.* at 9.
[263] *Id.* at 33.
[264] *Id.* at 40.
[265] *Id.* at 51 ("All utilities selected preferred portfolios with energy efficiency and new renewables, and half selected portfolios in which energy efficiency and renewables together constitute 50% or more of all new resources.").
[266] Georgetown Climate Center, Reducing Carbon Emissions in the Power Sector: State and Company Successes at 26.
[267] Bianco, Seeing is Believing at 14.
[268] *Id.*
[269] EPA, Cap and Trade: Acid Rain Program Results, available at http://www.epa.gov/capandtrade/documents/ctresults.pdf.
[270] EPA, "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix K: State, Tribal and Local Examples and Opportunities" at K-8 to K-9 (July

programs are effective because decreases in electricity demand reduce EGU emissions through the interconnected electricity system. Further, since 1998, each of EPA's rules to address the interstate transport of pollution from EGUs has incorporated energy efficiency compliance options; of these, the NO_x SIP Call also provided a renewable energy compliance option.[271] Taken together, these EPA and state programs have long demonstrated the ability of systems-based approaches to reduce power sector emissions, while providing flexibility and reducing compliance costs.

J. EPA Has Properly Interpreted the "Remaining Useful Life" Provision of Section 111(d).

EPA has appropriately interpreted the "remaining useful life" provision of section 111(d) in a way that is consistent with the statutory text and purpose, and that avoids creating a loophole that could erode the environmental integrity of the standards.

Section 111(d)(1) provides, in part:

> Regulations of the Administrator under this paragraph [section 111(d)(1)] shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

Essentially, this "remaining useful life provision" requires EPA to allow states to consider certain source-specific factors when the states apply section 111(d) standards of performance to particular existing sources. But the "remaining useful life" provision does not specify how or when states shall be permitted to consider source-specific factors in applying standards of performance. Consequently, the statute leaves EPA discretion regarding how it will permit states to consider these factors when they apply standards of performance to particular sources that are regulated under the states' 111(d) plans. EPA must permit

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2012), available at http://epa.gov/airquality/eere/pdfs/appendixK.pdf (To meet federal ambient air quality standards, Texas reduces NOx emissions "through reduced demand for fossil-fuel generation at power plants, as a result of EE measures implemented in new construction for single and multi-family residences in 2003."); id. at K-9 (Louisiana's plan for achieving federal ambient air quality standards included energy conservation measures at City buildings in Shreveport, which were "estimated to have saved 9,121 megawatt-hours (mWhs) of electricity per year with NOx emission reductions of 0.041 tons per ozone season-day").

[271] NO_x SIP Call, 63 Federal Register 57356, 57438 ("The EPA believes that, with respect to EGUs, there is a large potential for energy efficiency and renewables in the NO_x SIP call region that reduce demand and provide for more environmentally-friendly energy resources. For example, if a company replaces a turbine with a more efficient one, the unit supplying the turbine would reduce the amount of fuel (heat input) the unit combusts and would reduce NO_x emissions proportionately, while the associated generator would produce the same amount of electricity."); Clean Air Interstate Rule, 70 Federal Register 25162, 25279 (explaining that state decision regarding allowance allocation, including whether to use set-asides for energy efficiency, would not change environmental outcome of the cap-and-trade program); Cross State Air Pollution Rule, 76 Federal Register 48208, 48319 ("By reducing electricity demand, energy efficiency avoids emissions of all pollutants associated with electricity generation, including emissions of NO_x and SO_2 targeted by this final rule, and reduces the need for investments in EGU emission control technologies in order to meet emission reduction requirements.").

states to consider remaining useful life and other factors in a manner that is reasonable in any given rulemaking. This does not require a one-size-fits-all approach.

EPA has properly interpreted the "remaining useful life" provision in this rulemaking. EPA has proposed state-wide emission performance goals that can be met using a wide variety of compliance approaches. Each state has the enormous flexibility to consider affected facilities' source-specific characteristics throughout the entire process of designing a plan to meet its goal, including the application of standards of performance to particular sources.[272] As such, EPA's proposal allows states to refrain from requiring specific plants nearing retirement to install specific pollution controls. For instance, states may allow aging facilities to comply by deploying renewable energy or energy efficiency to secure emission reductions in the interim before retirement. Indeed, this rule provides the states with greater opportunity to take source-specific factors into account than any prior 111(d) guidelines.

EPA's approach promotes the apparent purpose of the "remaining useful life" provision, i.e., to avoid mandating major investments in facilities that are near retirement. EPA's proposal achieves this purpose by giving states a variety of options for how to design their standards of performance and implementation plans, including the option to set standards that facilities can meet without undergoing any retrofits whatsoever. Under the proposed guidelines, states apply standards of performance based on whatever considerations they deem appropriate, and can deploy renewable energy and energy efficiency as well as shifts in utilization towards lower-emitting units rather than retrofits to secure the required emission reductions. A state could choose to apply a standard that is satisfied through source emissions combined with the purchase of credits representing emissions reduced from renewable energy or energy efficiency (or allowances)—which would allow a source nearing retirement to purchase sufficient credits (or allowances) to achieved compliance until it retires.[273] Moreover, a state might apply a less stringent standard to older facilities than to newer facilities. By empowering states to consider cases where large expenditures would yield only relatively few emissions reductions due to the short remaining life of a source, the provision ensures that states need not require major expenditures by uniquely situated sources.

In this particular rulemaking, it is also appropriate for states' consideration of remaining useful life and other factors to occur as they design their plans because states must consider the achievability of performance standards during plan development. Specifically, state plan submissions must include "a demonstration that the plan is projected to achieve each of the state's emission performance levels for affected entities" and "[m]aterials supporting the projected emissions performance level that will be achieved by affected entities under the plan." 79 Fed. Reg. 34952. The analysis of the affected entities' projected emissions performance level will necessarily encompass each sources remaining useful life and

[272] Section 111(d)(1) requires EPA to permit states to consider a particular source's remaining useful life and other factors "in applying" standards of performance to that source. EPA's proposal does this; the proposed emission guideline permits states to consider any source-specific factors when the states choose the standard of performance that will apply to their existing sources. Plainly, a state is "applying a standard of performance" when it establishes the standards in its state plan. *See, e.g.*, Merriam-Webster Dictionary (defining "apply" to mean "to put into operation or effect <*apply* a law>"), available at http://www.merriam-webster.com/dictionary/apply. The proposal permits states to consider whatever factors they choose during that process.

[273] EPA has previously concluded that a cap-and-trade system satisfies the requirements of section 111(d)(1), including the "remaining useful life" provision. 70 Fed. Reg. 28,606 at 28,616-17.

other factors. This process is properly designed to ensure that states will not subject sources to standards of performance that they cannot achieve (whether due to a limited remaining useful life or other factors). Further, this process enables states to take into consideration the remaining useful life of sources as that will facilitate compliance, as the retirement of sources will reduce emissions and move states closer to compliance.

Nowhere does the statute require that states must have discretion to relax the state emission goal. The statute simply allows a state to consider "remaining useful life" when the state is "applying a standard of performance" to a source, and that is exactly what the state is doing as it establishes the standards in its state plan to meet its overall state emission goal. In prior instances, EPA has established generally applicable default standards to be applied to all sources, and in some circumstances authorized tailoring of the standards as states applied them to sources with specific difficulties in compliance or nearing the end of their useful life. Under the proposed Clean Power Plan, however, the situation is entirely different. The provision of average state emission targets—and flexible compliance options that do not require investments at specific sources to secure compliance either with the state target or with an individual source's standard—enable states to adjust to source-specific circumstances as they design their compliance plans and the standards that apply to specific sources.

The "remaining useful life" provision does not disrupt the basic structure of section 111(d), in which states must submit plans with standards of performance that reflect the EPA-determined BSER. EPA's proposal properly ensures that state standards of performance (taken together) reflect the emission reductions achievable through the application of the statewide BSER even if the state adjusts its application of a standard to a particular source due to remaining useful life or other factors. We agree with EPA's interpretation that the components of state plans, taken together, must be "at least as stringent as necessary to achieve the required emissions performance level for the state's affected EGUs." *See* 79 Fed. Reg. at 34891. Here, where EPA has applied BSER on a statewide basis, and provided for flexible compliance mechanisms that do not require infrastructure investments at specific sources, EPA has reasonably proposed permitting states to consider source-specific factors when they design their plans and apply standards of performance to those sources. In this manner, EPA's proposal fulfills the requirements of the "remaining useful life" provision in a manner consistent with its "best system of emission reduction" analysis of emission reduction potential and without undermining the environmental integrity of its emissions guidelines.

Previous 111(d) guidelines have generally not given states such an extensive opportunity to consider their sources' remaining useful life (and other site-specific factors) when they established performance standards for particular sources. Most of EPA's prior 111(d) guidelines for health-harming pollutants have specified presumptive standards of performance for all sources in a particular category. EPA's application of the "remaining useful life" provision in this rulemaking reasonably reflects the uncommon opportunities and incentives for states to consider their sources' remaining useful life and other factors as they craft flexible compliance plans and standards for their particular sources.

Currently, the following EPA implementing regulation generally applies to rulemaking under section 111(d):

> Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities, States may provide for the application of less stringent emissions standards or longer compliance schedules than those otherwise required by [40 CFR § 60.24(c)] provided that the State demonstrates with respect to each such facility (or class of facilities):
>
> (1) Unreasonable cost of control resulting from plant age, location, or basic process design;
>
> (2) Physical impossibility of installing necessary control equipment; or
>
> (3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.

40 CFR § 60.24(f). This "variance" provision is not required by section 111(d)(1), but reflects a reasonable approach to implementing section 111(d)(1) where emissions guidelines establish default source-specific standards. These general rules only apply "[u]nless otherwise specified in the applicable" emission guideline. *Id.* In several emissions guidelines, EPA has provided that section 60.24(f) does not apply. *See, e.g.*, 40 C.F.R. § 60.30b; § 60.5040.

EPA properly concluded that 40 C.F.R. § 60.24(f) should not apply to proposed subpart UUUU. Given the extensive compliance flexibilities provided to states (and which states can provide to sources) in the proposal, it is appropriate for EPA to interpret the terms "remaining useful life" and "other factors" for the purposes of this particular rulemaking, rather than apply the general provisions of 40 CFR § 60.24(f). Application of 60.24(f) is not necessary to achieve the apparent purpose of the "remaining useful life" provision—that is, avoiding stranded investments in control technologies—because EPA's proposed guidelines require nothing of any particular facility and certainly do not require expensive investment in controls at a facility nearing retirement. As explained above, EPA's proposal satisfies the requirements of the "remaining useful life" provision in a way that is well-tailored to the specific context of the Clean Power Plan.

K. State plans can be implemented using traditional environmental regulatory tools and frameworks

Contrary to assertions made by some critics of the Clean Power Plan, state air quality regulators are fully capable of implementing EPA's proposed state goals using traditional legal frameworks and environmental regulatory tools.

There are at a minimum two mechanisms by which state air quality regulators could utilize traditional regulatory tools to ensure compliance with the state goals. In both cases, these mechanisms would take the form of traditional requirements that apply directly to affected EGUs, and could be readily incorporated into operating permits for individual existing sources. These mechanisms include:

Allowance holding requirement consistent with mass-based state goal. A number of states have expressed interest in adopting a mass-based compliance framework. Section 111(d) compliance could be achieved by implementing a traditional mass-based emissions trading program, similar to those established by many states for carbon dioxide as well as SO_2 and NO_x. Under this approach, air quality regulators could adopt a mass-based state goal (providing a "budget" for overall emissions in the state), and then create a stock of allowances – each representing one ton of carbon dioxide — in an amount equivalent to the state budget. Each affected EGU in the state would be subject to an individual requirement to hold allowances in an amount equivalent to its emissions, either on an annual basis or some other compliance period defined by the state and in accordance with EPA's emission guidelines. Affected EGUs could be allocated allowances by the state through an administrative formula or a market-based mechanism (such as an auction), and could be allowed to trade allowances as needed to meet their holding requirements. This flexible and straightforward system would ensure that the state meets its emission goals over time, and would not rely upon any additional action by the public utilities commission or other authorities. PUCs would, of course, play their traditional oversight role in evaluating the plans of regulated companies to make changes to generation infrastructure and obtain allowances in order to meet their permit requirements. Many states adopted similar emissions budgets and allowance holding requirements under state implementation plans submitted pursuant to the Clean Air Interstate Rule and the NO_x SIP Call.[274] Other states, such as Utah, have also adopted emissions trading programs for electric generating units to meet federal regional haze requirements, acting under standing legal frameworks to protect air quality.[275] And as discussed elsewhere, states taking this approach could also facilitate even more cost-effective compliance by providing that they would accept credits from a specified set of states, or from any state taking a mass-based approach with a plan approved by EPA.

Rate-based emission standard with well-defined compliance crediting. An alternative approach would be to require individual EGUs within each state to comply with that state's rate-based state goal, and to allow individual EGUs to demonstrate compliance with that emission standard using the same kinds of instruments described in the proposed emission guidelines. To illustrate, a coal-fired EGU in a state with an emission target of 1,000 lbs/MWh would be subject to that emission standard in its operating permit. However, the operating permit would also provide that the EGU could demonstrate compliance with that

[274] Prior to the adoption of CSAPR, EPA approved SIP submittals for Alabama, Arkansas, Connecticut, Georgia, Indiana, Illinoi, Iowa, Kentucky, Louisiana Massachusetts, Michigan, Maryland, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas (NO_x only), Virginia, West Virginia, Wisconsin. To our knowledge, all of these SIPs adopted the respective state-wide emission budgets established in CAIR, authorized emissions trading by regulated EGUs, and provided the necessary administrative and reporting requirements to ensure compliance. *See* collected Federal Register notices at EPA, "EPA Rulemaking Actions on States' CAIR SIP Submissions: Federal Register Notices," http://www.epa.gov/cleanairinterstaterule/rulemakingactions.html (last visited Nov. 12, 2014).

[275] *See* Utah Admin. Code r.307-250 (2014) (establishing sulfur dioxide trading program to comply with regional haze requirements of the Clean Air Act, and invoking general rulemaking authority of the Utah Department of Environmental Quality). EPA has approved similar programs in at least three states. *See* Final Rule, Approval and Promulgation of State Implementation Plans; Wyoming, 77 Fed. Reg. 73,926, 73,926 (Dec. 12, 2012); Final Rule, Approval, Disapproval and Promulgation of State Implementation Plans; Utah, 77 Fed. Reg. 74,355, 74,355 (Dec. 14, 2012); Final Rule, Approval and Promulgation of State Implementation Plans; New Mexico, 77 Fed. Reg. 70,693, 70,693 (Nov. 27, 2012); Final Rule, Approval and Promulgation of State Implementation Plans; City of Albuquerque-Bernalillo County, 77 Fed. Reg. 71,119, 71,119 (Nov. 29, 2012).

emission standard by any combination of the following: a) averaging its emissions with a lower-emitting fossil fuel-fired EGU, either via a tradable credit or a contractual averaging arrangement; b) reducing its emissions rate by procuring and holding verified credits representing emission reductions from renewable energy, either generated within the state or by another state; or c) reducing its emissions rate using credits representing emission reductions from properly documented end-use energy efficiency savings (which could either take the form of a tradable credit created or recognized by the air quality regulator, or could be "allocated" by the air quality regulator to the EGU based on verified savings reported by the public utilities commission). The implementation of this regulatory approach would be greatly facilitated were the air regulator or EPA to create a system for registering and tracking credits related to renewable energy and energy efficiency projects. As discussed elsewhere, the air regulator in a state taking this approach could also ensure greater cost-effectiveness by also providing that it will accept credits generated within the state, within a specified set of states, or within any state taking a parallel rate-based approach with a plan approved by EPA. The creation of a tracking system for credits by EPA would greatly facilitate interstate coordination, and ensure that credits are not double counted towards compliance. However, such a system should not require new legislation or additional action by a public utility commission. This approach is broadly similar to an August 2014 proposal by Western Resource Advocates, describing a "carbon reduction credit" program that would allow affected EGUs to comply with state-wide emission standards by reducing their emissions using credits generated by lower-emitting EGUs, clean energy resources, and providers of verified energy efficiency savings.[276]

Both of these approaches establish enforceable emission limitations for existing EGUs based on traditional tools of air quality regulation, and should be well within the authority of state environmental protection agencies. Although complementary actions by a public utilities commission, state energy office, or other body could certainly be helpful in ensuring predictable and cost-effective implementation of the rules, a state plan adopting one of the two approaches above would not *necessitate* such action.

As discussed in section VIII, a state taking a portfolio or a state commitment approach would need to ensure that the emission reductions in the plan are federally enforceable to meet the requirements of the Clean Air Act. In the context of a portfolio approach, either the individual compliance measures would become federally enforceable (as is the case for typical control measures in the context of State Implementation Plans under Section 110 of the Clean Air Act) or plans must include a backstop mechanism that applies directly to the regulated sources that would ensure that any shortfall in emission reductions was remedied.[277] States adopting state commitment approaches would similarly require

[276] *See* Steven Michel & John Nielsen, Carbon Reduction Credit Program: A State Compliance Tool for EPA's Clean Power Plan Proposal (Western Resource Advocates Aug. 25, 2014).

[277] EPA should require states proposing to meet state goals through assigning RE and demand-side EE measures to entities other than regulated sources to include those measures in state plans as "plan elements." EPA has properly proposed "to interpret CAA section 111 as allowing state CAA section 111(d) plans to include measures that are neither standards of performance nor measures that implement or enforce those standards, provided that the measures reduce CO_2 emissions from affected sources." *Id.* at 34903. Requiring that these measures be included in state plans as "other plan elements" would ensure that the state plan as a whole, including both the standards of performance applicable to EGUs and the "other plan elements" applicable to entities other than EGUs, achieves emission reductions consistent with the BSER identified in EPA's emission guidelines.

source-based backstops to ensure enforceability and that any shortfalls would be remedied. Such backstop mechanisms would be implemented through the operating permits of regulated sources. Again, in these contexts, PUCs would play their important and traditional role of evaluating companies' plans to achieve compliance with the emission standards and backstops that would be a part of these types of plans. But the traditional (and traditionally linked) roles of air regulators and PUCs would be undisturbed, and the enforceability mandated by Section 111(d) ensured.

To be sure, the Clean Power Plan will affect the planning and investment decisions made by power companies around the country. In states with regulated utilities, some of these resource planning and investment decisions will require review and approval by a public utilities commission. However, this is the norm for environmental regulations affecting the power sector and does not in any way call into question EPA's authority to require reductions in carbon pollution under the Clean Power Plan. For example, following the enactment of Title IV of the Clean Air Act in 1990, many state PUCs took action to approve compliance actions by regulated utilities, including the establishment of rules governing cost recovery for sulfur dioxide allowance transactions; integrated resource plans demonstrating capital investments or changes in generation and fuel mix that would be required to cost-effectively comply; and approval of investments in individual pollution control projects.[278] Similarly, state PUCs undertook extensive proceedings to ensure that regulated utilities comply with the Clean Air Interstate Rule and install pollution controls needed to meet National Ambient Air Quality Standards.[279] And most recently, state PUCs around the country have been actively engaging with utilities to ensure smooth implementation of the Mercury and Air Toxics Standards, Cross State Air Pollution Rule, and other

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In order to provide the requisite specificity for judicial enforcement, EPA should require RE and demand-side EE measures imposed on non-EGUs to be expressed explicitly in the approved state plan as an objective and measurable requirement related to a specific action. This is generally consistent with the standard that courts have applied when determining whether requirements contained in state implementation plans for criteria pollutants are judicially enforceable. *See, e.g., McEvoy v. IEI Barge Servs*., 622 F.3d 671, 680 (7th Cir. 2010) (state code provision in approved SIP barring all unpermitted visible fugitive particle emissions was not enforceable through citizen suit because it failed to provide an objective standard for visibility threshold triggering the prohibition); *Wilder v. Thomas*, 854 F.2d 605, 613-614 (2d Cir. 1988) (citizen suit must allege violations of "specific provisions of an applicable [state] implementation plan."); *see also Action for Rational Transit v. West Side Highway*, 699 F.2d 614, 616 (2d Cir. 1983) ("the aims and goals of the SIP are not enforceable apart from the specific measures designed to achieve them").

[278] *See* Ron Lile & Dallas Burtraw, *State-Level Policies and Regulatory Guidance for Compliance in the Early Years of the SO_2 Emission Allowance Trading Program* 13-52 (May 1998) (summarizing orders and regulations issued by PUCs in response to the Clean Air Act Amendments of 1990, as well as some instances in which states passed new legislation to ensure timely and well-coordinated compliance. Examples include the establishment of new ratemaking rules requiring utilities to pass on to ratepayers certain profits from allowance transactions, or utilize those profits for demand-side management or other programs benefiting ratepayers; integrated resource planning processes requiring utilities to identify optimal combinations of shifts in generation, pollution control investments, fuel-switching, and other strategies to reduce sulfur dioxide; and approval of cost recovery for investments in flue gas desulfurization projects).

[279] *See* M.J. Bradley & Associates, Public Utility Commission Study, EPA Contract No. EP-W-07-064 (Mar. 31, 2011) (providing detailed case studies of the Indiana Utility Regulatory Commission's response to the Clean Air Interstate Rule and the Clean Air Mercury Rule; the Georgia Public Service Commission's efforts to implement a "Multipollutant Rule" adopted by the state air quality regulators to comply with the Clean Air Interstate Rule and the ozone and particulate matter NAAQS; and the West Virginia Public Service Commission's development of innovative financing mechanisms to ensure its regulated utilities complied with CAIR and CAMR).

environmental requirements through long-term planning and ratemaking proceedings.[280] We expect that state PUCs will similarly exercise prudent review and oversight of utility resource planning and economic decisions associated with investments to comply with the Clean Power Plan while protecting the interests of ratepayers in reliable, affordable electricity.

L. The proposed rule does not conflict with the Federal Power Act

The proposed Clean Power Plan does not conflict with the Federal Power Act (FPA), as some opponents of EPA action to regulate carbon pollution have argued. The FPA vests the Federal Energy Regulatory Commission (FERC) with exclusive jurisdiction to approve "just and reasonable" rates for the transmission of electric energy in interstate commerce and for wholesale sales of electric energy. [281] However, no provision of the FPA limits the authority of EPA under the Clean Air Act to establish emission guidelines (or other emission standards or limitations) for EGUs. Nor should such a limitation be implied, as the D.C. Circuit has ruled in dismissing past claims that the FPA exempts or displaces the nation's federal environmental laws.[282] In addition, no aspect of the Clean Power Plan requires EPA or the states to interfere with rates established by FERC. EPA's emission guidelines simply establish an emissions performance target for existing EGUs within each state, which can be implemented by the states in a manner parallel to other Clean Air Act emissions standards.

EPA's proposed guidelines —– once implemented by the states — may have the effect of altering the generating costs of fossil fuel EGUs, with indirect or incidental impacts on wholesale sales or transmission rates that are subject to FERC jurisdiction. This is true of most pollution limitations placed on power plants, and such effects do not present conflicts with FERC's authority under the FPA. For example, FERC has noted that sulfur dioxide allowances created under Title IV of the Clean Air Act may affect wholesale rates under the FPA, and has ruled that the costs of these emission allowances may be

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[280] *See* Matthew Bandyk, *State regulators approve Minnesota Power plan for coal retrofit, retirements,* SNL Sept.25, 2013 (reporting on Minnesota PUC's approval of a plan by Minnesota Power to install emission controls needed to comply with MATS at a 585 MW power plant); Matthew Bandyk, *We Energies coal-to-gas conversion gets approval from Wis. Regulators,* SNL Feb. 3, 2014 (describing Wisconsin PUC's approval of a Wisconsin Electric Power proposal to comply with MATS by converting an existing 256 MW coal-fired power plant to natural gas); Matthew Bandyk, *Kentucky Power gets approval to convert coal unit at Big Sandy to gas,* SNL Aug. 1, 2014 (describing Kentucky PUC's approval of a plan to convert a 268 MW coal-fired power plant to gas, also for purposes of complying with MATS).

[281] Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487 U.S. 354, 108 S. Ct. 2428, 2439, 101 L. Ed. 2d 322 (1988) (exclusive federal jurisdiction over wholesale electric rates under § 201 of the Federal Power Act, 16 U.S.C. § 824); id. at 2442 (Scalia, J., concurring in the judgment) ("if FERC has jurisdiction over a subject, the States cannot have jurisdiction over the same subject")

[282] *See Monongahela Power Co. v. Marsh,* 809 F.2d 41, 50 (D.C. Cir. 1987) (holding that hydroelectric facilities licensed by FERC are still subject to Clean Water Act permitting requirements, because ". . . the Power Act does not provide adequate justification for ignoring the express and unambiguous directive of the subsequently-adopted Pollution Control Act Amendments."); *cf. PUD No. 1 v. Wash. Dep't of Ecology,* 511 U.S. 700, 723 (1994) (refusing to limit applicability of Clean Water Act requirements to hydroelectric projects licensed by FERC on the basis of "hypothetical" conflicts between the Clean Water Act and FERC's authority under the FPA).

incorporated into rates approved by FERC.[283] FERC's recent Order No. 1000 also expressly recognizes that state and federal public policy requirements, such as renewable portfolio standards and emission limitations, can impact jurisdictional transmission rates — and requires that the impacts of those policies be taken into account in regional transmission planning processes.[284] And FERC has provided in individual ratemaking proceedings that utilities may allocate and recover costs associated with meeting federal and state "documented energy policy mandates or laws," such as state renewable portfolio standards.[285] Simply put, the FPA does not displace or preclude emission limitations established by EPA under the Clean Air Act – and nothing about the proposed Clean Power Plan suggests a different result would arise in this context.

Likewise, state plans submitted under the proposed Clean Power Plan can incorporate a variety of policies – including traditional rate or mass-based emission limitations, policies to promote renewable energy or energy efficiency, or integrated resource plans — which lie securely within the traditional authority reserved to the states under the FPA. Indeed, such policies have already been implemented in many states over the last several years, as EPA recognizes in the preamble to the proposed emission guidelines. There is no doubt that such policies are fully consistent with the FPA, given the high standard that the Supreme Court has articulated for preemption under the FPA and the Natural Gas Act (NGA). Specifically, the Supreme Court has held that state regulations are only preempted by these statutes if "it is impossible to comply with both state and federal law; [a] state regulation prevents attainment of FERC's goals; or [] a state regulation's impact on matters within federal control is not an incident of efforts to achieve a proper state purpose."[286] The Supreme Court has also recognized that "every state statute that has some indirect effect on rates and facilities of natural gas companies is not preempted."[287] Consistent with these principles, the lower courts have found that states retain broad authority to, among other things, regulate the type, quantity, and location of electricity generating resources within their borders.[288] FERC itself has repeatedly affirmed that "states have the authority to dictate the generation resources from which utilities may procure electric energy."[289] And, FERC's own administrative precedents have recognized that states

[283] *Edison Electric Institute,* 69 FERC ¶ 61,344 at 62,289 (1994) (holding also that sales of emission allowances that take place independent of a wholesale sale of electricity are not within FERC's jurisdiction).
[284] *See* Order No. 1000-A, ¶¶ 205-06, 336, 77 Fed. Reg. at 32,217-18, 32,236. The D.C. Circuit upheld this provision of Order No. 1000 in *South Carolina Pub. Serv. Auth. v. FERC,* No. 12-1232 (Aug. 15, 2014).
[285] *See Midwest Independent Transmission System Operator, Inc.,* 137 FERC ¶ 61,074 at P 20 (Oct. 21, 2011)
[286] *Northwest Cent. Pipeline Corp. v. State Corp. Comm'n,* 109 S.Ct. 1262, 1277 (1989). Although the holding in this case pertains to the Natural Gas Act, the federal courts typically interpret and apply the Natural Gas Act and the Federal Power Act in identical fashion. *See Ark. La. Gas Co. v. Hall,* 453 U.S. 571.
[287] *Schneidewind v. ANR Pipeline Co.,* 485 U.S. 293, 309 (1988).
[288] *See PPL EnergyPlus, LLC v. Solomon*, 766 F.3d 241, (3d Cir. 2014) ("The states may select the type of generation to be built—wind or solar, gas or coal—and where to build the facility. Or states may elect to build no electric generation facilities at all….The states' regulatory choices accumulate into the available supply transacted through the interstate market. The Federal Power Act grants FERC exclusive control over whether interstate rates are "just and reasonable," but FERC's authority over interstate rates does not carry with it exclusive control over any and every force that influences interstate rates.") (citing *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481, 386 U.S. App. D.C. 320 (D.C. Cir. 2009)).
[289] *See California Pub. Utilities Comm'n*, 134 FERC ¶ 61044, 61160 (Jan. 20, 2011); see also, e.g., *In re Midwest Power Systems, Inc.,* 78 FERC ¶ 61,067, 61,246 (1997) ("We find that the Iowa [law] [is] consistent with federal law to the extent that [it] requires electric utilities located in Iowa to purchase from certain types of generating facilities."); *In re S. Cal. Edison Co.*, 70 FERC ¶ 61,215, 61,676 (1995) (because "resource planning and resource

retain authority to use a variety of regulatory tools, including taxes and subsidies for particular fuels or generating types, to meet their electricity needs.[290] Congress intended the FPA "to supplement, not limit, the reach of state regulation."[291]

Nothing about EPA's proposed emission guidelines - or the state plans that would be submitted pursuant to those guidelines – infringe on FERC's authority under the FPA. Like every other emission standard that EPA and the states have implemented under the Clean Air Act, the proposed emission guidelines are fully consistent with the FPA.

M. EPA's BSER Determination Does Not "Redefine" Any Sources, a Concept from a Different Clean Air Act Program Inapplicable Here

Some stakeholders have suggested that EPA's BSER determination is too aggressive because it would inappropriately "redefine" or "redesign" the regulated entities.[292] In particular, some may try to use this claim to criticize EPA's proposal in the Notice of Data Availability that the Agency consider the potential for coal-fired boilers to co-fire with or convert to natural gas in assessing emission reduction potential in each state. Such an argument would fail because (a) the CPP does not redefine or redesign any particular source, and (b) the argument depends on a concept from a different program under the Clean Air Act (CAA) that is not relevant to the system-based approach of section 111(d).

As noted above, the CPP offers states and the power sector tremendous flexibility in deciding how to reduce greenhouse gas emissions and meet the state target. The rule sets state-specific goals for emissions reductions, based on a review of measures already being implemented throughout the country, but each state will choose how to meet its goal through whatever combination of measures reflects its particular circumstances and policy objectives. So some states may choose to require natural gas co-firing at some facilities and other states may not, depending on what is most effective, technically and economically, for the sources in each state. States also have the option to put in place market-based programs providing even greater flexibility, and in such states sources might choose to implement natural gas co-firing or conversion or not, depending upon what is most cost-effective for those sources. In no

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decisions are the prerogative of state commissions[,]" a state "may choose to require a utility to construct generation capacity of a preferred technology or to purchase power from the supplier of a particular type of resource").

[290] *See ISO New England and New England Power Pool,* 120 FERC ¶ 61,234 (2007) ("Nothing in the [minimum capacity] requirement prevents a state from requiring its LSEs to meet capacity requirements through demand response, or through contracts to purchase power…or through more environmentally friendly generation, or, generally speaking, through resources that meet state health or environmental or land-use planning goals…how those resources are provided is up to LSEs and the states."); *Southern California Edison,* 71 FERC ¶ 61,269 (1995) ("A state may, through state action, influence what costs are incurred by the utility . . . [as] part of a state's approach to encouraging renewable generation. For example, a state may impose a tax or other charge on all generation produced by a particular fuel, and thus increase the costs which would be incurred by utilities in building and operating plants that use that fuel. Conversely, a state may also subsidize certain types of generation, for instance wind, or other renewables, through, e.q., tax credits.").

[291] Kentucky West Virginia Gas Co. v. Pennsylvania Pub. Util. Com'n, 837 F.2d 600, 606 (3rd Cir. 1988).

[292] *See, e.g.*, North American Coal Corporation, Comments on Proposed Carbon Pollution Emission Guidelines For Existing Stationary Sources: Electric Utility Generating Units, EPA-HQ-OAR-2013-0602 (June 18, 2014) at 24-25.

sense, then, does the CPP force any particular source to fundamentally alter its operations. Instead, if a state finds that a source could co-fire, that regulatory option would be available to the state, but for those sources that would have significant challenges doing so, other options remain available under the CPP.

Moreover, any industry argument about "redefining" or "redesigning" would erroneously be trying to pull into section 111(d) a concept that arises in the very different "Prevention of Significant Deterioration" (PSD) program of section 165 of the CAA. The PSD program requires, among other things, a "new" or "modified" source in certain areas of the country to obtain a preconstruction permit that specifies emission limits reflecting the "best available control technology" (BACT) for regulated pollutants.[293] BACT is determined by EPA or the state permitting authority "on a case-by-case basis" for each individual facility that triggers PSD, taking into account the "energy, environmental, and economic impacts and other costs . . . for such facility."[294]

In the past, EPA as a matter of policy has taken the position that when determining BACT for any particular applicant, the agency will not require the source to fundamentally alter its design as a means of reducing emissions.[295] The policy stems from a concern that it might be disruptive for the facility seeking a permit if EPA were to second-guess some of the operator's fundamental choices.

There is nothing in the statute that compels that policy against "redesigning" or "redefining" a source (the two terms are often used interchangeably). Instead, as the Environmental Appeals Board (EAB) noted, "the policy is really an agency interpretation of ambiguous statutory provisions."[296] Likewise, in the key federal judicial decision on this issue, the court cited no CAA provisions directly on point when agreeing with EPA that it could choose not to redefine a source in the facility-specific BACT determination.[297] In fact, because the policy is not compelled by the statute, historically EPA has allowed state permitting authorities to take a different approach in their BACT determinations than set out in the policy, taking the position that "this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire."[298] Accordingly, EPA has explained that the BACT analysis for a coal-fired EGU does not always need to consider natural gas firing under its redefining-the-source policy,

[293] 42 U.S.C. § 7475(a)(1) (regulating "major emitting facility on which construction is commenced after August 7, 1977"); id. § 7479(a)(1) and (2)(C) (defining "major emitting facility" and "construction" to include modifications).
[294] Id. § 7479(3).
[295] *In re Pennsauken Cnty., N.J. Resource Recovery Facility*, 1988 EPA App. LEXIS 27, 13-14 (EPA App. 1988) (in a challenge to a permit issued under federal PSD permitting regulations, the Administrator of EPA held that "the conditions themselves [of such a PSD permit] are not intended to redefine the source").
[296] In re City of Palmdale (Palmdale Hybrid Power Project), PSD Appeal No. 11-07, 2012 EPA App. LEXIS 29, at *75 n.25 (EAB Sept. 17, 2012) (citations and internal quotation marks omitted). *See also* EPA, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011) at 27 ("EPA does not interpret the CAA to prohibit fundamentally redefining the source and has recognized that permitting authorities have the discretion to conduct a broader BACT analysis if they desire.").
[297] *Sierra Club v. EPA*, 499 F.3d 653, 654-55 (7th Cir. 2007) Sierra Club v. U.S. EPA, 499 F.3d 653, 655 (7th Cir. 2007) (noting that the policy is a refinement of "the statutory definition of 'control technology'" and "the kind of judgment by an administrative agency [of ambiguous statutory terms] to which a reviewing court should defer.").
[298] EPA Guidance on PSD and Nonattainment Area Permitting at B.13-B.14 (Draft, 1990).

but states retain discretion to consider changes in primary fuel type in Step 1 of the BACT analysis.[299] And because it is always appropriate to consider changes that do not "disrupt[] the applicant's basic business purpose for the proposed facility," states may often analyze fuel-switching in an economic environment where both coal- and natural gas-fired units can serve the fundamental business purposes of providing base-load and peaking power.[300]

Even if that limited approach makes sense in the context of the highly fact-specific, facility-by-facility inquiry of BACT, any limit on "redesigning" a source is not relevant to the system-wide determination of BSER under section 111(d) that looks at the potential for emission reduction at regulated sources given the unified nature of the electric grid. The PSD program and the section 111(d) program are substantially different, making any analogies between the two with respect to the redefining the source policy inappropriate. BACT is a case-by-case inquiry in which it may be appropriate to be concerned about "redefining the source" since, with only one project at issue, it might be disruptive if EPA were to push for substantial alterations to the project.

In contrast, an emission guideline under section 111(d) governs a source category on a nationwide basis. Such nationwide standards are designed to level the playing field throughout the regulated industrial sector, and as a result some facilities might be required to make fairly extensive changes to bring their operations up to par with other members of the source category.[301] Thus, the notion of not "redefining a source" is less relevant to nationwide standards for entire source categories, and those standards may sometimes be more intrusive for a particular facility than the BACT inquiry which specifically takes into account technical and economic feasibility for each individual facility seeking a PSD permit. In fact, though, the reality here is that the nationwide, system-based approach of the CPP actually offers considerably *more* flexibility to individual sources than a facility-only inquiry might allow, because, as noted above, the states have significant discretion to choose how to regulate sources within their state to meet the state-specific emissions goals, and state plans can provide sources with flexible compliance options to meet their standards.

In addition, the statutory language on BACT is distinctly different from the statutory language on BSER. The definition of BACT includes the term "system" within a much longer list of other possible descriptions of the scope of the BACT inquiry ("production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques"), and EPA has chosen to interpret its authority under that provision to preclude redefining the

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[299] EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 27-28; *see also id.* at 27, n.76 (noting that the Environmental Appeals Board has found consideration of repowering reasonable for a coal-fired unit that was equipped to burn natural gas).

[300] *See id.* at 26-27.

[301] Indeed, under some nationwide standards under the Clean Air Act and Clean Water Act, Congress contemplated that some members of the regulated category might not be able to survive. *See, e.g.*, 91 Cong. Senate Debates 1970, debating Conference Report on H.R. 17255 (Dec. 18, 1970), reprinted in CAA70 Leg. Hist. 13 at 42383 (exhibit introduced by S. Muskie summarizing provisions of the conference report by explaining that regulations promulgated under section 112 of the Clean Air Act "could mean, effectively, that a plant would be required to close because of the absence of control techniques."); S. Rep. 91-1196 (explaining that under the proposed national standards for hazardous air pollutants "[s]ome facilities will need altered operating procedures or a change of fuels. Some facilities may be closed.").

source. By contrast, section 111(a)(1) simply calls for standards of performance to be based on the best "system" of emission reduction, and there is no list of possible pollution reduction mechanisms that corresponds to BSER. In fact, BSER is not further defined by the statute. Hence, EPA is within its discretion here – in light of the different statutory text, structure, practical and policy considerations between the two programs – to interpret the scope of the BSER inquiry to be broader than the BACT inquiry.

To be sure, the statute provides that a BACT standard should not be less stringent (allowing greater emissions) than "any applicable standard established pursuant to section 7411 or 7412 of this title".[302] This provision is sometimes referred to as the "BACT floor", as the section 111 standards serve as a "floor" for the BACT limit. Opponents of the CPP proposal may try to suggest that this means that if EPA has chosen not to "redefine the source" for BACT, it also should not do so in the section 111(d) standards. That argument, however, would reverse the normal order of operations under the CAA. Section 111 initially requires EPA to identify pollution that endangers public health and welfare, to promulgate standards of performance for categories that it finds contribute significantly to that pollution with one year of its finding, and to revise those standards every eight years thereafter.[303] The purpose of the PSD program—and BACT more specifically—is to build upon those standards in the interval, as innovative technologies become available and are deemed ready for use on a case-by-case basis.[304] It would be perverse for a narrow policy interpretation of BACT to influence EPA's BSER determination, when the latter determination periodically is supposed to elevate the BACT floor, and when there is a reasonable basis, as here, for taking a different policy approach given the different goals and scope of the two programs.

Finally, evidence that the BSER determination is not limited by any notion of "redefining the source" is found in the regulations implementing section 111(d). 40 C.F.R. Pt. 60, Subpt. B (40 C.F.R. §§ 60.20-60.31). Nowhere do those regulations prohibit EPA, when establishing emission guidelines for the states to implement BSER, from considering alterations of the operations of the regulated facilities. At most, in section 60.24(f), EPA's regulations allow states to grant variances from the emission guidelines to account for differences in "basic process design" (an undefined phrase), but not always – only if the differences in basic process design make compliance with the emission guidelines "unreasonable". 40 C.F.R. § 60.24(f)(1).

In sum, EPA's Notice of Data Availability, which contemplates considering the potential for coal-fired boilers to co-fire with or convert to natural gas in assessing emission reduction potential in each state, is entirely consistent with EPA's authority under section 111(d) and does not run afoul of any concern about

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[302] 42 U.S.C. § 7479(3).

[303] *See id.* § 7411(b)(1)(A), 7411(b)(1)(B).

[304] *See, e.g.*, S. Rep. 95-127 (1977) at 18 ("This procedure to prevent significant deterioration requires a case-by-case determination by the States of best available control technology for any new major emitting facility that will be built in a clean-air region. Thus, each State is free to -- and encouraged to -- examine and impose requirements for the use of the latest technological developments as a requirement in granting the permit. This approach should lead to rapid adoption of improvements in technology as new sources are built, not the stagnation that occurs when everyone works against a single national standard for new sources.").

"redefining" sources, as that concept from the PSD program is inapplicable in the CPP's flexible, nationwide emission guidelines for a broad category of sources.[305]

N. Section 111(d) requires action on greenhouse gas emissions from EGUs, regardless of whether EGUs are subject to Hazardous Air Pollutant ("HAP") regulations.

Section 111(d)(1) sets out a mandatory command that EPA "shall" prescribe regulations providing for state plans for "any air pollutant" that is not in three enumerated categories. 42 U.S.C. § 7411(d)(1). The first two of these excluded categories of pollutants consist of criteria pollutants. *See id.* § 7411(d)(1)(i) (requiring regulation of pollutants "for which air quality criteria have not been listed or which is not included upon a list published under section 108(a)"). Because CO_2 is not a criteria pollutant, it is undisputed that this exclusion does not apply here.

The final category of pollutants excluded from the mandatory duty to promulgate section 111(d) regulations is defined by reference to section 112 of the Act. In the 1990 Clean Air Act Amendments, Congress enacted, and the President signed into law, two provisions containing different language effectuating this cross-reference. Each struck some of the same language in the preexisting section 111(d) (which was itself a reference to a specific provision in section 112 that was eliminated in the 1990 amendments). The two provisions—one originating in the House and one in the Senate—did not refer to one another.

The two 1990 cross-references have been the source of debate concerning the proper scope of regulation under sections 111(d) and 112. In litigation seeking to block the instant rulemaking and prohibit regulation of CO_2 emissions from existing sources, some parties have argued that the amendments must be read to deny EPA the authority to promulgate section 111(d) guidelines for CO_2 emissions from power plants, given that EGUs are listed and regulated under section 112(b).[306]

Contrary to these claims, EPA's authority and obligation to proceed under section 111(d) with respect to power plants is clear. Despite the unusual circumstance of two separate and simultaneously enacted changes to the same statutory text, nothing in the 1990 amendments can be fairly read to call into question EPA's authority to promulgate emissions guidelines for CO_2 emissions from EGUs.

Whatever uncertainties and interpretive challenges the two differing 1990 amendments may pose, it would not even be reasonable—let alone *mandatory* —to read either amendment, or both together, to

[305] As shown above [cross-reference], reduced utilization of high-emitting sources is a well-established regulatory tool that EPA rightly should consider in its BSER determination. Nevertheless, opponents of the CPP may try to suggest that such curtailments in operations inappropriately "redefine" the regulated entities. To the extent such an inaccurate claim is made about curtailments (or any other aspect of the CPP), the responses would be similar to those presented here on cofiring: The CPP does not redefine any particular source, and in any event the limit on "redefining" sources from the PSD program is not relevant to the system-based approach of section 111(d).

[306] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341); Brief of Amici Curiae West Virginia, et al., 2, *Murray Energy Corp. v. EPA*, No. 14-1112 (D.C. Cir. June 25, 2014) (Doc. 1499435).

preclude regulation of pollutants such as CO_2, that are *neither* listed under section 112(b) *nor* actually regulated under that provision as to any source category.

While the 1990 House and the Senate amendments differ in wording, and arguably to some extent in legal effect, they are similar in that both were intended to provide an updated cross-reference to newly amended section 112 and that Congress, in each amendment, wanted to make sure that section 111(d) guidelines would not be redundant with amended section 112. But there is absolutely no sign that Congress intended to place large categories of harmful pollution beyond the scope of any Clean Air Act regulation, as the litigants and other commenters' theories would posit. Congress surely did not want to prohibit regulation under section 111(d) of pollution that is not regulated under section 112, *i.e.*, emissions of dangerous non-HAP pollutants such as CO_2.

Under no *reasonable* reading of section 111(d) as amended in 1990 can EPA's authority to address non-HAP emissions from existing sources be doubted. The agency need not resolve in this rulemaking every conceivable issue that may arise from the peculiar interpretive issues presented by the dual 1990 amendments; it need not decide here, for example, whether and when HAPs from source categories that are not regulated under section 112 may be regulated under section 111(d). But EPA should clarify here, in the strongest terms, that the text, structure, legislative history, and policy logic of the Clean Air Act all confirm that the dangerous but non-"hazardous" emissions from a category of existing sources are not otherwise immunized from such regulation merely because *other* pollutants emitted by those sources are either listed or regulated under section 112(b).

1. **In CAA sections 110, 111(d), and 112, Congress established a comprehensive framework for controlling pollution from existing sources, in which each section addressed a separate class of pollutants.**

Since Congress first enacted the Clean Air Act in 1970, sections 110, 111(d) and 112 have fit together to ensure that *all* air pollution from existing sources is adequately controlled. Congress crafted these sections to focus on different pollution, forming an interlinked and complementary structure. Section 110 establishes a process for controlling pollutants that are subject to ambient air-quality standards. EPA determines the air-quality standards that will be sufficient to protect human health and the environment, while states are responsible for devising plans that ensure the air-quality standards are met. Because these "criteria pollutants" are emitted by a variety of sources and public health can usually be protected by limiting aggregate emissions in a particular area, states have significant discretion in setting standards under section 110.

Section 112 requires controls on emissions of hazardous air pollutants. In the Clean Air Act of 1970, Congress defined a "hazardous air pollutant" as a pollutant that is not subject to air-quality standards and that "may cause, or contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible, illness."[307] The Act originally required EPA to publish a list of hazardous air pollutants and establish standards that "provide[] an ample margin of safety to protect the public health

[307] Clean Air Amendments of 1970, Pub. Law 91-604, § 112(a)(1), 84 Stat. 1676, 1685 (1970).

from such hazardous air pollutant[s],"[308] but EPA failed to carry out this mandate. Frustrated by EPA's inaction, Congress overhauled section 112 in 1990 by establishing its own list of nearly 200 hazardous air pollutants and requiring EPA to set stringent technology-based standards for all major sources and many non-major ("area") sources of hazardous air pollutants, as discussed below.

Section 111(d) requires controls for source categories that "cause[] or contribute[] significantly to" air pollution which "may reasonably be anticipated to endanger public health or welfare," if the pollution is not regulated under either section 110 or 112. Thus, section 111(d) functions as a backstop for sections 110 and 112, preventing dangerous existing-source pollution from being left unregulated.

Congress' systematic approach allows these sections to sections to form an orderly framework. Sections 110 and 112 focus on specific classes of pollutants and section 111(d) acts as a gap-filler, addressing dangerous pollution not regulated under the sections tailored to address hazardous and ambient air pollution problems. The legislative history of the 1970 Clean Air Act confirms that this complementary framework was deliberate:

> It should be noted that emission standards for pollutants which cannot be considered hazardous (as defined in section 115 [the precursor to section 112]) could be established under section 114 [the precursor to section 111(d)]. Thus there should be no gaps in control activities pertaining to stationary source emissions that pose any significant danger to public health or welfare.[309]

2. The 1990 Clean Air Act amendments strengthened section 112's hazardous air pollution program while maintaining the basic relationship among the Act's stationary source provisions.

In 1990, Congress responded to the fact that few sources of hazardous air pollutants had been addressed under section 112 by revising section 112 in a manner that forced EPA to regulate multitudinous source categories.[310] Specifically, Congress amended section 112 to list nearly 200 toxic air pollutants and

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[308] *Id.* § 112(b)(1)(A)-(B).
[309] Sen. Rep. No. 91-1196, at 20 (1970).
[310] The legislative history emphasizes Congress' goal of ensuring that EPA would promulgate stringent regulations for hazardous air pollutants. For instance, during the debate on the conference bill, Senator Cohen expressed his support for the amendments by stating:

> One of the most health-threatening forms of air pollution comes in the form of toxic air emissions from a wide variety of sources. Some emissions occur on an everyday basis, while some are a result of accidents that often have drastic consequences. The EPA has done a woefully inadequate job of establishing emissions standards for the hundreds of toxic pollutants that exist. In 18 years, the agency has regulated only some sources of seven chemical pollutants. Several hundred chemicals remain unregulated, to the detriment of human health. The bill requires the EPA to set standards for approximately 200 hazardous air pollutants, and then define sources of those pollutants for the purpose of implementing the standards. All sources must install the strongest technology available. After this occurs, the EPA must then review emission levels to determine whether a significant health risk continues to exist despite the application of the best technology. If that health risk does exist, the source must achieve further reductions so that the risk to human health is reduced. This new air toxics control program

require EPA to regulate all major sources of these hazardous air pollutants.[311] In addition, Congress required EPA to regulate many area sources of hazardous air pollutants (those "representing 90 percent of the area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas").[312] Congress understood that dozens of source categories would be subject to regulation under section 112, as confirmed by section 112's implementation schedule.[313] Congress successfully catalyzed EPA action. EPA has promulgated hazardous air pollutant regulations for nearly 200 source categories and subcategories.[314] The source categories regulated under section 112 include all of the most significant sources of this nation's dangerous air pollution.

At the same time, Congress took pains to ensure that its strengthening of section 112 would not inadvertently impair any of the Clean Air Act's other vital protections. Congress explicitly provided in section 112 that "No emission standard or other requirement promulgated under this section shall be interpreted, construed or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to section [111] of this title, part C or D of this subchapter, or other authority of this chapter or a standard issued under State authority."[315] Consequently, EPA retains its obligation to—for example—regulate non-HAPs as well as HAPs from new stationary sources under section 111(b), regardless of whether those sources are also regulated under section 112. Similarly, states and EPA are required to ensure that state implementation plans under section 110 achieve attainment with National Ambient Air Quality Standards for criteria pollutants, even if those plans include requirements for existing sources that are also subject to section 112 standards. Congress unambiguously intended for the requirements of section 110, 111 and 112 to continue operating in careful coordination to protect the public from all harmful pollutants emitted by stationary sources.

In the 1990 amendments, Congress also carved out one categorical exception from the seamless threefold framework for controlling stationary source emissions. By enacting section 129, Congress crafted a unique regime for one type of source: solid waste incineration units. Congress decided to exclude these units from regulation under section 112 and instead subject them to tailored regulation under sections 129 and 111.[316] Thus, in the only case where Congress excluded a class of sources from regulation under sections 110, 111(d), or 112 because other CAA controls were sufficient, it provided for rigorous, source

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> is a very significant step forward in the effort to control air pollution. I believe it will result in significant improvements in the protection of human health from cancer risks and other threats.

Senate Debate on the Clean Air Act Amendments of 1990 Conference Report (Oct. 26, 1990), *reprinted in* U.S. Senate Comm. on Envt. & Pub. Works, Legislative History of the Clean Air Act Amendments of 1990, at 1105 (1993) (herinafter 1990 CAA Leg. Hist).

[311] 42 U.S.C. §§ 7412(b)(1), (d)(1).

[312] *Id.* §§ 7412(d)(1), (c)(3).

[313] *Id.* § 7412(e)(1). Congress required EPA to regulate at least 40 source categories and subcategories within two years of the 1990 amendments, and at least 25% of the source categories listed for regulation within four years. This indicates an assumption that the first 40 source categories regulated would be less than a quarter of the total number of regulated source categories (*i.e.*, that EPA would regulate no less than 160 source categories).

[314] EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP), http://www.epa.gov/ttn/atw/mactfnlalph.html.

[315] 42 U.S.C. § 7412(d)(7).

[316] Clean Air Act Amendments, Pub. L. 101-549, § 305, 104 Stat. 2399, 2583 (1990) (codified at 42 U.S.C. § 7429(h)(2)).

category-specific regulation elsewhere in the CAA.

The treatment of EGUs is entirely different. Congress authorized regulation of EGUs under section 112 if EPA "finds such regulation is appropriate and necessary after considering the results of" a study of the health risks of EGU HAP emissions after the implementation of other CAA requirements. 42 U.S.C. § 7411(n)(1)(A). Congress did not remove EGUs from the tripartite framework for stationary source regulation, but allowed EPA to forego regulation of EGU HAP emissions if incidental control of HAPs through other CAA programs (such as the CAA cap-and-trade program to reduce acid rain, which only affects EGUs) rendered that regulation unnecessary. In deciding whether to regulate EGUs' HAP emissions, EPA was required to consider its study of the public health impacts of those HAP emissions;[317] Congress did not require this study to analyze the public health impacts of non-HAP pollution from EGUs because the Act does not force EPA to choose between regulating non-HAP emissions from EGUs under 111(d) or regulating HAP emissions under 112.

The 1990 Clean Air Act Amendments also revised the Act to more effectively protect human health and the environment in several other important ways. For instance, Congress amended section 110 to authorize EPA to require SIP revisions that are necessary to adequately mitigate interstate pollution transport,[318] and authorized EPA to apply certain sanctions if a state submits an inadequate SIP.[319] The legislation introduced new landmark programs and strengthened existing programs, prompting President George H.W. Bush to declare: "This legislation isn't just the centerpiece of our environmental agenda. It is simply the most significant air pollution legislation in our nation's history, and it restores America's place as the global leader in environmental protection."[320]

3. In 1990, Congress enacted two amendments to section 111(d) that maintained the provision's historic role in preventing dangerous pollution from existing industrial sources from going uncontrolled.

a. The 1990 Clean Air Act Amendments contained two different amendments providing for changes to the same statutory language in section 111(d)(1).

Prior to 1990, section 111(d) clearly mandated action to control dangerous air pollutants from existing sources if those emissions were not already regulated under section 108 or section 112, for source categories regulated under section 111(b):

[317] 42 U.S.C. § 7412(n)(1)(A). Section 112(n) mandates three studies: EPA's study of the hazards EGU HAP emissions pose to public health after the imposition of other Clean Air Act requirements, which the agency must consider in its "appropriate and necessary" finding, § 7412(n)(1)(A); an EPA study of EGU mercury emissions and technologies for controlling such emissions, § 7412(n)(1)(B); and a National Institute of Environmental Health Sciences study on the threshold level of mercury exposure below which adverse human health effects are not expected, § 7412(n)(1)(C). None of these studies non-HAP emissions.
[318] *Id.*, § 101, 104 Stat. at 2407 (codified at 42 U.S.C. § 7410(k)(5)).
[319] *Id.*, § 101, 104 Stat. at 2407-08 (codified at 42 U.S.C. § 7410(m)).
[320] Remarks of President George H.W. Bush Upon Signing S. 1630, 26 Weekly Comp. Pres. Doc. 1824 (Nov. 19, 1990) (reprinting the President's signing statement of Nov. 15, 1990).

> The Administrator shall prescribe regulations which shall establish a procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan which (A) establishes standards of performance for any existing source for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title, but (ii) to which a standard of performance under this section would apply if such existing source were a new source.[321]

In 1990, Congress enacted two amendments to section 111(d)(1)(A)(i) addressing the same issue—when regulation under section 112 would supplant regulation under section 111(d). Some amendment to section 111(d) was necessary because the 1990 amendments deleted section 112(b)(1)(A), which was the subsection of section 112 that section 111(d) had cross-referenced since 1970. Bills originating in each chamber amended section 111(d)'s cross-reference to section 112(b)(1)(A) in different ways, and Congress ultimately enacted, and the President signed, a conference bill containing both amendments.

The amendment originating in the House revised section 111(d)(1)(A)(i) by striking the words "or 112(b)(1)(A)" and inserting in their place the following phrase: "or emitted from a source category which is regulated under section 112."[322] Congress also enacted an amendment originating in the Senate that revised the same subsection by striking the reference to "112(b)(1)(A)" and inserting in its place "112(b)."[323] The House amendment is located in section 108 of the Statutes at Large (under "Miscellaneous Guidance"); the Senate amendment is found in section 302 (under "Conforming Amendments"). The text and structure of the Act in the Statutes at Large (104 Stat. 2399) are the same as in the public law passed by both chambers and signed by President George H.W. Bush (101 P.L. 549).

The Office of the Law Revision Counsel[324] codified only the House amendment in the United States

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[321] 42 U.S.C. § 7411(d)(1) (West 1977).
[322] Pub. L. 101-549, § 108, 104 Stat. at 2467.
[323] *Id.*, § 302, 104 Stat. at 2574.
[324] Some commentators have suggested that codification decisions of the House Office of the Law Revision Counsel are entitled to some form of deference. However, the Office is not the expert agency charged with administering the CAA, and therefore not entitled to *Chevron* deference regarding the interpretation of that statute. *Chevron*, 467 U.S. at 844 ("We have long recognized that considerable weight should be accorded to an executive department's construction of a statutory scheme it is entrusted to administer, and the principle of deference to administrative interpretations has been consistently followed by this Court whenever decision as to the meaning or reach of a statute has involved reconciling conflicting policies, and a full understanding of the force of the statutory policy in the given situation has depended upon more than ordinary knowledge respecting the matters subjected to agency regulations.") (footnote and quotation omitted).

Accordingly, the Office does not even purport to interpret or amend the law in the codification process: "The translations and editorial changes made to sections of non-positive law titles are purely technical and do not change the meaning of the law." Office of the Law Revision Counsel, Detailed Guide to the United States Code Content and Features, *available at* http://uscode.house.gov/detailed_guide.xhtml. Even where there are plain errors in grammar, punctuation, or spelling, the Office does not correct them in the text of the code, but merely inserts a footnote indicating the probable error. *Id.*

The Office of the Law Revision Counsel could not purport to determine the text of section 111(d) without running afoul of the Supreme Court's jurisprudence on the separation of powers. Expunging the text of the Senate amendment from section 111(d) is a legislative act that can only be accomplished through the legislative process. *See INS v. Chadha*, 462 U.S. 919, 952-54 (1983) ("Amendment and repeal of statutes . . . must conform with [the

Code, 42 U.S.C. § 7411(d)(1)(A)(i). The codifier's notes to this section state that the Senate amendment ''could not be executed.'' Regardless, the Statutes at Large—not the United States Code—controls here. The Statutes at Large constitute the legal evidence of the laws for code titles that have not been enacted into positive law.[325] Because Title 42 of the United States Code has not been enacted into positive law,[326] the legal evidence of the relevant law is the statutes at large, which contains both amendments.[327]

b. The Senate amendment clearly requires 111(d) regulation of CO_2 from EGUs.

The Senate amendment is clear and consistent with the historic role of section 111(d) as a "backstop" to ensure protection of public health from existing-source emissions not regulated under section 112 or section 110. Read with the rest of section 111(d), the Senate amendment continues the longstanding policy of covering all non-HAP, non-criteria pollutants under section 111(d). The amendment was necessary to conform to the conference committee's amendments to section 112(b). Previously, section 112(b)(1)(A) required EPA to publish a list of HAPs it intended to regulate under section 112. The 1990 amendments removed subsection 112(b)(1)(A) entirely. The new section 112(b)(1) establishes an initial list of over 180 HAPs and section 112(b)(2)-(3) gives EPA authority to both add new HAPs to the list and to de-list certain HAPs. The Senate amendment simply updated EPA's section 111(d) authority to reflect the amended list of HAPs regulated under section 112.

While some have argued that EPA should disregard the text of the Senate amendment because its status as a "conforming amendment" renders it a poor indication of congressional intent and a likely scrivener's error, the Senate amendment cannot be disregarded. The D.C. Circuit has looked to conforming amendments in other statutes and given full effect to "the plain meaning of the statutory language in which Congress has directly expressed its intentions." *Washington Hospital Center v. Bowen*, 795 F.2d 139, 149 (D.C. Cir. 1986); *see also CBS v. FCC*, 453 U.S. 367, 381 ("Perhaps the most telling evidence of congressional intent, however, is the contemporaneous [conforming] amendment"). Further, the Senate amendment does not resemble a scrivener's error at all. A scrivener's error is "a mistake made by someone unfamiliar with the law's object and design," *United States Nat'l Bank v. Independent Ins. Agents of Am.*, 508 U.S. 439, 462 (1993), and produces language with "no plausible interpretation," *Williams Cos. v. FERC*, 345 F.3d 910, 913 n.1 (D.C. Cir. 2003). The Senate amendment is plainly not a scrivener's error. In keeping with the same protective statutory structure that Congress first crafted in the 1970 Clean Air Act, the Senate amendment has the entirely coherent purpose and effect of updating the section 111(d) cross-reference in light of amendments to section 112 that rendered the previous cross-reference meaningless by deleting previous subparagraph 112(b)(1)(A). Furthermore, because the text of the Senate amendment is unambiguous, EPA "can remain agnostic on the question whether Congress intentionally left [that] particular language in [the] statute or simply forgot to take it out. The suggestion that Congress may have 'dropped a stitch,' is not enough to permit [EPA] to ignore the statutory text."

bicameralism and presentment requirements of] Art. I.") "Congress must abide by its delegation of authority until that delegation is legislatively altered or revoked." *Id.* at 955.

[325] 1 U.S.C. §§ 112, 204(a); *U.S. Nat. Bank of Oregon v. Indep. Ins. Agents of Am., Inc.*, 508 U.S. 439, 448 (1993); *United States* v. *Welden,* 377 U.S. 95, 98 n.4 (1964). *Stephan v. United States*, 319 U.S. 423, 426, (1943).

[326] *See* Office of Law Revision Counsel, United States Code, listing titles that have been enacted into positive law with an asterisk, http://uscode.house.gov/browse.xhtml.

[327] *See, supra*, note 325; Clean Air Act Amendments, 104 Stat. 2399, 2467, 2474 (1990).

See United States ex rel. Totten v. Bombardier Corp., 380 F.3d 488, 496 (D.C. Cir. 2004) (quotations and citation omitted).[328] There is no exception here to the rule requiring EPA "to give effect, if possible, to every word Congress used." *See Reiter v. Sonotone Corp.*, 442 U.S. 330, 339 (1979).

c. The House amendment is most reasonably read to require regulation of CO_2 emissions from EGUs.

In contrast to the Senate amendment, the House amendment is subject to multiple interpretations. The ambiguous House amendment would require EPA's expert interpretation even if Congress had not also amended identical language in section 111(d) through the Senate amendment. *See Chevron, U.S.C., Inc. v. Natural Resources Defense Council*, 467 U.S. 837, 843 (1984). Because the Senate amendment unambiguously commands regulation of non-HAP pollutants such as CO_2, and because the House amendment is reasonably interpreted (even without reference to the Senate Amendment) to permit such regulation, EPA plainly has authority to regulate CO_2 emissions under section 111(d), and the agency need not resolve here whether there are scenarios in which some pollutant or source might be regulable under one amendment but not the other, and how to resolve that problem.

i. The House amendment provides for regulation of emissions that are not controlled under the hazardous air pollution program.

The House amendment is subject to multiple readings that would require regulation of CO_2 from sources like EGUs. As changed by the House Amendment, section 111(d) requires EPA to prescribe existing source regulations "for any air pollutant (i) for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or emitted from a source category which is regulated under section 112 of this title." (emphasis added). The most reasonable interpretation of the House amendment is to construe it to not authorize regulation under 111(d) as to particular pollutants that are actually regulated under Section 112(n) as to the source category in question. On this interpretation, Congress intended to safeguard section 111(d)'s gap-filling role by expanding the scope of the section to cover HAP emissions that would otherwise be unregulated under sections 112 or section 111(d).

Readings of the House amendment offered by parties seeking to block regulation of CO_2 under Section 111(d) have asserted that the provision necessarily bars regulation of any and all pollutants emitted by any source that is regulated under Section 112, even if it the specific *pollutant* in question is not a HAP and is therefore not regulated under 112.[329]

[328] *See also Owner-Operator Indep. Drivers Ass'n v. Landstar Sys.*, 622 F.3d 1307, 1327 (11th Cir. 2010) ("There is no reason for this Court to rewrite a statute because of an alleged scrivener error unless a literal interpretation would lead to an absurd result."); *Lewis v. Alexander*, 685 F.3d 325, 351-51 (3d Cir. 2012) (regardless of whether statutory text was the result of a drafting error, it was not a mere scrivener's error fit for judicial correction because Congress could have rationally chosen to enact the text at issue); *Nijjar v. Holder*, 689 F.3d 1077, 1084 (9th Cir. 2012) (same).

[329] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341); Brief of Amici Curiae West Virginia, et al., 2, *Murray Energy Corp. v. EPA*, No. 14-1112 (D.C. Cir. June 25, 2014) (Doc. 1499435).

But the text of section 112 is readily susceptible to reasonable interpretations under which the section 112-related exclusion from section 111(d) regulation is pollutant-specific. EPA may interpret the House amendment by resolving ambiguity in the phrase "emitted from a source category *which is regulated under section 112.*" A source category is "regulated" under section 112 not in the abstract, but with respect to particular pollutants. The term "regulated" can therefore be read to mean "regulated with respect to that pollutant under section 112," rather than "regulated as to any pollutant under section 112."

In other words, the House text could reasonably be understood to mean either (1) that EPA may not use section 111(d) when the source category is "regulated under section 112 for *the pollutant in question,*" *i.e.,* the same pollutant that is the candidate for regulation under section 111(d), or (2) that EPA may not use section 111(d) when the source category is "regulated under section 112 for *any* pollutant." The former is a sensible interpretation of the ambiguous term "regulated," and one that fits with a context that includes pollutant-specific phrasing of section 111(d) and a reference to a statutory provision, section 112, that "regulates" only hazardous pollutants. While the latter interpretation is plausible as a matter of ordinary understanding, it is not inevitable—and, as explained below, its practical consequences are starkly discordant with the statutory structure and purpose. Furthermore, it is common and proper under the Clean Air Act to construe potentially broad statutory language in light of the context in which the language appears, in order to produce a result that fits with the purpose and mechanics of the particular program in question. *See Utility Air Regulatory Grp. v. EPA*, 134 S. Ct. 2427, 2440 (2014) ("*UARG*") (citing numerous instances in which EPA has narrowed term "any air pollutant" to fit with context). A pollutant-specific reading of the Section 111(d) exclusion is easily permissible given the context here.

The House language may also be read to authorize EPA to regulate any air pollutant which is not a criteria pollutant and "any air pollutant [which is regulated under section 112] . . . which is not . . . emitted from a source category which is regulated under section 112." Under *Young v. Community Nutrition Institute*, an agency has discretion under *Chevron* to determine which terms are the object of a dangling modifier. 476 U.S. 974, 891 (1986) (granting *Chevron* deference to FDA's interpretation concerning which term was modified by a dangling participle in the Federal Food, Drug, and Cosmetic Act, even though a contrary "reading of the statute may seem to some to be the more natural interpretation"). Here, EPA can effectuate legislative intent by reading "which is regulated under section 112" to modify both "any air pollutant" and "source category."

Alternatively, the language "any air pollutant . . . emitted from a source category which is regulated under section 112" could be read to refer to hazardous air pollutants. This reading derives from the statutory context, in which hazardous air pollutants are the only pollutants regulated under section 112. As noted above, the Supreme Court has recently emphasized that the broad term "any air pollutant" as used in the Clean Air Act can take meaning from the context in which it is used. *See UARG*, 134 S. Ct. at 2440 (citing instances in which EPA has narrowed term "any air pollutant" to fit with context, such as EPA's having construed various provisions of section 111 that reference "any air pollutant" as limited to pollutants "*for which EPA has promulgated new source performance standards*"). Here, it is logical to understand Congress to have wanted to preclude section 111(d) regulation based on section 112 regulation only as to pollutants that are actually (or at least potentially) regulated under section 112. Moreover, under this interpretation, the House amendment would have essentially the same meaning as the Senate amendment and continue Congress' longstanding policy of using section 111(d) to control dangerous pollution that is not controlled under the criteria pollution provisions or section 112.

ii. The legislative history of the House amendment supports a narrow reading of the section 111(d) exclusion.

Reading the House version of the section 111(d) exclusion in a pollutant-specific way is not only consistent with the language of the statute, but also promotes the purpose that EPA has reasonably attributed to the House amendment, namely, "expand[ing] EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112,"[330]—thereby protecting against a regulatory gap that would provide no controls against HAP emissions from certain sources not regulated under section 112.

The version of the 1990 Clean Air Act Amendments that initially passed the House clarifies the purpose of the House amendment to section 111(d). As EPA has explained, the House amendment first passed the House in a bill that included several new opportunities for EPA to exercise discretion in whether to regulate HAP emissions under section 112.[331] That bill would have provided EPA significant additional discretion regarding when to promulgate regulations under section 112. Perhaps most importantly, the House bill would have allowed EPA to decline to regulate source categories under section 112 if EPA determined they were "already adequately controlled under this Act or any other Federal statute or regulation."[332] Furthermore, the House bill would have made regulation of non-major sources under section 112 entirely discretionary.[333] In this context, EPA reasonably noted the likelihood that "the House did not want to preclude EPA from regulating under section 111(d) those pollutants emitted from source categories which were not actually being regulated under section 112."[334] Even under the conference bill that became law, the prospect of certain HAP emissions not being regulated under section 112 may have motivated the expansion of section 111(d) to cover certain dangerous HAP emissions that might otherwise escape regulation, and that would not have been subject to section 111(d) standards as it was framed prior to 1990.[335]

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330 Revision of December 2000 Regulatory Finding on the Emissions of Hazardous Air Pollutants From Electric Utility Steam Generating Units and the Removal of Coal- and Oil-Fired Electric Utility Steam Generating Units From the Section 112(c) List, 70 Fed. Reg. 1594, 16031 (Mar. 29, 2005).
331 *Id.*
332 HR 3030, § 301, reprinted in 1990 CAA Leg. Hist. 3737 at 3933.
333 "The Administrator may designate a category or subcategory of area sources that he finds, based on actual or estimated agregate [sic] emissions of a listed pollutant or pollutants in an area, warrants regulation under this section." *Id.*, 1990 CAA Leg. Hist. 3737 at 3933. In contrast, the conference bill required EPA to regulate certain "area source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas." Pub. L. 101-549, § 301, 104 Stat. at 2537 (codified at 42 U.S.C. § 7412(c)(3).
334 70 Fed. Reg. at 16031.
335 Section 112 does not mandate controls for all source categories that emit HAPs. For instance, section 112 does not provide for the regulation of HAPs from oil and gas wells outside of certain metropolitan areas, unless those sources meet the statutory definition for "major sources." 42 U.S.C. § 7412(n)(4)(B). Also, section 112 requires EPA to regulate non-major sources "representing 90 percent of the [non-major] source emissions of the 30 hazardous air pollutants that present the greatest threat to public health in the largest number of urban areas," but otherwise only provides for regulation of non-major sources of HAPs if EPA determines they "present[] a threat of adverse effects to human health or the environment (by such sources individually or in the aggregate) warranting

The purpose of the House amendment is further illuminated by its context in the House bill *as introduced*. The House had initially proposed an overhaul of section 112 under which EPA would only be required to promulgate regulations for half the source categories it determines to be major and area sources of HAPs.[336] EPA would have been required to review the remaining fifty percent of listed source categories, and "designate the additional categories and subcategories [the EPA Administrator] finds, in his discretion, warrant regulation under this section."[337] This proposed system clearly entailed the potential for major sources of HAPs to escape regulation under section 112. Aware of this looming gap, the House proposed expanding section 111(d) to avoid leaving HAP emissions from numerous major sources unregulated.[338]

Interpretations that allow section 111(d) to continue providing for non-HAP regulation where needed to protect public health and welfare are true to the Clean Air Act's overarching structure for existing-source regulation. In addition to precluding any gaps in the regulatory framework for dangerous pollution from existing sources, these readings of the House amendment effectuate Congress' desire to make the CAA more protective through each revision. If EPA interprets the House amendment in this fashion, there will be no conflict in how the House and Senate amendments apply to the present rulemaking.

These readings have the benefit of not creating a bizarre and harmful gap in coverage of harmful pollutants that is entirely out of step with the tenor of the Act's regime and of the 1990 amendments. These interpretations are true to the Clean Air Act's overarching structure for existing-source regulation, as they allow section 111(d) to continue providing for coverage of non-HAP emissions where needed to protect public health and welfare.

These pollutant-specific readings of the House amendment are also consistent with the Supreme Court's observations about section 111(d) in *American Electric Power Company v. Connecticut*, 131 S. Ct. 2527 (2011). The Court described section 111(d)'s exclusions by stating: "There is an exception: EPA may not employ §[111(d)] if existing stationary sources of the pollutant in question are regulated under the national ambient air quality standard program, §§[108–110], or the "hazardous air pollutants" program, §[112]." *Id.* at 2537, n.7. This statement reflects the understanding that the exclusion for emissions regulated under section 112 works in parallel with the exclusion for emissions regulated under the NAAQS program. Indeed, the Court indicated that these exclusions comprise a single exception to section 111(d). There is no question that sources subject to regulation for criteria pollutant emissions

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regulation under this section." *Id.* § 7412(c)(3). Major sources are generally stationary sources with the potential to emit "10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants." *Id.* § 7412(a)(1).

[336] H.R. 3030, § 301 (introduced July 27, 1989, and referred to the Committee on Energy and Commerce), reprinted in 1990 CAA Leg. Hist. at 3936-37.

[337] *Id.* at 1990 CAA Leg. Hist. at 3937.

[338] It may also be noteworthy that neither the House bill nor conference bill posed any equivalent need to expand section 111(d) to cover criteria pollutants. This is likely due to the different nature of HAPs and criteria pollutants. Very small doses of HAPs can cause adverse impacts on public health and sources of HAPs impose the greatest burdens on nearby communities. Consequently, addressing HAP impacts requires controlling all major sources of HAPs. In contrast, the NAAQS program gives states discretion over which sources of criteria pollutants should be subject to regulation because states can adequately protect public health so long as they ensure ambient concentrations do not exceed the NAAQS.

under the NAAQS program are also subject to regulation for other emissions under section 111(d). Similarly, there should be no question that sources are subject to regulation for pollution that is not controlled by the HAPs program, even where sources are also regulated under section 112.

iii. In context, the House amendment cannot plausibly be read to end section 111(d)'s application to dangerous pollution that happens to be emitted by source categories regulated under section 112.

Although the House amendment might be read—acontextually—to diminish the scope of section 111(d), such a reading is inconsistent with the structure, purpose, and legislative history of the Clean Air Act.

Although, as demonstrated above, there are multiple ways to read the House amendment to continue 111(d)'s role as a backstop against unregulated, dangerous pollution, other readings of this ambiguous amendment have been proposed that would fundamentally alter the role of section 111(d). The most expansive reading of the House amendment would exclude from section 111(d) all pollutants emitted by sources that are regulated by section 112—even when those pollutants are emitted by a source *not* regulated under section 112. This reading would effectively nullify section 111(d) because there are few (if any) non-HAP pollutants that are *not* emitted by sources in one of the dozens of source categories regulated under section 112.[339] More vitally, this would leave a host of dangerous air pollutants wholly unaddressed by the Clean Air Act. This is made clear by the fact that none of EPA's pre-1990 emission guidelines could now be promulgated under such a regime, leaving communities vulnerable to pollutants such as sulfuric acid mist, reduced sulfur compounds, and fluoride.[340]

Some have argued that the House amendment must be read to exclude any regulation of all source categories regulated under section 112.[341] Even EPA has opined that "a literal" reading of the House amendment would exclude non-HAPs from regulation under section 111(d).[342] But no party has offered a plausible explanation for how Congress could have intended to obliterate the scope of section 111(d) through the House amendment.

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[339] *See* EPA, National Emission Standards for Hazardous Air Pollutants (NESHAP), http://www.epa.gov/ttn/atw/mactfnlalph.html (listing the nearly 200 source categories and subcategories affected by standards set under section 112).

[340] When Congress enacted the 1990 Clean Air Act Amendments, EPA had only issued four 111(d) emission guidelines, addressing total reduced sulfur from kraft paper mills, fluoride emissions from aluminum reduction plants, fluoride emissions from phosphate fertilizer plants, and sulfuric acid mist from sulfuric acid production units. Each of these source categories is now regulated under section 112 except for sulfuric acid production units. Yet sulfuric acid mist is emitted by other sources regulated under section 112, such as EGUs. *See* 76 Fed. Reg. 24976, 25,064 (May 3, 2011).

[341] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341)..

[342] Proposed National Emissions Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 69 Fed. Reg. 4652, 4685 (Jan. 30, 2004). In fact, however, a "literal" reading of section 111(d), both before and after the 1990 amendments would require section 111(d) regulation even for HAPs. That is because the exclusions for criteria pollutants and HAPs are structured as a mandate to regulate various classes of pollutants separated by an "or" in the alternative for which air quality criteria have not been issued or which is not included on a list published under section 7408(a) or 7412(b)(1)(A) of this title.

There is no evidence that it was Congress' intent to drastically roll back the protections in section 111(d). If Congress had intended such a radical departure from the statutory structure of the CAA, Congress would have made it explicit in the statute or some member would have at least mentioned it in the extensive legislative history of the 1990 amendments to the CAA. *See Chisom v. Roemer*, 501 U.S. 380, 396 n.23 (statutory interpretation that would work a "sweeping" and "unorthodox" change warrants skepticism). There is simply no evidence in the face of the statute or its legislative history that Congress intended such a major change in policy. Since Congress gave no indication regarding its intention to repeal the protections it established in 1970, reading such a repeal into an ambiguous statute would be strongly disfavored.[343] Here, as noted above, there are other provisions of the 1990 amendments—including section 112(d)(7)—that affirmatively indicate that Congress did *not* intend for section 112 regulations to displace or alter section 111 standards and Clean Air Act permitting programs.

A broad reading of the exclusion in the House amendment would create a hole in the Clean Air Act that is not only sweeping, but also highly anomalous. First, it is fanciful to believe Congress silently worked a major rollback of section 111(d) that is so jarringly discordant with the protective thrust of the 1990 Clean Air Act Amendments. It is simply not credible that Congress purposefully opened a major loophole—completely counter to the historic role of section 111(d)—that would leave dangerous air pollutants entirely unregulated, even as it strengthened environmental controls and systematically limited EPA's discretion to leave air pollution unregulated, purposely opened an unprecedented gap in the Clean Air Act's framework for stationary-source regulation. This reading also assumes that Congress created this unprecedented loophole surreptitiously, leaving major categories of pollutants wholly unregulated for the first time since 1970, at the same time that the supporters of the 1990 amendments uniformly praised the bill for *strengthening* the Clean Air Act.[344]

Second, this reading of the House amendment would insert an exclusion into section 111(d) that is unlike any other in the Clean Air Act. Congress has never allowed sources to release unlimited quantities of some pollutants simply because they must control *other* pollutants. *Cf. Desert Citizens Against Pollution v. EPA*, 699 F.3d 524, 527-28 (D.C. Cir. 2012) (holding that EPA reasonably rejected petitioners' interpretation of the Clean Air Act, which "would have the anomalous effect of changing the required stringency" for certain hazardous air pollutants at a given source "simply on the fortuity" of the source's other emissions).

Third, any attempt to actually implement the broad exclusion reveals additional anomalies. Even under the most expansive reading of the House amendment, pollutants are only excluded from regulation under 111(d) if EPA happens to regulate a source under section 112 first. If EPA first regulates a source

[343] The canon disfavoring implied repeals is discussed in section I.N.4.b.

[344] *See, e.g.*, Remarks of Rep. Dingell during the House Debate on the Conference Report, reprinted in 1990 CAA Leg. Hist. at 1187 ("America already has the toughest air quality laws in the world. With this act, we will be raising our standards even higher. We will also be fulfilling our responsibility to the American people who have told us that they are willing to make some sacrifices in pursuit of a cleaner environment."); Remarks of Rep. Green during House Debate on the Conference Report, reprinted in 1990 CAA Leg. Hist. at 1180 ("Mr. Speaker, the conference report before us today will help us to fulfill our promise to the American people of a clean, safe environment. Although some . . . may argue that the costs of enacting this bill are too great, I contend that the costs of not enacting clean air legislation this year are greater still.").

category under section 111(d) and then regulates the same source category under section 112, section 112(d)(7) provides that the HAP regulation does not diminish or replace the existing 111(d) standards. It is inconceivable that Congress would prohibit section 111(d) standards "simply on the fortuity" of EPA's timing for promulgating standards under section 112. *Accord Desert Citizens Against Pollution*, 699 F.3d at 527-28.

One company has developed a theory that attempts to explain how Congress could have intended to weaken section 111(d) in 1990: that Congress sought to strengthen section 112 without imposing "double regulation" on any source category.[345] This account is entirely unfounded. First of all, the Clean Air Act is full of examples of instances in which Congress, in the interest of protecting public health and welfare, subject pollution sources to multiple, overlapping requirements for the *same* pollutants. *See, e.g.*, 42 U.S.C. § 7475(a) (noting that sources subject to stationary source permitting requirements (and "best available control technology" requirement) also must comply with applicable increments and air standards under, as well as any applicable performance standards under section 111); *Id.* § 7416 (expressly preserving state regulation of stationary sources except where less stringent that Clean Air Act requirements). The 1990 legislative history makes clear that House members were aware that, under the House bill, stationary sources would continue to be regulated under multiple sections of the Clean Air Act.[346]

Most important, it is not "double regulation" for *different* pollutants from a single source category to be regulated under different regulatory programs. The notion that subjecting a source to regulation for some pollutant should immunize it from regulation as to other pollutants is odd and altogether alien to the CAA's protective design. The CAA framework often provides separate but complementary regulatory frameworks to address different types of pollution emitted by the same sources. Criteria pollutant standards also apply to the same sources whose emissions of hazardous air pollution are addressed by Section 112. For instance, the CAA's Prevention of Significant Deterioration program requires new major emitting facilities to use the "best available control technology" for criteria pollutants,[347] in addition to any standards promulgated under section 111(b) or 112. Nor do any of the CAA's stationary source provisions exclude sources from regulation because they are regulated under other federal environmental laws.[348]

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[345] Pet. for Extraordinary Writ, 6, *Murray Energy Corp. v. EPA*, No. 14-1112, (D.C. Cir. June 18, 2014) (Doc. 1498341).

[346] "Under H.R. 3030, states would be required to submit to EPA comprehensive permit programs for regulating stationary sources. The permitting requirements would extend to sources that are subject to new source performance standards, emission standards for hazardous air pollutants, requirements for preventing significant deterioration (PSD) of air quality, nonattainment new and existing source review, and acid deposition controls under Title V. They also apply to all sources of air pollution emitting over 100 tons a year." House Debate on H.R. 3030 (May 21, 1990), reprinted in 1990 CAA Leg. Hist. at 2566.

[347] 42 U.S.C. § 7475(a)(4).

[348] For certain sources regulated under other acts, the 1990 amendments required EPA to consider the efficacy of those regulations before issuing regulations under section 112. As amended in 1990, section 112 does not require EPA to regulate sources and substances regulated by the Nuclear Regulatory Commission if "the regulatory program established by the Nuclear Regulatory Commission pursuant to the Atomic Energy Act for such category or subcategory provides an ample margin of safety to protect the public health." 104 Stat. at 2542 (codified at 42

In summary, there is no reason to believe that the House amendment should be read to eviscerate section 111(d) and the House amendment can easily be read to preserve the gap-filling role of section 111(d) in the Clean Air Act's regulatory framework.

4. EPA can reasonably harmonize the two amendments to section 111(d) by adopting one of several reasonable interpretations of section 111(d), all of which require EPA to regulate non-HAP pollutants like CO_2.

a. Where one amendment clearly requires regulation of CO_2 emissions from EGUs and another amendment's treatment of such emissions is ambiguous, EPA must interpret the two amendments harmoniously.

The two amendments to section 111(d)(1)(A)(i) created a statutory ambiguity regarding the pollutants regulated under section 111(d). This ambiguity requires EPA's expert interpretation. *See Chevron,* 467 U.S. at 837.[349] EPA's expert interpretation of section 111(d) must be guided by the rule that "[t]he provisions of a text should be interpreted in a way that renders them, compatible, not contradictory."[350] EPA can reconcile the two amendments and interpret section 111(d) to require standards to address CO_2 emissions from EGUs.

b. Any conflict in the section 111(d) can be resolved by reasonably harmonizing the House and Senate amendments.

In the proposed rule, EPA has reasonably harmonized the text of the House and Senate amendments, through the following interpretation: "Where a source category is regulated under section 112, a section 111(d) standard of performance cannot be established to address any HAP listed under section 112(b) that may be emitted from that particular source category."[351] This interpretation follows the case law

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U.S.C. § 7412(d)(9)). In addition, Congress provided that "In the case of any category or subcategory of sources the air emissions of which are regulated under subtitle C of the Solid Waste Disposal Act, the Administrator shall take into account any regulations of such emissions which are promulgated under such subtitle and shall, to the maximum extent practicable and consistent with the provisions of this section, ensure that the requirements of such subtitle and this section are consistent." 104 Stat. at 2560 (codified at 42 U.S.C. § 7412(n)(7)).

[349] *See also Scialabba v. Cuellar de Osorio*, 134 S. Ct. 2191, 2203 (2014) (plurality opinion); *Id.* at 2219 n. 3 (Sotomayor, J., joined by Breyer, J., dissenting).

[350] Antonin Scalia and Bryan A. Garner, Reading Law: The Interpretation of Legal Texts (2012) at 180; *id.* ("The imperative of harmony among provisions is more categorical than most other canons of construction because it is invariably true that intelligent drafters do not contradict themselves (in the absence of duress). Hence there can be no justification for needlessly rendering provisions in conflict if they can be interpreted harmoniously."); s*ee also Ricci v. DeStefano*, 557 U.S. 557, 579-83 (2009) (where provisions of Title VII "could be in conflict absent a rule to reconcile them," Court adopted construction that "allows the [provision at issue] to work in a manner that is consistent with other provisions of Title VII"); *Watt v. Alaska*, 451 U.S. 259, 267 (1981) (construing potentially discordant statutory provisions "to give effect to each if [it] can do so while preserving their sense and purpose").

[351] EPA, "Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units" (2014) at 26. Over the span of a decade, EPA has interpreted the House and Senate amendments to section 111(d) consistently in each of the two rulemakings where they were at issue. Courts should give significant weight to EPA's unwavering interpretation of section 111(d). *See Good Samaritan Hospital v. Shalala*, 508 U.S. 402, 417 (1993) ("[T]he consistency of an agency's position is a factor in assessing the weight that position is due.").

regarding when and how to harmonize conflicting statutory provisions.

The D.C. Circuit has given EPA detailed instructions on "its responsibility to harmonize the statutory provisions" of the Clean Air Act when two provisions conflict and the statute does not plainly indicate which provision shall prevail. *See generally Citizens to Save Spencer Cnty v. EPA*, 600 F.2d 844 (D.C. Cir. 1979) (upholding EPA's harmonization of sections 165 and 168 of the 1977 Clean Air Act, which were drawn from "two bills originating in different Houses and containing provisions that, when combined, were inconsistent in respects never reconciled in conference"); *explained in NRDC v. Thomas*, 805 F.2d 410, 436 n.39 (D.C. Cir. 1986) ("[T]his court held that the agency had broad latitude to harmonize two Clean Air Act provisions that facially dealt with the same issue differently."); *see also Appalachian Power Co. v. EPA*, 249 F.3d 1032, 1043-44 (D.C. Cir. 2001) ("Lest it obtain a license to rewrite the statute" an agency alleging a scrivener's error "may deviate no further from the statute than is needed to protect congressional intent.") (quotations and citation omitted).

The court explained that "the maximum possible effect should be afforded to all statutory provisions . . . if the inconsistent provisions point generally in a common direction." *Spencer Cnty*, 600 F.2d at 870-71; *cf. United States v. Colon-Ortiz*, 866 F.2d 6 (1st Cir. 1989) (reading language out of a statute, where language inserted through a drafting error directly required the opposite outcome from what Congress had mandated elsewhere in the text). Harmonization of the House and Senate amendments to section 111(d) is appropriate because the two amendments point in a common direction. EPA has previously interpreted the House amendment to reflect the "House's apparent desire to increase the scope of EPA's authority under section 111(d) and to avoid duplicative regulation of HAP for a particular source category."[352] As EPA explained in its proposal for the Clean Air Mercury Rule, the House amendment can be reasonably interpreted to reflect a desire to expand the pollutants that EPA could regulate under section 111(d) so that EPA had authority to regulate HAPs emitted from source categories that were not actually being regulated under section 112 (such as existing area sources of HAPs that did not meet the statutory criterion in section 112(c)(3)). Similarly, the Senate amendment serves the general purposes of preserving EPA's authority to regulate non-HAPs under section 111(d) and avoiding duplicative regulation of HAPs. That is, the Senate's conforming amendment was necessary to give EPA authority to regulate any de-listed HAP under section 111(d). In addition, the Senate amendment avoids duplicative regulation of HAPs because it prevents EPA from regulating any HAP that is listed for regulation under section 112.

In harmonizing the House and Senate amendments to section 111(d), "it is appropriate for the agency . . . to look for guidance to the statute as a whole and to consider the underlying goals and purposes of the legislature in enacting the statute, while avoiding unnecessary hardship or surprise to affected parties." *Spencer County,* 600 F.2d at 871 (footnote omitted).

In the proposed rule, EPA has properly adhered to these principles in interpreting section 111(d). First, EPA concluded that it would be unreasonable to allow an expansive reading of the House amendment to prevail over the Senate amendment because such an interpretation would be inconsistent with "Congress' desire in the 1990 CAA Amendments to require the EPA to regulate more substances, and not to

[352] 69 Fed. Reg. at 4685.

eliminate the EPA's ability to regulate large categories of air pollutants."[353] Further, prohibiting the regulation of non-hazardous but dangerous pollutants from existing sources because hazardous emissions from those sources is appropriately regulated under Section 112 would expose American communities to health- and welfare-harming pollutants—clearly in conflict with Congress' effort in the Clean Air Act to protect Americans from harmful pollution. Thus, EPA has properly effectuated Congress' underlying goals and purposes in the Clean Air Act and subsequent amendments. Second, EPA reasoned that reading section 111(d) to exclude any air pollutant from a source category regulated under section 112 would be inconsistent with "the fact that the EPA has historically regulated non-hazardous air pollutants under section 111(d), even where those air pollutants were emitted from a source category actually regulated under section 112."[354] EPA's interpretation ensures the agency's continued ability to effectively protect public health and the environment, whereas interpreting the 1990 amendments to drastically curtail the agency's longstanding authority under section 111(d) would cause unexpected harm.

EPA's interpretation of section 111(d) is sound for several additional reasons. First, in accord with the interpretative canons against implied amendments and repeals, EPA has not read the 1990 amendments to repeal section 111(d)'s application to non-HAP emissions from sources regulated under section 112.

Reading the House amendment as certain court challengers have urged would deprive section 111(d) of most, if not all, of its traditional effect as a backstop that allows regulation of harmful pollution not covered under section 110 and 112. In the context of CO_2 emissions, this interpretation would not only preclude regulation of CO_2 emissions from the power sector; it would similarly bar any regulation in all other sectors of the nation's most significant sources of CO_2, because, like power plants, these categories too are regulated under section 112. EPA data confirms that—even outside the power sector—the chief emitters of CO_2 among stationary sources are subject to HAP regulation under section 112. According to EPA's Facility Level Information on GreenHouse gases Tool (FLIGHT), the non-power subsectors of the economy that emitted more than 10 million metric tons of CO_2 in 2013 were: Petroleum refineries; natural gas processing; natural gas transmission/compression; other petroleum and natural gas systems; petrochemical production; hydrogen production; ammonia production; other chemicals; iron and steel production, other metals; cement production; lime manufacturing; pulp and paper; other paper products; food processing; manufacturing; ethanol production; and other.[355] All of the major CO_2-emitting source categories in the defined subsectors on this list are regulated under section 112.[356] (The "other" category

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[353] EPA, "Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units" at 26-27.
[354] *Id.*
[355] *See* EPA FLIGHT, available at http://ghgdata.epa.gov/ghgp/main.do.
[356] 40 CFR §§ 63.640 et seq & 63.1560 et seq (NESHAPs for petroleum refineries, including units used for hydrogen production); §§ 63.760 et seq (NESHAP for oil and natural gas production facilities, including facilities that process natural gas and certain compressors); §§ 63.1270 et seq (NESHAP for natural gas transmission and storage facilities); subparts F, G, H & I (NESHAPs for the synthetic organic chemical manufacturing industry, including manufacturing of certain petrochemical products); §§ 63.11400 et seq (NESHAP for carbon black production area sources, which manufacture "petrochemical products"); §§ 63.2430 et seq (NESHAP for miscellaneous organic chemical manufacturing, which includes units classified under 1997 NAICS code 325, such as ammonia manufacturing); §§ 63.11494 et seq (NESHAP for chemical manufacturing area sources, which includes units classified under 1997 NAICS code 325); §§ 63.7680 et seq (NESHAP for iron and steel foundries); §§ 63.7780 et seq (NESHAP for integrated iron and steel foundries); §§ 63.10880 et seq (NESHAP for iron and steel

likely includes many source categories regulated under section 112).[357] Because of the sheer number of section 112-listed source categories, and the fact that they include most of the largest pollution sources, the suggested readings would likely have similarly dramatic effects on section 111(d)'s coverage as to other dangerous, but not hazardous, pollutants.

"[I]t is well settled that amendments by implication (like repeals by implication) are disfavored." *Natural Resources Defense Council, Inc. v. Hodel*, 865 F.2d 288, 318 (D.C. Cir. 1988). "[A]bsent a clearly expressed congressional intention, repeals by implication are not favored." *See Branch v. Smith*, 538 U.S. 254, 273 (2003); *see also Nat'l Ass'n of Home Builders v. Defenders of Wildlife*, 551 U.S. 644, 664 n.8 (2007) ("It does not matter whether this alteration is characterized as an amendment or a partial repeal."). Congress expressed no clear intention to drastically narrow the scope of section 111(d), given the plain text of the Senate amendment, the categorization of the House amendment as "Miscellaneous Guidance,"[358] the legislative history's silence on such a repeal, and the general thrust of the 1990 amendments to broaden regulation of air pollutants. EPA has properly refrained from interpreting the House amendment to require such a change because Congress "does not alter the fundamental details of a regulatory scheme in vague terms or ancillary provisions—it does not, one might say, hide elephants in mouseholes." *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 468 (2001).

Guided by the canon against implied repeals, the Supreme Court has held that an agency may read a later-enacted provision to not override an existing, express statutory mandate. *See Nat'l Ass'n of Home Builders*, 551 U.S. at 666 (approving a harmonizing interpretation of the Endangered Species Act, where one of the act's provisions directly conflicted with a clear mandate in the Clean Water Act). If there is any conflict between the pre-1990 text of the CAA and the 1990 amendments, EPA cannot assume Congress' intended to repeal longstanding mandates in the Act unless that intention is clearly expressed. In the 1990 amendments, Congress did not clearly signal its intent to repeal section 111(d)'s application to non-HAPs emitted by sources regulated under section 112, as the Senate amendment directs EPA to continue applying section 111(d) to these pollutants. EPA's interpretation of section 111(d) appropriately harmonizes the House and Senate amendments because it does not allow the House amendment to override the existing, express statutory mandate to regulate under section 111(d) any air pollutant that is not regulated under the NAAQS program or section 112.

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foundries area sources); §§ 63.1340 et seq (NESHAP for the Portland cement manufacturing industry); §§ 63.7080 et seq (NESHAP for lime manufacturing plants); §§ 63.440 et seq (NESHAP for the pulp and paper industry); §§ 63.7480 et seq (NESHAP for industrial, commercial, and institutional boilers and process heaters that are major sources of HAPs); §§ 63.11193 et seq (NESHAP for industrial, commercial, and institutional boilers and process heaters that are area sources of HAPs); §§ 63.6080 et seq (NESHAP for stationary combustion turbines); §§ 63.6580 et seq (NESHAP for reciprocating internal combustion engines). Boilers, turbines, engines, and process heaters are the main sources of CO_2 emissions from the food processing, manufacturing, and ethanol subsectors. *See* EPA, Who Reports?, http://www.ccdsupport.com/confluence/pages/viewpage.action?pageId=93290546 (explaining that facilities in the food processing, manufacturing, and ethanol subsectors are required to report emissions from stationary combustion if they meet an emissions threshold); 40 CFR § 98.30 ("Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.").

[357] For instance sources in the "other chemicals" category may be regulated under section 112 as part of the Chemical manufacturing Industry (area sources) source category, subpart VVVVVV or Miscellaneous Organic Chemical Production and Processing source category, subpart FFFF.

[358] Public Law 101–549, § 4108(g), 104 Stat. at 2467 (Nov. 15, 1990).

Similarly, *Watt v. Alaska* illustrates how the canon against implied repeals can guide EPA in its duty "to give effect to each [amendment] if [it] can do so while preserving their sense and purpose." *See* 451 U.S. 259, 267 (1981). That case examined two statutory provisions that, by their plain terms, gave conflicting instructions regarding the distribution of mineral revenue from all federal wildlife refuges.[359] The Court examined the later-enacted statute (the 1964 amendments to the Wildlife Refuge Revenue Sharing Act) for "clearly expressed congressional intention" to repeal the prior law, and found none. 451 U.S. at 273. The Court harmonized the conflicting provisions by reading the latter-enacted law to apply only to mineral revenues from the class of wildlife refuges that motivated congressional action in 1964. That is, the Court read the latter-enacted provision to establish the revenue-distribution formula for mineral revenues from lands acquired for wildlife refuges, reasoning that the purpose of the 1964 amendments was to facilitate acquisition of lands for wildlife refuges. 451 U.S. at 272.[360]

EPA's proposed interpretation of section 111(d) is entirely consistent with the Court's approach in *Watts.* EPA has interpreted the House amendment to refer to the class of pollutants that motivated the amendment: pollutants that were actually regulated under section 112. EPA has previously concluded that "the House's amendment to section 111(d) could reasonably reflect its effort to expand EPA's authority under section 111(d) for regulating pollutants emitted from particular source categories that are not being regulated under section 112."[361] This conclusion is supported by reading the House amendments to section 111(d) together with the House's proposed amendments to section 112. As discussed above, the House bill proposed giving EPA discretion to not regulate sources under section 112 in specific circumstances. While the House's proposed amendment to section 112 might have diminished the scope of regulation under that section, the House expanded the scope of section 111(d) and avoided creating a gap in the statutory framework for existing-source regulation. In this rulemaking, EPA has harmonized the House and Senate amendments to ensure the section 111(d) exclusion only applies to pollution that is actually regulated under section 112, thus giving an effect to both the House and Senate amendments that serves their respective purposes.

Second, EPA's proposed interpretation of section 111(d) is consistent with that section's role in the structure of the Clean Air Act. Section 111(d) provides for controlling dangerous existing-source pollution that would otherwise escape regulation, where EPA has regulated a source category under section 111(b) after finding that the category of sources "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." In short, the section fills gaps in the Act's framework for existing stationary sources that cause or contribute significantly to

[359] Under the Mineral Leasing Act of 1920, ninety percent of federal oil and gas revenue goes to the states and ten percent to the U.S. Treasury, whereas 1964 amendments to the Wildlife Refuge Revenue Sharing Act require twenty-five percent of the revenue from refuge resources (including "minerals") to goes to counties and seventy-five percent to the Department of Interior.

[360] The Court explained that the purpose of the 1964 amendments was to distribute more revenue to counties "as compensation for loss of taxable properties that have been acquired by the Federal wildlife refuge system." 451 U.S. at 270. The Court observed that "Congress might be expected to have mentioned a change" that would have increased federal revenues, especially when "Congress was concerned that the Department have sufficient funds to make the increased payments mandated by the amendments." 451 U.S. at 271.

[361] 70 Fed. Reg. at 16031.

harmful air pollution. Because section 112 does not require EPA to regulate HAPs from all sources,[362] some sources may emit dangerous amounts of hazardous pollutants even after EPA fully implements section 112. EPA's harmonization of the conflicting amendments would allow section 111(d) to play its gap-filling role for uncontrolled sources of hazardous air pollution (as well as for non-hazardous but dangerous pollutants emitted by sources that are regulated under Section 112).

Third, EPA's proposed approach is consistent with the canon that exemptions from regulation should be construed narrowly. See *Comm'r v. Clark*, 489 U.S. 726 (U.S. 1989). ("In construing provisions . . . in which a general statement of policy is qualified by an exception, we usually read the exception narrowly in order to preserve the primary operation of the provision"); *see Phillips, Inc.* v. *Walling*, 324 U.S. 490, 493 (1945) ("To extend an exemption to other than those plainly and unmistakably within its terms and spirit is to abuse the interpretative process and to frustrate the announced will of the people."). Here, because the amendments exempt certain pollutants from regulation, any ambiguity in the amendments should be construed in favor of limiting the range of pollutants that are exempted.

As the expert agency responsible for implementing the Clean Air Act, EPA is uniquely aware that narrowing the scope of section 111(d) would significantly harm public health and welfare, and that these harms are contrary to the purposes of the Act. *See* 42 U.S.C. § 7401(b)(1). A court would properly defer to EPA's regulatory expertise in determining whether EPA has reasonably harmonized the differing 1990 amendments to section 111(d). *See Nat'l Ass'n of Home Builders*, 551 U.S.at 666 (upholding EPA's expert harmonization of conflicting statutes, where the agency could not "simultaneously obey the differing mandates set forth in [the two provisions]" and "the statutory language . . . does not itself provide clear guidance as to which command must give way").

c. There are additional ways to harmonize the amendments that are consistent with the language and purpose of 111(d).

The most straightforward way of harmonizing the two amendments is to interpret the ambiguous House amendment to be consistent with the crystal-clear Senate amendment with respect to the question presented here—*i.e.*, EPA may, under section 111(d), regulate a non-HAP pollutant that is emitted from source category whose HAP emissions are regulated under section 112(d). As demonstrated above, there are multiple reasonable readings of section 111(d) as amended by the 1990 House language that would allow EPA to proceed with regulating CO_2 emissions from EGUs.

An alternative means of doing so would be to interpret the 1990 amendments as having included two different versions of 111(d), one reflecting the direction provided by House amendment and one the Senate amendment. Under this approach, the statute contains, with the Senate amendment, a separate, affirmative command to regulate all non-NAAQS, non-112(b)-listed pollutants. Each amendment mandates that EPA "*shall* prescribe regulations" for a set of air pollutants. 42 U.S.C. § 7411(d)(1) (emphasis added). Neither purports to *negate* regulatory obligations required by other provisions of the

[362] As discussed above, section 112 does not provide for regulation of certain area sources in the oil and gas sector and regulation of HAPs from many area sources is discretionary under section 112.

statute.[363] Thus, even if the House amendment is read to exclude EGUs (and to direct regulation of sources not regulated under 112), the two amendments set out compatible and additive commands to regulate (EPA must issue guidelines for all non-NAAQS pollutants not on a 112 pollutant list, and for sources of all non-NAAQS pollutants not regulated under 112). This reading allows EPA to "give effect to both" provisions, *see Morton v. Mancari*, 417 U.S. 535, 551 (1974), by doing what is required by either of the amendments.

Some commentators have suggested that the two 1990 amendments should both be given effect and that, if both are incorporated into the statute, the resulting language can be read to deny EPA authority to act here.[364] The premise that both amendments can be combined together and read as a single statutory command is problematic, since both provisions direct that the same language in the preexisting legislation be stricken; and neither amendment refers to or purports to take account of the other. There is no evidence that either house of Congress, in fact, legislated with the expectation that its change to section 111(d) would be combined with another change. The statute does not provide any definitive guidance for how to incorporate the different chambers' instructions; efforts to combine the language of the two amendments into a workable whole have a kind of artificiality in light of the strong indications that Congress did not actually make any decision that the two amendments were meant to operate together. But, contrary to the premise of the some supporters of this approach, the proper way to combine the amendments yields an approach that is grammatical, that attempts to heed Congress's instructions closely as possible; and that yields a result that is consonant with the statute.

The House and Senate amendments can be effectuated together as follows: First, both amendments would strike out the preexisting reference to "112(b)(1)(A)." The House amendment would then insert "or emitted from a source category" at the point in the text where "or 112(b)(1)(A)" was removed. The Senate amendment would require "112(b)" to be inserted at the point in the text where "112(b)(1)(A)" was removed, immediately after the original "or" that the House Amendment replaced. The combined section would read:

> The Administrator shall [establish emission guidelines] for any existing source for any air pollutant . . . which is not included on a list published under section . . . 112(b) emitted from a source category which is regulated under section 112 of this title.

The resulting amended statute would direct EPA to regulate all pollutants that are not criteria pollutants or emitted by source categories listed under section 112 and actually regulated under that section. Thus,

363 Indeed, the savings clause enacted as part of the 1990 amendments indicates that Congress recognized the importance of section 111(d) in controlling dangerous pollutants and did not want such regulation to be ousted lightly or by mere implication. That savings provision provides that "[n]o emission standard or other requirement promulgated under this section [112] shall be interpreted, construed, or applied to diminish or replace the requirements of a more stringent emission limitation or other applicable requirement established pursuant to Section 111 [and other programs]." 42 U.S.C. § 7412(d)(7).
364 See William J. Haun, The Clean Air Act As an Obstacle to the Environmental Protection Agency's Anticipated Attempt to Regulate Greenhouse Gas Emissions from Existing Power Plants 10-11 (Federalist Society 2013), available at http://www.fed-soc.org/library/doclib/20130311_HaunEPAWP.pdf.

reading the language added by the House and Senate amendments together yields a meaning that is coherent and maintains section 111(d)'s role in protecting human health and the environment.[365]

Any permissible harmonization of the House and Senate amendments must achieve the purpose of section 111(d), which is ensuring that dangerous pollution from existing industrial sources does not escape regulation. EPA cannot adopt an interpretation of section 111(d) that creates a gaping, inexplicable hole in the CAA's framework for regulating existing industrial sources. The commentators' alternative "harmonization" fails this basic requirement.

5. If harmonizing the amendments were not possible, any reasonable interpretation of section 111(d) would still allow EPA to regulate CO_2 emissions from EGUs.

If harmonizing the amendments were impossible, EPA could rely on several canons of statutory interpretation to resolve any conflict in section 111(d). Under any available rule of construction, section 111(d) controls dangerous non-HAP emissions regardless of whether they come from source categories that are subject to regulation under section 112. EPA's application of these canons to interpret conflicting provisions would be entitled to deference.[366]

First, as EPA observed, "[t]he ambiguities stem from apparent drafting errors that occurred during enactment of the 1990 CAA Amendments."[367] If conflicting language in section 111(d) is a result of a mistake, that mistake must have been the House amendment's exclusion of "sources" regulated under section 112 instead of "emissions" regulated under section 112. As described above, the apparent purpose of the House amendment to section 111(d) was to *avoid* creating a gap in the statutory structure for controlling emissions from existing sources; if the conference committee had adopted the House's amendments to section 112, an amendment to section 111(d) would have been necessary to ensure that EPA had authority to regulate existing-source HAP emissions that EPA chose to not regulate under section 112.

365 In contrast, the approach urged by Haun, supra, results in a formulation that would restrict section 111(d) to "any air pollutant . . . which is not included on a list published under section 7408(a) or 112(b) [Senate amendment] *or emitted from a source category which is regulated under section 112* [House amendment] of this title[.]" Haun at 10 (emphasis added by Haun). However such an interpretation would be properly interpreted, it clearly does not faithfully implement the amendments, since it results in smuggling in an extra "or" that Congress did not enact. The House Amendment struck one "or" (by striking "or section 112(b)(1)(A)"), and the Senate Amendment did not add any "or's." Yet the Haun approach manages to yield a new "or," by disregarding the instruction in the House amendment to strike the preexisting "or".

This purported harmonizing reading is also impermissible because it simply declines to give effect to the Senate amendment in this rulemaking. As discussed above, each amendment contains an exception to a regulatory mandate. But none of the exceptions in section 111(d) prohibit EPA action or otherwise detract from mandates to protect human health and the environment. This attempt at harmonization fails to give full effect to both amendments, as illustrated by its application to this rulemaking. Failure to issue guidelines for CO_2 emissions from EGUs would be a blatant violation of the Senate amendment's mandate to control all dangerous non-HAP, non-criteria pollutant emissions that are subject to standards under section 111(b).

366 *See Scialabba*, 134 S. Ct. at 2203 (plurality opinion); *Id.*. at 2219 n. 3 (Sotomayor, J., joined by Breyer, J., dissenting) (agreeing with plurality that where agency cannot "simultaneously obey" two statutory commands, "it is appropriate to defer to the agency's choice as to 'which command must give way'" (quotation marks omitted)).

367 79 Fed. Reg. at 34853.

Giving effect to the narrow interpretation of the House amendment does not promote the House's (and Congress') manifest intention to control all dangerous air pollution from existing sources. In contrast, the Senate amendment clearly retains EPA's authority to ensure effective regulation of dangerous non-HAP pollutants from existing sources under section 111(d) as a complement to regulation of HAPs under section 112. Accordingly, if EPA's attempts at harmonizing the amendments had failed, EPA could have shown that "Congress did not mean what it appears to have said" in the House amendment and that "as a matter of logic and statutory structure, it almost surely could not have meant it." *See Engine Mfrs. Ass'n v. EPA*, 88 F.3d 1075, 1089 (D.C. Cir. 1996). In such situations, EPA can interpret section 111(d) "by disregarding an obvious mistake." *See Bohac v. Dep't of Agric.*, 239 F.3d 1334, 1338 (Fed. Cir. 2001); *see also Am. Petroleum Inst. v. SEC,* 714 F.3d 1329, 1336-37 (D.C. Cir. 2013) (refusing to interpret a scrivener's error as indication that Congress intended to depart from a longstanding statutory scheme).[368]

If the two amendments were deemed incompatible, EPA could then choose which amendment is controlling, the agency has discretion in reading section 111(d) to effectuate congressional intent. *See Appalachian Power Co.*, 249 F.3d at 1044 n.3 ("[W]hen there are multiple ways of avoiding a statutory anomaly, all equally consistent with the intentions of the statute's drafters (and equally inconsistent with the statute's text), we accord standard *Chevron* step two deference to an agency's choice between such alternatives.") (quotation omitted); *see also Abdelqadar v. Gonzales*, 413 F.3d 668, 673 (7th Cir. 2005) (noting that judges cannot generally engage in "repair work" to rescue Congress from its drafting errors, "but agencies charged with superintending a comprehensive scheme traditionally have been afforded additional latitude"). In the context of the CAA's carefully crafted framework for controlling all dangerous emissions from existing sources, it would be implausible to read section 111(d) to let certain dangerous pollution go unregulated simply because EPA controlled *other* pollution from the same sources.

Second, if one of the amendments must prevail over the other, the canons against implied repeal and amendment hold that the Senate amendment must control.[369] EPA cannot presume that Congress intended to repeal its authority to regulate non-HAPs from sources regulated under section 112 unless Congress' intention to do so is "clear and manifest." *See Watt*, 451 U.S. at 267. Where there are two amendments to the same language, and those two amendments point in different directions, there is no "clear and manifest" intention. The Senate amendment is substantively similar to prior law and, therefore, should be given effect if EPA cannot discern Congress' clear and manifest intent to substantively change section

[368] If the inclusion of the House amendment did not create ambiguity in the statutory text, the plain language of the statute would control despite any errors in the drafting process. *See Lamie v. United States Trustee*, 540 U.S. 526, 542 (2004) ("If Congress enacted into law something different from what it intended, then it should amend the statute to conform it to its intent. It is beyond our province to rescue Congress from its drafting errors, and to provide for what we might think . . . is the preferred result.") (quotation omitted). But here, it is impossible for EPA to give effect to the House amendment without violating the mandate in the Senate amendment. As explained above, EPA may also respond to this scrivener's error by interpreting the House amendment in a way that gives it some effect but avoids an absurd result. *See United States ex rel. Holmes v. Consumer Ins. Group*, 318 F.3d 1199, 1209 (10th Cir. 2003) ("Under the doctrine of scrivener's error, a court may give an unusual (though not unheard-of) meaning to a word which, if given its normal meaning, would produce an absurd and arguably unconstitutional result.") (quotations omitted).

[369] These canons are discussed supra, section I.N.4.b, because they demonstrate that—if harmonization is possible—EPA's harmonization is reasonable.

111(d).[370]

Third, "[t]he established rule is that if there exists a conflict in the provisions of the same act, the last provision in point of arrangement must control." *Lodge 1858, American Fed. of Gov't Employees v. Webb*, 580 F.2d 496 (D.C. Cir. 1978). This rule applies regardless of whether the conflicting provisions are in the same statutory section. *See, e.g.*, *Merchants' Nat'l Bank v. United States*, 214 F. 200, 205 (2d Cir. 1914); *Mobile v. GSF Properties, Inc.*, 531 So. 2d 833, 837-38 (Ala. 1988).[371] Under this rule, the Senate amendment controls over the House amendment because it appears later in the Statutes at Large.

Finally, giving effect to the Senate amendment would allow EPA to avoid an absurd result. *See American Water Works Ass'n v. EPA*, 40 F.3d 1266, 1271 (D.C. Cir. 1994) ("where a literal reading of a statutory term would lead to absurd results, the term simply 'has no plain meaning … and is the proper subject of construction by the EPA and the courts'") (quoting *Chemical Mfrs. Assoc. v. Natural Resources Defense Council*, 470 U.S. 116, 126 (1985)). Reading section 111(d) to exclude from control the dangerous (though not hazardous) emissions from all sources regulated under section 112 would exclude myriad of the country's most significant sources of air pollution and profoundly undermine one of the Clean Air Act's basic mechanisms for protecting human health and the environment. Regardless of whether this broad exclusion is a "more natural reading" of the House amendment, EPA cannot give 111(d) a meaning that is at odds with Congressional intent. *See id.* (citing *Young v. Community Nutrition Inst.,* 476 U.S. 974, 980 (1986)). EPA cannot give effect to a reading of the House amendment that would render the Senate amendment ineffective in nearly any situation. *See United States v. Coatoam*, 245 F.3d 553, 557-58 (6th Cir. 2001) (refusing to adopt a defendant's literal reading of a statutory provision, which would have rendered another subsection surplusage in the vast majority of cases, where the government asserted that Congress made a drafting error when it amended the statute).

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370 Both the Senate amendment and then-effective law excluded the current list of HAPs from regulation under section 111(d).

371 The rationale for giving effect to the last provision in order of arrangement is that the last expression of the legislative will must prevail:

> [O]ne, for being earlier or later in position, must be deemed to render the other nugatory, or repeal it. The decisions are to the effect that the provision which is latest in position repeals the other. Being later in position, the prevailing provision is deemed a later expression of the legislative will. This rule and the reason for it have been criticized, because, all the provisions of an act being adopted at the same time, there is no priority in point of time on account of their relative positions in the statute. This is strictly true; but, in the reading of a bill, matter near the close may be presumed to revive the last consideration, and, if assented to, is a later conclusion.

Sutherland, Statutes and Statutory Construction (2d ed. 1904) vol. 2, § 349. This rationale applies despite the fact that the two relevant sections of the Statutes at Large amend the same statutory provision.

O. The Section 111(b) Standard for Modified and Reconstructed Sources is a Sufficient Predicate for the 111(d) Rule

Below, we demonstrate that the text, structure, and purpose of Section 111 unambiguously require state plans to cover any existing EGU that would be subject to a section 111(b) standard if it were to be newly built, modified, *or* reconstructed. Industry commenters' misguided view that EPA is barred from issuing emission guidelines for existing EGUs until it promulgates standards for *all* new sources is inconsistent with the statute and would frustrate the core purposes of section 111.

1. Section 111(d) Requires EPA to Regulate Carbon Emissions from any Existing EGU that Would be Subject to a Standard of Performance for Carbon Emissions if that Source Undertook Modification or Reconstruction.

Section 111(b) directs EPA to "list . . . categories of stationary sources" if a category "causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[372] It further directs EPA to establish "Federal standards of performance for new sources within such category."[373] Section 111(a) defines a "new source" as "any stationary source" that undertakes "construction *or* modification" after the proposal date of a standard of performance applicable to that source.[374] EPA's long-established interpretation of the statutory term "construction" includes the "reconstruction" of an existing source that is so extensive that the cost of the replaced components exceeds 50% of the fixed capital cost to construct a comparable new facility.[375] Section 111(d), in turn, directs EPA to ensure that state plans establish standards of performance for "any existing source . . . to which a standard of performance . . . would apply if [that] existing source were a new source." The statutory language is clear and unambiguous. Section 111(b) standards for any source fitting the statutory definition of "new"—which expressly includes modified sources and includes reconstructions through EPA's long-standing interpretation of the term "construction"—establish the category of sources for which Section 111(d) standards must be established for existing sources. Section 111(b) standards for newly constructed, modified, or reconstructed sources all equally fulfill this category-defining role for Section 111(d) standards.

EPA correctly concludes that section 111(d) requires the regulation of carbon pollution from any existing EGU that would, if it were "new", be covered by *any* 111(b) rulemaking establishing carbon pollution standards for EGUs.[376] Notwithstanding the unambiguous statutory language supporting EPA's conclusion, some industry commenters question whether the section 111(b) standards for modified and

[372] 42 U.S.C. § 7411(b)(1)(A).
[373] 42 U.S.C. § 7411(b)(1)(B).
[374] 42 U.S.C § 7411(a)(2) (defining "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.") (emphasis added).
[375] *See* 40 C.F.R. § 60.15; Part 60-Standards of Performance for New Stationary Sources Modification, Notification, and Reconstruction, 40 Fed. Reg. 58,416 (Dec. 16, 1975).
[376] *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,852 (June 18, 2014).

reconstructed EGUs would independently require regulation of carbon pollution from existing EGUs under section 111(d). In a joint comment filed in this docket,[377] a number of trade and business associations[378] claim that the structure of section 111 demonstrates that Congress intended that existing sources would not be regulated unless EPA first established standards of performance for *all* new sources (newly constructed, modified, and reconstructed).[379] These commenters further assert that such an interpretation of the statute is necessary to avoid the "nonsensical outcome" where existing sources become subject to regulation before EPA finalizes standards for newly constructed sources.[380]

Such arguments ignore the text of section 111(d), which compels EPA to regulate existing sources that would be covered by a section 111(b) standard if they were "new sources"— a term that expressly encompasses modified *or* newly constructed sources, and encompasses "reconstructed" sources under EPA's well-settled interpretation of the term "construction" in the statutory definition of "new source."[381] Nothing in the text of section 111(d) states or implies that EPA must defer regulation of existing sources that would be subject to a section 111(b) standard if they undertook modification or reconstruction until such time as EPA has established a section 111(b) standard for newly constructed sources in the same category. On the contrary, the text and structure of section 111 demonstrate that Congress was urgently concerned with identifying and regulating categories of sources contributing significantly to air pollution reasonably "anticipated to endanger public health or welfare."[382] Delaying regulation of existing sources until after the promulgation of standards for all possible forms of "new" sources within a category would be inconsistent with ensuring that all sources of dangerous pollution—even existing sources— are controlled once identified. Finally, the regulation of existing sources under 111(d) while 111(b) standards for newly constructed sources are pending does not produce a "nonsensical outcome."

The text and structure of section 111 demonstrate that a category of sources must be subject to 111(d) regulation if the category would be subject to *any* 111(b) standard. As noted above, section 111(a) explicitly provides that a "new source" includes "any stationary source" that undertakes "construction *or* modification" after the proposal date of a standard of performance applicable to that source.[383] Section 111(d), in turn, directs EPA to ensure that state plans establish standards of performance for "any existing source . . . to which a standard of performance . . . would apply if [that] existing source were a new source." This structure clearly contemplates that the regulation of existing sources in a category is

[377] Docket ID No. EPA–HQ–OAR–2013–0603; 79 Fed. Reg. 34,960 (June 18, 2014).
[378] The organizations include The American Chemistry Council, American Forest & Paper Association, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, American Petroleum Institute, American Wood Council, Brick Industry Association, Corn Refiners Association, Council of Industrial Boiler Owners, Electricity Consumers Resource Council, the NationalAssociation of Manufacturers, National Lime Association, National Oilseed Processors Association, Portland Cement Association, The Fertilizer Institute, and the U.S. Chamber of Commerce.
[379] *See* Comment submitted by Greg Bertelsen, National Association of Manufacturers (NAM), Docket ID. No. EPA-HQ-OAR-2013-0603-0192 (Oct. 16, 2014), at 11-12.
[380] *See id.*
[381] *See* 42 U.S.C. § 7411(a)(2); 40 C.F.R. § 60.15; Part 60-Standards of Performance for New Stationary Sources Modification, Notification, and Reconstruction, 40 Fed. Reg. 58,416 (Dec. 16, 1975).
[382] *See* 42 U.S.C. 7411(b)(1)(A).
[383] 42 U.S.C § 7411(a)(2) (defining "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.") (emphasis added).

triggered by the potential applicability of section 111(b) standards to *either* newly constructed *or* modified sources in that same category. Although Congress did not expressly include reconstructions in the definition of "new source," it is nonetheless clear that Congress contemplated more than one type of "new" source would be subject to 111(b) standards, and therefore that 111(d) standards for a category could be required as a result of EPA establishing 111(b) standards for any of the multiple possible types of "new source." Consequently, now that EPA has proposed standards of performance for modified and reconstructed EGUs, existing EGUs would satisfy the statutory and regulatory definitions of a "new source" if they were to undertake modification or reconstruction. The modified and reconstructed source standards thus serve as a separate and wholly sufficient predicate for the 111(d) standards for existing sources.

By contrast, the statutory text provides no support for the alternative view advanced by some industry commenters, which is that state plans may only regulate existing EGUs after promulgation of standards for new, modified, *and* reconstructed sources of the same type. If Congress had intended that section 111(d) requirements only apply to sources for which *all* possible section 111(b) standards have been promulgated, it would have so stated. Instead, Congress provided that a "new source" is one that undertakes "construction *or* modification" after the proposal of an applicable standard of performance, and did not require that EPA establish a single standard of performance for the different contemplated forms of "new" sources. On the contrary, the statute expressly provides EPA with discretion to establish different standards under section 111(b) for the multiple possible types of "new" sources, by authorizing EPA to distinguish between different types and classes of sources within a category.[384] Thus, because Congress clearly established that there are multiple avenues through which a source may be "new" for the purpose of applicability of a 111(b) standard, the mandate in section 111(d) to regulate existing sources that would be subject to 111(b) standards if they are "new" is triggered by an applicable standard of performance for either newly constructed, reconstructed, or modified sources.

EPA's position is also fully consistent with the purpose of section 111, whereas the position advanced by industry commenters would undermine the statutory purpose. The purpose of section 111, as demonstrated by its text and structure, is curbing the emission of harmful pollutants from *categories* of stationary sources identified as significantly contributing to dangerous pollution; this purpose is fulfilled through a statutory structure that ensures that air pollution emitted by both new and existing sources in those categories are regulated. To address pollution from the category effectively, and to fulfill Section 111's technology-forcing mandate, EPA *must* promptly establish standards under section 111(b) for newly constructed, reconstructed, and modified sources in each listed category.[385] Yet where existing sources are responsible for the vast majority of the pollution generated by the category, as is the case with respect to carbon pollution from power plants (and many other source types), establishing section 111(d) regulation is an even more urgent task to fulfill the Act's fundamental purpose of protecting human health and welfare. For this reason, section 111(d) requires EPA to ensure that standards of performance under section 111(d) are established for existing sources, which are defined as "any stationary source other than

[384] *See* 42 U.S.C. § 111(b)(2)("The Administrator may distinguish among classes, types, and sizes within categories of new sources for the purpose of establishing [111(b)] standards.")
[385] 42 U.S.C. § 7411(b)(1)(B).

a new source."[386] Because the goal of this statutory framework is ultimately to ensure that Americans are protected from dangerous air pollution through standards addressing the entire category, it would frustrate that purpose to delay the regulation of existing sources until standards of performance have been established for *all* forms of new sources. Conversely, interpreting section 111(d) as requiring the regulation of existing sources that would be subject to a 111(b) standard of performance if they were *any* form of "new source" is consistent with section 111's clear purpose of ensuring that emissions from the entire category become subject to pollution standards.

Contrary to industry assertions, the regulation of existing sources under 111(d) while 111(b) standards for newly constructed sources are pending does not produce a "nonsensical outcome." EPA's approach ensures that existing sources, responsible for the vast majority of the carbon pollution generated by this category of sources, would be subject to standards requiring the abatement of that pollution once there is a section 111(b) standard for any "new source" of the same type. This approach is wholly consistent with the unambiguous text of section 111(d) and comports with the Act's fundamental purpose of protecting Americans from dangerous air pollution.

2. EPA's Duty to Establish Emission Guidelines for Existing Sources is Not Altered By the Continuing Applicability of 111(d) Requirements to Sources that Subsequently Elect to Modify or Reconstruct

EPA has properly recognized that its duty to issue emission guidelines for existing sources now that the Agency has proposed standards of performance for reconstructed or modified sources is not affected by the clarification that 111(d) requirements continue to apply to sources that modify or reconstruct after becoming subject to 111(d) state plan requirements. Contrary to industry arguments,[387] the modified and reconstructed standard of performance is a sufficient predicate for the regulation of existing sources under 111(d) regardless of the continued applicability of 111(d) plan requirements to sources that modify or reconstruct because the statutory definitions of "new" and "existing" sources are relevant only to the *initial applicability* of the respective standards. Consequently, a source can be subject to ongoing 111(d) requirements because it was *formerly* an existing source, even though the source has also become subject to a 111(b) standard by meeting the section 111(a)(2) definition of a "new" source.

Industry comments rely on the flawed assumption that the ongoing applicability of 111(d) requirements to modified or reconstructed sources rests on the modified or reconstructed sources *continuing* to be "existing" sources as defined in section 111(a)(6). Specifically, the National Mining Association commented that "[i]f EPA intends to continue to subject sources that modify or reconstruct to the CAA section 111(d) plan, it must be because EPA considers modified and reconstructed sources to be existing sources for some reason."[388] Based on this conclusion, NMA asserted that if the modified and reconstructed sources are actually existing sources, the proposed rule cannot be a predicate for regulation

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[387] *See* Comment submitted by National Mining Association, Docket ID. No. EPA-HQ-OAR-2013-0603-0272 (Oct. 15, 2014) at 5-7.
[388] *Id.* at 7.

under the command of section 111(d)(1)(A).[389] As EDF has explained in its comment on the proposed 111(b) standards for modified and reconstructed EGUs, section 111 is ambiguous as to whether 111(d) requirements continue to apply to a source that modifies or reconstructs. A reasonable interpretation of this ambiguity is that the definitions of "new" and "existing" source are relevant to the question of what type of standard of performance initially applies to a source, but do not constrain whether that standard continues to apply once the same source meets the requirements for applicability of another standard under section 111. Consequently, the question of whether a source *continues* to be subject to a standard is separate from whether that source initially meets the statutory definition of "new source" or "existing source."

Under EPA's interpretation of the statutory ambiguity, sources that modify or reconstruct continue to be subject to the 111(d) standard not because they are *still* "existing" sources, but rather because the statute does not relieve sources of requirements that were imposed on them at an earlier time, when they *were* "existing" sources. Indeed, in the specific context of the Clean Power Plan, excluding modified or reconstructed sources from a section 111(d) state plan would not ensure that the standards for such sources reflect the "best system of emission reduction," as section 111(a)(1) requires. As EDF explained in our comments on this proposed rule, the BSER for modified and reconstructed EGUs necessarily encompasses not just systems such as heat rate improvements, considered in the proposed standards here, but also the potential to reduce carbon pollution through shifts in utilization towards lower- or zero-emitting generation and demand-side energy efficiency. This is the system that EPA has identified as the "best system of emission reduction" in the proposed emission guidelines for all existing plants because it achieves the greatest pollution reductions considering cost, energy requirements, and other health and environmental outcomes. The modification or reconstruction of an existing fossil fuel-fired EGU does not alter the fact that the flexible, cost-effective system of emission reduction identified by EPA remains the best system for that plant, achieving the greatest emission reductions considering cost and the other statutory factors. Rather, the modification or reconstruction means that there is an additional component of the best system for that source to ensure that the section 111(b) standard serves its technology-forcing, emission-reducing role when significant investments are being made in these plants.

Because EPA's interpretation that 111(d) requirements continue to apply to sources that later modify or reconstruct does not rely on defining those sources as continuing to be "existing" sources, the proposed 111(b) standards of performance for modified and reconstructed EGUs are in no way standards for "existing" sources. Thus, because the proposed standards are clearly standards of performance for "new" sources, fitting the definition of section 111(a)(2), the standards for modified and reconstructed EGUs are a sufficient predicate for the regulation of existing sources under section 111(d).

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[389] *Id.* at 7.

II. EPA Must Ensure that Modified and Reconstructed EGUs Achieve Emission Reductions that Reflect the BSER and Do Not Compromise the Integrity of Section 111(d) State Plans.

A critical issue raised in the proposed rule is whether fossil fuel-fired EGUs covered by state plans issued under section 111(d) must continue to comply with those state plans after undertaking a modification or reconstruction. EDF strongly believes that section 111(d) requirements must apply to all fossil fuel-fired EGUs that were "existing sources" as of the date the emission guidelines were proposed (June 18, 2014), regardless of whether those fossil fuel-fired EGUs subsequently modify or reconstruct. Allowing EGUs to exempt themselves from section 111(d) by modifying or reconstructing would not assure that these units are subject to a "standard for emissions of air pollutants which reflects . . . the best system of emission reduction," as required by sections 111(a) and (b) of the Clean Air Act.[390] For modified and reconstructed EGUs, the "best system of emission reduction" necessarily encompasses not just systems such as heat rate improvements, considered in the proposed standards here, but also the potential for shifts in utilization away from higher-emitting and towards lower- or zero- emitting generation and demand-side energy efficiency to reduce carbon pollution from these plants. This is the system that EPA has identified as the "best" system of emission reduction in the proposed emission guidelines for all existing plants because it achieves the greatest pollution reductions considering cost, energy requirements, and other health and environmental outcomes. The modification or reconstruction of an existing fossil fuel-fired EGU does not alter the fact that the flexible, cost-effective system of emission reduction identified by EPA remains the best system for that plant, achieving the greatest emission reductions considering cost and the other statutory factors—in combination with the additional BSER components described in these comments to ensure that the section 111(b) standard serves its technology-forcing, emission-reducing role when significant investments are being made in these plants.

Moreover, as EPA recognizes in the proposed emission guidelines,[391] an approach under which modified or reconstructed EGUs are no longer subject to section 111(d) would create perverse economic incentives for units to undertake modifications with the objective of avoiding emission reductions that would be

[390] Section 111(b) of the Clean Air Act requires that EPA establish "standards of performance" for "new sources," which are defined under section 111(a) to include sources that undertake modifications after the proposed date of an applicable standard of performance. Under section 111(a)(1) of the Clean Air Act, such standards of performance *must* "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." For modified and reconstructed EGUs, this "best system" includes not just the technology-based standards that EPA has included in the proposed rule, but also the same system-based "building blocks" that EPA determined to be the BSER for existing sources in its proposed Clean Power Plan.

[391] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,904 (proposed June 18, 2014) ("The EPA is concerned that owners or operators or units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d).").

required under their state plans. And as EPA also acknowledges, it would be highly disruptive for state plans—which in many cases will be based on the state-wide average performance of currently existing EGUs—if EGUs that were "existing" sources when the plan was designed were suddenly excluded from the plan upon modifying or reconstructing.

Maintaining the applicability of section 111(d) state plans to modified and reconstructed EGUs is not only supported by these compelling policy considerations, it is also consistent with the text of the Clean Air Act—as we describe in further detail below. For these reasons, we strongly support EPA's determination that fossil fuel-fired EGUs already subject to a section 111(d) state plan must continue to comply with those plans in the event those facilities later modify or reconstruct. In addition, we recommend that EPA extend this interpretation to ensure that *all* fossil fuel EGUs that are currently "existing sources" remain covered by section 111(d) state plans, regardless of whether or when they modify or reconstruct. Lastly, as a supplement to EPA's proposed approach, we also suggest two alternative mechanisms by which EPA could assure that modified and reconstructed EGUs achieve emission reductions consistent with the flexible, system-based BSER identified in the proposed Clean Power Plan: 1) committing to review the New Source Performance Standards (NSPS) for new, modified, and reconstructed EGUs at intervals shorter than the eight-year review period prescribed by the statute, such that all such units would promptly become "existing sources" subject to section 111(d); 2) including emissions from modified and reconstructed EGUs when determining compliance with the state goals under section 111(d).

A. EPA Has Reasonably Interpreted Section 111 as Requiring Sources to Continue to Comply with Section 111(d) State Plan Requirements Following a Modification or Reconstruction.

EPA's proposed rule correctly notes that section 111(d) is ambiguous as to whether state plan requirements must continue to apply to a source that modifies or reconstructs. In the preamble to the proposed emission guidelines for existing power plants, EPA explains that section 111 defines "new" and "existing" sources, and that section 111(d) clearly contemplates the submission of state plans that "establish[]" standards of performance for existing sources. However, the statute "does not say whether, once the EPA has approved a state plan that establishes a standard of performance for a given source, that standard is lifted if the source ceases to be an existing source."[392] EPA proposes to resolve this ambiguity by specifying that section 111(d) requires existing sources covered in a state plan to remain subject to the requirements of CAA section 111(d) plan after modifying or reconstructing.[393] EPA provides two reasons for this determination: (1) to avoid disruption and uncertainty as to which units will be part of state programs under a 111(d) plan; and (2) to avoid creating perverse incentives for sources to modify or reconstruct to escape 111(d) plan requirements, which could potentially be more stringent than 111(b) obligations.[394]

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[392] 79 Fed. Reg. at 34,903-04.
[393] *Id.* at 34,904.
[394] *Id.*

EPA's position is a reasonable resolution of the ambiguous language of section 111(d), and is therefore due deference under *Chevron v. Natural Resources Defense Council*.[395] As EPA notes, the plain language of section 111(d) requires only that EPA create a procedure for states to submit plans that "establish[] standards of performance" for any "existing source." This language does not clearly state *when* a source is to be considered "existing" for purposes of defining the scope of the state plan. A requirement that a state plan must "establish[]" performance standards for any source that is "existing" *at the time emission guidelines are proposed or at the time of plan submittal* is consistent with the text of the statute, and reasonable given the particular structure of the Clean Power Plan. Under this interpretation, the function of the section 111(d) reference to existing sources is to specify the group of existing sources that become subject to state plans pursuant to EPA emission guidelines, but is silent on whether the later triggering of a section 111(b) standard affects the on-going applicability of the 111(d) standards to which that source is subject under the state plan.

EPA's determination on this issue is also consistent with past practice. On at least two occasions, EPA addressed the applicability of state plans to modified and reconstructed sources when it finalized revisions to NSPS and emission guidelines. In these rulemaking actions, EPA provided that new sources—including modified and reconstructed sources—are simultaneously subject to both state plans adopted under section 111(d) and EPA-issued performance standards under section 111(b).[396] In both of these rules, EPA promulgated a revised NSPS at the same time that it promulgated revised emission guidelines; although sources subject to the earlier NSPS were not "new" units for the purpose of the revised NSPS, the sources continued to be "new" for the purpose of the earlier NSPS, while simultaneously being "existing" sources with respect to the revised emission standards. For example, in 2009, EPA issued a final rule amending the NSPS and emission guidelines for hazardous, medical, and infectious waste incinerators (HMIWI), which were both initially promulgated in 1997. In that rule, EPA noted that the 2009 revised emission guidelines were, for some pollutants, more stringent than the NSPS that applied to sources constructed or modified between 1997 and 2009. Accordingly, EPA amended the 1997 NSPS to require that those units comply with the more stringent of the pollutant specific limitations in either the emission guideline or the 1997 NSPS, thereby simultaneously subjecting some sources to both the revised emission guideline and the 1997 NSPS.[397] EPA adopted a similar approach in 1995, when it amended the

[395] 467 U.S. 837, 842–844 (1984); *See also EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1604 (U.S. 2014) ("Under *Chevron*, we read Congress' silence as a delegation of authority to EPA to select from among reasonable options.").
[396] *See, e.g.*, 74 Fed. Reg. 51,368, 51,374 (Oct. 6, 2009) (hazardous, medical, and infectious waste incinerators subject to 1997 NSPS must continue to comply with 1997 NSPS requirements that are more stringent than 2009 emission guidelines for sources existing as of 2009); 60 Fed. Reg. 65,382, 65382 (Dec. 19, 1995) (municipal waste combustors remain subject to 1991 NSPS and must also comply with 1995 emission guidelines for units existing as of 1995). Although both of these examples are in the context of joint section 129/111 rulemaking, that context does not diminish their relevance to section 111 rulemakings. Under joint 129/111 standard-setting, the effect of the section 111(a) definitions on the applicability of NSPS to modified units is the same as for rulemakings under section 111. *See Davis County Solid Waste Mgmt. v. United States EPA*, 108 F.3d 1454 (D.C. Cir. 1997) ("Although section 129 does not specifically state that the NSPS applies to modified units, it excludes modified units from the definition of existing units and provides that the NSPS shall be issued pursuant to 42 U.S.C. § 7411, which defines new sources as those sources modification or construction of which occurs after publication or proposal of regulations, whichever is earlier."); 42 U.S.C. §§ 129(a)(1), 129(g)(3); *see also* 42 U.S.C. § 7411(a)(2).
[397] *See* 74 Fed. Reg. at 51,374.

NSPS and emission guidelines for municipal waste combustors.[398] These examples both demonstrate that "new sources" can simultaneously be subject to section 111(b) performance standards and section 111(d) state plans, as well as EPA's practice of requiring that sources comply with the most stringent of overlapping section 111(b) and 111(d) standards.

It is also worth noting that under prior standards of performance for reconstructed sources, those sources would remain existing sources (despite undertaking a modification and becoming a (b) source) if the required feasibility review demonstrated that the source could not meet the reconstructed source standard.[399] This reinforces the interlinked and complementary roles of the section 111(d) and (b) standards for reconstructed units. When undertaking a reconstruction and making major investments in infrastructure, the reconstructed source standard ensures that the most rigorous emission reduction outcomes are achieved if they are feasible—but the existing source standard applies as a backstop in cases where meeting the reconstructed standard is not feasible. In the context of the carbon pollution standards, the situation is analogous—the section 111(b) standard for reconstructed units must ensure that sources are deploying the best technologies available as these major infrastructure investments are being made, while at the same time the continued participation in the section 111(d) program ensures that the sources remain subject to the emission reduction framework that can meet the statutory requirements of maximizing emission reductions considering cost, energy requirements, and impacts on other health and environmental outcomes. In both cases the applicability of the section 111(b) and (d) standards works to ensure that sources are subject to performance standards reflecting the best system of emission reduction that has been adequately demonstrated, maximizing emission reductions considering the other statutory factors.

As noted above, this interpretation of the ambiguity in section 111(d) is also necessary to ensure that modified and reconstructed sources continue to remain subject to standards that reflect the "best system of emission reduction," as required for all standards of performance under section 111. EPA's proposed emission guidelines for existing EGUs rest on the determination that a flexible, broad emission reduction system—including efficiency improvements at existing EGUs, shifts to low and zero-emitting resources, and demand-side energy efficiency improvements—constitute the "best system of emission reduction." That determination remains no less true for existing EGUs that subsequently modify or reconstruct. To allow existing EGUs to avoid requirements under a section 111(d) state plan by modifying or reconstructing would potentially lead to higher emissions from those EGUs – a result that is completely inconsistent with the proper identification of the "best system of emission reduction" for those sources. The existence of a standard for sources undergoing major changes reflects Congressional recognition of the fact that such changes and investments create an opening for emissions performance to be improved. Indeed, the courts have understood that the purpose of standards under section 111(b) is to ensure that the

[398] *See* 60 Fed. Reg. at 65,382 ("Subpart Ea is applicable to MWC units . . . for which construction, modification, or reconstruction was commenced after December 20, 1989 . . . It should be noted that plants that are subject to subpart Ea will also be subject to the emission guidelines contained in subpart Cb, which apply to plants constructed on or before September 20, 1994."). The 1995 regulation provided that MWCs subject to the 1991 NSPS would also be subject to the new 1995 rules governing existing sources, which superseded the 1991 guidelines for existing sources. *See* 40 C.F.R. part 60, subparts Cb and Ea.
[399] 40 C.F.R. § 60.15(b).

emission performance of sources is improved when major investments are being made in infrastructure.[400] Because EPA's proposed interpretation provides that modified sources will be subject to emission controls that are *additional* to the level of control already imposed under the 111(d) plan, it is consistent with the pollution-mitigating framework of section 111 recognized by courts.

Lastly, as EPA recognizes, its determination that state plans continue to apply to modified and reconstructed EGUs is necessary to avoid disrupting state plans submitted under the proposed emission guidelines. The proposed emission guidelines establish average performance standards for existing EGUs in each state, which are premised on the performance of EGUs that were "existing" as of January 8, 2014. If certain existing EGUs were to exit this system by modifying or reconstructing, states and utilities could potentially have difficulty complying with these goals. Indeed, state goals would potentially need to be recalculated or constantly adjusted as EGUs leave the "pool" of existing sources by modifying. Furthermore, the creation of a group of existing fossil-fired EGUs that are not subject to the same carbon reduction signal as EGUs governed by the state plan would potentially lead to market distortions and result in "leakage" of emissions, as generation from EGUs governed by the state plan is displaced by increased generation at modified/reconstructed units rather than low or zero-emission generation. By clarifying that sources subject to section 111(d) plan requirements must continue to comply with those requirements after becoming subject to the 111(b) standard, EPA has avoided creating a perverse incentive that would undermine the effectiveness of the existing source carbon pollution standards.

In summary, section 111 is ambiguous as to whether existing sources continue to be subject to 111(d) requirements after modification or reconstruction makes that source subject to section 111(b) standards. EPA has reasonably resolved this ambiguity by concluding that state plans must continue to apply section 111(d) carbon pollution standards to those sources regardless of a later modification or reconstruction. This interpretation is consistent with the statutory text, EPA's past practice, and judicial interpretations of the framework of section 111, and is necessary to avoid perverse incentives that could undermine the regulatory scheme and weaken limits on carbon pollution.

B. EPA Should Provide that Sources that Modify Prior to 111(d) State Plan Submission Are Subject to the 111(d) State Plan Requirements.

Whereas EPA has clearly stated that sources that modify or reconstruct *after* becoming subject to a section 111(d) state plan remain subject to the state plan requirements,[401] the Agency has not made it clear that sources modifying or reconstructing *prior* to submission of a state plan are subject to section 111(d) state plan requirements. Although one part of the proposal suggests that all modifications and reconstructions are subject to section 111(d),[402] another portion of the proposal asserts that sources that modify or reconstruct after plan submission will continue to be subject to the plan.[403] EPA should

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[400] *See Sierra Club v. Costle*, 657 F.2d 298, 325 (D.C. Cir. 1981) ("[Section 111(b)] standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install, thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth.").
[401] *See* 79 Fed. Reg. at 34,903-04.
[402] *See* 79 Fed. Reg. at 34,965/1.
[403] *See* 79 Fed. Reg. at 34,963/1.

expressly provide that sources modifying or reconstructing after the proposal of its emission guidelines and prior to state plan submission are still sources for which state plans must establish performance standards under section 111(d).

Sources that modify or reconstruct prior to submission of a section 111(d) plan should be subject to section 111(d) plan requirements for the same policy reasons described in the preceding section of these comments—most significantly, because the existing source "best system of emission reduction" remains the system that will ensure the greatest pollution reductions from these EGUs considering cost and other statutory factors. Further, as noted above, allowing such modified or reconstructed EGUs to exempt themselves from section 111(d) would potentially undermine the stringency of state plans by allowing "leakage" to modified or reconstructed sources. Moreover, such an approach would potentially require the recalculation of state goals and disrupt the development of state plans, all of which are premised on securing reductions from EGUs that were "existing" as of January 8, 2014.

Requiring, in the finalization of these standards, that state plans apply to all sources that were "existing" as of the date the emission guidelines were proposed is also consistent with the statutory text. As described above, section 111(d) vests EPA with broad authority to establish procedures governing the submission and content of state plans that "establish[]" performance standards for "any existing source." Also as noted above, the statute does not clearly delineate the point in time at which a source should be considered to be "existing" and therefore within the scope of a state plan. However, EPA's proposed emission guidelines set state-wide goals that are based on the "best system of emission reduction" for all EGUs that were under construction or in operation as of January 8, 2014. Accordingly, it is reasonable and consistent with the statute for EPA —acting under its authority to establish minimum requirements for state plans, including determining the scope of those plans—to require that state plans establish performance standards for the same set of existing sources addressed in the emission guidelines.

C. EPA Can Consider Additional Measures to Ensure that Modifications and Reconstructions Do Not Undermine State Goals Under Section 111(d).

Although EDF strongly supports EPA's proposal that section 111(d) standards remain applicable to sources that modify or reconstruct, we note that there are at least two additional mechanisms EPA can consider to ensure that the proposed emission guidelines for existing EGUs are coordinated effectively with the proposed standards for modified and reconstructed EGUs.

1. EPA Could Undertake Frequent Review of the NSPS.

Although section 111(b) of the Clean Air Act clearly requires that carbon pollution standards for new sources be reviewed at least once every eight years,[404] EPA could establish a more frequent schedule for revision (such as once every five years) in recognition of the rapid evolution of methods to reduce carbon pollution from the power sector. A more frequent schedule for revision of the carbon pollution standards for new, modified, and reconstructed EGUs would ensure that sources that modify or reconstruct quickly come into compliance with section 111(d), consistent with EPA's past practice of

[404] 42 U.S.C. § 7411(b)(1)(B).

subjecting modified and reconstructed sources to state plans upon revision of an applicable NSPS.[405] In so doing, EPA would also reduce potential incentives for EGUs to modify or reconstruct for the purpose of avoiding state plan requirements under section 111(d).

2. EPA Could Require that Emissions from Modified and Reconstructed Units "Count" When Determining State Compliance with Section 111(d).

Alternatively, in the event that modified or reconstructed EGUs are excluded from state plans under section 111(d), EPA could require that emissions from those units continue to be "counted" when determining whether states have complied with the goals promulgated in the emission guidelines. Such a requirement would not impose any section 111(d) obligations on the modified or reconstructed EGUs, but would ensure that limits on carbon pollution under section 111(d) are not undermined by "leakage" resulting from increased emissions at those modified or reconstructed EGUs. In practice, state regulators would have a strong incentive to ensure that modified and reconstructed units are subject to either state plans or to additional emission limitations in order to ensure compliance with the section 111(d) goals.

This approach is not precluded by the broad language of section 111(d), which affords EPA significant discretion to determine *how* states demonstrate compliance with an emission guideline. Moreover, EPA could justify this approach as necessary to ensure an accurate accounting of emissions from affected EGUs. This is because generation from any EGU that modifies or reconstructs would effectively be substituting for generation from the same EGU prior to its modification or reconstruction. If generation and emissions from modified and reconstructed EGUs were not counted in the state's emission rate under section 111(d), emissions from existing EGUs could *appear* to decrease solely because some of those units had become modified or reconstructed sources subject to section 111(b). EPA could reasonably conclude that to protect against such "over-crediting," emissions from modified and reconstructed EGUs must be included in a state's average emission rate.

This approach would also have the effect of treating modified or reconstructed EGUs in a way that is comparable to incremental nuclear, renewable energy and energy efficiency—all of which are considered as resources that displace affected EGUs and therefore enter into the compliance determination for each state as zero-emitting resources. Further, because the emissions from the units in question were taken into account when EPA established the state goals, it would be appropriate to find that those emissions must continue to count in determining compliance with that target. In other words, because the proposed state goals reflect the emissions from those units, the state's compliance demonstration must also include the emissions from those units.

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[405] As described in section I.a of our comments, *supra*, this practice was reflected in the 1995 revision of the NSPS for both municipal waste combustors and the 2009 revision of the NSPS for HMIWI.

III. Environmental Justice

We urge EPA to ensure that the communities long afflicted by power plant pollution are protected under the Clean Power Plan consistent with our nation's clean air laws and Executive Order 12898, *Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations*. Executive Order 12898 mandates that each Federal agency make achieving environmental justice part of its mission. Section 110(l) of the Clean Air Act has long prohibited state implementation plans that interfere with timely attainment or reasonable further progress in protecting human health from air pollution. EPA should apply this core tenet of protection to its administration of section 111 of the Clean Air Act and the Clean Power Plan. The bedrock protective intent of the Clean Air Act is established in its foundational statutory purpose—to "protect and enhance the quality of the Nation's air resources so as to promote the public health and welfare" (Section 101(b)(1))—and reflected throughout the fabric of the law. This can be effectuated by ensuring that the Mercury and Air Toxics Standards and health-based air quality standards are rigorously implemented alongside the Clean Power Plan, and by creating a strong framework for coordinated air quality planning so that emissions reductions are secured in areas with unhealthy air pollution concentrations.

We urge EPA to include in the final rule a robust discussion of how states can perform analyses to identify air pollution burdens disproportionately burdening disadvantaged communities and of the ways in which state plans can be designed to ensure that communities bearing a disproportionate share of air pollution burdens have those burdens reduced. These communities might be, in different states, geographically-defined communities, low-income communities, or communities of color.

This will be particularly important in the context of state planning to achieve the revised ambient air quality standards for particulate and ground-level ozone (the main component of smog), as fossil fuel-fired power plants, particularly coal-fired power plants, are both large sources of carbon pollution and of SO_2 and NO_x, which are key ingredients of particulate pollution and smog. Scientific evidence clearly indicates that exposure to these contaminants can reduce lung function and irritate airways, increasing respiratory problems and aggravating asthma and other lung diseases, leading to increased vulnerability to respiratory infections and increases in doctor visits, emergency room visits, hospital admissions, and school absences. Exposure also increases the risk of premature death from heart and lung disease. Children are at increased risk because their lungs are still developing and they are more likely to be active outdoors, increasing their exposure—and African American and Latino children are particularly at risk of asthma[406] and asthma-related hospitalizations.[407]

As states develop plans to address ozone, particulate and carbon pollution—and as sources prepare to meet Clean Air Act restrictions on emissions of mercury and other toxic air pollutants--the potential to reduce burdens on disadvantaged communities can and must be realized.

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[406] *See* http://www.lung.org/assets/documents/publications/solddc-chapters/asthma.pdf.
[407] *See* http://www.epa.gov/epahome/sciencenb/asthma/HD_Hispanic_Asthma.pdf; see also http://lulac.org/programs/health/asthma/.

The Clean Power Plan also creates an increased opportunity to deploy distributed renewable energy generation and demand-side energy efficiency to make American homes and businesses more efficient and energy independent, lowering utility bills, and stimulating local economies as bill savings are rededicated to other goods and services. EPA should urge states to ensure that communities that have borne heavy burdens from fossil fuel-fired power plant emissions—and low-income communities more broadly--have full access to opportunities to develop renewable generation (including distributed renewable generation) and opportunities to benefit from investments in demand-side energy efficiency improvements. Full access will likely mean ensuring that traditional barriers to accessing these types of cost-saving and energy-saving programs are overcome, including by encouraging innovative financing arrangements and addressing problems that arise when landlords are not paying energy bills and thus lack a sufficient incentive to invest in demand-side energy efficiency improvements. Further, in developing guidance for evaluation, measurement and verification of the energy savings that result from energy efficiency programs, EPA should prioritize developing guidance that will facilitate investments in energy efficiency in low-income communities and communities of color, and make it clear to states that these types of programs can be deployed, and verified, as part of a compliance strategy.

Under the newly proposed Clean Power Plan, EPA projects that by investing in energy efficiency household and business energy bills can decrease by about 8% by 2030.[408] As noted in our comments on the potential for demand side energy efficiency to provide more extensive direct bill savings for low income Americans, *through well designed state programs the bill savings to families could be significantly greater with greater deployment of energy efficiency —securing a 15% improvement in energy efficiency by 2030 could generate annual average household savings of $157. State deployment of demand side energy efficiency solutions to mitigate carbon pollution can provide both multipollutant reductions while providing direct bill savings for communities suffering from high pollution levels.*

[408] EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants, at 3-43 (June 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

IV. Support and Recommendations for Strengthening the BSER and Building Block Formula

A. Best System of Emissions Reduction and Building Block Formula

We strongly support EPA's proposed "best system of emission reduction" (BSER), which sets targets for each state's CO2-emitting power plants by looking at the real-world potential to reduce their carbon pollution by deploying renewable energy, harvesting our nation's vast energy efficiency resource, improving the efficiency of power plants, and relying more on lower-polluting and less on the highest-emitting power plants.

Under the Clean Air Act, EPA is required to identify the "best" system of emission reduction that has been "adequately demonstrated" considering cost, energy requirements, and other health and environmental outcomes. We know that the system of emission reduction proposed by EPA is adequately demonstrated because power companies and states across the country are effectively using each of the building blocks to cut emissions of carbon pollution and other dangerous air pollutants from fossil fuel-fired power plants. We agree with EPA that it is the "best" system as defined by the Clean Air Act because it has the potential to secure large reductions in carbon pollution at reasonable cost, and will provide companies and states with flexibility to manage energy requirements and identify the emission reduction pathways that make the most sense for them. (See our legal discussion in Section I for more detail on the legal justification for BSER)

This system of emission reduction reflects the real-world reality of the electricity system, within which different power generation sources and demand-side energy efficiency resources are managed dynamically to ensure that energy demand is met at each moment in time. Companies and states have long been relying on the interconnected nature of the electric grid to reduce harmful pollution from power plants. Adding renewable electricity backs down generation at fossil fuel-fired plants—and reduces emissions accordingly. Likewise, improving energy efficiency lowers demand for electricity, reducing power generation and thus emissions. States and power companies have been increasing use of natural gas plants which has reduced emissions from coal-fired power plants. Coal-fired power plants can (and many already do) co-fire with natural gas, which reduces combustion emissions. Coal plants can also be converted to burn natural gas which reduces combustion emissions, which has occurred at many facilities. These techniques—switching to lower carbon fuels, non-emitting generation resources, and improving energy efficiency—are traditional methods of addressing air pollution under the Clean Air Act.

As discussed *supra*, EPA's proposed system of emission reduction — an emission limit that power plants can achieve through compliance measures including efficiency improvements at power plants, shifts from coal to gas-fired power generation, deployment of renewable energy, and harvesting energy efficiency — meets the requirements of the Clean Air Act. The emission reduction techniques included in the targets are "adequately demonstrated" and enable sources to achieve the greatest emission reductions considering cost, impacts on energy, and other health and environmental outcomes (note comments below on expanding and strengthening the BSER). The flexibility of this system enables states to secure emission reductions cost effectively, to manage impacts on energy and ensure that there are no effects on reliability, and to reduce carbon emissions by building on existing state clean energy and efficiency programs. This system allows states to secure all of the co-benefits of transitioning to cleaner energy and harvesting energy efficiency, reducing not only carbon pollution but also the burden of other health-harming air pollution on their communities. Investment in renewable generation and energy efficiency will drive job creation. The fuel savings of renewable resources and energy efficiency improvements will lower utility bills for families and businesses. Those savings will then be spent on other goods and services, stimulating the economy, as states with strong energy efficiency programs are already experiencing.

1. Support for a Stronger BSER

The system of emission reduction identified by EPA can achieve even greater emission reductions than is reflected in EPA's analysis. In the comments and sections that follow we describe the opportunity to strengthen each of EPA's BSER Building Blocks and how to do so at reasonable cost.

The BSER building blocks proposed by EPA include:

Block 1: Making existing coal plants more efficient

Block 2: Using existing natural gas plants more effectively

Block 3: Increasing renewable and nuclear generation

Block 4: Increasing end-use energy efficiency

A careful analysis of the emission reduction opportunities in each of the four blocks identified by EPA demonstrates that even greater savings are available from each of the four blocks. As discussed in detail below and in EPA's Notice of Data Availability Released on October 27, 2014, in order to reflect the role of renewable energy and energy efficiency in displacing fossil generation emissions, EPA must also fix the formula for calculating state targets.

a. Implementation of BSER Goal-Setting Equation and Treatment of Incremental Renewables and Energy Efficiency

In its October 27, 2014 Notice of Data Availability (NODA), EPA explains that the original formula used in its proposed rule does not fully account for the emission reductions generated by renewables and energy efficiency. As EPA explains, the formula used in the proposed rule failed to account for the reduction in generation at coal and gas power plants that will occur when renewables are added to the grid and when we improve energy efficiency. When EPA sets final state targets, it should use the corrected formula proposed in the Notice of Data Availability. This is necessary to ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

i. The Formula Must Be Adjusted to Conform to the Preamble Explanation for Why Renewables and Energy Efficiency Are Included in the BSER

In the preamble, EPA explains that renewable energy and energy efficiency are part of BSER is because they all decrease the amount of generation at (and therefore emissions from) affected power plants.[409]

In the goal-setting equation, EPA correctly accounted for the emission-reducing effect of coal to gas shifts in utilization (by accounting for reductions in emissions from coal-fired power plants and increases in emissions at gas-fired power plants as the shift occurs) but failed to correctly account for the effect of renewable energy and demand-side energy efficiency in blocks 3 and 4 in displacing fossil emissions. The original proposal's state target calculation formula simply adds additional renewable energy and energy efficiency megawatts to the denominator of the state emission rate without commensurately reducing generation or emissions at fossil-fuel fired plants. As a result, increasing block 3 and 4 resources *dilutes* rather than *replaces* megawatts generated by block 1 and block 2 resources. This is inconsistent with the premise that these resources will "reduce, or avoid, generation from all affected EGUs on a state-wide basis."

The defect in the original formula is significant because the mathematical effect of subtracting fossil generation emissions more accurately reflects what actually happens when renewable power substitutes for, and energy efficiency obviates the need for, an equivalent quantity of fossil generation. EPA must correct the formula as described in the Notice of Data Availability in order to properly reflect the emission reductions achievable based on the best system of reduction identified by EPA.

ii. Recommendations for How to Implement the Corrected Formula

EPA has proposed two alternative approaches that would apply incremental renewable energy and energy efficiency to replace existing fossil generation. Under the first alternative approach, incremental RE and EE would displace historical fossil generation and emissions on a pro rata basis across all fossil generation types, including fossil steam and natural gas. Under the second alternative approach, the adjustment to the historical levels of fossil generation corresponding to the addition of zero-emitting generation would replace highest-emitting generation before replacing lower-emitting generation.

EDF supports both of these approaches, and believes both are valid for BSER state goal setting. EDF encourages EPA to adopt the first approach, revising the target-setting formula so that incremental RE and EE (beyond 2012 levels) directly replace fossil generation and the corresponding emissions in proportion to the 2012 fossil generation mix, which could be seen as reflecting the potential for states to substitute zero carbon resources and energy efficiency for the highest-polluting generation. However, we also support the alternative approach, noting thatit acknowledges that the addition of incremental RE and

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[409] 79 Fed. Reg. at 34891 ("the measures in building blocks 3 and 4 . . . reduce, or avoid, generation from all affected EGUs on a state-wide basis."); *see also id.* at 34852 (identifying BSER to include blocks two, three and four because "increases in . . . zero or low-emitting generation, as well as measures to reduce demand for generation . . . taken together, displace or avoid the need for, generation from affected EGUS").

EE could replace various fossil resource types without strictly replacing fossil in order of decreasing carbon intensity.

If EPA adopts a formula in which renewables and energy efficiency displace NGCC and coal-fired generation on a pro rata basis, it must also ensure that it corrects the potential emission reductions from building block 2. When renewables and energy efficiency displace NGCC generation, this will lower the capacity factor of NGCC plants and create additional potential reductions from building block 2. These additional reductions can be achieved either by displacing fossil generation from blocks 3 and 4 before calculating block 2 or by doing a true-up to block two to ensure that NGCC plants remain at a 70 percent capacity.

The formula adjustment will ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

B. Recommendations Regarding the 2012 Baseline & 3 year Average

EPA proposed using 2012 as the generation and emissions year from which to assess the opportunity to reduce emissions. EPA asked for comment on using 2010, 2011 or some average or combination of the three years. EPA also included all existing fossil generation in their calculation and formula, but the agency did not include total generation (all nuclear and hydro). The agency included non-hydro renewables and a portion of nuclear. In this section we address the baseline years and what should be factored in to the formula.

Baseline or Comparable Year

EDF strongly supports using the most up-to-date data and most recent baseline year to develop the emission reduction target for each state. The goal of this exercise is to reduce emissions from existing power plants, and the most recent data available on the sources and utilization of electric generation in each state is the best starting point for such an analysis. Data on the level and composition of generation from several years ago is less relevant to a forward-looking assessment of emission reduction opportunities in each state. Accordingly, EPA is right to start examining the potential to reduce emissions from where we are today and assessing the potential for states to reduce emissions based on that one common starting point.

However, some stakeholders have noted that any one year can have anomalies for one or more plants in a given state. While we do not think this issue is very significant, EPA could reasonably consider using a multi-year average as the starting point in their evaluation and formula for states with such anomalies. A relatively short averaging period, consisting of the most recent years of operating data, could help resolve concerns over unique operational circumstances that may have occurred in 2012.

EDF does not believe states should be allowed to pick from the three years, as this will inevitable create an incentive to pick only the highest emission year (s) in order to set the emissions standard at the highest point possible, reducing the requirement on generation in the state to change their emissions profile over time. Allowing states to choose years will undermine the environmental outcome of the CPP.

Inclusion of Renewables and Nuclear

EPA has included non-hydro renewables and a portion of nuclear power in calculating the 2012 state emission rates. We encourage EPA to examine the benefits of removing all the non-fossil generation from the BSER baseline year starting point in the formula given the following considerations.

1) Current State Renewables Policies and In-state vs. Out of State Considerations:

   In many states, the state policies that have delivered the most development and generation from new renewable energy have been state renewable energy or portfolio standards (RES/RPS). These standards have been increasing over time and have led to the development of significant new renewable resources, particularly wind and solar. However, while these state policies require an increasing percentage of the electricity delivered in the state to be from renewables, most of these state policies do not require the generating resource to be located in the state. Many states have developed or purchased large quantities of wind generation to satisfy the RES/RPS requirements in other states. Reflecting this market reality, EPA has proposed that credit for the emission reductions driven by renewable energy deployment be assigned to the purchaser of the renewable energy credit (REC), which we support.

   State 2012 emission rates under the proposal reflect in-state renewable energy—although the entities holding the RECs associated with that renewable energy may be out of state. EPA should address consistency between the BSER formula structure, current state renewables tracking, and planned compliance tracking. While there are other ways this could be done, we suggest the simplest way would be to consider only new renewables generation and not include existing generation in the BSER baseline. This allows EPA to avoid allocating generation from existing renewables in the BSER formula. Looking forward there would be no concern about using RECs for tracking generation whether from in-state or out of state generation.

2) Consistency of State Targets:

   Inclusion of non-fossil resources in the BSER formula leads to state targets that diverge more than when an average fossil rate is used as the starting point. If states develop a flexible rate-based policy approach and their neighboring state has a very different target level, there is a possibility that generators of the same type on either side of a state border would face different compliance costs. This kind of competitiveness issue could lead to environmental leakage, but it would be reduced if the starting point for developing the state standards was a fossil rate.

C. Comments on the Length of the Compliance Period

1. EPA Should Not Adopt the Alternative Option of a Single 5-year Compliance Period in Combination with Weaker CO_2 Emission Performance Goals

EPA should not adopt the alternative option imposing weaker CO_2 limits over a 5-yr time span. EPA's own data and analysis shows that the best system of emission reduction deployed over this time period would achieve significantly greater emission reductions than are reflected in the proposed alternative state goals. *See* 79 Fed. Reg. at 34,898.

EPA has not justified the assumptions underlying the reduced stringency of the alternative goals associated with the 5-year compliance plan alternative. In setting the interim and final goals for this alternative option, EPA made several adjustments to the set of assumptions used to generate the proposed goals associated with the 10-year compliance period. *See id.* at 34,898. First, with respect to the anticipated heat rate improvement from coal-fired EGUs under Block 1, EPA used a value of four percent instead of six percent. *Id.* Second, under Block 2, EPA assumed that the potential annual utilization rate for NGCC units would increase to 65 percent instead of 70 percent. *Id.* Third, under Block 4, EPA assumed that annual incremental electricity savings achievable through a portfolio of demand-side energy efficiency programs would be one percent instead of 1.5 percent. *Id.* As EPA has noted, these assumptions may be "overly conservative," and "underestimate the extent to which the key elements of the four building blocks . . . can be achieved." *Id.*

EPA has provided no analysis to support the adjusted assumptions aside from the assertion that "the time period for implementation relates directly to the emission reductions that are achievable[.]" *Id.* If EPA were to establish only a single 5-year compliance period, the state targets should reflect the full emission reduction potential available during that 5-year period, commensurate with potential shown during the initial five years of the proposed 10-year compliance period as strengthened through the recommendations discussed in these comments.

2. The Interim Standard is Amply Achievable and, As EPA Itself Finds, More Rigorous Emission Reductions are Achievable in 2025. Further, Consistent with the Statutory Requirements to Periodically Modernize BSER, EPA Must Establish a Legally Enforceable Mechanism that Requires a BSER Determination in 2025 to Secure Additional Deeper Reductions Beginning No Later Than 2030.

The Interim Standard that takes effect beginning in 2020 is amply achievable. The extensive analysis of the building blocks, set out above, addresses important and cost-effective ways the building blocks can be strengthened by achieving deeper emissions reductions and securing the emissions reductions more swiftly than assumed. This includes, for example, the availability of deeper reductions at the source through cost-effective co-firing and repowering with lower emitting fuels that is being widely deployed at coal plants today, the demonstrated potential to

deploy more extensive and cost-effective renewable energy resources, and the rapid mobilization of demand side energy efficiency including a broader array of efficiency solutions than considered by EPA. Further, as discussed in part XIII there is extensive flexibility integrated into the compliance design of the interim standards. In sum, there is a strong – more than amply achievable – basis for meeting the proposed interim standard.
Moreover, EPA expressly recognized that a more rigorous standard could be achieved by 2025, finding that it is achievable for power sector emissions to be 29 percent below 2005 levels in 2025 based on the changes reflected in the four building blocks:

> EPA's analysis shows that under the proposed goals described in Section VII.C above, power sector emissions will be 29 percent below 2005 levels in 2025, suggesting that the kinds of changes contemplated in the four building blocks, even as early as 2025, will be yielding reductions far greater than the 23 percent projected for the alternate goals as set forth above in this subsection.

79 Fed. Reg. at 34,899.

EPA's finding that a deeper reduction in 2025 is achievable based on solutions adequately demonstrated meets the pertinent statutory criteria for determining the best system of emission reduction and thereby requires EPA to establish such a standard in 2025 that "reflects the degree of emission limitation achievable." As such, EPA must establish a five year compliance requirement beginning in 2025 and continuing through 2029 that is far more rigorous than the 2020-2029 10-year average interim standard.

Finally, EPA requests public comment on whether to require maintenance of the 2030 standard beyond that date or, alternatively, to review and revise its BSER determination post 2030:

> The EPA also requests comment on whether we should establish BSER based state emission performance goals for affected EGUs that extend further into the future (e.g., beyond the proposed planning period), and if so, what those levels of improved performance should be. Under this alternative, the EPA would apply its goal-setting methodology based on application of the BSER in 2030 and beyond to a specified time period and final date. The agency requests comment on the appropriate time period(s) and final year for the EPA's calculation of state goals that reflect application of the BSER under this approach.
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> The EPA notes that CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources. This requirement provides for regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The agency requests comment on the implications of this concept, if any, for CAA section 111(d).

79 Fed Reg. at 34899.

As EPA recognizes, Congress has woven an updating mechanism into the fabric of section 111 that commands the Agency to refresh the BSER analysis for new sources "at least every eight years" and is inextricably connected with updating the existing source standards through the expansive statutory definition of the term "new source," the terms of section 111(d), and the long-standing EPA regulations implementing section 111(d) in parallel with section 111(b).

The availability of clean low carbon solutions is advancing at a rapidly accelerating pace as clean technologies are being drive to scale and meeting our nation's power needs at briskly diminishing costs. See WRI, *Seeing is Believing*. There is every indication that like other modern clean air solutions for the power sector, including scrubbers and SCR, as well as for other major source sectors, that emissions reductions in the near future will be achievable more swiftly, more deeply and at a fraction of the costs currently expected. See U.S. EPA, "The Clean Air Act Amendments: Spurring Innovation and Growth While Cleaning the Air" (prepared by ICF Consulting, 2005).

EPA must hew to the facts in determining BSER and carry out its legal responsibility to commit to determine in 2025 through a legally enforceable mechanism the BSER that applies over time – and that is not stagnant in maintaining in 2030 the standard of performance established a decade earlier. Rather, the BSER analysis must be, as Congress intended, a is vibrant, rigorous, and dynamic tool in securing for our nation's public health, environmental quality, and prosperity--no later than the 2030 timeframe--the additional far deeper "degree of emission reductions achievable."

D. EPA Should Not Adopt a BSER Based Only on Building Blocks 1 & 2

Across the country, states and power companies are reducing carbon pollution through increased deployment of low/zero-emission generation and demand side energy efficiency programs on the integrated power grid. EPA has documented these on-going initiatives to reduce CO_2 emissions from the power sector. *See* 79 Fed. Reg. at 34,848-50; *see also* Section I.I., *supra*. These systems of emission reduction are adequately demonstrated and are producing very significant reductions in carbon pollution at reasonable cost. As such, EPA has properly determined that the BSER includes these approaches to achieving emissions reductions.

EPA nonetheless solicits comment on whether to apply "only the first two building blocks as the basis for the BSER, while noting that application of only the first two building blocks achieves fewer CO_2 reductions at a higher cost." 79 Fed. Reg. at 34836. Applying only the first two building blocks as the basis for the BSER would needlessly exclude key demonstrated available emission reduction measures that, as EPA recognizes, will allow states to achieve greater emission reductions more flexibly, and to achieve those reductions more cost effectively while generating greater co-benefits in reductions of harmful co-pollutant emissions, utility bill savings, and economic stimulus.

As outlined in detail in these comments at section I.E, the statutory term "best system of emission reduction" is broad enough to encompass consideration of measures that have the effect of preferring lower polluting means of producing a product—in this case, energy services. Consequently, EPA has the authority (and indeed, the obligation) to consider the measures in building blocks three and four in determining the combination of measures that constitutes the BSER. Further, EPA's analysis demonstrates that a system of emissions reduction that combines these measures with the measures encompassed by Building Blocks 1 & 2 will achieve greater emissions reductions more cost effectively than a system relying only on Building Blocks 1 & 2. Because the proposed system of emission reduction is thus superior to a system relying on Building Blocks 1 & 2 only, EPA cannot adopt a BSER that disregards the use of key measures that states and companies are already undertaking to reduce emissions.

E. Net Generation Should Be the Basis for State Goals and Emission Reporting

EDF supports EPA's proposal to express the rate-based state goals in terms of emissions per unit of net generation, as opposed to gross generation, and believes that this approach should be extended to all of the pending proposed standards for fossil-fired EGUs.[410] As EPA acknowledged in the preamble to the proposed NSPS for new EGUs, the "net power supplied to the end user is a better indicator of environmental performance than gross output from the power producer."[411] Using net generation as the basis for rate-based standards appropriately incentivizes owners and operators of EGUs to optimize the efficiency of their plants by reducing parasitic loads associated with auxiliary equipment and emission controls. Such improvements in efficiency increase the *useful* output of the plant while avoiding increases in fuel consumption and emissions. Under a standard based on net generation, these improvements in efficiency would lower the emission rate and contribute towards bringing a fossil EGU into compliance. By contrast, a rate-based standard based on gross generation does not recognize any differences in efficiency of auxiliary equipment and pollution control systems among EGUs – and as such fails to fully incentivize the efficient generation of electricity. For this reason, a gross generation-based standard is inconsistent with the overall technology-forcing purpose of performance standards under section 111, as well as EPA's recognition in building block 1 that improvements in fossil plant efficiency – yielding greater useful output while maintaining or reducing emissions — are an important part of the BSER.

Establishing state goals in terms of net generation is also eminently feasible both for EPA and for the states. EPA recognizes in the preamble to the proposed rule that "[n]early all EGUs already have in place the equipment necessary to determine and report hourly net generation," indicating that monitoring and reporting net generation would not be burdensome.[412] Indeed, although net generation is currently not reported to EPA under 40 CFR Part 75, affected EGUs are generally required to report gross and net generation on a monthly basis to the Energy Information Administration (EIA) through Form 923

[410] *See* Comments of Sierra Club et al. on Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Docket ID No. EPA-HQ-OAR-2013-0495-9514, at 106 (May 9, 2014).
[411] 79 Fed. Reg. at 1448.
[412] *See* 79 Fed. Reg. at 34,894.

submittals.[413] Recent PSD permits for new and modified EGUs also include emission standards based on net generation, providing further support for the feasibility and reasonableness of this approach.[414] Accordingly, EDF strongly supports expressing all emission standards for fossil fuel-fired EGUs in terms of net generation – including the emission guidelines in the Clean Power Plan as well as the performance standards for new, modified, and reconstructed EGUs.

F. EPA Should Consider Combining the Source Categories for Affected EGUs

EDF supports consolidating the two source categories of affected EGUs covered by the emission guidelines – electric steam generating units and combustion turbines – into one regulated source category for purposes of establishing carbon pollution standards for all EGUs, including the emission guidelines for existing EGUs as well as the performance standards for new, modified, and reconstructed EGUs. As we explain below, a consolidated source category would reflect the identical market functions served by all of the affected EGUs covered by EPA's proposed carbon pollution standards. A single source category would also be consistent with the system-based approach EPA has proposed, which has important elements that reduce emissions from existing EGUs as a whole rather than solely from EGUs utilizing particular fuels or generating technologies.

In the proposed emission guidelines, EPA observes that the proposed emission guidelines apply to affected EGUs that EPA has separately listed in two source categories under section 111 — steam electric generating units (listed in 1971) and stationary fossil fuel-fired combustion turbines (listed in 1979). EPA also notes that it proposed to combine these two source categories in its January 8, 2014 proposed rule to establish carbon pollution standards for new fossil fuel-fired EGUs (alongside a "co-proposal" to retain the current source category listings), and solicits comment on that approach again here. EPA suggests that combining both source categories would, among other things, potentially facilitate emissions trading among the EGUs in the two currently-listed source categories, or simplify the implementation of certain system-wide emission reduction measures.[415]

As a threshold matter, EPA correctly states that it has clear legal authority to consolidate or reorganize an already-listed source category without making new regulatory findings that would be required for the listing of an entirely new source category under section 111(b)(1). Section 111(b)(1)(A) directs EPA to publish, "and from time to time thereafter…revise," a list of stationary source categories that in the Administrator's judgment cause or significantly contribute to pollution that endangers public health and welfare. Apart from the finding of endangerment required for the listing of a *new*, not previously-listed

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[413] *See* EIA, Form EIA-923: Power Plant Operations Report Instructions, OMB No. 1905-0129 (Exp. Dec. 31, 2015).
[414] *See* EPA, Prevention of Significant Deterioration Permit for Greenhouse Gas Emissions, Port Everglades Plant, Permit PSD-EPA-R4010 (Nov. 2013), *available at* http://www.epa.gov/region04/air/permits/ghgpermits/porteverglades /PortEverglades_FinalPermit_112513.pdf; *see also* EPA, Prevention of Significant Deterioration Permit for Pioneer Valley Energy Center, Final PSD Permit Number 052-042-MA15 (Apr. 2012) (Requiring that new 431 MW NGCC facility meet a CO2 emission standard of 825 lb/MWh on a net output basis).
[415] 79 Fed. Reg. at 1,455.

source category, the statute places no particular limits on EPA's authority to "revise" the list of stationary sources over time. EPA's proposed consolidation of the source categories for steam electric generating units and fossil fuel-fired combustion turbines would neither expand nor otherwise alter in any way the universe of sources comprising those source categories, and would therefore not constitute the listing of a new source category. Nor would it somehow alter the predicate endangerment finding that EPA made when it originally listed both source categories in the 1970's.[416] EPA is therefore free to make reasonable revisions to the source category listings, including the consolidation of already-listed source categories, without significant new findings.

Here, the proposed consolidation of the source categories would be reasonable for at least three reasons. First, steam electric generating units and fossil fuel-fired combustion turbines broadly serve the same market functions. Not only do units in these source categories all generate electricity for wholesale, they also increasingly provide similar *types* of generating service. In a climate of competitive natural gas prices and relatively high coal prices, coal-fired steam electric generating units now commonly provide intermediate or even peaking generation service rather than playing their traditional role as baseload resources. And as coal generation has declined, gas-fired combustion turbines – especially NGCC facilities – have become intermediate or baseload resources rather than providing primarily peaking service. Combining these two source categories to reflect their converging market functions, as we recommend, would be consistent with the categorization contemplated by Congress when it originally enacted section 111 in 1970.[417] It would also be consistent with the history of these *particular* source categories; for example, in 2005, EPA transferred integrated gasification combined cycle (IGCC) facilities to the steam electric generating unit source category on the grounds that IGCC facilities serve the same function.[418] And it would be consistent with various other instances in which EPA has established broad categories encompassing multiple types of sources that serve the same function, even though those source categories may encompass facilities using disparate fuels and industrial processes.[419]

Second, the consolidation of these two source categories would be consistent with the system-based nature of the BSER that EPA has proposed in these emission guidelines. Importantly, the four building blocks in EPA's BSER are intended to function in concert to reduce emissions from *all* EGUs across the two source categories. The effects of any individual building block on any one type of EGU, however,

[416] Although the statute does not require that EPA make a *new* finding of endangerment when regulating additional pollutants from an already-listed source category, EPA has provided more than ample evidence to support such a finding in its pending proposals to regulate carbon pollution from new and existing EGUs.
[417] The legislative history of the 1970 Clean Air Act indicates that Congress expected EPA would establish standards within broad functional categories of facilities. One representative, for example, stated that EPA "could establish uniform pollution control standards for the chemical, oil refining, foundries, food processing, and cement-making industry, and other industries. . . . Every plant within the same group could be required to maintain the same high standards." 116 Cong. Rec. 19,218 (1970) (statement of Rep. Vanik).
[418] *See* 77 Fed. Reg. 22392, 22,411/1 (April 13, 2012).
[419] For example, EPA designated a single NSPS for multiple copper smelting production methods as early as 1976. *See* 41 Fed. Reg. 2332-2333 (Jan. 15, 1976). Similarly, EPA's rotary lime kiln source category includes units fueled by coal, natural gas, and oil. *See* 47 Fed. Reg. 38832, 38843 (Sept. 2, 1982); *see also* 40 C.F.R. §§ 60.340(a), 60.342. And most recently, EPA included all Portland cement plants (*e.g.* "long wet," "long dry," "preheater," and "preheater with precalciner") in a single source category. 75 Fed Reg. 54970, 55,010-55,012, 55,015 (Sept. 9, 2010). This decision was ultimately held by the D.C. Circuit. *See Portland Cement Ass'n v. EPA,* 665 F.3d 177, 190-93 (D.C. Cir. 2011).

will depend upon power market dynamics. For example, building blocks 3 and 4 – which involve shifting generation to zero-carbon resources such as renewable energy and energy efficiency – displace the need for *both* generation from fossil fuel-fired combustion turbines and steam electric generating units. The extent to which these building blocks reduce generation from one or both types of EGUs, however, can vary by region of the country and even by season of the year. Establishing a single source category for both steam electric generating units and fossil fuel-fired combustion turbines would be consistent with the broad nature of the BSER that EPA has proposed, and simplify EPA's analysis by ensuring that all emission reductions from that BSER are attributed to one source category.

A single source category would also be consistent with the nature of the power sector. Utilities and independent system operators make dispatch decisions for the entire fleet of power plants without regard to whether those power plants are fueled by coal, natural gas, nuclear energy, or renewable resources. Operating the grid in this way allows utilities to dispatch the least expensive available generating resources. States and utilities may choose to consider compliance options for EPA's forthcoming 111(d) standards that follow similar principles, just as EPA's proposed system-based BSER reflects the capability of the electric system to achieve overall reductions in carbon pollution by increasing output from lower and zero-emitting resources.

Lastly, we note that the adoption of a broad source category encompassing all affected EGUs would not preclude EPA from recognizing appropriate subcategories where needed to establish performance standards for new sources. (Nor, conversely, would the retention of separate source categories preclude the flexible system of emission reduction EPA has proposed for the two categories here, where emission reduction opportunities are assessed and compliance allowed to be achieved comprehensively across the two categories.) Section 111(b), of course, gives EPA broad discretion to "distinguish among classes, types, and sizes within categories of new sources" by establishing subcategories when prescribing standards for new sources.[420] The courts have held that this discretion gives EPA the ability to reasonably subcategorize, or *not* subcategorize, depending on the characteristics of the source category and pollutant at hand.[421] This discretion should logically extend to the establishment of emission guidelines under section 111(d). Indeed, nothing in the text of section 111(d) requires that standards for existing sources replicate the category framework into which EPA organizes new sources, so long as the sources covered by section 111(d) would be subject to "a standard of performance under this section [111]" if they were new sources.[422] Further, EPA's 1975 Federal Register notice implementing section 111(d) also explicitly recognized that the categorization systems adopted under section 111(b) and (d) need not be identical.[423] Thus, combining steam electric generating units and fossil fuel-fired combustion turbines into one source category under section 111 would not limit EPA's authority to establish separate performance standards for distinct *subcategories* of new and modified coal and natural gas-fired EGUs. EDF supported this

[420] 42 USC § 7411(b)(2).
[421] *See Lignite Energy Council,* 198 F.3d 930, 933 (D.C. Cir. 1999) (deferring to EPA's judgment that it was feasible and cost-effective to require all new utility boilers to meet the same NOx emission standards regardless of fuel type, despite past practice establishing varying NOx standards for different subcategories of units).
[422] 42 USC § 7411(d)(1)(A)(ii).
[423] *See* 40 Fed. Reg. at 53,341 ("…while there may be only one standard of performance for new sources of designated pollutants, there may be several emission guidelines specified for designated facilities based on plant configuration, size, and other factors peculiar to existing facilities.").

subcategorization approach in the rulemaking proposing standards for new EGUs, as well as the June 18, 2014 proposal for modified and reconstructed EGUs.

G. Comments on Building Block 1: Onsite Emission Reductions

EPA's analysis demonstrates that the existing fleet of power plants is capable of reducing emissions considerably through onsite efficiency improvements resulting from cost-effective equipment upgrades and increased deployment of best operating practices. There are myriad ways in which plants can achieve such efficiency improvements, including many measures not specifically evaluated by EPA in its analysis. Among other things, heat rate improvements can be achieved through:[424]

- increased efficiency of motors and variable frequency drives for coal-handling equipment;
- replacement of inefficient economizers with more efficient ones;
- deployment of more advanced coal pulverizers that provide more consistent size and finer coal particles;
- switching from water-sluicing bottom ash system to a dry drag chain system,
- deployment of neural network systems to enhance plant control and evaluation;
- use of intelligent sootblowers;
- improvements to reduce air heater and duct leakage;
- lower air heater outlet temperature by injecting sorbents such as Trona or hydrated lime that can lower the dew point for acid gases;
- replace or overhaul steam turbines with advanced turbine designs;
- improving heat transfer surface area for feedwater heaters;
- condenser upgrades and maintenance;
- overhaul of boiler feed pumps
- upgrades or replacements to induced draft fans;
- upgrading variable frequency drives in flue gas systems;
- use of co-current spray tower quencher in flue gas desulfurization;
- use of turning vanes and perforated gas distribution palate to improve gas distribution in flue gas desulfurization systems;
- electrostatic precipitator energy management system upgrades;
- reducing pressure drop and using secondary air as dilution for ammonia vaporizer to reduce auxiliary power needs for selective catalytic reduction;
- better maintenance of water quality flowing into the boiler; and,
- better maintenance of cooling water systems to improve water quality

As EPA's analysis and other industry and academic studies find, there is significant variation in the heat rate of existing steam EGUs with similar characteristics — strongly indicating that many existing steam EGUs have failed to implement all cost-effective heat rate improvement measures and that significant opportunities remain to enhance onsite efficiency. In some cases, these opportunities exist because plants in rate regulated markets are allowed to pass fuel costs on to consumers, reducing the financial incentive

[424] GHG Abatement Measures TSD at 2-6 to 2-11.

for onsite efficiency improvements.[425] Coal plants in competitive markets seldom set the clearing price for electricity, and so may face reduced competitive pressure to look internally for all cost saving measures. Many plants may have failed to undertake such improvements in the past because of institutional barriers or lack of onsite engineering personnel focused on the issue.[426] In addition, many plants are old, with more than 30 percent of plants over 50 years of age.[427] There is reason to believe that a number of these plants and younger plants as well have waited to undergo significant upgrades until there was more clarity about the future regulatory environment for a range of air pollutants, including mercury and carbon dioxide.

While robust, EPA's Building Block 1 analysis omits considerable opportunities for additional reductions through the employment of overly conservative discount factors when evaluating opportunities for improvements through use of best practices and equipment upgrades. In addition, EPA excludes from the BSER conversion of utility boilers to natural gas, and co-firing with natural gas, based on an inappropriately narrow assessment of net benefits associated with such systems. As we describe below, there are many opportunities for plants to increase onsite combustion of lower carbon fuels through minimal equipment changes. In addition, we find numerous examples of coal-fired power plants already co-firing with lower carbon fuels and of plants being repowered to run entirely on lower carbon fuels as a result of the cost effectiveness of those conversions. This leads us to conclude that EPA has considerably understated the opportunities for onsite reductions in emissions at existing coal-fired electric generators. In the final rule, EPA should strengthen building block 1 to reflect the full range of opportunities for onsite emission reductions at steam EGUs, including use of lower-carbon fuels.

Opportunities for onsite efficiency improvements

Opportunities to reduce a plant's GHG emissions through onsite efficiency improvements are readily available and have been documented in numerous studies by Sargent and Lundy, the National Energy Technology Laboratories, Resources for the Future, and others. Some of these previous analyses have demonstrated a potential to achieve efficiency improvements that significantly exceed EPA's target of a six percent reduction in average heat rate. For example, as EPA notes in the GHG Abatement Measures TSD, the Department of Energy (DOE) and the National Energy Technology Laboratory (NETL) have undertaken extensive analysis on the performance of the existing fleet of coal-fired steam EGUs, informed by multiple workshops and consultations with industry experts. NETL's analysis identified 13 different subgroups of power plants based on characteristics that determine overall efficiency, and calculated best-in-class efficiency within each subgroup. Based on this analysis, NETL determined that a ten percent improvement in fleet-wide efficiency is a "reasonable average efficiency target" based on "a

[425] *See* DOE/NETL, *Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants: Workshop Report* 2 (July 2009).
[426] *See id.* at 2-3; Joshua Linn, Erin Mastrangelo, & Dallas Burtraw, *Regulating Greenhouse Gases From Coal Power Plants Under the Clean Air Act* 7-8 (Feb. 2013).
[427] http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states

combination of aggressive refurbishment and improved operation maintenance."[428] NETL's consultations with industry experts validated this conclusion, identifying over 50 opportunities to improve thermal efficiency[429] and finding that "there is 'headroom' for efficiency improvements among all plants including those that currently operate at below average, average, and above average efficiency levels."[430] The consultations also identified multiple institutional, regulatory, and market barriers that help explain why many coal-fired EGUs have failed to implement all cost-effective options for improving efficiency.[431]

EPA's own analysis takes a far more conservative approach to quantifying the average efficiency improvement that can reasonably be achieved by existing coal-fired generating units. For example, when examining opportunities to improve efficiency through best operating practices, EPA assumes that power plants can reduce only 30% of the difference between their own hourly heat rate and the heat rate of the top 10% of comparable power plants.[432] This results in substantially lower heat rate improvements than NETL's own analysis, which concluded that existing coal-fired power plants could achieve or exceed the performance of the top 10% of their peers through upgrades or operational improvements.[433] EPA's approach leaves potentially cost effective emissions reduction opportunities on the table. NETL, for example, undertook an alternative analysis in which it assumed that each existing coal-fired EGU simply returned to its own best level of performance over the period from 1998 to 2008 – without considering any potential for refurbishments or equipment upgrades. Even this narrower assessment resulted in an average fleet-wide improvement in efficiency of over six percent, more than fifty percent higher than the level EPA proposes for operational improvements under Building Block 1.[434] As EPA notes, its projected four percent improvement in heat rate from best operating practices is equivalent to requiring only that each existing coal-fired power plant return to its best three-year average performance during the period from 2002 to 2012.[435]

EPA's analysis of the potential for heat rate improvements from equipment upgrades is also highly conservative. Building block 1 only includes one half of the opportunity identified by EPA for equipment upgrades — reducing the potential improvement in heat rate from an average of 4 percent to just 2 percent. In addition, EPA's assessment of equipment upgrades examined only the four most cost-effective types of equipment upgrades identified in the 2009 Sargent and Lundy report. As noted above, NETL's own technical workshops with industry experts identified over 50 different heat rate improvement measures which would afford opportunities for greater efficiency not captured in EPA's analysis.

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[428] Phil DiPietro & Katrina Krulla, *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions* 5 (DOE/NETL-2010/1411, 2010).
[429] DOE/NETL, *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States* v (Feb. 2010).
[430] DOE/NETL 2009 at 2.
[431] DOE/NETL 2010 at vi.
[432] GHG Abatement Measures TSD at 2-32.
[433] DiPietro & Krulla, *supra* at 4-5.
[434] *Id.* at 6.
[435] GHG Abatement Measures TSD at 2-34.

Lastly, EPA's analysis of heat rate improvements only considers potential for improving *gross* heat rates. As EPA notes, "the HRI potential on a net output basis is somewhat greater than on a gross output basis, primarily through upgrades that result in reductions in auxiliary loads."[436] Since the state goals are expressed in terms of net output, the calculation of heat rate improvements on a gross basis is a further dimension of EPA's analysis that leads to a conservative result. We also encourage EPA to look more carefully at opportunities to improve the efficiency of auxiliary or parasitic loads, such as pumps, fans, motors, and pollution controls. As EPA notes, these loads represent from 4 to 12 percent of gross generation at a coal-fired steam EGU, and could present a key untapped opportunity for additional onsite improvements.[437]

It is also reasonable for EPA to base Building Block 1 on the *average* expected improvement in heat rate at existing coal-fired power plants, rather than demonstrate the feasibility of achieving this target at each individual plant. The case law under section 111 specifically recognizes that a standard of performance may be based on reliable data about the average performance of a control technology, so long as EPA grants sufficient flexibility in demonstrating compliance to account for the variability in performance of the control technology.[438] Here, there is ample evidence and multiple lines of analysis to support EPA's determination that a six percent average improvement in heat rate is feasible. Moreover, the flexible structure of the Clean Power Plan – which allows states to average the emissions rates of existing fossil fuel-fired EGUs, and comply using many combinations of emission reduction strategies, more than takes into account potential variability in heat rate improvement across units. The record demonstrates, for example, that there are many opportunities for heat-rate improvements at affected facilities beyond the thirteen measures that were the focus of EPA's analysis. Existing coal-fired power plants that are unable to achieve the six percent reduction in heat rate could also easily meet the anticipated reduction in emissions through modest co-firing with natural gas. Thus, EPA's target for average heat rate improvements is "achievable" under section 111 even in the speculative event that some facilities may need to employ additional heat-rate improvement strategies (or choose to comply through other flexible mechanisms) in certain circumstances. Even if EGUs incurred additional costs in implementing such measures, these costs would certainly be within the relevant limits that courts have placed on the costs of performance standards under section 111.[439]

Repowering with natural gas

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[436] GHG Abatement Measures TSD at 2-37.
[437] 79 Fed. Reg. at 34,860.
[438] *Sierra Club*, 657 F.2d at 372-73 (where EPA had based an NSPS on its estimation of the "average" amount of sulfur that could be removed through coal washing, the D.C. Circuit upheld the standard because utilities had several options for how to comply even when they purchased lots of washed coal that had not been washed to the desired level).
[439] Courts have determined that costs of performance standards under section 111 must not be "exorbitant," *see Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n v. EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive", *Sierra Club v. Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").

EPA considered conversion to natural gas as a potential BSER, but concluded that coal-to-gas conversion is not BSER due to the allegedly high costs of the resulting emission reductions.[440] However, as explained below, EPA's analysis does not appropriately characterize the costs of gas conversion or reflect full consideration of the BSER factors. Indeed, such measures are already commonplace in the industry, suggesting that they are cost-effective and adequately demonstrated even in the absence of carbon pollution standards for the power sector. In a white paper submitted with our comments as Attachment C, Andover Technology Partners verified that there are at least 24 such conversions in 19 states expected to be completed by 2020, when the Clean Power Plan goes into effect. Some studies have suggested that there could be more than 50 such conversions in 26 states at various stages of planning and development.[441] And recent reports indicate that almost 11 GW of coal generation is currently slated for conversion to natural gas.[442] As the Andover report indicates, many such conversion projects that are currently under way were undertaken for the purposes of pollution control and are being completed at plants of greatly varying size and capacity factor, including large intermediate load plants. Based on the Andover white paper and EPA's own analysis, we find that careful examination of BSER factors demonstrates that coal-to-gas conversion fits the statutory criteria for BSER for fossil fuel-fired utility boilers. Accordingly, we urge EPA to take into account the availability of coal-to-gas conversions when assessing the potential for emission reductions in each state and setting state targets.

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[440] 79 Fed. Reg. at 34,982.
[441] http://www.sourcewatch.org/index.php/Coal_plant_conversion_projects
[442] : See http://www.mining.com/web/snl-energy-coal-unit-retirements-conversions-continue-to-sweep-through-power-sector/

Table 1. List of announced coal to gas conversions or co-firing projects verified by Andover Technology Partners

State	Plant Name	Unit	MW	Status or completion date
AL	E C Gaston	1	254	Complete by 2015[17] ~30 mile pipeline
AL	E C Gaston	2	256	
AL	E C Gaston	3	254	
AL	E C Gaston	4	256	
AL	Greene County	1	254	Complete by 2016[18]
AL	Greene County	2	243	
AZ	Cholla	1	116	Convert in 2025[19]
AZ	Cholla	3	271	
AZ	Sundt, Irvington	4	156	Complete by 2018[20]
CO	Cherokee	4	352	Complete 2017[21] 34 mi. pipeline
DE	Edge Moor	3	86	Completed
DE	Edge Moor	4	174	Completed
GA	Yates	Y6BR	352	Complete by 2015[17]
GA	Yates	Y7BR	355	
IL	Joliet	71	250	Complete by 2016[22]
IL	Joliet	72	251	
IL	Joliet	81	252	
IL	Joliet	82	253	
IL	Joliet	9	590	
IN	IPL - Harding Street Station (EW Stout)	5	106	Complete by 2016[23]
IN	IPL - Harding Street Station (EW Stout)	6	106	
IN	IPL - Harding Street Station (EW Stout)	7	435	
IA	Riverside	9	128	Complete by 2016[24]
MS	Watson	4	232	Complete by April 2015[18]
MS	Watson	5	474	
MN	Hoot Lake	2	58	Complete by 2020[25]
MN	Hoot Lake	3	80	
MN	Laskin Energy Center	1	55	Complete in 2015[26]
MN	Laskin Energy Center	2	51	
MO	Meramec	1	119	Units 1 & 2 to be converted in 2016[27]
MO	Meramec	2	120	

State	Plant Name	Unit	MW	Status or completion date
NJ	Deepwater	1	82	Completed
NJ	Deepwater	8	73	Completed
NY	Dunkirk	1	75	Requires construction of 9 or 11 mile pipeline. To be complete 2015[28]
NY	Dunkirk	2	75	
NY	Dunkirk	3	185	
NY	Dunkirk	4	185	
OH	Avon Lake	7	96	To be complete 2016, ~20 mile pipeline to be built.[29]
OH	Avon Lake	9	640	
OK	Muskogee	4	505	Complete by 2017[30]
OK	Muskogee	5	517	
PA	Brunner Island	1	312	Pipeline being added, unclear which units to be converted or use of cofiring[31, 32]
PA	Brunner Island	2	371	
PA	Brunner Island	3	744	
PA	New Castle	3	93	Complete by 2016[33]
PA	New Castle	4	95	
PA	New Castle	5	132	
VA	Clinch River	1	230	Two of three to be converted by September 2015, third to shutdown[34]
VA	Clinch River	2	230	
VA	Clinch River	3	230	
WI	Blount Street	8	51	Completed[35]
WI	Blount Street	9	50	
WI	Valley (WEPCO)	1	67	Complete in 2015/16
WI	Valley (WEPCO)	2	67	
WI	Valley (WEPCO)	3	67	
WI	Valley (WEPCO)	4	67	
WY	Naughton	3	330	By 2017[36]

Notes: This table is likely to be an incomplete list of all announced projects. Also, an effort was made to verify that the units on this table were not subsequently retired or are not being converted to combustion turbines or combined cycle.

Andover Technology Partners Findings in Brief.

The accompanying white paper by Andover Technology Partners provides general background on the economic, logistical, and engineering dimensions of converting utility boilers to gas. In addition, Andover provides sixteen in-depth case studies of conversion projects that have either been recently concluded or are currently planned. It concludes that:

> *In recent years the economics of converting to natural gas has changed for many facilities. First, natural gas prices fell rapidly a few years ago – reaching a historic low in real (inflation adjusted) cost in 2012 - and although gas prices have risen from that low, natural gas prices have – for most locations in the US - been much more stable than in the past. Second, increased stringency of environmental regulations have increased the cost of burning coal. As such, utilities have become reluctant to expend capital on aging coal units that are less economically viable than in the past. As will be demonstrated in the case studies in this report, avoiding the costs associated with complying with US EPA's Mercury and Air Toxic Standards (MATS) or the Regional Haze Rule (RHR, and the need to install Best Available Retrofit Technology, or BART) have been important motivators in the conversion of some of these facilities to natural gas. There are other factors as well. Some of these facilities have low capacity factors in part due to increased renewable generation and natural gas combined cycle that have displaced coal from base load use to cycling duty. In some of these cases it was more economical to convert the now cycling coal boiler to natural gas than to build new simple cycle combustion turbines for peaking conditions that have*

similar heat rates as the boiler..For the most part, where cost information was available, the cost of the boiler modifications were usually lower than anticipated by EPA in the Technical Support Document for the proposed Clean Power Plan. This is because EPA's cost estimates for natural gas conversion include several elements that are not necessary in many cases.

BSER Factor Analysis – Technical feasibility. The technology to convert a coal-fired utility boiler to burn natural gas is well-demonstrated and commercially available, as EPA acknowledges. Utilities have been converting coal-fired units to burn natural gas for at least a decade.[443] As demonstrated by Andover Technology Partners and others, industry is undertaking conversions at a wide variety of units, including very old EGUs,[444] baseload power plants,[445] and facilities that are over thirty miles from natural gas pipelines.[446] As further evidence of the technical feasibility of coal-to-gas conversion, several engineering firms have developed literature outlining economic and technical considerations for utilities that are considering such projects.[447] A recent Black & Veatch paper describes the well-understood process for converting a coal-fired unit to run entirely on natural gas.[448]

Although conversion of a boiler to operate on natural gas involves some physical modifications to the facility, these modifications are often relatively modest. Coal-to-gas conversion projects can usually be accomplished without replacing the existing boiler, and often entail only the construction of natural gas delivery infrastructure (where not already available) and modifications to burners and ducts.[449] Indeed, the Andover report indicates that many such projects can be completed during periods when a plant would otherwise need to be offline for maintenance, and in most cases take only a few months to complete (excluding any pipeline construction). We are unaware of any existing sources for which conversion to natural gas is technologically infeasible.

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[443] *See, e.g.*, Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp (Possum Point Power Station "Units 3 & 4 are fired using natural gas but were converted from coal in May of 2003. Unit 3 generates 96 MW and Unit 4 generates 220 MW.").

[444] The Blount Street power plant was first built in 1903 and converted to burn natural gas in 2010. Thomas Content, "MG&E stops burning coal in Madison plant," Milwaukee Journal Sun (March 18, 2010), available at http://www.jsonline.com/business/88508257.html.

[445] Darren Epps, "Alabama Power switching to natural gas from coal at 4 Gaston plant units," SNL (Jan. 17, 2014) (reporting Alabama Power's application to convert 4 units, each with a capacity of about 250 MW, to burn natural gas); Colorado Department of Regulatory Agencies, "Colorado's electric grid and the role of base load and "peaker" electric generating units" (classifying the 352-Mw Cherokee unit 4 as a baseload plant).

[446] Xcel Energy, Cherokee Repowering & Natural Gas Pipeline Projects, available at http://www.xcelenergycherokeepipeline.com ("The Cherokee Natural Gas Pipeline Project has been completed."); Thomas Spencer, "Alabama Power to connect Shelby plant to natural gas line," The Birmingham News, available at http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html (citing an Alabama Power spokesperson for information that the coal-to-gas conversion project at the Gaston Steam Plant will involve building a gas pipeline to tie into the Transcontinental pipeline, which runs across Alabama about 30 miles south of the plant).

[447] *See generally* Babcock & Wilcox, Natural Gas Conversions of Existing Coal-Fired Boilers (2010) ("This paper will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision."); Black & Veatch, Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch (2012) ("This paper explores several technically feasible options available on the current market" for retrofitting coal-fired units, including full conversion to natural gas).

[448] Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch.

[449] *See* Babcock & Wilcox at 2.

BSER Factor Analysis - Emission reductions. Switching to natural gas fuel has very significant potential for reducing the combustion carbon emissions from fossil fuel-fired utility boilers and IGCC units—a critical factor in the BSER analysis. EPA's analysis of conversions for the proposed emission guidelines concluded that a converted utility boiler firing 100% natural gas would have an emissions rate of 1,239 lb CO_2/MWh_{net}, representing a 41% reduction in CO_2 emissions rate from 100% coal firing.[450] The case studies in the Andover report confirm that coal-to-gas conversions can achieve significant reductions in CO_2; the five units covered in the report that have already completed conversions have reported an average 38% reduction in CO_2 emission rates.[451]

EPA should also consider the benefits of co-pollutant emission reductions that would result from converting a unit to burn natural gas. EPA reasonably estimated that converting to 100% natural gas would significantly reduce a unit's emissions of SO_2, NO_x, and $PM_{2.5}$.[452] The five completed conversion projects documented in the Andover report reported average reductions in SO_2 emission rates of 99% and average reductions in NO_x emission rates of 48%. These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between $\$67/MWh_{net}$ and $\$150/MWh_{net}$—a factor of at least two times the costs associated with conversion, as noted below.[453] By promulgating an appropriately stringent standard for CO_2 emissions from existing sources, EPA can greatly reduce the health burdens on the communities living near these sources.

BSER Factor Analysis – Costs. EPA rejected coal-to-gas conversions as BSER because it found that unit conversions were "an inefficient way to generate electricity compared to use of an NGCC" and that CO_2 reductions from this option were "relatively expensive."[454] However, even where up-front costs are substantial, some utilities have projected net savings for electricity consumers, as the result of reductions in a unit's fixed and variable operating costs.[455] As the Andover report notes, coal-to-gas conversions are currently being undertaken by many utilities because they sometimes represent the most economical option for meeting emission reduction requirements at units that have low to intermediate capacity factors.

EPA estimates the costs of CO_2 avoided from a conversion project to be \$83 per metric ton in a representative case, and as low as \$75 per metric ton where fuel-switching would not require capital investment or impact on unit performance.[456] In terms of generation, EPA estimated that conversion to

[450] EPA Office of Air and Radiation, GHG Abatement Measures at 6-6, Table 6-1 (June 2014) ("TSD").
[451] Andover report at 3.
[452] TSD at 6-6, Table 6-2. EPA reasonably estimated that 100% gas conversion would reduce emissions of SO_2 by 3.1 lb/MWh_{net}, reduced NO_x by 2.04 lb/MWh_{net}, and reduced $PM_{2.5}$ by .2 lb/MWh_{net}.
[453] TSD at 6-7, Table 6-3. Even given a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through natural gas conversion to be between $\$61/MWh_{net}$ and $\$140/MWh_{net}$. *Id.*
[454] 79 Fed. Reg. at 34982.
[455] *See* Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be \$62 million and "rates for electric customers will go down by .31%, for a net savings of \$10.2 million in 2016").
[456] 79 Fed. Reg. at 34982.

natural gas would increase the fuel costs of an EGU by approximately \$30/MWh (three cents per kWh), increase capital costs by \$5/MWh, and *reduce* fixed operating costs by 33% and variable operating costs by 25%.[457] These net costs may be higher than other options EPA has considered, but they are significantly lower than the benefits associated with criteria pollutant reductions from conversion—which as noted above, are approximately \$67-150/MWh_{net}. Adding in the benefits of reduced carbon pollution would only increase the net benefits of conversion as a BSER. The net costs of conversion to gas are certainly within the relevant limits that courts have placed on the costs of performance standards under section 111.[458] Indeed, the fact that many conversion projects have been recently completed or are currently underway shows that the costs are reasonable, and in no way approach the legal standard for a BSER.

Moreover, there is evidence to suggest that EPA's cost estimates are unrealistically high. Andover's white paper concludes that EPA's capital cost estimates are too high because they include all possible modifications that might be necessary as a result of a coal-to-gas conversion, rather than the more modest modifications that are typically required at the average plant. Andover's survey of coal to gas conversions found that the typical capital costs are closer to \$3/MWh, or 40% lower than EPA's estimate. In addition, it appears that EPA has significantly underestimated the costs of coal for many utility boilers by citing national averages instead of specific coal types. In the Technical Support Document, EPA states " base case projections for delivered gas prices…are about double projected delivered coal prices on average (\$2.62/MMBTU for coal and \$5.36/MMBTU for gas). As a result, the fuel cost for a typical converted boiler burning 100% gas is expected to be at least double its prior fuel cost on an output basis as well."[459] However, according to EIA data, in November 2014 spot prices were about \$4.50 per mmBtu of Central Appalachian coal, \$4.89 per mmBtu of Northern Appalachian coal, \$3.79 per mmBtu of Illinois Basin Coal, \$3.23 per mmBtu of Uinta Basin coal, but only \$1.31 per mmBtu of Powder River Basin coal.[460] In the Annual Energy Outlook, EIA projects that mine mouth prices for coal will increase approximately 17 and 33 percent by 2020 and 2030, respectively. This suggests that natural gas may be cheaper than some sources of coal by 2020, and that the price gap for many sources of coal could narrow considerably.

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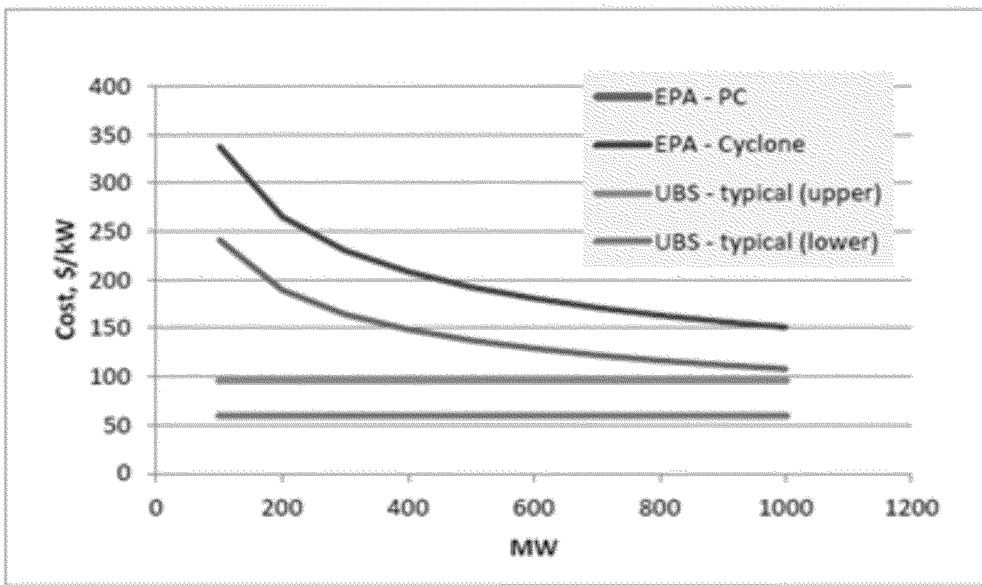
[457] TSD at 6-4. According to EIA's most recent estimates of generation costs, fixed O&M costs for an advanced pulverized coal EGU are approximately \$31-38/kW-yr (equivalent to approximately \$5/MWh) and variable O&M costs are approximately \$4.50/MWh. *See* EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants at 6 (Apr. 2013).

[458] Courts have determined that costs of performance standards under section 111 must not be "exorbitant", *see Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive", *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").

[459] GHG Abatement Measures TSD at 6-5.

[460] *See* EIA, *Coal News and Markets,* http://www.eia.gov/coal/news_markets/ (last visited Nov. 26, 2014).

Figure 2. Estimated cost for boiler modifications associated with gas conversion



Coal-to-gas conversion has emerged as a means of complying with emission standards precisely because it is sometimes the most cost-effective strategy.[461] Several coal-fired units are being converted to burn natural gas because it is the units' most economical option for complying with other emission limitations.[462] The cost of converting to natural gas fuel depends on whether the unit was originally designed to be capable of burning natural gas. The cost of fuel-switching boilers is minimal for units that are already designed to burn gas, but the cost of more extensive retrofits is still moderate (and well below the legal standard for BSER) in the context of carbon pollution standards for existing power plants.[463]

[461] Michael Niven and Neil Powell, "Coal unit retirements, conversions continue to sweep through power sector," SNL Data Dispatch (Oct. 14, 2014).
[462] Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6 at 1-18 ("Finally, for the remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost- effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel, with coal used as a backup fuel."); *see also id.* at 1-11 (requesting favorable amortization of "approximately $14 million of Plant Yates Units 6 and 7 environmental construction work in progress"). Conversion to natural gas is likely to be a cost-effective compliance option for any facility with limited planned service hours. Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch at 7, Table 7.
[463] Ameren Missouri, 2014 Integrated Resource Plan at 4-18:

> Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired

Even where retrofit costs are significant, the conversion to natural gas is cost-effective and can be achieved in a manner that enables electricity consumers to save money.[464]

For some units, building a pipeline is one cost associated with conversion to natural gas. EPA's cost estimates assumed that a unit converting to natural gas would need to build a 50-mile pipeline at a cost of $50 million.[465] EPA estimated pipeline construction would contribute $100/kW to the capital costs of a 500 MW unit, while capital costs as a whole represented only one-seventh of the cost impact of natural gas conversion.[466] EPA's analysis shows that building a long pipeline is generally a relatively small part of the cost of converting a unit to burn natural gas. Consequently, units can undergo conversion at reasonable cost even when they are located at a significant distance from existing pipeline infrastructure. For most units, however, the cost of building a pipeline is likely to be less than EPA assumed. This is because the median distance of a coal-fired unit from a pipeline is 28.3 miles—just over half the length of the pipeline in EPA's calculations.[467]

BSER Factor Analysis – Non-air health and environmental impacts. EPA did not consider the non-air quality health and environmental impacts of the systems it identified as potentially representing the BSER.[468] If EPA had performed the "mandated consideration of the factors enumerated in section 111(a),"[469] the agency would have recognized that switching to natural gas firing at existing units has substantial non-air health and environmental benefits. For example, coal-to-gas conversion eliminates an existing EGU's production of coal combustion residuals (also known as coal ash), which is an industrial waste that contains a range of toxic substances, including arsenic, selenium, and cadmium. Carcinogens and toxic chemicals from coal ash can leach into drinking water supplies and accumulate in the fish we eat.[470] Conversion to natural gas firing also reduces on-site water quality impacts.[471]

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operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

[464] See e.g. Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be $62 million and "rates for electric customers will go down by .31%, for a net savings of $10.2 million in 2016")

[465] TSD at 6-4.

[466] TSD at 6-4 to 6-5. In EPA's estimation, increased fuel costs were responsible for most of the cost of natural gas conversion. *Id.*

[467] See EPA, Table 522 Cost of Building Pipelines to Coal Plants. The average length of pipeline that would need to be built to hook up a coal-fired unit is 61.6 miles. The average is greater than the median because there are a few outliers that are very far from a pipeline hookup. The most isolated coal-fired unit is 713.3 miles from a hookup.

[468] 79 Fed. Reg. at 34981-85. *Sierra Club*, 657 F.2d at 323 ("the agency must consider all of the relevant factors and demonstrate a reasonable connection between the facts on the record and the resulting policy choice").

[469] *Sierra Club*, 657 F.2d at 346, n.175.

[470] EPA, Human and Ecological Risk Assessment of Coal Combustion Wastes (draft) (April 2010). One of the study's conclusions was that managing coal ash in unlined or clay-lined waste management units results in up to 1 in 50 excess cancer risks.

[471] As the Wisconsin Public Service Commission observed in approving the conversion of Valley Power Plant, "Converting the plant from coal to natural gas would eliminate some discharge sources and reduce wastewater treatment requirements. Conversion would eliminate coal pile runoff, yard runoff, ash transport water, and equipment wash wastewaters that convey coal or ash, thereby removing a potential source of mercury." Public Service Commission of Wisconsin, Final Decision, Application of Wisconsin Electric Power Company for

EPA should consider the energy benefits of a standard based on coal-to-gas unit conversion. Conversion to natural gas would likely reduce the energy requirements of the unit because natural gas units have lower parasitic loads. Unit conversion also reduces electricity demand for fuel preparation (including coal transport, crushing, pulverizers).[472] The reduction in parasitic load results in an increase in net output.

Conclusion. A careful weighing of the statutory criteria leads to the conclusion that conversions to natural gas fuel are part of the BSER for existing fossil fuel-fired utility boilers and IGCC units. This system will achieve greater reductions than EPA's current proposal for Building Block 1, and can do so at a cost that is well below the legal standard. Moreover, a standard based on natural gas conversion will have important non-air health and environmental benefits and reduce dangerous co-pollutant emissions.

Co-firing with natural gas

EPA considered co-firing with natural gas as a potential BSER, but concluded that it was not BSER due to the allegedly high costs of the resulting emission reductions.[473] However, as with natural gas repowering, EPA's analysis does not appropriately characterize the costs of co-firing or reflect full consideration of the BSER factors. Natural gas co-firing is already commonplace in the industry. Natural gas can be used to assist with startup or shutdown, to make up for the low Btu values in Western coals in boilers originally designed to combust eastern coals, and it has been used historically as a NOx emissions controls through a process known as reburning. Although EPA's analysis indicates that the net benefits of conversion to gas are greater than those associated with co-firing, EPA should consider significant levels of co-firing with gas as part of the BSER under Building Block 1 in the event that it determines conversion to gas does not meet the BSER criteria, or does not meet those criteria for all coal-fired plants.

BSER Factor Analysis – Technical feasibility and cost. The technology to co-fire that natural gas co-firing in coal-fired utility boiler is well-demonstrated and commercially available, being used for a variety of different reasons, including startup, emissions control, and to make up for the low Btu value of western coals. According to the Andover white paper,

> *Modifying a boiler for natural gas cofiring can sometimes be done with fairly minimal modifications, depending upon the intent and how much gas will be co-fired. Facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters. In this case gas cofiring up to the capacity of the gas igniters can be performed at no additional capital cost. In some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications.*

Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility (March 17, 2014) at 19, available at http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=200566.

[472] Richard Vesel, "Utilities Can Improve Power Plant Efficiency, Become Emission-compliant in Short Term" Electric Light & Power (Nov. 1, 2012), available at http://www.elp.com/articles/print/volume-90/issue-6/sections/utilities-can-improve-power-plant-efficiency-become-emission-compliant-in-short-term.html.

[473] 79 Fed. Reg. at 34,982.

Furthermore, Andover found that natural gas reburning has been used commercially and was demonstrated commercially as early as the 1990s as a means of NOx control. They found that the cost of natural gas reburning was approximately $15/kW when including the cost of gas injectors, overfire air, and associated controls. Adjusting for today's costs, they estimate that similar retrofits would cost $23/kW today. However, they determined that actual costs may be less today because many boilers have installed overfire air systems and other modifications that were typically performed then but may be unnecessary today.

Natural gas is frequently co-fired in coal-fired boilers during start-up as gas igniters heat up the furnace in order to allow ignition of the coal. According to analysis by Andover Technology Partners, facilities that start up on gas have the ability to burn at least 10% of the heat input on gas through the gas igniters at no additional capital cost. They also found that in some cases, the boiler is designed to accept higher levels of natural gas without any additional modifications.

Gas cofiring is also common at facilities that have converted from Eastern to Western coal due to its lower Btu value. The number of facilities that have done so may be significant, particularly when one considers the significant expansion of Western coal since the 1990s and even since the 1990s, after which relatively few new coal plants were built.

BSER Factor Analysis – Emission reductions. Co-firing with natural gas fuel has very significant potential for reducing the carbon emissions from fossil fuel-fired utility boilers and IGCC units—a critical factor in the BSER analysis. EPA's analysis for the proposed emission guidelines concluded that a utility boiler firing 10% natural gas would have an emissions rate of 2,021 lbs CO_2/MWh_{net}, representing a 4% reduction in CO_2 emissions rate from 100% coal firing.[474] Supplying 50% of the boiler's heat input with natural gas would lower the emission rate to 1,673 lbs CO_2/MWh_{net}, a 21% reduction in emissions rate from 100% coal firing.

EPA should also consider the benefits of co-pollutant emission reductions that would result from converting a unit to burn natural gas. EPA reasonably estimated that converting to 10% natural gas would reduce a unit's emissions of SO_2, NO_x, and $PM_{2.5}$.[475] These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between $\$6.5/MWh_{net}$ and $\$15/MWh_{net}$.[476] The benefits of co-firing at 50% would likely be proportionally greater – or approximately $30 to $75/MWh.

Conclusion. A careful weighing of the BSER criteria leads to the conclusion that significant co-firing of natural gas can be part of the best system for emissions reduction for existing coal-fired utility boilers and IGCC units, in the event that EPA determines full coal-to-gas conversion does not meet the BSER criteria (or does not meet the criteria at certain plants). This will achieve far greater reductions than the current

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[474] EPA Office of Air and Radiation, GHG Abatement Measures at 6-6, Table 6-1 (June 2014) ("TSD").

[475] TSD at 6-6, Table 6-2. EPA reasonably estimated that 100% gas conversion would reduce emissions of SO_2 by 3.1 lb/MWh_{net}, reduced NO_x by 2.04 lb/MWh_{net}, and reduced $PM_{2.5}$ by .2 lb/MWh_{net}.

[476] TSD at 6-7, Table 6-3. Even given a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through natural gas conversion to be between $\$61/MWh_{net}$ and $\$140/MWh_{net}$. *Id.*

proposal for Building Block 1, and can do so at a cost that is well below the legal standard. Furthermore, this system can yield significant co-pollutant reduction and health benefits.

Onsite redeployment.

Additional CO2 emissions reductions could be achieved by switching the deployment order of different units at a single power plant based on the efficiency of the unit and/or the CO_2 intensity of the fuel deployed. We encourage EPA to evaluate the opportunities for such reductions in the final rule.

H. Comments on Building Block 2: Increase Dispatch of Lower-Carbon Generation

In Building Block 2, EPA considers the potential to reduce emissions by redispatching generation from coal-fired steam generation to existing natural gas combined cycle (NGCC) plants, which emit roughly half as much carbon dioxide per megawatt hour of generation. EPA's June 2, 2014 proposal focused on redispatch from coal-fired steam generation to existing NGCC plants operating at less than 70 percent capacity. EPA also requested comment on whether it should allow new NGCC plants to be a source of compliance credits even if those plants were not considered in setting the targets. As described below, EPA must maintain symmetry between the target setting and compliance.

On October 30, 2014, EPA published a Notice of Data Availability evaluating the potential to reduce emissions by switching dispatch to new NGCC units and by using natural gas at existing coal plants through co-firing or conversion of those plants. 79 Fed. Reg. 64543 (Oct. 30, 2014). EPA also requests comment on an approach that would treat the increased use of natural gas "comprehensively" rather than considering separately the potential to redispatch generation to: 1) existing NGCC, 2) new NGCC, and 3) co-fire natural gas at coal plants or to convert coal plants to run on natural gas. *Id.* at 64546.

EPA should take such a comprehensive approach. We recommend that EPA adopt as a component of BSER a minimum level of generation shift from higher-emitting to lower-emitting fossil sources that can be met by any of these methods. This minimum level should be based on what is cost-effective and reasonable based on historic trends and electric and natural gas sector modeling. As discussed below, EDF believes EPA should assume that at least two percent of a state's coal use shifts to natural gas per year from 2020 to 2029 (at least 20% over a ten year period) through a combination of these three means. This would be a minimum value. If the amount of underutilized existing NGCC capacity in a state (or other pathways of coal to gas transition) would allow for a greater redispatch between coal and gas, that higher level should be used to set the state's target.

These comments address the question of what carbon reduction techniques EPA should use to set state targets in the BSER Guideline. State compliance plan development will involve different considerations. We believe that even if EPA follows all our recommendations for strengthening the targets deemed BSER, EPA will not have exhausted the scope of cost-effective reductions achievable through the various building blocks. In other words, even the analysis we present is likely to conservatively underrepresent the true volume of cost-effective reductions available to EGUs. Thus, states (and likely sources) will have significant flexibility in choosing which combination of measures to employ to meet their applicable targets. We will urge states to rely as much as possible on efficiency and renewables to achieve compliance, in order to avoid or limit expanded reliance on natural gas. This is because investments in energy efficiency and renewable energy provide the soundest long-term investment in our clean energy future.

1. Treatment of New NGCC for Target Setting and Compliance Must be Symmetrical

The definitions of "standard of performance" and "emissions guideline" both provide, in substance, that standards must achieve as much emission reduction as is technically achievable by the sources subject to them considering cost. EPA must determine that the emission limit achieves the emission reductions that are "achievable" using measures that are "adequately demonstrated"— a test of feasibility. The agency also must "tak[e] into account the cost" as well as energy and non-air environmental impacts. The result is "the best system of emission reduction."

The technical and economic feasibility of an emission limit is linked to the methods available for demonstrating compliance.[477] If a guideline allows compliance through a given method of reducing emissions, and that method is a superior system of emission reduction or would be part of a superior system of emission reduction, then EPA must consider that compliance method when determining the level of reductions that the standard of performance or target requires. The statute requires symmetry. It *would be a deviation from the statute* for EPA to set a target based on a reasonably foreseeable emission reduction technique but not allow that technique to be used for compliance purposes. Likewise, it would be a deviation from the statute to allow the use of a reasonably foreseeable emission reduction technique for compliance purposes but exclude it from consideration when setting the target—particularly when that emission reduction technique is expected under the Agency's own analysis (79 Fed. Reg. at 34,876) to play a significant role in compliance.

In this instance, given existing market trends and the Agency's own analysis of possible compliance scenarios, it is reasonable to project the construction of certain amounts of new NGCC capacity; such capacity must reasonably be considered adequately demonstrated at a reasonable cost. The emissions limit in the guideline must reflect the emission reductions that can be achieved through the use of such new NGCC plants.

EPA's initial proposed rule suggested that it might consider excluding new NGCC plants from the determination of the targets but would allow them to be used to generate credits. This asymmetry is not permitted. If EPA were to exclude a new NGCC capacity from target-setting but allow it to be used for compliance, the standard would under-represent the degree of reduction achievable at reasonable cost.

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[477] *See,* e.g., *Portland Cement Association v. Ruckelshaus.* 486 F.2d 375. 396 (D.C. Cir. 1973) (measurements relied on to demonstrate achievability may have "deviate[d] from procedures, outlined by regulation, for ascertaining compliance with prescribed standards").

2. Redispatching generation from coal to natural gas, co-firing, and conversion of coal plants to operate on natural gas are all adequately demonstrated and cost-effective.

The potential to reduce carbon pollution at the point of combustion by using natural gas in lieu of coal is fully demonstrated. The power sector has been constructing and generating electricity with natural gas in combined cycle natural gas plants for many decades. After a long period during which coal-fired steam generation dominated baseload generation in the United States, a significant switch of baseload capacity from coal-fired steam generation to NGCC has occurred. EIA data indicate that from 2003 to 2012, coal generation fell from about 2 million GWh to 1.5 million GWh.[478] During the same period, natural gas capacity increased from 165 GW to 242 GW and generation climbed from about 650 thousand GWh to over 1.2 million GWh, as a result of both increased capacity factors at existing plants and new facility construction. Today, natural gas plants are commonly operating as baseload plants, providing 27 percent of U.S. net power generation in 2013,[479] compared to only 10 percent in 1994.[480]

According to EIA, annual changes in natural gas capacity and generation have been significant. Over the ten year period from 2003 to 2012:

- Annual natural gas capacity increases have averaged 12 GW per year with 41 GW added in 2003 (and in 2002), which is an average annual increase of 6% and a maximum of 25%.

- Annual natural gas generation increases have averaged 5% per year with a maximum of 17%.

Likewise, the use of natural gas to co-fire alongside coal in steam generating plants and the conversion of coal-fired power plants to operate on natural gas is well established.

The potential carbon pollution reductions are well established. Burning coal to generate a given unit of energy generates nearly twice the carbon at the stack as does burning natural gas to generate the same unit of energy.[481] (As we note in more detail below, in order for these emission reductions to mitigate rising atmospheric levels of greenhouse gases it is also critical that EPA act to reduce the methane leakage that occurs during the production and distribution of natural gas and during the mining of coal.)

a. Redispatch to Existing NGCC

The capacity to operate NGCC plants at a 70 percent capacity factor is well established. As EPA notes, more than ten percent of existing NGCC plants have operated at a seventy percent capacity factors in recent years.[482] Similarly, IPM modeling demonstrates that operating each state's NGCC fleet at such a

[478] EIA, Electric Power Monthly (Apr. 2014), at Table 1.1, *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01.
[479] *Id.*
[480] EIA, Electric Power Monthly (July 1996), *available at* http://205.254.135.7/electricity/monthly/archive/pdf/02269607.pdf.
[481] http://www.eia.gov/environment/emissions/co2_vol_mass.cfm
[482] *See* Greenhouse Gas Abatement Technical Support Document at 3-9.

capacity factor (on average) is technically feasible.[483] The costs of such redispatch are also reasonable. EPA reports that the IPM model shows the cost of such redispatch to be 30 or 33 dollars per metric ton of avoided carbon, depending on whether a regional or state-specific approach was taken. 79 Fed. Reg. at 34865. As EPA notes, these costs are reasonable even without considering the additional public health and climate benefits that such a shift in dispatch would create.

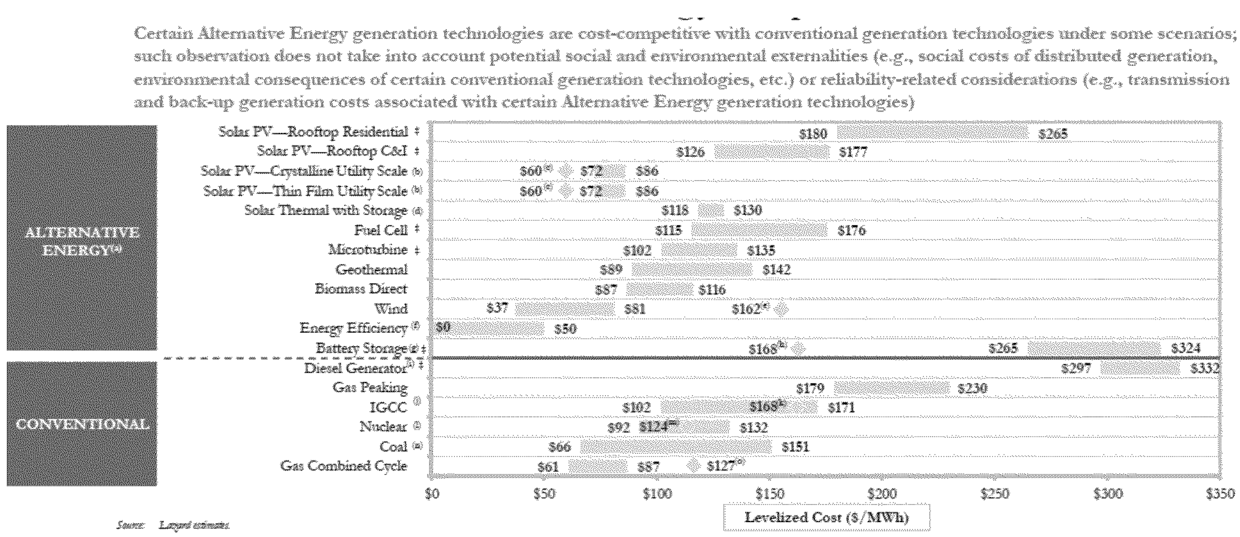
b. New NGCC Plants

The 119 GW of new NGCC plants that have been constructed over the ten year period from 2003 to 2012 (EIA) confirm that it is reasonable to anticipate a continued rate of expansion of this well-understood technology.[484] This conclusion is affirmed by the IPM compliance modeling of the Clean Power Plan conducted by EPA, which showed that "construction and operation of new NGCC capacity will be undertaken as a method of responding to the proposal's requirements." 79 Fed. Reg. at 34,876.

The IPM model results also affirm that the costs of new NGCC are reasonable. The IPM model seeks to satisfy each state's target rate through the least expensive methods. Thus, the fact that the model selected new NGCC (even though NGCC was not included to set the targets) demonstrates that the costs of such plants are reasonable. (We note, however, that neither the renewable energy nor the energy efficiency costs were accurately represented in these modeling runs, as discussed further below.)

In addition, financial analysts such as Lazard have determined that new NGCC is one of the lower cost generation resources available to power companies today, as shown in the figure below (energy efficiency, wind, and utility scale solar are also competitive with natural gas).[485]

Figure 3. Comparison of Unsubsidized Levelized Costs of Energy Generation



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[483] *See* 79 Fed. Reg. at 34,865.
[484] http://www.eia.gov/todayinenergy/detail.cfm?id=1690.
[485] Lazard's Levelized Cost of Energy Analysis – version 8.0, http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

In recent years, a number of utilities have retired coal-fired power plants and replaced the generation capacity with new NGCC units. For example, in 2007 Xcel Energy retired the coal-fired plant at its High Bridge Generating Station in St. Paul, Mississippi and replaced it with generation from new NGCC that came on-line in May 2008.[486] In 2011, the Tennessee Valley Authority (TVA) replaced the coal-fired generation at its John Sevier plant in Tennessee with new NGCC generation, and is in the midst of replacing coal-fired units at the Paradise Fossil Plant in Kentucky with new NGCC.[487] In October 2012, Georgia Power completed construction on three new combined-cycle units at its Plant McDonough-Atkinson in Smyrna, Georgia to replace two coal-fired steam turbines that were retired in September 2011 and February 2012.[488] In 2012, Duke Energy accelerated the retirement of its Cape Fear coal-fired power plant in North Carolina and its H.B. Robinson coal plant in South Carolina by replacing the generation from those plants with power from a new 920-MW NGCC plant at the site of the H.F. Lee plant near Goldsboro, North Carolina.[489] Following the proposal of the Clean Power Plan, additional coal-to-new-NGCC replacement plans have been announced.[490]

c. Co-firing with or Conversion to Natural Gas

The third method of using natural gas to reduce emissions at coal-fired power plants — co-firing or conversion — is similarly well-demonstrated and of reasonable cost. As discussed in more detail in section G of these comments, a number of coal-fired steam generating units have already converted, or are planning to convert, to natural gas. Some utilities converted steam generating units to natural gas more than a decade ago.[491] Conversions—including Alabama Power's conversion of four units at the Gaston

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[486] Xcel Energy, High Bridge Generating Station, http://www.xcelenergy.com/About_Us/Our_Company/Power_Generation/High_Bridge_Generating_Station (last visited Nov. 13, 2014).

[487] Dave Flessner, *TVA's power shift spurs debate over wind, gas*, Times Free Press on-line (Aug. 12, 2014) *available at* http://www.timesfreepress.com/news/2014/aug/12/tvas-power-shift-spurs-debate-over-wind/.

[488] Matthew Bandyk, *Georgia Power finishes major coal-to-gas generation conversion*, SNL (Oct. 29, 2012) *available at* https://www.snl.com/InteractiveX/articleabstract.aspx?ID=16152278&KPLT=2.

[489] Duke Energy, *Progress Energy Carolinas to retire two coal-fired power plants Oct. 1*, Press Release (Sept. 28, 2012), http://www.duke-energy.com/news/releases/2012092801.asp;
John Crawford, *Duke speeds retirement of Cape Fear coal units, unveils Robinson closure*, SNL (Jul. 27, 2012) available at https://www.snl.com/InteractiveX/articleabstract.aspx?ID=15413584&KPLT=2.

[490] For instance, the TVA announced that it will replace aging coal-fired units at the Thomas H. Allen plant in Memphis, Tenn., with a new 2-on-1 combined-cycle natural gas power plant by December 2018, and Ameren Missouri recently announced that it plans to retire 984 MW of coal-fired units Sioux Energy Center, with the generation to be partially replaced by construction of a 600 MW new NGCC plant to be built by 2034. Anna Lee Grant, *TVA approves replacing Tenn. coal plant with 1,000-MW gas unit*, SNL (Aug. 21, 2014) *available at* https://www.snl.com/Cache/snlpdf_4d94da97-70d7-4420-8cc9-1e35e8ad4b1b.pdf; Eric Wolff, *Ameren Missouri to add renewables, cut coal power in 20-year plan*, SNL (Oct. 1, 2014) *available at* https://www.snl.com/InteractiveX/article.aspx?ID=29378157; *see also* Matthew Bandyk, *TVA proposes retiring Allen coal-fired plant, replacing it with gas generation*, SNL (Jul. 2, 2014) *available at* http://www.snl.com/InteractiveX/article.aspx?ID=28537041; Darren Epps, *Even as it cuts coal, TVA sees difficult road to meet Clean Power Plan rule*, SNL (Aug. 7, 2014) *available at* http://www.snl.com/interactivex/article.aspx?id=28848062&KPLT=6.

[491] In 2003, Dominion Energy converted two units at its Possum Point Power Station from coal to gas. Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp.

Electric Generating Plant—have occurred at baseload generating units.[492] Utilities have even found it economical to convert to gas even when this required the construction of more than thirty miles of pipeline.[493] The cost of conversion is minimal for units that are already designed to burn gas,[494] but even where up-front costs are substantial, some utilities have projected net savings for electricity consumers, as the result of reductions in a unit's fixed and variable operating costs.[495] Recent reports indicate that 10,894 Mwh of coal generation are currently slated for conversion to natural gas.[496]

As EPA notes in the NODA, co-firing also results in significant operational advantages. These include significant reductions of criteria air pollutants including nitrogen oxides, sulfur dioxide, particulate matter, and of hazardous air pollutants, including mercury. 79 Fed. Reg. at 64550. These reductions could allow co-firing power plants to reduce the pollution control equipment operating costs. *Id.* Co-firing could also allow for faster ramp-up and down, allowing for more cost-effective operation of the plants. *Id.* Finally, co-firing is generally not capital intensive.

The cost of co-firing or conversion is within an acceptable range. EPA may select any system that satisfies the other requirements of BSER as long as the system's costs are not "exorbitant."[497] The costs of conversion meet this standard easily. The number of existing and planned conversion projects taken absent any regulatory carbon pollution mandate is strong evidence that the costs are reasonable. Moreover, EPA's own data demonstrate that conversion to natural gas generates substantial net benefits. EPA estimated that the capital costs of conversion (including new pipeline) are $5 per MWh and the increased fuel cost is $30 per MWh, but the health benefits alone of conversion are between $60 and $140 per MWh.[498] EPA observes that the cost per ton of CO_2 avoided is "relatively expensive," but it is certainly not "exorbitant," especially when the full range of benefits associated with conversion are taken into account.

[492] *See* Scott Disavino, *Southern to Repower Three Alabama Coal Power Plants with Natgas*, REUTERS (Jan. 16, 2014), http://www.reuters.com/article/2014/01/16/utilities-southern-alabama-idUSL2N0KP1WA20140116
[493] *See* Thomas Spencer, *Alabama Power to Connect Shelby Plant to Natural Gas Line*, BIRMINGHAM NEWS (May 12, 2012), http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html.
[494] *See* Ameren Missouri, 2014 Integrated Resource Plan at 4-18, http://www.ameren.com/sitecore/content/Missouri%20Site/Home/environment/renewables/ameren-missouri-irp (noting that the cost to convert Units 1 & 2 at Meramec Energy Center Units 1–4 from coal to natural gas was less than $2 million, because these units were designed with the capability to operate on natural gas).
[495] *See* Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be $62 million and "rates for electric customers will go down by .31%, for a net savings of $10.2 million in 2016").
[496] : See http://www.mining.com/web/snl-energy-coal-unit-retirements-conversions-continue-to-sweep-through-power-sector/
[497] Essex Chem. Corp. v. Ruckelshaus, 486 F.2d 427, 433-34 (D.C. Cir. 1973); Lignite Energy Council v. EPA, 198 F.3d 930, 933 (D.C. Cir. 1999).
[498] Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants, GHG Abatement Measures, Chapter 6, Docket ID No. EPA-HQ-OAR-2013-0602, at 6-4 to 6–8 (Jun. 10, 2014).

3. Pipeline Capacity

While some additions to today's natural gas delivery infrastructure may be necessary before 2030, the current natural gas delivery infrastructure is robust and is capable of delivering significantly more natural gas to the power fleet than it does today. This is particularly true on an annual basis, but is also true even during peak periods of demand. Even during extreme cold weather conditions when aggregate natural gas demand for both heating and electric generation is highest (such as during the January 2014 polar vortex), many pipelines have available and unused capacity to deliver more gas. This is not to suggest that there are not periods when some pipelines deliver gas at or near full capacity; it is simply untrue, however, that current pipeline infrastructure is insufficient to deliver substantially more gas to support increased capacity factors for natural gas-fired power plants.

We also note that the Federal Energy Regulatory Commission (FERC) is in the midst of efforts to refine the standards and rules governing interstate gas transportation to among other things, ensure that the market design better serves natural gas-fired electricity generators. These actions should allow utilities to more fully utilize the natural gas delivery infrastructure of today and tomorrow, which will allow the electric power sector to reduce emissions at an even lower cost than would otherwise be possible.

On March 20, 2014 FERC issued a Notice of Proposed Rulemaking ("NOPR") regarding proposed revisions to the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation services.[499] FERC proposed, as part of a series of orders, to revise its regulations to better coordinate the scheduling of natural gas and electricity markets "in light of increased reliance on natural gas for electric generation. . . ." As noted by the Commission, "this trend is expected to continue, resulting in greater interdependence between the natural gas and electric industries."[500] Beginning in 2012, FERC hosted a series of meetings to engage natural gas pipelines, electric transmission operators, and other market participants and stakeholders in both industries regarding natural gas and electric industry coordination. In its April 2013 technical conference, market participants and FERC staff considered natural gas and electric scheduling practices including whether and how natural gas and electric industry schedules could be harmonized in order to achieve the most efficient scheduling systems for both industries.[501] The NOPR was issued in response to an interest in updating market design to enhance the ability of natural gas-fired generators to acquire natural gas, and to augment the means by which the pipelines schedule and deliver natural gas to power plants.

In brief, the NOPR proposes to align the timing for gas pipeline scheduling and delivery to the timetables and utilization patterns prevalent in the electricity markets (e.g., the morning ramp up). It also proposes to increase flexibility for gas-fired generators by requiring pipelines to provide additional delivery scheduling opportunities so that power grid operators and power plants can better adjust to contemporaneous market and operational conditions. In the NOPR, the Commission presented specific

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[499] *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities,* 79 Fed. Reg. 18, 223 (April 1, 2014) ("NOPR").
[500] 79 Fed. Reg. 18, 224 (April 1, 2014).
[501] See, *Staff Report on Gas-Electric Coordination Technical Conferences*, Docket No. AD12-12-000, *available at* http://elibrary.ferc.gov/idmws/File_List.asp.

proposed reforms to existing natural gas industry scheduling practices and also provided market participants within the natural gas and electricity industries an opportunity to collaboratively develop alternatives for changes in scheduling practices, through a consensus standards-development process at NAESB. After a series of meetings and votes over the summer 2014, representatives of the two industries reached a series of agreements to enhance coordination and NAESB subsequently filed a series of consensus standards with the Commission on September 29, 2014. While there remains an open issue regarding the start of the gas day, it is highly likely that FERC's final order, when issued, will include a series of new scheduling and delivery standards which will enhance the operational capabilities of natural gas-fired power plants and the deliverability of natural gas.

Importantly, improvements to gas market design such as those currently being considered by FERC will considerably enhance gas supply and deliverability to power generators from the existing infrastructure. This would allow the electric power sector to reduce emissions at an even lower cost than would otherwise be possible.

4. EPA Should Adopt a Minimum Level of Generation Shift from Higher-emitting to Lower-emitting Sources.

In the NODA, EPA sought comment on an alternative approach that would comprehensively consider generation shift from coal to gas through the three vehicles discussed above – redispatch to existing NGCC, to New NGCC and use of natural gas at coal-fired steam generating units. EPA suggests that a minimum level of generation shift could be adopted for each state. We strongly support this approach for several reasons. First, it is important to take advantage of the potential reductions in point-of-combustion emissions that can be achieved through new NGCC as well as co-firing. Treating different methods of switching from coal to gas comprehensively also makes sense given that these methods can be considered variations of the same basic shift toward cleaner fuels. Second, the minimum shift approach ensures that the potential to shift from coal-to-gas will contribute to the targets in all states with coal-generation, not just those states that happen to have underutilized existing NGCC capacity.

Based on trends in increases in natural gas generation and declines in coal generation over the past ten years, we believe it would be reasonable to expect that natural gas generation to increase at an annual rate of 5% per year from the present through 2030. EPA would need to consider the effect of such an expansion rate on natural gas and electricity prices when evaluating the total costs of the BSER targets. The ramp rate should reflect the actual potential for and any infrastructure build-out needed to facilitate increased use of gas through the three respective pathways—and as such may be different for the different pathways. We urge EPA to consider ramp rates up to and including a continuation of a five percent per year shift rate, the historical average over the last 10 years.

5. New NGCC Subject to 111(b) Standards Can Be Considered for Purposes of Setting 111(d) Targets.

The fact that new NGCC plants are subject to standards of performance under section 111(b) does not prevent EPA from considering their emission reduction potential when establishing targets under section 111(d). New NGCC capacity would not be regulated under section 111(d) any more than new renewable capacity. Rather, EPA would simply consider the potential for existing coal-fired EGUs to cost-effectively acquire credits derived from either source (new NGCC or new renewables) in determining the target appropriate for such EGUs. EPA's proposal to consider new NGCC plants simply requires that new combined cycle gas (NGCC) plants be treated like new renewables or new efficiency: all three are sources of megawatt hours with emissions rates lower than coal plants (or old gas plants) that they would displace. This does not mean that a 111(b) source is placed under a 111(d) obligation. Under EPA's proposal, the agency considers generation created (or avoided) by new renewables, efficiency, and nuclear in its BSER determination but does not propose to make them regulated facilities under 111(d). EPA can apply the same approach to new NGCC plants, which would remain subject only to section 111(b).

6. EPA Must Promptly Limit Methane Emissions from the Oil and Gas Sector

As noted above, carbon dioxide emissions due to coal combustion are roughly twice as high per megawatt hour as carbon emissions from natural gas at existing natural gas combined cycle plants. Exploration, production, and delivery of natural gas, however, results in significant methane emissions—which is a potent climate pollutant, and, if left unaddressed, could undermine the relative climate benefits of replacing coal-fired generation with natural gas combined cycle plants. President Obama committed to taking action on methane as part of the Climate Action Plan, and it is vital for EPA to follow through on this pledge by promptly commencing and completing a rulemaking to set standards limiting emissions of methane from new and existing sources in this sector.

There is an urgent need to reduce emissions of methane and other harmful pollutants from the U.S. oil and natural gas sector. Recently, the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC) concluded that methane is a much more potent driver of climate change than was understood just a few years ago—with a global warming potential as much as 34 times greater than carbon dioxide (CO_2) over a 100-year time frame, and 84 times greater than CO_2 over a 20-year time frame.[502] Approximately one-third of the anthropogenic climate change we are experiencing today is attributable to methane and other short-lived climate pollutants, and about 30 percent of the warming we will experience over the next two decades as a result of this year's greenhouse gas emissions will come from methane.[503] Climate scientists are now recognizing that avoiding catastrophic climate change will

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[502] Working Group I, Intergovernmental Panel on Climate Change (IPCC), *Climate Change 2013: The Physical Science Basis, Fifth Assessment Report* 714, tbl.8.7 (2013), *available at* http://www.climatechange2013.org/images/report/WG1AR5_ALL_FINAL.pdf.

[503] *Id.*

require *both* a long-term strategy to reduce carbon dioxide emissions *and* near-term action to mitigate methane and similar "accelerants" of climate change. As a recent article in the journal *Science* stated, "The only way to permanently slow warming is through lowering emissions of CO_2. The only way to minimize the peak warming this century is to reduce emissions of CO_2 and [short-lived climate pollutants, including methane]."[504]

Reducing emissions from the U.S. oil and gas sector is an indispensable part of such a comprehensive climate strategy. Oil and gas facilities are the largest industrial source of methane in the United States, accounting for approximately thirty percent of the nation's total methane emissions.[505] Estimates of methane emissions in EPA's Annual Inventory of Greenhouse Gas Emissions and Sinks are based on bottom-up assessments. In addition to these, there have been numerous, recent top-down studies uniformly suggesting that oil and gas methane emissions are substantially greater than bottom-up inventories would predict,[506] further underscoring the urgency of action.

Moreover, methane from oil and gas facilities is frequently co-emitted together with other harmful pollutants, including ozone precursors such as VOCs and carcinogenic substances such as benzene and other hazardous air pollutants (HAPs).[507] And because methane is a valuable commodity, reductions in methane emissions often pay for themselves due to increased resource recovery—making methane emission mitigation a low-cost (and sometimes *negative* cost) proposition.

The President has committed to addressing methane emissions—first in the Climate Action Plan[508] and then in a more detailed Strategy to Reduce Methane Emissions.[509] Pursuant to the Methane Strategy, EPA issued a series of five white papers examining available, low-cost technologies that could substantially reduce methane emissions from the oil and natural gas sector. EDF provided peer review comments on these technical white papers, and the Methane Strategy includes a commitment for EPA to determine appropriate additional measures to reduce methane emissions by this fall.

[504] J.K. Shoemaker et al., What Role for Short-Lived Climate Pollutants in Mitigation Policy? 342 Science 1323, 1324 (2013).

[505] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012* (2012).

[506] A.R. Brandt et al., *Methane Leaks from North American Natural Gas Systems*, 343 Science 33-34 (2014) (reviewing 20 years of technical literature on natural gas emissions in the U.S. finding that "measurements at all scales show that official inventories consistently underestimate actual [methane] emissions").

[507] Petron *et al.*, 2014 A new look at methane and nonmethane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin, Journal of Geophysical Research: Atmospheres, online: 3 JUN 2014 DOI: 10.1002/2013JD021272.

[508] Executive Office of the President, The President's Climate Action Plan (June 2013), *available at* http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[509] Executive Office of the President, Strategy to Reduce Methane Emissions (March 2014), *available at* http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.

In this proposal, EPA concludes that net upstream methane emissions impacts will likely be small, attributing this finding to reductions in coal mine methane emissions due to decreased coal utilization.[510] This finding, however, does not adequately address upstream methane emissions from the oil and natural gas sector in light of the current methane emissions from this sector and the potential for increased utilization of natural gas.

EPA must address these methane emissions from the oil and natural gas sector directly—establishing standards for both new and existing sources that are based on the highly cost-effective technologies EPA evaluated as part of the white paper process and ICF concluded could reduce methane emissions by 40% in 2018 for a cost of just one penny per thousand cubic feet of natural gas produced.[511] Indeed, states like Colorado[512] and Wyoming[513] have already adopted measures to reduce methane emissions from these key sources and organizations from labor unions[514] to the investment community[515] support rigorous action to reduce methane emissions.

It is critical that the President and EPA promptly follow through on this commitment to address methane emissions, and we urge EPA to establish rigorous emissions standards for new and existing sources in the oil and natural gas sector.

7. The Emission Guidelines Should Apply to Emissions From Simple Cycle Combustion Turbines

In comments on the Section 111(b) proposed standards for carbon pollution for new EGUs, we urged EPA to set a standard of 1,100 lbs CO_2/MWh_{net} for simple cycle combustion turbines operating less than 1,200 hours per year (i.e., combustion turbines providing "peaking" service). In comments on the Section 111(b) proposed standards for modified and reconstructed units, we urged EPA to require a rigorous initial performance test for all sources subject to standards under Section 111(b). These two approaches,

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[510] 79 Fed. Reg. 34,862; *see also* EPA, Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants at Appendix 3A (June 2014).

[511] ICF International, *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries* (March 2014), *available at* http://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

[512] Co. Dep't of Pub. Health & Env't Reg. No. 7 (5 CCR 1001-9) (adopted Feb. 23, 2014).

[513] Wyo. Dep't of Envtl. Quality, Proposed Nonattainment Area Regulations, Ch. 8, Sec. 6 (proposed Oct. 31, 2014), *available at* http://deq.state.wy.us/aqd/Resources-Division/Proposed%20Rules%20and%20Regs/Chapter%208%20-%20NAA-Existing%20Source,%20IBR%20draft%2010-24-14_REDLINE.pdf.

[514] BlueGreen Alliance, *Letter: BlueGreen Alliance Urges the Administration to Adopt a National Methane Reduction Strategy* (Oct. 10, 2014), *available at* http://www.bluegreenalliance.org/news/publications/document/100914-BGA-methane-letter-vFINAL.pdf.

[515] Letter from NYC Comptroller Scott Stringer and Investors to EPA Administrator Gina McCarthy, *Re: National Oil and Gas Methane Regulation* (Oct. 9, 2012), *available at* http://www.trilliuminvest.com/wp-content/uploads/2014/10/EPA-Methane-Regulation-Letter-10.09.14.pdf. Also, on the June 9, 2014 edition of the Charlie Rose show, Goldman Sachs CEO Lloyd Blankfein made clear that investors need strong and stable rules for methane emissions in order to make long-term investments in sectors that use natural gas. *See* http://www.charlierose.com/watch/60403647.

taken together, can ensure that new, modified, and reconstructed power generation infrastructure utilizes the best available technologies currently available.

For simple cycle combustion turbines, the initial performance test should reflect the emission rate achievable using the best system of emission reduction when a plant is operating at optimal conditions to ensure that these facilities are built, reconstructed, or modified using the lowest-emitting technologies and operating systems available, fulfilling the technology-forcing and pollution-minimizing purposes of Section 111. A rigorous initial performance test, combined with an emission standard that recognizes the peaking and load-following services that many simple cycle combustion turbines provide, will enable these units to continue to provide that role while also ensuring that they incorporate the most efficient and lowest polluting technologies available, ensuring that the standards fulfill the Section 111 statutory requirements and case law.

Applying section 111(b) standards to simple cycle combustion turbines will require the inclusion of these sources in Section 111(d) plans. As EPA noted, peaking plants play an important role in the power generation system, and often are used to "balance" intermittent renewable generation. These units emit significant quantities of carbon pollution, however, and as such it is important for the environmental integrity of the standards and for efficient operation of power markets that they are incorporated within the standards for existing fossil fuel-fired power plants and state plans to reduce carbon pollution from the power sector. Incorporating these plants will avoid the creation of perverse incentives to run peaker plants more (and inefficiently) were they not subject to carbon pollution standards. Incorporating existing peaker plants in state plans to address carbon pollution will ensure that plans can secure carbon pollution reductions cost-effectively and efficiently (as all existing fossil fuel-fired power plants would be subject to the plans, and the carbon reduction obligations) and avoid power market distortions that could have the effect of increasing carbon emissions from these plants.

I. Comments on Building Block 3: Zero Carbon Energy Generation

1. Renewable Energy

EDF commends EPA on the Clean Power Plan's adoption of a system-based approach, which includes the full range of technologies available to reduce carbon pollution from existing power plants. Zero-emission, renewable energy technologies are currently reducing overall emissions from a state's generation fleet, and expanding renewable energy should be included in the Best System of Emissions Reduction. EDF's comments on building block 3 address three primary points. First, EDF addresses why EPA properly included renewable energy in setting the BSER.

Second, EDF explains how EPA's analysis relied on outdated renewables cost data that fails to capture the significant cost reductions that have occurred in recent years. EPA must update its analysis to incorporate current renewable cost information. Because of its use of outdated cost data, EPA has significantly underestimated the potential for renewable energy to reduce power sector emissions.

Third, EDF addresses the method EPA should use to determine the amount of renewable energy available in each state. We recommend that EPA adopt a modified version of the Alternative Proposal.

a. EPA Properly Included the Addition of Renewable Energy in the BSER

Electricity generation from renewable resources – such as wind, solar, or geothermal – has been demonstrated to be a cost-effective means of displacing emissions from fossil fuel generation. Given the nature of the electricity grid, the addition of renewable energy will directly result in reduction in other generation. And there is ample evidence that it is fossil-fuel fired generation that is reduced as additional renewables are brought on-line. For instance, the New York State Department of Public Service conducted extensive modeling of the economic and environmental effects of that state's renewable portfolio standard and concluded that increased renewable energy generation would displace generation from higher-emitting sources, primarily natural gas-, coal-, and oil-fired units.[516] Likewise, a recent white paper concluded that in the RGGI region the addition of renewable energy sources have almost entirely displaced coal-fired generation.[517]

Renewable energy also meets EPA's cost criteria. Recent analysis by Lazard suggests that the costs of carbon abatement from building a new wind or solar project, relative to building a new coal or gas plant, are within EPA's range of $10-$40/ton and, particularly in areas with strong wind resources, can result in net savings to electricity customers.[518] A recent LBNL survey of state renewable generation cost assessments found that most states that assessed benefits of RPS policies determined that the policy resulted in net benefits due to, among other things, pollution reductions, economic development, and natural gas price suppression.[519]

b. EPA Must Update the Cost Data it Relies on to Assess Potential Growth in Renewable Energy

Renewable energy costs have fallen dramatically and renewable energy performance has improved in recent years. These changes are well recognized and consistent with the price declines expected as an industry experiences the kind of growth that the renewables industry has seen in the U.S. and abroad.[520] But EPA's analysis fails to account for either the cost reductions that have already occurred or the cost

[516] New York Department of Public Service, Final Generic Environmental Impact Statement (2004) at 111 (Table 6.4-1), available at http://www.dps.ny.gov/NY_RPS_FEIS_8-26-04.pdf. The potential for clean energy to displace fossil-fuel-fired generation also has important benefits for public health. *See id.* at 2ES ("Modeling reveals that the addition of new renewable energy sources at the 25 percent target level could annually reduce NOX emissions by 4000 tons (6.8%), SO2 emissions by 10,000 tons (5.9%), and carbon dioxide (CO2) emissions by 4,129,000 tons (7.7%).").

[517] Brian C. Murray, Peter T. Maniloff, Evan M. Murray, "Why Have Greenhouse Emissions in RGGI States Declined? An Econometric Attribution to Economic, Energy Market, and Policy Factors" at 18, available at http://sites.nicholasinstitute.duke.edu/environmentaleconomics/files/2014/05/RGGI_final.pdf (quantitatively attributed emissions effects to policy and market factors in the RGGI region).

[520] Electric Power Research Institute, "Modeling Technology Learning for Electricity Supply Technologies",

reductions that can reasonably be expected to continue. EPA must properly account for these cost reductions and re-analyze the quantity of renewable energy that is available.

In EPA's analysis of renewable energy (conducted through its Integrated Planning Model IPM®) Base Case v5.13,4), EPA adopts load forecasts and new technology costs from the Energy Information Administration's (EIA) Annual Energy Outlook 2013 (AEO2013).[521] More recent industry data demonstrate that modeling assumptions used for the cost and performance characteristics of new generating technologies are significantly out of date. These cost estimates are especially important because, as discussed below, the costs for new generation technologies constrain the amount of renewable energy available to reduce carbon pollution under the Clean Power Plan.

AEO2013's assumptions are outdated and do not reflect the dramatic cost declines seen in recent years. In fact, we find that AEO2013's cost assumptions for renewables are 46% above current averages for wind and solar technologies. This is not surprising, given that the AEO2013 cost assumptions were based on projects completed in 2012 and reflect pricing contracts that may have been signed several years prior to project completion.[522]

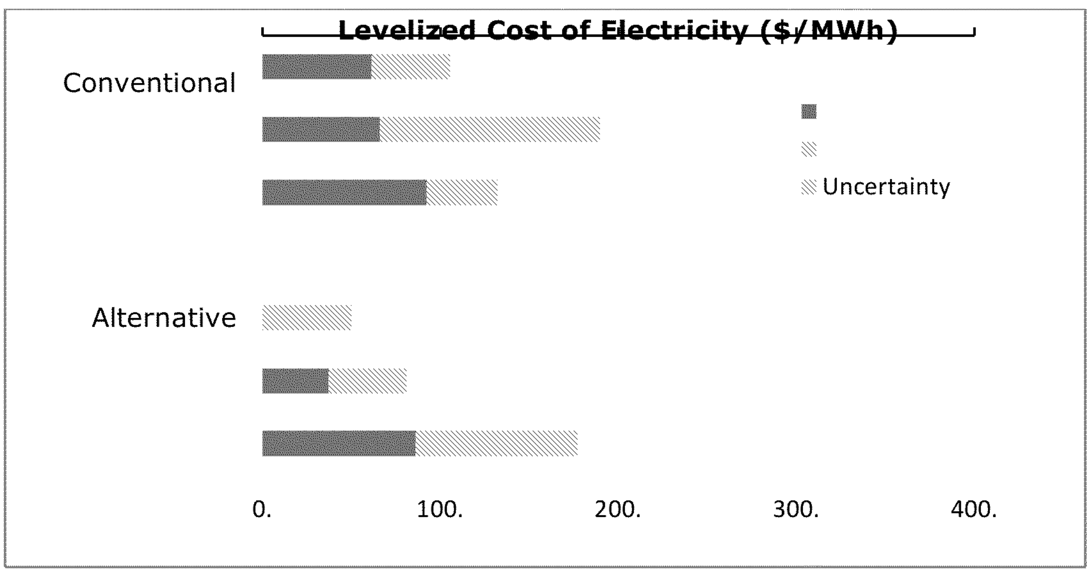
Since 2010, the cost of building utility-scale solar projects has declined by about 50 percent from \$3400/kW to \$1500–1800/kW in 2014.[523] These declines are consistent with NREL's modeled prices using its bottom-up modeling methodology – NREL estimates that the price of solar declined to \$1800/kW_{dc} in Q4 2013.[524] The declines are also reflected in average PPAs for utility-scale solar which, in the past year alone, have dropped from \$123/MWh to \$86/MWh, with several projects reporting prices (including incentives) below \$70/MWh – competitive with new NGCC plants.[525]

[521] The projections in EIA's Annual Energy Outlook focus on long term trends in the U.S. energy system. The AEO 2013 Reference Case assumes that current non–expiring laws and regulations remain unchanged through 2040, the end of the forecast period. The Production Tax Credit (PTC) and 30% Investment Tax Credit (ITC) for renewables are not extended past their current end date. AEO 2013 is available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf.
[522] EIA reports and other government-issued reports typically have an 18-month or greater time lag due to the comprehensive nature of acquiring, reviewing and reporting on energy data from contributing energy generation, delivery and consumption for the entire country. LBNL has emphasized that reported installed price data "may reflect transactions that occurred several or more years prior to project completion" and therefore are often unable to accurately reflect current prices in such a rapidly changing industry. (LBNL, Tracking the Sun VII).
[523] This range is based on data from the following sources: U.S. DOE Sunshot, "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections." October 2014; "Bloomberg New Energy Finance. "H1 2014 Levelized Cost of Electricity – PV." February 2014; Lazard. "Levelized Cost of Energy – v. 8.0; Bloomberg New Energy Finance/World Energy Council. "World Energy Perspective: Cost of Energy Technologies." 2013; Solar Energy Industries Association. Personal Communications. August 14, 2014. The above sources are available at: http://www.nrel.gov/docs/fy14osti/62558.pdf; https://www.iea.org/media/workshops/2014/solarelectricity/bnef2lcoeofpv.pdf; http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf; http://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf.
[524] DOE/NREL, "Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections." October 2014.
[525] Lawrence Berkeley National Laboratory, "Utility-scale Solar 2012", September 2013, available at:

Wind prices have experienced similar declines since 2010. The capital cost of developing onshore wind turbines has also declined, from $2260/kW to $1750/kW on average.[526] LBNL reports that PPAs for wind projects (including incentives) fell, after peaking briefly at $70/MWh in 2009, to a national average of $25/MWh in 2013.[527] Moreover, technology improvements have allowed for taller wind turbines, enhancing performance through faster and steadier wind speeds at higher elevation. As a result of these advances, Lawrence Berkeley National Laboratory (LBNL) researchers have indicated that average capacity factor has increased by 10 percent across all wind classes since 2012.[528] Taller wind turbines significantly expand the geographic area suitable for wind turbines.

Lazard estimates that the current range of LCOEs for onshore wind, *without* any subsidies, is between $37/MWh and $81/MWh. In contrast, EIA's out-of-date estimate projects that the LCOE in 2019 will be between $70/MWh and $90/MWh.

Figure 4: Levelized Cost of Electricity for Conventional vs. Alternative Technologies[529]



*Low end of uncertainty range represents utility-scale system at $1500/kW; high end represents commercial system at $3000/kW.

There is no basis for EPA to rely on AEO2013's out of date data when it has before it recent government and credible industry analysts' cost data, e.g. NREL, LBNL, BNEF and Lazard. AEO2013's use of

http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends

526 Lawrence Berkeley National Laboratory. "2013 Wind Technologies Market Report". August 2014, available at: http://emp.lbl.gov/publications/2013-wind-technologies-market-report.

527 *id.*

528 Trabish, H. "Experts: The Cost Gap Between Renewables and Natural Gas 'Is Closing'." Greentech Media. May 6, 2014, available at: http://www.greentechmedia.com/articles/read/The-Price-Gap-Is-Closing-BetweenRenewables-and-Natural-Gas.

529 All cost estimates and corresponding assumptions from Lazard, Levelized Cost of Electricity v. 8.0, 2014.

installed costs means that the data presented will have an 18-month or greater time lag. As LBNL has noted installed cost data "may reflect transactions that occurred several or more years prior to project completion" and therefore are often unable to accurately reflect current prices in such a rapidly changing industry.[530] In this case, the delay causes the analysis to miss key data showing major price declines, and therefore significantly overestimate current costs and underestimate recent performance. EPA can also check the monthly FERC-issued grid interconnection report, which shows the utility-scale projects that have both been approved for interconnection or commissioned as a new generating resource for the regional transmission authorities that lie under FERC jurisdiction.

Importantly, there is no reason to believe that the declines in cost will not continue. DOE/NREL Sunshot Vision study, which constructs a detailed roadmap for continued cost declines in solar PV technologies, projects that solar system prices can drop 75% between 2010 and 2020.[531] In its 2014 update on Solar PV pricing trends, NREL also predicted that solar prices are still on track to meet the Sunshot goal of $\$1/W_{dc}$ by 2020 for utility-scale systems.[532] This would place utility-scale solar projects in direct competition with NGCC plants, without any incentives or carbon policy. Likewise, many industry analysts predict that wind and solar will become increasingly competitive with new NGCC plants and will make up a major market share of new U.S. demand. [533,,,534535] As noted, average PPAs for utility-scale solar in the past year alone have dropped to levels (including incentives) competitive with new NGCC plants.[536] Meanwhile, a new Deutsche Bank report predicts that distributed solar power will be cheaper than average retail electricity prices in 36 states by 2016 (47 states if the 30% ITC is extended).[537]

Recent analysis also shows that higher penetrations of renewable energy are feasible. Detailed analyses performed on the PJM grid, the Eastern Interconnect, and Western Interconnect have all found that renewables can provide up to 10% of generation on major ISOs with little to no additional costs, and can provide up to 30% of total generation with only minor adjustments to the existing grid and proper system planning.[538,539, 540]The findings of these studies demonstrate that it is technically achievable to incorporate higher levels of renewable energy into the existing grid than what has been proposed in EPA's target-setting.

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530 LBNL Tracking the Sun VII Report (p. 39)
531 DOE/NREL, Sunshot Vision Study, February 2012, available at: http://energy.gov/eere/sunshot/sunshot-vision-study
532 *Ibid.*
533 Credit Suisse. "The Transformational Impact of Renewables." 2013.
534 Bloomberg New Energy Finance, "2030 Market Outlook: Focus on Americas", 2013, available at: http://bnef.folioshack.com/document/v71ve0nkrs8e0/106y4o
535 Greentech Media, "Experts: The Cost Gap Between Renewables and Natural Gas 'Is Closing'", May 2014
536 Lawrence Berkeley National Laboratory, "Utility-scale Solar 2012", September 2013, available at: http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends
537 Bloomberg, "While You Were Getting Worked Up Over Oil Prices, This Just Happened to Solar" , October 2014, available at: http://www.bloomberg.com/news/2014-10-29/while-you-were-getting-worked-up-over-oil-prices-this-just-happened-to-solar.html
538 PJM Integration Study
539 NREL Western Wind and Solar Integration Study
540 NREL Eastern Wind Integration Study

There is no basis for EPA to rely on outdated cost information in its analysis when it has more recent data available showing that current costs are lower. This is particularly true because the cost differential is dramatic. Based on NRDC's analysis of recent data, the costs EPA relied on are 46 percent above current average costs for, respectively, wind and solar energy.[541] As explained in detail below, the lower costs mean that substantially more renewable energy can and should be included in the state targets.

c. EPA Should Strengthen the Alternative Approach To Determining the Amount of Renewable Energy Available at Reasonable Cost in Each State

EDF recommends that EPA adopt the Alternative Approach presented in the proposed rule, which reflects state and regional technical and economic potential. But EPA should strengthen this approach by using updated cost and performance data for renewable energy technologies and removing the benchmark utilization rate.

Update Cost and Performance Assumptions

Under the alternative approach, EPA uses economic modeling of renewable energy using IPM to determine the amount of renewable energy available at reasonable cost in each state. For the reasons describe above, the costs used by EPA are significantly higher than current solar or wind prices. EPA must update these costs with and re-run its IPM economic modeling. This modeling should use the most reliable and up-to-date cost and performance assumptions available, which will provide a more accurate representation of the cost competitiveness of renewables and lead to increased deployment.

Updated installed capacity and generation data

If EPA continues to utilize its benchmark rate methodology within the Alternative Approach, EPA should use updated data on installed capacity and generation – there has been significant growth in wind and solar capacity and generation since 2012, and this capacity will continue to grow between now when the standards take effect. Recent growth in both wind and solar capacity, shown in Table 2 below, highlights the need to use the most up-to-date data available in markets growing at unprecedented rates.

[541] See http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf

Table 2: Growth in Installed Capacity[542]

Cumulative Installed Capacity (MW)							
	2008	2009	2010	2011	2012	2013	Jul-14
Onshore Wind	25,068	35,064	40,298	46,919	60,007	61,091	61,322
Total Solar PV	485	920	1,772	3,691	7,060	11,811	15,900

Refine the Alternative Approach

We support using a state's technical and economic renewable energy potential to determine its potential to reduce carbon pollution from fossil generation by deploying renewable energy; however, the benchmark development rate does not capture the rapid growth of renewable energy. As described in more detail *supra*, both wind and solar capacity have grown at remarkable rates over the past 5-10 years – taking a snapshot of 2012 capacity to set a benchmark development rate simply does not fully capture this progress. Installed capacity has grown significantly even between 2012 and today, and even those states that have deployed significant renewable resources can and should be expected to continue to grow their renewable energy portfolio into the next decade. As discussed below, the benchmark rates not only fail to capture current growth in renewable energy, but it is also redundant and unnecessary when combined with IPM, which already contains technical constraints.

Eliminate benchmark rate, rely solely on technical and economic potential within IPM

IPM results already reflect both constraints through detailed resource supply curves. For example, as stated in the IPM documentation, "EPA worked with the U.S. Department of Energy's National Renewable Energy Laboratory, to conduct a complete update…of the potential onshore, offshore (shallow and deep) wind generating capacity."[543] However, IPM is capable of modeling technical potential in an even more granular fashion than NREL's technical potential, as it details the amount of resources available by cost class. Therefore, IPM has the potential to not only model technical potential limits, but also place economic limitations on resource availability within the overall technical potential — a more accurate representation of market dynamics than EPA's proposed use of benchmark development rates. While this more granular data was not used by EPA in their analysis, we recommend that EPA consider using it when determining technical and economic potential for each state and region.

Another problem with the benchmark development rate is that it places an unnecessary constraint on states that are currently leaders in renewable energy development. If IPM results demonstrate that these states can continue to develop their renewable resources at a reasonable cost, then these states' targets should be set accordingly. Cost-effective renewable resources should not be arbitrarily excluded from the

[542] EIA Form 860 Data; LBNL Tracking the Sun VII, AWEA annual reports
[543] Page 4-31, EPA IPM Documentation, ch. 4

BSER determination based on artificial constraints such as the benchmark development rates described in the Alternative Proposal.

Implement grid integration constraints or costs that supplement and strengthen IPM's capabilities

Instead of using the benchmark rate, EPA should consider implementing constraints that more closely simulate real-world grid operations. There is a growing body of research on grid integration of renewables, and several studies have suggested that at least 30% of renewables can be handled by the existing grid, providing that there is adequate transmission expansion and proper system planning.[6,7] While higher levels could be integrated with some management and investment changes,[544, 545] 30% represents a clearly achievable near-term limit. EPA modeling should reflect this.

Distributed Generation

Distributed solar and other forms of distributed generation are distinctive in their ownership, operation, significance of siting, and relationship to the existing grid. These systems provide quantifiable benefits such as grid support, lower transmission losses, and reduced need for additional capacity, as well as less monetized benefits such as hedging against fuel prices and reduced security risk. As PV module costs continue to decline, rooftop solar is becoming and will continue to become an economic option for an increasing number of residential and commercial customers. [5, 546] Omitting DG from the RE block paints an unrealistic picture of the current and future RE generation mix. In fact, net metered capacity now makes up about half of total U.S. solar PV capacity.[547] NREL's Open PV Project Database provides up-to-date capacity and price data by state, based on a sample of installations,[548] which should be used to incorporate rooftop PV generation into the alternative approach.

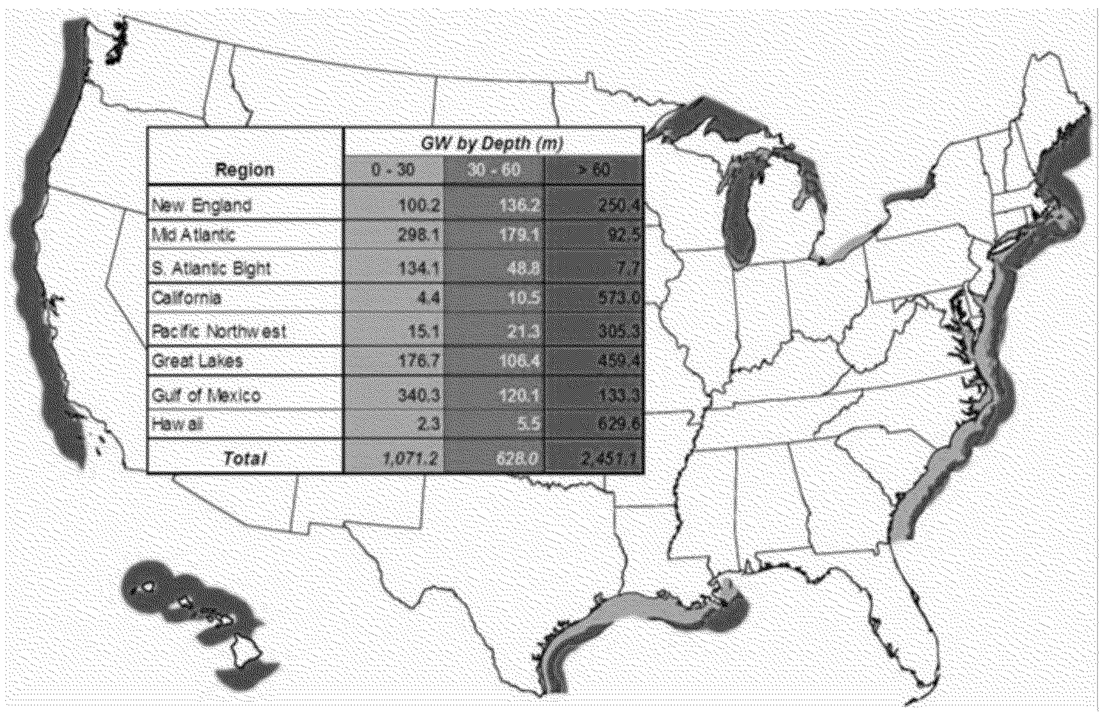
Although there are methods in which distributed PV can be implemented into IPM as a resource available to utilities, it may be more accurate to rely on separate modeling that fully accounts for market dynamics at the customer level. As one example, NREL has developed the Solar Deployment System (SolarDS) model, a modeling complement to ReEDS which projects distributed solar installations by state based on system prices, retail rates, and consumer economics.[549] Outputs of SolarDS or similar modeling can then be hard-wired into IPM to ensure that the effects on the grid and other generation options are captured.

544 Energy and Environmental Economics (E3). "Investigating a Higher Renewable Portfolio Standard in California." January 2014, available at: https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf
545 NREL, GE Energy Consulting, and JBS Energy. "California 2030 Low Carbon Grid Study", August 2014, available at: http://www.lowcarbongrid2030.org/wp-content/uploads/2014/08/LCGS-Factsheet.pdf
546 NREL Residential Grid Parity Report, 2013
547 http://www.eia.gov/electricity/monthly/update/archive/april2014/; SEIA data (from EIA)
548 https://openpv.nrel.gov/
549 NREL, "The Solar Deployment System (SolarDS) Model: Documentation and Sample Results", September 2009, available at: http://www.nrel.gov/docs/fy10osti/45832.pdf

Offshore Wind

The resource potential for offshore wind in the United States is vast, and adjacent to many metropolitan areas with high electricity demand. According to the Bureau of Ocean Energy Management, over 1,000 GWs are available in 0-30 foot depth waters, 628 GW in 30-60 feet, and over 2,400 GW over 60 feet deep. This power is spread across a diverse geography, as shown in the figure below.

Figure 5: Map of Offshore Wind Potential[550]



Region	GW by Depth (m)		
	0 - 30	30 - 60	> 60
New England	100.2	136.2	250.4
Mid Atlantic	298.1	179.1	92.5
S. Atlantic Bight	134.1	48.8	7.7
California	4.4	10.5	573.0
Pacific Northwest	15.1	21.3	305.3
Great Lakes	176.7	106.4	459.4
Gulf of Mexico	340.3	120.1	133.3
Hawaii	2.3	5.5	629.6
Total	*1,071.2*	*628.0*	*2,451.1*

As a less mature technology and industry, offshore wind is at a higher cost point on the development and deployment curve. However, if it follows the historical trajectories of onshore wind and solar power, increasingly higher deployment levels will likely bring substantial cost and performance improvements. These gains come about from a number of factors, including economy of scale; learning by doing; development of needed supply chains; development of transportation infrastructure; streamlining of permitting, financing, and other "soft costs"; and continued research, development, and innovation. Several studies suggest costs could even fall more quickly than they did for onshore wind energy.[551]

[550] NREL, *Dynamic Maps, GIS Data, and Analysis Tools: Wind Maps*, U.S. 90 m Offshore Wind Map, *available at* http://www.nrel.gov/gis/wind.html.
[551] https://www.ieawind.org/index_page_postings/WP2_task26.pdf

Currently there are 14 commercial scale projects in advanced development that would constitute almost 5 GW of capacity.[552] America's first offshore wind project, Cape Wind, is set to produce 75% of the electricity used on Cape Cod and the Islands of Martha's Vineyard and Nantucket with zero pollution emissions.[553] Furthermore, this project is expected to lead to a net reduction in the wholesale cost of power in the region.[554] This phenomenon is not unique to Cape Wind – a recent comprehensive study by DOE details the numerous benefits that development of offshore wind can have for the U.S. electric grid.[555]

The potential to capture the nation's large off-shore wind resources is further evidence of the conservative nature of EPA's assessment of renewable energy potential. Regardless of whether this resource is considered in assessing state emission reduction potential in the current proposal, EPA should revise its best system of emission reduction analysis and state targets as the availability of such resources is demonstrated.

Supporting Analysis

Independent modeling studies have also determined that higher penetrations of renewable energy are both technically feasible and economically achievable. Such studies should serve as further confirmation that much higher levels of renewable energy can and should be considered part of the BSER.

For example, rigorous analyses have been done using NREL's Renewable Energy Deployment System (ReEDS) model. Like IPM, ReEDS is a long-term capacity-expansion model for the deployment of electric power generation technologies and transmission infrastructure throughout the contiguous United States. Additionally, ReEDS features the following capabilities to model renewable energy:

> "[ReEDS] addresses a variety of issues related to renewable energy technologies, including accessibility and cost of transmission, regional quality of renewable resources, seasonal and diurnal load and generation profiles, variability and uncertainty of wind and solar power, and the influence of variability on the reliability of electric power provision. ReEDS addresses these issues through a highly discretized regional structure, explicit statistical treatment of the variability in wind and solar output over time, and consideration of ancillary service requirements and costs."[556]

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[552]Navigant, "Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment", *prepared for the Department of Energy,* available at: http://energy.gov/sites/prod/files/2014/09/f18/2014%20Navigant%20Offshore%20Wind%20Market%20%26%20Economic%20Analysis.pdf
[553] http://www.capewind.org/what/benefits
[554] Charles River Associates. "Analysis of the Impact of Cape Wind on New England Energy Prices." February 2010.
[555] Department of Energy. "National Offshore Wind Energy Grid Interconnection Study." July 2014
[556] For more on NREL's ReEDS model, see http://www.nrel.gov/analysis/reeds/documentation.html.

NREL RE Futures Study. Recent analyses by the National Renewable Energy Lab (NREL) and U.S. Department of Energy (DOE) demonstrate the potential for much higher renewables penetration than EPA's proposed targets, even under restrictive sensitivity cases. NREL/DOE used the Regional Energy Deployment System (ReEDS) to model an aggressive target of 80 percent renewable energy by 2050 under several sets of assumptions.

NREL modeled four cases – three assumed a 0.17% annual growth in electricity demand; the fourth specified a high-demand scenario of 0.84% per year annual growth. We focus here on the first three scenarios, which are much closer to specified demand levels in the proposed Clean Power Plan. One case assumed partial achievement of future technology performance and cost advancements, or "incremental technology improvements"(ITI); a second used the same ITI assumptions, but added significant restrictions on transmission, policy flexibility, and reliability ("ITI-Constrained"); the third assumed "advanced technology improvements" (ATI), characterized by aggressive cost reductions for solar and onshore wind technologies.

The ReEDS modeling suggests that states could achieve significantly higher renewables deployment without a significant impact on electricity prices. Depending upon the scenario and year, solar and wind generation levels are two to three times higher in ReEDS than EPA's targets and, in many cases, electricity price projections are lower than EPA's. In 2020, all three scenarios project lower retail electricity prices than EPA (11.1 cents/kWh for EPA, and 10.5, 10.7, and 10.3 cents/kWh for the ITI, ITI-Constrained, and ATI scenarios, respectively). In 2030, retail electricity prices are roughly the same in the ITI and ATI scenarios as EPA's (11.5 and 10.7 cents/kWh vs. 11.2 cents/kWh, respectively), and slightly higher under the ITI-Constrained case (12.1 cents/kWh).

UCS Analysis of Proposed RE Targets. In its comments to EPA, the Union of Concerned Scientists (UCS) has proposed a "Demonstrated Growth" approach to target-setting, which results in 995 TWh of renewable energy deployment.[557] UCS has assessed the technical and economic feasibility of reaching these targets using NREL's ReEDS model, and has reached similar conclusions as NRDC regarding the achievability of these targets.

UCS has also found that the incremental cost of high levels of RE deployment under their proposal was at or below $30/MWh, assuming national trading of RECs. Additionally, UCS examined the impacts on natural gas prices, because diversifying the electricity mix with renewable energy would help reduce the economic risks associated with an overreliance on natural gas.[558] Reducing the demand for natural gas would also lead to lower and more stable natural gas and electricity prices.

[557] For more on UCS's proposal, see http://www.ucsusa.org/sites/default/files/attach/2014/10/Strengthening-the-EPA-Clean-Power-Plan.pdf.
[558] Bolinger, M. 2013. *Revisiting the long-term hedge value of wind power in an era of low natural gas prices*. Golden, CO: Lawrence Berkeley National Laboratory (March 2013) *available at* http://emp.lbl.gov/sites/all/files/lbnl-6103e.pdf (last accessed on October 2, 2014); Fagan, B., P. Lucklow, D. White, and R. Wilson. 2013. *The net benefits of increased wind power in PJM*. Cambridge, MA:

The UCS analysis found that national average consumer electricity prices are a maximum of 0.3% higher per year than BAU through 2030. As a result, a typical household (using 600 kWh per month) would see a maximum increase of 18 cents on their monthly electricity bill on average at the national level. In the UCS analysis, the national average price of natural gas delivered to the electricity sector would be 9% lower than business as usual by 2030. At the regional level, consumer electricity prices would range from a 3.7% reduction to a 3.4% increase, while power sector natural gas price reductions would range from 8 percent to 17%.

Preliminary Results from DOE's Wind Vision Report. While the full Wind Vision report is not scheduled to be released until early next year, DOE issued an early release of the Executive Summary and Roadmap chapter on November 19, 2014.[559] The early release shows that increasing wind power from 4.5% of U.S. electricity use in 2013 to 10% in 2020, 20 percent in 2030, and 35% in 2050 is technically and economically feasible. Achieving these targets would require less than 5 percent of the country's available wind resource potential and would result in a less than 1% (0.1 cents/kWh) increase in electricity costs by 2030, and a 2% reduction in electricity costs by 2050. In addition, the study found that achieving the Wind Vision (compared to a baseline scenario) would result in cumulative (2013-2050) savings of:

- $400 billion in avoided global climate change damages from reducing power plant carbon emissions by 12.3 Gt of CO_2-equivalent (a 14% reduction)

- $108 billion in avoided health and economic damages from reducing particulate matter, nitrous oxide, and sulfur dioxide emissions and

- $280 billion in lower consumer natural gas bills and total electric system costs that are 20% less sensitive to natural gas price fluctuations.[560]

Final Recommendations

EDF commends EPA on the Clean Power Plan's system-based approach, which includes the full range of technologies available to reduce carbon pollution from existing power plants. We fully agree that zero-emission, renewable energy technologies are currently reducing overall emissions from a state's generation fleet, and expanding renewable energy should be included in the Best System of Emissions Reduction. EPA proposed two different approaches to determining how much renewable energy should be included in establishing state targets. Both approaches to Building Block 3 are well-supported but EDF

Synapse Energy Economics, Inc. Mercurio, A. 2013. *Natural gas and renewables are complements, not competitors*. Washington, DC: Energy Solutions Forum, Inc.

[559] U.S. Department of Energy, *Wind Vision: A New Era for Wind Power in the United States (Industry Preview)*. DOE/GO-102014-4557 (2014) *available at* http://energy.gov/eere/wind/downloads/draft-industry-preview-wind-vision-brochure.

[560] Cumulative figures from the study are calculated based on the present value of costs and savings between 2013 and 2050, using a 3 percent discount rate.

recommends that EPA adopt a strengthened Alternative Approach, which better reflects state and regional technical and economic potential, and strengthen the approach by using updated cost and performance data for renewable energy technologies. In the above comments, we have cited research and data to support an overall strengthening of the Renewable Energy building block, as summarized by the recommendations below.

The alternative approach's strengths lie in its use of technical and economic data to calculate the state renewable energy potential, but EPA has relied on outdated data. EPA uses EIA AEO 2013, which contains several-year old cost and performance data and results in levelized costs for wind and solar which are 46% above current averages for each technology. EPA's modeling should use the most reliable and up-to-date cost and performance assumptions available, which will provide a more accurate representation of the cost competitiveness of renewables and demonstrate that more renewables can be deployed at reasonable cost. EDF recommends the following changes to the Alternative Approach (as detailed in previous sections):

- Update cost and performance assumptions for renewable energy technologies, based on recent government or industry data
- Eliminate the benchmark development rate constraint
- Include distributed solar generation through separate modeling (e.g. NREL's Solar Deployment System (SolarDS) model)

Appendix 1: Distributed Solar Projections from NREL's Sunshot Vision Study

Distributed solar PV is a distinctive, customer-sited generation resource, and therefore it may be difficult to represent in a wholesale power model such as IPM. Instead, it is appropriate to rely on NREL's modeling using the SolarDS model, which takes into account various factors that affect the decision-making of homeowners and businesses.

In its 2012 Sunshot report, NREL modeled solar PV penetration across the country for several sensitivity scenarios, based on expected price declines. NREL's October 2014 Sunshot pricing update indicates that system prices are in fact on track to meet a 75% price reduction by 2020.

Table 3. DOE/NREL Sunshot, Distributed solar capacity projections for -62.5% price case[561]

Distributed Solar Projections (GWdc)				
	2014	2020	2025	2030

[561] NREL, "Sunshot Vision Study", February 2012 (Table A3).

AL	0.00	0.04	0.11	0.18
AZ	0.58	0.95	2.86	4.76
AR	0.00	0.01	0.04	0.07
CA	2.55	3.96	11.87	19.78
CO	0.27	0.52	1.57	2.62
CT	0.09	0.23	0.69	1.14
DE	0.03	0.06	0.18	0.30
FL	0.07	0.94	2.82	4.70
GA	0.04	0.20	0.59	0.98
ID	0.00	0.00	0.01	0.02
IL	0.01	0.15	0.44	0.73
IN	0.00	0.08	0.25	0.42
IA	0.02	0.12	0.37	0.62
KS	0.00	0.13	0.39	0.65
KY	0.00	0.02	0.07	0.12
LA	0.07	0.16	0.49	0.81
ME	0.01	0.05	0.14	0.23
MD	0.12	0.16	0.47	0.78
MA	0.42	0.42	0.68	0.95

MI	0.01	0.13	0.40	0.67
MN	0.02	0.12	0.37	0.61
MS	0.00	0.01	0.04	0.06
MO	0.07	0.20	0.59	0.99
MT	0.01	0.03	0.08	0.14
NE	0.00	0.06	0.19	0.32
NV	0.06	0.42	1.27	2.12
NH	0.01	0.02	0.05	0.09
NJ	1.05	1.05	1.13	1.21
NM	0.07	0.14	0.43	0.71
NY	0.17	0.79	2.37	3.95
NC	0.03	0.25	0.75	1.25
ND	0.00	0.01	0.03	0.05
OH	0.07	0.07	0.19	0.30
OK	0.00	0.15	0.45	0.75
OR	0.07	0.07	0.20	0.32
PA	0.20	0.32	0.95	1.59
RI	0.01	0.07	0.22	0.37
SC	0.00	0.06	0.17	0.28

SD	0.00	0.03	0.10	0.16
TN	0.00	0.07	0.21	0.35
TX	0.07	1.54	4.63	7.71
UT	0.02	0.08	0.24	0.40
VT	0.11	0.11	0.11	0.11
VA	0.02	0.16	0.48	0.79
WA	0.03	0.32	0.95	1.58
WV	0.00	0.02	0.05	0.09
WI	0.01	0.10	0.30	0.50
WY	0.00	0.02	0.05	0.09
Total	6.4	14.6	41.0	67.44

Appendix 2: Comments on Proposed Approach

Although the bulk of our comments on the renewable energy building block focus on improvements to the Alternative Approach based on cost and performance data, we note also that the Proposed Approach succeeds in recognizing the regional nature of renewable energy markets, as well as the value of existing RPS requirements as an indicator of feasibility. However, this approach can be improved in several ways.

If EPA decides to use the Proposed Approach to determine the renewable energy component of the emissions reduction target, we recommend the following improvements to EPA's methodology to more accurately reflect best practices and existing trends of renewable energy growth.

Update RPS Requirement. Many of the state RPS goals extend beyond 2020, yet EPA used 2020 targets only in determining average regional RPS levels for the states for a 2030 emissions reduction target. EPA should reassess regional targets based on the last target year in state law: whether it be 2015, 2020, 2025 or another year, in setting the 2030 renewable target.

Some states have multiple RPS targets for different load serving entities (for example, one target for investor-owned utilities and another for coops or municipal utilities; or one target for larger utilities and another for smaller utilities). In any state with multiple targets, EPA should use the larger of the targets in formulating the regional average. Since EPA seeks the best system of emissions reductions, it should use the highest renewables targets being adequately demonstrated by states. While some states may have determined that lower targets are acceptable for some classes of utilities, they did not do so in the context of seeking the best system of emissions reductions. The higher targets, which have been demonstrated to be economically and technically achievable, clearly demonstrate a better system of emissions reductions.

Eliminate growth rate constraint, and choose best of: existing generation, existing state RPS requirement, and state goal based on the regional RPS average . We agree that Renewable Portfolio Standards are instructive in evaluating the best available emissions reductions opportunities. Some states have achieved higher renewable energy generation and integration than is required by their RPS, indicating that an RPS should not be a cap on renewable generation. However, in EPA's target-setting methodology, some state targets fall below existing generation and existing state RPS requirements. We believe that a state's existing generation and, if applicable, its existing state RPS requirement, should both serve as a floor to set the minimum level of emissions reductions available for that state. Using a level lower than the state has already demonstrated (either through generation or a state RPS target) would indicate a lower level of emissions reductions than the state has found to be available.

Further, in establishing a regional growth rate, EPA used unnecessary constraints that limited the pace of renewable energy growth. EPA's approach generated growth rates well below what has been demonstrated in the last several years and below what is achieved in most projections for the next decade. For example, the top 16 states in solar deployment all grew at growth rates higher than 40%, with 11 states growing at rates above 100%, between 2009 and 2013. According to EIA data, the top 16 states in wind development have all experienced growth at rates higher than 15%, with a national growth rate of 30%, sustained over a longer period between 2006 and 2013. In contrast, only one region in EPA's Proposed Approach is expected to meet a growth rate above 15% (East Central, 17%) in EPA's target-setting. Furthermore, when setting a growth rate EPA should rely on the most recent available capacity data, and should not ignore new and under-construction capacity. Renewable generation is quickly growing to meet and exceed state RPS requirements, and states with those standards have demonstrated that the levels required by these standards are both feasible and economic.[562] As such, assumed growth rates should more closely resemble the impressive growth from leading states during the last decade.

[562] NREL/LBNL, "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards", May 2014

Tables 4 and 5. Recent growth rates in solar PV and wind generation by state.

Solar PV Generation (GWh)						
State	2009	2010	2011	2012	2013	AAGR
CA	647	769	889	1,382	3,865	56%
AZ	14	16	83	955	2,041	247%
NV	174	217	291	473	749	44%
NJ	11	21	69	304	546	165%
NM	0	9	128	334	414	258%
NC	5	11	17	139	379	195%
FL	9	80	126	194	240	127%
CO	26	42	105	165	199	66%
TX	0	8	29	118	176	180%
MA	0	1	5	30	109	378%
PA	4	8	23	32	82	113%
MD	0	0	3	22	80	416%
IL	0	14	14	31	64	66%
OH	0	13	15	37	64	70%
DE	0	0	8	23	57	167%
NY	0	0	6	53	53	197%
U.S.	157	423	1,012	3,451	8,327	170%

Net Generation from Wind (GWh)									
State	2006	2007	2008	2009	2010	2011	2012	2013	AAGR
TX	6,671	9,006	16,225	20,026	26,251	30,548	32,214	35,937	27%
IA	2,318	2,757	4,084	7,421	9,170	10,709	14,032	15,571	31%

CA	4,883	5,585	5,385	5,840	6,079	7,752	9,754	13,230	15%
OK	1,712	1,849	2,358	2,698	3,808	5,605	8,158	10,881	30%
IL	255	664	2,337	2,820	4,454	6,213	7,727	9,607	68%
KS	992	1,153	1,759	2,863	3,405	3,720	5,195	9,430	38%
MN	2,055	2,639	4,355	5,053	4,792	6,726	7,615	8,065	22%
OR	931	1,247	2,575	3,470	3,920	4,775	6,343	7,452	35%
CO	866	1,292	3,221	3,164	3,452	5,200	5,969	7,382	36%
WA	1,038	2,438	3,657	3,572	4,745	6,262	6,600	7,008	31%
ND	369	621	1,693	2,998	4,096	5,236	5,275	5,530	47%
WY	759	755	963	2,226	3,247	4,612	4,369	4,415	29%
NY	655	833	1,251	2,266	2,596	2,828	2,992	3,548	27%
IN	0	0	238	1,403	2,934	3,285	3,210	3,483	71%
PA	361	470	729	1,075	1,854	1,794	2,129	3,339	37%
SD	149	150	145	421	1,372	2,668	2,915	2,688	51%
U.S.	26,589	34,450	55,363	73,886	94,652	120,177	140,822	167,665	30%

J. Comments on Building Block 4: Demand-Side Energy Efficiency

1. Overview

EDF strongly supports EPA's determination that demand-side reductions in carbon pollution from the power sector through increased energy efficiency measures are an integral part of the BSER for existing power plants. Energy efficiency has long been recognized as the most cost-effective way to meet our electricity needs,[563] and a variety of recent studies — as well as the experience of states and utilities that have been implementing energy efficiency programs for many years — confirm that there remains vast potential to achieve significant further reductions in electricity demand. As EPA recognizes, every megawatt-hour saved through energy efficiency translates into reduced generation from units operating

[563] *See, e.g.,* Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* 52 (World Resources Institute, Oct. 2014) ("Over the past decade, efficiency has remained the least-cost option for utilities, with levelized costs to utilities ranging from 2 to 5 cents per kilowatt hour, about one-half to one-third the cost of new electricity generation options.").

"at the margin," which in almost all cases will be an affected EGU utilizing fossil fuel.[564] As a result, energy efficiency is a highly economical and effective mechanism for reducing emissions from the power sector. Underscoring this conclusion, various federal and state regulatory programs have already sought to reduce emissions of carbon dioxide and other pollutants from the power sector by incentivizing energy efficiency.[565] EPA's inclusion of energy efficiency as part of the BSER under section 111(d) is a well-justified part of its system-wide approach to determining the level of emission reductions that state plans should achieve.

Many states and utilities have already taken action to realize this enormous opportunity for consumer savings and climate protection, providing further support for EPA's conclusion that energy efficiency is an "adequately demonstrated" and cost-effective element of the BSER. Indeed, twenty-six states around the country – including states in the Midwest, Southwest, West Coast, and the Northeast – have adopted energy efficiency standards or targets for their utilities that, in many cases, require investments matching or exceeding the level EPA has assumed in its BSER analysis. In recent years, state investments in consumer-funded EE programs increased to nearly $6 billion in 2012, representing a 28% increase in just three years. And incremental electricity savings reported by the states have increased by approximately 120% over the same period, reaching 22 million MWh in 2011 — equivalent to about 0.6% of retail sales – with 14 states reporting savings of more than 1% of retail sales.[566] A recent report by the Georgetown Climate Center contains numerous case studies of states and utilities that have successfully implemented energy efficiency programs to reduce greenhouse gas emissions and save customers money.[567] And a 2013 report by LBNL indicates that, under trends in existing programs, utility investments in energy efficiency are likely to increase to $9.5 billion by 2025 — with a corresponding increase of nearly 60% in

[564] The impacts of energy efficiency (and renewable energy) on the emissions of marginal EGUs is vividly illustrated in EPA's recently-released AVERT model, which draws from historical data on EGU operations to calculate the marginal emission reductions associated with energy efficiency and renewables deployment on an hour-to-hour basis. Other analyses carried out by grid operators confirm that the effect of energy efficiency and renewable energy is to displace generation – and emissions – from fossil fuel-fired EGUs on a continuous basis. For a more detailed explanation of the impacts of energy efficiency and renewable energy on emissions from fossil fuel-fired EGUs, please see section I.F of our comments.

[565] For example, in Title IV of the Clean Air Act Congress directed EPA to create an incentive program awarding allowances to utilities that reduce sulfur dioxide emissions through energy efficiency. For over a decade, EPA has also encouraged states to consider energy efficiency in developing state implementation plans (SIPs) to achieve National Ambient Air Quality Standards under section 110 of the Clean Air Act. *See generally* EPA, *Guidance on State Implementation Plan (SIP) Credits for Emission Reductions From Electric-Sector Energy Efficiency and Renewable Energy Measures* (Aug. 2004); EPA, *Roadmap for Incorporating Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans* (July 2012). And EPA has approved at least three SIPs that incorporate emission reductions from energy efficiency and renewable energy as compliance measures for achieving air quality standards. *See* EPA Roadmap, Appendix K at K-8 to K-10.

[566] American Council for an Energy Efficient Economy (ACEEE), *2013 State Energy Efficiency Scorecard* 19, 27, 30-31 (Nov. 2013).

[567] *See* Georgetown Climate Center, *Reducing Carbon Emissions in the Power Sector* 12, 15, 17, 26 (2013) (citing, among other examples, energy efficiency programs implemented by Xcel Energy and Black Hills Energy that reduced CO2 emissions by 1 million tons over 2009-2011; Minnesota's Conservation Improvement Program, which achieved CO2 reductions of 800,000 tons in 2010; an EE program by National Grid that benefits 1.8 million customers and saves 660,000 tons of CO_2 per year; and an energy efficiency initiative in Kentucky that is designed to reduce energy consumption by 18% by 2025).

total electricity savings.[568] EPA's recognition of energy efficiency as part of the BSER builds on the widespread — and rapidly increasing — deployment of energy efficiency around the country to benefit ratepayers and reduce emissions.

EPA's technical analysis of energy efficiency in "Building Block Four" contains two major components, both of which we support and reinforce in our comments below. First, EPA concludes – on the basis of recent potential studies as well as the experience of states that have succeeded in developing energy efficiency programs — that all states can eventually achieve annual incremental energy savings of at least 1.5% of retail sales each year. As we discuss below and as documented in a white paper separately filed in this docket by Analysis Group,[569] this assessment is amply supported by individual energy efficiency potential studies that have been performed around the country, as well as by broader national and regional studies. Moreover, EPA's assessment is conservative because it is based largely on efficiency opportunities that have historically been captured through ratepayer-funded energy efficiency programs. Importantly, these are programs where the cost effectiveness of energy efficiency investments are typically evaluated in the absence of carbon dioxide emissions standards for the power sector. Factoring in those avoided compliance costs will inherently increase the amount of cost effective energy efficiency investments. As such, EPA's analysis does not fully account for many *existing* energy efficiency technologies and practices – such as whole-building retrofits, commercial building commissioning, upgrades to transmission and distribution infrastructure, voltage/VAR optimization, and combined heat and power – that are typically not included in achievable potential studies but are nonetheless available to states and utilities. Nor does EPA's analysis fully reflect the many emerging energy efficiency technologies that will increase future technical and economic potential for energy savings. And EPA's assessment does not capture the many innovative mechanisms now being developed by states, utilities, and the private sector to streamline the financing and delivery of cost-effective energy efficiency solutions, all of which will have the effect of increasing achievable potential. In light of these considerations, EPA's 1.5% target likely understates the actual magnitude of savings that states can and will achieve as they implement state plans.

The second major component of EPA's analysis concerns the pace and timing of energy efficiency savings. Based on current energy efficiency targets adopted by states around the country, and historical rates of increase in energy efficiency savings, EPA concludes that each state can reasonably increase its energy efficiency savings by 0.2% of retail sales per year. Like EPA's assessment of ultimate savings potential, this projected "ramp-up" rate is conservative based on the actual experiences of states and utilities. Below, we discuss a second white paper filed in this docket by Analysis Group that examines ramp-up rates achieved by utilities in various states and concludes that EPA's projected rate has been met or exceeded in numerous instances over the last seven years.[570] Based on this analysis we conclude that EPA should increase the ramp rate to no less than 0.3%, and consider increasing it to 0.5% per year or more. In addition, we find that the experience of leading states and utilities — coupled with the vast

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[568] Galen L. Barbose et al., *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025* at 5 (LBNL, Jan. 2013)
[569] *See* Paul J. Hibbard, Katherine Franklin, & Andrea M. Okie, *The Economic Potential of Energy Efficiency: A Resource Potentially Unlocked by the Clean Power Plan* (Dec. 1, 2014) ("AG Potential Analysis").
[570] Paul J. Hibbard, Andrea M. Okie & Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels* (Dec. 1, 2014) ("AG Ramp Rate Anaylsis").

additional potential for energy savings not included in EPA's 1.5% target — provides ample support for EPA's expectation that a savings rate of up to 1.5% can be sustained through 2030.

Our comments also show that EPA's assumed costs for energy efficiency measures greatly exceed the most recent assessments in the literature, and recommend that EPA adopt lower and more realistic cost estimates that better reflect the opportunities for cost-effective pollution reductions available under the proposed Clean Power Plan. Lastly, our comments recognize that rigorous evaluation, measurement and verification (EM&V) for energy efficiency savings is a critical issue for state plans that rely on reported savings as an important part of demonstrating compliance. EDF looks forward to EPA's eventual guidance on EM&V. To assist EPA in preparing such guidance, we provide a brief review of the recommendations of Analysis Group on EM&V in section 111(d) state plans – which were included in a white paper published in March 2014, and which we have previously filed in this docket.[571]

2. EPA's Assessment of Energy Efficiency Potential is Conservative and Readily Achievable

EPA's proposed annual energy savings target of 1.5% of retail sales is readily achievable and, indeed, likely underestimates the full potential for cost-effective energy savings. As EPA notes in the TSD accompanying the proposed rule, the 1.5% target is consistent with average achievable energy savings in twelve recently-conducted potential studies from around the country, and with an ACEEE analysis from April 2014.[572] In addition, three states were already achieving this level of energy savings as of 2012, and an additional nine states will be required to achieve this level by 2020 under existing energy efficiency policies.[573, 574] These considerations all indicate that the 1.5% target is adequately demonstrated.

States have made these investments because these programs are good for consumers, even absent limits on carbon pollution. According to analysis by the World Resources Institute, these programs "regularly save customers over $2 for every $1 invested, and in some cases up to $5."[575] According to ACEEE, ramping up every start target to 1.5 percent would increase GDP by over $17 billion by 2030 while creating over 600,000 new jobs.[576]

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[571] *See* Paul J. Hibbard & Andrea Okie, *Crediting Greenhouse Gas Emission Reductions from Energy Efficiency Investments,* Document ID No. EPA-HQ-OAR-2013-0602-6120 (Mar. 2014).
[572] *See* GHG Abatement Measures TSD at 5-24 (citing ACEEE, *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution* (Report E1401, Apr. 2014).
[573] *See* GHG Abatement Measures TSD at 5-32 to 5-33.
[574] Among all states with energy efficiency targets, ACEEE found that "In 2011, 13 states exceeded their electricity savings targets, and 6 others came within 90% of them. Only two states achieved less than 80% of their targeted electricity savings. In 2012, 15 states met or exceeded their electricity savings targets, and 6 others came within 90% of their savings targets for the year. Only one state met less than 80% of its target." See Annie Downs and Celia Cui, Energy Efficiency Resource Standards: A New Progress Report on State Experience. ACEEE. April 2014. Available at http://aceee.org/sites/default/files/publications/researchreports/u1403.pdf
[575] Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014)
[576] H.Hayes, G. Herndon, J. P. Barrett, J. Mauer, M. Molina, M. Neubauer, D. Trombley, and L. Ungar, 2014, "Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution," April, Report E1401, American Council for an Energy-Efficient Economy (ACEEE), Washington, DC, accessible at http://www.aceee.org/sites/default/files/publications/researchreports/e1401.pdf.

Further support for EPA's proposal appears in two recent white papers prepared by the Analysis Group and submitted separately to this docket. The AG Potential Analysis focuses specifically on the 1.5% target, evaluating both EPA's meta-analysis and a recent comprehensive study by ACEEE (2014), as well as other literature. The Analysis Group's review confirms that the studies considered by EPA and ACEEE are thorough, geographically diverse, and represent sound methodologies for evaluating energy efficiency potential. Further, the Analysis Group review finds that energy efficiency potential studies have found economic and achievable energy savings potential well in excess of 1.5% per year in all major regions of the country, and over varying forecast periods ranging up to 20 years. The Analysis Group report also includes a critical evaluation of the EPRI (2009) analysis reported in the TSD, which found significantly lower energy savings potential than other studies reported in the literature; the Analysis Group notes that, among other flaws, the EPRI analysis excluded savings from a wide range of efficiency measures and did not take into account the potential to reduce energy consumption through accelerated replacement of equipment.

As the Analysis Group report also explains, the methodology used by EPA (and other similar analyses) to quantify achievable potential is likely to lead to a conservative result that understates the full scale of energy savings that can be achieved by states and utilities. This is because "achievable" potential is typically defined to represent only a fraction of cost-effective energy efficiency potential, and is often intentionally restricted to reflect current energy efficiency program budgets and limitations. As the National Academy of Sciences described it in a 2010 review of potential studies, "The risk of overestimating efficiency potential *is minimal*, owing to the methodologies that are used in the studies…the studies openly and intentionally make assumptions that lead to 'conservatively' low estimates of the efficiency resource."[577] These are considerations that are not binding in the context of an emission reduction program such as the Clean Power Plan.

There are at least four additional reasons why EPA's analysis likely underestimates the full potential for energy savings in each state:

- **Alternative EE measures**. First, the potential studies reviewed in the EPA, ACEEE, and similar analyses are typically prepared for state PUCs or utilities interested in determining potential savings from ratepayer-funded programs; as such, only a minority of those studies include savings that can be achieved through measures that are typically not included in such programs, such as through improvements in building codes and appliance standards or through investments in CHP.[578] These measures can make significant contributions to total energy savings. For example, a 2011 study by the Edison Foundation's Institute for Electric Efficiency indicated approximately 8.6-13.6% of total electricity demand in 2025 (approximately 351-556 TWh) could be achieved by adopting "moderate" to "aggressive" new energy codes for buildings and appliances at the state level.[579] These savings are comparable in magnitude to the *total* savings

[577] AG Potential Analysis at 17 (citing National Academy of Sciences, *Real Prospects for Energy Efficiency in the United States* 59 (2010)).
[578] *See* Max Neubauer, Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies 38 (Aug. 2014).
[579] According to the Department of Energy, only one-quarter of states have adopted the most up-to-date codes for residential and commercial buildings. This is notable as these codes can reduce energy use in new residential and commercial buildings by 20 and 25 percent, respectively. Importantly, building codes have shown themselves to be

EPA projects from ratepayer-funded programs alone in 2030 under building block 4 (approximately 500 TWh).[580] Another example of a demonstrated technology not included in EPA's analysis is Voltage/VAR optimization, which was recently highlighted in a report documenting new strategies being used by utilities to achieve higher levels of energy efficiency savings.[581] As described more fully in Table 7, VVO is a cost-effective resource that states can use to generate significant additional savings and that is not typically considered in potential studies. For example, Xcel Energy is projecting energy savings equivalent to approximately 1.8% of its retail load by 2020 as a result of a proposed voltage optimization project throughout its system.[582]

- **Emerging technologies**. Potential studies also have difficulty capturing changes in technical and economic potential that may result over time due to technological innovation and declining costs of new technologies. This is likely one reason why potential studies with longer time horizons tend to report lower annualized savings than studies that assess short term potential.[583] Yet, the history of energy efficiency deployment shows that savings potential has remained steady or increased over time due to the introduction of new technologies.[584] For example, the Northwest Power and Conservation Council's most recent regional energy plan, issued in 2010, reported a 136% increase in energy efficiency potential relative to 2005 – primarily because of "changing technology that has created new efficiency opportunities and reduced costs."[585] If history has shown anything is that change is norm for this industry. As the World Resources Institute notes, "Major household appliances—including refrigerators, dishwashers, and clothes washers—have become 50 to 80 percent more energy efficient over the last two decades." For example, new refrigerators, clothes washers, dishwashers, and air conditioners use 75, 70, 40, and 50 percent

cost effective, with codes adopted between 1992 and 2012 expected to save consumers more than $40 billion from buildings constructed during these 20 years alone. See U.S. Department of Energy (DOE), 2014, Building Energy Codes Program: "Status of State Energy Code Adoption," July, U.S. DOE Office of Energy Efficiency and Renewable Energy, accessible at http://www.energycodes.gov/adoption/states. See also U.S. Department of Energy (DOE), Building Technologies Office, "Building Energy Codes Program," DOE Office of Energy Efficiency & Renewable Energy, accessible at https://www.energycodes.gov/.

[580] *See* RIA at 3-27. Although there is likely to be overlap between savings that could be achieved through ratepayer-funded programs and savings that would result from building codes and appliance standards, this comparison nonetheless demonstrates that there are viable alternative pathways for achieving significant savings that are not considered in EPA's core analysis.

[581] Howard Geller, Jeff Schlegel & Ellen Zuckerman, *Maintaining High Levels of Energy Savings from Utility Energy Efficiency Programs: Strategies From the Southwest* 5-152 (ACEEE Summer Study on Energy Efficiency in Buildings, 2014)

[582] *Id.*

[583] National Academy of Sciences, Real Prospects for Energy Efficiency in the United States at 57.

[584] *See id.* at 58 (Comparing potential studies conducted in New York State in 1989 and 2003, which found very similar levels of economic potential, and stating "Studies of technical and economic energy-savings potential generally capture energy efficiency potential at a single point in time based on technologies that are available at the time a study is conducted. But new efficiency measures continue to be developed and to add to the long-term efficiency potential.")

[585] Sixth Northwest Conservation and Electric Power Plan," Northwest Power and Conservation Council, February 2010, p. 10-4.

less energy, respectively, than they did in 1990.[586] Meanwhile, lighting continues to improve by leaps and bounds. LED lighting has fallen in cost by approximately 75% over the last several years and achieves significant energy savings even relative to compact fluorescent bulbs.[587] One recent report notes that Southwestern utilities have increasingly begun incentivizing customers to switch to LED bulbs in order to meet more stringent energy savings targets, as the cost and performance of this technology has improved.[588] Table 7 highlights other emerging technologies, such as high-efficiency HVAC units and intelligent energy monitoring instruments, that demonstrate the potential to maintain or increase technical and economic potential for energy efficiency over time.

- **Innovation in program design and financing**. EPA's analysis is based on studies of "achievable" potential, which is a term of art that refers to the most conservative assessment of energy savings potential taking into account current budgetary and administrative constraints facing utilities or PUCs in a specific policy context. Achievable potential *can* be increased by utilities and state agencies — even without improvements in the cost or effectiveness of energy efficiency technologies — through concerted investment and improvement in program design and financing. And indeed, there are many examples of such innovations taking place just in the last few years. For example, at least twenty states now have utilities that offer "on-bill" loan programs that allow ratepayers to finance energy efficiency projects at competitive rates, and repay the cost of the loans through monthly energy bills.[589] Since 2009, over two dozen states have authorized local governments to implement Property Assessed Clean Energy (PACE) programs to provide competitive financing for energy efficiency projects by allowing property owners to repay the costs of energy efficiency investments gradually through their property taxes.[590] And individual utilities are increasingly devising other creative customer outreach and

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[586] Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014)

[587] Neabauer, *supra* at 14 n.13.

[588] Howard Geller, Jeff Schlegel & Ellen Zuckerman, *Maintaining High Levels of Energy Savings from Utility Energy Efficiency Programs: Strategies From the Southwest* 5-151 to 5-152 (ACEEE Summer Study on Energy Efficiency in Buildings, 2014) (describing new programs being implemented by Southwestern utilities to increase deployment of LEDs, and noting that these savings are more than offsetting other reductions in energy savings from lighting that were occurring as a result of new federal efficiency standards).

[589] *See* Catherine Bell, Steven Nadel, & Sara Hayes, *On-Bill Financing for Energy Efficiency Improvements: A Review of Current Program Challenges, Opportunities, and Best Practices* (Dec. 2011) (identifying twenty states with on-bill financing programs, and providing 19 case studies of such programs).

[590] Although a 2010 administrative decision by the Federal Housing Finance Administration (FHA) hindered the development of residential PACE programs, PACE programs for commercial buildings continue to be developed and had financed approximately 71 projects in four counties as of early 2011. In addition, we note that some states have managed to find a way to continue operating their residential PACE programs. According to the World Resources Institute, these states are "insuring mortgage holders against losses they may incur because of PACE financing, subordinating the status of residential PACE liens, or maintaining the senior status of PACE liens and providing disclaimers to homeowners interested in enrolling." LBNL, Renewable Funding & Clinton Climate Initiative, *Policy Brief: Property Assessed Clean Energy (PACE) Financing: Update on Commercial Programs* 1 (Mar. 2011); *see also* Katrina Managan & Kristina Klimovich, *Setting the PACE: Financing Commercial Retrofits* 6-7 (Feb. 2013) (indicating that 26 states and DC have enabling legislation, and that sixteen active PACE programs in seven states are financing commercial PACE projects as of early 2013). Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014)

financial incentive programs that enhance participation in energy efficiency initiatives and help achieve greater levels of energy savings.[591] A recent systematic analysis of innovative energy efficiency program designs estimated that such programs could achieve total savings of almost 1,200 TWh in 2030, or approximately 27% of baseline electricity demand – well in excess of EPA's target.[592]

- **Private investments in EE**. Because many studies of achievable potential are designed to take into account the limitations of ratepayer-funded programs, it is unclear whether or how these studies take into account the potential for private actors to deliver energy savings additional to those that would be captured through programs administered by utilities or states. Nevertheless, there is a significant opportunity for private sector investment in cost-effective energy efficiency projects. The private energy services performance contracting industry, for example, has been growing at a rapid pace in recent years, and achieved average annual savings of approximately 26-40 TWh (including both electricity and gas savings) over the period 2003-2012. [593] It is reasonable to expect that this industry and others like it will see significant new growth if energy efficiency investments are incentivized through section 111(d).

As noted above, it is critical to understand that analyses of "achievable" potential are limited by the policy context in which they are developed. The Clean Power Plan creates a fundamental change in the portion of economic energy efficiency that is "achievable" by making energy efficiency a means of achieving compliance with federal carbon pollution standards.

In addition to the conservative assessments of achievable potential reflected in EPA's analysis, several national and regional studies have found technical, economic, and achievable efficiency potential that significantly exceeds EPA's target.[594] These corroborating studies provide further confirmation that EPA's target is eminently reasonable and, in fact, conservative:

- A February 2014 study by LBNL estimated energy efficiency potential in the Western Interconnection in both 2021 and 2032. For 2021, LBNL estimated that aggressive deployment of economically cost-effective energy efficiency measures could reduce annual energy demand in the Western Interconnection by 18% relative to a business as usual scenario. For 2032, LBNL found technical potential for a 22% decrease in demand *above and beyond* savings that would

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[591] *See* Seth Nowak et al., *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs* (June 2013) (Reviewing leading energy efficiency programs being implemented by states and utilities, and noting several emerging trends in successful program design including more sophisticated and segmented marketing, adoption of "one stop shopping" and other customer-friendly delivery approaches, and adoption of new financing programs); Geller et al., *supra*, at 5-149, 5-153 to 5-154 (describing utility programs providing financial incentives to builders and developers for constructing or retrofitting buildings that exceed minimum energy code requirements; incentivizing homeowners for undertaking whole-home energy savings; and adopting innovative marketing strategies to encourage greater participation in energy saving programs).

[592] *See* Dan York et al., *Frontiers of Energy Efficiency: Next Generation Programs Reach for High Efficiency Savings* (ACEEE, Jan. 2013).

[593] *See* Elizabeth Stuart et al., *Current Size and Remaining Market Potential of the U.S. Energy Service Company Industry* 1, A-6 (LBNL, 2013).

[594] As discussed below, because these studies report aggregate reductions in energy demand, they tend to support the *combination* of EPA's 1.5% annual energy savings target and the assumed "ramp-up" rate at which savings can be increased to the target level.

already occur as a result of energy efficiency programs that are already in place – many of which could be counted by states towards compliance with their state goals.[595] Both of these estimates greatly exceed EPA's proposed targets, which imply a 3% decrease in overall electricity demand in 2020 and a 11% decrease in electricity demand by 2030.[596]

- A January 2013 study published by Oak Ridge National Laboratory and conducted by researchers at Georgia Tech considered energy efficiency potential in the Eastern Interconnection. Like the LBNL study, the ORNL report found very high potential for energy savings. Moreover, ORNL's study was arguably more conservative than the LBNL study, in that it examined *achievable potential* for savings using a limited suite of 12 selected policies to incentivize or require greater efficiency in residential, commercial, and industrial buildings. These policies do not even come close to representing the full range of measures that states and utilities could implement to increase energy efficiency savings. Even so, the study found that the combination of examined policies would reduce total electricity use in the Eastern Interconnection by almost 7% in 2020 and approximately 10.2% in 2035, which is more than double the level of demand savings implied by EPA's target for 2020 and is very comparable to EPA's target for 2030.[597]

- A 2012 report by the Southwest Energy Efficiency Project (SWEEP) reviewed the historical performance of "best practice" energy efficiency programs for both residential and commercial buildings, and estimated the energy savings that could be achieved in six Southwestern states (Arizona, Colorado, Nevada, New Mexica, Utah, and Wyoming) if similar best practice programs were adopted in the region. Because this analysis is based on savings and participation rates achieved by actual energy efficiency programs being implemented around the country, it is best characterized as an assessment of achievable potential. SWEEP projected that these best practice energy efficiency programs could achieve savings equivalent to over 20% of retail sales by 2020 – reducing electricity demand to approximately 18% below the reference case.[598] The SWEEP study suggests that Southwestern states could achieve a level of energy savings by 2020 that significantly exceeds even EPA's long-term targets for 2030.

- An exhaustive 2009 analysis by McKinsey & Company analyzed the economic potential to deploy hundreds of already-available technologies in buildings and industrial processes. This study found that the country's total end-use energy consumption could be reduced by 23% by 2020 relative to a business-as-usual scenario, relying only on measures that pay for themselves over time.[599] This vastly exceeds the level of energy savings expected by EPA for 2030, albeit using an economic potential metric rather than achievable potential.

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[595] *See* Galen Barbose et al., *Incorporating Energy Efficiency into Western Interconnection Transmission Planning,* 19, 36 (LBNL Feb. 2014).
[596] RIA at 3-17.
[597] *See* Marilyn Brown & Yu Wang, *Estimating the Energy-Efficiency Potential in the Eastern Interconnection* (ORNL Jan. 2013).
[598] Howard Geller, *The $20 Billion Bonanza: Best Practice Utility Energy Efficiency Programs and Their Benefits for the Southwest* xi (2012).
[599] Hannah Choi Granade et al., *Unlocking Energy Efficiency in the U.S. Economy* v (2009).

- A 2010 report by the National Academy of Sciences reviewed a number of studies of EE in residential and commercial buildings, and similarly found that a 25-30% energy savings for the building sector as a whole could be achieved between 2030 and 2035, at a cost of just 2.7 cents per kWh saved. The NAS report also reviewed studies finding that approximately 14-22% of industrial electricity demand could be cost-effectively reduced by 2020.[600] These estimates significantly exceed the levels of energy savings EPA's target implies for 2030.

Lastly, the individual experiences of large energy users that have voluntarily implemented energy efficiency measures are consistent with the findings from these forward-looking studies, and suggest that there is significant, untapped potential to achieve energy savings well in excess of the levels EPA has assumed. Over the last several years, for example, over 190 organizations that collectively own or operate approximately 3.3 billion square feet of building space and over 600 manufacturing facilities have partnered with the U.S. Department of Energy to monitor and improve their energy efficiency through a program called the Better Buildings Challenge.[601] This partnership has furnished a wealth of information about the potential to significantly reduce energy use in commercial, residential, and industrial buildings, and yielded a number of best practices and implementation models that can be adopted by both private and public sector institutions.[602] Since 2011, the Better Buildings Challenge partners have reduced the energy intensity of their buildings by an average of 2.5% each year. More than 2,100 of the 9,000 participating facilities have improved their performance by 20% or more, and more than 4,500 have improved their performance by at least 10%.[603] Many of the large companies and municipal entities that are taking part in the Challenge have reported reductions in building energy use as great as 40%, through the adoption of leading energy efficiency technologies as well as careful energy management practices.[604] These achievements further corroborate the results of the energy efficiency potential studies reviewed above, and suggest that even deeper savings can be achieved through well-coordinated investments in efficiency.

Taken together, both the evidence that EPA cites in the proposed rule and the additional studies and reports highlighted above indicate that the target of 1.5% of savings per year is conservative and readily achievable.

3. EPA's Projected Rate of Increase in Energy Savings is Conservative and Should be Increased

EPA's projection that states can increase energy savings at a rate of 0.2% of retail sales per year is conservative according to recent experiences at the state level, as Analysis Group concludes in a second white paper filed separately in this docket. According to work by the Analysis Group, it is very common for states to achieve a ramp rate in excess of 0.3 percent per year, and most of those states were able to

600 America's Energy Future Panel on Energy Efficiency Technologies, *Real Prospects for Energy Efficiency in the United States* 7-8, 15-16 (2010).
601 *See* U.S. Department of Energy, *Better Buildings Challenge: Progress Update Spring 2014* 1 (May 2014).
602 *See* U.S. Department of Energy, *Better Buildings Challenge: Three Ways to Find a Solution for You*, *http://www4.eere.energy.gov/challenge/browse-market* (last visited November 24, 2014) (gathering implementation models used by Better Buildings Challenge partners).
603 BBC Spring 2014 Progress Update, *supra* at 2.
604 *Id.* at 9.

sustain this high rate of savings growth over multiple years. However, the Analysis Group also documents many cases where states recorded an annual rate of energy savings growth from 0.5%-0.9% at various times from 2006-2013, including California, Massachusetts, Ohio, Oregon, Rhode Island, and Vermont. In addition, we note that EPA's own analysis of past rates of energy savings shows that states achieving moderate levels of savings recorded an average rate of improvement of incremental annual savings of 0.30% per year, and that the high performers achieved an increase in incremental annual savings of 0.38% per year.[605] Because the actual performance of programs so regularly exceeds the ramp rates from EERS targets, EPA should use historical data when determining what energy efficiency ramp rate constitutes the best system of emissions reductions. Based on these analyses, we recommend that EPA increase the ramp rate to no less than 0.3%, and consider increasing it to 0.5% per year or more.

As the Analysis Group also demonstrates through in-depth case studies, these periods of high energy savings growth often followed changes in state-level policies that were specifically intended to spur investment in energy efficiency. Thus, the experience of these states suggests that state-level decisions – such as programs and regulatory policies that will be adopted as part of state plans under section 111(d) — can have a decisive impact on the pace and performance of energy efficiency investments. To take one example, the state of Arizona has rapidly become a national leader in energy efficiency over the last seven years, increasing its state-wide energy savings by 1.57% of retail sales between 2006 and 2013 (reflecting an annual average rate of increase of over 0.2% per year). As the Analysis Group report demonstrates, this increase in energy savings directly followed the adoption of an expanded system benefits charge in 2006 that significantly expanded the resources available for utility-sponsored energy efficiency programs. In 2010, Arizona took the further step of enacting a rigorous energy efficiency resource standard (EERS) that requires cumulative energy savings to reach 22% of sales by 2020. These two policies combined have helped Arizona sustain a rapid upward trajectory of energy savings growth – helping Arizona exceed EPA's 1.5% target in both 2012 and 2013.[606]

In addition to supporting EPA's conclusions regarding feasible rates for increasing energy efficiency savings, the Analysis Group also documents the ability of states and utilities to *sustain* high savings levels over time. As noted above, the existence of massive technical and economic potential for energy savings – including savings from measures and programs that are not explicitly included in EPA's analysis – strongly suggests that states will be able to achieve high levels of energy savings over an extended period of time. However, Analysis Group also provides many examples of leading states and utilities that have demonstrated this ability in recent years. For example, the Analysis Group notes that San Diego Gas & Electric, one of California's "big three" large investor-owned utilities, has reported energy savings well in excess of 1.5% of sales every year since 2007. In 2009 alone, SDG&E reported energy savings of over 2.5% of sales. Similarly, the state of Massachusetts achieved energy savings exceeding 1.5% of sales in each year from 2011 to 2013, with savings exceeding 2% of sales in both 2012 and 2013. And Vermont has exceeded the 1.5% target every year from 2007 to 2012, with energy savings in three of those years at or exceeding 2% of sales. These and other examples in the Analysis Group report demonstrate that high

[605] GHG
[606] AG Ramp Rates Analysis at 23-25.

savings rates can not only be reached at the rate that EPA projects in building block 4, but can also be met over extended periods.[607]

In addition to the Analysis Group white paper, many of the regional and national studies cited above in the context of EPA's 1.5% target also lend support EPA's assumptions regarding ramp-up rates and sustained savings. These regional and national studies report aggregate reductions in demand in future years, which can be compared to EPA's projected demand savings in 2020 and 2030. And EPA's projected energy savings, in turn, are based on *both* the 1.5% savings target and the ramp-up rate. The fact that the demand reductions in these regional and national studies either meet or significantly exceed EPA's projections therefore indicates that the combination of savings target and ramp-up rate is reasonable and achievable.

4. Other Elements of EPA's Goal-Setting Approach Contribute to a Conservative Assessment of Potential

There are two other aspects of EPA's goal-setting approach that lead to an overall conservative assessment of potential energy savings, and that further indicate EPA's proposed energy savings levels in Building Block 4 are readily achievable.

First, EPA assumes that each year's energy efficiency investments have a limited measure lifetime of 20 years, and that the energy savings resulting from any given measure decline at a rate of 5% per year starting the year after the measure is installed. This means that cumulative savings in the year 2030 reflect only 50% of the first-year energy savings achieved by energy efficiency measures installed in the year 2020, and just 35% of the first-year energy savings from measures installed in 2017. This is a highly conservative assumption, given data from LBNL indicating that minimum lifetimes for energy efficiency measures are at least 5 years.[608] Moreover, the practical effect of this assumption is to reduce the cumulative savings that are used to calculate each state's goal. EPA's TSD, for example, shows that for South Carolina the "expiring" savings reduced the state's cumulative savings by approximately 5% in 2025.

Second, EPA applies the 1.5% goal in a way that results in *annual average* reductions of slightly less than 1.5%. As noted above and in the TSD, the 1.5% goal was drawn from analyses of annual average energy efficiency savings – defined as cumulative savings divided by the total time period over which those savings can be achieved. However, when calculating state goals, EPA does not determine annual savings by applying the 1.5% goal to a fixed baseline, as the potential studies do; rather, EPA applies the 1.5% goal to the prior year's sales in each year (after the state has ramped up to that level). As a result, EPA's target-setting approach results in annual average savings that are slightly *less* than 1.5% over the 13-year period in the proposed emission guidelines. This effect is illustrated in Table 6 below, which shows the cumulative savings that would result from a 1.5% per year energy savings in a state with business as usual (BAU) demand growth of 0.8%. As the table shows, the 1.5% target results in annual average savings of

[607] *Id.* at 33-35, 38-40, 50.

[608] Megan A. Billingsley et al., *The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs* 17 (LBNL Mar. 2014) (reporting range of measure lifetimes for twelve different categories of energy efficiency measures; no measure had a lifetime of less than five years).

approximately 1.37% by 2013. This only underscores that EPA's goal is readily achievable and well within the range of savings reported in energy efficiency potential studies.

Table 6. Annual Average Savings for a Hypothetical State Experiencing Incremental Annual Savings of 1.5% and Business as Usual Demand Growth of 0.8%

Year	BAU Demand	Demand Net of EE Savings	Cumulative Savings Relative to BAU	Annual Average Savings (Cumulative Savings/Time Period)
2017	100	100	0	0
2018	100.8	99.3	1.5	1.5%
2019	101.6	98.6	3.0	1.49%
2020	102.4	97.9	4.5	1.48%
2021	103.2	97.2	6.1	1.47%
2022	104.1	96.5	7.6	1.46%
2023	104.9	95.8	9.1	1.45%
2024	105.7	95.1	10.6	1.43%
2025	106.6	94.4	12.1	1.42%
2026	107.4	93.8	13.7	1.41%
2027	108.3	93.1	15.2	1.40%
2028	109.2	92.4	16.7	1.39%
2029	110.0	91.8	18.3	1.38%
2030	110.9	91.1	19.8	1.37%

5. The RIA Significantly Overestimates the Projected Costs of Energy Efficiency Measures

EPA has significantly overestimated the costs of implementing energy efficiency measures at the pace and level contemplated in building block four. A more realistic assessment of these costs, based on the long track record of energy efficiency programs that have been deployed over the last few decades, would significantly lower the overall compliance costs anticipated for the Clean Power Plan and perhaps alter the overall balance of carbon pollution reduction measures that EPA would consider cost-effective in its BSER analysis.

According to the RIA, EPA assumed that the total levelized cost of energy efficiency projects would be approximately 8.5 cents per kWh saved in 2020, 8.9 cents/kWh in 2025, and 9 cents/kWh in 2030, assuming a 3% discount rate. In projecting these costs, EPA assumed that the first-year cost of saved energy would increase by 20% once a state reached a savings level of 0.5% per year, and by 40% once a state reaches savings of 1.0% per year.[609]

[609] RIA at 3-18.

These cost estimates are much higher than the recent literature and the historical record indicate. As noted above, states frequently find that such programs make sense even in the absence of policies to reduce CO_2 emissions because they save customers money.[610]

In March 2014, LBNL published a comprehensive survey of energy efficiency program costs in March 2014 that collected data from more than 1,700 energy efficiency programs in 31 states – the most recent, rigorous, and expansive review of energy efficiency program costs that we have encountered. LBNL found that on a savings-weighted basis, the average levelized cost of saved energy across the programs sampled was just 2.1 cents per kWh.[611] Although this figure only includes costs incurred by program administrators, LBNL also estimated (based on more limited data) that *total* resource costs, including both program and participant costs, would be about twice the program costs. This suggests that total levelized costs for the programs surveyed by LBNL would be about 4.2 cents per kWh saved — less than half the cost that EPA estimated for 2020. Given that the GHG Abatement Measures TSD references the LBNL study, it is not clear why EPA adopted a much higher cost estimate from a much older and less comprehensive 2009 analysis.[612]

Even taking into account EPA's assumption that the costs of energy efficiency will escalate by 40% for states that exceed a savings rate of 1% per year, LBNL's levelized cost figure would still be much lower than the values EPA derived. Nevertheless, the evidence simply does not support EPA's assumption that states will experience increasing costs at energy savings levels below 1.5% per year. The Analysis Group white paper on ramp-up rates, for example, highlights an empirical study of energy efficiency program costs for a variety of jurisdictions reflecting a wide range of energy savings levels.[613] Based on a regression analysis of this historic cost data, the study found that the first-year cost of saved energy *declines* as a state increases its savings level to 2.5%. Only once savings levels reach 2.5% did the study find that diminishing returns cause the cost of saved energy to increase. These results are consistent with a 2008 study by economists at Synapse Energy Economics, which also found that the unit cost of saved energy for a cross-section of high-performing utilities declined with increasing levels of savings, even at savings levels of 2% of annual sales.[614] The Synapse researchers concluded that their results likely reflected economies of scale and learning effects, and stated that "While there exists a possibility that unit

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[610] *See* Nicholas Bianco et al., *Seeing is Believing: Creating a New Climate Economy in the United States* (World Resources Institute, Oct. 2014) (finding that energy efficiency programs regularly save customers over two dollars for every dollar invested, and sometimes yield savings as great as five dollars for every dollar of investment); H.Hayeset al., *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution*, (ACEEE Report E1401, April 2014), accessible at http://www.aceee.org/sites/default/files/publications/researchreports/e1401.pdf (ramping up every state target to 1.5 percent would increase GDP by over $17 billion by 2030 while creating over 600,000 new jobs).

[611] Megan A. Billingsley et al., *The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs* xi (LBNL Mar. 2014).

[612] GHG Abatement Measures TSD at 5-50 to 5-51.

[613] *See* AG Ramp Rates Analysis, *supra* nat 53 (citing John Plunkett, Theodore Love, & Francis Wyatt, *An Empirical Model for Predicting Electric Energy Efficiency Resource Acquisition Costs in North America: Analysis and Application* 5-347 (ACEEE Summer Study on Energy Efficiency in Buildings, 2012)).

[614] Kenji Takahashi & David Nichols, *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence From Experience to Date* 8-369 (ACEEE Summer Study on Energy Efficiency in Buildings, 2008).

costs might begin to increase at much higher levels of EE program savings, this evidence suggests that current program savings levels have not yet approached any such point."[615]

Accordingly, EPA should revise its cost assumptions for energy efficiency to better reflect the results of the LBNL analysis and other credible studies, as well as the literature finding little to no relationship between total energy savings and costs at levels of 1.5% per year or less. We believe that more realistic cost projections for energy efficiency would significantly reduce the overall anticipated cost of the Clean Power Plan, and indicate that increased levels of pollution reduction are cost-effective to achieve.

6. Comments on Evaluation, Measurement & Verification (EM&V)

Credible and workable plans for evaluating, measuring and verifying energy efficiency savings will be a critical part of state plans under the proposed emission guidelines, especially in states with rate-based goals where reported savings will be directly used to demonstrate compliance. As EPA recognizes in the TSD,[616] EM&V approaches to quantify energy savings from energy efficiency measures have been demonstrated for several decades and have grown increasingly rigorous. Over the last two decades, at least fourteen states and several regional transmission organizations (RTOs) and regional partnerships have developed M&V protocols for quantifying energy savings.[617] Reflecting growing confidence in these techniques, verified energy savings are now widely used as the basis for critical regulatory proceedings and market functions, including utility ratemaking[618] and regional forward capacity markets.[619] And although M&V practices continue to vary widely among states and utilities,[620] serious efforts have been undertaken to develop consensus as to best practices and standardized protocols. These initiatives include the Department of Energy's Uniform Methods Project; the International Performance Measurement and Verification Protocol and associated professional certification program; regional technical initiatives such as the Northeast Energy Efficiency Partnership and Pacific Northwest Regional Technical Forum; and the evaluation guides and studies produced by the State and Local Energy Efficiency Action Network (SEE Action).

EDF believes these initiatives provide a sound foundation for EM&V frameworks that could be integrated into state plans, and looks forward to further guidance from EPA regarding satisfactory state plan

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[615] *Id.* at 8-371.
[616] State Plan Considerations TSD at 37.
[617] *See* Steven Schiller et al., *National Energy Efficiency Evaluation, Measurement and Verification (EM&V) Standard: Scoping Study of Issues and Implementation Requirements* 51 (State & Local Energy Efficiency Action Network, Apr. 2011).
[618] Thirty states currently have or are implementing a performance incentive rewarding utilities for EE investments. ACEEE, *2013 State Energy Efficiency Scorecard* at 37.
[619] Two major federally-regulated regional transmission organizations (RTOs), PJM Interconnection and the New England Independent System Operator (ISO-NE), allow EE resources to bid on a level playing field with traditional generating resources in specialized markets that ensure the long-term ability of the power grid to meet demand. Moreover, both organizations have adopted manuals for measuring and verifying EE resources with sufficient reliability to be counted as a capacity resource. *See* State & Local Energy Efficiency Action Network, *Energy Efficiency Program Impact Evaluation Guide* 7-5 (Dec. 2012).
[620] *See generally* Mike Messenger et al., *Review of Evaluation, Measurement and Verification Approaches Used to Estimate the Load Impacts and Effectiveness of Energy Efficiency Programs* (Lawrence Berkeley National Laboratory, Apr. 2010); Martin Kushler et al., *A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs* (ACEEE, Feb. 2012).

provisions on EM&V. To support the development of this guidance, EDF has commissioned a white paper from the Analysis Group (filed previously in this docket) that suggests possible frameworks for integrating EM&V into state plans. Broadly speaking, the Analysis Group framework seeks to balance the following policy priorities:

- Environmental rigor, which in this context means utilizing EM&V approaches that account for uncertainty by yielding conservative quantifications of energy savings;
- Flexibility with respect to the types of energy savings measures that can be certified and the types of EM&V approaches that can be approved;
- Compatibility with well-established and rigorous existing approaches to EM&V;
- Providing a cost-effective and administratively efficient process for states, utilities, and energy efficiency providers.

The report describes suggested guidance to the states on a number of issues, including documentation and reporting requirements for entities seeking to certify energy savings; assumed lifetimes of energy efficiency measures; the determination of baselines against which energy savings are to be measured; and consensus-based processes for reviewing and improving EM&V methods over time. The report also identifies three broad categories of EM&V approaches that EPA could recognize in guidance to the states, including 1) deemed savings values and algorithms; 2) measurement-based (or "tailored") EM&V approaches; and 3) PUC-approved EM&V programs, which often reflect combinations of deemed savings and measurement-based evaluations. For each pathway, the report recommends minimum quality assurance elements that would be included in a state plan, as well as potential existing protocols that a state could adopt "off the shelf" to minimize the administrative burdens of developing an EM&V plan. State plans could adopt one pathway or any combination of these pathways, and would include a reasonable basis for adjusting reported energy savings for uncertainty. Although EDF believes that EM&V guidance could take a number of reasonable forms, the Analysis Group report presents one possible framework EPA could consider.

EDF has also reviewed the joint comments on EM&V filed by the Northeast Energy Efficiency Partnership (NEEP) and other organizations, and believes these comments provide many useful recommendations for the development of EPA's EM&V guidance. Among other things, the comments identify credible EM&V protocols that have been established by national and regional partnerships, recommend the development of cross-cutting protocols to assure the rigor of EM&V, and provide recommendations as to the process for establishing and improving EM&V guidance over time. EPA should give careful consideration to these comments as it considers guidance on EM&V.

Table 7. Existing and Emerging Energy Efficiency Technologies With Significant Potential for Additional Energy Savings

Volt/VAR Optimization. VVO involves the management of various electric distribution system assets and advanced control technologies to "right-size" the voltage delivered to end-use electric customers. Reductions in distribution system voltage have been demonstrated to result in reductions in energy consumption across the electric circuits on which these are applied.

Electric customers across circuits with active VVO management and lower voltage levels typically consume less energy without needing to make changes to their individual consumption behavior. Investments in VVO technology and grid modernization can result not only in energy reductions, but also may provide additional service and operational benefits for the customers and the electric system in general.

The magnitude of the energy reductions can vary by location given different system configurations, the nature of customer consumption (including the types of appliances used), and what the voltage levels were before VVO was deployed, among other factors. Various studies, however, have demonstrated the significant energy conservation potential of VVO. In its final report of its "gridSMART" demonstration project, American Electric Power (AEP) estimated based on project results that "a 3 percent reduction in energy consumption and a 2 to 3 percent reduction in peak demand can be obtained on those circuits on which VVO technology is deployed."[621]

In a separate report, the Pacific Northwest National Laboratory concluded that Conservation Voltage Reduction (CVR) provides peak load reduction and annual energy reduction of approximately 0.5%-3% depending on the specific feeder". Additionally, "when extrapolated to a national level it can be seen that a complete deployment of CVR, 100% of distribution feeders, provides a 3.04% reduction in annual energy consumption."[622]

Designing appropriate Evaluation, Measurement and Verification (EM&V) protocols are critical in creating an effective compliance mechanism with the Clean Power Plan goals. The AEP gridSMART final report additionally identified one method to translate the energy savings from VVO deployment to carbon emissions avoided over its entire system area, using regional emissions data already collected by the EPA. [623] Whole-Building Energy Retrofits. There is widespread recognition that building energy efficiency can be dramatically improved by carefully integrating improvements to multiple building systems at once, rather than incrementally improving individual systems such as insulation, lighting, or appliances. One high-profile example of this "deep retrofit" strategy is the Empire State Building, which

[621] https://www.smartgrid.gov/sites/default/files/doc/files/AEP%20Ohio_DE-OE-0000193_Final%20Technical%20Report_06-23-2014.pdf
AEP Ohio – Final Technical Report – gridSMART Demonstration Project, June 2014
[622] http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf
Schneider, K., Tuffner, T., Fuller, J., & Singh, R. (2010). Evaluation of Conservation Voltage Reduction on a National Level. Pacific Northwest National Laboratory.
[623] https://www.smartgrid.gov/sites/default/files/doc/files/AEP%20Ohio_DE-OE-0000193_Final%20Technical%20Report_06-23-2014.pdf
AEP Ohio – Final Technical Report – gridSMART Demonstration Project, June 2014

undertook extensive renovations in 2009 that were anticipated to yield a 38% reduction in energy use and annual utility savings of approximately $4.4 million. The building's performance has succeeded beyond expectations, exceeding the energy reduction projections by 4-16% in each of the last three years.[624] Similar deep retrofits, yielding energy savings as high as 30 to 50% of baseline energy consumption, have been demonstrated in many other buildings over the last two decades.[625]

Intelligent Energy Management. Advancements in sensors and control systems are now enabling building owners and operators to optimize their energy use in real-time, achieving reductions in building electricity use of as much as 30%.[626] Using the modest 1.5% annual improvement in energy efficiency proposed by EPA, it would take more than 20 years for such opportunities to be exhausted – twice as many years as covered by the Clean Power Plan.

High-Performance Rooftop HVAC. As a result of an initiative by the Department of Energy to improve the efficiency of large rooftop HVAC systems used in approximately half of U.S. commercial buildings, two manufacturers are now producing rooftop HVAC systems that can help reduce energy consumption for cooling by as much as 50% relative to current industry standards. If all existing rooftop units were replaced with systems meeting DOE's new specifications, businesses around the country would realize approximately $1 billion in energy savings each year.[627]

Dynamic Windows. New "dynamic" windows that change opacity automatically in response to electronic controls or thermal conditions can significantly limit heat gain and improve comfort in buildings with significant light exposure. These windows are now commercially available, and a recent pilot test by the General Services Administration (GSA) at a federal building in Denver, Colorado found that the technology could reduce heating and cooling electricity consumption by about 9-10% compared to modern high-efficiency windows.[628] This technology is likely to see increasing use in the future as it comes down in price and as architects and builders gain familiarity with it.

[624] C40 et al., *Innovative Empire State Building Program Cuts $7.5M in Energy Costs Over Past Three Years* (Aug. 14, 2014).
[625] *See* Sameer Kwatra & Chiara Essig, *The Promise and Potential of Comprehensive Commercial Building Retrofit Programs* 1-3 (ACEEE, May 2014) (citing Pacific Northwest National Laboratory, *Advanced Energy Retrofit Guide* (2011); J. Amann & E. Mendelsohn, *Comprehensive Commercial Retrofit Programs: A Review of Activity and Opportunities* (ACEEE, 2005)).
[626] WRI, *Seeing is Believing* at 60 (citing Mary Ann Piette et al., *Intelligent Building Energy Information and Control Systems for Low-Energy Operations and Optimal Demand Response* (LBNL, 2012)).
[627] U.S. Department of Energy, *DOE and Private Sector Partners Introduce a New Money-Saving Specification for Commercial Air Conditioners* 1 (Apr. 2012).
[628] General Services Administration, *Electrochromic and Thermochromic Windows* (Mar. 2014), available at http://www.gsa.gov/portal/mediaId/188003/fileName/Smart-Windows-Findings-508.action (last visited Nov. 24, 2014)

V. Early Action

Under the Clean Power Plan, the United States will finally have Clean Air Act standards to address carbon pollution from existing power plants. During the long wait for these standards, a diverse group of states and companies have acted—have led the way in reducing carbon pollution. They have done so by deploying renewable energy, harvesting demand-side energy efficiency, and by shifting utilization away from high emitting and towards lower emitting power plants.

State and private sector leadership in addressing pollution is something that should be recognized, and supported. Action at the federal level to address climate-destabilizing pollution is lagging perilously far behind the scope and pace of action that scientists tell us is necessary to mitigate harmful climate impacts and reduce the risk of catastrophic climate change. We have for these reasons long supported the recognition of early action in the context of the Clean Power Plan. Yet the question of how to do so in the context of the proposed framework is complex.

Under Section 111(d), EPA identifies the best system of emission reduction available to address dangerous air pollution from stationary sources, and sets emission performance targets achievable using that best system. This framework—like other frameworks under the Clean Air Act—looks at existing pollution problems and how they can be addressed going forward. It does not provide for an assessment of past emission reduction performance by those sources (or that state).

Of course, under the Clean Power Plan, states and companies that have already transitioned towards lower carbon and zero carbon energy and energy efficiency are closer to the full deployment of the best system of emission reduction than others—and EPA should consider clarifying that states that go beyond their targets under the Clean Power Plan would receive credit for those actions under future updating of the carbon pollution standards for power plants. In addition, the standard only applies to fossil generators, so those states with less fossil generation in their system mix will bear less cost.

The years between 2012 and 2020 present a distinct challenge. EPA uses 2012 data on power sector infrastructure in assessing the potential for emission reductions to be secured under the best system of emission reduction during the 2020-2029 compliance period. Crediting emission reductions secured between 2012 and 2020 would encourage states and companies to act earlier, moving emission reductions forward in time. All else being equal, earlier action to reduce emissions is certainly better than later action. But the potential to reduce carbon pollution during 2012 to 2020 was not taken into account in setting the state targets. As such, giving compliance credit to those actions taken during this time that would have happened regardless of the Clean Power Plan—take, for example, renewable energy deployed by a renewable energy standard in a state strongly committed to clean energy—creates a bank of compliance credits that will be used by that state during the compliance period in the place of other, beyond business-as-usual emission reducing actions—and the overall emission reductions achieved by the Clean Power Plan will be reduced by the same amount.

There are, of course, highly compelling reasons to begin to take action now to reduce carbon pollution. States and companies can take advantage of the 5 years between the finalization of the standards and the beginning of the compliance period to gradually build out renewable generation and build up energy efficiency programs so that these resources are ready to deliver carbon reductions. The reductions in co-pollutants that will result will help states deliver cleaner air for their citizens and meet other clean air standards. Companies can develop business models built on a foundation of clean energy and efficiency, and investments in cleaner energy and efficiency will create jobs. Improvements in energy efficiency will cut utility bills for homes and businesses, and spending those savings in their communities will stimulate the local economy. These are simply common sense actions, with tremendous co-benefits—and the existence of an initial compliance date for the long-awaited carbon pollution standards does not alter that common sense.

If EPA does decide to provide early action credit, we urge the Agency to ensure that such crediting does not erode the environmental integrity of the Clean Power Plan by crediting business-as-usual actions. Further, crediting for early action should take place in the context of strengthened state targets that better reflect the full potential for emission reductions under the best system of emission reduction, as discussed above with respect to each of the building blocks and the formula change.

It is naturally difficult to determine what generation is avoided as a result of early actions that commence before the start of the interim compliance period. Therefore, we recommend that EPA credit such actions in a manner that does not over-reward such actions and undermine the benefits of the Clean Power Plan. One possible approach that EPA may wish to consider is comparing early action in states employing rate or mass based programs against the emissions standard for new natural gas plants under section 111(b), or the state's GHG emissions rate for the interim control period, whichever is lower. Another possible approach that could be used in conjunction with or in place of the first approach would be to credit states adopting mass-based programs based on how much they reduce emissions below their approved cap for the interim compliance period.

VI. Renewables and Energy Efficiency Crediting and Tracking

We recommend that EPA establish clear guidelines for the crediting and tracking of energy efficiency and renewable generation. Guidelines may differ depending on whether a state employs a mass-based program or a rate-based program.

A. Tracking

States employing rate-based compliance programs should credit renewable energy and energy efficiency in the form of tons of CO_2 as opposed to trading credits of MWh through RECs or some other mechanism. So doing will simplify compliance across regulated entities and avoid creating significant administrative challenges for state renewable portfolio standards, which in many states will have a different compliance entity than the state's compliance program for 111(d). As a result, RECs will continue to be used by load serving entities for compliance with state renewable standards, while CO_2 emissions credits will be used by electric generators for compliance under section 111(d).

Credit should be provided at the time of generation or at the time energy efficiency projects are verified. This should be done in whatever system is used to track CO_2 credits and compliance. EPA should allow states to determine the frequency with which credits are created in this system, though we would recommend that such credits are created no less frequently than quarterly in order to ensure that projects can quickly capitalize on the value they create.

To ensure that the system can be properly reviewed and problems corrected if they arise, each allowance should be labeled in a manner that indicates its point of origination. For renewable projects this would require that a CO_2 credit could be connected with a particular REC and its associated MWh and generating facility in one of the mandatory or voluntary tracking systems.

In order to facilitate inter-state trading and to simplify state implementation, we recommend that EPA design and operate a tracking system that states can opt to use if they choose.

B. Crediting

Due to the interconnected nature of the electric grid, it is not possible to determine which power plants reduce their generation as a result of each and every MWh of electricity avoided due to efficiency measures, or generated from new carbon free projects such as wind, solar, hydro, or nuclear uprates. In order to ensure that crediting does not overestimate the emission reductions secured by these projects, we recommend that such projects are credited in an amount based on the emissions standard for new natural gas plants established under section 111(b), or the state's GHG emissions rate for the interim control period, whichever is lower. Another approach could be to credit the projects in an amount based on the state's GHG emissions rate for the interim control period or the average emissions rate in their market region (consistent with the regions used to establish the requirements for the renewables building block), whichever is lower.

C. Tracking and Crediting for States Employing a Mass-based Program

Regardless of how states convert EPA's rate-based standard to a mass-based standard, they should not increase their cap each time new generation comes online or new efficiency projects are deployed, as so doing would compromise the emissions benefits of the program. However, a state that has adopted a mass-based standard could incentivize such projects by providing them with free allowance allocations or allowance auction revenue, without modifying its cap. This approach would preserve the environmental integrity of the state goal while promoting the development of projects that contribute to emission reductions from existing power plants.

VII. State Plan Submission Deadline Extensions and the Proposed Compliance Period

EPA has proposed allowing states to apply for a one-year extension beyond the state plan submission deadline if it is not possible to complete a state plan in one year and for a two-year extension if the state is pursuing a multi-state approach. This goes well beyond general EPA requirements. EPA's long-standing regulations implementing section 111(d) generally require state plan submittal within 9 months of EPA's final Emissions Guidelines. 40 CFR § 60.23(a)(1). And with only one exception, EPA has set the deadline for submitting state plans within 12 months of its final guidelines.[629]

While we appreciate EPA's efforts to balance the importance of timely state plan submittal with other considerations, we are quite concerned about delays in carrying out these important emission reductions. And, as noted, states have ample authority to carry out the Emission Guidelines through long established emission reduction measures that apply to the regulated sources, such as Title V operating permits implementing, for example, intrastate emissions averaging across regulated sources.

While we also recognize the dual environmental and economic benefits of regional collaboration, these benefits can be fully realized through timely submittal of state plans developed under existing authority that rely on informal MOUs or agreed upon consistencies across state plans to harness efficiencies in existing cross state markets and platforms within the plan development period provided. For example, states can adopt state programs under existing law and effectuate MOUs for crediting the emission reductions associated with RECs or energy efficiency "white tags" across states to smooth compliance across jurisdictions. Further, states could develop stand-alone state plans initially and subsequently submit revised plans to enable multi-state collaboration.

EPA seems to erroneously presuppose that well designed and efficient regional collaboration must necessarily take the form of formalistic and complex regional programs that impose new burdens on long established, time tested state authorities and prerogatives. This is not the case. There are an extensive suite of opportunities and approaches that states can deploy to mobilize and optimize the synergies of cross border coordination that are thoroughly anchored in existing law. And states can always develop more formal inter-state frameworks over time.

We recommend that any enlargement of time for state plan submittal beyond the extension of time from 9 months to 13 months that EPA has proposed for all states be based on documented exigencies stemming from state laws that preceded the *proposed* Clean Power Plan. Those exigencies should be limited to democratic process requirements—a legislative calendar that is demonstrably not within the state plan development window in a state where legislative action is required for state plan submittal, or a regulatory process that must, by its express terms, take more than 13 months to complete.

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[629] EPA, Final Guideline Document: Control of Flouride Emissions from Existing Phosphate Fertilizer Plants (1977) (OAQPS No. 1.2-070) at 1-2 ("After publication of a final guideline document for the pollutant in question, the States will have nine months to develop and submit plans for control of that pollutant from designated facilities."); EPA, Final Guideline Document: Control of Sulfuric Acid Mist Emissions from Existing Sulfuric Acid Production Units (1977) (OAQPS No. 1.2-078) at 1-2 (same); EPA, Kraft Pulping: Control of TRS Emissions from Existing Mills (1979) (EPA-460/2-78-003b) at 1-2 (same); EPA, Primary Aluminum: Guidelines for Control of Flouride Emissions from Existing Primary Aluminum Plants (1979) (EPA-450/2-78-049b) at 1-2 (same); 40 CFR part 60, subpart Cc (establishing emission guidelines for municipal solid waste landfills without setting out exception to the general rule that state plans are due within 9 months of EPA emission guidelines). *But see* 70 Fed. Reg. 28,606, 28,650 (requiring states to submit state plans within 18 months of the finalization of the Clean Air Mercury Rule). Under section 129, state plans must be submitted within 12 months of promulgation of joint section 129/111(d) emission guidelines. 42 U.S.C. § 7429(b)(2). Accordingly, all joint 129/111(d) guidelines have required the submittal of state plans within 12 months of promulgation. 40 CFR § 60.39b (setting 12-month submission deadline for plan submittal); § 60.39e (same); § 60.1505 (same); § 60.2505 (same); § 60.2981 (same); § 60.5005 (same).

Further, there is no justification for providing extensions for actions or steps beyond those in a state's plan development process that make the extension necessary. As such, EPA should require all steps that can be completed during the provided time period should be completed.

To effectuate these central principles, we make the following recommendations. Any initial plan submittal that requests an enlargement of time for plan submittal beyond 13 months must include, at a minimum:

- A complete regulatory framework (with regulatory text) and a demonstration that the plan will meet the state targets, understanding that the plan might change while undergoing pre-existing mandated regulatory or legislative processes that would manifestly take longer than a year. As suggested by EPA, it is also reasonable to require that a state must document that it has at least proposed any necessary regulations and introduced any necessary legislation within the first 13 months to qualify for additional time to complete a state plan.

- A demonstration that completion of the plan during one year is, in fact, not possible given pre-existing regulatory requirements or legislative processes that cannot be completed within one year. If legislative processes are cited, the submittal must also demonstrate that the plan cannot be put in place through regulatory processes standing alone. Neither technical work nor coordination with third parties should be a sufficient predicate for a one-year extension.

- Documentation of notification provided to the owners and operators of all regulated sources that their operating permits will come up for review at a specified date to enable eventual state plan requirements to be incorporated (sufficiently prior to 2020 to enable compliance with the interim targets to be achieved). This is important as some states may not have an existing framework in place to ensure that state plan requirements can be incorporated into regulated source operating permits in a timely fashion.

- For all operating permits of regulated sources, a requirement that the source not increase its CO_2 emissions, measured on an annual basis, to be in place until replaced by requirements incorporated in the final state plan.

- A comprehensive roadmap for completing the plan expeditiously with clear and concrete milestones and timetables that would become the basis for plan disapproval if not achieved.

- For formal, joint multi-state plans, a demonstration that the specific extension requested is necessary and documentation that all plan development steps that can be completed without formal multi-state agreements have been carried out. For multi-state plans that could function initially as state-only plans (e.g. plans that establish intra-state trading mechanisms but allow for inter-state trading of credits or allowances), complete state plans should be submitted by the deadline with the multi-state components to follow within the extension period. States seeking an extension for development of a multi-state plan should also be required to develop a "backup" stand-alone, compliant state plan by the June 2016 deadline to be put in place should the multi-state process not be completed in the allotted time.

VIII. Enforceability of the Portfolio and State Commitment Approaches

To ensure environmental integrity and to fulfill the requirements of Section 111, EPA should ensure that "portfolio" and "state commitment" plans are either composed of specific federally enforceable components or contain backstops that are federally enforceable.

Enforceability is key to the environmental integrity of the Clean Power Plan, and is explicitly provided for in Section 111(d). *See* 42 U.S.C. § 7411(d)(1)(B) (requiring state plans to "provide[] for the implementation and enforcement of . . . standards of performance" established under section 111(d)). State plans composed of an emission rate trading program, an allowance trading program, or other requirements that apply directly to sources will provide a clear and traditional enforcement pathway. The proposed portfolio and state commitment approaches, however, propose to take a different approach in which third parties other than emitting EGUs (including the state itself) could be responsible for securing emission reductions under a state plan. The preamble for the proposed rule describes the "portfolio approach" as one in which:

> *[T]he [state] plan would include emission limits for affected EGUs along with other enforceable measures, such as RE and demand-side EE measures, that reduce CO_2 emissions from affected EGUs. Under this approach, it would be all of the measures combined that would be designed to achieve the required emission performance level for affected EGUs as expressed in the state goal. Under this approach, the emission limits enforceable against the affected EGUs would not, on their own, assure, or be required to assure, achievement of the emission performance level.* ***Rather, the state plan would include measures enforceable against other entities that support reduced generation by, and therefore CO2 emission reductions from, the affected EGUs. As noted, these other measures would be federally enforceable because they would be included in the state plan.***

79 Fed. Reg. at 34901 (emphasis added).

In describing the "state commitment" approach to RE and demand-side EE measures, the preamble for the proposed rule states:

> *As another vehicle for approving CAA section 111(d) plans for states that wish to rely on state RE and demand-side EE programs but do not wish to include those programs in their state plans, the EPA requests comment on what we refer to as a "state commitment approach." This approach differs from the proposed portfolio approach, described above, in one major way:* ***Under the state commitment approach, the state requirements for entities other than affected EGUs would not be components of the state plan and therefore would not be federally***

> ***enforceable. Instead, the state plan would include an enforceable commitment by the state itself to implement state-enforceable (but not federally enforceable) measures*** *that would achieve a specified portion of the required emission performance level on behalf of affected EGUs. . .* ***if those state programs fail to achieve the expected emission reductions, the state could be subject to challenges—including by citizen groups—for violating CAA requirements and, as a result, could be held liable for CAA penalties***.

79 Fed. Reg. at 34902 (emphasis added).

Under either a portfolio or a state commitment approach, in order to satisfy the enforceability requirements of the statute and to ensure the environmental integrity of the standards, either:

(1) specific measures must be federally enforceable (e.g. the state's renewable portfolio standard becomes federally enforceable, or the delivery of a specific quantity of demand-side energy efficiency [kW of demand reduced] by an energy efficiency program becomes federally enforceable); or

(2) the state plan must include federally enforceable, backstop policy measures that will be automatically triggered and take effect without further action by the state or EPA should the state fail to achieve its required emission budget or rate by more than a de minimis percentage at any required reporting deadline.[630] The backstop must be designed by the state to secure at minimum the "missed" emission reductions, and apply directly to the regulated sources. A backstop could, for example, require regulated sources to secure renewable energy credits (or some other type of credit allowed to be submitted for compliance) sufficient to make up the shortfall within a year and a half of the compliance failure. The obligation to make up the shortfall could be allocated among sources in any manner acceptable to the state (for example, the credit obligation above could be distributed among EGUs in a manner proportional to the sources' emissions in the year of the shortfall). The backstop would be included in the operating permits of the regulated entities as part of the section 111(d) standard of performance, and would be federally enforceable by EPA and through citizen suits under sections 113 and 304 of the Act, respectively.

This backstop approach would allow states to satisfy the requirement that state plans contain enforceable measures, while also preserving flexibility for states to adopt state commitments or portfolio approaches that are not themselves federally enforceable. The backstop would also give states the flexibility to design the backstop that best suits local circumstances, with input from their stakeholders. It would provide regulated sources with certainty about the implications of any failure of the state to meet its compliance obligations. However, it would also be important for states to—as proposed—take "corrective measures" to ensure that the compliance failure was not repeated.

IX. Enforcement Guidance for Non-EGUs

[630] See, e.g., section 172(c)(9) of the CAA.

Because existing EPA guidance on the enforceability of RE and EE measures does not provide clear examples of how such measures would be *federally* enforceable against non-EGU entities, EPA should develop new guidance specifically addressing the enforceability of such measures for non-EGUs in the 111(d) context. EPA seeks comment on "the appropriateness of existing EPA guidance on enforceability in the context of state plans under CAA section 111(d), considering the types of affected entities that might be included in a state plan." 79 Fed. Reg. at 34,909. Existing EPA guidance addressing RE and EE measures is tailored specifically to the section 110 State Implementation Plan context.[631] EPA's 2004 Guidance on SIP Credits for Emission Reductions from Electric Sector Energy Efficiency Measures specifies that EPA considers RE/EE requirements imposed on non-source entities to be enforceable, such that emissions reductions resulting from those measures "count" toward compliance with emission reduction requirements, where:

> (a) The activity or measure is independently verifiable;
>
> (b) Violations are defined;
>
> (c) Those liable for violations can be identified;
>
> (d) [The State] and EPA maintain the ability to apply penalties and secure appropriate corrective actions where applicable;
>
> (e) Citizens have access to all the required activity information from the responsible party;
>
> (f) Citizens can file suits against the responsible party for violations; and
>
> (g) The activity or measure is practicably enforceable in accordance with EPA guidance on practicable enforceability.[632]

Current EPA guidance discusses how states have actually used RE and demand-side EE measures in SIPs, but provides only one example where such measures were directly enforceable against non-EGU entities.[633] Furthermore, that example does not make it clear how the measure in question would be

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[631] *See, e.g.*, U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012; U.S. EPA, Office of Air and Radiation, Incorporating Emerging and Voluntary Measures in a State Implementation Plan (SIP), September 2004; U.S. EPA, Office of Air and Radiation, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric Sector Energy Efficiency and Renewable Energy Measures, August 2004.
[632] U.S. EPA, Office of Air and Radiation, Guidance on State Implementation Plan (SIP) Credits for Emission Reductions from Electric Sector Energy Efficiency and Renewable Energy Measures, August 2004, at 6.
[633] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-8-K-9 (discussing the inclusion of EE measures aimed at reducing NOx emissions for Dallas-Fort Worth into the Texas SIP).

federally enforceable.[634] Instead, the current guidance relevant to RE and EE measures focuses largely on the use of voluntary measures that are supported by an "enforceable commitment" by the state.[635] Because of the absence of clear examples specifically making measures federally enforceable against non-source entities, EPA should provide new guidance specifically addressing this issue.

The need for guidance tailored to the section 111(d) context is especially important because EPA's current guidance on enforceability relies on the federalization of state law requirements that are included in an EPA-approved section 110 SIP to conclude that any SIP component, whether imposed on sources or non-source entities, will be *federally* enforceable by both EPA and citizens. For example, in advising Connecticut on incorporating its state law RPS and energy efficiency programs into its section 110 SIP, EPA Region 1 noted that federal enforceability would be ensured merely by the inclusion of the mandatory state law requirements into the text of the SIP.[636] Consequently, EPA should provide specific guidance that addresses how such requirements should be structured to ensure that they will be enforceable by both EPA and citizens.

Furthermore, as discussed above, to ensure federal enforceability, EPA should require that state plans taking a "state commitment" approach include a backstop that ensures ultimate responsibility for remedying any shortfall in emission reductions rests with the regulated sources. In the context of section 110 SIPs, present EPA guidance does address the enforceability of RPS and EE requirements imposed on EGUs, but provides no example of states that have actually federalized such requirements by inclusion in a SIP.[637] EPA should provide guidance to states on how to structure RE and EE programs to ensure that specific backstop requirements applied to EGUs to remedy any emissions shortfall will be enforceable by the state, EPA, citizens.

X. Rate to Mass Conversion

[634] The Texas SIP revision mandated the statewide adoption of the International Residential Code (IRC) and the International Energy Conservation Code (IECC), and directed counties to develop ordinances to impose EE requirements on the construction of new homes to reduce electricity consumption in those counties by at least 5% each year for 5 yrs. *See* 73 Fed.Reg. 47835, 47836 (Aug. 15, 2008); Texas Commission on Environmental Quality, Revisions to the State Implementation Plan (SIP) for the Control of Ozone Air Pollution, Apr. 27, 2005, at ES-5, 5-2, 5-3. The enforceability of the EE measures in the Texas SIP appears to stem from the enforceability of the new building codes *under state law and local ordinances*. EPA does not specifically address how the requirements would be enforceable either by EPA under section 113 or by citizens bringing suit under section 304 of the Act.
[635] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at 35-36, Appendix K, K-9.
[636] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at K-36.
[637] *See* U.S. EPA, Office of Air Quality Planning and Standards, Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, July 2012, at K-9-K-10, K-12-K-14.
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In the proposed rule, EPA established a rate-based emission target, under which state goals were measured in pounds of CO_2 per megawatt-hour of electricity generated. EPA recently issued a supplemental notice regarding potential approaches for translating the emission rate-based goals to an equivalent mass-based metric.[638] EDF agrees that states should have the option of taking a mass-based approach to compliance. EDF also urges EPA to conduct this conversion for states or, at a minimum, establish a presumptive methodology and minimum standards to ensure that the rate-to-mass conversion does not become a vehicle for weakening standards. In particular, EPA must define a uniform electricity demand growth projection that can be used in a rate-to-mass conversion. EDF recommends that the energy information agency projections provide the maximum demand growth that can be included.

In its rate-to-mass conversion Notice, EPA provides two options for conversion of an emission rate-based goal to a mass-based form.[639] The two approaches include one that provides "mass-based equivalent metrics that apply to existing affected EGUs only."[640] The second provides for a mass-based equivalent that applies to both existing and any new power plants.

The first approach – a mass-based target applicable only to existing power plants – is a viable option only if EPA requires mechanisms to ensure that the mass-based emissions limit is not achieved simply by reducing generation from covered sources and increasing generation at new plants built in the state, an outcome through which the targets could ostensibly be met without achieving actual emission reductions equivalent to those that would be achieved under a rate-based system. (As we discuss in section XII, similar protections must be established to ensure that interstate changes in dispatch do not compromise the actual emission reductions.)

The second approach – a mass-based target that is "*inclusive* of new fossil fuel-fired sources"[641] – is a preferable option and should be the default approach. This approach avoids the complication of tracking excess new fossil generation. The critically important aspect of this approach is the determination of the level of demand growth. This determination must be subject to a uniform methodology established by EPA. An excessive projection of demand growth will weaken the target and void the required equivalency between the rate-based and mass-based targets. Even states that are not attempting to weaken their target will inevitably face pressure to adopt an overly optimistic demand growth projection consistent with the state's aspirations for future economic development. In its TSD accompanying the supplemental notice of the rate-to-mass conversion, EPA bases its annual average growth rate on regional demand projections from the 2013 Annual Energy Outlook published by the Energy Information Administration.[642] EPA must adopt a consistent and unbiased demand growth projection and we suggest that EPA use of the EIA projection.

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[638] Notice: Additional information regarding the translation of emission rate-based CO2 goals to mass-based equivalents. 79 Fed. Reg. 67406 (November 13, 2014).
[639] 79 Fed. Reg. 67406, 67408.
[640] 79 Fed. Reg. 67406, 67408 (emphasis added).
[641] 79 Fed. Reg. 67406, 67408 (emphasis added).
[642] Technical Support Document: *Translation of the Clean Power Plan Emission Rate-based CO2 Goals to Mass-based Equivalents,* page 6 (November, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-11/documents/20141106tsd-rate-to-mass.pdf.

In sum, EDF supports the EPA's continued flexibility in the state emission reduction planning process under section 111(d). But EPA must clearly define the acceptable methods for converting rate-based targets and requirements for existing-only mass-based caps in order to ensure that equivalent emission reductions will be achieved.

XI. State and Regional Plan Policy Options and Criteria

While we support EPA providing states with significant flexibility in the development of state plans, it will also be helpful to provide guidance that assists states with the planning process and describes minimum criteria for state plans to ensure environmental integrity and achievement of the state standards of performance. There will inevitably be new ideas developed by states – state innovation is desired – but there are four categories of policies that EPA should consider providing guidance on and must develop minimum criteria for.

The four policy approaches we hear states and stakeholders discussing most are:

1) Flexible Intensity-based Standards
2) Mass-based Standards
3) Carbon Fees
4) Resource Standards or Portfolio Approaches

EPA, the states, and other jurisdictions have experience with all of these policy approaches and EPA should look to those existing programs as guidance and minimum criteria are developed.

Table 8, below, describes the four policy approaches, provides ideas on how EPA could establish minimum criteria, and provides background on how they impact different resource types and stakeholders.

There is also discussion of how the different approaches could work regionally and how interstate problems could develop with different policy approaches existing on either side of a state line. The interstate and market issues that will develop if EPA does not proactively address them in their guidance and minimum criteria are significant – these include environmental leakage[643] and market distortions and associated competitiveness issues for generators of a similar type one either side of a state border. Many of these issues are minimized or not a concern if market regions can agree on consistent policy approaches, but it is important for EPA to proactively consider and address these issues. See also our comments in Section XII on leakage.

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[643] Environmental leakage is a transfer of emissions from one region to another. For example one state could set a mass-based cap and a neighboring state a flexible rate based standard, leading to a competitive advantage for natural gas generators in the rate-based state and emissions rising significantly in that state even though they meet the rate-based standard.

The following are minimum criteria by policy type EPA should work with and add to as further guidance on state plans is developed. We are suggesting this as additional criteria by policy approach, on top of the proposed components of state plans EPA presented in the CPP proposal.

1. Flexible Intensity-based Standards
   a. Requirement on the regulated fossil generator to meet the emissions standard on an annual or multi-year basis, with the opportunity to offset emissions with credits from non- and low-emitting sources;
   b. Normal reporting, compliance, and enforcement provisions:
   c. Energy efficiency evaluation, monitoring and verification requirements in order to certify units of energy savings that can be converted to credits;
   d. Renewable energy certificate (REC) tracking system to avoid double counting and allow tracking of units of energy that can be converted to credits;
   e. System and methodology to convert efficiency and renewable MWhs to emissions credits and a platform to track and trade those credits;
   f. Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports;
   g. Prohibition on conversion of RECs and efficiency savings to emissions credits from mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state could still be used for RPS compliance)
2. Mass-based Standards
   a. Requirement on the regulated fossil generator to meet the emissions standard by holding emissions allowances equal to their emissions;
   b. Normal reporting, compliance, and enforcement provisions
   c. Note: we do not think a leakage requirement is needed in mass-based or carbon fee states, as the potential for leakage and increased generation exists primarily in the states that adopt a rate-based approach that allows generation and total emissions to increase.
3. Carbon Fees
   a. Requirement on the regulated fossil generator to pay a fee based on their emissions over a given period of time;
   b. Normal reporting, compliance, and enforcement provisions;
   c. Backstop requirement to track and regularly adjust fees (not longer than annually) if emissions rise above levels allowed by the state standard of performance and have an adjustment made to ensure the standard is being met if emissions rise above allowed levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d))
4. Resource Standards or Portfolio Approaches
   a. Requirement on the regulated load serving entity (LSE) or distribution company providing services to consumers to procure a set amount of efficiency or renewables based on percentages of sales or what is cost-effective (note, there could be other state policy approaches that regulate other entities beyond fossil generators or the LSE);
   b. Normal reporting, compliance, and enforcement provisions:
   c. Energy efficiency evaluation, monitoring and verification requirements;
   d. Renewable energy certificate (REC) tracking system to avoid double counting;

e. Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports;
f. Prohibition on claiming an emissions benefit from RECs generated in mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state could still be used for RPS compliance)
g. Backstop requirement to track emissions in relation to the state standard of performance and have an immediate adjustment made to ensure the standard is being met if emissions rise above allowed levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d))

Table 8. Primary Policy Options for State and Regional Plans

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Examples:	Phase-out of lead in gasoline; NRDC 111(d) proposal	EPA acid rain and ozone trading programs; RGGI, CA and EU carbon trading programs	Great River/Brattle proposal; British Columbia carbon tax	Renewable and clean energy standards in many states; energy efficiency procurement and EERS requirements in many states
Regulated Entity:	Fossil power plants (could be all fossil or just existing - all fossil ensures a level playing field among generators)	Fossil power plants (could be all fossil or just existing - all fossil ensures a level playing field among generators)	Fossil power plants (could be all fossil or just existing - all fossil ensures a level playing field among generators)	Load serving entity (those that deliver energy to customers, not necessarily the generator owners); also EGUs under Clean Power Plan performance standards
Environmental Goal, Units & Outcome:	Each state has an intensity or rate goal (lbs/MWh) that all generators have to meet and declines over time to meet the reduction goal established by EPA; the total emissions outcome is tied to energy production/use; potential for environmental leakage due to increased generation/exports	Each state has a goal expressed in tons, which is fixed and certain and declines over time to meet the reduction goal established by EPA; potential for environmental leakage due to decreased generation/imports; the emissions limit could also be set at the operating company rather than state or regional level for large utilities that want to meet their target internally	A carbon fee would be established at a price estimated to deliver the environmental goal established by EPA (including a decline over time); the price is known but the environmental outcome is uncertain; adjustments may be needed to meet the goal (backstop needed); possible leakage issues if next to intensity-based approaches	Minimum requirements would be set for procurement of non-emitting resources (efficiency and renewables) at levels estimated to deliver the environmental goal established by EPA (backstop needed), with procurement tracked in MWh of energy delivered/saved; possible tracking and crediting issues if buying from mass-based states unless a hybrid approach is adopted that provides for compliance on a mass-basis

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Market Structure & Trading:	Fossil power plants that emit above the intensity standard have to buy credits from other resource types that operate below the standard and generate credits for every unit of energy (MWh) they produce; the credits (denominated in tons) are issued by the environmental agency and then traded; the credit price will float and depend on supply and demand in the market; high emitting fossil plants have to pay for credits and become less competitive in the market in comparison to low- or non-emitting resources; credits could be banked (held) for future compliance periods	The environmental agency issues allowances (tons) equal to the emissions limit; allowances can be auctioned or allocated and fossil power plants have to hold an allowance for every ton of emissions; allowances are tradable and the price will float and depend on supply and demand in the market; high emitting fossil plants have to buy or hold more allowances and become less competitive in the market in comparison to low- or non-emitting resources; allowances are usually allowed to be banked (held) for future compliance periods	The environmental agency estimates the carbon price needed to achieve the emissions goal and then they, another state agency, or the ISO/RTO collect the fee based on emissions rates from power plants; high emitting fossil plants have to pay a higher fee and become less competitive in the market in comparison to low- or non-emitting resources; revenue from the fee could be returned to utility customers through investments in energy efficiency programs, rebates or used for other state policy goals ; there is no trading although the cost flows through the power markets	For generation, eligible resources are identified (i.e. renewables) and the energy (MWh) are tracked using generator certificate/attribute tracking systems; the LSEs need a certain number of certificates in comparison to the energy they are providing customers (i.e. 20%) and the certificate price will float and depend on supply and demand in the market; non-emitting resources will become more attractive investments compared to high emitting resources; certificates could be banked (held) for future compliance periods. Energy efficiency could similarly receive credits and satisfy LSE holding requirements. All EGUs also subject to a performance standard.

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Crediting Non-emitting Resources:	Each unit of energy generated from a low- or non-emitting resource will need to be tracked (likely using a generator certificate/attribute system); the environmental agency would issue an appropriate emissions credit (in tons) associated with the MWh and the difference between its emissions rate and the emissions goal in the state or an average emissions rate; energy efficiency will also be credited based (in tons) based on units of energy saved (MWh); the emissions credits are then sold to the fossil generators who use them to offset emissions.	In a mass-based approach, all fossil generators in the program have their costs rise based on their emissions rate (allowance price driven); higher emitting generators become less competitive than low or non-emitting resources over time; non-emitting resources are not directly credited but become more competitive because they do not need to submit allowances to cover their generation; there is also an opportunity to auction the allowances and use the revenue to benefit consumers, with energy efficiency being a preferred investment, as it reduces consumers' bills and lowers the cost of the program as a whole.	In a fee-based approach, all fossil generators in the program have their costs rise based on their emissions rate (driven by the fee level); higher emitting generators become less competitive than low or non-emitting resources over time; non-emitting resources are not directly credited but become more competitive because they do not need to pay fees to cover their generation ; there is also an opportunity to use revenue from the fee to benefit consumers, with energy efficiency being a preferred investment, as it reduces bills and lowers the cost of the program as a whole.	Resource standards directly require increased investment in the qualified technologies, such as renewables and energy efficiency; depending on the structure, there can either be a floating price for delivery of energy from the technology type or procurement through a planning process; there is a clear incentive and known increase in production from the technologies in the standard, but only up to the requirement level; for example, once the percentage requirement for renewables is reached, demand or incentives above the wholesale energy price go to zero unless additional investments can be sold to assist other entities with compliance such as through a hybrid approach.
Electric System Reliability:	All of these market-based approaches provide significant flexibility for plant operators, ISO/RTOs, and regulators to ensure reliability requirements are met. If a plant is needed in the short-term it can keep operating by buying allowances, credits or paying a fee. In any of the approaches a unit could be designated as "must-run" for reliability reasons until the reliability constraint is addressed, as long as other facilities could adjust their performance to accommodate the output from that plant.			
New vs. Existing Sources:	A key issue across all of the program types is what resources are included or not. This is primarily associated with designating facilities as regulated entities or as eligible for crediting. This decision can have a significant impact on generators of the same type who happen to be constructed or become operation on either side of a date. In general, EPA and states should examine the market impacts of a decision to include or exclude resource types and be sure that it: 1) maximizes the development of new non-emitting resources and the degree to which emissions decline, and 2) minimizes unequal treatment of resources with the same or similar emissions characteristics in a way that could cause older resources to retire in favor of new units with identical emissions characteristics (note that many non-emitting resources have low marginal costs and markets and operators will choose to run them regardless of their treatment).			

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Regional Approaches:	There are significant benefits associated with states pursuing consistent regional approaches to compliance. The primary benefits are: 1) LOWER COST - a larger market should be more efficient and reduce costs; 2) EQUAL TREATMENT - generators, market participants, and consumers should face consistent market signals, costs and benefits; 3) IMPROVED ENVIRONMENTAL OUTCOME - regional approaches avoid different price signals across a market region and on either side of state boundaries could lead to emissions leakage and higher national emissions than anticipated; and 4) ENHANCE RELIABILITY PROTECTIONS - a larger market and additional flexibility enhances reliability			

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Minimum Requirements for State Plans:	1) Requirement on the regulated fossil generator to meet the emissions standard on an annual or multi-year basis, with the opportunity to offset emissions with credits from non-emitting sources; 2) Normal reporting, compliance, and enforcement provisions: 3) Energy efficiency evaluation, monitoring and verification requirements in order to certify units of energy savings that can be converted to credits; 4) Renewable energy certificate (REC) tracking system to avoid double counting and allow tracking of units of energy that can be converted to credits; 5) System and methodology to convert EE & RE MWhs to emissions credits and a platform to track and trade those credits; 6) Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports; 7) Prohibition on conversion of RECs to emissions credits from mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state	1) Requirement on the regulated fossil generator to meet the emissions standard on an annual or multi-year basis by holding emissions allowances equal to their emissions; 2) Normal reporting, compliance, and enforcement provisions 3) Note: we do not think a leakage requirement is needed in mass-based or carbon fee states, as the potential for leakage and increased generation exists primarily in the states that adopt a rate-based approach that allows generation and total emissions to increase.	1) Requirement on the regulated fossil generator to pay a fee based on their emissions over a given period of time; 2) Backstop requirement to track emissions in relation to the state standard of performance and have an immediate adjustment made to ensure the standard is being met if emissions rise above allowed levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d)) 3) Normal reporting, compliance, and enforcement provisions;	1) Requirement on the regulated load serving entity or distribution company providing services to consumers to procure a set amount of efficiency or renewables based on percentages of sales or what is cost-effective; 2) Normal reporting, compliance, and enforcement provisions: 3) Energy efficiency evaluation, monitoring and verification requirements; 4) Renewable energy certificate (REC) tracking system to avoid double counting; 5) Requirement to address emissions leakage or increased emissions associated with expanded fossil generation and exports; 6) Prohibition on claiming an emissions benefit from RECs generated in mass-based states (the mass based state is already accounting for the emissions reduction; note that RECs from that state could still be used for RPS compliance); 7) Backstop requirement to track emissions in relation to the state standard of performance and have an adjustment to ensure the standard is being met if emissions rise above allowed

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
Legislative Requirements:	Most state environmental statutes provide the environmental or air agency with broad authority to develop regulations under the Clean Air Act that limit emissions from stationary sources like power plants. These agencies can in most cases develop this kind of program without additional state legislation. Energy efficiency and renewables crediting would likely be improved if the utility regulator in the state collaborated with the environmental agency.	Most state environmental statutes provide the environmental or air agency with broad authority to develop regulations under the Clean Air Act that limit emissions from stationary sources like power plants. These agencies can in most cases develop this kind of program without additional state legislation. Auctioning of allowances and distribution of revenue would require legislation in most states.	Legislation would be required in most states to collect revenue and distribute or appropriate it.	Legislation may necessary in many states to require load serving entities or distribution companies to procure specific resources over time. However, if such plans were implemented via permit requirements on EGUs, most state environmental statutes provide the environmental or air agency with broad authority to develop regulations to secure compliance with Clean Air Act standards.
Complimentary Programs / Policies Needed:	State and utility energy efficiency programs would likely remain an essential source of efficiency credits and should be expanded by the utility regulator as long as it is cost-effective. Renewable portfolio standards also contribute credits and are complementary and could be expanded in parallel.	While energy efficiency and renewables will be more competitive and cost-effective under this policy approach, market barriers will still remain. Energy efficiency and renewables programs and policies should remain and be expanded, which will reduce the cost of achieving the carbon goal and can be funded through the auction of allowances. Low income and worker transition assistance can also be funded with auction revenue.	While energy efficiency and renewables will be more competitive and cost-effective under this policy approach, market barriers will still remain. Energy efficiency and renewables programs and policies should remain and be expanded, which will reduce the cost of achieving the carbon goal and can be funded through the revenue raised through the application of a carbon fee. Low income and worker transition assistance can also be funded with revenue raised by the carbon fee.	NA

XII. Environmental Leakage

A. Addressing Challenges for Rate-based Trading Programs

Whenever a shift in the deployment of generation assets is treated as delivering greater GHG emissions reductions than actually occur, emissions "leakage" can be said to have occurred. Environmental leakage is a transfer of emissions from one region to another. For example one state could set a mass-based cap and a neighboring state a flexible rate based standard, leading to increased generation by the natural gas generators in the rate-based state and emissions rising significantly in that state even though they meet the rate-based standard. Some analysis has suggested that the threat of leakage could significantly reduce the CO_2 emissions benefits of the program. Under the Clean Power Plan, leakage can occur in two basic ways:

1. Rate to Rate Leakage – Leakage can occur as a result of electric generation moving from a state with a lower emissions rate standard to a state with a higher emissions rate standard.

2. Rate to Mass Leakage – Leakage can occur as a result of shifts in electric generation from states with a fixed mass-based cap to states with a rate-based program. Under this scenario there is an increase in emissions in the rate-based state that allows the state implementing a mass-based program to avoid actions that result in real emission reductions.

Note there is no threat of mass to mass leakage. There is no impact on emissions as a result of electric generation shifting from one state implementing a mass-based program to another state implementing a mass-based program. This is because the cap is fixed in both states.

1. Rate to Rate Leakage

A wide variation in rate-based targets could lead to significant discrepancies in incentives for generators in different states. For example, Minnesota and North Dakota share a common border, and both are in the MISO region, but have very different emissions targets in 2030 under EPA's proposed rule – 873 lbs CO_2/MWh and 1783 lbs CO_2/MWh, respectively. Because of this differential in targets, shifting 20 MWhs of coal-based generation (assuming 2,200 lbs CO_2/MWh) from Minnesota to North Dakota would generate a credit equal to 18,200 lbs of CO2 (about 9 tons of CO2), even though the atmosphere would have not seen any reduction in actual CO_2 emissions.

Any action EPA takes to reduce the variation in state targets by increasing the GHG emissions reductions required in states that currently have higher emissions rate standards will help reduce the level of emissions leakage that could be expected. This is one of the reasons we recommend that EPA exclude existing renewables from its calculations of a state's initial emissions level. If EPA does this, and expands building block 1 to include opportunities for co-firing natural gas at coal plants, as we discuss supra, or new natural gas plants in building block 2, then the risk of leakage will decrease. However, some risk of leakage will remain unless EPA standardizes state emissions targets across grid regions or takes other steps to address it, as discussed below.

2. Rate to Mass Leakage

Mass-based programs are superior to rate based programs for a number of reasons, including: 1) they guarantee emissions reductions, 2) they significantly minimize reporting and verification needs for energy efficiency programs, which are a critical cost saving opportunity for state plans, 3) they provide a clear and consistent carbon signal to the power markets, enhancing the efficiency and cost-effectiveness of emission reductions, and 4) there is no threat of leakage between the borders of two adjacent states that are employing mass-based compliance programs no matter how different their target are. However, there are boundary challenges between a state employing a rate-based program and a state employing a mass-based program.

For example, consider West Virginia, which has a proposed interim target of 1,748 lbs CO_2/MWh. It borders Maryland, which participates in the Regional Greenhouse Gas Initiative (RGGI). Under the Clean Power Plan, shifting 10 MWh of natural gas generation from Maryland to West Virginia would generate a credit equal to approximately 7,480 lbs CO_2 in West Virginia without resulting in a commensurate decrease in the RGGI cap (assuming the natural gas plant has an emissions rate of 1,000 lbs CO_2/MWh).

B. Options for Addressing Leakage

Pressures for emissions leakage will depend both on the final form of the 111(d) regulations as well as state plans, making it is difficult to assess at this time just how significant the risk is. But the risk is great enough that EPA must ensure that it is addressed in EPA's final guideline and in state plans. Therefore, we recommend that EPA describe a methodology for how they will measure and evaluate leakage over time. In addition, EPA must address leakage in order to ensure the equivalency of state-established standards of performance with the emission reductions achievable under the best system of emission reduction identified by EPA, as required by the statute (standards of performance, which states establish in their plans, are defined by Section 111(a) as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which . . . the Administrator determines has been adequately demonstrated.") We recommend that the responsibility to address leakage be placed on the states that increased electricity production as that is the source of the environmental leakage. States employing a rate-based approach or a portfolio approach should be required to include a policy fix in their state plan to address leakage. Several approaches to address leakage are outlined below.

OPTION 1: First jurisdictional deliver approach

Under this approach, an entity that exports power out of a given state is required to submit credits to the state equal to the emissions leakage that would otherwise occur (note that this approach was first developed for California where the obligation could only be placed on the importer, while we are recommending the rate-based state or exporter be given the obligation). The advantage to this approach is that it imposes the burden on the importer and not the state. The disadvantage is that given the interconnected nature of the electric grid, it may be challenging to determine where exported power comes from in some regions. The Western Climate Initiative, the Regulatory Assistance Project (www.raponline.org/document/download/id/6509), and NextGen have done considerable research into the practical implementation questions surrounding these approaches.

OPTION 2: Ex post evaluation and adjustment of state-level emissions reductions

Leakage is caused by a shift in the net balance of imports and exports between states with disparate rate standards or at the border of states employing rate and mass-based programs. Therefore, EPA could require states to evaluate shifts in their balance of electricity supply and demand on an annual or bi-annual basis and account for it through automatic ex-post adjustment of their GHG programs. This approach can address the threat of leakage over time through adjustments, but potentially in some circumstances could increase uncertainty for power companies. NextGen has done considerable work into practical implementation questions surrounding ex post evaluation approaches.

OPTION 3: Require all states to evaluate state-wide power sector performance against mass-based targets

As detailed there is no threat of leakage between states implementing mass-based compliance programs. Because the cap is fixed in both states, shifts in generation between those states will not impact total emissions of CO2 to the atmosphere. Therefore, EPA could eliminate the threat of leakage by requiring all states, including those that adopt a rate-based approach, to evaluate whether the state's actual emissions exceeded the mass-based target that the state would have been subject to had it adopted a mass-based approach. States that exceeded their mass-based target would be required to adjust for excess emissions.

OPTION 4: Ex ante adjustment to level the playing field for generation.

Under this approach all new generation would be compared to the emissions rate for new units established under 111(b) or the state rate standard, whichever is lower, in order to prevent sources from taking advantage of higher state emissions targets. This rate would apply to new fossil-based generation, new renewable generation, increased deployment of energy efficiency resources, as well as significant increases in generation at existing power plants. .

Again, this approach is based on the observation that leakage is caused by a shift in the net balance of imports and exports between states with disparate standards. However, instead of applying an ex post adjustment at the state level, it applies an up-front adjustment at the plant level, which provides greater certainty for project developers. These obligations could either be placed on plants whose generation is increasing, or plants whose generation is decreasing. In addition, the approach simultaneously addresses the question of how much to credit increased deployment of energy efficiency resources and renewables.

By creating a more level playing field, this approach would reduce but not completely eliminate the risk of leakage.

C. Complementary State-Level Measures

Mass-based programs get the benefit of added efficiency and renewables, with the additional generation or energy efficiency allowing fossil plants to run less and making it easier to achieve the cap level. If rate-based states were allowed to use generation from neighboring mass-based states as emissions credit generators, they would effectively be double counting the emissions benefit. EPA's approach for addressing leakage should address this challenge.

One effective approach for doing so would be to establish a clear prohibition on rate-based states converting RECs and efficiency savings from mass-based states to emissions credits. Under this approach, rate-based states could still be allowed to purchase RECs from mass-based states for other renewables requirements like RES/RPSs, but not claim a Section 111(d) emissions benefit from those purchases.

XIII. Reliability

EDF appreciates the crucial importance of maintaining the reliability of the electric grid while securing urgently-needed reductions in carbon pollution, and believes that the proposed emission guidelines provide a sound framework for meeting both goals.

There are at least three critical design features of the proposed Clean Power Plan that will enable states, system operators, utilities and other entities to preserve electric system reliability and achieve the required carbon pollution reductions. First, the proposed Clean Power Plan allows states unparalleled flexibility to meet their carbon pollution goals through a wide variety of low-carbon resources – including highly efficient fossil resources, energy efficiency, renewable energy, and other clean energy sources. This flexibility opens the door for each state, working together with utilities, regional entities, and other stakeholders, to develop a tailored compliance plan that reflects its own resource mix and reliability needs. Second, the proposed Clean Power Plan also provides great flexibility as to how states may demonstrate compliance — allowing states, among other things, to average their emissions over the period from 2020 to 2029; average the emissions of multiple EGUs when determining fleet-wide emission rates; and utilize market-based mechanisms, including credit trading systems that build on frameworks already in place in many states, to show that carbon pollution goals are being met. Third, the proposed Clean Power Plan provides a long, multi-year period for developing state plans as well as for demonstrating compliance. The relatively extended period for implementing these guidelines allows sufficient time for stakeholders to plan for future resource needs, and develop and deploy any infrastructure that may be needed to maintain reliability while reducing emissions from existing EGUs. All three of these features contribute to reliability by allowing states considerable latitude to determine the optimal timing, manner, and distribution of emission reductions across their fleet of existing EGUs.

In addition to these inherently reliability-preserving aspects of the Clean Power Plan itself, there are many existing federal, state, and regional tools and processes that are currently in place to ensure that our electricity needs are met while satisfying a number of other public policy goals – including environmental requirements, resource diversity, and affordability. Some examples of the tools that state, federal, and regional entities use to uphold their shared responsibilities for reliability include:

- Mandatory reliability standards for the bulk power system that are approved by FERC, and developed by the North American Electric Reliability Corporation (NERC) and regional reliability entities;
- Long-term regional transmission planning processes, overseen by FERC under Order 1000, that require public utilities to consider resource and transmission needs in light of both federal and state public policy requirements, and develop coordinated plans for meeting those needs;
- Wholesale market instruments, such as forward capacity markets, day-ahead markets, and ancillary services markets, that provide both short-term and long-term incentives to develop adequate supply resources;
- "Reliability must run" contracts to ensure that generating resources are on-call to meet electricity needs on an emergency basis, as needed; and
- Annual updates on short and long-term reliability issues produced by NERC and regional reliability entities;

These mechanisms have proven highly effective, and in the last decade have successfully preserved reliability during a period of significant changes in the power sector – including large-scale shifts of generation from coal to natural gas; integration of new resources such as renewables and demand response; and implementation of major pollution control projects to reduce emissions of air toxics, ozone precursors, and other pollutants. The Clean Power Plan builds on these ongoing trends, and will lead to changes in the power sector of a kind and scale that existing reliability entities and processes are fully capable of managing.

In light of these reliability safeguards and the ample flexibility provided in the Clean Power Plan — as well as EPA's own rigorous modeling showing that the Clean Power Plan is consistent with reliability needs — we do not believe it is necessary for EPA to provide less stringent standards or compliance schedules specifically for purposes of preserving reliability, as some stakeholders have suggested. Such measures would undermine the environmental and public health benefits of the Clean Power Plan while making no meaningful contribution to reliability.

XIV. EPA should facilitate multi-state compliance by enabling credits and allowances from approved programs to be used for compliance in multiple states, and should provide a tracking system for these credits to prevent double-counting.

EPA has proposed that states could jointly submit plans providing for multi-state compliance with state targets. We strongly support facilitating multi-state compliance, as states working together can secure reductions in carbon pollution more cost-effectively and with greater flexibility. However, we urge EPA to enable a less structured form of multi-state compliance as well. States may comply with their emission targets by putting in place source-based trading programs, under which a regulated unit is required under its permit to hold enough allowances to match its emissions (under a mass-based approach) or enough credits to meet a specified emission rate (under a rate-based approach). In the emission guidelines, EPA should provide that states designing such state-based plans with credits or allowances can specify that they will accept for compliance credits or allowances originating in their state or originating in another state taking the same type of target (mass or rate-based) with an approved plan. EPA should also provide a centralized tracking system for credits and allowances that cross state borders in order to facilitate multi-state compliance and to ensure that these credits and allowances are not double counted.

XV. EPA should provide templates for different plan designs and components.

In order to support states in their efforts to design plans to meet their carbon emission reduction targets, EPA should provide templates for different plan designs (e.g. a mass-based trading framework, a rate-based trading framework, multi-state compliance, and a utility-based portfolio approach) and for specific plan components (e.g. how to incorporate a state renewable energy standard and an energy efficiency program into a state plan; how to assess the emission reductions delivered by renewable energy and energy efficiency). One or more of the state plan templates could take the form of the federal implementation plan that will become the default framework for any states that choose not to submit a compliant implementation plan.

To: Hoffman, Howard[hoffman.howard@epa.gov]
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Sent: Wed 11/5/2014 11:27:13 PM
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CARBON REDUCTION CREDIT PROGRAM

A State Compliance Tool for EPA's Clean Power Plan Proposal

By Steven Michel and John Nielsen[1]

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Working Paper

This paper is distributed for comment and discussion.
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CARBON REDUCTION CREDIT PROGRAM

A State Compliance Tool for
EPA's Clean Power Plan Proposal

Abstract: A credit-based carbon dioxide (CO_2) emission rate reduction program for existing power plants is presented. This program provides an easy-to-administer system for state policymakers and regulators to comply with federal guidelines under Section 111 of the Clean Air Act (CAA), currently being developed by the Environmental Protection Agency (EPA). The proposal awards carbon reduction credits (CRCs) to generators and others based upon their output and CO_2 emission rate relative to the EPA standards. Owners or operators of regulated facilities then retire CRCs in sufficient amounts to demonstrate emission rate compliance. The standard is flexible, technology neutral and market based. CRCs are tradable, and the program is designed so that policymakers can begin implementation at the state level and later merge into multi-state or regional efforts, if desired. An appendix provides model regulatory language.

1.0 Introduction

On June 25, 2013 President Obama spoke at Georgetown University and laid out his Administration's plan to address climate change. Among the items identified by the President were carbon pollution standards established by the Environmental Protection Agency for new and existing power plants. Section 111 of the Clean Air Act is the statute EPA is using to develop its proposals, with subsection (b) applying to new sources and subsection (d) applying to existing sources. On September 20, 2013 EPA issued its new-source proposal and on June 2, 2014 the existing-source proposal was released. The standards for new sources are to be finalized in January 2015, with final existing-source standards to follow in June 2015. State compliance plans are to be submitted in 2016, with some opportunities to extend that date. Both the President and EPA have emphasized the prominent role states will play to develop specific regulatory programs that work best for them in implementing EPA's standards.

2.0 Overview of EPA's Proposals

EPA's proposals for new and existing power plants limit the rate of emissions, in pounds of CO_2 per megawatt-hour of electricity produced, rather than the total mass (e.g. pounds or tons) of emissions. This type of policy is often referred to as an emission performance standard.

For new sources, which are facilities that meet a threshold size and for which construction commenced after the September 20, 2013 proposed rule release date, the proposed standard is between 1000 and 1100 pounds of CO_2 per megawatt-hour (lbs/MWh), depending on the resource type and measurement period. These rates are comparable to those of a gas-fired power plant. In other words, as long as a new source emits at a rate no greater than approximately 1000-1100 lbs/MWh, it would be permitted.

EPA's existing-source proposal identified the specific fossil-fueled power plants in each state – referred to as electric generating units or EGUs – which would be subject to the regulation. The agency then established emission rate standards for the years 2020 to 2030 and thereafter, to be achieved across all of each state's affected EGUs.

EPA's emission rate standard is based upon the "best system of emission reduction" (BSER) available in each state during the 2020 to 2030 period. BSER includes four "building blocks." Building block 1 is heat rate improvements at EGUs. Building block 2 is re-dispatch from coal-fired to gas-fired facilities. Building block 3 is the deployment of zero-emission resources such as renewable or nuclear energy. Building block 4 is reducing demand for generation through energy efficiency. In developing its proposed standards EPA determined each state's 2012 emission rate and then calculated what rate could be achieved in that state over time using the BSER available in that state. As an example, EPA determined that Colorado's EGUs could achieve an overall emission rate of 1159 pounds of CO_2 per megawatt-hour between 2020 and 2029, and 1108 lbs/MWh in 2030 and beyond.

An important part of EPA's proposal is to allow states to count savings from energy efficiency, and production from renewable energy and some hydro and nuclear power,[2] toward meeting their standards. To do so, EPA allows the energy associated with these zero-emission resources to be included in calculating, and lowering, a state's overall EGU emission rate.

This paper describes a state regulatory framework which relies on a system of tradable carbon reduction credits to implement EPA's existing-source emission rate standard.[3] The program would be overseen by state air regulators, in cooperation with state utility commissions.

3.0 Why Develop a Carbon Reduction Credit Program?

Before describing the Carbon Reduction Credit Program, it is important to understand why such a program would be helpful to a state crafting a compliance strategy.

EPA's proposal establishes *statewide* standards. It is left to states to translate those statewide requirements into specific, enforceable requirements for regulated facilities. Concerns have been expressed that EPA's proposal would be complicated and expensive to implement, difficult to enforce, and could place state or federal environmental regulators in a role typically reserved for state public utility commissions– overseeing and enforcing specific state renewable energy and energy efficiency requirements, and power plant development and operation. A well-designed state program would overcome these concerns and would also be fair, so that facilities assume responsibility for their impact on state compliance. The program described in this paper satisfies these objectives. In particular, the program's advantages include:

1. **Simplicity:** Uses a straightforward emission accounting mechanism to assure compliance with the statewide emission rate standard.

2. **Clarity:** Preserves the traditional roles of utility regulators and air regulators and identifies for each EGU what its compliance obligation is, and how to comply.

3. **Enforceability:** Contains specific state enforcement provisions to assure that state control of renewable energy and energy efficiency programs, as well as power plant development and operation, is preserved.

4. **Fairness:** Assigns credit and responsibility to facilities based upon their impact on state compliance.

5. **Low cost:** Creates a statewide trading platform to assure the most economic CO_2 reduction opportunities can be deployed. The program is designed so that it can be expanded over time into a multi-state or regional effort that can further reduce cost.

4.0 The Carbon Reduction Credit (CRC) Program

The Carbon Reduction Credit Program uses a tradable credit system[4] to implement EPA's proposed existing-source performance standards. The program awards carbon reduction credits, or CRCs, based on the CO_2 emission rate and output of generators over time, and requires credits to be periodically retired to demonstrate compliance with EPA's standard. Under this program, for each MWh of electricity produced (or saved with energy efficiency), one credit is awarded for each pound of emissions less than that permitted by EPA's proposal. To the extent that a source emits at a rate greater than the EPA standard, a credit deficit is established. The program accommodates trading, either intrastate or interstate, to enable excess reductions from one facility to be used for compliance at a deficient facility. One of the attractive features of this program is that it can be developed incrementally – starting with individual state programs that, over time, could link together into multi-state and regional efforts.

4.1 The Mechanics of the Program

There are three steps in administering the program. The first is to provide credits, or establish credit deficits, each year for each affected electric generating unit in a state based upon its output and emission rate relative to the EPA-approved state standard for that year. The second task is to award credits to eligible zero-emission resources (e.g. renewable energy, nuclear energy and energy efficiency) based upon their output or savings each year. The final task is to require EGUs to periodically retire enough credits to offset any credit deficit they have at the end of the relevant compliance period.

4.1.1 Provide Credits or Establish a Credit Deficiency for Electric Generating Units

The first step is to provide credits, or establish a credit deficiency, for each affected EGU in the state each year. To do so, state air regulators would determine, each year, the emissions for each of the EGUs that EPA has identified as affected facilities in the state. EPA prescribes acceptable procedures for measuring emissions in its proposed rule. Additionally, owners or operators of affected EGUs would measure and report the megawatt-hours produced by their facility during that same annual period.

To determine the number of credits each EGU receives, regulators would compare the emission rate of the EGU in a compliance year to the required standard for that same year. Each generator would receive one carbon reduction credit for each pound of CO_2 per megawatt-hour that its emission rate was less than the standard in that year, multiplied by the output in that year. So, if the standard was 1200 lbs/MWh in a particular year, and a generator produced 1000 MWh with an emission rate of 1000 lbs/MWh, that generator would receive 200,000 credits for that year.

$$\left(1200 \frac{pounds}{MWh} - 1000 \frac{pounds}{MWh}\right) \times 1000\ MWh \times 1 \frac{CRC}{pound} = 200{,}000\ credits$$

Mathematically, the number of CRCs provided to a facility each year can be shown as:

$$CRC = (R_{STATE} - R) \times E \times C$$

R_{STATE}	is the state's CO_2 emission rate (lbs/MWh) standard for that year
R	is the CO_2 emission rate (lbs/MWh) of the facility in that year
E	is the output, i.e. net[5] energy (MWh), produced by the generator during the year
C	is the conversion factor of 1 CRC per pound

Facilities that emit CO_2 at a rate greater than the standard for that year would have a credit deficiency (negative credits), using the same formula as above. This is important because EGUs with credit deficits will have a compliance obligation to the extent of that negative balance, which they would meet by acquiring or earning CRCs. At the end of a compliance period, an EGU will be in compliance with the standard if it does not have a credit deficit.[6] Provided that none of the state's EGUs have a credit shortfall, the state will be able to demonstrate compliance with EPA's performance standard.

4.1.2 Provide Credits to Eligible Zero-Emission Resources

The second step is to provide credits to zero-emission resources. EPA has identified zero-emission (renewable and some nuclear and hydroelectric) energy production and energy efficiency programs as emission reduction systems that states can use to reduce the emission rates of their generation portfolios. Because these measures produce or avoid megawatt-hours and have zero emissions, EPA has authorized the energy associated with either measure to reduce the average emission rate for all generators in a state. To receive credit for either zero-emission energy or energy efficiency,[7] a state would determine the energy production or, in the case of energy efficiency, the savings.

Those financially responsible for the development of these resources, e.g. the utility or renewable energy certificate (REC) holder, would be entitled to receive CRCs. The program described here would allow any renewable or efficiency resource, regardless of where it produced or saved energy, to receive CRCs in a state so long as safeguards were in place to prevent duplicative CRC awards. Allowing out-of-state providers to receive CRCs is consistent with the "system" of emission reduction EPA has identified. If state law defines RECs to include *all* environmental attributes, CRCs would be awarded to a REC holder only if that person or entity commits to retire the RECs in the same state where the CRCs are used for compliance, or to hold the RECs until they expire.

The award of credits to renewable energy, eligible nuclear and hydroelectric energy, and energy efficiency is straightforward, and uses the same formula as for EGU's above except that the resource emission rate is zero. Put another way, for every megawatt-hour produced or saved in a year, these measures receive credits equal to the state's emission rate standard for that year. EPA has prescribed specific metering requirements to measure renewable energy production, and intends to develop evaluation, measurement and verification (EM&V) protocols for energy efficiency as part of its final rule. The CRC program would also allow aggregated renewable distributed generation, such as rooftop solar, to receive credits for its metered production. Using the scenario above, if a renewable resource produced 1000 MWh, or an efficiency measure reduced consumption by 1000 MWh, 1,200,000 CRCs would be awarded.

$$(1200\frac{\square}{\square} - 0\frac{\square}{\square}) \square 1000 \; \square \; 1\frac{\square}{\square} = 1{,}200{,}000 \; \square$$

4.1.3 Retire Carbon Reduction Credits for Compliance

The final task of this regulatory mechanism is to periodically require the retirement of creditsto ensure compliance with the standard. This obligation is on each affected EGU. The number of credits to retire equals the credit deficit, if any, that an EGU accumulated during the compliance period. So, if a generator had a credit deficit of 100,000 for each of two years, at the end of a two-year compliance period[8] the EGU would need to retire 200,000 credits. Any person, entity or generator that was awarded credits at any time would have those credits available to provide or sell to deficient EGUs. Put another way, an EGU whose emissions exceed the state standard emission rate in a year would offset its excess emissions through the retirement of CRCs. Those CRCs represent emission reductions beyond the standard at another EGU, or created by an emission reduction measure. Under this program, until retired for compliance, credits can be banked, sold or traded, and do not expire.

4.2 Example of a Compliance Strategy

This section provides an example of a system with three types of generation to demonstrate how various aspects of the program work. Appendix A provides three additional examples. It is important to emphasize that EPA does not require use of building blocks, or their use in specific amounts, to achieve compliance. In addition to the building blocks, covered facilities can use power plant retirements, plant ramp-ups and ramp-downs, and reworked maintenance schedules to assist in achieving compliance. This program also allows EGUs to purchase, sell, trade or bank CRCs as a part of an overall compliance strategy.

In our example we look at a system with three types of generation: coal, gas and wind, emitting 2000, 1000 and 0 pounds of CO_2 per megawatt-hour, respectively. The coal and gas plants are EGUs with a compliance obligation, and the wind facility is an emission reduction measure. Each generator also produces 1000 MWh. If a state's standard in a particular year is 800 lbs/MWh, we have the following CRC awards or deficits:

$$:\ (800 - 2000)\ 1000\ 1 = -1{,}200{,}000$$

$$:\ (800 - 1000)\ 1000\ 1 = -200{,}000$$

$$:\ (800 - 0)\ 1000\ 1 = 800{,}000$$

$$= -600{,}000$$

For the state to come into compliance, resources must adjust in a way that offsets the deficit of 600,000 CRCs, and then exchange credits such that each EGU (fossil generator) has a zero or positive balance. There are many ways to adjust the resources to accomplish a zero-balance outcome. One way would be to increase renewable energy generation by 750 MWh, which earns 600,000 CRCs. A second is to ramp down coal generation by 500 MWh, which reduces its CRC deficit to negative 600,000. A third way is to re-dispatch 600 MWh from coal to gas-fired generation, which creates a zero balance across the three resources. In each case the state would be compliant, and it would be up to the EGUs to acquire sufficient credits to establish a zero balance:

1) Increasing renewables or efficiency by 750 MWh adds 600,000 CRCs:

$$(800 - 0)\ 750\ 1 = 600{,}000$$

2) Ramping down 500 MWh of coal reduces the coal CRC deficit from 1,200,000 to 600,000:

$$(800 - 2000)\ 500\ 1 = -600{,}000$$

3) Re-dispatching 600 MWh of coal to gas balances the CRCs across the three resources:

$$:\ (800 - 2000)\ 400\ 1 = -480{,}000$$

$$:\ (800 - 1000)\ 1600\ 1 = -320{,}000$$

$$:\ (800 - 0)\ 1000\ 1 = 800{,}000$$

Under each of these scenarios the overall state emission rate is compliant at 800 lbs/MWh:

1) Increase renewables or efficiency by 750 MWh: $\frac{3{,}000{,}000}{3750} = 800\ /$

2) Ramp down 500 MWh of coal: $\frac{2{,}000{,}000}{2500} = 800\ /$

3) Re-dispatch 600 MWh coal to gas: $\frac{2{,}400{,}000}{3000} = 800\ /$

5.0 Additional Topics

In this section we discuss two additional topics of importance to regulators and policymakers. The first has to do with exchanging credits within and between state Section 111 programs. The second is a discussion of rate impacts to electricity customers under this program.

5.1 Linking State Programs Using a Carbon Reduction Credit Approach

There are many policies that can be used to drive CO_2 emission reductions. Of these, however, market-based systems are often able to deliver the most economic outcomes. This is both because a market-based system makes the lowest cost emission reductions available throughout the participating market, and because competition in markets will drive innovation and new technology.

The effectiveness of market-based systems can be increased by linking with other, perhaps differently designed, market-based programs in order to expand the area of participation. EPA has identified multi-state and regional programs as a possible compliance strategy for Section 111(d). The CRC program described here has this linkage potential. While *intrastate* credit exchange among sources is straightforward under this program, the different state stringency requirements of EPA's proposed regulation make *interstate* linkage more complicated.

One way to develop a multi-state or regional program is for participating states to adopt a single, weighted-average stringency requirement for EGUs across the states. Because EPA has assigned each state a different stringency requirement, and those requirements are rate-based rather than mass-based, developing a uniform requirement that achieves the same overall outcome as stand-alone programs could prove challenging. In addition, states with weaker stringencies may be reluctant to accept higher, averaged, requirements for their EGUs.

At the same time, if two linking states do not adopt a uniform stringency, but simply agree to accept each other's credits at face value, there will be an incentive to locate zero emission resources in the state with the weaker, i.e. higher, emission standards. This is because those resources will receive a greater number of credits in the state with the higher standard. For example, 1 MWh of renewable energy located in a state with a 2000 lbs/MWh standard would receive twice the number of credits as an identical resource located in a state with a 1000 lbs/MWh standard. This is a "leakage" problem that advantages some states in a multi-state program over others for resource siting, and compromises the overall emission outcome EPA's program would otherwise achieve.

To examine this issue in more detail, assume that both State A and State B have EGUs producing 2000 MWh with emissions of 1500 lbs/MWh. In a particular year, State A has a stringency requirement of 1000 lbs/MWh and State B has a stringency requirement of 500 lbs/MWh. Acting alone, State A would need to add 1000 MWh of renewables to achieve compliance:

$$\frac{\left(1500\,\frac{lbs}{MWh} \times 2000\,MWh\right) + \left(0\,\frac{lbs}{MWh} \times 1000\,MWh\right)}{3000\,MWh} = 1000\,\frac{lbs}{MWh}$$

And State B, also acting alone, would need to add 4000 MWh of renewables to achieve compliance:

$$\frac{\left(1500\,\frac{lbs}{MWh} \times 2000\,MWh\right) + \left(0\,\frac{lbs}{MWh} \times 4000\,MWh\right)}{6000\,MWh} = 500\,\frac{lbs}{MWh}$$

In total then, acting separately, 5000 MWh of renewables would be needed for compliance in the two states. If the two states linked, but did not adjust imported credits, then compliance could be achieved with only 3000 MWh of additional renewables located entirely in State A. This is because the CRC deficiency in the two state programs would be:

$$: \left(1000\,\frac{\ }{\ } - 1500\,\frac{\ }{\ }\right)\ 2000\ \ 1\,\frac{\ }{\ } = -1{,}000{,}000$$

$$: \left(500\,\frac{\ }{\ } - 1500\,\frac{\ }{\ }\right)\ 2000\ \ 1\,\frac{\ }{\ } = -2{,}000{,}000$$

And if the two states linked and accepted imported credits at face value, they could comply by simply locating 3000 MWh of renewables in State A, where they receive 1000 CRCs per MWh. A solution to this leakage issue is for states with different stringencies to link their programs, preserve their respective standards, and adjust the number of out-of-state credits as though they were created in the recipient state.

To illustrate this concept using the example above, State B would reduce State A credits by the ratio of the (origin) State A stringency to the (recipient) State B stringency, or 2:1. When that is done, the intended 5000 MWh rather than 3000 MWh of renewable energy must be developed to achieve compliance. And those 5000 MWh of renewable resources can be developed in either state without a locational preference created by the different stringencies. If all the renewables are developed in State A, 5,000,000 CRCs are awarded,[9] with 4,000,000 used to achieve State B compliance (reduced by a 2:1 ratio) and 1,000,000 used in State A. Conversely, if all 5000 MWh of renewables are developed in State B, 2,500,000 State B CRCs are awarded, with 500,000 used in State A to achieve compliance (at an adjusted 1:2 ratio), and 2,000,000 used in State B. We believe this avoids the locational incentive to develop resources in State B over State A, and preserves the overall stringency of EPA's proposed program.

As a final note, while EPA's rate-based stringency proposal lends itself to a simple ratio mechanism, that may not be the case for other types of compliance programs such as a mass-based approach that EPA might allow, or existing cap & trade programs in the Western and Eastern United States.[10] These cap & trade programs include rigorous protocols with strict carbon accounting to assure specific tonnage outcomes. Linking mass-based programs with rate-based mechanisms that lack a cap on overall emissions could dilute the outcome in the mass-based jurisdictions. To link these mixed types of programs, therefore, the price of credits from the less rigorous program might be further discounted to reflect the uncertainty of the tonnage outcome.

5.2 Electricity Rate Impacts

In developing this program, several provisions have been included to ensure that the rate impact of this regulation on electric utility customers is minimized.

The first involves matching the periodic compliance obligation to the lumpiness of typical utility resource development and retirement. This lumpiness can create short-term credit shortfalls that would be difficult or costly to address. To mitigate this concern, while the regulation calls for an annual accumulation of CRC retirement obligations, the compliance periods are spaced two years apart – to conform to EPA's proposal that emission rate reduction progress be assessed at least biannually. Because credits do not expire unless retired for compliance, and can be banked, sold or exchanged, this two-year window should provide ample flexibility for generator compliance. And given that CO_2 is a global pollutant that stays in the atmosphere for 100 years or more, the extended compliance periods should have little impact on the overall benefits of the program.

In addition, to assure that market failures or other dislocations do not create short-term credit scarcities and extraordinary prices, an affected EGU that is unable to comply with the standard in a particular compliance period would be permitted to make up its deficiency within twelve (12) months by retiring 125% of the CRC shortfall. This provision protects against price spikes if the market temporarily fails. Requiring non-compliant EGUs to later retire 125% of their deficit should provide a strong incentive for timely compliance.

Finally, it is worth noting that the rate impacts associated with this program will be small. To understand the magnitude of the rate impact, consider a typical utility with an average electricity rate of $100/MWh and an overall emission rate of 1400 lbs/MWh. If the utility has a 30% reduction requirement by 2030 and can reduce emissions at a cost of $0.015 per pound ($33 per metric ton),[11] the *total* increase to electricity rates, from today's levels, in 2030 would be 6.3%, or 0.4% per year on average.

$$1400\,\frac{lbs}{MWh} \times 30\% \times \$0.015/lb = \$6.30/MWh \quad (\text{i.e. } 6.3\% \text{ of } \$100)$$

6.0 Conclusions

The Environmental Protection Agency has issued proposed emission rate standards to be achieved between now and 2030. Once those standards are final, states will be tasked with developing state programs to effectuate them. We believe the Carbon Reduction Credit Program described in this paper fits well with state interests and provides a flexible, low-cost, market-based and technology-neutral approach that states can use to comply with EPA's proposal. The program also allows states to develop stand-alone programs that can later merge into broader multi-state or regional efforts.

Appendix B provides model regulatory language that states could use as a starting point to effectuate the concepts described in this paper (using Colorado as an example).

APPENDIX A

In this Appendix, we provide three additional compliance strategies and how they could work in the CRC Program. The first involves a re-dispatch of generation from coal to gas. The second involves simply adding renewable energy. The third utilizes each of the four building blocks identified by EPA.

1) Re-dispatch generators

First, we look at the example of a re-dispatch program that moves 1000 MWh of production from coal to gas. Prior to re-dispatch, a coal plant produces 2000 MWh and emits 2000 lbs/MWh. At the same time, an available gas plant would emit 1000 lbs/MWh. If the emission rate standard is 1500 lbs/MWh, before re-dispatch the coal plant would have a 1,000,000 credit deficit:

$$\left(1500 - 2000\right) 2000 \cdot 1 = -1{,}000{,}000$$

After re-dispatch, the gas and coal plants will be in compliance when considered together, with the gas plant receiving 500,000 CRCs to offset the coal plant's 500,000 CRC deficit:

$$\left(1500 - 2000\right) 1000 \cdot 1 = -500{,}000$$

$$\left(1500 - 1000\right) 1000 \cdot 1 = 500{,}000$$

At the same time, the two facilities in combination achieve the emission rate standard of 1500 lbs/MWh:

$$\frac{(2000 \cdot 1000) + (1000 \cdot 1000)}{2000} = 1500$$

Renewable energy would work the same way as re-dispatch, except that more credits would be awarded because renewables have zero emissions rather than 1000 lbs/MWh. Providing 1000 MWh of energy efficiency savings would have the same result as re-dispatching to renewables.

2) Add renewable energy

It is important to understand that under EPA's proposal and this program, even if a specific high-emission generator in a state is not curtailed, it is still possible to achieve compliance by providing additional low-emission resources or energy efficiency to the system. Because of the nature of electricity and the overall inability to store power, supply will equal demand. This means that when renewables are producing energy, or efficiency is providing savings, even if not associated with ramping down a particular generator in a particular state, there will be less generation than otherwise, somewhere on the system. In the example below, we show that adding 1000 MWh of renewables to 3000 MWh of coal generation can achieve compliance with a 1500 lbs/MWh standard, without ramping down the coal plant:

$$\square\square{:}\ \left(1500\frac{\square\square\square\square\square\square}{\square\square\square} - 2000\frac{\square\square\square\square\square\square}{\square\square\square}\right)\square 3000\ \square\square\square\square \cdot 1\frac{\square\square\square\square\square\square}{\square\square\square\square\square\square} = -1{,}500{,}000\ \square\square\square\square\square\square\square\square\square$$

$$\square\square\square\square\square\square{:}\ \left(1500\frac{\square\square\square\square\square\square}{\square\square\square} - 0\frac{\square\square\square\square\square\square}{\square\square\square}\right)\square 1000\ \square\square\square\square \cdot 1\frac{\square\square\square\square\square\square}{\square\square\square\square\square\square} = 1{,}500{,}000\ \square\square\square\square\square\square\square\square\square$$

In this scenario, one sees that the emission rate achieved is the state standard of 1500 lbs/MWh:

$$\frac{\left(2000\frac{\square\square\square\square\square\square}{\square\square\square}\square 3000\ \square\square\square\right) + \left(0\frac{\square\square\square\square\square\square}{\square\square\square}\square 1000\ \square\square\square\right)}{4000\ \square\square\square} = 1500\frac{\square\square\square\square\square\square}{\square\square\square}$$

3) Four building blocks

In our final example we look at a compliance strategy that includes coal plant heat rate improvement, re-dispatch, renewable energy development and energy efficiency, i.e. all four building blocks.

To start, assume that a state has a coal plant and a gas plant, each producing 2000 MWh with emission rates of 2000 lbs/MWh and 1000 lbs/MWh, respectively. This means the starting average emission rate is 1500 lbs/MWh. Also, assume the emission rate standard for a compliance year is 1250 lbs/MWh.

A compliance strategy that uses all four building blocks would improve the coal plant's emission rate by 5% (from 2000 lbs/MWh to 1900 lbs/MWh), re-dispatch 300 MWh of coal to natural gas, and add 300 MWh of renewable energy and 124 MWh of efficiency. When this is done, we have the following zero-credit balance outcome:

$$\square\square{:}\ \left(1250\frac{\square\square\square\square\square\square}{\square\square\square} - 1900\frac{\square\square\square\square\square\square}{\square\square\square}\right)\square 1700\ \square\square\square\square \cdot 1\frac{\square\square\square\square\square\square}{\square\square\square\square\square\square} = -1{,}105{,}000\ \square\square\square\square\square\square\square\square\square$$

$$\square\square{:}\ \left(1250\frac{\square\square\square\square\square\square}{\square\square\square} - 1000\frac{\square\square\square\square\square\square}{\square\square\square}\right)\square 2300\ \square\square\square\square \cdot 1\frac{\square\square\square\square\square\square}{\square\square\square\square\square\square} = 575{,}000\ \square\square\square\square\square\square\square\square\square$$

$$\square\square\square\square\square\square{:}\ \left(1250\frac{\square\square\square\square\square\square}{\square\square\square} - 0\frac{\square\square\square\square\square\square}{\square\square\square}\right)\square 300\ \square\square\square\square \cdot 1\frac{\square\square\square\square\square\square}{\square\square\square\square\square\square} = 375{,}000\ \square\square\square\square\square\square\square\square\square$$

$$\square\square\square\square\square{:}\ \left(1250\frac{\square\square\square\square\square\square}{\square\square\square} - 0\frac{\square\square\square\square\square\square}{\square\square\square}\right)\square 124\ \square\square\square\square \cdot 1\frac{\square\square\square\square\square\square}{\square\square\square\square\square\square} = 155{,}000\ \square\square\square\square\square\square\square\square\square$$

And the overall emission rate is compliant:

$$\frac{\left(1900\frac{\square\square\square\square\square\square}{\square\square\square}\square 1700\ \square\square\square\right) + \left(1000\frac{\square\square\square\square\square\square}{\square\square\square}\square 2300\ \square\square\square\right) + \left(0\frac{\square\square\square\square\square\square}{\square\square\square}\square 300\ \square\square\square\right) + \left(0\frac{\square\square\square\square\square\square}{\square\square\square}\square 124\ \square\square\square\right)}{4424\ \square\square\square} = 1250\frac{\square\square\square\square\square\square}{\square\square\square}$$

At the end of the compliance period, the coal plant in this scenario would need to acquire and retire the CRCs of the other facilities, in order to zero out its negative credit balance and show that it is individually meeting its obligations.

APPENDIX B

CARBON REDUCTION CREDIT RULE
FOR ELECTRIC GENERATING UNITS

Section A: Objective. The objective of this Rule is to establish a State of Colorado[12] program for emission rate reductions from electric generating units that complies with the Clean Air Act and EPA regulations pursuant thereto, and to address and mitigate global warming and climate change.

Section B: Definitions. As used in this Rule the following definitions shall apply, provided however that in the event of a conflict the definition provided in this Section shall prevail for purposes of this Rule.

(1) **compliance year emission rate** means 1244 lbs/MWh in 2020, 1220 lbs/MWh in 2021, 1197 lbs/MWh in 2022, 1175 lbs/MWh in 2023, 1155 lbs/MWh in 2024, 1135 lbs/MWh in 2025, 1123 lbs/MWh in 2026, 1117 lbs/MWh in 2027, 1112 lbs/MWh in 2028, and 1108 lbs/MWh in 2029 and thereafter;[13]

(2) **CDPHE** means the Colorado Department of Public Health and Environment;

(3) **carbon reduction credit**, **CRC** or **credit** means an instrument, in a format approved and issued by CDPHE, which represents one pound of carbon dioxide emissions by an EGU less than would have been emitted had it operated at the compliance year emission rate, which amount can be negative and, if so, represents a compliance obligation. For Emission Reduction Measures, it equals the number of MWh produced or saved multiplied by the compliance year emission rate. Mathematically, the number of CRCs provided to a facility each year is:

[illegible]

R_{CY}	is the compliance year emission rate (lbs/MWh)
R	is the CO_2 emission rate (lbs/MWh) of the facility in that year
E	is the net energy (MWh) produced or saved during the year
C	is the conversion factor of 1 CRC per pound;

(4) **CO_2** means carbon dioxide;

(5) **Division** means the Air Pollution Control Division of the CDPHE;

(6) **electric generation unit** or **EGU** means the following electricity producing facilities: Arapahoe (units 3 and 4), Arapahoe Combustion Turbine Project (units 5,6 and 7), Brush Generation Facility (ST1, ST2, ST4,GT1,GT2 and GT3), Cherokee (units 1,3 and 4), Comanche (units 1,2 and 3), Craig (units 1,2 and 3), Fort St. Vrain (units 1,2,3 and 4), Front Range Power Plant (units 1,2 and 3), Hayden (units 1 and 2), J.M. Shafer Generating Station (STA, STB, LMA, LMB, LMC, LMD and LME), Lamar Plant (unit 4), Martin Drake (units 5,6 and 7), Nucla (ST4), Pawnee (unit 1), Pueblo Airport Generating Station (units 4,5,6,7,43 and 53), Rawhide (unit 1), Ray D. Nixon (unit 1), Rifle Generating Station (ST1 and GT4), Rocky Mountain Energy Center (STG1, CTG1 and CTG2), Thermo Power & Electric (GEN1, GEN2, GEN3), Valmont (unit 5), W. N. Clark (unit 2) and Zuni (unit 2);[14]

(7) **emission(s)** means carbon dioxide emitted into the atmosphere by an EGU;

(8) **emission rate** means pounds of emissions from a facility in a calendar year divided by net megawatt-hours of production in that same calendar year;

(9) **emission reduction measure** or **ERM** means a non-nuclear zero-emission electricity production facility, six percent of the capacity of a nuclear facility in service on June 2, 2014, one hundred

percent of a nuclear-powered facility in construction or for which construction commenced or any life extension or capacity addition occurred after June 2, 2014,[15] additional or new hydroelectric facilities[16] developed after June 2, 2014, or any evaluated, measured and verified electric energy efficiency savings provided through a program overseen by a state agency. Such measures include, but are not limited to, wind, solar, nuclear and hydro electricity production, as well as aggregated and metered distributed renewable generation. ERMs that are not nuclear or hydro-electric may be from outside Colorado;

(10) **EPA** means the Environmental Protection Agency of the United States of America;

(11) **ERM provider** means the owner, operator, provider or other person or entity financially responsible for the ERM. For energy efficiency, it is the person or entity that administers or directs the state overseen program. For renewable energy production which is an ERM and for which renewable energy certificates or credits (RECs) have been created and are compliant with EPA standards for Clean Air Act §111d compliance, it is the person or entity holding the RECs associated with the production, provided that person or entity commits to extinguish the associated RECs or retire the associated RECs in the same state that the CRC is retired;

(12) **Evaluated, measured and verified (EM&V)**, or **metered** means that the MWh of production or savings are determined in a manner that meets EPA established protocols for energy efficiency and renewable energy;[17]

(13) **megawatt-hour** or **MWh** means one thousand kilowatt-hours;

(14) **net MWh** means generation output of an EGU measured at the point of delivery to the transmission grid;[18] and

(15) **origin state** means the state in which an EGU or ERM is physically located or providing energy efficiency savings.

Section C: Electric Generating Units (EGUs) and ERMs.

(1) On or before March 31, 2020, and each year thereafter, each EGU shall accurately report its emissions and net MWh during the prior calendar year to the Division. The report shall include a detailed description of how the emissions and net MWh were measured or estimated. Emissions monitoring and calculation methods provided in 40 CFR Part 98, or other methods chosen by the EGU, may be used to meet this requirement, provided those methods comply with protocols established by the EPA.

(2) In order to receive credits for its contribution toward lower emission rates, on or before July 31, 2021, and each year thereafter, each ERM provider shall accurately report the MWh produced, or saved in the case of energy efficiency measures, during the prior calendar year to the Division. The report shall include a detailed description of how the MWh were evaluated, measured and verified or metered, and shall be certified by the Colorado Public Utilities Commission (CPUC) or the Colorado Energy Office. In the event that the CPUC or Energy Office has not certified the results by July 31, the ERM may seek an extension of time to submit its report.

(3) The Division shall approve or disapprove each EGU's annual emissions and net MWh report, and each ERM provider's report, along with any adjustments thereto, by September 30 of the year of report submission. In the event of disapproval, the EGU or ERM provider may correct the report or appeal the Division's decision to the Colorado Air Quality Control Commission.

Section D: Carbon Reduction Credits (CRCs)

(1) The Division shall provide an EGU one CRC each calendar year commencing in 2020 for each pound of CO_2 that it emits in that year less than the compliance year emission rate would allow, for all net MWh produced. An EGU that emits an amount greater than the compliance year emission rate would allow in a calendar year shall have a credit deficit to the extent of its excess emissions for that year. A credit deficit represents a compliance obligation for that EGU.

(2) The Division shall provide to each ERM one CRC each calendar year commencing in 2020 equal to the compliance year emission rate multiplied by the net MWh produced by that ERM, or saved if from an energy efficiency program, in accordance with Section C(2), *supra*.

(3) CRCs may be sold, traded or otherwise transferred, do not expire, and may be used at any time unless and until they are retired for compliance with this rule or a similar emission reduction program in another jurisdiction. The Division shall allow credits or allowances created in another state(s), with a rule approved to comply with federal Clean Air Act Section 111(d) stringency requirements for CO_2, to be used for compliance in Colorado, provided the other state(s) accepts credits from Colorado for compliance with its own program, and provided that the number of credits or allowances tendered for compliance in Colorado shall be increased or reduced by the ratio that the emission rate stringency requirement in Colorado bears to the emission rate stringency requirement of the origin state in the year the credit or allowance was created. As an example, if the origin state has a stringency requirement of 1000 pounds per MWh in 2020, credits created in that year shall be valued at 1.244 times (1244/1000) their face value if tendered for compliance in Colorado. If the stringency in the origin state is of a different nature than that of Colorado (for example, not expressed in pounds per MWh), the Division shall establish a stringency ratio, subject to EPA approval, for application to that origin state's credits or allowances that fairly reflects the relative emission rate stringencies of the two states.

Section E: Compliance

(1) Each EGU shall demonstrate compliance by the certified retirement, in a manner prescribed by the Division, of CRCs every two years. The number of CRCs to be retired for compliance shall equal the credit deficit, if any, accumulated by that EGU during the prior two-year period.

(2) An EGU shall first present and retire CRCs on or before March 1, 2022 for compliance in the 2020 through 2021 period, and shall retire CRCs every two years thereafter for compliance during that intervening two-year period. The Division shall certify the retirement of CRCs and otherwise assure compliance with this rule.

Section F: Record Retention

All filings, submittals, work papers, records, data and any other documentation of the administration of this rule shall be preserved by the Division for at least ten (10) years from the date of its preparation.[19]

Section G: Non-compliance

Any EGU that fails to comply with the CRC credit balance requirements established by this Rule shall be required to make up the shortfall by retiring one hundred twenty-five percent (125%) of the deficient CRCs within the following twelve (12) months. Each day that a deficiency exists after this twelve (12) month extension shall be considered a separate violation of this Rule.

End Notes

[1] Mr. Michel holds a B.A. in economics and history from Northwestern University and M.B.A. and J.D. degrees from Vanderbilt University. Mr. Nielsen holds a B.A. in economics and mathematics from the University of Colorado and a Master of Philosophy degree in economics from Yale University. Both Mr. Michel and Mr. Nielsen are with the Energy Program of Western Resource Advocates, an environmental law and policy center. The authors wish to acknowledge the contribution and assistance of Stacy Tellinghuisen, Erin Overturf, Douglas Howe, David Berry, David Farnsworth and Brad Musick to the development of this paper.

[2] EPA's proposal would allow the emissions from new nuclear facilities to contribute to a state's emission rate compliance. For currently operating nuclear plants, EPA's proposal would allow 6% of the nuclear capacity in each state to contribute to that state's emission rate calculation (EPA proposed rule at pp. 114 and pp. 214-217).

[3] EPA's proposed existing-source standard includes an option for states to develop mass-based standards instead of EPA's rate-based proposal. A mass-based standard would have states achieve an actual tonnage reduction from power plant emissions, as opposed to a reduction in the rate of emissions. EPA provides guidelines for how states might establish a mass-based alternative.

[4] Using a credit system to drive emission reductions was introduced by the authors in *The Electricity Journal* in May 2008 as a way to approach a mass-based regional greenhouse gas regulation with incomplete market participation. The concept was updated to address different regulatory scenarios in three subsequent articles of that same journal. See *The Electricity Journal*: Vol. 21, Issue 4, May 2008, p. 31; Vol. 22, Issue 8, October 2009, p. 45; Vol. 24, Issue 3, April 2011, p. 45; Vol. 26, Issue 93, November 2013. Former Senator Jeff Bingaman proposed a credit system as part of a rate-based emission program in his Clean Energy Standards Act of 2012, and the Department of Interior has committed, as part of a proposed resolution for Navajo Generating Station regional haze issues, to use a mass-based, credit-based system to reduce the CO_2 emissions associated with some of its usage. In 2012, Resources for the Future released a discussion paper with an emission rate credit concept similar to the one presented here: "Tradable Standards for Clean Air Act Carbon Policy," Burtraw, Fraas and Richardson, Resources for the Future (2012).

[5] EPA proposes that the MWh to be used for compliance purposes must be "net," meaning that they are measured at the point of interconnection with the transmission grid and exclude energy consumed at the plant site.

[6] To show that that an affected source will be in compliance with the EPA standard if and only if its CRC holdings at the end of the compliance period are non-negative, simply rearrange the equation as: [illegible]
For R to be less than or equal to R_{EPA}, [illegible] must be non-negative. Given that C and G are positive, this can only be the case if CRC holdings are greater than or equal to zero.

[7] Energy efficiency is widely regarded as the lowest cost, least environmentally impacting resource available to meet the energy needs of customers. See "Reducing Greenhouse Gas Emissions: How Much at What Cost?" U.S. Greenhouse Gas Abatement Mapping Initiative, Executive Report, December 2007, McKinsey & Company: http://www.mckinsey.com/clientservice/ccsi/pdf/US_ghg_final_report.pdf. When a new zero-emission generator such as a renewable resource is dispatched to meet load, it produces energy with zero emissions. Similarly, when energy efficiency is deployed and reduces load by the same amount, the environmental outcome is identical. Therefore it makes sense to provide equivalent credit for renewable energy and energy efficiency, which is included in EPA's proposal and captured by this credit system.

[8] EPA's proposed rule at p. 44 has state program performance evaluated at least every two years.

[9] 5000 MWh x 1000 lbs/MWh x 1 CRC/lbs = 5,000,000 CRCs.

[10] The Western Climate Initiative (WCI) and the Regional Greenhouse Gas Initiative (RGGI).

[11] $33 per tonne is likely a conservative estimate given that most carbon markets are trading in the $10/tonne range, and given EPA's estimated costs for the 4 building blocks: $6-$12/tonne for heat rate improvements, $30/tonne for re-dispatch, $10-$40/tonne for zero-emission resources and $16-$24/tonne for efficiency – EPA proposed rule at pp. 143-152.

[12] Underlined items are placeholders specific to Colorado.

[13] EPA proposed rule: 20140602tsd-state-goal-data-computation.xlsx.

[14] EPA proposed rule: 20140602tsd-plant-level-data-unit-level-inventory.xlsx.

[15] EPA proposed rule at e.g. p.503.

[16] EPA proposed rule at p.200.

[17] EPA proposed rule at p.485.

[18] EPA proposed rule at p.343.

[19] EPA proposed rule at p.453.

To: Megan Ceronsky[mceronsky@edf.org]
From: Megan Ceronsky
Sent: Sun 10/19/2014 8:59:12 PM
Subject: EDF comments on proposed carbon pollution standards for modified and reconstructed EGUs
EDF 111b mods comments.pdf

Please find attaching EDF's comments on EPA's proposed carbon pollution standards for modified and reconstructed EGUs.

Best regards,

Megan

Megan Ceronsky
Director of Regulatory Policy and Senior Attorney

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1200 Pennsylvania Ave., NW
Washington, DC 20460

Attn: Docket ID No. EPA-HQ-OAR-2013-0603

Re: Comments of Environmental Defense Fund on EPA's Proposed Carbon Pollution Standards for Modified and Reconstructed Electric Utility Generating Units

The Environmental Defense Fund (EDF) appreciates the opportunity to provide the following comments on the Environmental Protection Agency's (EPA) June 18, 2014 proposed rule to establish performance standards for carbon pollution from modified and reconstructed electric utility generating units (EGUs).[1] Representing over 750,000 members nationwide, EDF is a national non-profit, non-partisan organization dedicated to protecting human health and the environment by effectively applying science, economics, and the law. EDF has long recognized the urgent and critical threat that climate change poses to public health and welfare, and it is one of our top priorities to advocate for rigorous measures to secure rapid reductions in emissions of climate-destabilizing pollutants – especially emissions of carbon dioxide from fossil fuel-fired EGUs, which currently account for nearly 40 percent of the United States' carbon pollution. Accordingly, we strongly support EPA's initiative to establish the first nation-wide limits on carbon pollution from fossil fuel-fired EGUs using its existing authorities under section 111(b) and (d) of the Clean Air Act.[2]

EPA's proposed rule for modified and reconstructed EGUs is a vital part of this initiative. Our comments below are directed at ensuring that these pollution standards meet the Clean Air Act's standard—that they deliver the maximum possible emission reductions considering cost and the other statutory factors—and are coordinated effectively with EPA's emission guidelines for existing fossil fuel-fired EGUs. Specifically, our comments:

[1] Carbon Pollution Standards for Modified and Reconstructed Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,960 (proposed June 18, 2014).
[2] 42 U.S.C. § 7411(b), (d).

- Strongly support EPA's determination that requirements for existing fossil fuel-fired EGUs established under section 111(d) of the Clean Air Act will continue to apply in the event those units undertake modification or reconstruction;
- Urge EPA to extend this interpretation to assure that section 111(d) requirements apply to any existing fossil fuel-fired EGU that modifies or reconstructs prior to the adoption of state plans;
- Suggest two alternative approaches that EPA can adopt to appropriately ensure improved emission performance from modified and reconstructed EGUs, in addition to providing for the continued applicability of section 111(d) state plans to such units;
- Recommend that EPA adopt significantly more stringent standards for reconstructed coal-fired EGUs, based on fuel-switching to natural gas as the best system of emission reduction (BSER) to achieve greater emission reductions than the proposal;
- Recommend that EPA adopt significantly more stringent standards for modified coal-fired EGUs, based on fuel-switching to natural gas to achieve greater emission reductions than the proposal;
- Support EPA's proposed BSER for natural gas combustion turbines, but recommend that EPA adopt more stringent standards that reflect the performance of state-of-the-art natural gas combined cycle (NGCC) facilities (as described in our comments on EPA's proposed carbon pollution standards for new fossil fuel-fired EGUs[3]); and
- Urge EPA to adopt an initial performance test for all affected EGUs to ensure these facilities adopt the most efficient generating technologies and operating systems available, similar to requirements already included in recently-issued Prevention of Significant Deterioration (PSD) permits for NGCC facilities, to ensure that Section 111's technology-forcing role is fulfilled.

All prior written and oral testimony and submissions to the Agency in this matter, including all citations and attachments, as well as all of the documents cited to in these comments and attached hereto are hereby incorporated by reference as part of the administrative record in this EPA action, Docket ID No. EPA–HQ–OAR–2013–0603.

I. EPA Must Ensure that Modified and Reconstructed EGUs Achieve Emission Reductions that Reflect the BSER and Do Not Compromise the Integrity of Section 111(d) State Plans.

One of the most important issues raised in the proposed rule is whether fossil fuel-fired EGUs covered by state plans issued under section 111(d) must continue to comply with those state plans after undertaking a modification or reconstruction. EDF strongly believes that section 111(d) requirements must apply to all fossil fuel-fired EGUs that were "existing sources" as of the date the emission guidelines were proposed (June 18, 2014), regardless of whether those fossil fuel-fired EGUs subsequently modify or reconstruct. Allowing EGUs to exempt themselves from section 111(d) by modifying or reconstructing would not assure that these units are subject to a "standard for emissions of air pollutants which reflects . . . the best system of emission reduction," as required by sections 111(a) and (b) of the

[3] Comments of Joint Environmental Commenters, EPA-HQ-OAR-2013-0495-9514, at 83-106, included as Appendix A to these comments.

Clean Air Act.[4] For modified and reconstructed EGUs, the "best system of emission reduction" necessarily encompasses not just systems such as heat rate improvements, considered in the proposed standards here, but also the potential for shifts in utilization away from higher-emitting and towards lower- or zero- emitting generation and demand-side energy efficiency to reduce carbon pollution from these plants. This is the system that EPA has identified as the "best" system of emission reduction in the proposed emission guidelines for all existing plants because it achieves the greatest pollution reductions considering cost, energy requirements, and other health and environmental outcomes. The modification or reconstruction of an existing fossil fuel-fired EGU does not alter the fact that the flexible, cost-effective system of emission reduction identified by EPA remains the best system for that plant, achieving the greatest emission reductions considering cost and the other statutory factors—in combination with the additional BSER components described in these comments to ensure that the section 111(b) standard serves its technology-forcing, emission-reducing role when significant investments are being made in these plants.

Moreover, as EPA recognizes in the proposed emission guidelines,[5] an approach under which modified or reconstructed EGUs are no longer subject to section 111(d) would create perverse economic incentives for units to undertake modifications with the objective of avoiding emission reductions that would be required under their state plans. And as EPA also acknowledges, it would be highly disruptive for state plans—which in many cases will be based on the state-wide average performance of currently existing EGUs—if EGUs that were "existing" sources when the plan was designed were suddenly excluded from the plan upon modifying or reconstructing.

Maintaining the applicability of section 111(d) state plans to modified and reconstructed EGUs is not only supported by these compelling policy considerations, it is also consistent with the text of the Clean Air Act—as we describe in further detail below. For these reasons, we strongly support EPA's determination that fossil fuel-fired EGUs already subject to a section 111(d) state plan must continue to comply with those plans in the event those facilities later modify or reconstruct. In addition, we recommend that EPA extend this interpretation to ensure that *all* fossil fuel EGUs that are currently "existing sources" remain covered by section 111(d) state plans, regardless of whether or when they modify or reconstruct. Lastly, as a supplement to EPA's proposed approach, we also suggest two alternative mechanisms by which EPA could assure that modified and reconstructed EGUs achieve emission reductions consistent with the flexible, system-based BSER identified in the proposed Clean Power Plan: 1) committing to review the New Source Performance Standards (NSPS) for new, modified,

[4] Section 111(b) of the Clean Air Act requires that EPA establish "standards of performance" for "new sources," which are defined under section 111(a) to include sources that undertake modifications after the proposed date of an applicable standard of performance. Under section 111(a)(1) of the Clean Air Act, such standards of performance *must* "reflect[] the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." For modified and reconstructed EGUs, this "best system" includes not just the technology-based standards that EPA has included in the proposed rule, but also the same system-based "building blocks" that EPA determined to be the BSER for existing sources in its proposed Clean Power Plan.

[5] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,904 (proposed June 18, 2014) ("The EPA is concerned that owners or operators or units might have incentives to modify purely because of potential discrepancies in the stringency of the two programs, which would undermine the emission reduction goals of CAA section 111(d).").

and reconstructed EGUs at intervals shorter than the eight-year review period prescribed by the statute, such that all such units would promptly become "existing sources" subject to section 111(d); 2) including emissions from modified and reconstructed EGUs when determining compliance with the state goals under section 111(d).

a. EPA Has Reasonably Interpreted Section 111 as Requiring Sources to Continue to Comply with Section 111(d) State Plan Requirements Following a Modification or Reconstruction.

EPA's proposed rule correctly notes that section 111(d) is ambiguous as to whether state plan requirements must continue to apply to a source that modifies or reconstructs. In the preamble to the proposed emission guidelines for existing power plants, EPA explains that section 111 defines "new" and "existing" sources, and that section 111(d) clearly contemplates the submission of state plans that "establish[]" standards of performance for existing sources. However, the statute "does not say whether, once the EPA has approved a state plan that establishes a standard of performance for a given source, that standard is lifted if the source ceases to be an existing source."[6] EPA proposes to resolve this ambiguity by specifying that section 111(d) requires existing sources covered in a state plan to remain subject to the requirements of CAA section 111(d) plan after modifying or reconstructing.[7] EPA provides two reasons for this determination: (1) to avoid disruption and uncertainty as to which units will be part of state programs under a 111(d) plan; and (2) to avoid creating perverse incentives for sources to modify or reconstruct to escape 111(d) plan requirements, which could potentially be more stringent than 111(b) obligations.[8]

EPA's position is a reasonable resolution of the ambiguous language of section 111(d), and is therefore due deference under *Chevron v. Natural Resources Defense Council*.[9] As EPA notes, the plain language of section 111(d) requires only that EPA create a procedure for states to submit plans that "establish[] standards of performance" for any "existing source." This language does not clearly state *when* a source is to be considered "existing" for purposes of defining the scope of the state plan. A requirement that a state plan must "establish[]" performance standards for any source that is "existing" *at the time emission guidelines are proposed or at the time of plan submittal* is consistent with the text of the statute, and reasonable given the particular structure of the Clean Power Plan. Under this interpretation, the function of the section 111(d) reference to existing sources is to specify the group of existing sources that become subject to state plans pursuant to EPA emission guidelines, but is silent on whether the later triggering of a section 111(b) standard affects the on-going applicability of the 111(d) standards to which that source is subject under the state plan.

EPA's determination on this issue is also consistent with past practice. On at least two occasions, EPA addressed the applicability of state plans to modified and reconstructed sources when it finalized revisions to NSPS and emission guidelines. In these rulemaking actions, EPA provided that new

[6] 79 Fed. Reg. at 34,903-04.
[7] *Id.* at 34,904.
[8] *Id.*
[9] 467 U.S. 837, 842–844 (1984); *See also EPA v. EME Homer City Generation, L.P.*, 134 S. Ct. 1584, 1604 (U.S. 2014) ("Under *Chevron*, we read Congress' silence as a delegation of authority to EPA to select from among reasonable options.").

sources—including modified and reconstructed sources—are simultaneously subject to both state plans adopted under section 111(d) and EPA-issued performance standards under section 111(b).[10] In both of these rules, EPA promulgated a revised NSPS at the same time that it promulgated revised emission guidelines; although sources subject to the earlier NSPS were not "new" units for the purpose of the revised NSPS, the sources continued to be "new" for the purpose of the earlier NSPS, while simultaneously being "existing" sources with respect to the revised emission standards. For example, in 2009, EPA issued a final rule amending the NSPS and emission guidelines for hazardous, medical, and infectious waste incinerators (HMIWI), which were both initially promulgated in 1997. In that rule, EPA noted that the 2009 revised emission guidelines were, for some pollutants, more stringent than the NSPS that applied to sources constructed or modified between 1997 and 2009. Accordingly, EPA amended the 1997 NSPS to require that those units comply with the more stringent of the pollutant specific limitations in either the emission guideline or the 1997 NSPS, thereby simultaneously subjecting some sources to both the revised emission guideline and the 1997 NSPS.[11] EPA adopted a similar approach in 1995, when it amended the NSPS and emission guidelines for municipal waste combustors.[12] These examples both demonstrate that "new sources" can simultaneously be subject to section 111(b) performance standards and section 111(d) state plans, as well as EPA's practice of requiring that sources comply with the most stringent of overlapping section 111(b) and 111(d) standards.

It is also worth noting that under prior standards of performance for reconstructed sources, those sources would remain existing sources (despite undertaking a modification and becoming a (b) source) if the required feasibility review demonstrated that the source could not meet the reconstructed source standard.[13] This reinforces the interlinked and complementary roles of the section 111(d) and (b) standards for reconstructed units. When undertaking a reconstruction and making major investments in infrastructure, the reconstructed source standard ensures that the most rigorous emission reduction outcomes are achieved if they are feasible—but the existing source standard applies as a backstop in cases where meeting the reconstructed standard is not feasible. In the context of the carbon pollution standards, the situation is analogous—the section 111(b) standard for reconstructed units must ensure that sources

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[10] *See, e.g.*, 74 Fed. Reg. 51,368, 51,374 (Oct. 6, 2009) (hazardous, medical, and infectious waste incinerators subject to 1997 NSPS must continue to comply with 1997 NSPS requirements that are more stringent than 2009 emission guidelines for sources existing as of 2009); 60 Fed. Reg. 65,382, 65382 (Dec. 19, 1995) (municipal waste combustors remain subject to 1991 NSPS and must also comply with 1995 emission guidelines for units existing as of 1995). Although both of these examples are in the context of joint section 129/111 rulemaking, that context does not diminish their relevance to section 111 rulemakings. Under joint 129/111 standard-setting, the effect of the section 111(a) definitions on the applicability of NSPS to modified units is the same as for rulemakings under section 111. *See Davis County Solid Waste Mgmt. v. United States EPA*, 108 F.3d 1454 (D.C. Cir. 1997) ("Although section 129 does not specifically state that the NSPS applies to modified units, it excludes modified units from the definition of existing units and provides that the NSPS shall be issued pursuant to 42 U.S.C. § 7411, which defines new sources as those sources modification or construction of which occurs after publication or proposal of regulations, whichever is earlier."); 42 U.S.C. §§ 129(a)(1), 129(g)(3); *see also* 42 U.S.C. § 7411(a)(2).
[11] *See* 74 Fed. Reg. at 51,374.
[12] *See* 60 Fed. Reg. at 65,382 ("Subpart Ea is applicable to MWC units . . . for which construction, modification, or reconstruction was commenced after December 20, 1989 . . . It should be noted that plants that are subject to subpart Ea will also be subject to the emission guidelines contained in subpart Cb, which apply to plants constructed on or before September 20, 1994."). The 1995 regulation provided that MWCs subject to the 1991 NSPS would also be subject to the new 1995 rules governing existing sources, which superseded the 1991 guidelines for existing sources. *See* 40 C.F.R. part 60, subparts Cb and Ea.
[13] 40 C.F.R. § 60.15(b).

are deploying the best technologies available as these major infrastructure investments are being made, while at the same time the continued participation in the section 111(d) program ensures that the sources remain subject to the emission reduction framework that can meet the statutory requirements of maximizing emission reductions considering cost, energy requirements, and impacts on other health and environmental outcomes. In both cases the applicability of the section 111(b) and (d) standards works to ensure that sources are subject to performance standards reflecting the best system of emission reduction that has been adequately demonstrated, maximizing emission reductions considering the other statutory factors.

As noted above, this interpretation of the ambiguity in section 111(d) is also necessary to ensure that modified and reconstructed sources continue to remain subject to standards that reflect the "best system of emission reduction," as required for all standards of performance under section 111. EPA's proposed emission guidelines for existing EGUs rest on the determination that a flexible, broad emission reduction system—including efficiency improvements at existing EGUs, shifts to low and zero-emitting resources, and demand-side energy efficiency improvements—constitute the "best system of emission reduction." That determination remains no less true for existing EGUs that subsequently modify or reconstruct. To allow existing EGUs to avoid requirements under a section 111(d) state plan by modifying or reconstructing would potentially lead to higher emissions from those EGUs – a result that is completely inconsistent with the proper identification of the "best system of emission reduction" for those sources. The existence of a standard for sources undergoing major changes reflects Congressional recognition of the fact that such changes and investments create an opening for emissions performance to be improved. Indeed, the courts have understood that the purpose of standards under section 111(b) is to ensure that the emission performance of sources is improved when major investments are being made in infrastructure.[14] Because EPA's proposed interpretation provides that modified sources will be subject to emission controls that are *additional* to the level of control already imposed under the 111(d) plan, it is consistent with the pollution-mitigating framework of section 111 recognized by courts.

Lastly, as EPA recognizes, its determination that state plans continue to apply to modified and reconstructed EGUs is necessary to avoid disrupting state plans submitted under the proposed emission guidelines. The proposed emission guidelines establish average performance standards for existing EGUs in each state, which are premised on the performance of EGUs that were "existing" as of January 8, 2014. If certain existing EGUs were to exit this system by modifying or reconstructing, states and utilities could potentially have difficulty complying with these goals. Indeed, state goals would potentially need to be recalculated or constantly adjusted as EGUs leave the "pool" of existing sources by modifying. Furthermore, the creation of a group of existing fossil-fired EGUs that are not subject to the same carbon reduction signal as EGUs governed by the state plan would potentially lead to market distortions and result in "leakage" of emissions, as generation from EGUs governed by the state plan is displaced by increased generation at modified/reconstructed units rather than low or zero-emission generation. By clarifying that sources subject to section 111(d) plan requirements must continue to comply with those

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[14] *See Sierra Club v. Costle*, 657 F.2d 298, 325 (D.C. Cir. 1981) ("[Section 111(b)] standards must to the extent practical force the installation of all the control technology that will ever be necessary on new plants at the time of construction when it is cheaper to install, thereby minimizing the need for retrofit in the future when air quality standards begin to set limits to growth.").

requirements after becoming subject to the 111(b) standard, EPA has avoided creating a perverse incentive that would undermine the effectiveness of the existing source carbon pollution standards.

In summary, section 111 is ambiguous as to whether existing sources continue to be subject to 111(d) requirements after modification or reconstruction makes that source subject to section 111(b) standards. EPA has reasonably resolved this ambiguity by concluding that state plans must continue to apply section 111(d) carbon pollution standards to those sources regardless of a later modification or reconstruction. This interpretation is consistent with the statutory text, EPA's past practice, and judicial interpretations of the framework of section 111, and is necessary to avoid perverse incentives that could undermine the regulatory scheme and weaken limits on carbon pollution.

b. EPA Should Provide that Sources that Modify Prior to 111(d) State Plan Submission Are Subject to the 111(d) State Plan Requirements.

Whereas EPA has clearly stated that sources that modify or reconstruct *after* becoming subject to a section 111(d) state plan remain subject to the state plan requirements,[15] the Agency has not made it clear that sources modifying or reconstructing *prior* to submission of a state plan are subject to section 111(d) state plan requirements. Although one part of the proposal suggests that all modifications and reconstructions are subject to section 111(d),[16] another portion of the proposal asserts that sources that modify or reconstruct after plan submission will continue to be subject to the plan.[17] EPA should expressly provide that sources modifying or reconstructing after the proposal of its emission guidelines and prior to state plan submission are still sources for which state plans must establish performance standards under section 111(d).

Sources that modify or reconstruct prior to submission of a section 111(d) plan should be subject to section 111(d) plan requirements for the same policy reasons described in the preceding section of these comments—most significantly, because the existing source "best system of emission reduction" remains the system that will ensure the greatest pollution reductions from these EGUs considering cost and other statutory factors. Further, as noted above, allowing such modified or reconstructed EGUs to exempt themselves from section 111(d) would potentially undermine the stringency of state plans by allowing "leakage" to modified or reconstructed sources. Moreover, such an approach would potentially require the recalculation of state goals and disrupt the development of state plans, all of which are premised on securing reductions from EGUs that were "existing" as of January 8, 2014.

Requiring, in the finalization of these standards, that state plans apply to all sources that were "existing" as of the date the emission guidelines were proposed is also consistent with the statutory text. As described above, section 111(d) vests EPA with broad authority to establish procedures governing the submission and content of state plans that "establish[]" performance standards for "any existing source." Also as noted above, the statute does not clearly delineate the point in time at which a source should be considered to be "existing" and therefore within the scope of a state plan. However, EPA's proposed emission guidelines set state-wide goals that are based on the "best system of emission reduction" for all

[15] *See* 79 Fed. Reg. at 34,903-04.
[16] *See* 79 Fed. Reg. at 34,965/1.
[17] *See* 79 Fed. Reg. at 34,963/1.

EGUs that were under construction or in operation as of January 8, 2014. Accordingly, it is reasonable and consistent with the statute for EPA —acting under its authority to establish minimum requirements for state plans, including determining the scope of those plans—to require that state plans establish performance standards for the same set of existing sources addressed in the emission guidelines.

c. EPA Can Consider Additional Measures to Ensure that Modifications and Reconstructions Do Not Undermine State Goals Under Section 111(d).

Although EDF strongly supports EPA's proposal that section 111(d) standards remain applicable to sources that modify or reconstruct, we note that there are at least two additional mechanisms EPA can consider to ensure that the proposed emission guidelines for existing EGUs are coordinated effectively with the proposed standards for modified and reconstructed EGUs.

1. EPA Could Undertake Frequent Review of the NSPS.

Although section 111(b) of the Clean Air Act clearly requires that carbon pollution standards for new sources be reviewed at least once every eight years,[18] EPA could establish a more frequent schedule for revision (such as once every five years) in recognition of the rapid evolution of methods to reduce carbon pollution from the power sector. A more frequent schedule for revision of the carbon pollution standards for new, modified, and reconstructed EGUs would ensure that sources that modify or reconstruct quickly come into compliance with section 111(d), consistent with EPA's past practice of subjecting modified and reconstructed sources to state plans upon revision of an applicable NSPS.[19] In so doing, EPA would also reduce potential incentives for EGUs to modify or reconstruct for the purpose of avoiding state plan requirements under section 111(d).

2. EPA Could Require that Emissions from Modified and Reconstructed Units "Count" When Determining State Compliance with Section 111(d).

Alternatively, in the event that modified or reconstructed EGUs are excluded from state plans under section 111(d), EPA could require that emissions from those units continue to be "counted" when determining whether states have complied with the goals promulgated in the emission guidelines. Such a requirement would not impose any section 111(d) obligations on the modified or reconstructed EGUs, but would ensure that limits on carbon pollution under section 111(d) are not undermined by "leakage" resulting from increased emissions at those modified or reconstructed EGUs. In practice, state regulators would have a strong incentive to ensure that modified and reconstructed units are subject to either state plans or to additional emission limitations in order to ensure compliance with the section 111(d) goals.

This approach is not precluded by the broad language of section 111(d), which affords EPA significant discretion to determine *how* states demonstrate compliance with an emission guideline. Moreover, EPA could justify this approach as necessary to ensure an accurate accounting of emissions from affected EGUs. This is because generation from any EGU that modifies or reconstructs would effectively be substituting for generation from the same EGU prior to its modification or reconstruction.

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[18] 42 U.S.C. § 7411(b)(1)(B).
[19] As described in section I.a of our comments, *supra*, this practice was reflected in the 1995 revision of the NSPS for both municipal waste combustors and the 2009 revision of the NSPS for HMIWI.

If generation and emissions from modified and reconstructed EGUs were not counted in the state's emission rate under section 111(d), emissions from existing EGUs could *appear* to decrease solely because some of those units had become modified or reconstructed sources subject to section 111(b). EPA could reasonably conclude that to protect against such "over-crediting," emissions from modified and reconstructed EGUs must be included in a state's average emission rate.

This approach would also have the effect of treating modified or reconstructed EGUs in a way that is comparable to incremental nuclear, renewable energy and energy efficiency—all of which are considered as resources that displace affected EGUs and therefore enter into the compliance determination for each state as zero-emitting resources. Further, because the emissions from the units in question were taken into account when EPA established the state goals, it would be appropriate to find that those emissions must continue to count in determining compliance with that target. In other words, because the proposed state goals reflect the emissions from those units, the state's compliance demonstration must also include the emissions from those units.

II. EPA Should Achieve Greater Emission Reductions by Adopting Significantly More Stringent Standards for Reconstructed and Modified Coal-Fired EGUs

EPA's proposed standards for reconstructed and modified coal-fired EGUs do not reflect the greatest degree of emission reduction that can be achieved at reasonable cost, and are inconsistent with the purpose of section 111, noted above, to control emissions from new facilities to the "maximum practicable degree."[20] EPA has proposed to find that the BSER for reconstructed coal-fired EGUs is a conventional, uncontrolled generation process consisting of a supercritical pulverized coal (SCPC) or circulating fluidized bed (CFB) boiler for high heat-input EGUs, and a subcritical boiler for low heat-input EGUs.[21] For modified coal-fired EGUs, EPA has proposed a standard that is based either on a source-specific energy efficiency audit or slight improvements over the best historical performance of the unit.

As our comments below demonstrate, there are readily available, cost-effective means of securing greater emission reductions from reconstructed and modified coal-fired EGUs. Specifically, we believe that the BSER for reconstructed and modified coal-fired EGUs consists of complete conversion to natural gas fuel, because this well-demonstrated BSER would achieve significantly greater emission reductions than EPA's proposed standards while satisfying the other statutory factors.

a. The BSER for reconstructed fossil fuel-fired utility boilers and IGCC units is conversion to a natural gas-fired facility to secure greater emission reductions.

As noted above, EPA has proposed to find that the BSER for reconstructed coal-fired EGUs is a conventional, uncontrolled generation process consisting of a supercritical pulverized coal (SCPC) or

[20] *See Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427, 434 n.14 (D.C. Cir. 1973) ("Congress was most concerned that new plants -- new sources of pollution -- would have to be controlled to the greatest degree practicable if the national goal of a cleaner environment was to be achieved"); *see also Sierra Club v. Costle*, 657 F.2d 298, 325-326 (D.C. Cir. 1981) (relying on the undisputed legislative purpose of "reducing emissions as much as practicable" to reject a challenge to a standard promulgated under section 111(b)).
[21] 79 Fed. Reg. at 34,813.

circulating fluidized bed (CFB) boiler for high heat-input EGUs, and a subcritical boiler for low heat-input EGUs. This standard would not provide significant emission reductions relative to converting these units to combust natural gas. EPA considered conversion to natural gas as a potential BSER, but concluded that coal-to-gas conversion is not BSER due to the allegedly high costs of the resulting emission reductions.[22] However, EPA's analysis does not appropriately characterize the costs of gas conversion or reflect full consideration of the BSER factors. Careful examination of these factors demonstrates that coal-to-gas conversion is the system that best fits the statutory criteria for BSER for reconstructed fossil fuel-fired utility boilers.

Technical feasibility. The technology to convert a coal-fired utility boiler to burn natural gas is well-demonstrated and commercially available, as EPA acknowledges.[23] Utilities have been converting coal-fired units to burn natural gas for at least a decade.[24] Industry is undertaking conversions at a wide variety of units, including very old EGUs,[25] baseload power plants,[26] and facilities that are over thirty miles from natural gas pipelines.[27] As further evidence of the technical feasibility of coal-to-gas conversion, several engineering firms have developed literature outlining economic and technical considerations for utilities that are considering such projects.[28] A recent Black & Veatch paper describes the well-understood process for converting a coal-fired unit to run entirely on natural gas.[29]

Although conversion of a boiler to operate on natural gas involves some physical modifications to the facility, such investments are reasonable as part of a BSER given that a reconstruction "generally entails fundamental decisions about what type of unit to rebuild."[30] Moreover, as described below, the

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[22] 79 Fed. Reg. at 34,982.
[23] Id. ("conversion to . . . natural gas in a utility boiler is a technically feasible option to reduce CO_2 emission rates"); GHG Abatement Measures TSD at 6-1, 6-2.
[24] *See, e.g.*, Dominion Energy, https://www.dom.com/about/stations/fossil/possum-point-power-station.jsp (Possum Point Power Station "Units 3 & 4 are fired using natural gas but were converted from coal in May of 2003. Unit 3 generates 96 MW and Unit 4 generates 220 MW.").
[25] The Blount Street power plant was first built in 1903 and converted to burn natural gas in 2010. Thomas Content, "MG&E stops burning coal in Madison plant," Milwaukee Journal Sun (March 18, 2010), available at http://www.jsonline.com/business/88508257.html.
[26] Darren Epps, "Alabama Power switching to natural gas from coal at 4 Gaston plant units," SNL (Jan. 17, 2014) (reporting Alabama Power's application to convert 4 units, each with a capacity of about 250 MW, to burn natural gas); Colorado Department of Regulatory Agencies, "Colorado's electric grid and the role of base load and "peaker" electric generating units" (classifying the 352-Mw Cherokee unit 4 as a baseload plant).
[27] Xcel Energy, Cherokee Repowering & Natural Gas Pipeline Projects, available at http://www.xcelenergycherokeepipeline.com ("The Cherokee Natural Gas Pipeline Project has been completed."); Thomas Spencer, "Alabama Power to connect Shelby plant to natural gas line," The Birmingham News, available at http://blog.al.com/businessnews/2012/05/alabama_power_to_connect_shelb.html (citing an Alabama Power spokesperson for information that the coal-to-gas conversion project at the Gaston Steam Plant will involve building a gas pipeline to tie into the Transcontinental pipeline, which runs across Alabama about 30 miles south of the plant).
[28] *See generally* Babcock & Wilcox, Natural Gas Conversions of Existing Coal-Fired Boilers (2010) ("This paper will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision."); Black & Veatch, Paper of the Year: A Case Study on Coal to Natural Gas Fuel Switch (2012) ("This paper explores several technically feasible options available on the current market" for retrofitting coal-fired units, including full conversion to natural gas).
[29] Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch.
[30] 79 Fed. Reg. at 34984.

required physical modifications are often relatively modest. Coal-to-gas conversion projects can usually be accomplished without replacing the existing boiler, and often entail only the construction of natural gas delivery infrastructure (where not already available) and modifications to ancillary equipment such as burners and ducts.[31]

We are unaware of any existing sources for which conversion to natural gas is technologically infeasible. Regardless, a standard based on the reductions achievable from coal-to-gas conversion would not apply to any such unit. Under EPA's longstanding regulations, a source is only subject to reconstructed-source standards if "[i]t is technologically and economically feasible to meet the applicable standards."[32] Therefore, the remote possibility that some unit could not comply with a standard based on conversion should not dissuade EPA from adopting rigorous standards for reconstructed fossil fuel-fired utility boilers and IGCC units.

Emission reductions. In comparison to EPA's proposed BSER, switching to natural gas fuel has very significant potential for reducing the carbon emissions from reconstructed fossil fuel-fired utility boilers and IGCC units—a critical factor in the BSER analysis. EPA's analysis of conversions for the proposed emission guidelines concluded that a reconstructed utility boiler firing 100% natural gas would have an emissions rate of 1,239 lb CO_2/MWh_{net}, representing a 41% reduction in CO_2 emissions rate from 100% coal firing.[33] Reductions of this magnitude are especially significant at reconstructed EGUs, which are, by definition, undertaking large capital investments that potentially allow the plant to operate for many years.[34]

EPA should also consider the benefits of co-pollutant emission reductions that would result from converting a reconstructed unit to burn natural gas. EPA reasonably estimated that converting to 100% natural gas would significantly reduce a utility boiler's emissions of SO_2, NO_x, and $PM_{2.5}$.[35] These pollutants' serious health impacts are well documented, and EPA reasonably estimated the value of the health benefits associated with these reductions to be between \$67/MWh_{net} and \$150/MWh_{net}—a factor of at least two times the costs associated with conversion, as noted below.[36] By promulgating an appropriately stringent standard for CO_2 emissions from reconstructed sources, EPA can greatly reduce the health burdens on the communities living near these sources.

Costs. EPA rejected coal-to-gas conversions as BSER because it found that unit conversions were "an inefficient way to generate electricity compared to use of an NGCC" and that CO_2 reductions

[31] *See* Babcock & Wilcox at 2.
[32] 40 C.F.R. § 60.15(b)(2). A unit that does not qualify as "reconstructed" because compliance with the standard for reconstructed sources is technologically infeasible will continue to be regulated as an existing source under section 111(d).
[33] EPA Office of Air and Radiation, GHG Abatement Measures at 6-6, Table 6-1 (June 2014) ("TSD").
[34] 40 CFR 60.15(b)(1) ("reconstruction" requires replacement of components with new components costing more than 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility).
[35] TSD at 6-6, Table 6-2. EPA reasonably estimated that 100% gas conversion would reduce emissions of SO_2 by 3.1 lb/MWh_{net}, reduced NO_x by 2.04 lb/MWh_{net}, and reduced $PM_{2.5}$ by .2 lb/MWh_{net}.
[36] TSD at 6-7, Table 6-3. Even given a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through natural gas conversion to be between \$61/MWh_{net} and \$140/MWh_{net}. *Id.*

from this option were "relatively expensive."[37] EPA estimated the costs of CO_2 avoided from a conversion project to be $83 per metric ton in a representative case, and as low as $75 per metric ton where fuel-switching would not require capital investment or impact on unit performance.[38] In terms of generation, EPA estimated that conversion to natural gas would increase the fuel costs of an EGU by approximately $30/MWh (three cents per kWh), increase capital costs by $5/MWh, and *reduce* fixed operating costs by 33% and variable operating costs by 25%.[39] The net costs may be higher than other options EPA has considered, but they are significantly lower than the benefits associated with criteria pollutant reductions from conversion—which as noted above, are approximately $67-150/$MWh_{net}$. Adding in the benefits of reduced carbon pollution would only increase the net benefits of conversion as a BSER. Further, the net costs of conversion to gas are certainly within the relevant limits that courts have placed on the costs of performance standards under section 111.[40] Indeed, the fact that many conversion projects have been recently completed or are currently underway shows that the costs are reasonable, and in no way approach the legal standard for a BSER. The fact that relatively few EGUs have undertaken modifications or reconstructions in the past would further limit the impact of this BSER on electricity prices or energy supply.

It was also inappropriate for EPA to reject unit conversion as too costly by comparing that system to new NGCC facilities.[41] Where, as here, an agency must make a decision based on a finite set of statutorily enumerated considerations, the agency may consider additional factors only to the extent they are relevant to the statutory factors.[42] In its proposal, EPA has failed to offer a reasonable explanation for how the cost-effectiveness of emission reductions by NGCC units is relevant to "the cost of achieving [emission] reduction" through the BSER for the sources affected by this rulemaking.[43] Here, EPA's rejection of a potential BSER based on its consideration of a different source category undermines the Congressional purposes for section 111 because it would lead to a standard that does not "reduc[e]

[37] 79 Fed. Reg. at 34982.
[38] 79 Fed. Reg. at 34982.
[39] TSD at 6-4. According to EIA's most recent estimates of generation costs, fixed O&M costs for an advanced pulverized coal EGU are approximately $31-38/kW-yr (equivalent to approximately $5/MWh) and variable O&M costs are approximately $4.50/MWh. *See* EIA, Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants at 6 (Apr. 2013).
[40] Courts have determined that costs of performance standards under section 111 must not be "exorbitant", *see Lignite Energy Council* v. *EPA,* 198 F.3d 930, 933 (D.C. Cir. 1999) ("EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.''); "greater than the industry could bear and survive", *Portland Cement Ass'n* v. *EPA,* 513 F.2d 506, 508 (D.C. Cir. 1975); or "excessive", *Sierra Club* v. *Costle,* 657 F.2d 298, 343 (D.C. Cir. 1981) ("EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.").
[41] EPA has observed that "coal-to-gas conversion of an existing boiler is less efficient than constructing a new natural gas combined cycle (NGCC) turbine in its place." That may be true in some cases. Where it is, the regulated community maintains the option of retiring the coal-fired unit and building a new NGCC facility.
[42] *See, e.g.*, *Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983) ("normally, an agency rule would be arbitrary and capricious if the agency has relied on factors which Congress has not intended it to consider")*; Bluestone Energy Design v. FERC*, 74 F.3d 1288, 1294-95 (D.C. Cir. 1996); *Sierra Club*, 657 F.2d at 346-47. If the statute does not directly address the question of whether the non-statutory factor is relevant, the agency must "explains[] the link between" the non-statutory factor and any of the statutory factors. *Bluestone Energy Design*, 74 F.3d at 1295.
[43] *See* 42 U.S.C. § 7411(a)(1) (establishing the statutory factors for determining the BSER for a particular source category).

emissions as much as practicable."[44] It would be unreasonable to impose a weak standard on existing sources undergoing a modification or reconstruction because another category of newly constructed sources is lower emitting. Moreover, EPA's consideration of NGCC in setting standards for reconstructed fossil fuel-fired utility boilers and IGCC units is inconsistent with its January 8, 2014 proposal for new EGUs.[45] There, the agency proposed a stringent standard for steam electric utility boilers and IGCC facilities without considering whether reductions could be achieved more cost-effectively by building an NGCC unit instead.[46]

Coal-to-gas conversion has emerged as a means of complying with emission standards precisely because it is sometimes the most cost-effective strategy.[47] Several coal-fired units are being converted to burn natural gas because it is the units' most economical option for complying with other emission limitations.[48] The cost of converting to natural gas fuel depends on whether the unit was originally designed to be capable of burning natural gas. The cost of fuel-switching boilers is minimal for units that are already designed to burn gas, but the cost of more extensive retrofits is still moderate (and well below the legal standard for BSER) in the context of an EGU reconstruction project.[49] Even where retrofit costs are significant, the conversion to natural gas is cost-effective and can be achieved in a manner that enables electricity consumers save money.[50]

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[44] *See id.* at 325 (listing the Congressional purposes of section 111).
[45] Cf. *Motor Vehicle Mfrs. Ass'n,* 463 U.S. at 56 ("an agency changing its course must supply a reasoned analysis") (citing *Greater Boston Television Corp.* v. *FCC*, 444 F.2d 841, 852 (1970) (footnote omitted), cert. denied, 403 U.S. 923 (1971)).
[46] *See generally* 79 Fed. Reg. at 1430.
[47] Michael Niven and Neil Powell, "Coal unit retirements, conversions continue to sweep through power sector," SNL Data Dispatch (Oct. 14, 2014).
[48] Georgia Power Company's 2013 Integrated Resource Plan and Application for Decertification of Plant Branch Units 3 and 4, Plant McManus Units 1 and 2, Plant Kraft Units 1-4, Plant Yates Units 1-5, Plant Boulevard Units 2 and 3, and Plant Bowen Unit 6 at 1-18 ("Finally, for the remaining coal-fired units that will continue to operate, the Company has concluded that it is not cost-effective to install the environmental controls necessary to enable these units to remain operational on coal. Instead, the Company has found it to be most cost- effective for customers to switch Plant Yates Units 6 and 7 and Plant Gaston Units 1–4 to natural gas as the primary fuel, with coal used as a backup fuel."); *see also id.* at 1-11 (requesting favorable amortization of "approximately $14 million of Plant Yates Units 6 and 7 environmental construction work in progress"). Conversion to natural gas is likely to be a cost-effective compliance option for any facility with limited planned service hours. Black & Veatch, A Case Study on Coal to Natural Gas Fuel Switch at 7, Table 7.
[49] Ameren Missouri, 2014 Integrated Resource Plan at 4-18:

> Ameren Missouri conducted an internal preliminary evaluation for the potential conversion of the Meramec Energy Center Units 1-4 from coal to natural gas-fired operations. Units 1&2 were designed with the capability to operate on natural gas; however, these units have not operated at full load on natural gas since 1993. Therefore, restoration of devices and equipment is needed for Units 1&2 to operate fully on natural gas. The expected cost to restore Units 1&2 to natural-gas operations is estimated to be less than $2 million. Units 3&4 are currently capable of coal-fired operations only. The expected cost to convert Units 3&4 to natural-gas operations is expected to be over $40 million.

[50] See e.g. Testimony of Alan Mihm before the Wisconsin Public Service Commission (Aug. 20, 2013) (supporting Wisconsin Electric Power Company's application to convert the Valley power plant from coal to gas, estimating that the cost of the conversion would be $62 million and "rates for electric customers will go down by .31%, for a net savings of $10.2 million in 2016").

For some units, building a pipeline is one cost associated with conversion to natural gas. EPA's cost estimates assumed that a unit converting to natural gas would need to build a 50-mile pipeline at a cost of $50 million.[51] EPA estimated pipeline construction would contribute $100/kW to the capital costs of a 500 MW unit, while capital costs as a whole represented only one-seventh of the cost impact of natural gas conversion.[52] EPA's analysis shows that building a long pipeline is generally a relatively small part of the cost of converting a reconstructed unit to burn natural gas. Consequently, units can undergo conversion at reasonable cost even when they are located at a significant distance from existing pipeline infrastructure. For most units, however, the cost of building a pipeline is likely to be less than EPA assumed. This is because the median distance of a coal-fired unit from a pipeline is 28.3 miles—just over half the length of the pipeline in EPA's calculations.[53]

As noted above, this standard would not apply to any facilities for which compliance is economically infeasible.[54] If site-specific factors render coal-to-gas conversion exorbitantly expensive (such as inordinate distance from a natural gas pipeline), a unit would not qualify as a reconstructed source.

Non-air health and environmental impacts. EPA impermissibly failed to consider the non-air quality health and environmental impacts of the systems it identified as potentially representing the BSER.[55] If EPA had performed the "mandated consideration of the factors enumerated in section 111(a),"[56] the agency would have recognized that switching to natural gas firing at reconstructed units would have far greater non-air health and environmental benefits than its proposed standard. This alternative would eliminate the unit's production of coal combustion residuals (also known as coal ash). Coal ash is an industrial waste that contains a range of toxic substances, including arsenic, selenium, and cadmium. Carcinogens and toxic chemicals from coal ash can leach into drinking water supplies and accumulate in the fish we eat.[57] EPA has proposed regulating the disposal of coal ash for the first time,[58] but even promulgation of a robust rule cannot be completely effective in protecting communities from the dangers of coal ash. Conversion to natural gas firing also reduces on-site water quality impacts.[59]

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[51] TSD at 6-4.
[52] TSD at 6-4 to 6-5. In EPA's estimation, increased fuel costs were responsible for most of the cost of natural gas conversion. *Id.*
[53] See EPA, Table 522 Cost of Building Pipelines to Coal Plants. The average length of pipeline that would need to be built to hook up a coal-fired unit is 61.6 miles. The average is greater than the median because there are a few outliers that are very far from a pipeline hookup. The most isolated coal-fired unit is 713.3 miles from a hookup.
[54] 40 C.F.R. § 60.15(b)(2).
[55] 79 Fed. Reg. at 34981-85. *Sierra Club*, 657 F.2d at 323 ("the agency must consider all of the relevant factors and demonstrate a reasonable connection between the facts on the record and the resulting policy choice").
[56] *Sierra Club*, 657 F.2d at 346, n.175.
[57] EPA, Human and Ecological Risk Assessment of Coal Combustion Wastes (draft) (April 2010). One of the study's conclusions was that managing coal ash in unlined or clay-lined waste management units results in up to 1 in 50 excess cancer risks.
[58] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities; Proposed Rule, 75 Fed. Reg. 35128 (June 21, 2010).
[59] As the Wisconsin Public Service Commission observed in approving the conversion of Valley Power Plant, "Converting the plant from coal to natural gas would eliminate some discharge sources and reduce wastewater treatment requirements. Conversion would eliminate coal pile runoff, yard runoff, ash transport water, and equipment wash wastewaters that convey coal or ash, thereby removing a potential source of mercury." Public

Energy requirements and impacts on power sector. EPA has reasonably concluded that its proposed emission standard for reconstructed fossil fuel-fired utility boilers and IGCC units will not have significant adverse impacts on nationwide electricity prices, fuel diversity, the structure of the power sector, or electricity supply because so few units are expected to undergo reconstructions and there are already strong incentives to utilize efficient generation technologies at these facilities.[60] A standard based on the reductions achievable with coal-to-gas conversion would also avoid these impacts, for the very same reasons. Moreover, it is improbable that any rigorous reconstructed-source standard would negatively affect electricity prices because the standard would not apply to units where it is not economically feasible to meet.[61]

EPA should consider the additional benefits of a standard based on coal-to-gas unit conversion. Conversion to natural gas would likely reduce the energy requirements of a reconstructed unit because natural gas units have lower parasitic loads. Unit conversion reduces electricity demand for fuel preparation (including coal transport, crushing, pulverizers).[62] The reduction in parasitic load results in an increase in net output.

Conclusion. A careful weighing of the BSER criteria—excluding any improper considerations regarding the cost of reductions in other source categories—leads to the conclusion that converting to burn natural gas is the best system for emissions reduction for reconstructed fossil fuel-fired utility boilers and IGCC units. This system will achieve far greater reductions than the one EPA has proposed selecting as BSER, and can do so at reasonable cost—well below the legal standard.[63] Moreover, a standard based on natural gas conversion will have important non-air health and environmental benefits and reduce dangerous co-pollutant emissions.

b. If EPA does not adopt conversion to gas as BSER for reconstructed coal-fired EGUs, it should at a minimum base the standard on performance of an efficient IGCC unit.

EPA also failed to consider whether an efficient IGCC unit represents the BSER for reconstructed coal-fired EGUs. Instead of fully considering the emission reductions achievable through modern IGCC technology, EPA's proposal merely states that "[t]he DOE/NETL estimates that an IGCC unit emission rate is comparable to those achieved by a supercritical coal-fired EGU."[64] If EPA had fully considered efficient IGCC technology, the agency likely would have concluded it is the most efficient coal-fired generation technology available and that this technology supports an emission standard as low as 1,600 lb CO_2/MWh_{net}.

Service Commission of Wisconsin, Final Decision, Application of Wisconsin Electric Power Company for Authority to Convert the Valley Power Plant from a Coal-Fired Cogeneration Facility to a Natural Gas-Fired Cogeneration Facility (March 17, 2014) at 19, available at http://psc.wi.gov/apps35/ERF_view/viewdoc.aspx?docid=200566.

[60] 79 Fed. Reg. at 34984.

[61] 40 C.F.R. § 60.15(b)(2).

[62] Richard Vesel, "Utilities Can Improve Power Plant Efficiency, Become Emission-compliant in Short Term" Electric Light & Power (Nov. 1, 2012), available at http://www.elp.com/articles/print/volume-90/issue-6/sections/utilities-can-improve-power-plant-efficiency-become-emission-compliant-in-short-term.html.

[63] See discussion *supra* at 12.

[64] 79 Fed. Reg at 34,985.

As explained below, IGCC better satisfies the statutory criteria for BSER than the conventional, uncontrolled SCPC system that EPA has proposed.

Technical feasibility. IGCC systems have been commercially available for years and is clearly an adequately demonstrated technology. In the January 8, 2014 proposed carbon pollution standards for new EGUs, EPA stated that "Generation technologies representing enhancements in operational efficiency (e.g., supercritical or ultra-supercritical coal-fired boilers or IGCC units) are clearly technically feasible and present little or no incremental cost compared to the types of technologies that some companies are considering for new coal- fired generation capacity."[65] Indeed, EPA's proposal for new units indicates that each of the coal-fired units EPA found to be in the advanced stages of construction and development utilize IGCC.[66] The technical literature confirms the technical feasibility of IGCC technology.[67]

EPA incorrectly suggested that IGCC technology could not achieve a lower emissions rate than an SCPC facility. Even five years ago, a new IGCC facility could achieve an emission rate of 1,745 lb CO_2/MWh_{net}—substantially lower than the 1,900 lb/MWh_{net} emission rate that EPA has proposed for large reconstructed coal-fired EGUs.[68] Today, IGCC units with Shell Global Solutions gasifiers can achieve an emission rate of 1,595 lb CO_2/MWh_{net}. IGCC configurations using General Electric Energy and ConocoPhillips gasifiers can achieve rates of 1,723 lb CO_2/MWh_{net} and 1,710 lb CO_2/MWh_{net}, respectively.[69] Accordingly, modern IGCC technology can readily achieve an emission standard between 1,600 and 1,700 lb CO_2/MWh_{net}.[70]

As noted above, a facility that cannot feasibly meet this standard is not "reconstructed." *See* 40 C.F.R. § 60.15(b)(2) (establishing technological and economic feasibility as part of the definition of "reconstruction"). If site-specific challenges make it impossible for certain units to achieve an emissions rate between 1,600 and 1,700 lb CO_2/MWh_{net}, those units would not be considered "reconstructed" sources and would be required to comply with state plans under section 111(d).

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65 79 Fed. Reg. at 1,435

66 79 Fed. Reg. at 1442 ("Progress on Southern Company's Kemper County Energy Facility, which will deploy IGCC with partial CCS, has continued, and the project is now over 75 percent complete. Additionally, two other projects, Summit Power's Texas Clean Energy Project (TCEP) and the Hydrogen Energy California Project (HECA)—both of which will deploy IGCC with CCS— continue to move forward."

67 NETL, Cost and Performance Baseline for Fossil Energy Plants Volume 1, Revision 2a (Sept. 2013) (examining the deployment of CCS with IGCC and other technology that is available today); IEA Clean Coal Centre, Recent operating experience and improvement of commercial IGCC (Aug. 2013) at 5 ("IGCC has today reached a status where experience is available from first and second generation plants, built in the 1970s/1980s and in the 1990s respectively, as commercial-scale demonstration plants for coal-based applications."); EPRI, 2012 Integrated-Gasification Combined-Cycle (IGCC) Research and Development Roadmap, Technology Development for Improved Performance and Economics: Public Version at viii (Technical Update, December 2012) ("IGCC technology has been commercially demonstrated at multiple domestic and international units over the past two decades. During that time, the industry has accumulated considerable knowledge about how to design and operate these units for maximum efficiency, improved reliability, and minimum environmental impact.").

68 NETL, Assessment of Power Plants that Meet Proposed Greenhouse Gas Emission Performance Standards (Nov. 2009) at 120, Exhibit 4-10, available at http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Coal/CA_GHG_Grol_042310.pdf.

69 NETL, Cost and Performance Baseline for Fossil Energy Plants at 5, Exhibit ES-2.

70 *Id.*

Emission reductions. Establishing a standard that is 200-500 lb CO_2/MWh_{net} lower than the one EPA has proposed can lead to significant emission reductions over the lifetime of a facility. Fossil fuel-fired utility boilers and IGCC units have lifespans of several decades. It is essential that EPA avoid policies that would allow the lock-in of high-emitting infrastructure.

Costs. A reconstructed unit can deploy IGCC technology at reasonable cost—well below the legal standard for BSER. NETL estimates the levelized cost of electricity from an IGCC unit to be about \$94 to \$103/MWh (in 2007 dollars).[71] This is slightly higher than the levelized cost of electricity from an SCPC unit, which NETL estimates to be \$75/MWh (2007\$).[72] It is also comparable to the cost of electricity a new coal-fired EGU with partial CCS, which EPA estimated at approximately \$110/MWh (2011\$) excluding revenue from sale of the captured CO_2.[73] The cost of an IGCC unit is well within the range of costs determined to be appropriate by courts reviewing section 111 performance standards.[74] Thus, cost considerations are not a barrier to selecting IGCC as BSER for these reconstructed units.

Moreover, EPA should consider how changes in the regulatory environment may affect the relative costs of IGCC and SCPC units. The NETL report was based on a study that was conducted before EPA promulgated the Mercury Air Toxics Standards (MATS) and its cost projections assumed that the performance target for new IGCC and SCPC units would be a mercury emissions rate of .02 lb/GWh.[75] This is significantly less stringent than the finalized MATS standard for these units—.003 lb/GWh.[76] The mandate to rigorously control mercury emissions may have eroded the SCPC units' cost advantage over IGCC because it has historically been far more expensive to control mercury emissions from SCPC units than from IGCC units.[77]

Non-air health and environmental impacts. Selecting an efficient IGCC facility as BSER would avoid significant impacts on water resources. IGCC facilities produce much less wastewater than SCPC facilities; a recent NETL survey of the environmental performance of IGCC units found wastewater production of 1.2-1.6 gallons per minute (gpm)/MW_{net}, as opposed to 2.0 gpm/MW_{net} at an SCPC unit.[78] In addition, IGCC facilities consume less water than SCPC facilities; the same NETL survey showed the IGCC unit's raw water consumption to be 5.3-6.0 gallons per minute (gpm)/MW_{net}, as opposed to 7.7 gpm/MW_{net} at an SCPC unit.[79]

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[71] *Id.*
[72] *Id.*
[73] 79 Fed. Reg. at 1,476 (citing DOE/NETL analyses).
[74] See discussion *supra* at 12.
[75] NETL, Cost and Performance Baseline for Fossil Energy Plants at 36. The IGCC units examined in the NETL study emitted less than half the mercury of an SCPC unit, on a lb/TBtu basis. *Id.* at 5, Exhibit ES-2.
[76] 40 C.F.R. Part 63 Table 1 to Subpart UUUUU (mercury limitations for IGCC units and Coal-fired units (not low rank virgin coal).
[77] NETL, Major Environmental Aspects of Gasification-Based Power Generation Technologies (Dec. 2002) at ES-5 ("Compared with combustion-based power plants, IGCC plants have a major advantage when it comes to mercury control. . . . Based on an eighteen-month carbon replacement cycle and 90% reduction of mercury emissions, the total cost of mercury reduction is estimated to be \$3,412 per pound of mercury removed, which is projected to be about one-tenth the cost of flue gas-based mercury control.").
[78] NETL, Cost and Performance Baseline for Fossil Energy Plants at 5, Exhibit ES-2.
[79] *Id.*

Innovation. EPA has the opportunity to spur significant innovation in IGCC technology. A recent study by EPRI identified "[s]everal key technological advances . . . that could contribute to increasing net plant efficiency [at an IGCC facility with CCS] by more than 11 percentage points while cutting the cost of electricity in half."[80] Several of these innovations could improve efficiency and reduce costs at an IGCC facility that does not utilize CCS. For instance, advanced gas turbines with a firing temperature of 2900°F are predicted to increase efficiency by 5.5% and reduce the cost of electricity by 21% (measured in cost/MWhr).[81] EPRI predicts that the capital costs of IGCC "should come down as the technology matures and more units are constructed, but it is the next generation of technologies discussed in this roadmap that will have the most significant impact on the competitiveness of IGCC" relative to other coal power technologies."[82]

Relying on IGCC technology is also consonant with deploying CCS technology.[83] With currently available technology, CCS is generally more economical at an IGCC facility than at an SCPC facility.[84] Each of the three coal-fired EGUs that are at an advanced stage of construction and development are utilizing CCS and IGCC technology together,[85] taking advantage of opportunities for efficient deployment of CCS.

Energy requirements and impacts on power sector. The net plant efficiency (measured on an HHV basis) is comparable at IGCC and SCPC facilities.[86] Accordingly, basing BSER on the reductions achievable with efficient IGCC technology would not impose more burdensome energy requirements than an SCPC-based standard. In addition, selecting efficient IGCC technology as BSER would not have a significant impact on nationwide electricity prices, fuel diversity, the structure of the power sector, or electricity supply. EPA reasonably concluded that the proposed rule would not have significant impacts on these issues because few units are expected to undergo reconstructions and there are already strong incentives to utilize efficient generation technologies at these facilities,[87] and the same analysis would apply to a standard based on IGCC.

Conclusion. As the evidence described here demonstrates, IGCC technology is currently available. IGCC technology is a more appropriate BSER than SCPC or CFB because it supports standards that are significantly more protective of human health and the environment than EPA's

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[80] EPRI at vii.
[81] *Id.*; Canadian Clean Coal Coalition, Advanced IGCC Final Phase III Report, at A23 (June 2011), available at http://www.canadiancleanpowercoalition.com/files/3213/2621/7548/Appendix%20A.pdf. The potential to make supercritical steam at an advanced gas turbine provides additional opportunities to improve efficiency. "As gas turbines evolve in frame size and firing temperature, the exhaust temperatures from these machines go up, providing sufficient conditions to produce supercritical steam. While it is currently not possible to make supercritical steam in a conventional heat recovery steam generator (HRSG) due to thermodynamic and materials limitations, it is expected to be possible in the future should the materials issues be resolved." Canadian Clean Coal Coalition at A23.
[82] EPRI at viii.
[83] See 79 Fed. Reg at 1468-69.
[84] Global CCS Institute, Economic Assessment of Carbon Capture and Storage Technologies (2011 update) at Figure 4-2; *see also* IEA Clean Coal Centre at 5 (describing IGCC as a "capture ready" technology for CO_2 abatement).
[85] 79 Fed. Reg. at 1442.
[86] NETL, Cost and Performance Baseline for Fossil Energy Plants at 5, Exhibit ES-2.
[87] 79 Fed. Reg. at 34984.

proposed standards. Moreover, emission standards for reconstructed units based on efficient IGCC technology would catalyze important innovations, promote the protection of other environmental resources, and could be achieved at reasonable cost—well below the legal cost threshold for BSER. Consequently, it was unreasonable for EPA to fail to consider efficient IGCC technology as the basis for BSER for reconstructed fossil fuel-fired utility boilers and IGCC units. It is likely that if EPA had fully considered IGCC, the agency would have reasonably concluded that an efficient IGCC system is BSER for these reconstructed sources.

c. The BSER for modified fossil fuel-fired utility boilers and IGCC units is conversion to a natural gas-fired facility to secure greater emission reductions.

As noted above, for modified coal-fired EGUs, EPA has proposed a standard that is based either on a source-specific energy efficiency audit or slight improvements over the best historical performance of the unit. This standard would not secure significant emission reductions, and the alternative approach described here, requiring conversion to natural gas, would better fulfill the Clean Air Act's requirement that performance standards reflect the "best" system of emission reduction—securing the greatest possible emission reductions considering the other statutory factors. Conversion to natural gas is the BSER for modified coal-fired EGUs because this system would result in lower emissions of carbon pollution and other harmful pollutants at costs that are well within the legal standard.[88] In the present proposal, EPA concludes that conversion to natural gas is not the BSER for modified coal units because "it is an inefficient way to generate electricity compared to use of an NGCC and the resultant CO_2 reductions are relatively expensive."[89] Regardless of whether conversion is a more expensive option than replacement with a new NGCC, conversion would result in greater reductions of carbon than the proposed system and could be implemented at costs that would not exceed the legal standard.[90] Although EPA has discretion to weigh cost as factor, that discretion must be exercised in accordance with ensuring that emissions are controlled to the "maximum practicable degree."[91] Furthermore, EPA's proposal fails to consider, much less give weight to, the potential health benefits that would result from the greater reduction of co-pollutants that would be achieved by conversion to gas.

Technical feasibility. As discussed in detail in the section on reconstructed fossil-fired EGUs above, conversion to gas is a well-established technology that has been demonstrated at a variety of coal-fired EGUs over the last decade. As EPA acknowledges, most coal-fired EGU boilers can be modified to switch to 100% gas input, and this modification can be accomplished through changes to the existing boiler.[92]

Cost. The cost of conversion to natural gas is reasonable, as discussed above—adding approximately 3.5 cents per kilowatt-hour to the cost of generating electricity, even conservatively assuming the construction of more extensive gas delivery infrastructure that many EGUs will actually

[88] See discussion *supra* at 12.
[89] 79 Fed. Reg. at 34,985 (referring to rationale provided for reconstructed units); 79 Fed. Reg. 34,982 (col.2-3) (rationale for rejecting conversion to gas as BSER for reconstructed units).
[90] *Portland Cement Association v. Train*, 513 F.2d 506, 508 (D.C. Cir. 1975).
[91] *See Sierra Club v. Costle*, 657 F.2d 298, 326 (D.C. Cir. 1981); s*ee also Essex Chem. Corp. v. Ruckelshaus*, 486 F.2d 427 (D.C. Cir. 1973).
[92] GHG Abatement Measures TSD, available in Docket EPA-HQ-OAR-2013-0602, at 6-1, 6-2.

require. Many utilities have shown that they find such costs reasonable—even separate from the need to secure carbon pollution reductions—as shown by recent gas conversion projects. Furthermore, these costs are clearly outweighed by the health benefits associated with lower emissions of sulfur dioxide, nitrogen oxides, and particulate matter. Thus, the cost of gas conversion is well below the legal standard.[93]

As we explained above, it is also unreasonable for EPA to reject gas conversion as a BSER because the CO_2 reductions resulting from conversion are expensive relative to replacement with a new NGCC.[94] The relevant statutory question is whether the cost of conversion is within the appropriate range—not whether the system in question is more expensive than another system that EPA *is not even considering* as an alternative. NGCC replacement is not an alternative BSER that EPA has considered for modified coal-fired EGUs; unlike conversion, which can be achieved by modifications to the EGU's existing boiler,[95] NGCC replacement requires retirement of the existing EGU and construction of an entirely new EGU.

Even if the comparison to NGCC were appropriate, EPA's assessment of costs for modified coal-fired EGUs should take into consideration that modifications may be intended to achieve short-term extensions of the service life of the EGU. In the proposed rule, EPA appears to be comparing the costs for conversion and NGCC replacement that are associated with a projected service life of 30 years.[96] But when considered with respect to a 10-year service life, the gap between the cost per ton of CO_2 removal for conversion and NGCC narrows considerably. [97] This shorter service life comparison is arguably more appropriate for modifications.

Finally, the actual cost of conversion is likely to be lower than EPA's estimates because, for most units, the cost of building a pipeline is likely to be less than EPA assumed. The median distance of a coal-fired unit from a pipeline is 28.3 miles—just over half the length of the pipeline in EPA's calculations.[98]

Emission Reductions. As discussed above, the overriding purpose of section 111 is to ensure that pollution is reduced to the maximum extent practicable, giving adequate consideration to other costs and factors. EPA's analysis indicates that conversion to natural gas will typically reduce the emission rate of carbon pollution from a utility boiler by 41%, to a level of approximately 1,239 lb CO_2/MWh_{net}.[99] In contrast, the BSER EPA has proposed will reduce emissions to no less than 1,900 lbs CO_2/ MWh_{net} for

[93] See discussion *supra* at 12.
[94] *See* 79 Fed. Reg. 34982 (col.2); GHG Abatement Measures TSD at 6-9.
[95] *See* GHG Abatement Measures TSD at 6-2.
[96] *See* GHG Abatement Measures TSD at 6-4–6-9.
[97] *See* Reinhart, Brian et al. (Black & Veatch), A Case Study on Coal to Natural Gas Fuel Switch, Power-Gen International, December 2012, Figure 2. Whereas, with respect to a 30-yr service life, the levelized cost of electricity from a NGCC is less expensive than from a converted EGU, with respect to a 10-yr service life, the levelized cost of electricity from a converted EGU is generally lower than from a NGCC replacement.
[98] See EPA, Table 522 Cost of Building Pipelines to Coal Plants. The average length of pipeline that would need to be built to hook up a coal-fired unit is 61.6 miles. The average is greater than the median because there are a few outliers that are very far from a pipeline hookup. The most isolated coal-fired unit is 713.3 miles from a hookup.
[99] GHG Abatement Measures Technical Support Document, available in Docket EPA-HQ-OAR-2013-0602, at 6-6.

high heat input sources and 2,100 lbs CO_2/ MWh_{net} for other sources.[100] EPA's analysis demonstrates that a standard based on conversion would achieve considerable additional carbon reductions at each EGU.

In addition, EPA should also consider the benefits of co-pollutant emission reductions that would result from converting a modified unit to burn natural gas. EPA reasonably estimated that converting to 100% natural gas would significantly reduce a unit's emissions of SO_2, NO_x, and $PM_{2.5}$.[101] The health benefits associated with these reductions are between \$67/MWh_{net} and \$150/MWh_{net},[102] greatly exceeding the costs associated with conversion.

Non-air health and environmental impacts. Conversion to natural gas firing at modified units would also have far greater non-air health and environmental benefits than EPA's proposed standard, as described above.[103] These benefits include reduced generation of coal ash and reduced water consumption.

Energy requirements and impacts on power sector. EPA has reasonably concluded that its proposed emission standard for modified fossil fuel-fired utility boilers and IGCC units will not have significant adverse impacts on nationwide electricity prices, fuel diversity, the structure of the power sector, or electricity supply because so few units are expected to undergo modifications and there are already strong incentives to utilize efficient generation technologies at these facilities.[104] A standard based on the reductions achievable with coal-to-gas conversion would also avoid these impacts, for the very same reasons. EPA should also consider that conversion to natural gas will reduce parasitic loads associated with fuel preparation at conventional coal-fired EGUs, as described above.[105]

Conclusion. A careful weighing of the BSER criteria supports conclusion that converting to natural gas meets the statutory requirements for the best system of emission reduction for modified coal-fired EGUs, for many of the same reasons supporting gas conversion as the BSER for reconstructed coal-fired EGUs—and primarily because it would secure greater emission reductions.

III. EPA Should Adopt More Stringent Standards for Reconstructed and Modified Natural Gas Combustion Turbines

EPA has proposed to determine that NGCC technology is the "best system of emission reduction" for natural gas combustion turbines, for the same reasons EPA presented in the preamble to the proposed carbon pollution standards for new EGUs. As EPA observes in the preamble, NGCC is an efficient

[100] 79 Fed. Reg. at 34962, 34987.

[101] TSD at 6-6, Table 6-2. EPA reasonably estimated that 100% gas conversion would reduce emissions of SO_2 by 3.1 lb/MWh_{net}, reduced NO_x by 2.04 lb/MWh_{net}, and reduced $PM_{2.5}$ by 0.2 lb/MWh_{net}.

[102] TSD at 6-7, Table 6-3. Even given a steep 7% discount rate, EPA estimated the health benefits of reducing co-pollutants through natural gas conversion to be between \$61/MWh_{net} and \$140/MWh_{net}. *Id.*

[103] Indeed, EPA has not identified *any* non-air environmental benefits of its proposed standard for reconstructed fossil fuel-fired utility boilers and IGCC units.

[104] 79 Fed. Reg. at 34987.

[105] Richard Vesel, "Utilities Can Improve Power Plant Efficiency, Become Emission-compliant in Short Term" Electric Light & Power (Nov. 1, 2012), available at http://www.elp.com/articles/print/volume-90/issue-6/sections/utilities-can-improve-power-plant-efficiency-become-emission-compliant-in-short-term.html.

generating technology that is highly cost-effective and in widespread use.[106] Accordingly, we agree that it is appropriate to base performance standards for modified and reconstructed natural gas combustion turbines on the performance of NGCC technology.

However, we do not believe that a performance standard based on NGCC *alone* reflects the BSER for modified and reconstructed natural gas combustion turbines, as section 111 requires. Rather, the BSER for these sources consists of NGCC *in addition* to the requirements of an applicable section 111(d) state plan. As discussed in section I of these comments, EPA's proposed goals under section 111(d) reflect four "building blocks" that are based on well-established means for reducing carbon pollution from the power sector as a whole. We strongly support EPA's determination in the proposed emission guidelines that this system-based approach constitutes the BSER for all EGUs that were existing sources as of January 8, 2014, including existing natural gas combustion turbines.[107] This system-based approach is equally effective and efficient in reducing emissions from existing EGUs that subsequently undertake modifications and reconstructions—and better fulfills the statutory criteria for BSER than any of the proposed alternatives. Indeed, *failing* to apply this system-based BSER to natural gas combustion turbines that modify or reconstruct would potentially lead to increased emissions if those EGUs do not also remain subject to section 111(d) state plans—a perverse outcome that is inconsistent with the structure and purpose of section 111, as discussed in section I above. Accordingly, EPA should explicitly provide in the final rule that compliance with an applicable section 111(d) state plan, together with an NGCC-based emission limitation, represents the BSER for modified and reconstructed natural gas combustion turbines.

Further, we also urge EPA to ensure that the final standards of performance for these sources reflect the *best* emissions performance demonstrated by NGCC facilities. In comments filed jointly with other environmental organizations on the proposed carbon pollution standards for new EGUs, we demonstrated that the proposed performance standards of 1,000 lb/MWh (for units with heat input greater than 850 mmBTU/hr) and 1,100 lb/MWh (for units with heat input less than 850 mmBTU/hr) can be easily achieved by almost all NGCC facilities currently in operation. More stringent standards can be cost-effectively achieved by currently available NGCC technologies, and would have substantially lower emissions. Consistent with our comments in Docket ID No. EPA-HQ-OAR-2013-0495, we recommend that EPA recognize three subcategories of NGCC facilities—baseload units, intermediate units, and peaking units—and establish separate performance standards for each:

- Peaking units (defined as affected EGUs that operate less than 1200 hours per year) would be subject to a net output-based emission limit of 1,100 lb CO_2/MWh.
- Intermediate/load-following units (defined as EGUs that operate between 1,200 and 4,000 hours annually) would be subject to a net output-based emission limit of 875 lb CO_2/MWh.
- Baseload units (defined as EGUs that operate over 4,000 hours annually) would be subject to a net output-based emission limit of 825 lb CO_2/MWh.

[106] 79 Fed. Reg. at 34,989.
[107] We do not take a position here as to whether EPA should adopt one of the alternative characterizations of the BSER that are presented in the proposed emission guidelines, but intend to file comments on this issue in Docket ID No. EPA-HQ-OAR-2013-0602.

These recommended standards are based on the reported performance of NGCC units in each of these subcategories, as described more fully in our comments on the proposed carbon pollution standards for new EGUs.[108] In addition, these recommendations are contained in joint comments filed by EDF and other environmental organizations in the docket for the current rulemaking.

IV. EPA Should Encourage Adoption of the Most Efficient Generating Technologies by Requiring a Rigorous Initial Performance Test for All Sources Subject to Carbon Pollution Standards Under Section 111.

Lastly, EDF is concerned that EPA's proposed standards do not include an initial performance demonstration to ensure that modified and reconstructed EGUs utilize the most efficient and least-polluting generating technologies available. Instead, the proposed standards require only that these EGUs meet the applicable average emission standard after the first 12-month compliance period has ended.[109] For natural gas combustion turbines, these average standards do not even reflect the performance of the most efficient NGCC facilities currently being operated, let alone the best performance of a NGCC facility operating under optimal conditions.

In order to ensure that modified and reconstructed EGUs incorporate the most efficient generating technologies available, it is essential that EPA augment the average annual performance standards with an initial performance test—consistent with our comments on EPA's proposed standards for new EGUs.[110] This is precisely the approach that state permitting authorities and EPA have undertaken in recent PSD permits for NGCC facilities, which require that the permitted facilities meet a stringent initial CO_2 performance standard within 180 days after startup (as currently required for other pollutants in the General Provisions of the NSPS, at 40 C.F.R. § 60.8(e)).[111] Because the purpose of these initial performance tests is to ensure that the facilities are utilizing the lowest-emitting equipment and processes available and therefore perform as efficiently as possible under ideal operating conditions, the tests are conducted while the facility is operating at 90 to 100% of rated capacity and are normalized for temperature, pressure, and other variables. There are circumstances, such as in the case of "peaking" power plants, where normal operation results in variable and on average higher emission rates than the plant can achieve under optimal operating conditions. A continuously applying emission standard for such units would be set at a level that reflected this variability.[112] The incorporation of an initial

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[108] Comments of Joint Environmental Commenters, EPA-HQ-OAR-2013-0495-9514, at 95-101.

[109] Memorandum, Office of Air Quality Planning Standards, "Amended Regulatory Text (Broad Applicability" (June 2014) (proposed 40 CFR §§ 60.46Da(e), 60.4333(c)).

[110] Comments of Joint Environmental Commenters, EPA-HQ-OAR-2013-0495-9514, at 118-20.

[111] *See* EPA, Prevention of Significant Deterioration Permit for Pioneer Valley Energy Center, Final PSD Permit Number 052-042-MA15 (Apr. 2012) (Requiring that new 431 MW NGCC facility meet a CO_2 emission standard of 825 lb/MWh_{net} while operating at 90% capacity as part of an initial performance test to be completed no later than 180 days after startup; the purpose of the initial performance test was "to ensure the owner/operator has designed and installed an energy efficient [combined cycle turbine]." Following the initial performance test, the permitted facility was required to meet an annual average CO_2 emission standard of 895 lb/MWh_{net}); *see also* Commonwealth of Massachusetts Department of Environmental Protection, Prevention of Significant Deterioration Permit Application No. NE-12-022 (Jan. 2014) (Requiring 692 MW NGCC facility to meet similar initial and annual emission standards).

[112] Analysis of 2012 emission and performance data from EPA's Clean Air Markets Division for all CCGT and CT natural gas-fired EGUs in the U.S. fleet demonstrates that new peaking units (both combined cycle and simple cycle

performance test, however, that reflects the emission rate achievable using the best system of emission reduction when a plant is operating at optimal conditions ensures that facilities are built, reconstructed, or modified using the lowest-emitting technologies and operating systems available, fulfilling the technology-forcing and pollution-minimizing purposes of Section 111.[113] As such they are an essential component of the carbon pollution standards for newly constructed, modified, and reconstructed units, ensuring that the standards fulfill the Section 111 statutory requirements and case law.

Requiring an initial performance test is not only reasonable for modified or reconstructed EGUs, it is also fully consistent with similar requirements for other pollutants regulated under the NSPS. For example, Subpart KKKK currently requires that natural gas combustion turbines complete initial performance tests no later than 180 days after startup to demonstrate compliance with emission standards for nitrogen oxides and sulfur dioxide.[114] EGUs covered by Subpart Da are similarly required to complete initial performance tests within 180 days of startup for particulate matter, sulfur dioxide, and nitrogen oxides.[115] EPA has not explained why it has departed from this time-tested requirement in the proposed standards, especially when PSD permits for have shown that initial performance tests are both feasible and desirable to ensure that NGCC facilities (and potentially other EGUs) incorporate the most efficient available generating technologies.

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turbines) should be required to meet a standard of $<$ 1200 hours per year = 1,100 lb CO_2/MWh. Comments of Joint Environmental Commenters, EPA-HQ-OAR-2013-0495-9514, at 95-98.

[113] *See Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981) ("Recognizing that the Clean Air Act is a technology-forcing statute, we believe EPA does have authority to hold the industry to a standard of improved design and operational advances" when setting standards under section 111); *Portland Cement Ass'n v. Ruckelshaus*, 486 F.2d 375, 391 (D.C. Cir. 1973) ("[s]ection 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present"); *id.* (holding that EPA may make a reasonable "projection based on existing technology" when selecting the best system of emission reduction); S. Rep. No. 91-1196, at 16 (1970) (new source performance standards should reflect "the degree of emission control that has been or can be achieved through the application [of] technology which is available or normally can be made available. This does not mean that the technology must be in actual, routine use somewhere."); *id.* at 17 ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources . . . ."); *see also* H.R. Rep. No. 95-294, at 186 (1977) (noting that one of the purposes of new source performance standards is to create an incentive for technological innovation by providing a "guaranteed market" for new control technology). The Congressional Research Service, in documenting the technology-forcing function that section 111 has played in the past, notes that the flexibility inherent in the Administrator's authority to determine which technologies have been adequately demonstrated "has been used to authorize control regimes that extended beyond the merely commercially available to those technologies that have only been demonstrated, and thus are considered by many to have been 'technology-forcing.'" Larry Parker & James E. McCarthy, Cong. Res. Serv., R40585, Climate Change: Potential Regulation of Stationary Greenhouse Gas Sources Under the Clean Air Act 12 (2009).

[114] *See* 40 C.F.R. §§ 60.4400, 60.4415.

[115] *See* 40 C.F.R. §§ 60.42Da, 60.43Da, 60.44Da.

V. Conclusion.

We appreciate the opportunity to provide comments on this important rulemaking. Please direct any inquiries regarding these comments to Megan Ceronsky, Director of Regulatory Policy and Senior Attorney at EDF.

Respectfully submitted,

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To: liz.perera@sierraclub.org[liz.perera@sierraclub.org]
From: Hoffman, Howard
Sent: Mon 7/21/2014 10:00:06 PM
Subject: Hi, Liz
ShiraRascoe-resume-july2014.pdf

Hi, Liz –

I'm in EPA's Office of General Counsel. We met this past Thursday when you and your folks came to EPA to discuss the 111(d) rule. (I was sitting across the table and to your right. ☺)

If you have some time -- and it's certainly understandable if you don't -- I wonder if I could trouble you to talk to Ex. 6 - Personal Privacy a very talented recent college grad who seems quite committed to environmentalism and would like to try to find a job in D.C. in government or an NGO. She's Ex. 6 - Personal Privacy Ex. 6 - Personal Privacy If you have any time to give her any pointers on a job search, that would be great. Her resume is attached.

Much appreciate anything you might be able to do.

Howard

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