UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

	)	
Carbon Pollution Emission Guidelines	)	**Docket No. EPA-HQ-OAR-2013-0602**
for Existing Stationary Sources:	)	
Electric Utility Generating Units	)	*Via regulations.gov*
	)	*December 1, 2014*
	)	

Thank you for accepting these comments on EPA's proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34830 (June 2, 2014).

We submit these comments on behalf of the Natural Resources Defense Council (NRDC). NRDC is a national nonprofit environmental organization representing 1.4 million members and online activists. NRDC uses law, science, and the support of its members to ensure a safe and healthy environment for all living things. One of NRDC's top priorities is to reduce emissions of the air pollutants that are causing climate change.

EXECUTIVE SUMMARY

NRDC strongly supports the U.S. Environmental Protection Agency's (EPA) proposed Clean Power Plan, which will establish landmark carbon pollution standards for existing fossil-fuel power plants. The Clean Power Plan is an essential step toward ending unlimited carbon pollution into our atmosphere from the largest source in the United States – existing power plants. It sets the first-ever national limits on how much carbon pollution the country's existing power plants can release, and is a groundbreaking step toward combating climate change before it's too late to avoid the worst impacts. The Clean Power Plan is flexible and affordable. NRDC's analysis shows that once updated cost and performance data for energy efficiency and renewable energy are factored in, the Clean Power Plan emission reduction targets proposed in June 2014 can be met at a net savings to Americans of $1.8 billion in 2020 and $6.6 billion in 2030.

EPA can and should strengthen the Clean Power Plan's targets, most importantly by more fully recognizing the vast potential for scaling up energy efficiency and renewable energy throughout the United States. NRDC has presented a number of ways to improve and strengthen the CPP and with just three of these major recommendations: 1) updated baseline and cost and performance data, 2) implementation of the noticed formula change to properly account for energy efficiency and renewables, and 3) adoption of a minimum transition from older steam generation to new natural gas combined cycle units, we find that EPA can significantly strengthen the proposal at reasonable cost. Emissions reductions of 36% below 2005 by 2020 and 44% by 2030 can be accomplished at a cost of $6.5 Billion in 2020 and $10.5 Billion in 2030 with net benefits estimated to be up to $70 Billion and $108 Billion respectively. These projections, along with results of other scenarios we analyzed, are illustrated in Figures ES-1 and ES-2 below. We urge EPA to strengthen and finalize the Clean Power Plan on schedule by June 1, 2015.

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.

In November 2014, the world's leading scientists released their gravest warning yet about the threat of climate change, saying we will face "severe, pervasive and irreversible impacts" unless we act now. This report from the United Nations Intergovernmental Panel on Climate Change confirms that climate change is already contributing to intense drought, flooding, and heat waves. And it says we will see widespread impacts worldwide including food shortages and armed conflict if the human community fails to reduce dangerous carbon pollution.

Here at home, 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 sulfur dioxide, nitrogen oxides, particulates, and mercury, beyond the reductions to be delivered by other standards. Reducing these co-pollutants will reduce asthma attacks, heart attacks, hospital admissions, missed school and work days, and premature deaths.

For more than 40 years the Clean Air Act has been used successfully to reduce emissions of sulfur, nitrogen, and mercury, with benefits for Americans' health that far exceed the costs. Yet there are currently no national limits on the amount of carbon dioxide that power plants can pump into the air. The Clean Power Plan answers this need.

The Clean Power Plan's "Best System of Emission Reductions"

The Clean Air Act requires EPA to set standards of performance at the level that reflects the emissions reductions achievable by the "best system of emission reduction" that has been "adequately demonstrated" considering cost, energy requirements, and other health and environmental outcomes. The Clean Power Plan's proposed "best system of emission reduction" sets targets for each state's fossil fuel 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.

NRDC strongly supports this approach, which fully comports with the Clean Air Act. EPA's proposed best emission reductions system in the Clean Power Plan is certainly "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. NRDC agrees 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.

EPA's System of Emissions Reductions Can Achieve Even Greater Emission Reductions Than Reflected In EPA's Analysis

The emissions reductions Building Blocks proposed by EPA in the Clean Power Plan include:

1) Making existing coal plants more efficient;
2) Using existing natural gas plants more effectively;
3) Increasing renewable and non-fossil fuel generation; and
4) Increasing end-use energy efficiency

These four Building Blocks are appropriate and legally supported. However, in the proposed Clean Power Plan, EPA significantly underestimates the carbon pollution reductions that can be achieved at reasonable costs. NRDC's analysis of the emission reduction opportunities in the blocks identified by EPA demonstrates that even greater savings are available at reasonable cost, if not savings, from each of the four blocks. EPA should correct its analysis to reflect these greater opportunities in the states' targets. EPA must also fix the formula for calculating state targets to properly account for greater reductions from renewable energy and energy efficiency than the proposed Clean Power Plan assumes.

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 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. In setting state targets, EPA should employ a formula that fully reflects the potential for zero-emitting resources and demand-side efficiency to reduce emissions from fossil generating units (as they have done with natural gas in Block 2). This will be achieved by basing targets on the use of available Block 3 and Block 4 resources to displace the highest-emitting fossil units (generally coal-fired power plants) first. This approach will achieve the greatest emission reductions from the available resources and thus comports with the Act's mandate to base standards on the best system of emission reduction.

Building Blocks 1 & 2 – Making Existing Power Plants More Efficient

EPA's analysis appropriately considered the potential for efficiency improvements at power plants – the opportunity to produce greater amounts of electricity using less fuel, thus reducing pollution emissions. 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.

EPA has also requested comment on whether it should consider the potential to shift electricity production from coal plants to existing natural gas combined cycle power plants, and the potential to co-fire existing coal plants with natural gas or convert them to natural gas. We believe that scaling up energy efficiency and renewable energy is the best and least-cost compliance pathway, and we will urge states to create state plans that rely, to the maximum extent possible, on energy efficiency and renewable energy. But it is also important that EPA set carbon pollution reduction targets that reflect the emission reduction opportunities presented by coal conversion options. These stronger reduction targets are amply justified under the Clean Air Act. Already all of the coal conversion pathways are being deployed across the country even without carbon pollution standards —and as such they are clearly adequately demonstrated, and reasonable in cost.

Securing the full benefit of the Clean Power Plan also requires effective measures to curb the high levels of methane leakage and venting upstream of gas-using power plants. Given the recent increases in the use and extraction of natural gas, it is imperative that EPA directly regulate emissions of methane, a potent climate pollutant, from the natural gas sector under section 111(b) and (d) of 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 setting standards limiting emissions of methane from new and existing sources in this sector.

Building Block 3 – Increasing renewable and non-fossil fuel generation

EPA appropriately included in the best system of emission reduction the potential to reduce emissions from fossil fuel 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 using out-of-date data that fails to reflect dramatic cost reductions in renewable energy sources such as solar and wind 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 lower than EPA assumed in its analysis. We urge EPA to use current data 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.

Building Block 4 – Increasing End-Use Energy Efficiency

EPA's Clear Power Plan also properly included in the best system of emission reduction the potential to use improved demand-side energy efficiency to drive reductions in carbon pollution. Energy efficiency measures 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.

Based on its analysis, EPA determined that energy efficiency can supplant 1.5 percent of retail electricity sales. This is an underestimation of energy efficiency's potential, which excludes a number of important additional opportunities for energy efficiency such as building codes, transmission and distribution, voltage optimization, and combined heat and power. EPA should include all available energy efficiency opportunities in its analysis. Energy efficiency can achieve savings equal to 2 percent of retails sales per year. 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 ramp up energy efficiency programs 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 many states. EPA should use a faster ramp up rate, allowing for greater overall emission reductions from energy efficiency.

NRDC notes in particular that energy savings from affordable multi-family housing programs should be credited in state compliance plans. More than 20 million American households, almost 18% of the nation's total, live in apartments and condominium communities. Energy efficiency is a key resource for maintaining and improving quality of life for residents and owners of affordable housing. The affordable multi-family sector is also a critical untapped resource for achieving widespread energy demand reductions, and thus emissions reductions, in the residential sector.

In addition to the potential energy savings, improving the energy efficiency of multifamily housing also improves the stability of vulnerable households. Most multifamily households are renters, whose average annual income is just over half that of homeowners. This means that nationally, the burden of the untapped savings in the older and less energy-efficient multifamily housing stock is being borne by the families with the fewest resources. As a result, renters typically pay a higher percentage of their income for energy. This lowers their discretionary income and makes them much more vulnerable to fluctuations in energy prices. Thus, efficiency gains from multifamily retrofits have the concurrent benefit of relieving low- and middle-income families of some of their financial strain and uncertainty.

Unfortunately, only a fraction of the potential energy savings in the multifamily sector has been realized despite the economies of scale not available in single-family homes. By investing more resources into the multi-family sector, states can scale up energy efficiency programs much more rapidly than previously imagined, enabling real energy savings quickly.

A Strengthened Clean Power Plan is Cost Effective

NRDC's technical comments focus on how EPA can strengthen the Clean Power Plan and make even deeper cuts to dangerous carbon pollution. Through our analyses of several different policy scenarios, and associated sensitivity analyses, we demonstrate that there is ample room to strengthen the CPP and achieve even deeper emissions reductions at reasonable compliance costs, and that the benefits consistently outweigh the costs. It is important to note that we examined a few illustrative policy scenarios which do not reflect our full set of recommendations for strengthening the Clean Power Plan, and that there are some additional pieces of analysis still under development (we will submit additional material to the docket in the coming weeks).

First, we examined compliance with EPA's state targets, and then performed the same analysis with updated cost and performance data for renewables and efficiency. Further detail on this subject may be found in NRDC's November 2014 issue brief, titled, "The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030," available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf.

NRDC analyzed potential strengthening of state targets based primarily on the ideas put forth in EPA's October 28, 2014 Notice of Data Availability (NODA). We evaluated compliance for the resulting set of state targets under both approaches described in the NODA. These model runs are described below as "NODA Dirtiest First" and "NODA Pro Rata" cases. Under both "NODA Dirtiest First" and "NODA Pro Rata" target-setting approaches, we also analyzed a second list of state targets that accounts for a minimum generation conversion from higher-emitting sources to lower-emitting sources. These are referred to as "NODA Dirtiest First + Conversion" and "NODA Pro Rata + Conversion." Summary results from these policy runs are shown below.

Figure ES-1. Historical and Projected Electricity Sector CO2 Emissions

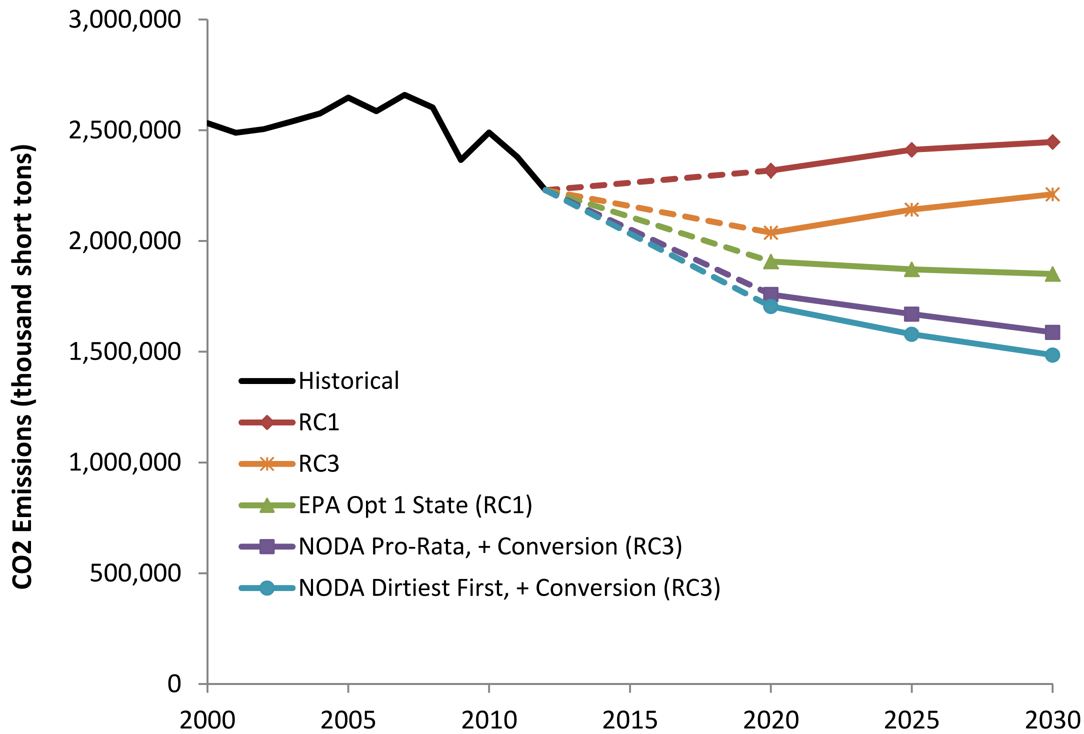
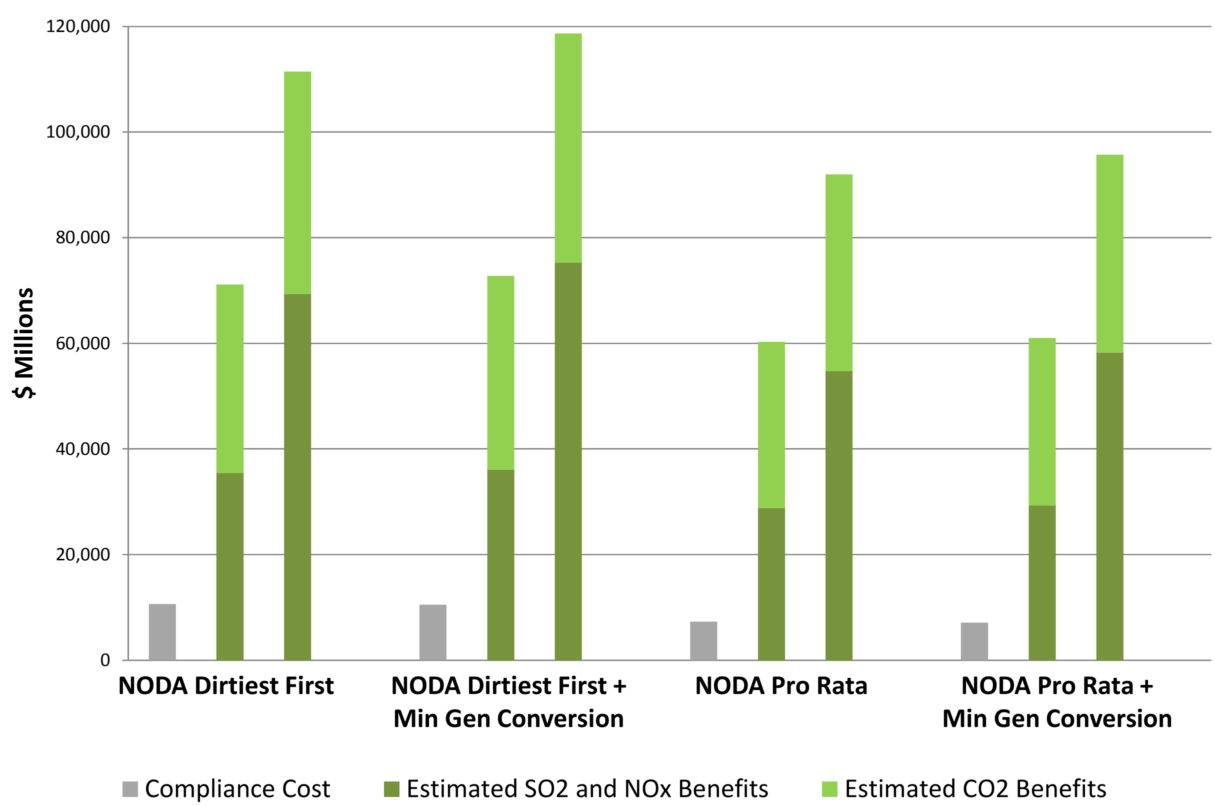


Figure ES-2. Compliance Costs and Net Benefits in 2030



NRDC has presented a number of ways to improve and strengthen the CPP and with just three of these major recommendations: 1) updated baseline and cost and performance data, 2) implementation of the noticed formula change to properly account for energy efficiency and renewables, and 3) adoption of a minimum transition from older steam generation to new natural gas combined cycle units, we find that EPA can significantly strengthen the proposal at reasonable cost. Emissions reductions of 36% below 2005 by 2020 and 44% by 2030 can be accomplished at a cost of $6.5Billion in 2020 and $10.5 Billion in 2030 with net benefits estimated to be up to $70 Billion and $108 Billion respectively.

Environmental Justice Considerations

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. NRDC's suggested improvements will deliver even larger benefits. However, we urge EPA to include in the final rule a robust discussion of the ways in which state plans can be designed to ensure that pollution will be reduced in communities currently bearing a disproportionate share of ambient air pollution burdens. State plans will determine how the carbon pollution reductions required by the state targets are achieved—and those decisions will also determine how much reduction takes place in harmful co-pollutants, and where. This will be particularly important in the context of state planning for attainment of ozone ambient air quality standards and other clean air protections, enabling comprehensive planning to help states ensure that carbon pollution is reduced and other harmful air pollution problems are addressed.

Table of Contents

Appendices:

1.0 Introduction

As EPA has properly concluded, the scientific record demonstrating that "elevated concentrations of greenhouse gases in the atmosphere may reasonably be anticipated to endanger the public health and welfare of current and future U.S. generations is robust, voluminous, and compelling."[1] Electric generating units ("EGUs") are the single largest source of domestic greenhouse gas ("GHG") emissions and EPA act to control greenhouse gas pollution from new and existing power plants under section 111 of the Clean Air Act ("CAA" or the "Act"), 42 U.S.C. § 7411. Significantly reducing these emissions from domestic power plants is necessary to mitigate the serious harms associated with climate change in the United States.

In this introductory section, we briefly describe some of the harms associated with greenhouse gas emissions and show why the emissions profile of the EGU sector demands expeditious regulation under Section 111.

1.1 Climate change and ocean acidification caused by EGU emissions threaten public health and welfare.

EPA's Regulatory Impact Analysis ("RIA")[2] provides an overview of the pressing threats posed by GHG emissions and canvasses the dangers that the Existing Stationary Source rule must combat. The RIA is based largely on EPA's 2009 Endangerment Finding as well as on major assessments by the U.S. Global Change Research Program ("USGCRP"), the Intergovernmental Panel on Climate Change ("IPCC"), and the National Research Council ("NRC").[3] The climate science that forms the basis of the Endangerment Finding provides a legally sufficient and scientifically compelling justification for curbing greenhouse gas emissions from power plants. Global greenhouse gas emissions and atmospheric concentrations, and hence the risk of catastrophic damage, have increased since EPA issued the Endangerment Finding, a fact that highlights the importance of emissions controls.[4] Climate research and assessment reports

---

[1] 75 Fed. Reg. 49,556, 49,557 (Aug. 13, 2010) (Endangerment Reconsideration Denial); *see also* 74 Fed. Reg. 66,496, 66,523 (Dec. 15, 2009) (Endangerment Finding)*; Coalition for Responsible Regulation, Inc. v. EPA*, 684 F.3d 102, 122—28 (D.C. Cir. 2012) (upholding Endangerment Finding in its entirety).

[2] EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants*, EPA-452/R-14-002 (June, 2014), *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf [hereinafter RIA].

[3] RIA, *supra* note 2 at 1-2, 4-2, 4-3, 7-10.

[4] In addition to abrupt changes in the climate system itself, steady climate change can cross thresholds that trigger abrupt changes in other physical, natural, and human systems. NRC, *Abrupt Climate Change, Anticipating Surprises,* page 2 (2013) *available at* http://www.nap.edu/catalog/18373/abrupt-impacts-of-climate-change-anticipating-surprises; Such thresholds include melting of the Greenland Ice Sheet, dramatic changes in weather systems, and Amazon and boreal forest dieback. *See* Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., *2014: Climate Change Impacts in the United States: The Third National Climate Assessment*, U.S. Global Change Research Program, page 812, figure 24 (May, 2014) *available at*

published since 2009 further emphasize the urgency of tackling climate change and the need to mitigate greenhouse gas emissions.[5]

1.1.1 ***Harms associated with climate change*.**

Climate change will comprehensively alter our world. As the RIA recognizes, these changes will endanger public health, will jeopardize ecosystems, and cause a wide variety of harms to the world's oceans.

1.1.1.1 *Direct threats to public health and welfare from climate change.*

Climate change is threatening, and will continue to threaten, public health in many regards. For instance, it is expected to increase the incidence and severity of heat waves, which are particularly dangerous to the elderly, the very young, and the infirm.[6] Warmer days lead to enhanced ozone (or smog) formation, which can exacerbate respiratory illnesses, contribute to asthma attacks and hospitalizations, and heighten the risk of premature death among affected populations.[7] Because a warmer atmosphere retains more moisture, climate change will produce heavier precipitation events, stronger tropical cyclones, and associated flooding, spreading toxins and diseases and causing severe infrastructure damage, social upheaval, and widespread injury and death.[8] Pathogens and pests are expected to increasingly disseminate among susceptible populations due to changes in those species' survival, persistence, habitat range, and transmission under changing climate conditions, further endangering the public.[9]

As EPA has attested at length, climate change also threatens public welfare. Sea level rise is well documented and is very likely to accelerate over the coming decades.[10] Rising seas, amplified by storm surges and stronger tropical cyclones, will threaten our coastal homes, cities, and

---

http://nca2014.globalchange.gov/system/files_force/downloads/low/NCA3_Climate_Change_Impacts_in_the_United States_LowRes.pdf [hereinafter USGCRP 2014].

[5] *See, e.g.* IPCC, *Climate Change 2013, The Physical Science Basis, Working Group I Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* (2013) *available at* http://www.ipcc.ch/report/ar5/wg1/; NRC, *Abrupt Climate Change, Anticipating Surprises,* (2013); USGCRP 2014, *supra* note 4; UNEP, *The Emissions Gap Report 2014* (2014) available at http://issuu.com/unep/docs/the_emissions_gap_report_2014?e=1015067/10215862*;* Department of Defense, *2014 Climate Change Adaptation Roadmap* (October 13, 2014) *available at* http://www.acq.osd.mil/ie/download/CCARprint.pdf; *see also* RIA, *supra* note 2 at 4-2 and 4-3 (listing publications).

[6] RIA, *supra* note 2 at 7-10.

[7] *Id.* at 4-1, 4-14-4-21. *See also* Pfister *et al.*, *Projections of Future Summertime Ozone Over the U.S.*, Journal of Geophysical Research: Atmospheres (May 5, 2014) (higher temperatures increase smog formation in already polluted areas).

[8] RIA, *supra* note 2 at 4-6.

[9] *Id.* at 4-6, 4-59

[10] *Id.* at 1-2, 4-3.

infrastructure, forcing expensive efforts to protect or relocate critical resources.[11] Millions of U.S. citizens will be affected and many will be displaced. Droughts, especially in the western and southern United States, are expected to occur more frequently, and reduced access to drinking and irrigation water will further strain agricultural and municipal reserves.[12] This phenomenon will exacerbate the water scarcity already affecting numerous regions of the country.[13] Furthermore, the combination of changing atmospheric chemistry and more violent weather patterns will likely cause crop damage and crop failure, with corresponding increases in food prices and declines in availability.[14] On forested lands, the same changes will instigate more severe fires, pest outbreaks, and higher tree mortality, which will likely disrupt timber production.[15]

1.1.1.2 *Climate-linked threats to ecosystems upon which society depends.*

Natural environments and biodiversity provide humans with a wide range of benefits or "ecosystem services," including fresh water supplies, fertile soil for agriculture, fisheries, climate regulation, and aesthetic, cultural, and recreational benefits.[16] However, climate change will have major implications for wildlife, biodiversity, and the fundamental ecosystem services upon which we depend. Observed changes in our climate are already shifting habitat ranges, altering migration patterns, and affecting reproductive timing and behavior.[17] In the coming decades, climate-related disturbances, such as altered precipitation regimes and extremes in weather and temperature, will continue to have marked impacts on ecosystems, creating shifting habitat ranges, and accelerating species migration and extinction.

In some cases, climate change will cause entire ecosystems to transition to significantly different community types.[18] Biome shifts, or a certain species' replacement at a particular location of another species, has been seen over the past century in boreal, temperate and tropical ecosystems.[19] The IPCC's projections of climate changes' impact on vegetation distribution indicates that "many biomes could shift substantially, including in areas where

---

[11] *Id.* at 4-3, 4-6.
[12] *Id.* at 4-6; IPCC, *Climate Change 2014 Impacts, Adaptation, and Vulnerability Part A: Global and Sectoral Aspects: Working Group II Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, at 494 (2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/wg2/WGIIAR5-FrontMatterA_FINAL.pdf.
[13] RIA, *supra* note 2 at 4-4; U.S. Department of Agriculture, *2014 Adaptation Plan*, page 9-10 (June 2014) *available at* http://www.usda.gov/oce/climate_change/adaptation/USDA%20Climate%20Change%20Adaptation%20Plan_Only.pdf.
[14] RIA, *supra* note 2 at 4-3, 4-6, 4-60.
[15] U.S. Department of Agriculture, *2014 Adaptation Plan*, page 11-12 (June 2014); RIA, *supra* note 2 at 4-59, 4-60.
[16] USGCRP 2014, *supra* note 4 at 160.
[17] *Id.* at 201, 205.
[18] *See generally* Peters *et al*., *Directional climate change and potential reversal of desertification in arid and semiarid ecosystems*, 18 Global Change Biology 151 (2012).
[19] IPCC 2014: Terrestrial and Inland Water Systems, *supra* note 20 at 278.

ecosystems are largely undisturbed by direct human land use."[20] However, climate change is also expected to alter agricultural use of land. While climate change is expected to have a mixed effect on the *pathogens* that cause disease in the wheat, rice, soybean and potato crop staples, climate change is anticipated to increase the risk of *insect* damage to plants.[21] Trout and salmon populations, economically and ecologically important species, are becoming increasingly fragmented with reduced genetic diversity.[22] Such changes in ecosystem composition and function will pose critical adaptation challenges for affected human communities.

The resilience of many ecosystems is likely to be exceeded this century by an unprecedented combination of climate change's associated disturbances, for example, flooding, drought, wildfire, insects, and ocean acidification, and other global change drivers, like land use change, pollution, fragmentation of natural systems, and overexploitation of resources.[23] At anticipated levels of increased global temperature, many terrestrial, freshwater, and marine species are at far greater risk of extinction than in the past.[24] Research indicates that climate change and other anthropogenic factors are causing the sixth mass extinction of global biodiversity in the last 600 million years of life on Earth, with current extinction rates 100 to 1,000 times greater than historical rates.[25] The IPCC predicted in 2007 that at least 20–40% of assessed species, or between 12,000–24,000 species, may be at an "increased risk of extinction" if mean global temperatures were to increase between 2.7–4.5°F.[26] Current emissions trends are on track for

---

[20] *Id*.

[21] IPCC, *Climate Change 2014: Impacts, Adaptation, and Vulnerability, Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Food Security and Food Production Systems*, page 506-507 (2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/wg2/WGIIAR5-Chap7_FINAL.pdf.

[22] U.S. Global Change Research Program, *Our Changing Planet: The U.S. Global Change Research Program for Fiscal Year 2015*, page 23 (October 2014) *available at* http://www.globalchange.gov/sites/globalchange/files/Our-Changing-Planet-FY-2015-full-res.pdf [hereinafter USGCRP, Our Changing Planet, 2015].

[23] Heat stress, extreme precipitation, inland and coastal flooding, landslides, air pollution, drought, and water scarcity pose risks in urban areas for people, assets, economies, and ecosystems (very high confidence). IPCC, *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, Summary for Policymakers, page 18 (2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/wg2/ar5_wgII_spm_en.pdf; Population growth, poverty, marginalization, and environmental degradation are coupled in socioecological feedback loops that drive the system into a downward spiral. World Bank 2014, *supra* note 16 at 137.

[24] *Id.* at 216, 218

[25] Barnosky *et al.*, *Has the Earth's sixth mass extinction already arrived?*, 471 Nature 51 (2011); Pereira *et al.*, *Scenarios for Global Biodiversity in the 21st Century*, 330 Science 1496, 1497 (2010).

[26] Anthony D. Barnosky, *et al. Scientific Consensus on Maintaining Humanity's Life Support Systems in the 21st Century: Information for Policy Makers,* The Anthropocene Review, 78-109 (2014) (citing IPCC, *Climate Change 2007: Impacts, Adaptation, and Vulnerability* (2007)).

an increase of 7.2°F.[27] Today, the IPCC predicts that many species will be unable to disperse and migrate quickly enough to track the changing climate.[28]

Species with a narrow tolerance for changes in environmental conditions,[29] and spatially restricted species, such as those confined to isolated mountain streams,[30] are particularly vulnerable to the threat of extinction due to climate change. Studies have shown that a third of reef-building coral species, vulnerable to temperature change yet responsible for supporting significant marine life, have an elevated risk of extinction, due to increased sea surface temperatures and local-scale anthropogenic disturbances.[31] Similarly, tropical species and ecosystems, like those in the Amazon regions, may be more sensitive to climate change disruptions than other species located in areas with more climactic variability, like boreal ecosystems.[32] The situation is particularly dire for Arctic wildlife, as climate change causes significant loss of sea ice and a dramatic reduction in marine habitat for polar bears, ice-inhabiting seals, and other animals.[33]

Even species that do not go extinct will have to contend with ecological conditions they have not previously faced, as both spatial and temporal species shifts occur. A species' current ecological niche may become smaller due to changing climactic and environmental conditions, leading to shifts in "ecological zones."[34] Shifts in seasons, especially in the duration and intensity of winter, are also having significant impacts on ecosystems. Plant and animal species in the northern hemisphere have recently begun demonstrating "spring advancement," or the earlier occurrence of breeding, flowering, and migration.[35] These range shifts are likely to cause unprecedented interactions among species, and is increasing the likelihood of mismatches between interdependent species (e.g., predator and prey, insects and flowers).[36]

---

[27] *Id*.
[28] IPCC 2014: Terrestrial and Inland Water Systems, *supra* note 20 at 275.
[29] *See generally* Clavel *et al.*, *Worldwide decline of specialist species: toward a global functional homogenization?,* 9 Frontiers in Ecology and the Environment 222 (2011).
[30] IPCC 2014: Terrestrial and Inland Water Systems, *supra* note 20 at 275.
[31] Kent E. Carpenter *et. al.*, *One-Third of Reef-Building* Corals *Face Elevated Extinction Risk from Climate Change and Local Impacts*, 321 *Science* 560 (2008).
[32] IPCC 2014: Terrestrial and Inland Water Systems, *supra* note 20 at 301.
[33] Global marine mammal diversity is projected to decline at lower latitudes and increase at higher latitudes due to changes in temperatures and sea ice, with complete loss of optimal habitat for as many as 11 species by mid-century. *Id.* at 205.
[34] World Bank 2014, *supra* note 16, at 34.
[35] IPCC 2014: Terrestrial and Inland Water Systems, *supra* note 20 at 291.
[36] *See generally, e.g.*, Miller-Rushing *et al.*, *The effects of phenological mismatches on demography*, 365 Philosophical Transactions of the Royal Society B: Biological Sciences 3177 (2010); Thackeray *et al*., *Trophic level asynchrony in rates of phenological change for marine, freshwater and terrestrial environments*, 16 Global Change Biology 3304 (2010); Yang *et al.*, *Phenology, ontogeny and the effects of climate change on the timing of species interactions*, 13 Ecology Letters 1 (2010).

In short, greenhouse gas emissions are fundamentally destabilizing global ecosystems. Because human society depends upon the goods and services these ecosystems provide, this ecological crisis is a pressing threat to public welfare.

1.1.1.3 *Harms associated with ocean acidification.*

The oceans have absorbed roughly 30% of the total CO_2 emitted by humans.[37] As increasing CO_2 emissions from fossil fuel combustion is subsequently absorbed by the world's oceans, significant chemical disruptions occur. Because carbonic acid forms when carbon dioxide dissolves in water, rising CO_2 emissions are causing the seas to become more acidic.[38] The NRC reported that ocean acidity is changing at an "unprecedented rate and magnitude due to anthropogenic carbon dioxide emissions."[39] According to a 2012 study that surveyed hundreds of millions of years of ocean chemistry, the current rate of CO_2 release into the oceans (and hence the rate of acidification) "stands out as capable of driving a combination and magnitude of ocean geochemical changes potentially unparalleled in at least the last ~300 [million years] of Earth history."[40]

Increased acidification poses a significant threat to the ocean's critical food webs. For example, the acidification of seawater increases the dissolution of calcium carbonate shells and skeletons, impacting oysters, mussels and many microscopic creatures that form the foundation of marine food webs.[41] In addition, the increased surface stratification mentioned above, combined with heightened acidity, has been shown to dramatically reduce the photosynthesis and growth of diatoms, currently responsible for approximately 40% of total primary production in the oceans.[42] Accordingly, the combination of heightened acidification and ocean stratification may result in a "widespread decline in marine primary production," doing great damage to the base of the oceanic food chain with potentially devastating effects on the food supply for many regions around the globe.[43] By disrupting the delicate balance of oceanic ecosystems, acidification could have devastating impacts on coastal communities that rely heavily on the sustained health of their fisheries.

---

[37] IPCC, *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Observations: Ocean*, page 292 (2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/wg1/WG1AR5_Chapter03_FINAL.pdf.
[38] The pH of ocean surface water has decreased by 0.1 (high confidence), corresponding to a 26% increase in acidity, measured as hydrogen ion concentration. IPCC, *Fifth Assessment Synthesis Report*, page 2 (November, 2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_LONGERREPORT.pdf.
[39] NRC, *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (2010) *available at* http://dels.nas.edu/Report/Ocean-Acidification-National-Strategy/12904.
[40] Hönsich *et al.*, *The Geological Record of Ocean Acidification*, 335 Science 1058 (2012).
[41] *Id*. at 4.
[42] *Id.* at 519-522.
[43] *Id.* at 519.

1.1.2 *New research, reports, and assessments show increasing severity of harm*.

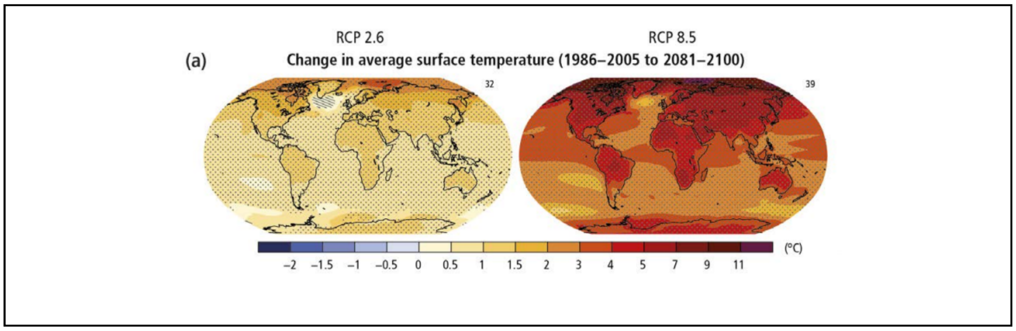
Greenhouse gas emissions and atmospheric carbon concentrations have continued to rise in the years since EPA made its Endangerment Finding. As EPA moves forward with the proposed rule on existing EGUs, the evidence of an intensifying threat reflects the importance of selecting the most protective standards possible in this rule, as well as the need for continued efforts to control emissions from other sectors.

In 2013, the IPCC's Working Group I noted that the overall warming of the climate was "unequivocal," with unprecedented atmospheric and ocean warming, diminishing snow and ice, and increasing greenhouse gas concentrations.[44] The 2014 IPCC Synthesis Report expanded upon these dire projections, finding that "continued emission of greenhouse gases will cause further warming and long-lasting changes in all components of the climate system, increasing the likelihood of severe, pervasive and irreversible impacts for people and ecosystems."[45]

The IPCC Synthesis Report analyzed multiple "concentration pathways," or emission scenarios, with differing levels of climate impact anticipated based on the varying projections in global greenhouse gas emissions.[46] However, the Synthesis Report noted that global surface temperature is projected to rise under all assessments, as seen in Figure 1.1 below.[47] The temperature change for the period of 2016–2035 is projected to range from 0.3˚C to 0.7˚C for most scenarios, yet temperature change varies significantly by 2081-2100 based on the different scenarios. For example, the likely global mean surface temperature change for the RCP 2.6 scenario, or the stringent mitigation scenario, is 0.3˚C to 1.7˚C, while the temperature change for the RCP 8.5 scenario, or the very high greenhouse gas emissions scenario, is 2.6˚C to 4.8˚C.[48] In addition, heat waves are expected to become more frequent and intense.[49]

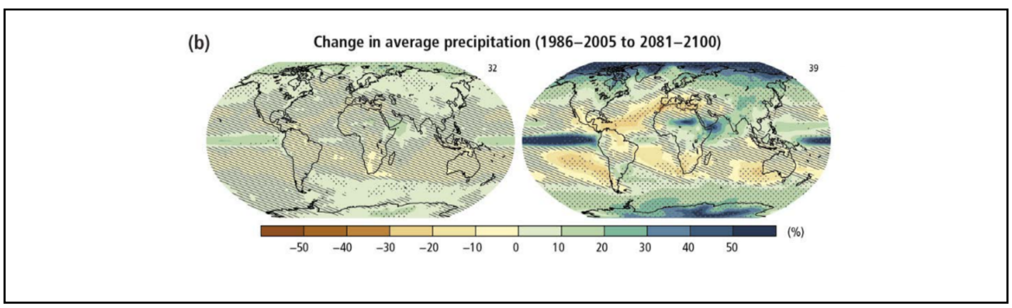
[44] IPCC, 2013: Summary for Policymakers. Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.
[45] IPCC, *Fifth Assessment Synthesis Report*, page 8 (November, 2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_LONGERREPORT.pdf.
[46] The Representative Concentration Pathways represent the range of greenhouse gas emissions in the wider literature well (Box 2.2, Figure 1); they include a stringent mitigation scenario (RCP2.6), two intermediate scenarios (RCP4.5 and RCP6.0), and one scenario with very high greenhouse gas emissions (RCP8.5). Scenarios without additional efforts to constrain emissions ("baseline scenarios") lead to pathways ranging between RCP6.0 and RCP8.5. RCP2.6 is representative of a scenario that aims to keep global warming likely below 2°C above pre-industrial temperatures. *Id*. at 59.
[47] *Id*. at 61.
[48] Id. at 63.
[49] *Id*.

Figure 1.1: IPCC Projected Surface Temperature Increase.



Increasing surface temperatures will be accompanied by significant regional changes in precipitation. As seen in Figure 1.2 below, the IPCC projects that the RCP 8.5 scenario would result in significant increases in annual mean precipitation in the high latitudes and the equatorial Pacific, with decreasing precipitations in mid-latitude and subtropical regions.[50] The IPCC predicted that all RCPs would result in an increase in monsoon systems, and intensified El Niño-Southern Oscillation-related precipitation variability.[51]

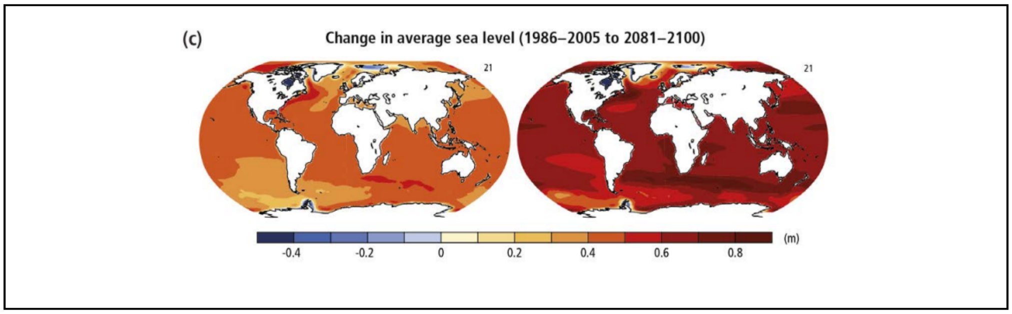
Figure 1.2: IPCC Projected Average Precipitation Increase.



In addition, the global mean sea levels are projected to increase, as seen in Figure 1.3 below. Under RCP 2.6, global sea level will likely rise between 0.26 to 0.55 meters by 2081-2100, while the RCP 8.5 scenario projects sea levels to rise between 0.45 to 0.82 meters within the same time period.[52] Although it is "very likely" that sea levels will rise in more than 95% of the ocean area, sea level rise will not be consistent across all regions.[53] Instead, roughly 70% of the world's coastlines will experience changes ±20% of the global mean. By 2100, it is "very likely" that certain regions will experience a "significant increase in the occurrence of future sea-level extremes," resulting in disproportionate regional impacts of climate change.[54]

[50] *Id*. at 64.
[51] *Id*. at 65.
[52] *Id*. at 63.
[53] *Id*. at 65.
[54] *Id*.

Figure 1.3: IPCC Projected Sea Level Rise.



In addition to the IPCC reports, the USGCRP's 2013 report for its Third Climate Assessment reflects a similar pattern. The authors emphasized that "[h]eavy precipitation and extreme heat events are increasing in a manner consistent with model projections, the risks of such extreme events will rise in the future."[55] The Report stated that global average temperature over both land and oceans has increased by over 0.8°C between 1880 and 2012.[56] Domestically, USGCRP noted that the most recent decade in the U.S. was the warmest on record, with temperatures projected to continue to rise.[57] In addition, the Report anticipated small increases in overall precipitation, with "substantial shifts" in where and how rainfall occurred, with increases in monsoons in the tropical Pacific, and further drying in the subtropical regions.[58] The USGCRP expected sea level increases of 1-4 feet by the end of the century, although the regional impact was expected to vary.[59] Within the U.S., the impact of rising sea levels will be felt by nearly five million Americans, and hundreds of billions of dollars of property is located within areas that are less than four feet above the local high-tide mark.[60] The Report noted that "[a] longer and better-quality history of sea level rise has increased confidence that recent trends are unusual and human-induced."[61]

1.2 Climate stabilization requires immediate, deep reductions in emissions from the EGU sector.

According to the USGCRP, current carbon emissions are "significantly higher than the total land sink's capacity to absorb and store them."[62] Carbon emissions from power plants remain the single largest source of U.S. greenhouse gas pollution and are a significant component of global

---

[55] USGCRP 2014, *supra* note 4 at 21.
[56] *Id*. at 23.
[57] *Id*. at 28.
[58] The widespread trend of increasing heavy downpours is expected to continue, with precipitation becoming less frequent but more intense. *Id*. at 26.
[59] *Id*. at 9-10.
[60] *Id*.
[61] *Id*. at 21.
[62] USGCRP 2014, *supra* note 4, at 358.

emissions.[63] Without emissions controls for the EGU sector, it will be impossible to stabilize atmospheric greenhouse gas emissions at a safe level.

1.2.1 *Emissions from the U.S. power sector must be controlled to prevent serious harm to public health and welfare*.

As detailed above, increasing greenhouse gas emissions accelerate climate change, severely impact the atmosphere, oceans, and jeopardize the Earth's flora and fauna. In addition, these GHG emissions, and associated ambient fine particulate matter in particular, negatively impact human health. The EPA notes that human health effects associated with ambient particulate matter and ozone are associated with "premature morality and a variety of morbidity effects" from both acute and chronic exposure.[64]

In May 2013, the Interagency Working Group on the Social Cost of Carbon ("IWG"), which includes representatives from a host of federal agencies (including EPA), published an updated assessment of the social cost of carbon that increases with the predicted threat that climate change poses and will continue to pose into the future. The IWG's original estimate in 2010 provided four potential values to represent the cost that each metric ton of CO_2 emissions will impose on society for the year 2020: $7, $26, $42, and $81.[65] The 2013 estimate increases those values to $12, $43, $65, and $129, respectively.[66]

There are significant benefits to mitigating such costs. Recent studies from scientists at Lawrence Berkeley National Laboratory, the National Institute of Environmental Health Sciences and the University of Washington show that significant health benefits will result from GHG emission reduction activities in different sectors.[67] The study contemplates emission reductions generated through multiple "wedges" such as coal power plant efficiency improvements, substitution of coal electricity with lower-carbon energy sources, and building energy efficiency improvements.[68] The study suggests that reduced exposure to harmful emissions would

[63] The combustion of fossil fuels to generate electricity is the largest single source of CO_2 emissions in the nation, accounting for about 38% of total U.S. CO_2 emissions and 31% of total U.S. greenhouse gas emissions in 2012. EPA, *Climate Change, Overview of Greenhouse Gases* (last visited November 25, 2014) *available at* http://www.epa.gov/climatechange/ghgemissions/gases/co2.html.
[64] RIA, *supra* note 2 at 4-16, 4-17 Table 4-6.
[65] IWG, *Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, page 2 (May, 2013) *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf.
[66] *Id.*
[67] *See e.g.,* John M. Balbus, *et. al.*, *A Wedge-Based Approach to Estimating Health Co-Benefits of Climate Change Mitigation Activities in the United States*, 127 Climactic Change Vol. 2, 199 (October, 2014) *available at* http://link.springer.com/article/10.1007/s10584-014-1262-5.
[68] A wedge is a scenario of activities that reduce annual CO_2 emissions by 150 million metric tons in 2020 and 750 million metric tons in 2060. *Id*.

generate between $6 to $30 billion in economic benefits in the year 2020.[69] These health benefits are the equivalent of between $40 and $198 per metric ton of CO_2 generated.[70]

While we believe that these figures may fundamentally underestimate the true cost of carbon emissions, they nonetheless reflect the same trend as seen in the scientific literature: not only does the potential harm from carbon emissions increase with each additional ton released into the atmosphere, but the severity of the predicted harm for both human and environmental health increases as our understanding of climate change grows. These new studies, reports, and assessments indicate that the urgency of acting to curb greenhouse gas emissions has, if anything, grown since the 2009 Endangerment Finding. Emission trajectories are causing severe effects on an accelerated timeline. In the absence of substantial emissions reductions, the harms to public health and welfare from climate change will prove catastrophic.

1.2.2 Deep cuts in U.S. power sector emissions are consistent with the need for global emissions reductions.

EPA's Inventory of Greenhouse Gas Emissions and Sinks reports that electricity generation was responsible for 2,022 million metric tons of CO_2 in 2012, the most recent year for which data is available, constituting 37.5% of annual U.S. CO_2 emissions.[71] Power plant emissions of GHGs are larger than those of the next largest stationary source category, oil and gas production, and are larger than emissions from the entire U.S. transportation sector.[72]

Domestic action to combat climate change will have benefits that extend far beyond our borders. As of 2010, the U.S. was responsible for approximately 13.4% of global anthropogenic greenhouse gas emissions.[73] The U.S. power sector emissions constitute approximately 4.5% of worldwide emissions of all anthropogenic greenhouse gas emissions and over 6% of all CO_2 emissions.[74] Reducing carbon pollution from domestic power plants will help to substantially curb our contribution to climate change. Reductions from large sources like the U.S. power sector are important because steep global cuts are necessary to prevent truly disastrous climate impacts. IPCC's Working Group 3, focusing on climate change mitigation strategies, stated that "the stabilization of GHG concentrations requires fundamental changes in the global

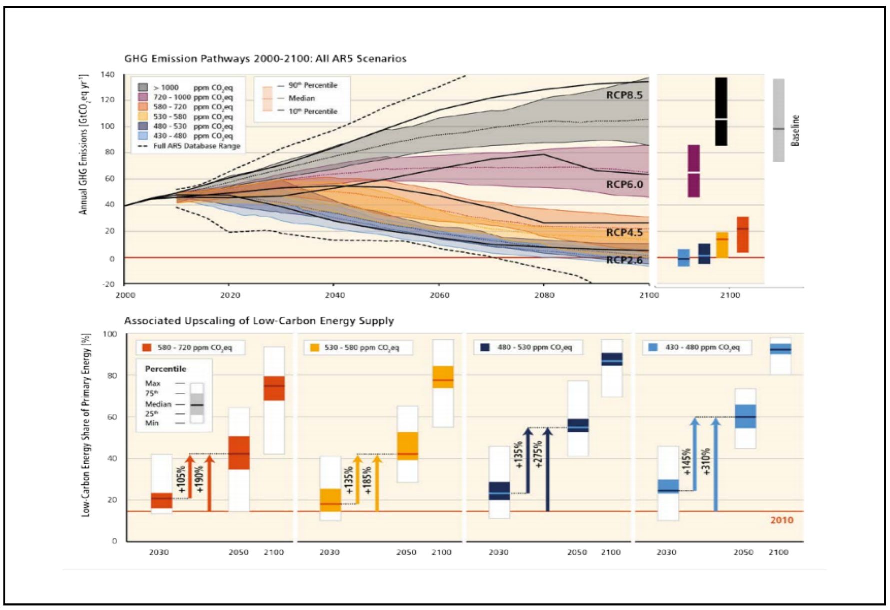
---

[69] Values generated are based on 2008 USD. *Id*.
[70] *Id*.
[71] EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990—2012* (April, 2014), at Table 2-1.
[72] *Id.*
[73] European Union Emission Database for Global Atmospheric Research (EDGAR), *GHG (CO_2, CH4, N2O, F-gases) Emission Time Series 1990-2010 Per Region/Country*, *available at* http://edgar.jrc.ec.europa.eu/overview.php, and CO2 time series 1990-2012 per region/country, *available at* http://edgar.jrc.ec.europa.eu/overview.php?v=CO2ts1990-2012.
[74] According to the EDGAR database, global GHG emissions in 2010 were 50,101 million metric tons CO_2e. *Id.*

energy system relative to a baseline scenario,"[75] and that "[t]he electricity sector plays a major role in mitigation scenarios with deep cuts of GHG emissions."[76]

The IPCC's 2014 Synthesis Report published findings on emission scenarios, detailed in Figure 1.4 below. The report stated that emission scenarios to maintain warming below 2°C over the 21st century relative to pre-industrial levels will require 40% to 70% global anthropogenic GHG emissions reductions by 2050 compared to 2010.[77] Scenarios characterized by concentrations below 430 ppm CO2-eq by 2100, which are "more likely than not to limit warming to 1.5°C by 2100" require emission reduction between 70% and 95% below 2010 by 2050.[78] In another scenario, IPCC predicted that GHG concentrations in 2100 of 500 ppm CO2-eq or lower are "about as likely as not" to limit temperature change to less than 2°C. However, emission scenarios with higher emissions in 2050 are characterized by a greater reliance on Carbon Dioxide Removal technologies.[79]

Figure 1.4: IPCC Emission Pathways 2000-2100.



[75] IPCC, *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change. Energy Systems*, page 58 (2014) *available at* http://report.mitigation2014.org/drafts/final-draft-postplenary/ipcc_wg3_ar5_final-draft_postplenary_chapter7.pdf.
[76] *Id.* at 64.
[77] IPCC, *Fifth Assessment Synthesis Report*, page 21 (2014) *available at* http://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_LONGERREPORT.pdf.
[78] *Id*.
[79] *Id*.

The IPCC has determined that "[d]elaying mitigation efforts beyond those in place today through 2030 is estimated to substantially increase the difficulty of the transition to low longer-term emissions levels and narrow the range of options consistent with maintaining temperature change below 2°C relative to pre-industrial levels."[80] It will be difficult, perhaps impossible, to meet the reductions needed to stave off the most extreme effects of climate change without swift and significant emissions controls for the U.S. power sector.

If we are to reduce the United States' contribution to global warming, we must address this major emissions source. Doing so will require controlling emissions from all fossil fuel-fired EGUs, both new and existing. Furthermore, it is essential that the nation's clean air and clean energy policies stimulate innovation in and deployment of low-carbon and renewable energy resources and energy efficiency. These technologies are critical if we are to transition to an electricity sector that minimizes our impact on global climate change. Otherwise, we will be unable to curb dangerous climate-destabilizing emissions and responsibly manage the nation's natural resources.

In the remainder of these comments, we explain what EPA must do in order to meet its Clean Air Act mandate to ensure that all affected sources in this sector comply with Section 111 standards. A comprehensive and flexible rule is critical to achieving the emissions reductions necessary to address the dangers of climate change and protect public health.

---

[80] IPCC, *Statement of Renate Christ, Secretary of the IPCC at the opening of SBSTA-40 Bonn, Highlights of the WG III Report*, page 2 (June 4, 2014) *available at* http://www.ipcc.ch/pdf/unfccc/sbsta40/140604_SB40_oc_Christ.pdf.

2.0 Legal and Structural Issues

We strongly support EPA's proposed "best system of emission reduction" (BSER), which sets targets for each state's CO2-emitting power plants by assessing the real-world potential to reduce their carbon pollution by deploying renewable energy (RE), harvesting our nation's vast energy efficiency (EE) resource, improving the efficiency of power plants, and relying more on lower-polluting power plants and less on the highest-emitting power plants.

The definitions of "standard of performance" and "emissions guideline" both provide, in substance, that standards must achieve as much emission reduction as is technically and economically achievable by the sources subject to them. The EPA must determine that the emission limit achieves the emission reductions that are "achievable" using measures that are "adequately demonstrated"— a test of technical 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."

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 a system that includes improvements in fossil plant efficiency, displacement of higher-emitting plants with lower-emitting plants, increased reliance on renewable generation and increased investments in demand-side efficiency 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 such a system 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 are best suited to their particular circumstances.

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, including demand-side management, to meet system demand while reducing harmful pollution from power plants. Adding renewable electricity can displace generation from fossil fuel-fired plants—and will reduce emissions accordingly. Similarly, improving energy efficiency lowers demand for electricity, reducing power generation and associated 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 has been done at many plants) and this also reduces combustion emissions. These techniques—switching to lower carbon fuels, non-emitting generation resources, and improving energy efficiency—have all been used to comply with a range of air pollution programs 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 — is authorized by 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. Below we provide comments on expanding and strengthening the various components of the system proposed by EPA). The flexibility of this system enables sources and states to develop plans that will secure emission reductions cost effectively, ensure that there are no effects on reliability, and reduce carbon emissions. This system allows sources and 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. In the comments and sections that follow, we describe the opportunity to appropriately increase the emissions reductions through each of EPA's BSER Building Blocks and how to do so at reasonable cost.

The BSER building blocks proposed by EPA include:

1) Block 1: Making existing coal plants more efficient

2) Block 2: Using existing natural gas plants more effectively

3) Block 3: Increasing renewable and nuclear generation

4) 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 emission reductions are available from each of the four blocks.

Below, we discuss the legal basis for EPA's proposed best system of emission reduction, additional legal issues concerning the proposed guideline, and the need to correct the formula for calculating state targets to properly account for reductions from renewable energy and energy efficiency.

2.1 EPA's first co-proposed definition of "best system of emission reduction" is a permissible interpretation of the Act.

EPA's first co-proposed alternative would establish that the "best system of emission reduction" for affected EGUs is a combination of certain cost-effective actions that EGUs can undertake to reduce emissions from electricity generation in the state. Specifically, EPA's first alternative provides that the best system of emission reduction for affected EGUs is the combination of source-based actions that reduce the emissions of individual facilities and credits for actions that reduce emissions from the power grid as a whole – including redispatch from higher- to lower-emitting generating facilities, increased generation at renewable energy facilities, and demand-side energy efficiency projects.

EPA describes several alternative ways of implementing this alternative, including "a tradable emission rate system, under which the state would impose an emission rate limit on the steam generating unit" that the unit could meet by a combination of emission reductions at the source and purchasing credits from increased utilization of NGCC units, generation from new renewable units, or demand reduction from expanded energy efficiency measures. Another approach would be "an allowance-based system," of which the Regional Greenhouse Gas Initiative (RGGI) is an example, where the CO2-emitting EGUs would have the responsibility to hold allowances for each ton of its emissions. *See* 79 Fed. Reg. 34830, 34,882.

This proposal is a permissible construction of section 111. Section 111(d) provides for states to adopt plans similar to the "state implementation plans" that are required under section 110. Because state implementation plans under section 110 may allow affected sources to comply with relevant emission standards through participation in a system-based credit programs, EPA has historically taken the position that state plans submitted pursuant to section 111(d) may also allow affected sources to comply with relevant emission standards by participating in credit programs. Because such credit programs are available for compliance purposes in state 111(d) plans, section 111 requires that EPA take into account the reductions reasonably achievable using these methods when determining the performance standard that reflects the emissions limitations achievable using the best system of emission reduction. This conclusion is reinforced by usage of the term "system" and "system of emission reduction" elsewhere in the Clean Air Act.

2.1.1 *Section 111(d) of the Clean Air Act authorizes the system-based approach EPA has proposed.*

2.1.1.1 *It is reasonable to include all of the interconnected fossil-fuel generated EGUs in a single category.*

In the proposed rule, EPA seeks comment on whether it should combine the category of coal-fired steam power plants and gas turbines (including combined cycle turbines). 79 Fed. Reg. at 34,892. As NRDC indicated in its comments on the proposed section 111(b) standards for new power plants (incorporated herein by reference), NRDC supports consolidating the two source categories of affected EGUs covered by the emission guidelines into one regulated source category. This is appropriate because both coal-fired steam power plants and NGCC power plants serve the same function of providing base-load and intermediate load electricity. A single category is also 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.

2.1.1.2 *Section 111(d) authorizes emission standards based on flexible means of compliance.*

Section 111(d) was modeled on section 110 of the Clean Air Act. Section 110 establishes a process for attaining the national ambient air quality standards established by EPA under section 109. To attain these standards, each state must submit a state implementation plan (SIP) that establishes "enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights)." CAA Section 110(a)(2)(A). EPA reviews these plan submissions and must approve them if they satisfy the applicable requirements of the Clean Air Act. *See* Section 110(a)(2)(A), (k)(3). If EPA determines that a state implementation plan does not provide for timely attainment of the national ambient air quality standards or meet other statutory requirements, EPA must disapprove the plan and promulgate a federal implementation plan (FIP). A FIP, no less than a SIP, may include "enforceable emission limitations or other control measures, means, or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances)." CAA § 302(y).[1]

[1] Likewise, state nonattainment plans under section 172 of the Act may include "economic incentives such as fees, marketable permits, and auctions of emissions rights." Section 172(c)(6). In addition, Federal regulations of consumer or commercial products that emit volatile organic compounds may include "any system or systems of regulation as the Administrator may deem appropriate, including … economic incentives (including marketable permits and auctions of emission rights) concerning the manufacture, processing, distribution, use, consumption, or disposal of the product." Section 183(e)(4). And states in extreme ozone non-attainment areas may be required to implement an economic incentive program which would include "State established emissions fees on sale or manufacture of products the use of which contributes to ozone formation." Section 182(g)(4)(A).

Like section 110, section 111(d) provides for state implementation of federal targets – in this case, federal performance standards. Section 111(d) requires EPA to establish "a procedure similar to that provided by [section 110] under which each State shall submit to the Administrator a plan" that establishes "standards of performance" for each existing source located in the state and "provides for the implementation and enforcement" of these standards. CAA § 111(d)(1). A "standard of performance" is

> 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.

CAA § 111(a)(1); *see* 40 C.F.R. § 60.22. EPA reviews state plans, and approves them if they are "satisfactory." CAA § 111(d)(2)(A); *see* 40 C.F.R. § 60.27(b). If a state plan is not "satisfactory," EPA has "the same authority to prescribe a plan for a State … as [it] would have under section [110(c)] in the case of failure to submit an implementation plan." CAA § 111(d)(2)(A); 40 C.F.R. § 60.27(c).

Based on the structural similarity of 111(d) and 110, underlined by the specific reference in section 111(d) to section 110, it is reasonable for EPA to conclude that the state and federal plans provided for under section 111(d) may also include "enforceable emission limitations or other control measures, means, or techniques (including economic incentives, such as marketable permits or auctions of emissions allowances)."

Although section 111(d) does not elaborate the specific implementation and enforcement measures that must be included in a 111(d) plan, EPA has taken the position that section 111(d) authorizes such plans to include the same kind of credit instruments that are available under section 110. *See* 40 C.F.R. 60.24(b)(1) (providing that emission standards included in state plans may "be based on an allowance system"); *see also* 40 C.F.R. § 60.33b(d)(1) (providing that state 111(d) plans for large municipal waste combustors may "allow nitrogen oxides emissions averaging"); Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units, 70 Fed. Reg. 28,606, (May 18, 2005) (vacated on other grounds) ("EPA interprets the term "standard of performance," as applied to existing sources, to include a cap-and-trade program.").

Further support for this approach comes from the term "system of emission reduction" in section 111(a)(1)'s definition of "standard of performance." This definition applies to the term "standard of performance" as used in section 111(d). An approach that allows EGUs to comply with standards by means of reductions achieved through Block 1 or by means of credits derived from activities described in Blocks 2–4 is a reasonable interpretation of the term "system of emission reduction."

As EPA has noted, the Act "does not define the term 'system,' and as a result, that term should be given its ordinary, everyday meaning: 'a set of things working together as parts of a mechanism or interconnecting network; a complex whole.' This definition is broad. It encompasses virtually any 'set of things' that reduce emissions."[2]

It is noteworthy that "system of emission reduction," as used in section 111(a) does not have any modifiers that would limit methods of compliance to Block 1 measures alone. In 1977 Congress added special language that required standards for *new EGUs only* to employ the "best *technological* system of emission reduction." But this limitation – which Congress deleted in 1990 – *never* applied to standards of performance for existing sources (including EGUs) under section 111(d).

Other provisions of the 1990 Clean Air Act Amendments use the term "system" to refer to market-based pollution control mechanisms. For example, the 1990 Amendments refer to the Acid Rain Program as an allowance "allocation and transfer system."[3] Elsewhere, the 1990 Amendments authorize EPA to develop a "system or systems of regulation" that may employ "economic incentives" to control emissions of volatile organic compounds from consumer or commercial products.[4] It is ordinarily presumed "that identical words used in different parts of the same act are intended to have the same meaning," *Atl. Cleaners & Dyers v. United States*, 286 U.S. 427, 433 (1932), and there is nothing to rebut this presumption here. Hence, EPA may reasonably conclude that the term "system" as used in section 111(a)(1) and reflected in section 111(d) encompasses the same type of market-based approaches to pollution control

[2] Legal Memorandum for Proposed Carbon Pollution Emission Guidelines for Existing Electric Utility Generating Units at 51 (2014) (citing Oxford Dictionary of English (3rd ed.) (published 2010, online version 2013) (defining "system")).

[3] Clean Air Act section 401. Under this system, each affected EGU is required to "hold allowances to emit not less than the unit's total annual emissions." Section 404(a)(1)(B). EGUs may also generate allowances by undertaking "qualified renewable energy" or "qualified energy conservation" measures to the extent that these measures reduced sulfur dioxide emissions from any EGU. Section 404(f). By allowing sources to comply with their emission targets by driving emission reductions anywhere on the power grid, the Acid Rain Program ensured that the necessary emission reductions would be achieved at the lowest possible cost.

[4] Federal regulations of consumer or commercial products that emit volatile organic compounds may include "any system or systems of regulation as the Administrator may deem appropriate, including … economic incentives (including marketable permits and auctions of emission rights) concerning the manufacture, processing, distribution, use, consumption, or disposal of the product." Section 183(e)(4). And states in extreme ozone non-attainment areas may be required to implement an economic incentive program which would include "State established emissions fees on sale or manufacture of products the use of which contributes to ozone formation." Section 182(g)(4)(A).

encompassed by the Acid Rain Program's "allowance system" and the volatile organic compounds "system or systems of regulation."

Thus, it is a reasonable interpretation of the statute for EPA to set standards of performance for existing sources predicated on Building Block 1 *and* credits from activities described in Building Blocks 2–4. The four building blocks represent a "system of emission reduction" that taps the emission reduction potential achievable at reasonable cost across the interconnected electricity system, using emission limitation methods, including crediting systems, authorized under section 110(a)(2).

2.1.2 *Performance standards for existing EGUs must reflect the emission reduction potential of the measures available for compliance.*

2.1.2.1 *EPA may reasonably establish binding emission guidelines.*

As a preliminary matter, EPA reasonably interpreted section 111(d) in its 1975 regulations to provide for the promulgation, after notice and comment, of binding emission guidelines that specify the emissions performance level that is required of standards of performance included in state plans.

As noted above, section 111(d) provides for EPA to review state plans and approve them if "satisfactory." When a state fails to submit a satisfactory state plan, EPA is required to issue a federal plan. These provisions authorize EPA to apply substantive criteria, not only procedural criteria, in making the determination whether a state plan is "satisfactory." Further, section 111(a)(1), which defines the term "standard of performance" used in section 111(d), provides that it is "*the Administrator*" who determines the "best system of emission reduction." Given that EPA may apply substantive criteria in its approval/disapproval decision *after* a state submits a plan, it is within EPA's discretion to articulate the criteria that will govern its approval/disapproval decisions *beforehand*, in emission guidelines adopted through notice and comment.

Congress recognized and approved the guidelines-setting process that EPA established in its 1975 regulations, when amending the Clean Air Act in 1977 and 1990. In 1977, the House committee explained that under section 111(d) the Administrator "would establish *guidelines* as to what the best system for each . . . category of existing sources is."[5] In 1990, in section 129 of the Clean Air Act, Congress directed EPA to adopt standards for solid waste combustion through a process that expressly refers to "*guidelines* (under section 7411(d) of this title . . .)."[6]

[5] H.R. Rep. No. 95-294, at 195 (1977) (emphasis added).
[6] Section 129(a)(1)(A) (emphasis added).

Section 129 requires EPA to promulgate guidelines "pursuant to section 7411 (d) of this title and this section [that] shall include . . . emissions limitations" and requires each state to submit to EPA a plan to implement and enforce those guidelines within a year following their promulgation.[7]

2.1.2.2 *EPA may reasonably establish differentiated performance standards on a state-by-state basis.*

It is reasonable for the EPA to establish different performance standards (or targets) for each state in order to reflect differences in the states' current electric generation mixes and future emission reduction capabilities. Existing EGUs differ from other types of sources previously regulated under section 111(d) in several important respects. Most source categories covered by past section 111(d) guidelines have consisted of small numbers plants operating independently at significant distances from one another, and emitting pollutants with localized impact. State-by-state target differentiation did not arise as an issue for these source categories.

In contrast, there are more than 1500 fossil-fueled EGUs that are functionally interconnected and interdependent in the electric grid, and they emit carbon dioxide, a pollutant that mixes uniformly in the atmosphere on a national and global basis. Further, the distribution of fossil-fueled EGUs differs from state to state, with some states having predominantly coal-fired units, others having predominantly gas-fired units, and others various mixes in between. In addition, the distribution of system-wide emission reduction opportunities from non-fossil generating resources (renewables, nuclear, hydro) and energy savings investments also varies from state to state.

In this context – and especially since section 111(d) provides for state-by-state implementation – it is reasonable for EPA to aggregate fossil-fueled EGUs by state and set differentiated targets on a state-by-state basis. This approach solves a significant problem with respect to the uneven distribution of types of EGUs: framing targets in terms of reduction from a baseline year, and differentiating those targets across the states makes it feasible to cost-effectively obtain the most CO2 reductions across the system. EPA's choice to set differentiated standards by state in this manner is reasonable.

---

[7] Section 129(b)(1)-(2). *See* the comments of Environmental Defense Fund (EDF) for further explanation of why EPA's 1975 emission guideline regulations comport with section 111(d). EDF explains also why any attack on the 1975 regulations would now be time-barred. NRDC agrees with EDF in these arguments. *See also* EDF, *The Legal Foundation for Strong, Flexible & Cost-Effective Carbon Pollution Standards for Existing Power Plants,* (revised Feb. 2014), http://www.edf.org/sites/default/files/section-111-d-of-the-clean-air-act_the-legal-foundation-for-strong-flexible-cost-effective-carbon-pollution-standards-for-existing-power-plants.pdf.

2.1.2.3 *EPA must take into account the emission reduction potential of permissible compliance methods when establishing standards of performance in emission guidelines.*

The statute requires consistency between the emission reduction methods considered in establishing a standard of performance and the emission reduction methods available for demonstrating compliance with that standard. This has been called the "symmetry principle."[8] Where the emission guideline allows compliance with a performance standard through a broad range of emission reduction methods, EPA must consider the emission reduction potential of those compliance methods when determining the level of reductions that the standard requires.

The symmetry requirement works in both directions. Standards must reflect the degree of reduction achievable through the best system of emission reduction, considering costs. It would violate that requirement for EPA to set a performance standard based on a given emission reduction method, but then not allow that method to be used for compliance purposes; such a standard would be more stringent than the statute permits. Likewise, it would violate the statute to allow the use of an identified emission reduction method for compliance purposes, but then ignore the reduction potential of that method when setting the target; such a standard would be less stringent than the statute requires. Neither standard would represent the degree of emission reduction achievable at reasonable cost through the best system of emission reduction. The first would over-represent what is achievable considering costs; the second would under-represent it.[9]

Thus, EPA's determination of the performance standard or target must be informed by the compliance methods EPA allows under the rule. Once EPA has identified the system of emission reduction that will be available for compliance purposes, it must set an emission standard that reflects the degree of emission limitation achievable, taking into account cost, by that system.

---

[8] *See* Kate Konschnik, Ari Peskoe, Harvard Law School, Environmental Law Program Policy Initiative, *Efficiency Rules: The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants,* page 5-6 (March 3, 2014) *available at* http://blogs.law.harvard.edu/environmentallawprogram/files/2013/03/The-Role-of-Energy-Efficiency-in-the-111d-Rule.pdf; *see also* NRDC, *Questions and Answers on the EPA's Legal Authority to Set "System Based" Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d),* page 5-6 (October, 2013) *available at* http://www.nrdc.org/air/pollution-standards/files/system-based-pollution-standards-IB.pdf.

[9] The symmetry principle receives further support from the innovation-forcing purpose of section 111. Indeed, the need to promote "innovation" is one of the factors that EPA is required to consider in establishing standards of performance under section 111. *See Sierra Club v. Costle*, 657 F.2d 298 (D.C. Cir. 1981); *see* S. Rep. 91-1196 at 16 (1970) ("Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources."). Clearly, a standard of performance will not succeed in promoting innovation unless it reflects, at minimum, the most stringent emission rate that can be achieved with available compliance mechanisms.

The inclusion of credits derived from Building Blocks 2-4 substantially simplifies the question of assessing technical feasibility, because it changes the inquiry from what emission reductions are available to each source *acting on its own*, to what emission reductions are available to each source *through the combination of measures acting alone and measures implemented through credit mechanisms across the electric system*. The same is true regarding the consideration of costs. Case law reviewed below establishes that EPA must show the costs of compliance are not exorbitant for existing power plants considered as a group. That judgment must be made in light of the compliance methods the standard permits. Any given standard will be less expensive to meet if it allows compliance on a system-wide basis – that is, by measures both within and beyond the fenceline – than if it allows compliance only by on-site measures. Thus, for any given cost, system-based standards can achieve greater emission reductions.[10]

Although EPA must "tak[e] into account the cost of achieving such reduction," nothing in section 111 requires the standards to preserve the unregulated economic position of individual facilities. Indeed, the D.C. Circuit has specifically rejected such a requirement, concluding that EPA may consider costs and energy 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 v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). EPA may not impose regulatory costs that are "exorbitant" or "greater than the industry could bear and survive" when considered "at the national and regional levels and over time." *Essex Chemical Corp. v. EPA*, 486 F.2d 427, 433 (D.C. Cir. 1973); *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999). Within that constraint, EPA is permitted to establish performance standards that are expected to result in the reduced utilization or retirement of affected sources.

[10] Some may argue that EPA must allow a state to grant variances exempting individual sources from meeting the state's target emission rate for their "remaining useful life." To the contrary, in the context of the flexible, system-based approach that EPA has proposed, there is no need – indeed no *room* – for allowing a state to grant variances that breach the applicable target emission rate (or mass-based limit). The statute provides for recognizing existing sources' "remaining useful life," but it does not define the term or the procedure that must be used. EPA's 1975 regulations constructed a variance process, but that is not the only reasonable way to give effect to "remaining useful life." In fact, the flexible design of the proposed emission guideline for EGUs *inherently* accommodates the "remaining useful life" of individual units while preserving overall emission reductions. The analysis supporting the final state target adopted next June will include an economic assessment – through IPM modeling and other means – that already accounts for the overall system costs of complying with those targets by all the EGUs subject to them – including the costs borne by units with the greatest emission reductions to make – and EPA will have determined those overall system costs to be reasonable. It would breach the integrity of those targets and double count costs to then allow some sources to operate under variances without covering their excess emissions. This does not prevent a plant owner from operating a facility for as long as it finds economically useful, provided the owner covers the unit's excess emissions with credits derived from eligible activities (e.g., Block 2-4 activities). *See* NRDC, *Questions and Answers on the EPA's Legal Authority to Set "System Based" Carbon Pollution Standards for Existing Power Plants under Clean Air Act Section 111(d),* page 8-9 (October 2013) *available at* http://www.nrdc.org/air/pollution-standards/files/system-based-pollution-standards-IB.pdf.

The history and purpose of the section 111 and the Clean Air Act as a whole support EPA's authority to establish a cost-justified emission standard even if it is expected to result in reduced operation or retirement of affected sources. Congress intended section 111 to incentivize the "constant improvement in techniques for preventing and controlling emissions," S. Rep. 91-1196 at 16 (1970), and further recognized that one of the most powerful ways to incentivize these improvements to ask industry "to do what seems to be impossible at the present time." 116 Cong. Rec. 32,901–02 (1970) (remarks of Sen. Muskie). Congress knew that in some cases, what seemed impossible would in fact *be* impossible, and that some industrial sources of pollution would have to be "closed down." S. Rep. No. 91-1196, at 2–3 (1970); *cf. Union Elec. Co. v. EPA*, 427 U.S. 246, 270 n.1 (1976) (Powell, J., concurring) ("The record is clear beyond question that at least the sponsors and floor leaders of the Clean Air Act intended that industries unable to comply with approved state implementation plans … would be 'closed down'"). But in other cases, the Act's "[t]echnology forcing hopes [would] prove realistic," *Whitman v. Am. Trucking Assn.*, 531 U.S. 490, 490–92 (2001) (Breyer, J., concurring in part and concurring in the judgment), and sources would be able to comply with applicable emission standards without curtailing their operations. Hence, the history and purpose of the Clean Air Act support EPA's authority to establish a cost-justified emission standard that is expected to cause some affected EGUs to reduce generation or retire.[11]

The D.C. Circuit has also held, in *Portland Cement v. Ruckelshaus,* 486 F.2d 375, 387 (D.C. Cir. 1973), that EPA is not required to perform a cost-benefit analysis under section 111 but must consider the results of such analyses when available. In this case, EPA has performed such analyses itself, and these analyses show that the quantifiable climate protection and public health benefits of meeting the proposed carbon pollution reduction targets vastly exceed the costs of implementation. NRDC submits that while no cost-benefit analysis is required, when such an analysis shows that benefits vastly exceed costs, EPA may – indeed, must – conclude that costs are reasonable and non-exorbitant.

NRDC's comments demonstrate that EPA's June proposal overestimated costs in a number of crucial respects, making the preponderance of benefits over costs even more striking. Further, NRDC has analyzed the impact of the range of corrections and improvements recommended in these comments, using the same IPM modelling platform that EPA used for the proposal. These IPM analyses show that the net effect of improving and strengthening the targets as NRDC recommends is a benefit-cost proposition even more favorable than EPA presented at proposal

[11] The Supreme Court ruled in analogous circumstances under the Federal Water Pollution Control Act of 1972 that the costs of an existing source standard are reasonable even if they lead some sources to curtail operations or close. See *EPA v. National Crushed Stone Association,* 449 U.S. 64, 76 (1980) (Water Act "contemplated regulations that would require a substantial number of point sources with the poorest performances either to conform to [best practicable technology] standards or to cease production").

(see Section 8 of our comments). Thus these recommended changes are justified under all reasonable methods by which EPA may "tak[e] into account costs."

2.1.3 *EPA must review and, if appropriate, revise the state targets at least every eight years.*

Section 111(d)'s duty to set standards for existing sources within a category is triggered by the establishment of standard for new sources within the category under section 111(b). *See* section 111(d)(1) and 40 C.F.R. § 60.22(a). Section 111(b)(1)(B) creates a requirement for periodic review and revision of standards; it states that "[t]he Administrator shall, at least every 8 years, review and, if appropriate, revise such standards following the procedure required by this subsection for the promulgation of such standards."

Given that the duty to set existing source standard under subsection (d) is directly linked to the duty to set new source standard under subsection (b), EPA must read the review and revision provision as a matter of plain meaning to trigger a review/revision requirement for existing source standards whenever review/revision falls due for new source standards. At the very least, EPA would be reasonable in reading the statute this way, and NRDC submits that to read it otherwise – to freeze existing source standards in place for all time irrespective of the need for continued emission reductions and irrespective of the occurrence of improvements in technology and costs – would be highly unreasonable.

In the present case, by June 2015 EPA will have promulgated both the pending proposed standards for CO2 emissions from new and modified EGUs and the emission guideline for existing EGUs. The legal obligation to review and, if appropriate, revise these standards therefore will mature, at the latest, in June 2023. NRDC strongly recommends, however, that EPA commit to review these standards on a five-year cycle, *i.e.*, by June 2020 and each five years thereafter, for the following reasons. NRDC elsewhere in these comments recommends establishing *in this rulemaking* a standard for 2025 – thus, breaking the proposed 10-year interim standard into two parts, with the 2025 standard establishing more ambitious targets for the second five-year period that reflects the full technological and economic potential for emission reductions. We also recommend that EPA set post-2030 standards on a five-year cycle, so that the 2030 standard would apply for the years 2030-2034, and a standard would be set for each subsequent five-year period.

Consistent with this five-year structure, NRDC submits that not later than June 2020 EPA should complete a review and revision rulemaking that (a) reviews the 2025 and 2030 targets and strengthens them to reflect technological progress and potential evident at that time, and (b) establishes targets for the five-year period beginning in 2035 that reflect the potential reductions achievable in that time period. A subsequent review should take place in five years, i.e., by June 2025, reviewing the 2030 and 2035 targets and establishing ones for 2040, and so forth. In this way, EPA will assure that standards stay reasonably up-to-date as measured against current data, and at the same time that industry and others will have ample notice of, and lead-time to meet, future responsibilities.

2.2 State plans may include "portfolio measures" that provide for "implementation" of the relevant standards of performance, but plans must also provide federally enforceable emission limits for EGUs sufficient to meet targets.

Section 111(d)(1) provides that states shall submit "plan[s] which … establish standards of performance for any existing source" and "provide[] for the implementation and enforcement of such standards of performance." As noted above, EPA observes that one acceptable form of state plans is one that establishes emission rate standards for each fossil-fueled EGU together with emission credit trading provisions, and another acceptable form is a plan that establishes a mass-based limit and tradable emissions allowances. In addition, EPA requests comment on "the extent to which measures such as RE and demand-side EE may be considered implementing measures in state plans if they are not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources." 79 Fed. Reg. 34,903

NRDC believes that state plans may include "implementation" measures that do not directly reduce emissions from affected sources, as well as measures that regulate entities other than affected EGUs. However, NRDC believes that any plan adopting these "portfolio" measures must also include federally enforceable emission limitations like those described in the previous paragraph, which require affected EGUs to demonstrate compliance with the relevant standards of performance in the event that the portfolio measures fail to deliver the required emission reductions.

EPA is correct that states may include portfolio measures in their 111(d) plans as "implementation" measures. Section 111(d) provides that state plans under this subsection should be modeled on the state implementation plans that states develop under section 110 to provide for attainment of national ambient air quality standards. Section 110 provides that "state implementation plans" may include a variety of measures that do not directly reduce emissions from affected sources, as well as measures that regulate entities other than pollution sources.[12] Because Congress provided that "state implementation plans" may regulate entities

[12] For example, section 110 authorizes state implementation plans to include "any indirect source review program" which EPA may "approve and enforce, as part of an applicable implementation plan." Clean Air Act § 110(a)(5)(A)(i). An indirect source review program regulates any "facility, building, structure, installation, real property, road, or highway which attracts … mobile sources of pollution," and requires that indirect sources take "measures as are necessary to assure … that a new or modified indirect source will not attract mobile sources of air pollution." Clean Air Act § 110(a)(5)(A).

other than pollution sources or include measures that do not directly result in emission reductions, it is reasonable for EPA to conclude that state section 111(d) plans "for the implementation [of] … standards of performance" may include similar measures.

EPA may approve a state plan that includes portfolio measures, however, only if the plan also "provides for the … enforcement of [the] standards of performance" established for the affected sources. CAA § 111(d)(1)(B). Thus, even if a state intends to rely on portfolio measures to deliver the emission reductions required by its state target, its section 111(d) plan must provide for federal enforcement of the relevant standards of performance in the event that the portfolio measures fail to deliver the required emission reductions. The backstop would need to be designed to secure from affected EGUs any "missing" emission reductions from portfolio measures that fall short of their goals. The necessary provisions could take the form of a requirement that regulated EGUs make sufficient reductions or secure sufficient credits from redispatch, renewable energy generation, and energy efficiency activities to make up the shortfall within the same compliance year. The obligation to make up the shortfall could be allocated among sources in any manner acceptable to the state. The backstop would be included in the operating permits of the regulated entities, and would be federally enforceable by EPA under section 113 of the Clean Air Act, and by citizens under section 304 of the Act.

2.3 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 and 2011 as well, 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 all nuclear generation and excluded all hydro generation. The agency included non-hydro renewables and a portion of nuclear. In this section, we address the baseline years and what generation should be factored in to the formula.

2.3.1 *Baseline or comparable year.*

NRDC strongly supports using the most up-to-date data and most recent baseline year to develop the target emission rate for each state. The goal of this exercise is to reduce emissions from existing power plants. The farther back in time EPA looks, the higher emissions are and the more variability there is by state. Emissions have been declining nationally since 2005/2007, but not consistently in all states. 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.

That being said, 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, it is reasonable for EPA to examine and potentially use a multi-year average as the starting point in their evaluation and formula.

NRDC does not believe states should be allowed to pick from the three years, as this will inevitably create an incentive to pick only the highest emission year(s) in order to set the emissions standard at the highest point possible, thus inaccurately limiting the requirement on state generators to reduce their emissions. Allowing states to pick a year(s) will arbitrarily undermine the environmental outcome of the Clean Power Plan.

2.3.2 *Inclusion of renewables and nuclear.*

EPA has included non-hydro renewables and a portion of nuclear power in 2012. However, EPA should assess the benefits of removing all the non-fossil generation from the BSER baseline year in the formula, by starting with a fossil-only intensity rate and crediting incremental low- and non-emitting generation added after the baseline year after accounting for the following issues:

1) Current State Renewables Policies and In-state vs. Out of State Considerations:

    In many states, the state policy that has delivered the most development and generation from new renewable energy has been state renewable energy standards or portfolio standards (RES/RPS). These standards have increased 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 large quantities of wind generation to satisfy the RES/RPS requirements in other states.

    EPA has developed the BSER baseline and formula by including all the renewables located within each state when developing that state’s target. But in many instances another state may be claiming the output or credit for that development and be buying the energy and/or hold the renewable energy certificates (RECs) associated with generation. EPA is also considering tracking ownership of renewables in rate-based approaches using RECs, which could be from in-state or out-of-state generation.

    EPA should create greater consistency between the BSER formula structure, current state renewables tracking, and planned compliance tracking. While there are several ways this could be accomplished, the simplest way would be to consider only new RE generation and not include existing RE generation in the BSER baseline. This allows EPA to avoid allocating generation from existing renewables in the BSER formula, which may be located in one state with output claimed by another state. Looking forward there would be no concern about using RECs for tracking generation whether from in-state or out of state generation, if the formula is no longer based only on in-state generation. It also avoids the problem of including in-state generation in the determination of a state's target when the state does not receive the output of generation delivered to and utilized by another state.

2) Crediting for Early Action:

   Many states and companies have expressed a wish to receive credit for early action in BSER state target calculation, in general and also in relation to renewables. However, there is significant misunderstanding about credit and burden-sharing: Clean Power Plan requirements only apply to fossil plants, and clean plants face little to no additional cost or burden. As a result, under the rule as proposed, states that currently have larger than average amounts of non-emitting generation in fact have much less work to do, contrary to some stakeholders' misunderstanding.

   The current proposed approach ties target setting to the renewables generation in the state and not to the purchaser of that generation. To address this unnecessary complication, EPA should remove the existing generation from the BSER target setting formula to address this issue. As discussed in Section 6 on renewables and Building Block 3, one way to address early action for state renewable policies would be to make the strengthening changes we recommend for Block 3 and then adjust the renewables target down based on the generation a state RPS has delivered in 2012 (or over the three year average).

3) Implications of Including all Non-fossil Resources if Plants Retire:

   Another option that has been discussed by stakeholders is to include total generation and emissions from all sources in the BSER formula, including all nuclear and hydro. This approach would deliver a lower emissions standard. While this would create an incentive to keep non- and low-emitting resources running and force any retirements to be replaced with resources of similarly low emissions, we are concerned that the approach would impose an unfair burden on states that face retirements and thus incentivize the continued use of nuclear plants that may be unsafe (see Section 6).

4) Consistent Treatment of Resource Types:

   While there are legitimate reasons to include renewables in the BSER calculation, especially those developed in response to RES/RPS requirements which were implemented to address emissions goals, it is simpler to treat all resources with the same emissions profile the same. This allows EPA to be technology-neutral and not have to classify resources by type or category, which would be inevitably contentious and time-consuming. For example, existing wind (100% included), hydro (0% included), and nuclear (5.8% included) are all treated differently in the BSER formula. Again, if the existing resources are excluded from the BSER formula, EPA can credit all new non-emitting resources in the same way going forward and avoid concerns about inconsistent treatment.

5) Consistency of State Targets:

   Including non-fossil resources in the BSER formula leads to more disparate state targets than if an average fossil-only rate is used as the starting point. Of greater concern are the distortions such inclusion would create during compliance: 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, which would be solved if the starting point for developing the state standards was a fossil-only rate.

2.4 EPA should not adopt the alternative option of a single five-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 show 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.[13]

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.[14] 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.[15] Second, under Block 2, EPA assumed that the potential annual utilization rate for NGCC units would increase to 65 percent instead of to 70 percent.[16] 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[17] As EPA has noted, these assumptions may be "overly

[13] *See* 79 Fed. Reg. 34,830, 34,898.
[14] *See id*. at 34,898.
[15] *Id*.
[16] *Id*.
[17] *Id*.

conservative," and "underestimate the extent to which the key elements of the four building blocks . . . can be achieved."[18]

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[.]"[19]

2.5 EPA should not adopt a BSER based only on building blocks 1 & 2.

Across the country, states and power companies have reduced and continue to reduce carbon pollution through increased deployment of low- and zero-emission generation and demand side energy efficiency programs, across the integrated power grid. EPA has documented these ongoing initiatives to reduce CO_2 emissions from the power sector.[20] These systems of emission reduction are adequately demonstrated and are already producing 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."[21] 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 more cost effectively, while generating greater co-benefits through reductions of harmful co-pollutant emissions, utility bill savings, and increased economic activity.

As outlined in detail in Section2.1, the statutory term "best system of emission reduction" is broad enough to encompass measures that have the effect of preferring lower-polluting means of producing electricity. Consequently, EPA has the authority and 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 more efficacious than 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 already effectively utilize to reduce carbon pollution.

---

[18] *Id*.
[19] *Id*.
[20] *See* 79 Fed. Reg. 34,830 34,848-50.
[21] *Id.* at 34836.

3.0 Implementation of BSER Goal-Setting Equation and Treatment of Incremental Renewables and Energy Efficiency

3.1 Background and Introduction.

In its October 27, 2014 Notice of Data Availability (NODA), 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. In setting state targets, EPA should employ a formula that fully reflects the potential for zero-emitting resources and demand-side efficiency to reduce emissions from fossil generating units. This will be achieved by basing targets on the use of available Block 3 and Block 4 resources to displace the highest-emitting fossil units (generally coal-fired power plants) first. This approach will achieve the greatest emission reductions from the available resources and thus comports with the Act's mandate to base standards on the best system of emission reduction.

3.1.1 *EPA's rationale for relying on renewables and energy efficiency to define BSER is correct but its proposed formula is not consistent with the rationale.*

In the June proposal, EPA states that the reason that renewable energy and energy efficiency are part of BSER is because they all decrease the amount of generation at the power plants subject to the rule ("affected units"). For example, EPA states that renewables and energy efficiency are included in BSER because "the measures in building blocks 3 and 4 . . . reduce, or avoid, generation from all affected EGUs on a state-wide basis."[1]

In the goal-setting equation, EPA correctly accounted for the displacement effect of the resources in Block 2 (natural gas units) but failed to correctly account for the effect of the resources in Blocks 3 and 4. For Block 2, EPA accurately reflected the fact that the increase in generation from natural gas units can achieve a corresponding decrease in generation (and emissions) at coal-fired steam power plants. But EPA failed to apply this approach for Blocks 3 and 4. Rather, the original proposal's state target calculation formula simply adds additional renewable energy and energy efficiency megawatt-hours to the denominator of the formula without reducing generation or emissions at fossil-fuel fired plants. As a result, under the proposed formula, Block 3 and 4 resources do not reduce generation or emissions from

[1] 79 Fed. Reg. 34,830, 34,891 (June 18, 2014); *see also* 79 Fed. Reg. 34,830, 34,852 (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").

affected units. Rather, they simply result in a somewhat lower state target based on the *dilution* effect of dividing a fixed amount of carbon pollution by a larger number of megawatt-hours. This fails to achieve EPA's stated objective to consider the ability of the Block 3 and 4 resources to "reduce, or avoid, generation from all affected EGUs on a state-wide basis."

The defect in the original formula is significant because it fails to use block 3 and 4 resources to actually achieve emission reductions from affected units, thus resulting in numerically larger state targets that allow significantly higher emissions from those affected units to continue. 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.

3.2 Recommendations for correcting the BSER formula.

EPA has proposed two alternative approaches for determining the target that could be achieved by use of incremental renewable energy and energy efficiency to displace generation from existing fossil units. Under the first alternative approach, incremental renewables and energy efficiency would be assumed to displace fossil generation on a pro rata basis across all fossil generation unit types, including fossil steam and natural gas. [2] Under the second alternative approach, the target would be based on the reductions achievable by displacing the highest-emitting generation first with the incremental renewables and energy efficiency resources.

In states with a substantial amount of coal-based generation remaining after application of Block 2, the latter approach (assume highest-emitting units are displaced first by RE and EE) results in substantially more protective targets and achieves greater emission reductions. It is the approach that best implement the Act's mandate to base standards on the "best" system of emission reduction because it achieves the greatest emission reduction. Based on modeling already completed, NRDC submits that this approach can be implemented at reasonable costs and thus is the approach required to implement the Act's BSER mandate.[3]

[2] If EPA were to adopt a formula in which RE and EE displace all existing fossil generation on a pro rata basis, it would have to ensure that it maintains the potential emission reductions from building block 2. If RE and EE are assumed to displace NGCC generation, that would lower the capacity factor of NGCC plants and create additional potential reductions from building block 2, when using a 70 percent (or any other) achievable NGCC capacity factor in target setting. The correct reductions from NGCC units could be calculated either by displacing fossil generation with block 3 and 4 resources before calculating the block 2 resources or by doing a true-up to block 2 to restate the achievable reductions by returning NGCC units to the specified 70 percent capacity factor.

[3] These comments include several modeling analyses in Section 8, and NRDC will be submitting additional results as soon as they are completed.

In its NODA, EPA raises the issue whether some renewables and energy efficiency resources might be used to meet demand growth in some states and thus not available to displace generation from existing fossil units. First, it is important to restate that EPA's assumptions regarding resource deployment in its building block formulas are not in any way binding as requirements for deploying resources. They are simply an analytic construct designed to assess the technical and economic feasibility of various patterns of resource deployment for standard-setting purposes.

As a technical and reliability matter, there is no conflict between basing state targets on the use Block 2, 3, and 4 resources to displace existing dirtier fossil generation and ensuring adequate resources to meet system demand. First, states can moderate demand growth by deploying EE above the amounts assumed by EPA in Block 4. And any unmet projected demand can be met by deploying resources that are not subject to the requirements of EPA's 111(d) rules: new fossil generation, additional renewables, and nuclear. There may be incremental system costs associated with these investments and those costs may properly be considered by EPA in determining the final state targets but EPA may not legally decline to recognize the ability of cleaner resources to displace high-emitting existing fossil generation based on general claim that there may be competing uses for those cleaner resources.

EPA correctly explains that the displacement approach in its October 2014 NODA would "recognize a greater reduction potential in carbon intensity from incremental renewables and energy efficiency, and it would be more closely analogous to the treatment of incremental NGCC generation identified under building block 2 (given that under the proposal, generation from building block 2 was assumed to reduce carbon intensity by replacing generation from 2012 levels)."

3.3 The alternative approaches to state goal calculation produce more ambitious state goals and drive greater emission reductions without significant cost increases.

This formula correction to apply a consistent displacement assumption for all cleaner resources alone will demonstrate that more ambitious state targets are achievable. As discussed above, this approach is called for by the Act's BSER mandate because it ensures that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

EPA also raised additional considerations in its NODA, including increased stringency, and increased costs along with increased benefits. NRDC disagrees that increasing the stringency of these standards will lead to increasing costs above the range of costs shown in the proposal.

As NRDC demonstrated in a November 2014 issue brief[4], EPA's June proposal used conservative and out-of-date assumptions on the costs of both energy efficiency and new renewable technologies. The EPA assumptions led to an overestimation of compliance costs associated with the proposed Clean Power Plan. In fact, NRDC found that compliance with the Clean Power Plan would deliver savings to the electric power sector and its consumers.

Consequently, EPA has significant headroom to strengthen the standards while keeping compliance costs within the proposed range. It is critical that EPA utilize updated cost and performance data for renewables and energy efficiency in its evaluation of the final Clean Power Plan.

In the Notice of Data Availability, EPA points out that a number of the possible changes it sought comment on might interact. NRDC views these considerations as part of the broader BSER definition. In finalizing the Clean Power Plan, when applying a corrected, consistent displacement approach for calculating state goals, EPA may also consider whether adjustments to any other building block parameters are appropriate. For example, EPA could consider inclusion of new NGCC units in calculating state targets, as well as alternatives to the assumption of 70% NGCC utilization in 2020. However, as EPA considers these kinds of adjustments, it must bear in mind the importance of strengthening the near-term environmental outcome in 2020 and the goal of significantly strengthening the emissions outcome between 2020 and the final compliance date.

[4] NRDC's November 2014 issue brief, titled, "The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030," available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf (attached as Appendix 8C).

4.0 BSER Block 1 – Coal Plant Efficiency

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.[1] EPA's analysis and other industry and academic studies also find significant variation in the heat rate of comparable existing steam EGUs, strongly indicating that many existing steam EGUs have not yet implemented all cost-effective heat rate improvement measures.

There are a number of reasons why even cost-effective coal plant efficiency improvements have not been implemented. These include the fact that, in some rate-regulated markets, power plants are allowed to pass fuel costs on to consumers, reducing the financial incentive for onsite efficiency improvements.[2] In addition, coal plants in competitive markets seldom set the clearing price for electricity, and so may not face competitive pressure to look internally for all cost saving measures. At some plants, there are institutional barriers to making such changes, or a lack of onsite engineering personnel focused on increasing efficiency.[3] Finally, many plants are old, with more than 30 percent of plants over 50 years of age.[4] The operators of a number of these plants, and younger plants as well, may have deferred significant upgrades until the future regulatory environment for a range of air pollutants, including mercury and carbon dioxide, became clearer.

As described below, EPA's Building Block 1 analysis represents a highly conservative evaluation of the potential opportunities for coal plant efficiency improvements. Moreover, EPA's Building Block 1 analysis does not include any of the substantial opportunities to reduce emissions by co-firing with natural gas. 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.

---

[1] EPA, GHG Abatement Measures Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602, page 2-6 to 2-11 (June 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

[2] *See* DOE/NETL, *Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants: Workshop Report*, page 2 (July 2009) *available at* http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/OpportImproveEfficExistCFPP-ReportFinal.pdf.

[3] *See id.* at 2-3; Joshua Linn, Erin Mastrangelo, & Dallas Burtraw, *Regulating Greenhouse Gases From Coal Power Plants Under the Clean Air Act*, page 7-8 (Feb. 2013) *available at* http://www.rff.org/rff/Documents/RFF-DP-13-05.pdf.

[4] World Resources Institute, *Seeing is Believing: Creating a New Climate Economy in the United States* (October 2014) *available at* http://www.wri.org/publication/seeing-believing-creating-new-climate-economy-united-states.

4.1 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 Laboratory (NETL), Resources for the Future, and others.

4.1.1 *Heat rate improvements.*

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 NETL have extensively analyzed 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" given "a combination of aggressive refurbishment and improved operation maintenance."[5] NETL's consultations with industry experts validated this conclusion, identifying over 50 opportunities to improve thermal efficiency[6] 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."[7] 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.[8]

EPA's own analysis takes a far more conservative approach to quantifying the average efficiency improvement that existing coal-fired generating units can reasonably achieve. For example,

---

[5] Phil DiPietro & Katrina Krulla, *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions*, DOE/NETL-2010/1411, page 5 (April 16, 2010) *available at* http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf.

[6] DOE/NETL, *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States*, page v (Feb. 2010) *available at* http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf.

[7] DOE/NETL, *Opportunities to Improve the Efficiency of Existing Coal-Fired Power Plants: Workshop Report,* page 2 (July 2009) *available at* http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/OpportImproveEfficExistCFPP-ReportFinal.pdf.

[8] DOE/NETL, *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States*, page vi (Feb. 2010) *available at* http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf.

when examining opportunities to improve efficiency through best operating practices, EPA assumes that power plants can eliminate only 30 percent of the difference between their own hourly heat rate and the heat rate of the top 10 percent of comparable power plants.[9] This results in substantially lower heat rate improvements than NETL's analysis, which found that existing coal-fired power plants could achieve or exceed the performance of the top 10 percent of their peers through upgrades or operational improvements.[10] NETL also 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 refurbishments or equipment upgrades. Even this more conservative 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.[11] As EPA notes, its projected four percent improvement in heat rate from best operating practices would require only that each existing coal-fired power plant return to its best three-year average performance during the period from 2002 to 2012.[12]

EPA's analysis of the potential for heat rate improvements from equipment upgrades is also highly conservative. Building Block 1 includes only one half of the opportunity identified by EPA for equipment upgrades, reducing the potential improvement in heat rate from an average of four percent to just two percent.

Finally, EPA's analysis of heat rate improvements neglects opportunities to improve net heat rates through upgrades to auxiliary equipment that consume electricity onsite.[13] As EPA notes, these loads – which include pumps, fans, motors and pollution controls – represent between four to 12 percent of gross generation at a coal-fired steam EGU.[14]

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 demonstrating 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

---

[9] EPA, GHG Abatement Measures Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602, page 2-32 (June 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

[10] Phil DiPietro & Katrina Krulla, *Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions*, DOE/NETL-2010/1411, page 4-5 (April 16, 2010) *available at* http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf..

[11] *Id.* at 6.

[12] GHG Abatement Measures Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602, page 2-34 (June 10, 2014).

[13] *Id*. at 2-37.

[14] 79 Fed. Reg. 34,830, 34,860.

demonstrating compliance to account for the variability in performance of the control technology.[15] Here, there is ample evidence to support EPA's determination that a six percent average improvement in heat rate is feasible, without even considering co-firing with natural gas. 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 by using various emission reduction strategies – allows for compliance by all units, regardless of the potential variability in the opportunity for heat rate improvements. The record also demonstrates that there are many opportunities for heat-rate improvements at affected facilities beyond the particular measures that were the focus of EPA's analysis. Existing coal-fired power plants whose owners believe they cannot achieve the six percent reduction in heat rate could also easily meet the anticipated reduction in emissions through modest co-firing with natural gas. In sum, EPA's target for average heat rate improvements is "achievable" under section 111.

4.1.2 *Repowering and co-firing with natural gas.*

EPA considered co-firing and conversion to natural gas as a potential BSER, but concluded that coal-to-gas conversion is not a BSER due to the allegedly high costs of the resulting emission reductions.[16] However, 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. Please see further discussion on the opportunity to transition existing coal to existing and new natural gas in Section 5 and comments on this topic from the Environmental Defense Fund.

4.1.3 *Onsite redeployment.*

Additional carbon dioxide 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 carbon intensity of the fuel deployed. We encourage EPA to evaluate the opportunities for such reductions in the final rule.

---

[15] *Sierra Club v. Costle*, 657 F.2d 298, 372-73 (D.C. Cir. 1981) (where EPA had based an NSPS on its estimation of 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).
[16] 79 Fed. Reg. 34,830, 34,982.

5.0 BSER Block 2 – Reducing Emissions by Shifting Generation from Coal to Gas

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 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 though those plants were not considered in setting the targets. As described below, EPA must maintain symmetry between the target setting and compliance.

EPA's Notice of Data Availability (NODA) of October 30, 2014, evaluated 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.[1] EPA also requested comment on an approach that would treat the increased use of natural gas "comprehensively" rather than considering separately the potential to redispatch coal-fired generation to 1) existing NGCC, 2) new NGCC, and 3) to co-fire natural gas at coal plants or to convert coal plants to natural gas plants.[2]

EPA should take this "comprehensive" approach to increased utilization of natural gas. 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 cost-effectively and reasonably 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, in setting targets, EPA should assume that at least two percent of a state's coal-fired generation 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 would allow for a greater redispatch between coal and gas, that higher level should be used to set the state's target.

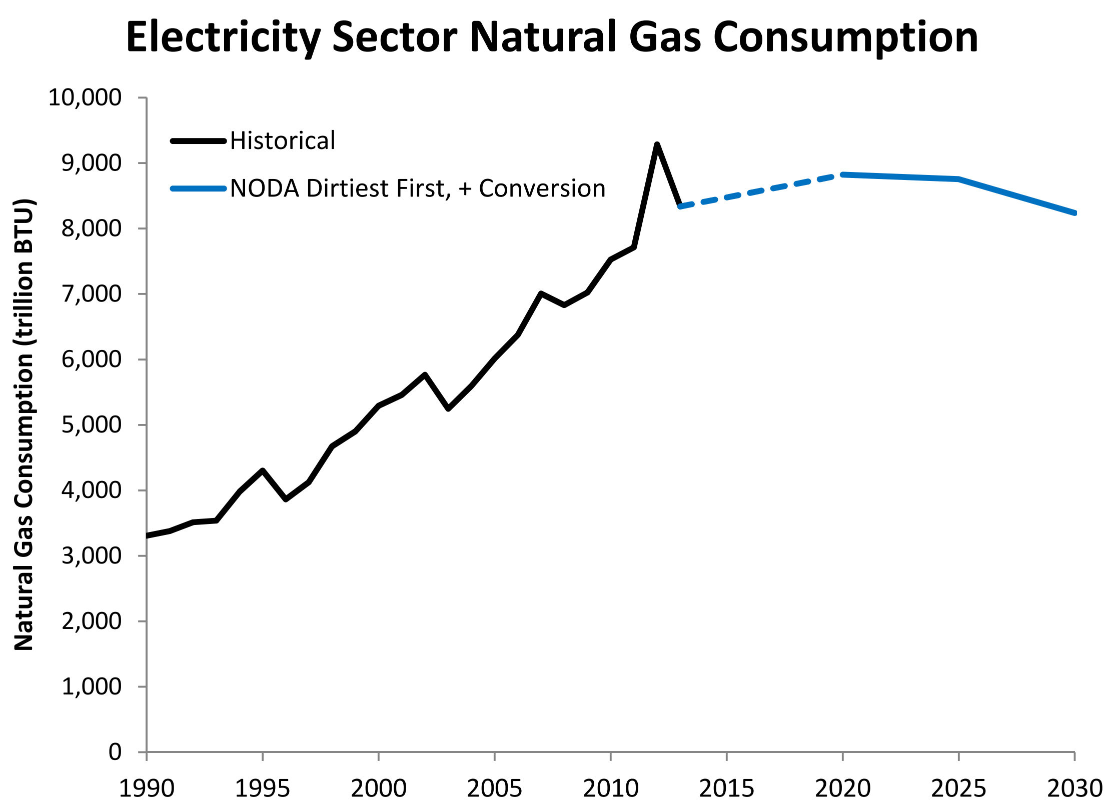
These suggestions for improving the Clean Power Plan address the question of what cost-effective, reasonable carbon reduction techniques EPA should use to set state targets in the BSER Guideline. We believe that even if EPA follows all our recommendations for strengthening the targets deemed BSER, EPA 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

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, Notice of Data Availability, 79 Fed. Reg. 64,543 (Oct. 30, 2014).
[2] *Id.* at 64,546.

EGUs. Thus 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, 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 a lower carbon-polluting energy mix.

Indeed, if EPA adopts the changes NRDC recommends, natural gas use will fall over the ten year period: NRDC retained ICF to use its IPM model to show the level of natural gas usage as states meet the targets NRDC recommends. The result of this modeling is shown in figure 5.1 below. As the chart illustrates, even with the recommended redispatch included in building block two and even if states have the option of using new and existing gas and co-firing, ICF's analysis shows that the Clean Power Plan will result in declining natural gas usage by the end of the ten-year compliance period.

Figure 5.1. Historical and Projected Natural Gas Consumption Under the NODA Dirtiest First, + Conversion Policy Scenario.



5.1 Treatment of new NGCC for target setting and compliance must be symmetrical.

The technical and economic feasibility of an emission limit is linked to the methods available for demonstrating compliance.[3] If a guideline allows compliance through a given method of reducing emissions, then EPA must consider that compliance method when determining the level of reductions that the standard of performance or target requires. In other words, the statute requires symmetry. Accordingly, it would be a legal deviation 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 legal deviation to allow the use of a reasonably foreseeable emission reduction technique for compliance purposes but exclude it from consideration when setting the target. The first standard would over-represent what is achievable; the second would under-represent it. Neither standard would represent the degree of emission reduction achievable at reasonable cost through the best system of emission reduction.In this instance, it is reasonable to accurately project the construction of certain amounts of new NGCC capacity based as such a projection would be on the historical level of new, additional NGCC capacity that is already reducing net carbon emissions rates. 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. Indeed, EPA's own IPM compliance modelling runs assumed new NGCC capacity would count for compliance, even though it was not taken into account when calculating building block 2. This asymmetry must be addressed in the final rule by accounting for new NGCC in building block 2.

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 BSER 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.

5.2 Redispatching generation from coal to natural gas, co-firing, or conversion of coal plants to natural gas plants 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, and should be included in calculating BSER. The power sector has been constructing and generating electricity with natural gas in combined cycle natural gas plants for many decades. After many decades in which coal-fired steam generation dominated baseload generation in the United States, a significant switch of baseload capacity from coal-

---

[3] *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").

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.[4] During the same period, natural gas generation climbed from about 650 thousand GWh to over 1.2 million GWh, and capacity increased from 165 GW to 242 GW, 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,[5] compared to only 10 percent in 1994.[6]

According to EIA, annual increases 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 an annual increase high of 25%.

- Annual natural gas generation increases have averaged 5% per year, with an annual increase high 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 from increased natural gas utilization 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.[7] (As we note in more detail below, however, it is also critical that EPA act to reduce the emission of methane that occurs during the production and distribution of natural gas and during the mining of coal.)

5.2.1 *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 seventy percent

[4] EIA, Electric Power Monthly, at Table 1.1 (Apr. 2014) *available at* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_1_01.
[5] *Id.*
[6] EIA, Electric Power Monthly, DOE/EIA-0226(96/07) (July 1996), *available at* http://205.254.135.7/electricity/monthly/archive/pdf/02269607.pdf.
[7] EIA, Carbon Dioxide Emissions Coefficients (Feb. 2013) *available at* http://www.eia.gov/environment/emissions/co2_vol_mass.cfm.

capacity factors in recent years.[8] Similarly, IPM modeling demonstrates that operating each state's NGCC fleet at such a capacity factor (on average) is technically feasible.[9]

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 before considering the additional public health and climate benefits that such a shift in dispatch would create.

5.2.2 *New NGCC plants.*

The 119 GW of new NGCC plants that have been constructed over the ten-year period from 2003 to 2012 confirm that it is reasonable to anticipate a continued rate of expansion of this well-understood technology.[10] 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."[11]

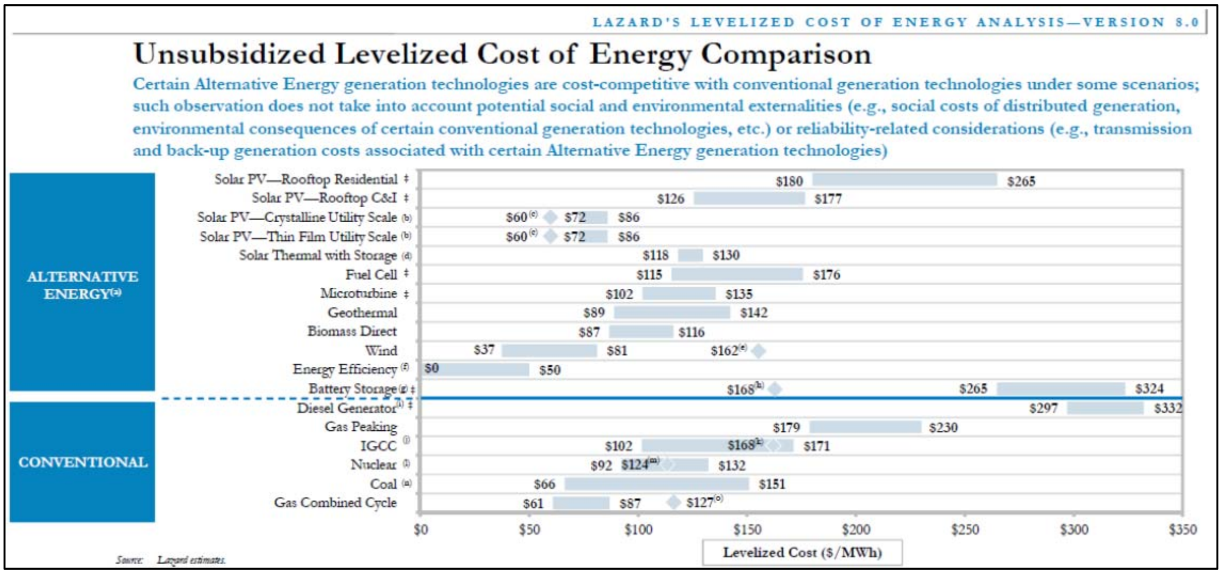
The IPM model results also affirm that the costs of new NGCC are reasonable. The IPM model seeks to satisfy each state's target rate through the least expensive methods. Thus, the fact that the model selected new NGCC (even though NGCC was not included to set the targets) demonstrates that the costs of those plant builds are least-cost and therefore reasonable.

In addition, financial analysts such as Lazard illustrate that new NGCC is one of the lower cost generation resources available to power companies today, as shown in Figure 5.2 below (energy efficiency, wind, and utility scale solar are also competitive with natural gas).[12]

---

[8] *See* EPA, Greenhouse Gas Abatement Measures, Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602, page 3-9 (June 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.
[9] *See* 79 Fed. Reg. 34,830, 34,865.
[10] *See* EIA, Recent Mix of Electric Generating Capacity Additions More Diverse (June 2011) *available at* http://www.eia.gov/todayinenergy/detail.cfm?id=1690; *see also* EIA, AEO2014 Early Release Overview, Electricity Generation (December 2013) *available at* http://www.eia.gov/forecasts/aeo/er/early_elecgen.cfm.
[11] 79 Fed. Reg. 34,830, 34,876.
[12] Lazard, Levelized Cost of Energy Analysis – version 8.0 (2014) *available at* http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf.

Figure 5.2: Lazard's Levelized Cost of Energy Analysis.



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.[13] 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.[14] 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.[15] 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.[16] Following the proposal of the Clean Power Plan, additional

[13] 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).
[14] 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/.
[15] 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.
[16] Duke Energy, *Progress Energy Carolinas to retire two coal-fired power plants Oct. 1*, Press Release (Sept. 28, 2012) *available at* 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.

coal-to-new-NGCC replacement plans have been announced.[17] Clearly, new NGCC capacity is a predictable means of reducing carbon pollution rates and should be included in BSER.

5.2.3 *Conversion to or co-firing with natural gas.*

The third method of using natural gas to reduce emissions at coal-fired power plants — conversion or co-firing — is similarly well-demonstrated and of reasonable cost.

Already a number of coal-fired steam generating units have converted, or are planning to convert, to natural gas, with some utilities converting over a decade ago.[18] Conversions—including Alabama Power's conversion of four units at the Gaston Electric Generating Plant—have occurred at baseload generating units.[19] Utilities have even found it economical to convert to gas even when doing so required the construction of more than thirty miles of pipeline.[20] The cost of conversion is minimal for units that are already designed to burn gas,[21] 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.[22] Recent

---

[17] 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. Robert Varela, *TVA proposes to replace coal-fired plant with natural gas units*, Public Power Daily (July 7, 2014) *available at* http://www.publicpower.org/media/daily/ArticleDetail.cfm?ItemNumber=41721; 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.

[18] In 2003, Dominion Energy converted two units at its Possum Point Power Station from coal to gas. Dominion Energy, https://www.dom.com/corporate/what-we-do/electricity/generation/fossil-fueled-power-stations/possum-point-power-station.

[19] *See* Scott Disavino, *Southern to Repower Three Alabama Coal Power Plants with Natgas*, REUTERS (Jan. 16, 2014) *available at* http://www.reuters.com/article/2014/01/16/utilities-southern-alabama-idUSL2N0KP1WA20140116.

[20] *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.

[21] *See* Ameren Missouri, 2014 Integrated Resource Plan, page 4-18 (2014) *available at* 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).

[22] *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").

reports indicate that 10,894 Mwh of coal generation are currently slated for conversion to natural gas.[23]

Co-firing also results in significant operational advantages, as EPA notes in its NODA. 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 64,550. 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 costs of conversion and co-firing are 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."[24] The costs of conversion easily meet this standard. The number of existing and planned conversion projects already 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: 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.[25] 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.

5.3 EPA should adopt the minimum level of generation shift from higher-emitting to lower-emitting sources.

In its 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 through co-firing. Treating different methods of switching from coal to gas in a

---

[23] *See* SNL Energy, Coal unit retirements, conversions continue to sweep through power sector (October 14, 2014) *available at* http://www.mining.com/web/snl-energy-coal-unit-retirements-conversions-continue-to-sweep-through-power-sector/.

[24] *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).

[25] EPA, GHG Abatement Measures, Technical Support Document, Docket ID No. EPA-HQ-OAR-2013-0602, Chapter 6, at 6-4 to 6–8 (Jun. 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

comprehensive manner is also not only reasonable, but also logical, since these methods are variations of the same basic, already-occurring shift toward cleaner fuels. Second, the NODA's minimum shift approach ensures that the cost-effective potential to shift from coal-to-gas will be more accurately reflected in the targets of all states with coal-generation, not just in those states that also happen to have underutilized existing NGCC capacity under the original proposal.

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 could 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. NRDC assessed a far more conservative approach – a two percent per year rate of coal-to-gas shift (20% from 2020 to 2029) – along with other suggested changes using the IPM model (see results in Section 8). Our modeling result demonstrates that a coal-to-gas shift at the two percent rate is highly cost-effective. We did not have time or resources to complete additional IPM runs testing the cost-effectiveness of higher shift rates within the comment period. We urge EPA to consider higher shift rates, up to and including a continuation of a five percent per year shift rate, which is the already-existing historical average over the last 10 years.

5.4 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). EPA's proposal to consider new NGCC plants simply requires that new 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. Thus, new NGCC capacity would not be regulated under section 111(d) any more than new renewable capacity. 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.

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).

5.5 EPA must promptly set standards for methane emissions from the oil and gas sector.

The methane pollution that occurs during the exploration, production and distribution of oil and gas is a major problem for the climate and public health. NRDC takes this opportunity to reiterate the importance of reducing these emissions from both existing and new sources in the oil and gas sector. 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 this sector and address the upstream emissions from natural gas power plants.

6.0 BSER Block 3 – Renewables and Nuclear

6.1 Renewable energy.

NRDC 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 states' generation fleets, and expanding renewable energy (RE) should be included in the Best System of Emissions Reduction (BSER).

NRDC's comments on building block 3 address four primary points.

First, NRDC addresses why EPA properly included renewable energy in setting the BSER.

Second, NRDC recommends that EPA adopt its Alternative Approach for renewable energy target-setting. In this approach, EPA sets state targets based on analysis in the Integrated Planning Model, and NRDC believes that this approach best reflects the technical and economic availability of renewable energy in each state. NRDC then explains how EPA's analysis of its Alternative Approach relied on outdated renewables cost data that fails to capture the significant cost reductions in RE that have occurred in recent years. EPA must update its analysis to incorporate current renewable cost and performance information. Because of its use of outdated data, EPA has significantly underestimated the potential for renewable energy to reduce power sector emissions. As NRDC shows below, when EPA corrects this cost information, it will find that 973 TWh of renewable energy is technically and economically achievable and therefore should be included in setting targets.[1]

Third, NRDC addresses the method EPA should use to determine the amount of renewable energy available in each state. We recommend that EPA adopt a regional version of the Alternative Approach, as described in EPA's Notice of Data Availability.

Fourth, NRDC addresses the treatment of existing and under-construction nuclear energy under the proposal.

6.1.1 *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

[1] This section addresses ways in which EPA can strengthen its Alternative Approach for setting renewable energy targets. If EPA chooses to adopt its Proposed Approach, we have outlined our recommendations for this approach in Appendix 6A.

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.[2]

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/tonne and, particularly in areas with strong wind resources, can result in net savings to electricity customers.[3] A recent LBNL survey of state renewable generation cost assessments found that most states which 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.[4]

6.1.2. *EPA should use and strengthen its alternative approach to determining the amount of renewable energy available at reasonable cost in each state*.

NRDC recommends that EPA adopt the Alternative Approach presented in the proposed rule, which reflects state and regional technical and economic potential. However, EPA should improve the Alternative Approach by using more accurate and updated cost and performance data for renewable energy technologies, removing the benchmark utilization rate, and allocating targets based on each state's share of regional CO_2 emissions.

6.1.2.1 *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

---

[2] New York Department of Public Service, Final Generic Environmental Impact Statement, page 111 (2004) (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%).").

[3] Lazard, *Lazard's Levelized Cost of Energy Analysis Version 8.0* (September 2014), *available at* http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

[4] Heeter, J., G. Barbose, L. Bird, S. Weaver, F. Flores-Espino, K. Kuskova-Burns, and R. Wiser. 2014. *A survey of state-level cost and benefit estimates of renewable portfolio standards.* Golden, CO: National Renewable Energy Laboratory (May, 2014) *available at* www.nrel.gov/docs/fy14osti/61042.pdf.

declines expected as an industry experiences the kind of growth that the renewables industry has seen in the U.S. and abroad.[5]

However, EPA's analysis fails to account for either the cost reductions that have already occurred or the cost 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 cost-effectively and available.

In EPA's analysis of renewable energy (conducted through its Integrated Planning Model IPM®) Base Case v5.13,[6] EPA adopts load forecasts and new technology costs from the Energy Information Administration's (EIA) Annual Energy Outlook 2013 (AEO2013).[7] More recent industry data demonstrate that such 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.

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.[8] 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.[9] 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,

---

[5] Electric Power Research Institute, *Modeling Technology Learning for Electricity Supply Technologies* (Sept. 2013) *available at* http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000871.
[6] Environmental Protection Agency, *Analysis of the Clean Power Plan* (June 2014) *available at* http://www.epa.gov/airmarkets/powersectormodeling/cleanpowerplan.html
[7] 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. EIA, *Annual Energy Outlook 2013* (Dec. 2013) *available at* http://www.eia.gov/forecasts/aeo/pdf/0383.pdf.
[8] 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) *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf; Jenny Chase, *H1 2014 Levelized Cost of Electricity – PV*, Bloomberg New Energy Finance (February 2014) *available at* https://www.iea.org/media/workshops/2014/solarelectricity/bnef2lcoeofpv.pdf; Lazard. *Levelized Cost of Energy – v. 8.0* (2014) *available at* http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20%20Version%208.0.pdf; Bloomberg New Energy Finance/World Energy Council. *World Energy Perspective: Cost of Energy Technologies* (2013) *available at* http://www.worldenergy.org/wp-content/uploads/2013/09/WEC_J1143_CostofTECHNOLOGIES_021013_WEB_Final.pdf; Solar Energy Industries Association. Personal Communications. August 14, 2014.
[9] DOE/NREL, *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections* (October 2014) *available at* http://www.nrel.gov/docs/fy14osti/62558.pdf.

with several projects reporting prices (including incentives) below $70/MWh – competitive with new NGCC plants.[10] EPA's modelling should reflect this current energy market reality.

Wind prices have experienced similar declines since 2010. The capital cost of developing onshore wind has declined from $2260/kW to $1750/kW on average.[11] 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.[12] 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.[13] Because wind resources are generally stronger at higher altitudes, taller wind turbines significantly expand the geographic area suitable for wind turbines.[14] Furthermore, NREL has recently announced funding to try to scale turbines up to 140 m (from an average of 80-90 m today), which it estimates would result in an additional 1800 GW, or 237,000 sq. miles, of wind resource potential nationwide.[15]

Furthermore, Lazard estimates that the current range of LCOEs for onshore wind, *without* any subsidies, is between $37/MWh and $81/MWh. Lazard's comparison that shows wind and solar PV are increasingly cost-competitive with conventional generation technologies is in Figure 6.1 below.

In contrast to these updated costs, EIA's out-of-date estimate projects that the LCOE of wind generation in 2019 will be between $70/MWh and $90/MWh.

---

[10] Lawrence Berkeley National Laboratory, *Utility-scale Solar 2012* (Sept. 2013) *available at* http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends

[11] Lawrence Berkeley National Laboratory. *2013 Wind Technologies Market Report* (August 2014), *available at* http://emp.lbl.gov/publications/2013-wind-technologies-market-report.

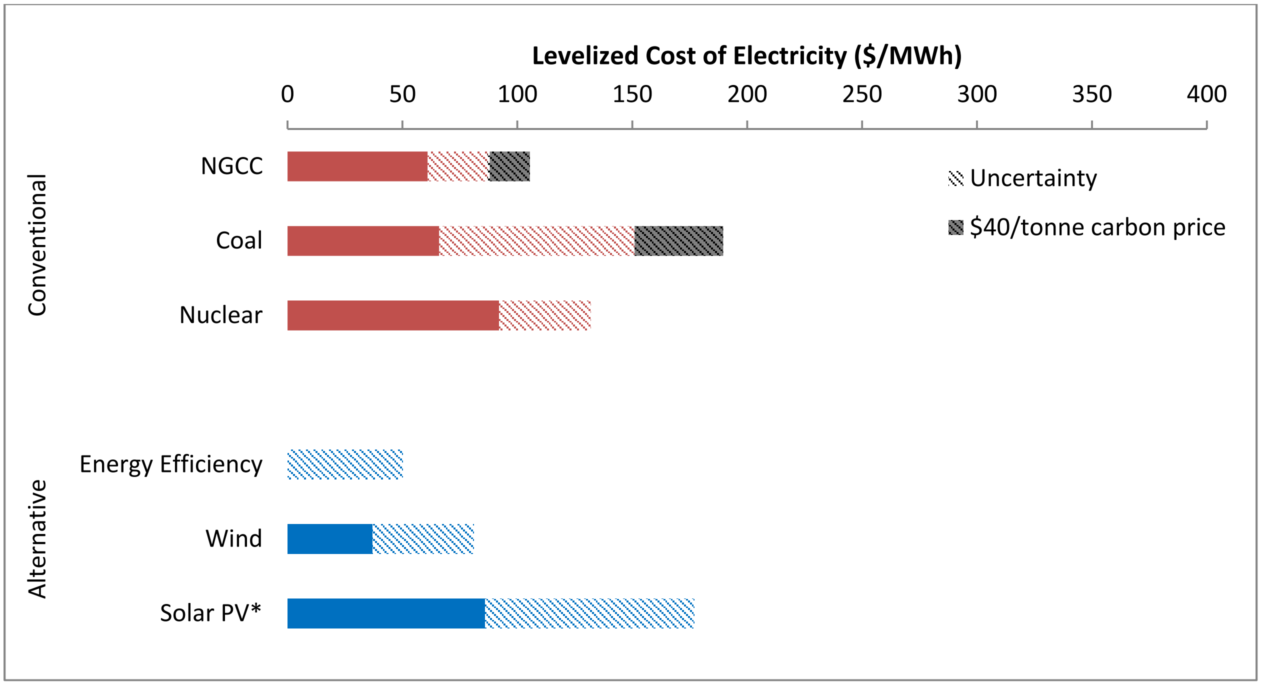
[12] *Id.*

[13] Discussions with American Wind Energy Association and updated industry data: 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-Between-Renewables-and-Natural-Gas.

[14] For example, compare NREL's 80 m and 100 m wind resource maps, *available at* http://www.nrel.gov/gis/wind.html.

[15] DOE/NREL, *Energy Department Announces Funding to Access Higher Quality Wind Resources and Lower Costs*, (Jan. 30, 2014) *available at* http://energy.gov/eere/articles/energy-department-announces-funding-access-higher-quality-wind-resources-and-lower.

Figure 6.1: Levelized Cost of Electricity for Conventional vs. Alternative Technologies.[16]



*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 EIA's AEO2013 out-of-date data when it has ready access to recent government and credible industry analysts' cost data, e.g. NREL, LBNL, BNEF and Lazard. EIA's data is outdated for easily identified reasons: AEO2013's use of 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.[17] 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. For government-based data quality assurance, EPA can 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. In Table 6.1, we compare EIA AEO

[16] All cost estimates and corresponding assumptions from Lazard, *Levelized Cost of Electricity v. 8.0* (2014). Carbon price impacts are NRDC calculations. This carbon price is for illustrative purposes only, and the level of this carbon price was chosen based on the $40/tonne equivalent used in EPA's Alternative Approach for RE target-setting.
[17] Lawrence Berkeley National Laboratory, *Tracking the Sun VII*, page 39 (Sept. 2014) *available at* http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20.

2013 to our review of updated cost and performance assumptions for renewable energy technologies.

Table 6.1: Installed Cost Estimates

Renewable Energy Cost and Performance Assumptions				
	Installed Costs ($/kW)		Average Capacity Factor	
	Onshore Wind	Solar PV[18]	Onshore Wind	Solar PV[19]
EIA AEO 2013[20]	2213	3098	35%	20%
NRDC RE Market Potential	1750[21]	1770[22]	45%[23]	19%[24]

Importantly, there is no reason to believe that the decline in cost will not continue. The 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.[25] In its 2014 update on Solar PV pricing trends, NREL projected that solar prices are still on track to meet the Sunshot goal of $1/W$_{dc}$ by 2020 for utility-scale systems.[26] This would place utility-scale solar projects in direct competition with NGCC plants, without any incentives or carbon policy.[27] 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

---

[18] Cost and performance assumptions for solar are given in terms of kWdc. EIA's assumptions are converted from AC to DC using a 0.8 derate factor.
[19] *Id.*
[20] EIA Annual Energy Outlook 2013 (April, 2013) *available at* http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf.
[21] Lawrence Berkeley National Laboratory. *2013 Wind Technologies Market Report* (August 2014) *available at* http://emp.lbl.gov/publications/2013-wind-technologies-market-report.
[22] Range of estimates based on data from range of bottom-up modeling sources. *See* EIA, *Annual Energy Outlook 2013* (Dec. 2013) *available at* http://www.eia.gov/forecasts/aeo/pdf/0383.pdf.
[23] Discussions with American Wind Energy Association and updated industry data.
[24] Solar performance estimates are based on performance at TMY3 weather stations in each state as modeled using PVWatts in NREL's System Advisor Model (SAM). Data provided by Solar Energy Industries Association. Note that this data has been updated since NRDC's earlier CPP compliance modeling to reflect updates to PVWatts. Additionally, NRDC acknowledges that through innovation such as oversized inverters, individual projects have reported capacity factors of up to 30%, but we are not aware of publicly available data that captures this trend at a national level.
[25] DOE/NREL, *Sunshot Vision Study* (Feb. 2012) *available at* http://energy.gov/eere/sunshot/sunshot-vision-study.
[26] *Id.*
[27] *Id.*

U.S. demand.[28,29,30,31] As noted, average PPAs for utility-scale solar in the past year alone have dropped to levels (including incentives) competitive with new NGCC plants.[32] Meanwhile, a new Deutsche Bank report predicts that distributed solar power will be cheaper than average retail electricity prices in 36 states by 2016 (in 47 states if the 30% ITC is extended).[33]

Recent analyses also show 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.[34,35,36] 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.

It is particularly important for EPA to update its costs and performance data because the impacts on the targets of updating are dramatic. Based on NRDC's analysis of recent data, the costs EPA relied on are 46 percent above current average costs for wind and solar energy.[37] As explained in detail below, the lower costs mean that between 65% and 86% more renewable energy can and should be included in the state targets.

---

[28] Cardwell, D., *Solar and Wind Energy Start to Win on Price vs. Conventional Fuels. New York Times* (Nov. 23, 2014) *available at* http://www.nytimes.com/2014/11/24/business/energy-environment/solar-and-wind-energy-start-to-win-on-price-vs-conventional-fuels.html.

[29] Credit Suisse, *The Transformational Impact of Renewables* (Dec. 2013).

[30] Bloomberg New Energy Finance, *2030 Market Outlook: Focus on Americas* (2013) *available at* http://bnef.folioshack.com/document/v71ve0nkrs8e0/106y4o.

[31] Greentech Media, *Experts: The Cost Gap Between Renewables and Natural Gas 'Is Closing'* (May 2014) *available at* http://www.greentechmedia.com/articles/read/The-Price-Gap-Is-Closing-Between-Renewables-and-Natural-Gas.

[32] Lawrence Berkeley National Laboratory, *Utility-scale Solar 2012* (Sept. 2013) *available at* http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends.

[33] Bloomberg, *While You Were Getting Worked Up Over Oil Prices, This Just Happened to Solar* (October 29, 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.

[34] GE Energy Consulting, *PJM Renewable Integration Study* (March 31, 2014) *available at* http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx.

[35] GE Energy Consulting, *Western Wind and Solar Integration Study*, performed for NREL (September 2013) *available at* http://www.nrel.gov/electricity/transmission/western_wind.html.

[36] GE Energy Consulting, *Eastern Renewable Generation Integration Study*, performed for NREL (2010) *available at*: http://www.nrel.gov/electricity/transmission/eastern_renewable.html.

[37] Natural Resources Defense Council, *The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030* (November 2014) *available at* http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf.

EPA must update these costs and re-run its IPM economic modeling to accurately determine the amount of renewable energy available for cost-effective emissions reductions.

6.1.2.2 *EPA should eliminate the benchmark rate and rely solely on technical and economic potential within IPM.*

We support using a state's technical and economic potential to determine its RE levels in BSER; however, the benchmark development rate does not capture the rapidly growing nature of renewable energy. As described in more detail in Appendix 6E, 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 top 16 states can and should be expected to continue to grow their renewable energy portfolio into the next decade. The benchmark rates not only fail to capture current growth in renewable energy, but they are also redundant and unnecessary when combined with IPM, which already contains technical constraints.

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."[38] The technical potential data in IPM represents a much more granular and complete picture than NREL's technical potential, as it details the amount of resources available by cost class. Therefore, IPM not only contains the same technical potential limit, but also places economic limitations on resource availability within the overall technical potential, which is a more accurate representation of market dynamics than the benchmark development rates.

Another pitfall of 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 further develop their renewable resources at least-cost (i.e. under the applied $30/MWh cost reduction), then these states' targets should be set as such and should not be excluded from BSER.

6.1.2.3 *Updated installed capacity and generation data.*

If EPA continues to utilize its benchmark rate methodology within the Alternative Approach (see previous Section 6.1.2.2), EPA should use updated data on installed capacity and

[38] EPA, *IPM Base Case Documentation*, Page 4-31, ch. 4, *available at* http://www.epa.gov/powersectormodeling/BaseCasev513.html.

generation – there has been significant growth in wind and solar capacity and generation since 2012, which will continue to grow between now and 2017 when the standards take effect. When applying the Alternative Approach, EPA should, at a minimum, use the most up-to-date installed capacity available as the starting point, although this is likely to significantly underestimate 2017 markets. EPA should also use available data on planned and under construction projects to determine a more accurate – albeit conservative – picture of 2017 renewable energy capacity.[39] Recent growth in both wind and solar capacity, shown in Table 6.2 below, highlights the need to use the most up-to-date data available in markets growing at unprecedented rates.

Table 6.2: Growth in Installed Capacity[40]

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

6.1.2.4 *EPA should update capital cost adders and capacity bounds.*

In its analysis, EPA "includes a short-term capital cost adder that kicks in if the capacity deployed in a specific model run year exceeds certain upper bounds. This adder is meant to reflect the added cost incurred due to short-term competition for scarce labor and materials."[41] The upper bounds for renewable energy are extremely restrictive, because they are well below the growth potential already widely-demonstrated by the wind and solar industries. For example, the step 1 upper bound over the 2016-2018 model period is 11.6 GW for onshore wind; in reality, the capacity-weighted average capital cost of wind projects installed in the U.S. dropped by 10 percent in 2012, despite installing a record 13.1 GW that year, and a combined 19.7 GW over the 2011-2012 period.[42] Additionally, the step 1 upper bound for solar PV is only

[39] For example, LBNL has recently relied on SNL energy to provide this information. SEIA and AWEA also have data on projects scheduled to be completed in the next several years.
[40] EIA, *Form 860 Data* (October 10, 2013) *available at* http://www.eia.gov/electricity/data/eia860/; LBNL, *Tracking the Sun VII* (Sept. 2014) *available at* http://eetd.lbl.gov/sites/all/files/tracking_the_sun_vii_report.pdf; AWEA Annual Market Reports, *available at* http://www.awea.org/marketreports.
[41] EPA, *IPM Base Case Documentation*, Page 4-24, ch. 4, *available at* http://www.epa.gov/powersectormodeling/BaseCasev513.html.
[42] LBNL, *Wind Technologies Market Report* (August, 2014) *available at* http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.

0.3 GW, but utility-scale installations were nearly 10x that amount in 2013, reaching 2.9 GW.[43] In light of recent sustained growth in the solar PV and onshore wind industry (see Table 6.2 or Appendix 6E), in parallel with declining costs, we strongly recommend that these capital cost adders be updated to better reflect real-world conditions.

6.1.2.5 *EPA should implement grid integration constraints or costs that supplement and strengthen IPM's capabilities.*

Instead of using the benchmark rate, EPA should implement 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 incorporated into the existing grid, providing that there is adequate transmission expansion and proper system planning.[44] While higher levels could be integrated with some management and investment changes,[45, 46] 30% represents a clearly achievable near-term limit. Therefore, EPA can utilize this constraint at the ISO level, either in modeling or in post-processing, to account for possible grid integration costs that may arise and which are not fully accounted for in IPM. This constraint has been modeled in previous versions of IPM (v. 4.10) at 20% of the generation mix. Although it was excluded from IPM v. 5.13, we have added it back in for our RE Market Potential modeling and updated this constraint based on the latest available literature.

6.1.2.6 *EPA should include additional resources.*

In its Alternative Approach, EPA leaves out two technologies that will likely feature heavily in the future generation mix. Distributed solar generation is rapidly expanding in the U.S. and abroad, and the global market is projected to double by 2023.[47] Offshore wind technologies are rapidly improving and there are several projects currently in advanced stages of development in the United States; the industry is also growing in Europe and Asia, as discussed below. IPM

---

[43] SEIA/GTM Research, *U.S. Solar Market Insight Q2 2014, available at* http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

[44] *See* GE Energy Consulting, *PJM Renewable Integration Study* (March 31, 2014) *available at* http://www.pjm.com/~/media/committees-groups/task-forces/irtf/postings/pris-executive-summary.ashx; GE Energy Consulting, *Western Wind and Solar Integration Study*, performed for NREL (September 2013) *available at* http://www.nrel.gov/electricity/transmission/western_wind.html; GE Energy Consulting, *Eastern Renewable Generation Integration Study*, performed for NREL (2010) *available at*: http://www.nrel.gov/electricity/transmission/eastern_renewable.html.

[45] 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.

[46] 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.

[47] Navigant Research, *Global Distributed Generation Deployment Forecast,* (September 2014) *available at* http://www.navigantresearch.com/research/global-distributed-generation-deployment-forecast

does not currently have the capability to calculate economic constraints for distributed solar and other customer resources, and does not capture potential progress in offshore wind development. Regardless, these two resources should be included in target-setting to provide a more accurate picture of the technical and economic potential for increased renewable generation.

6.1.2.6.1 *Inclusion of distributed solar generation.*

Distributed solar and other forms of distributed generation are unique in their ownership, operation, siting, and relationship to the existing grid. These systems provide quantifiable benefits, including grid support, lower transmission losses, and reduced need for additional capacity, as well as less monetized benefits such as hedging against fuel prices.[48] As discussed above, solar PV costs have declined rapidly in the past several years, and DOE's Sunshot study has provided a roadmap for sustained cost declines. Indeed, as PV module costs continue to drop, rooftop solar is becoming and will continue to become an economic option for an increasing number of residential and commercial customers.[49,50]

Omitting DG from BSER 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.[51] To correct this deficiency and incorporate rooftop PV generation into the Alternative Approach, EPA should use NREL's Open PV Project Database, which provides up-to-date capacity and price data by state, based on a sample of installations.[52]

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

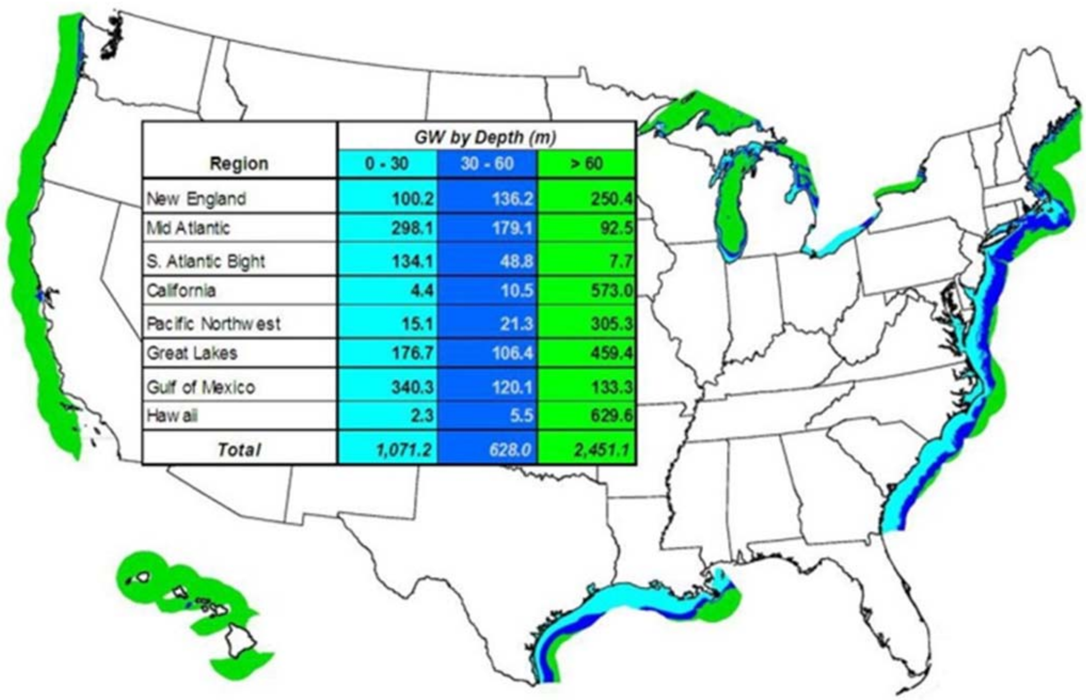
[48] For example, *see* CrossBorder Energy, *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service,* performed for SEIA, (May 8, 2013) *available at http://www.seia.org/sites/default/files/resources/AZ-Distributed-Generation.pdf*
[49] Bloomberg, *While You Were Getting Worked Up Over Oil Prices, This Just Happened to Solar* (October 29, 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.
[50] NREL, *Residential Grid Parity Report* (2013) *available at*
http://www.nrel.gov/docs/fy12osti/54527.pdf.
[51] Energy Information Administration, *Electricity Monthly Update* (April 2014) *available at*
http://www.eia.gov/electricity/monthly/update/archive/april2014/.
[52] NREL, *The Open PV Project*, *available at* https://openpv.nrel.gov/.

economics.[53] 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.

6.1.2.6.2 *Inclusion of 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 Figure 6.2 below.

Figure 6.2: Map of Offshore Wind Potential[54]



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 offshore wind follows the historical trajectories of onshore wind and solar power, increasingly higher deployment levels will likely

[53] NREL, *The Solar Deployment System (SolarDS) Model: Documentation and Sample Results* (September 2009) *available at* http://www.nrel.gov/docs/fy10osti/45832.pdf.
[54] 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.

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 already have for onshore wind energy.[55]

There are 14 commercial-scale projects in advanced development that would constitute almost 5 GW of capacity,[56] and a recent comprehensive study by DOE details the numerous benefits that development of offshore wind can have for the U.S. electric grid.[57] Furthermore, the state of the industry outside of the United States demonstrates its potential for growth. Since the world's first offshore wind farm was built in 1991, turbine size has increased fifteenfold, projects have been built in deeper waters further from shore, and costs have gone down by about 30% per decade.[58] The average size of European wind farms constructed in 2013 grew 70% from 2012, confirming the industry's trend toward larger turbines and bigger wind farms.[59]

In Europe, there are currently 73 fully grid-connected offshore wind farms with a combined capacity of more than 7.3 GW.[60] Projects currently under construction will provide 4,900 MW of new capacity when fully commissioned.[61] An additional 22 GW of consented offshore wind farms have been identified across Europe.[62] Industry momentum is especially strong in the UK, which leads the world in installed capacity and employs more than 6,800 full time employees.[63] In addition to the eleven European countries that have installed offshore wind projects, offshore wind development is also expanding in China, Japan, South Korea, and Taiwan.[64] China

---

[55] NREL/LBNL, *IEA Wind Task 26: The Past and Future Costs of Wind Energy* (May 2012) *available at* https://www.ieawind.org/index_page_postings/WP2_task26.pdf.

[56] Navigant, *Offshore Wind Market and Economic Analysis: 2014 Annual Market Assessment*, *prepared for the Department of Energy* (Sept. 8, 2014) *available at* http://energy.gov/sites/prod/files/2014/09/f18/2014%20Navigant%20Offshore%20Wind%20Market%20%26%20Economic%20Analysis.pdf.

[57] Department of Energy. *National Offshore Wind Energy Grid Interconnection Study* (July 2014) *available at* http://energy.gov/eere/downloads/national-offshore-wind-energy-grid-interconnection-study-nowegis.

[58] Global Wind Energy Council, *Global Wind Report Annual Market Update 2013* (April 9, 2014) *available at* http://www.gwec.net/wp-content/uploads/2014/04/GWEC-Global-Wind-Report_9-April-2014.pdf.

[59] European Wind Energy Association, *The European offshore wind industry – key trends and statistics 2013* (January 2014) *available at* http://www.ewea.org/fileadmin/files/library/publications/statistics/European_offshore_statistics_2013.pdf.

[60] *Id.*

[61] *Id.*

[62] *Id.*

[63] Global Wind Energy Council, *Global Wind Report Annual Market Update 2013* (April 9, 2014) *available at* http://www.gwec.net/wp-content/uploads/2014/04/GWEC-Global-Wind-Report_9-April-2014.pdf.

[64] *Id.*

alone has installed a total of 428.6 MW, with more than 1,000 MW currently under construction.[65]

In its target-setting, EPA should recognize the unique benefits that offshore wind can provide, and should use the most recent cost and resource potential curves developed by NREL in its forthcoming Wind Vision report.[66] Using this updated data may demonstrate that, as the costs of offshore wind continue to decline, this resource can play a substantial role in reducing carbon emissions.

6.1.2.7 *EPA should continue to exclude biopower from targets.*

In the alternative approach, EPA only models the technical and economic potential of expanding wind and solar PV generation through its IPM modeling and does not include new biopower in setting the states' targets. Available supplies of low-carbon biomass are likely to be very limited and EPA has no established or accurate method of how much low-carbon biomass will be available where and at what price or even how low the net carbon pollution will be. Therefore this exclusion is appropriate and should be sustained.

All solid biomass results in more carbon pollution per MWh at the stack than fossil fuels. The latest science has demonstrated that burning whole trees and other large-diameter woody biomass for electricity increases carbon emissions in the atmosphere compared to coal for anywhere from 35 to 100 years or more.[67] Some biomass, such as true residuals from forestry operations (tops and limbs that would otherwise be burned or quickly decay on the forest floor, releasing their carbon anyway), or sustainably grown dedicated energy crops, such as switchgrass, could offer a source of low-carbon biomass. However, available supply of low-carbon biomass is likely to be limited.

As discussed in more detail in Section 9, EPA recently released a revised framework for accounting for carbon from biopower and a guidance memorandum from Acting Assistant Administrator Janet McCabe that accompanied the revised Framework (the "McCabe

---

[65] *Id.*

[66] DOE/NREL, *Wind Vision: A New Era for Wind Power in the United States Industry Preview, Draft Release*, (November 2014) *available at* http://energy.gov/sites/prod/files/2014/11/f19/Industry%20Preview_Wind%20Vision%20Brochure_Draft%20Results%20November%202014%20.pdf.

[67] *See* Walker, T. et al., *Biomass Sustainability and Carbon Policy Study*, Manomet Center for Conservation Sciences, June 2010; Clark, J. et al., "Impacts of Thinning on Carbon Stores in the PNW: A Plot Level Analysis", Oregon State University, May, 2011; Mitchell, S.R. et al., *Carbon Debt and Carbon Sequestration Parity in Forest Bioenergy Production*, Duke University and Oregon State University, May 2012.

Memo").[68] However, these do not offer a legally or scientifically valid way to assess the technical and economic potential of low carbon biomass and thus leave EPA without a way to accurately include biomass in setting state targets. EPA is sending the revised framework back to a science advisory board for review.[69] An SAB review of the first framework made clear that all biomass cannot be assumed to be carbon neutral and that the carbon impacts of using different types of biomass can only be understood by comparing the atmospheric carbon of the biomass scenario to the alternative absent the biomass harvest. The revised Framework currently offers little in the way of specific direction.[70] In most instances, the document catalogs the numerous options for analyzing biogenic emissions, but fails to signal a preference for one approach or another.

If EPA chooses correctly among the options it catalogs in the revised Framework—*i.e.*, if the Agency requires states to account for biogenic emissions using anticipated future baselines, a compact (and policy-relevant) timescale for analysis, spatial scales that facilitate meaningful distinctions between biomass types, and mechanisms that address leakage—the resulting emissions modeling could reasonably simulate the effect that biogenic emissions will have on the atmosphere during the policy-relevant timeframe. This would make it useful for compliance as further discussed in Section 9, but it still would not be useful in setting targets.

If EPA makes incorrectly choices with respect to these analytic criteria - or allows states to make incorrect choices - the analyses that result will be inaccurate and highly misleading and thus not even helpful for compliance purposes. For example, if EPA allows states to analyze biogenic emissions over a protracted timeframe—such as 50 years, which the Agency contemplates in Appendix 6B to the revised Framework[71]—affected sources would be free to burn biomass feedstocks that will produce significantly higher GHG emissions over the next several decades, including the time period covered by the ESPS.

The MaCabe memo does not mention target setting instead discussing state compliance plans, but the standard it discusses for judging these plans illegal and ill-advised for that purpose and would be equally so if applied to state targets. The memo states:

[68] Janet G. McCabe, Acting Assistant Administrator, EPA Office of Air and Radiation, "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" (November 19, 2014) ("McCabe Memo") at 2;EPA, *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* (November 19, 2014) *available at* http://www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.
[69] EPA, *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* (November 19, 2014) *available at* http://www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.
[70] *Id*.
[71] EPA Revised Framework-Appendix B: Temporal Scale.

> When considering state compliance plans, the Agency expects to recognize the biogenic CO2 emissions and climate policy benefits of waste-derived and certain forest-derived industrial byproduct feedstocks, based on the conclusions supported by a variety of technical studies, including the revised Framework.[72]

The memo confuses matters by also stating: "…the EPA expects that states' reliance specifically on sustainably-derived agricultural- and forest-derived feedstocks may also be an approvable element of their compliance plans."

It would be arbitrary and illegal to designate classes of biomass fuel as "approvable" simply based on a claim of sustainability. "Sustainably-derived" is an ambiguous standard: it has not been defined in the agency's November 19 memorandum and has not been identified as a means of carbon accounting in the accompanying revised Framework.

In addition to being an ambiguous standard, sustainability is not a measure of carbon impacts, however defined. Even if fully specified to include considerations of forest growth and removals, sustainability criteria will fail to fully account for changes in carbon emissions, and cannot be justified as a proxy for carbon accounting. The fact that a regulated EGU burns only "sustainably-derived feedstocks" says very little, if anything, about the amount of biogenic CO2 emitted by the source or the net effect of those emissions on climate change.

Moreover, a robust definition of sustainable would produce very limited amounts of biomass. One needs only look at the growing loss of biodiversity and the loss of critical and imperiled forest types to know that even if EPA were to mistakenly substitute sustainability for carbon accounting, there would be a very limited supply of truly sustainable biomass.

Finally, the EPA proposal to judge sustainably-derived feedstocks in parallel with further work on the framework runs the risk of pre-empting the agency's technical review process by prematurely generating exemptions for broad categories of fuel types.

In sum, EPA's plan to effectively exempt from ESPS scrutiny those emissions that occur when EGUs combust "sustainably-derived feedstocks" could result in a net increase of CO2 emissions for decades. Consequently, EPA cannot meet its obligations under CAA §111(d) by solely requiring affected sources to show that they rely on "sustainably-derived feedstocks," and must not use this standard when setting state targets. EPA should continue to exclude biomass when setting state targets.

---

[72] EPA, Memorandum Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources (November 19, 2014) *available at* http://www.epa.gov/climatechange/downloads/Biogenic-CO2-Emissions-Memo-111914.pdf

We provide more recommendations on how EPA should not include biopower as part of state compliance in Section 9 of our comments.

6.1.2.8 *EPA should take regional considerations into account.*

While targets specific to each state are important for the purposes of BSER, the renewable energy market is regional in nature due to regional energy markets, renewable energy credit (REC) trading, and transmission across state borders. To maintain symmetry between target-setting and compliance options available to states, we agree with the ideas put forth in the October 27, 2014 Notice of Data Availability, which recommend "better aligning goal-setting to probable compliance approaches" and distributing renewable energy targets across potential compliance regions.

A regional approach to target setting more realistically and meaningfully captures renewable energy markets, especially since the resource will likely be utilized across the region. The economic potential for each state should include access to RE from states in the same market/transmission region. EPA should allow states to use renewables and/or RECs they buy from out-of-state for compliance, to the extent that both the state buying renewables and/or RECs and the state originating them have compliance accounting systems, such that the generation and emissions reductions are not double counted. In addition, the REC tracking requirements should be in harmony with existing tracking systems where processes are in place to prevent double counting both for generation tracked within projects and between projects and other REC tracking systems.[73]

We have incorporated this recommended change into our analysis of the Alternative Approach – our proposed methodology and a comparison of possible approaches can be found in Appendix 6C.

6.1.3 *NRDC analysis of our recommended changes to the alternative approach.*

NRDC had ICF reconstruct EPA's RE Market Potential scenario, in which a $30/MWh cost reduction is applied to onshore wind and solar PV. NRDC adjusted the input assumptions based on the recommendations above.

Specifically, NRDC updated capital costs and performance for onshore wind and utility-scale solar PV, based on Table 6.1, and included conservative assumptions about solar cost

[73] Center for Resource Solutions, *Tracking Renewable Energy for EPA's Clean Power Plan: Guidelines for States to Use Existing REC Tracking Systems to Comply with 111(d)* (June 25, 2014) *available at*: http://www.resource-solutions.org/pub_pdfs/Tracking%20Renewable%20Energy.pdf.

declines.[74] NRDC also updated the capital cost adders to reflect recent industry growth. Lastly, based on the results of several studies outlined above, variable renewable generation was constrained at 30% of generation, defined at the ISO level. In future updates to state targets, EPA should examine the latest available research, as we expect that this constraint will be revised upwards as a result of improvements and innovations in grid management and operations.

We modeled two scenarios – one with and one without deployment of distributed solar PV. In the run with distributed solar PV incorporated into IPM, capacity installations by state are developed using DOE/NREL Sunshot projections under the -62.5% price scenario (Appendix 6D). Additionally, our case with distributed solar was also updated based on the most recent Sunshot update – we assumed solar prices would reach the -62.5% reduction by 2020 and the full -75% reduction by 2030.

Aside from these updates, NRDC attempted to match EPA's modeling exercise as closely as possible. The results demonstrate the extent to which renewables can economically exceed the amount of generation proposed in either of EPA's target-setting approaches.

NRDC then applied a post-processing calculation to calculate the total renewable energy in each region, and re-distribute state targets each state's emissions. As outlined above, this regional approach to target-setting more closely resembles real-world power purchase agreements, in which a state with high electricity demand consumes renewable energy which is built in a neighboring state with stronger (and lower-cost) renewable energy resources.

Overall, our updates to EPA's Alternative Approach demonstrate that renewable energy generation can reach 873 TWh from utility-scale plants, and can reach 973 TWh when distributed solar is accounted for (the full set of state targets is provided in Appendices 6B and 6C) – between 65% and 86% higher than both of EPA's target-setting approaches. Significant emissions reductions are achieved through the deployment of high levels of renewables, and the incremental system costs of this CO_2 abatement actually fall well below the \$40/tonne threshold EPA anticipated. The \$30/MWh cost reduction leads to an average cost of CO_2 abatement of only \$14/tonne in 2020, rising slightly to ~\$19/tonne in 2030, as shown in Table 6.3.

---

[74] Notes on solar assumptions: In our case without DG, and in all our compliance modeling (see Chapter 2), we assumed that prices decline to reach the full 75% price reduction by 2050. We also assumed an average CF of 16% based on PVWatts data provided by SEIA. However, in our preferred (and most recent) model run with DG, we updated solar price declines to reach the 75% price reduction by 2030 – reflective of, but still more conservative than, NREL's recent Sunshot update. Additionally, based on a September update to the PVWatts model, we updated capacity factors by state to reflect a national average of 19%.

This average cost of abatement reaffirms that an electricity sector with high RE deployment represents a cost-effective system of emissions reduction, and EPA can and should strengthen Building Block 3 to more accurately reflect the full potential of renewable energy to reduce carbon emissions.

Table 6.3. Illustrative costs of abatement for Utility-scale RE Market Potential case.[75]

RE Market Potential with Updated Costs and Performance			
	2020	2025	2030
RE Generation (TWh)	591	810	873
CO2 Emissions Reductions (MMT)	107	227	236
Costs of abatement ($/tonne)[76]	14.4	14.2	18.9

6.1.4 *Supporting analyses verify that higher renewable deployment in the alternative approach is cost-effective and achievable.*

Independent modeling studies have also determined that the higher national penetrations of renewable energy projected in our updated Alternative Approach are both technically and economically achievable. These studies should serve as further confirmation that much higher levels of renewable energy can and should be included in the Best System of Emissions Reduction.

All three of the supporting analyses referenced here rely on 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

[75] The results presented in Table 6.3 and the corresponding discussion are for the IPM run that does not include distributed solar PV. The costs associated with building DG are higher than the costs of wholesale power plants, but do not reflect the significant economic benefits that solar DG can provide for customers, and the system as a whole. The costs and benefits of a system which includes wholesale and distributed resources are difficult to quantify comprehensively. *See*, *e.g.*, Rocky Mountain Institute, *emPower: Accurately Valuing Distributed Energy Resources* (Sept. 2013) *available at* http://www.rmi.org/elab_emPower.

[76] The costs of abatement in this IPM run may also be due to indirect effects of high RE deployment, such as increased fuel-switching from coal to natural gas for added grid flexibility. The emissions impacts cannot be isolated to solely renewable energy generation, but does represent a total cost of abatement from an overall system of emissions reductions that results from high levels of renewable energy deployment.

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."[77]

6.1.4.1 *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 EPA could set significantly higher renewables targets 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 only slightly higher under the ITI-Constrained case (12.1 cents/kWh).

[77] For more on NREL's ReEDS model, see http://www.nrel.gov/analysis/reeds/documentation.html.

6.1.4.2 *UCS analysis of their 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 nationally.[78] (There are some regional differences between NRDC and UCS targets.) UCS has assessed the technical and economic feasibility of reaching these targets using NREL's ReEDS model, and has reached similar conclusions as NRDC has 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.[79] Reducing the demand for natural gas would also lead to lower and more stable natural gas and electricity prices.

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% to 17%.

6.1.4.3 *Preliminary results from DOE's wind vision report.*

While the full Wind Vision report isn't scheduled to be released until early 2015, DOE issued an early release of the Executive Summary and Roadmap chapter on November 19, 2014.[80] 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% of the country's available wind

---

[78] For more on UCS's proposal, see http://www.ucsusa.org/sites/default/files/attach/2014/10/Strengthening-the-EPA-Clean-Power-Plan.pdf.

[79] 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: Synapse Energy Economics, Inc. Mercurio, A. 2013. *Natural gas and renewables are complements, not competitors*. Washington, DC: Energy Solutions Forum, Inc.

[80] 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.

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.[81]

6.1.5 *Final RE recommendations.*

NRDC 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 states' generation fleets, 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 NRDC strongly recommends that EPA adopt a strengthened Alternative Approach, which better reflects state and regional technical and economic potential, and that EPA improve upon this approach by using updated cost and performance data for renewable energy technologies. In the above comments, we have provided 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; however, EPA has weakened the approach by relying on outdated and thus inaccurate 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 instead use the most reliable and up-to-date cost and performance assumptions available, which provide a more accurate representation of the cost competitiveness of renewables and demonstrate that more renewables can be deployed at reasonable cost.

[81] 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.

NRDC 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;
- Modify (or remove) the capital cost adders to reflect recent industry growth;
- Eliminate the benchmark development rate constraint;
- Include distributed solar generation through separate modeling (e.g. NREL's Solar Deployment System (SolarDS) model);
- Re-distribute regional renewables generation when setting state targets, so that fossil generators have access to credits from across the market region and states are not required to build all the generation that is cost-effective in their state;
- The resulting national target for renewable generation nearly doubles from EPA's approaches, growing from 520-530 TWh to ~973 TWh, and clearly demonstrates that significantly higher levels of renewable energy are both technically and economically achievable.

6.2 Nuclear energy.

As discussed in the section above on the BSER formula and baseline issues, NRDC recommends removing all existing non-fossil generation from the BSER formula and starting with a fossil intensity standard that is adjusted by the new resources and changes delivered by the 4 building blocks. This has the effect of removing both existing non-hydro renewables and the partial inclusion of nuclear and allows all non-fossil resources to be treated the same.

While we understand the concern of increased CO2 emissions if existing nuclear plants retire, we believe each plant should be evaluated by state and federal regulators individually. Public safety is our institution's foremost concern regarding nuclear power. Many NRDC members live within the emergency planning zones (i.e., within a ten mile radius) of nuclear power plants. Existing nuclear plants need to implement the full set of post-Fukushima accident safety upgrades and complete the intensified flood and seismic risk reviews required on a rolling basis since the Fukushima accident– as well as any subsequent plant safety modifications. We are also concerned about heavy reliance on nuclear energy, given its consistently poor economics and the longstanding, unsolved problems for nuclear energy: reactor safety, radioactive waste, and nuclear weapons proliferation.

States and regions can choose to adopt policy approaches that assist older non-fossil resources to remain economic, taking into account public safety impacts.

NRDC supports the inclusion of under construction nuclear plants in target setting.

7.0 BSER Block 4 – Energy Efficiency

7.1 Summary.

In a 2014 study, the International Energy Agency found that the global savings from energy efficiency are greater than the output from *any other single fuel source* – including coal, oil, nuclear, and gas.[1] This makes energy efficiency the world's primary or first fuel.[2] Forty years of sustained improvements in the productivity of energy use have also made energy efficiency the United States' largest single-energy resource.[3] Since 2000, the national growth rate for electricity consumption has dropped below that of the population for an extended period, thanks in large part to our increased energy efficiency.[4] Yet significant cost-effective energy efficiency remains untapped in every sector and in every region, due to a number of market barriers.

NRDC applauds EPA's recognition of energy efficiency's demonstrated potential to reduce power plant emissions at low cost by including it in the Best System of Emission Reduction (BSER) in its draft Clean Power Plan. Our comments on Block 4, which addresses energy efficiency's potential to reduce emissions, include evidence additional to that provided in the Proposed Rule indicating that EPA's proposal is achievable. We include recommendations on how the proposal can be strengthened in ways that will provide even more savings to consumers, the economy and the environment, as well as additional flexibility, tools, and certainty to states and electric generating units (EGUs).

The Proposed Rule assumed that states can achieve a rate of increase in energy efficiency savings of 0.2 % of annual retail electric sales, and reach and sustain a level of energy efficiency savings of 1.5 % annually throughout the rule period. Based on the data provided below, the evidence shows that energy efficiency savings can expand at a rate of at least 0.25 % of annual retail electric sales per year and can reach and sustain a level of energy efficiency savings of 2 % annually.

Our comments include discussion of the following issues and recommendations:

There are sufficient cost-effective opportunities to achieve energy efficiency improvements of 2 % per year;

---

[1] IEA, *Energy Efficiency Market Report 2014: Market Trends and Midterm Prospects* (2014).

[2] *Id.*

[3] *See, e.g.*, Bipartisan Policy Center, America's Energy Resurgence, page viii (February 2013) (Over the last four decades, energy savings achieved through improvements in energy productivity have exceeded the contribution from all new supply resources in meeting America's growing energy needs).

[4] NRDC, *Positive Energy Trends Bode Well for U.S. Security and the Economy* (October, 2014) *available at* http://www.nrdc.org/energy/energy-environment-report/files/energy-environment-report-2014.pdf.

- EPA's Block 4 BSER can be delivered through state-run programs or by EGUs working with private energy efficiency services companies

- EPA should not discount energy efficiency for either net electricity-importing or net electricity-exporting states, and instead should base estimated emission reductions on the "avoided net generation value"

- EPA should correct its analysis to reflect the potential to achieve more energy efficiency, faster and at lower cost than proposed

- EPA should consider energy efficiency opportunities associated with building code compliance and adoption, ESCO projects, and transmission and distribution

- EPA should highlight energy efficiency opportunities available in multi-family housing, the industrial sector, state appliance standards, combined heat and power systems, behavioral and financing programs

- Compliance issues including evaluation, measurement and verification, and credit for early action.

7.2 Energy efficiency has been adequately demonstrated (as a component of the BSER).

Energy efficiency is a proven resource with significant potential to dramatically reduce power plant emissions, and do so at low cost. We know that energy efficiency has been adequately demonstrated and that the savings are real because utilities, state regulators, independent system operators, businesses and energy service companies have relied on these investments to provide savings for customers and avoid the need for generation, transmission and distribution for more than 30 years. In 2012, $12.2 billion was invested in electric energy efficiency programs by program administrators and customers.[5] Assuming no new policy developments such as EPA's Clean Power Plan, a Lawrence Berkeley National Laboratory study estimates that utility investments in energy

[5] A recent study by Lawrence Berkeley National Laboratory found that every $1 invested by program administrators drew ~$0.95 from participants. Charles A. Goldman, Ian M. Hoffman, Gregory M. Rybka, Greg Leventis, and Lisa C. Schwartz, *The Total Cost of Saved Energy For Utility Customer-Funded Energy Efficiency Programs*, LBNL. NARUC Annual Meeting (November 17, 2014) *available at* http://emp.lbl.gov/cost-saved-energy.

efficiency programs could surpass $12.2 billion per year, which, including customer investments, would put annual investments close to $24 billion.[6]

Section 111 requires the BSER to be "adequately demonstrated." The D.C. Circuit's case law indicates that "[a]n *adequately demonstrated system*" is one that has been shown to be "reasonably reliable, reasonably efficient, and which can reasonably be expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way." *Essex Chemical Corp. v. Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973). A paper by the Harvard Law School Environmental Law Program argues that energy efficiency constitutes an "adequately demonstrated" system of emission reduction: "Energy efficiency is ripe for inclusion as part of the "best system of emission reduction" for existing power plants because it is adequately demonstrated and cost-effective, imposes minimal environmental costs, and reduces overall energy requirements."[7]

In setting state goals, EPA determined that accelerated use of energy efficiency policies in all states, in a manner consistent with recent industry trends, could feasibly reduce or avoid 1.5 % of retail sales per year. This level of energy efficiency is well within the level already achieved by many existing state and utility programs, as discussed below, and is thus well demonstrated. End-use energy efficiency programs have been adequately demonstrated as cost-effective methods for achieving energy savings and reducing air pollution.[8] Regions, states, public and private utilities, and third parties have over thirty years of experience investing in energy efficiency programs and enacting energy efficient building codes and appliance and equipment standards. In order to ensure they get what they pay for and can build investments into their planning, they have developed processes and protocols to evaluate, measure, and verify (EM&V) energy savings (discussed later in these comments).

[6] Barbose, G. L., C.A. Goldman, I. M. Hoffman, M. A. Billingsley, *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025*, LBNL-5803E (January 2013) *available at* http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend.

[7] Kate Konschnik and Ari Peskoe, *Efficiency Rules*: *The Case for End-Use Energy Efficiency Programs in the Section 111(d) Rule for Existing Power Plants*, the Harvard Law School Environmental Law Program (March 3, 2014) *available at* http://blogs.law.harvard.edu/environmentallawprogram/files/2013/03/The-Role-of-Energy-Efficiency-in-the-111d-Rule.pdf.

[8] EPA included energy efficiency as a compliance mechanism in its Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans.

State utility regulators, publicly-owned utility governing boards, and independent system operators (ISOs) are sufficiently confident in the results to use energy efficiency in resource planning and procurement. A very small sampling includes:

- The New England ISO (ISO-NE) projects that because of anticipated savings from energy efficiency, there will be no growth in electricity consumption and low growth in peak demand over the coming decade. The region's six states expect to invest $5.7 billion in energy efficiency between 2015-2021, and as a result of its confidence in past results and existing EM&V structure, ISO-NE believes the region can defer 10 transmission upgrades previously considered necessary to ensure reliability.[9]

- Energy efficiency is at the core of the blueprint guiding the operation and procurement of electricity in the Pacific Northwest region of Washington, Oregon, Idaho and Montana. Developed by the Northwest Power and Conservation Council (NWPCC), the plan finds that cost-effective efficiency can meet 85 % of new demand over the next 20 years and, combined with more renewable energy, could delay investments in future fossil fuel power plants. This plan addresses and applies equally to both the investor-owned and publicly-owned utilities in the region. In fact, since 2010, Northwest publicly-owned utilities (municipals and cooperatives) and the Bonneville Power Administration (BPA) have saved at least 560 average megawatts of electricity, greatly surpassing the five year goal of 510 average megawatts set by the NWPCC in its Sixth Power Plan.[10] The NWPCC estimates energy efficiency is now one of the top three electricity resources in this region, which has some of the lowest electricity rates in the nation. The region has already avoided more than 10-12 large power plants.[11] According to NWPCC, the average cost of efficiency improvements is $.017/kWh, about five times less than the cost of power from a new gas-fired plant. And without these savings, it would have to generate enough additional electricity to power 3.6 million Northwest homes. [12]

- The Michigan Public Service Commission reported that every year since 2009, Michigan has exceeded its targets of saved megawatt hours (MWh) of electricity due to energy efficiency programs. The savings targets increase each year, and

[9] ISO on Background: Energy Efficiency Forecast. ISO New England (December 12, 2012) *available at* http://www.iso-ne.com/nwsiss/pr/2012/ee_forecast_slides_final_12122012.pdf.
[10] Bonneville Power Administration, *Northwest public utilities, BPA top five-year energy savings target* (Nov. 24, 2014) *available at* http://www.bpa.gov/news/newsroom/releases/Documents/20141124-PR-23-14-BPA-Northwest-public-utilities-top-energy-saving-target.pdf.
[11] Northwest Power and Conservation Council, *Sixth Northwest Conservation and Electric Power Plan* (September 2011) *available at* http://www.nwcouncil.org/energy/powerplan/6/plan/.
[12] *Id*.

Michigan's actual electric savings in 2011 not only exceeded the savings target for that year, but the 2012 target as well. The actual amount of electricity saved by the Michigan utilities in 2011 was 1,000,437 MWh. According to the report, that is enough electric energy to power 1.5 million homes for a year.[13] Governor Snyder has described energy efficiency as, "the best example of a no-regrets policy Michigan can have."[14]

7.2.1 *There are sufficient cost-effective opportunities to save energy to support EPA's best practices level of performance (1.5 % savings per-year) and EPA's alternative 2% savings per-year level.*

In describing the opportunity for energy efficiency to reduce greenhouse gas emissions from power plants, EPA examines recent assessments of energy efficiency potential.[15] Energy efficiency potential studies are, as EPA states, a common tool used by policymakers, utilities, and stakeholders to inform both energy savings goals and energy efficiency program development. Most potential studies evaluate technical, economic, and "achievable potential," but there remains significant variation in the analytic methods and assumptions used to estimate energy efficiency potential.[16]

One of the chief sources of variation is the analysis of achievable potential. As stated in a recent report:

> Although the achievable framework is useful from a practical standpoint, too often projections of achievable savings are seen as precise forecasts or even upper limits on what level of demand reduction can be attained through energy efficiency initiatives. Labeling a projection as "achievable" to distinguish it from more theoretical technical and economic projections may sometimes have the

[13] Michigan Public Service Commission, *2012 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs* (November 30, 2012) *available at* http://www.michigan.gov/documents/mpsc/2012_EO_Report_404891_7.pdf.
[14] State of Michigan, Energy Efficiency, *available at* http://www.michigan.gov/energy/0,4580,7-230-68204_54284---,00.html; Rebecca Stanfield, NRDC Switchboard, *Michigan Utilities Smash Energy Efficiency Targets: Customers, Economy, Environment Reap the Rewards* (December 14, 2012) *available at* http://switchboard.nrdc.org/blogs/rstanfield/michigan_utilities_smash_energ.html.
[15] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, page 5-20 (June 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.
[16] *See* National Action Plan for Energy Efficiency, *Guide for Conducting Energy Efficiency Potential Studies* Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc. (2007) *availavble at* www.epa.gov/eeactionplan.

> unintended consequence of making anything above the forecast seem "unachievable."[17]

Some have attempted to directly measure achievable potential. The Hood River Conservation Project study, conducted in the early 1980s, found a 91 % response rate for home energy assessments (out of roughly 3,500 eligible participants) and an 85 % participation rate for the subsequent implementation of conservation measures, when measures were free to participants.[18] The Northwest Power Conservation Council uses this 85 % participation rate in part to determine what fraction of measures that pass its cost-benefit test (economic potential) is achievable, along with commercial availability of products and limits on the annual ramp rate of measures.[19]

EPA's use of potential studies is well-justified, but the economic and achievable potential reported in past studies likely understates the amount of energy efficiency that can be implemented as part of the Clean Power Plan. Among other factors, the Clean Power Plan will alter the economics of energy efficiency because under the Plan, energy efficiency will be used as a means of compliance with standards of performance for power plants.

To further refine EPA's meta-analysis of recent energy efficiency potential studies, we added some three new recent potential studies (from New York,[20] Ohio,[21] and the Pacific Northwest[22]), and substituted one to better reflect "maximum achievable potential" (California[23]), recalculating average annual projected potential as a percentage of baseline sales. As shown in Table 7.1 below, the average annual achievable potential as a percentage of baseline sales remains the same with these additions and changes: 1.5%. Average annual economic potential remains at 2.4%.

---

[17] Kramer, C., and Reed, G., *Ten Pitfalls of Potential Studies*, Regulatory Assistance Project, page 5 (November 2012) *available at* www.raponline.org/document/download/id/6214.

[18] Fuller, Merrian et al, *Driving Demand for Home Energy Improvements*. Berkeley: LBNL, Hood River Conservation Project (2010) *available at* http://drivingdemand.lbl.gov/reports/lbnl-3960e-print.pdf.

[19] Northwest Power and Conservation Council, 6th Northwest Power Plan, Page 4-5 (February 2010).

[20] Mosenthal, P., et al., Energy Efficiency and Renewable Energy Potential Study of New York State, Volume 2, Optimal Energy for the New York State Energy Research and Development Authority, Figure 2, Page 13 (April 2014).

[21] Economic and High Case, Cumulative Annual Gross Energy Savings at Meter (2034), Navigant for American Electric Power-Ohio, EE/PDR Potential Study, Appendix A, Page A-48, Table 28 (March 26, 2014).

[22] 5860 aMW of Achievable Potential in 2030 / 25275 aMW demand in 2030. Northwest Power and Conservation Council, Sixth Northwest Conservation and Electric Power Plan, Table 3.3 and Page 4-1, (February 1, 2010).

[23] Navigant, 2013 California Energy Efficiency Potential and Goals Study Final Report, Prepared for California Public Utilities Commission, February 14, 2014, Page 23; Sales forecast from California Energy Commission, California Energy Demand 2014-2024 Final Forecast LSE and Balancing Authority Forecasts, Tables 1.1c, Electricity Deliveries to End-Users by Agency (GWh) (April 15, 2014).

Table 7.1: NRDC Summary of Recent (2010-2014) Electric Energy Efficiency Potential Studies.

State	Client	Analyst	Study year	Study period	End-year projected potential as % of baseline sales		Average annual projected potential as % of baseline sales	
					Economic	Achievable	Economic	Achievable
Arizona	Salt River Project	Cadmus Group	2010	2012-2020	29%	20%	3.20%	2.20%
California	California Public Utilities Commission	Navigant	2013	2014-2024	not reported	19.80%		1.80%
Colorado	Xcel Energy	Kema, Inc.	2010	2010-2020	20%	15%	1.80%	1.40%
Delaware	Delaware DNR/DEC	Optimal Energy, Inc.	2013	2014-2025	26.30%	not reported	2.20%	
Illinois	ComEd	ICF Internationa l	2013	2013-2018	32%	10%	5.30%	1.70%
Michigan	Michigan PSC	GDS Associates	2013	2014-2023	33.80%	15%	3.40%	1.50%
New Jersey	Rutgers University	EnerNOC Utility Solutions	2012	2013-2024	27.10%	18.80%	2.30%	1.60%
New Mexico	State of New Mexico	Global Energy Partners	2011	2012-2025	14.70%	11.10%	1.10%	0.80%
New York	ConEd	Global Energy Partners	2010	2010-2018	19.60%	15%	2.20%	1.70%
Pacific Northwest (Idaho, Montana, Oregon, Washington)	US DOE	LBNL	2014	2011-2021	11%	not reported	1.00%	
Pennsylvania	Pennsylvania PUC	GDS Associates and Nexant	2012	2013-2022	27%	17.30%	2.70%	1.70%
Tennessee	TVA	Global Energy Partners	2011	2012-2030	24.80%	19.80%	1.30%	1.00%
Additional								
Ohio	American Electric Power	Navigant	2014	2015-2034	52.10%	37.40%	2.60%	1.90%
Pacific Northwest (Idaho, Montana, Oregon, Washington)	Northwest Power and Conservation Council	Northwest Power and Conservation Council	2010	2010-2030	not reported	23.20%	not reported	1.20%
New York	NYSERDA	Optimal Energy	2014	2013-2032	not reported	18%	not reported	0.90%
			Range					**.8% - 2.2% per year**
			Average					**1.50%**

Even these averages are likely conservative assessments of potential, because potential studies usually constrain the list of potential measures to only those already incorporated into programs, reduce the potential applicability of measures based on arbitrary realization factors, fail to consider systems integration or integrated design, assume static technological progress, and ignore the value of non-energy benefits.[24]

Energy efficiency potential studies generally only examine the potential impact of utility energy efficiency programs, which leaves out several energy efficiency opportunities. These opportunities, which would add to achievable potential if included, include:

- Transmission and distribution system investments that reduce utility losses or reduce the energy used by appliances and devices by optimizing voltage.
- Performance contracting or ESCO projects.
- Efficient combined heat and power systems.
- State appliance and device efficiency standards, additive to the extent they allow a higher share of the market (potentially approximately 100%) to shift to the efficient option.
- State building codes, additive to the extent they allow a higher share of the new construction or retrofits (potentially 100%) to meet minimum levels of efficiency.
- Increasing compliance with building codes, additive because potential studies assume that energy efficiency programs use the existing building code as the baseline from which savings are measured. Increasing the extent to which buildings meet this code increases savings.
- State and local efforts, including financing or building benchmarking.

[24] Goldstein, D., Extreme Efficiency: How Far Can We Go If We Really Need To?, Proceedings of the 2008 Summer Study on Energy Efficiency in Buildings (2008) *available at* http://nature.berkeley.edu/er100/readings/Goldstein_2008.pdf.

7.2.2 *EPA's Block 4 BSER can be delivered through state-run programs or by EGUs working with private energy efficiency services companies.*

Recommendation: *EPA's final rule should highlight different structures through which energy efficiency improvements can be achieved.*

While most energy-efficiency programs currently in place operate through a PUC-managed process, this structure is by no means necessary to achieve energy efficiency improvements. EGUs can also procure energy savings that reduce emissions at reasonable cost by working directly with the energy-efficiency services companies. As EPA states, "owners of affected EGUs as well as other parties can contract for demand-side energy efficiency."[25] An EGU can contract with companies in the energy efficiency program industry—as well as with energy service performance contractors or with large energy users—to design and implement energy efficiency programs, and to estimate savings. The EGU can use existing relationships and public and commercially available data to identify and target customers. In addition, many energy efficiency opportunities can be captured without touching the customer directly: instead targeting actors "upstream" of the customer, for example, providing incentives to retailers to stock and sell energy efficient products. The EGU might also collaborate with other EGUs in the state to fund and implement programs jointly, as utilities regularly do today.[26] Finally, as with other pollution-reduction measures undertaken by EGUs, the EGU has access to the capital needed to fund energy efficiency improvements.

The energy efficiency program industry—companies that offer services to utilities and other entities and run programs that save energy—is a robust sector that already operates to implement existing energy efficiency programs. Some of the services this sector provides are summarized with this very short list of examples:

- Energy efficiency portfolio management: Ameren Illinois Utilities[27] contracts with Conservation Services Group[28] to manage its portfolio of residential energy

[25] 79 Fed. Reg. 34830, 34884, VI.E.4.d (June 18, 2014).
[26] *See* MOU between the Los Angeles Department of Water and Power and Southern California Gas, PR Newswire, SoCalGas And LADWP Now Offer Joint Energy-Efficiency Upgrades To Shared Customers, (April 23, 2014) *available at* http://www.prnewswire.com/news-releases/socalgas-and-ladwp-now-offer-joint-energy-efficiency-upgrades-to-shared-customers-204125141.html; *see also* American Electric Power-Ohio and Columbia Gas. Columbia Gas of Ohio, *EPA Recognizes AEP Ohio/Columbia Gas of Ohio New Homes as 2012 ENERGY STAR® Partner of the Year* (March 15, 2012) *available at* https://www.columbiagasohio.com/about-us/news-room/2012/03/15/ENERGY-STAR%C2%AE-EPA-Recognizes-AEP-Ohio-Columbia-Gas-of-Ohio-New-Homes-as-2012-ENERGY-STAR%C2%AE-Partner-of-the-Year.
[27] Act on Energy (last visited December 1, 2014) *available at* http://www.actonenergy.com/.

efficiency programs, including a lighting program, an appliance recycling program, an HVAC program, and a multifamily energy efficiency program. Energy efficiency portfolio management: as part of an EPA consent decree[29] requiring it to invest $15 million in an environmental mitigation project, American Municipal Power,[30] a non-profit wholesale power provider, contracted with the Vermont Energy Investment Corporation to manage and implement a portfolio of energy efficiency programs offered to AMP's member utilities.[31]

- Energy efficiency program management: When they purchase a new refrigerator, customers often move the old refrigerator into another area of their home and keep it plugged in. Because new refrigerators are much more efficient than older refrigerators, removing these second refrigerators—and disposing of them so they do not appear on the secondary market—is a substantial energy efficiency opportunity. Jaco Environmental[32] has worked with utilities[33] and local governments in 28 states to remove and safely recycle refrigerators.

These types of companies either operate or carry out a significant portion of today's energy-efficiency programs. Electric utilities are responsible for 89 % of the total customer-funded electric efficiency investments nationwide.[34] Some states, however, have state government service as program administrators, or use independent third parties, such as the Conservation Services Group and the Vermony Energy Investment Corporation, to design and manage program portfolios.[35] More importantly, even in the majority of programs that utilities run, a large portion of program implementation, or

---

[28] The Conservation Service Group (last visited December 1, 2014) *available at* http://www.csgrp.com/.
[29] *U.S. v. American Municipal Power,* Consent Decree (S.D. Ohio) *available at* http://www2.epa.gov/sites/production/files/documents/amp-cd_0.pdf.
[30] American Municipal Power (last visited December 1, 2014) *available at* http://www.amppartners.org/.
[31] Vermont Energy Investment Corporation, *VEIC To Create EFFICIENCY SMART POWER PLANT For American Municipal Power Members In Six States* June 15, 2010() *available at* http://www.veic.org/media-room/news/2010/06/15/VEIC_To_Create_EFFICIENCY_SMART_POWER_PLANT_For_American_Municipal_Power_Members_In_Six_States.aspx.
[32] JACO Environmental (last visited December 1, 2014) *available at* https://www.jacoinc.net/.
[33] Including nationalgrid (http://www.nationalgridus.com/aboutus/a3-1_news2.asp?document=4204), American Electric Power-Ohio (https://www.aepohio.com/info/news/viewRelease.aspx?releaseID=1597), Efficiency Vermont (https://www.efficiencyvermont.com/For-My-Home/ways-to-save-and-rebates/Appliances/Refrigerators/Refrigerator-Recycling), and Idaho Power (http://www.idahopower.com/EnergyEfficiency/Residential/Programs/Refrigerator/)
[34] "Summary of Electric Utility Customer-Funded Energy Efficiency Savings, Expenditures, and Budgets." Institute for Electric Innovation, March 2014.
[35] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 13 (Dec., 2014).

the delivery of programs, is carried out not by the utilities themselves, but by third party companies. This private sector efficiency service infrastructure is available to deliver the energy efficiency needed by EGUs whether or not states choose to implement or expand energy efficiency programs through public service commissions.

The energy efficiency program industry is also sufficiently robust to have its own publications,[36] such as E Source and Greentech Efficiency; conferences, such as the biennial ACEEE's Energy Efficiency as a Resource Conference; professional organization (the Association of Energy Service Professionals); and in California, a trade association, the California Energy Efficiency Industry Council.[37] Large businesses such as Lockheed Martin,[38] Leidos,[39] and EnerNOC[40] have built or acquired energy efficiency program industry businesses.

It is difficult to determine exactly how costs might differ between energy efficiency programs operated by a public utility commission and electric distribution utility, relative energy efficiency delivered by private energy efficiency services companies for EGUs. For the most part, the costs should be the same, particularly given the substantial role of energy efficiency service companies already play in designing and implementing energy efficiency programs. There are two ways that EGUs and the private market might face higher costs.

First, some EGUs (other than those that are part of vertically integrated companies) likely have fewer direct customer relationships than the electricity distribution utilities. This could lead to the need to do more market-research and advertising. Second, EGUs are not able to recoup the costs of energy efficiency programs concurrently with energy efficiency program spending, as an electric distribution utility (EDU) can, by collecting costs of energy efficiency programs on the utility bill. Even assuming that EGUs and private energy-efficiency service providers cannot achieve offsetting program efficiencies, these additional costs are reasonable. We estimate the extra costs would increase the total cost of energy efficiency programs (the incremental cost of energy

---

[36] E Source (last visited December 1, 2014) *available at* http://www.esource.com/.
[37] California Energy Efficiency Council, *Our Members* (last visited December 2, 2014) *available at* http://efficiencycouncil.org/our-members/.
[38] Lockheed Martin, *Utility Energy Efficiency* (last visited December 1, 2014) *available at* http://www.lockheedmartin.com/us/products/energy-efficiency-services/utility-ee.html
[39] Leidos, Energy Management (last visited December 1, 2014) *available at* https://www.leidos.com/engineering/energy-management
[40] EnerNOC, Energy Efficiency (last visited December 1, 2014) *available at* http://www.enernoc.com/for-utilities/energy-efficiency.

efficiency measures plus the costs of program administration) by only 12.5 %.[41] Even if EGUs faced this additional level of cost, energy efficiency programs would still be an extremely cost-effective way to achieve energy efficiency programs. Indeed, even with these additional costs, the actual program costs would be far lower than the costs EPA estimated in the Proposed Rule, which as explained in Section 7.3.1.4 below, were significantly overestimated.

7.2.3 *Treatment of energy efficiency in net electricity importing states.*[42]

> ***Recommendation:*** *In estimating emission reductions from building block 4, EPA should make no adjustment for either net electricity-importing or net electricity-exporting states, and instead base estimated emission reductions on the "avoided net generation value."*

In determining the emissions reduction potential of energy efficiency, because some states are net electricity importers (using more than they produce), EPA adjusted the estimated reduction in generation by the state's affected EGUs downward. This reflected an expectation that a portion of the generation avoided by demand-side energy efficiency measures in an importing state would occur at EGUs in other states.[43] EPA requests comment on all aspects of the goal computation procedure,[44] and specifically with respect to Building Block 4 on an alternative to scaling up the estimated reduction in generation by affected EGUs in net electricity exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side energy efficiency in other, net electricity-importing states would occur at those EGUs, and an alternative to making no adjustment for either net electricity-importing or net electricity-exporting states.[45]

---

[41] 22% of 2012 US electric energy efficiency expenditures were for marketing and administration costs, and another 55% of expenditures were for incentives and rebates. Consortium for Energy Efficiency, *State of the Energy Efficiency Program Industry Report*, Annual Industry Report 2013, Figure 7, Page 26 (March 24, 2014) *available at* http://library.cee1.org/content/2013-state-efficiency-program-industry-report. Total costs can be estimated by assuming that incentives and rebates are set at 50 percent of the incremental cost of energy efficiency measures, making the total cost of EDU energy efficiency 1.55 on a relative scale (1 + .55). To estimate costs of EGU-funded energy efficiency programs, we assumed that marketing and administration costs increase by 50 percent (from .22 to .33) and that total EGU costs (1.11) were funded with capital that costs the EGU 7.5 percent/year. Total EGU costs are thus (1.11*1.075) 1.19325. Including customer costs (.55), this cost is 1.74, compared to 1.55 for the EDU program, a difference of 12.5 percent.

[42] Responding to requests for comment in the Proposed Rule. 79 Fed. Reg. 34,830, 34,897 (2014).

[43] *Id*.

[44] *Id*.

[45] *Id.*

The opportunity for a state to reduce the amount of greenhouse gasses emitted using demand-side energy efficiency improvements depends on the size and composition of electricity loads in the state. EPA should recognize this in applying Building Block 4 to set state goals: estimating the amount of annual incremental reductions in the state's electricity usage solely by applying an annual percentage savings rate to a state's baseline annual sales, accounting for transmission and distribution system losses. EPA should not then reduce this amount by the portion of a state's load served by out-of-state generation, as proposed and as detailed in the Goal Computation TSD at 17. This unbalanced adjustment does not reflect the load-based nature of the energy efficiency opportunity, unfairly deprives importing states the full greenhouse-gas reducing impact of demand-side energy efficiency measures its electricity customers pay for, and leaves the excess efficiency in net-importing states unused in the target-setting process, even though this excess efficiency will actually decrease affected EGU emissions.

Making no adjustment in Step 5 for either net electricity-importing or -exporting states would best reflect the actual potential for energy efficiency in each state. If EPA chooses to retain an adjustment, EPA should scale up the estimated reduction in generation by affected EGUs in net electricity-exporting states to reflect an expectation that a portion of the generation avoided in conjunction with the demand-side energy efficiency efforts of other, net electricity-importing states would occur at those EGUs.

7.3 In setting state goals, EPA can better reflect the large efficiency opportunity and multiple options for states and EGUs to save energy by changing the best practices level of savings to 2% per year.

Recommendation: *EPA's assumption of a 1.5% reduction in retail sales per year from energy efficiency for BSER is achievable, but low. EPA should adopt at least a 2% reduction in retail sales per year as BSER for Block 4 energy efficiency.*

EPA's conservative approach to the assumptions for Block 4 led to an underestimation of the potential for compliance using energy efficiency, and an overestimation of the costs of efficiency deployment.[46] EPA concluded that states could ramp up their savings at a rate of 0.2 % per year, and by 2030, could sustain annual average savings of 1.5 % of the state's retail electricity sales. EPA relies on experience with energy efficiency programs in several key states in order to determine the potential impact of energy

[46] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602 (June 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf. Chapter 5 discusses demand-side energy efficiency.

efficiency as a compliance mechanism and identify the energy efficiency component of BSER. EPA acknowledges that its assumptions are very conservative.

The evidence shows that EPA's assumptions understate the potential amount of energy efficiency that can be achieved in all states. NRDC believes that more than 1.5 % annual savings can be achieved for every state, and that energy efficiency programs can expand faster, and at a lower cost than EPA assumed in setting the targets in the proposal.[47] In fact, many are already doing so, or planning to do so.

We cite evidence below to support our recommendations for strengthening Block 4, and thus the proposed standard. Like EPA, our recommendations also represent an underestimate, since they also rely on examples of what is possible in a world without the Clean Power Plan, which will itself open up new energy efficiency opportunities.

Below, NRDC has updated the assumptions EPA used to calculate their proposed savings level to reflect today's technologies and performance for utility and state energy efficiency programs, and evaluated the potential savings from other proven energy efficiency measures in the BSER not included in EPA's 1.5 % savings estimate[48] (discussed in later sections). We believe that a minimum level of 2% annual reduction in retail sales is achievable.[49]

[47] 79 Fed. Reg. at 34875 (Building Blocks) "For demand-side EE, we also specifically invite comment on several issues: (1) increasing the annual incremental savings rate to 2.0 percent and the pace of improvement to 0.25 percent per year to reflect an estimate of the additional electricity savings achievable from state policies not reflected in the 1.5 percent rate and the 0.20 percent per year pace of improvement, such as building energy codes and state appliance standards, (2) alternative approaches and/or data sources (i.e., other than EIA Form 861) for determining each state's current level of annual incremental electricity savings, and (3) alternative approaches and/or data sources for evaluating costs associated with implementation of state demand-side energy efficiency policies."

[48] EPA limited its analysis only to programs that "are realized exclusively through the adoption and implementation of energy efficiency programs." 79 Fed. Reg. at 34872.

[49] EPA requested comments on the alternative ramping up to 2% savings per year from a combination of utility and nonutility energy efficiency policies. 79 Fed. Reg. at 34875. In keeping with this and the following section, there is no justification for the EPA to use the alternatively proposed 1% annual reduction in total retail sales. 79 Fed. Reg. at 34873.

7.3.1 *Customer-funded energy efficiency programs can achieve higher savings, faster and at lower cost than proposed.*

7.3.1.1 *Energy efficiency programs alone already reach 1.5 % of sales, and leading program administrators save best practices amounts of energy efficiency year after year*.

A savings level of 1.5 % total reduction in retail sales per year is achievable. In fact, 15 states have already achieved it, or have standards to achieve that level or above (Arizona, California, Colorado, Hawaii, Illinois, Iowa, Maine, Massachusetts, Michigan, Minnesota, New York, Ohio, Rhode Island, Vermont, and Washington).[50] Vermont and Massachusetts, and National Grid in Rhode Island have all delivered above two %. In all, 28 states now have a standard for either a specific energy efficiency resource standard or a requirement to pursue all cost-effective energy efficiency.[51]

To determine best practices level of energy efficiency performance, EPA used the past performance of states as an indicator of the achievable incremental levels of energy savings. EPA used EIA Form 861 data to determine incremental savings as a percentage of retail sales at the state level in 2012.[52] EPA found that three states (Arizona, Maine, and Vermont) exceeded 1.5 % incremental savings in 2012, and that eight states saved between 1 % and 1.5 %. Because utilities in a state have varying levels of energy efficiency performance, EPA's approach understates the extent to which utilities around the country are implementing best practice-level energy efficiency programs.

We used the same EIA Form 861 data as EPA, but used the utility as the unit of analysis instead of the state, comparing retail sales (bundled and delivery) and incremental energy savings (Total Energy Efficiency Incremental Effects (MWh)), for years 2012, 2011, and 2010, as detailed below in Table 7.2. We identified eight investor-owned utilities that saved more than 1.5 % of electricity sales in 2012, and a further 27 investor-owned utilities that saved between 1 % and 1.5 % that year. We also examined performance in 2011 for these utilities, and found that average performance among this group of top performers was higher in 2012 than 2011: average savings were 1.34 % in

[50] *See* A. Gilleo, et al.,*The 2014 State Energy Efficiency Scorecard* (October 21, 2014) http://www.aceee.org/research-report/u1408; and A. Downs, et al., *The 2013 State Energy Efficiency Scorecard* (November 4, 2013) *available at* http://aceee.org/research-report/e13k.

[51] *See* 2014 and 2013 Scorecard and the "RAP State Energy Policy Inventory." Updated through December 2010. www.raponline.org/document/download/id/4741 .

[52] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, page 5-32 (June 10, 2014) *available at* http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf. Chapter 5 discusses demand-side energy efficiency.

2012 and 1.14 % in 2011. This shows that utilities ramped up programs in 2011. We also identified 12 publicly-owned utilities that saved more than 1.5 % of electricity sales in 2012, and a further 17 publicly-owned utilities that saved between 1 and 1.5 % of sales. The large differences between these leading utilities—in climate, utility size, urban/rural mix—show that states and program administrators around the country can run energy efficiency programs at best practice levels. The track record of these utilities, saving best practice-amounts of energy year after year, helps show that energy efficiency at EPA's best practice-level is adequately demonstrated.

Table 7.2: 2010-2012 Energy Savings for Leading Investor-Owned Utilities.

Utility (investor-owned only)	State	2010 Savings (% of sales)	2011 Savings (% of sales)	2012 Savings (% of sales)
Western Massachusetts Elec Co	MA	1.27%	1.47%	2.09%
West Penn Power Co	PA	did not report	1.01%	1.97%
Massachusetts Electric Co	MA	did not report	1.71%	1.91%
Arizona Public Service Co	AZ	1.15%	1.41%	1.77%
UNS Electric, Inc.	AZ	0.71%	0.80%	1.68%
San Diego Gas & Electric Co	CA	did not report	1.38%	1.67%
Interstate Power and Light Co	MN	0.38%	0.85%	1.61%
Northern States Power Co - Minnesota	MN	1.21%	1.36%	1.59%
Otter Tail Power Co	MN	1.59%	1.34%	1.48%
Puget Sound Energy Inc	WA	1.19%	1.48%	1.47%
Southern California Edison Co	CA	2.39%	1.65%	1.45%

Metropolitan Edison Co	PA	0.27%	0.73%	1.38%
Interstate Power and Light Co	IA	1.11%	1.29%	1.36%
Pennsylvania Power Co	PA	did not report	0.82%	1.31%
The Potomac Edison Company	MD	0.21%	1.00%	1.31%
The DTE Electric Company	MI	did not report	1.00%	1.27%
Dayton Power & Light Co	OH	1.26%	1.16%	1.27%
Pacific Gas & Electric Co	CA	1.76%	1.17%	1.25%
Public Service Co of Colorado	CO	0.83%	0.98%	1.24%
MidAmerican Energy Co	IA	1.19%	1.01%	1.23%
Ohio Power Co	OH	0.63%	1.04%	1.22%
PPL Electric Utilities Corp	PA	did not report	1.41%	1.16%
Idaho Power Co	ID	1.34%	1.25%	1.13%
PacifiCorp	WA	0.97%	1.15%	1.13%
Connecticut Light & Power Co	CT	1.37%	1.30%	1.13%
Duquesne Light Co	PA	0.55%	1.38%	1.12%
Consumers Energy Co	MI	0.61%	0.92%	1.09%
El Paso Electric Co	NM	0.40%	1.18%	1.08%
Black Hills/Colorado Elec.Util	CO	did not report	0.94%	1.08%
United Illuminating Co	CT	1.55%	1.54%	1.08%
Pennsylvania Electric Co	PA	0.22%	0.79%	1.07%

NorthWestern Energy, LLC - (MT)	MT	0.97%	0.79%	1.05%
Commonwealth Edison Co	IL	did not report	0.71%	1.05%
Madison Gas & Electric Co	WI	1.65%	1.05%	1.04%
Duke Energy Ohio Inc	OH	1.14%	0.99%	1.03%

Energy efficiency is a sustainable resource that we will be able to rely on for the duration of this initial standard and beyond. As discussed in Section 7.2.1, no one knows the upper limit of what we can achieve with energy efficiency because design biases found in most existing studies make even their sizable projections low.[53] But we do know that we have not come close to capturing the immense capacity for cost-saving efficiency since potential studies keep showing that cost-effective investments and even long-standing efforts are not seeing diminishing returns in investments. A recent ACEEE study found that estimates of energy efficiency savings potential had not changed noticeably over the past decade or more, despite having harvested all the savings from previous programs, and despite a major recession, a drop in natural gas prices, and the impacts of codes and standards. This observation shows that states and utilities are still finding a substantial amount of energy efficiency savings potential after more than ten years of aggressive pursuit.[54]

An assessment by the Analysis Group (AG) found that states could achieve and sustain levels of energy savings (and associated emission reductions) for many years above 1.5% of state retail electric sales from energy efficiency.[55] The assessment also found that the "successful demonstration of states' ability to meet aggressive ramp rate and/or sustained savings levels holds true across a wide cross-section of states and delivery mechanisms, representing different electric industry structures; different electricity costs; different parts of the country with different climates and electricity needs; different mixes of residential, commercial, and industrial customers; and vastly different

---

[53] Lester B. Lave, et. al., *Real Prospects for Energy Efficiency in the United States*, Washington, D.C.: National Academies Press (2009).

[54] Max Neubauer, *Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential Studies*, ACEEE Report U1407 (August 2014) *available at* http://www.aceee.org/sites/default/files/publications/researchreports/u1407.pdf.

[55] Paul J. Hibbard and Andrea M. Okie, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Program Ramp Rates and Savings Levels*, Analysis Group, Inc. DRAFT (November 2014).

modes of implementation (e.g., by utilities, compacts/associations, state agencies, and third-party contractors)."[56]

AG also found that, for at least several years, leading states—including those that have implemented energy efficiency programs for over a decade—continue to achieve high levels of annual energy efficiency savings as programs grow.

Energy efficiency is a renewable resource. As companies innovate and produce more advanced products, they will develop new cost-effective applications to improve energy use. The Northwest Power and Conservation Council (a regional organization that develops and maintains a regional power plan that aggressively targets energy efficiency) estimated an available cost-effective energy efficiency potential in their Sixth Power Plan (2010) at more than double the already aggressive levels in the Fifth Power Plan, in large part due to technological innovation that resulted in creating new efficiency opportunities and reduced costs.[57]

7.3.1.2 *In setting state goals, EPA should recognize that states can and have ramped up to best practice levels of energy efficiency much faster than provided by EPA's ramp rate.*

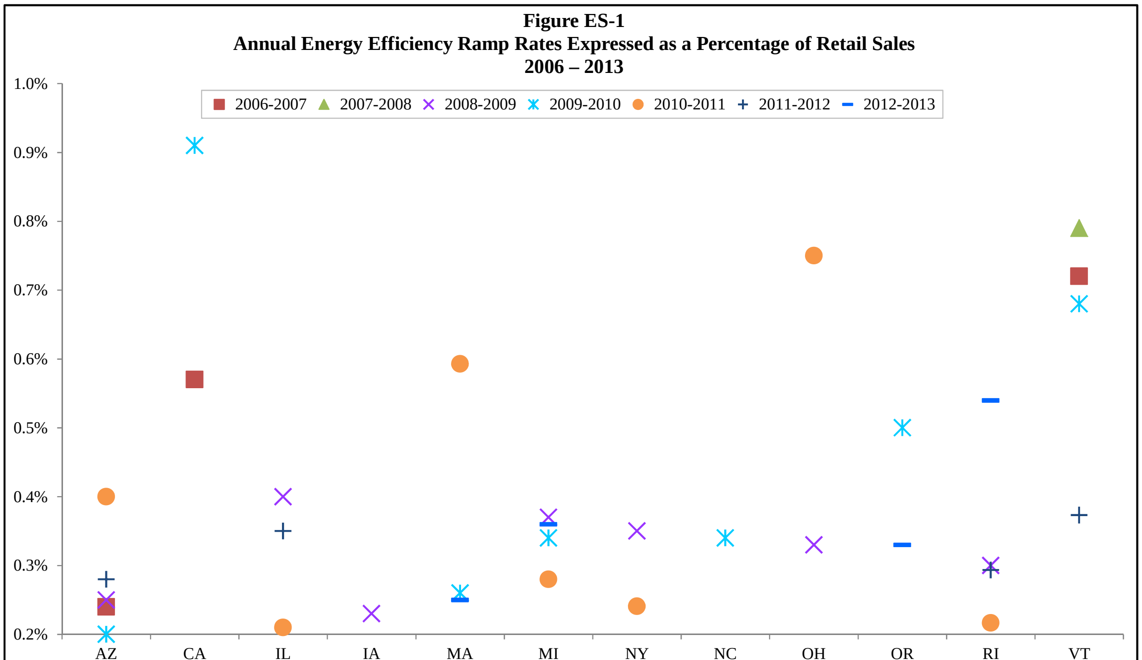
Recommendation: *EPA's assumption of a 0.2 % ramp rate for BSER is achievable, but low. EPA should adopt at least a 0.25 % ramp rate in its BSER for Block 4 energy efficiency.*

EPA concluded that states could ramp up their energy efficiency programs at a rate of 0.2 % per year, but also requested comment on whether it should adopt a 0.25 % growth rate.[58] When looking at actual program performance, EPA itself found an average rate of improvement of the annual savings rate of 0.3 % for states at the moderately performing level (0.8-1.5 % annual savings levels), and 0.38 % at the high performing level (>1.5 % annual savings levels).[59] Additional evidence exists to support the feasibility of at least a 0.25 % annual growth rate.

[56] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 8 (December 1, 2014).
[57] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 54 (December 1, 2014).
[58] 79 Fed. Reg. 34,830, 34,875.
[59] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, page 5-34, 35; 5-69, 70 (June 10, 2014).

The assessment by AG, referenced above, found that states could achieve rates of growth in energy efficiency savings in excess of 0.2 % per year and that many states and/or individual utilities have already demonstrated this ability, including a number of states that achieved *double and triple that rate*.[60] In fact, they found that at least 12 states have achieved ramp rates of their energy efficiency programs at or in excess of 0.2 % since 2006, and that most of these states achieved these ramp rates consistently over multiple years.[61] See Figure 7.1. These states represent a wide cross-section of geographies, customer bases, electricity pricing contexts, and public policies.

Figure 7.1: State Energy Efficiency Ramp-up Rates



Notes & Sources:
Sources for savings vary by year. Ramp rate is calculated as the change in savings between two years. Savings data for 2013 are from the 2014 ACEEE State Scorecard when available. For 2012, sustained savings figures are from NEEP when available, otherwise savings are from Appendix H of the 2013 ACEEE State Scorecard. When neither NEEP nor ACEEE data are available for 2012, EIA Form 861 data are used. For 2011, sustained savings figures are from NEEP when available, otherwise savings are from the 2012 ACEEE State Scorecard. For the years 2006 to 2010, sustained savings are from the 2008 – 2011 ACEEE State Scorecards. Prior to 2010, incremental energy efficiency savings from the EIA are reported at a NERC region level. Savings are mapped to states for these years, first, by mapping utilities to states using EIA data from 2010 to 2012, and remaining savings were mapped using sales data for a given year.

---

[60] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 7 (December 1, 2014).

[61] Many more states and utilities achieved ramp rates at or above 0.2 percent than are included in Figure 7.1. For example, at least the following states have achieved a ramp rate at, or above, 0.2 percent in at least one year between 2006 and 2012: Arizona, California, Connecticut, District of Columbia, Hawaii, Idaho, Illinois, Indiana, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nebraska, Nevada, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, Utah, Vermont, and Wisconsin. Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 22 (December 1, 2014).

Several states and utilities have ramped up very quickly, going from zero or near-zero to as much as one % total annual load reduction in just three to four years in response to changes in policy. This indicates that rapid and major expansion of energy efficiency programs does not require a long lead time. An Edison Foundation Institute for Electric Innovation report found five states (Indiana, South Dakota, Tennessee, Virginia, and West Virginia) more than doubled their electric efficiency expenditures in 2012 relative to 2011, and in 2011, three states (Indiana, Ohio, and Pennsylvania) had doubled their spending relative to 2010 levels.[62]

AG found that higher ramp rates have often followed changes in state level policies that support, encourage, or require savings from energy efficiency programs, similar to what is expected under the Clean Power Plan. A cross-section of four state examples illustrates what is feasible with policy encouragement.

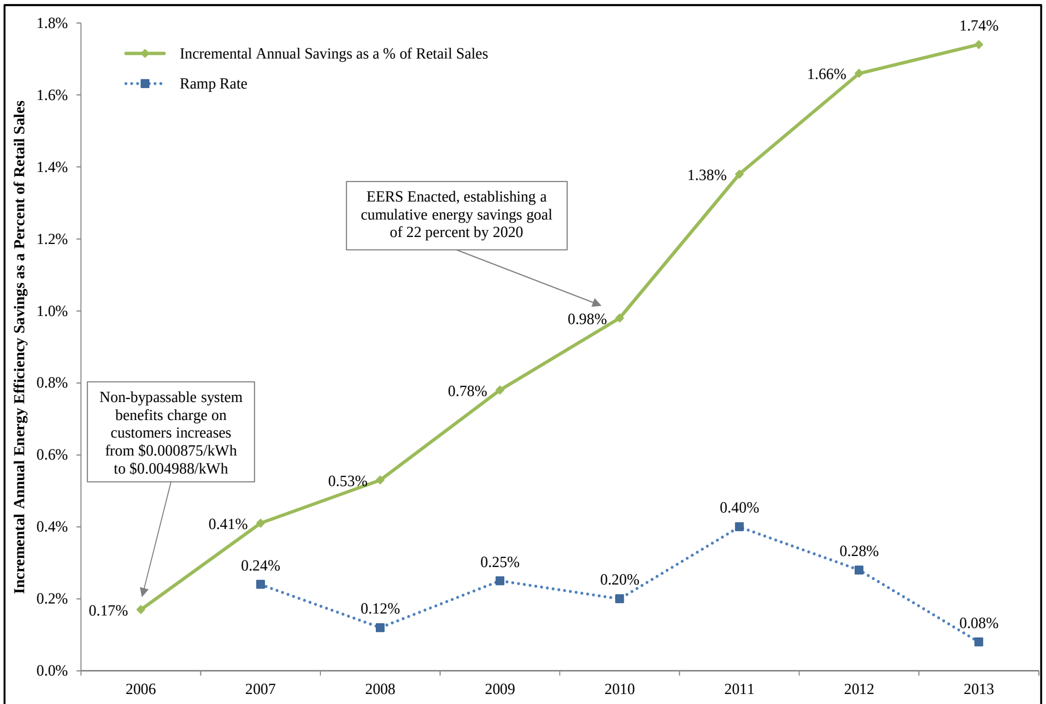
Arizona

The success of energy efficiency programs in Arizona is due in large part to policies that provide funding for the programs and establish an efficiency savings standard that applies to both investor-owned and electric cooperatives. Between 2006 and 2013, annual savings from energy efficiency increased from 0.06% of retail sales to 1.74 % and the ramp rate between each year was either at or above 0.2% for five of the seven years.[63] Figure 7.2, below, illustrates this progress.

[62] Barbose, G. L., C.A. Goldman, I. M. Hoffman, M. A. Billingsley, "The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025," January 2013, LBNL-5803E.

[63] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 23-25 (December 1, 2014).

Figure 7.2: Arizona's Annual Energy Efficiency Savings and Ramp Rates Expressed as a Percentage of Retail Sales, 2006 – 2013.



Notes & Sources:
[1] Incremental annual energy efficiency savings as a percentage of retail sales from ACEEE State Energy Efficiency Scorecards, 2008 – 2014.
[2] Ramp rate is calculated as the change in percentage savings between two years.

Illinois

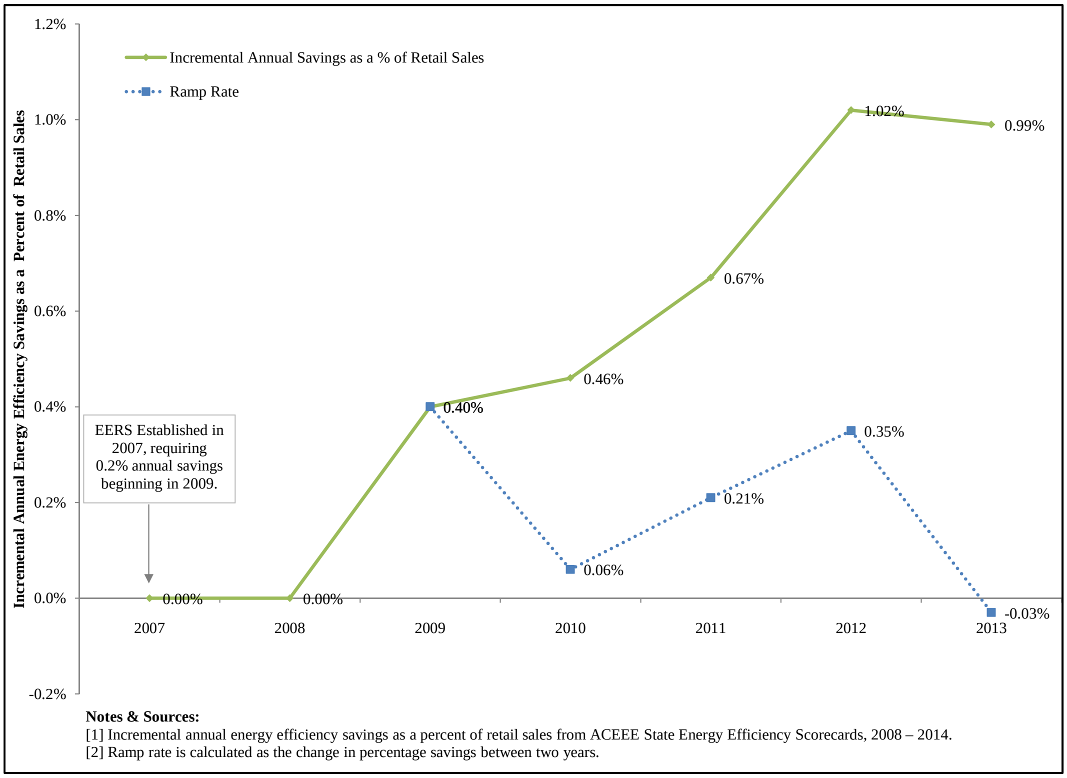
Illinois is a state that effectively started from zero when it passed an energy efficiency standard that started at 0.2 % of electric sales in 2009, to be ramped up to 2 % of annual sales in 2016 and beyond.[64] The state was very successful in rapidly expanding its programs, reaching to over 1 % in 2012, and achieving an average ramp rate in that time of 0.26 %. However, the state also provides an example of how policy can hinder progress in achieving cost-effective energy efficiency, as is illustrated in results after 2012 when the arbitrary limits to investment (funding cap) in energy efficiency programs established in legislation started kicking in.[65] See Figure 7.3. But Illinois also has a policy that allows for additional energy efficiency investment as part of the utility resource planning process, outside of the investment cap that is part of the standard.

---

[64] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 25-27 (December 1, 2014).
[65] *Id*.

Due to this additional policy, it is expected that by 2015, these programs will be reducing electricity sales by 1.4 % per year.[66]

Figure 7.3: Illinois' Annual Energy Efficiency Savings and Ramp Rates (Expressed as a Percentage of Retail Sales, 2007 – 2013).



Michigan

In 2008, Michigan passed its own policies supportive of energy efficiency investments and established a savings standard that applies to investor-owned, municipal, and electric cooperative utilities. This has led to a significant ramp-up in savings, from effectively no savings to annual savings of 1.51 % of retail sales in just five years, with growth averaging 0.3 % annually.[67] See Figure 7.4. Unfortunately, Michigan also passed an investment limit based on a percentage of revenues from retail sales, which could potentially constrain higher savings levels and ramp rates. The programs are

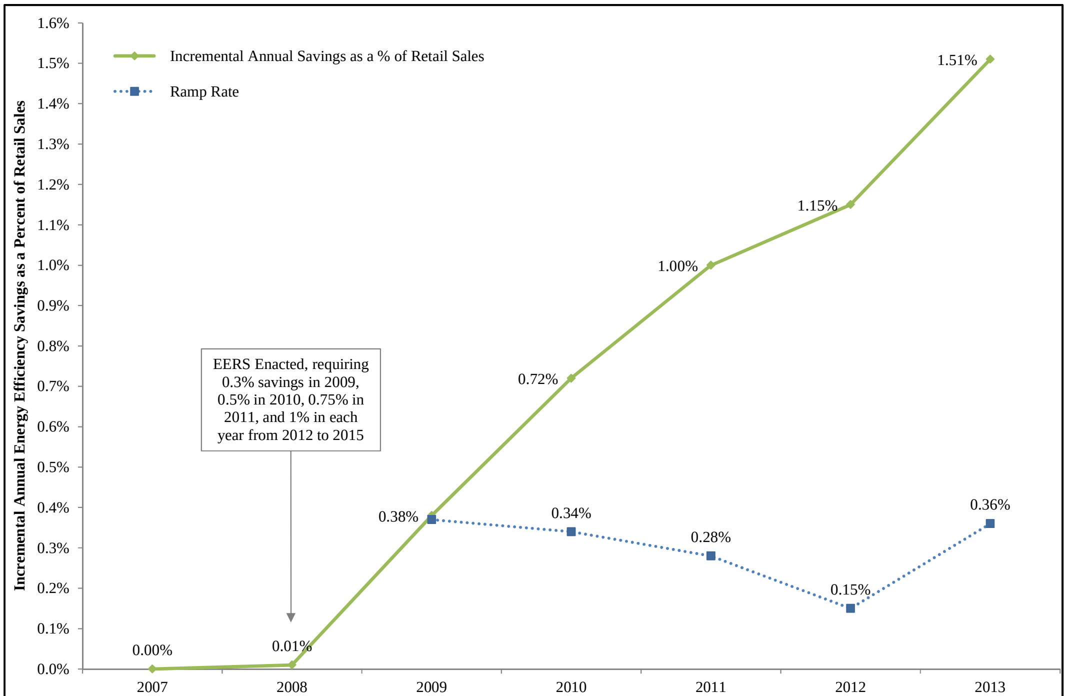
---

[66] *See* Rebecca Stanfield, *Illinois' Climate Plant Can Also be its Plan for Economic Growth*, NRDC Switchboard (September, 2014) *available at* http://switchboard.nrdc.org/blogs/rstanfield/illinoiss_climate_solutions_ca.html.

[67] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 27-30 (December 1, 2014).

administered by all categories of utilities, and a third party program administrator (Efficiency United) oversees a small number of energy efficiency programs funded by an alternative compliance mechanism.[68]

Figure 7.4: Michigan's Annual Energy Efficiency Savings and Ramp Rates (Expressed as a Percentage of Retail Sales, 2007 – 2013).



Notes & Sources:
[1] Incremental annual energy efficiency savings as a percent of retail sales from ACEEE State Energy Efficiency Scorecards, 2008 – 2014.
[2] Ramp rate is calculated as the change in percentage savings between two years

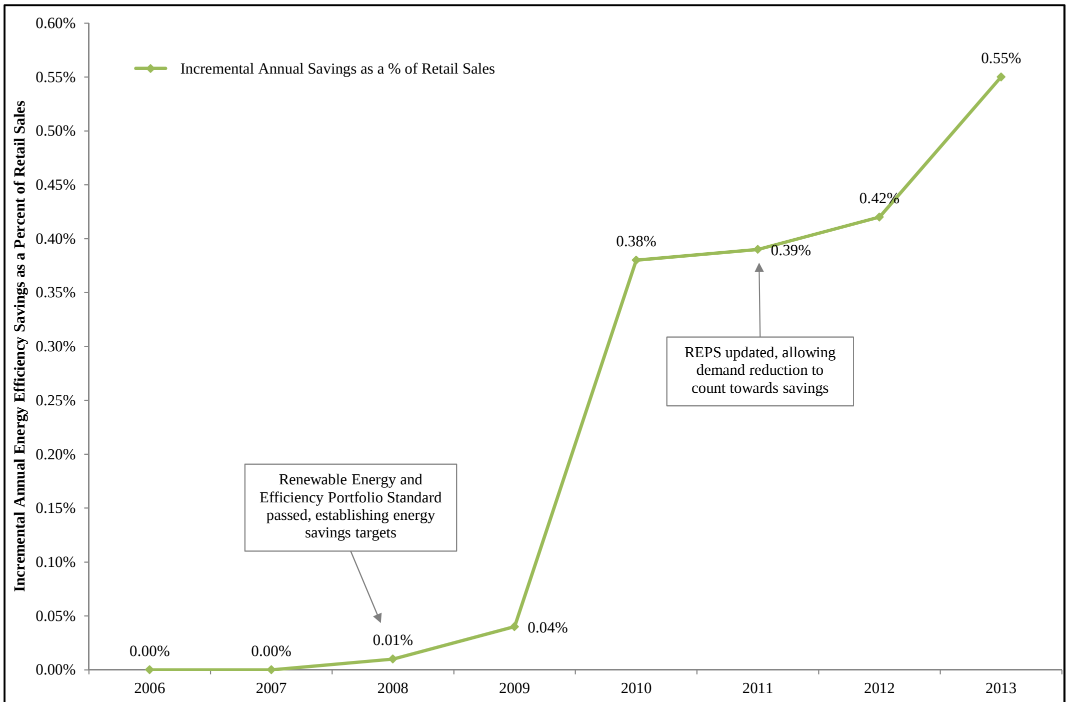
North Carolina

North Carolina adopted a Renewable Energy and Energy Efficiency Portfolio Standard in 2008, which capped savings that can come from energy efficiency at 25 % of the 2012-2018 targets and 40 % of the 2021 target. This standard covers investor-owned, municipal and cooperative electric utilities, but the limiter only applies to the investor-owned utilities. Figure 7.5 illustrates how the enactment of the standard in 2008 and an update to it in 2011 affected energy efficiency savings, despite the significant limitations

68 *Id*.

placed on the contribution of energy efficiency. Between 2009 and 2010, incremental savings increased by 0.34 %, and from 2012 to 2013 by 0.13 %.[69]

Figure 7.5: North Carolina's Annual Energy Efficiency Savings, 2006 – 2013.



Notes & Sources:
[1] Incremental annual energy efficiency savings as a percentage of retail sales from ACEEE State Energy Efficiency Scorecards, 2008 – 2014.

7.3.1.3 *Average Measure Life Is Longer And Savings Do Not Stop At The End Of Measure Life.*

> ***Recommendation:*** *EPA should at a minimum increase the average measure life to 12 years, and should consider reducing or eliminating the decline in savings expected due to the incorrect assumption that savings "disappear" after a measure's useful life.*

The lifetime of energy efficiency measures is discussed in detail in the GHG TSD.[70] EPA assumes an average life of 10 years, and that savings from a measure end at the completion of its "useful life." There are two problems with these assumptions.

---

[69] Paul J. Hibbard, Andrea M. Oakie, and Katherine Franklin, *Assessment of EPA's Clean Power Plan: Evaluation of Energy Efficiency Ramp Rates and Savings Levels*, Analysis Group, Inc., page 43-45 (December 1, 2014).
[70] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, page 5-42 (June 10, 2014).

First, in most cases usage does not jump back up at the end of a measure's useful life. Most often, the measure is replaced with one that is equivalent or more efficient than the previous measure due to market transformation, state or federal standards, or technology innovation. Heating and cooling systems installed today will be replaced with higher SEER/EER/HSPF ones in 20 years. Refrigerators will be replaced in 15 years with more efficient ones. Insulation will stay in attics and walls. As a result, the sharp decline in savings shown in the GHG TSD is inaccurate and states will in most cases benefit from steady savings at the end of a measure's "useful life." EPA should consider reducing or eliminating the decline in savings expected due to this effect. However, if the EPA chooses to take a conservative position and declines to acknowledge this effect, we offer our second point to adjust the average measure life.

Second, EPA uses an average measure life of 10 years. The recently-released data from Lawrence Berkeley National Lab (LBNL),[71] which is the most complete dataset available and includes programs from at least four states in each U.S. region, should instead be used. These data report an average savings-weighted measure life of 12.5 years, and we recommend that the EPA use at least an average measure life of 12 years to set the BSER.

7.3.1.4 *EPA's Cost Analysis Overstates the Costs of Saving Energy.*

> ***Recommendation:*** *EPA should adopt a levelized cost of saved energy of \$44/MWh based on actual utility and state analysis recently compiled by the Lawrence Berkeley National Laboratory.*

In the Proposed Rule,[72] and in greater detail in the GHG TSD,[73] EPA proposes a levelized cost of saved energy (LCOSE) of \$85-90/MWh. EPA directly acknowledges that this "range of LCOSE is notably conservative (leading to higher costs) in comparison with most utility and state analysis." This is accurate, and the most comprehensive analysis to date of actual program data has been released by LBNL since the EPA issued its proposed rule, which further supports using a much lower LCOSE.

---

[71] Ian M. Hoffman, Steven R. Schiller, Annika Todd, Megan A. Billingsley, Charles A. Goldman, Lisa C. Schwartz, *Energy Savings Lifetimes and Persistence: Practices, Issues and Data*, Lawrence Berkeley National Laboratory. Technical Brief (2014).
[72] 79 Fed. Reg. 34,830, 34,874.
[73] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, page 5-51 (June 10, 2014).

The recent LBNL analysis shows an average savings-weighted total resource cost of saved energy as $44/MWh.[74] This result is derived from the analysis of 2,100 program years from 2009 to 2013, run by 50 administrators in 19 states that include every U.S. region. This number is the "total resource" cost, which includes both program administrator and participant costs, and is the best comparison to the EPA's estimate of $85-90/MWh. LBNL also reports the program administrator costs for this dataset, which is $23/MWh. ACEEE has also looked at program results from across the country, and reported an average cost of $28/MWh when just considering program administer costs (LBNL and ACEEE use slightly different assumptions, and LBNL uses a larger database of programs).[75] They also report a total cost of $54/MWh using limited data from just seven states. Because the LBNL analysis draws on the most current, comprehensive, and regionally-representative dataset available today, we recommend using their result of $44/MWh for the total resource cost of saved energy.

We also note there is no reason to assume that costs will rise over the compliance period. One study presented at the 2012 ACEEE's Summer Study estimated the cost of energy efficiency resource acquisition using data from over 30 program administrators in the U.S. and Canada. The results of their regression analysis indicate that the cost of saved energy falls as savings increase, until approximately 2.5 % of annual energy savings are achieved.[76] Additionally, ACEEE's analysis of programs between 2009 and 2012 shows no evidence that the average cost of saved energy increased over this time period.[77] Also, while some lower-cost efficiency measures, such as CFLs, will likely play a much smaller role in achieving energy savings going forward, new technologies that are already viable such as LED lighting, smart thermostats, advance controls technology, heat pump clothes dryers, and others will increase savings potential at low cost.

---

[74] Charles A. Goldman, Ian M. Hoffman, Gregory M. Rybka, Greg Leventis, and Lisa C. Schwartz , LBNL, The *Total Cost of Saved Energy For Utility Customer-Funded Energy Efficiency Programs*, presentation at the NARUC Annual Meeting (November 17, 2014) *available at* http://emp.lbl.gov/cost-saved-energy.
[75] M. Molina. *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs.* Washington, DC: American Council for an Energy-Efficient Economy (March 25, 2014) *available at* http://www.aceee.org/research-report/u1402.
[76] John Plunkett, Theodore Love, and Francis Wyatt, Green Energy Economics Group, Inc., *An Empirical Model for Predicting Electric Energy Efficiency Resource Acquisition Costs in North America: Analysis and Application*, ACEEE Summer Study on Energy Efficiency in Buildings (2012) *available at* http://www.aceee.org/files/proceedings/2012/data/papers/0193-000170.pdf.
[77] *See* M. Molina. *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs.* Washington, DC: American Council for an Energy-Efficient Economy (March 25, 2014).

7.3.1.5 *Publicly-Owned Utilities and Rural Cooperatives Can Save Energy On Par With Investor-Owned Utilities, the EPA Should Not Modify the Best Practices Scenario for These Utilities.*

Recommendation*: Assumptions used for publicly-owned utilities and rural cooperatives for the Block 4 targets should not differ from investor-owned utilities.*

Municipal utilities and rural cooperatives, as EPA states, "have multiple options for reducing CO2 emissions," including the ability to employ energy efficiency.[78] In states where municipal or cooperatively-owned utilities operate under similar regulatory (by local boards or councils) or customer pressure to implement demand-side energy efficiency programs as their investor-owned utility counterparts, these utilities have implemented robust energy efficiency programs.

In California, for example, Senate Bill 1307, signed in 2005, requires municipally and cooperatively-owned utilities, in procuring energy, to first capture all energy efficiency resources that are cost-effective, reliable, and feasible. Assembly Bill 2021, signed in 2006, requires municipally and cooperatively owned utilities to establish 10-year energy efficiency targets and report progress to the California Energy Commission.

Under this framework, California's publicly-owned utilities, ranging in size from the Los Angeles Department of Water and Power (LADWP), the nation's largest municipal utility, to Truckee Donner Public Utility District, which provides electric power to 13,200 customers,[79] have implemented robust energy efficiency efforts. Over the past three years, LADWP's annual savings have increased 40 % per year, and last year LADWP's programs saved around one % of sales. LADWP's board recently adopted 10-year energy-saving targets that will have the utility ramp up annual savings to 1.7 % of sales.[80] Truckee-Donner's energy efficiency programs saved three % of sales in 2008, more than two % of sales in 2009 to 2011, 1.9 % of sales in 2012, and 1.7 % of sales in 2013. In 2009, Truckee-Donner devoted 4.5 % of gross electric sales to energy efficiency

[78] 79 Fed. Reg. 34, 34887.

[79] Trucker Donner Public Utility District, *Audited Financials and Budget* (last visited December 1, 2014) *available at* http://www.tdpud.org/about-us/budgets-and-financials.

[80] Dylan Sullivan, *Los Angeles' city-owned electric utility raises its energy efficiency ambitions*, NRDC Switchboard (August 11, 2014) *available at* http://switchboard.nrdc.org/blogs/dsullivan/los_angeles_city-owned_electri.html; Minutes of Regular Meeting of the Board of Water and Power Commissioners, City of Los Angeles (August 5, 2014) *available at* http://ladwp.granicus.com/DocumentViewer.php?file=ladwp_d6f654ebf92e417d66336df9f14c1b80.pdf&view=1.

programs, and implemented 16 energy efficiency programs.[81] California's publicly-owned utilities as a group invested almost $140 million in energy efficiency programs in 2013.[82] Best practices in the sector include working with other utilities, including investor-owned utilities that operate in the same region. Southern California's publicly-owned utilities, together as the Southern California Public Power Authority, jointly issue requests for proposals for energy efficiency programs, jointly apply for grant monies, jointly train staff, and meet regularly to exchange information.[83]

Since 2010, Northwest publicly-owned utilities (municipals and cooperatives) and the Bonneville Power Administration (BPA) have saved at least 560 average megawatts of electricity, greatly surpassing the five year goal of 510 average megawatts set by the NWPCC in its Sixth Power Plan.[84] The NWPCC estimates energy efficiency is now one of the top three electricity resources in this region with some of the lowest electricity rates in the nation, having already avoided more than 10-12 large power plants.[85] According to NWPCC, the average cost of efficiency improvements is $.017/kWh, about five times less than the cost of power from a new gas-fired plant. And without these savings, it would have to generate enough additional electricity to power 3.6 million Northwest homes. BPA and Northwest publicly owned utilities administer programs that pursue cost-effective energy savings in all sectors of the economy in support of public power's share of the region's energy efficiency target, which is roughly 42 % of the total regional target.

Other municipally- and cooperatively-owned utilities around the country have had similar successes. In fiscal year 2012, Austin Energy (TX) invested $17.7 million in energy efficiency rebates and its programs saved .83 % of load.[86] Iowa also provides an example of municipal and cooperative utilities active in promoting energy efficiency and

---

[81] California Municipal Utilities Association, En*ergy Efficiency in California's Public Power Sector, A Status Report*, page 205 (March 2010) *available at* http://www.ncpa.com/current-issues/energy-efficiency-reports.html.

[82] California Municipal Utilities Association, *Energy Efficiency in California's Public Power Sector, A 2014 Status Report*, Page 24, Figure 9 (March 2014) *available at* http://www.ncpa.com/current-issues/energy-efficiency-reports.html.

[83] Southern California Public Power Authority, *Public Benefits Committee* (last visited December 1, 2014) *available at* http://www.scppa.org/pages/committees/publicbenefits.html.

[84] Bonneville Power Administration, *Northwest public utilities, BPA top five-year energy savings target* (November 25, 2014) *available at* http://www.bpa.gov/news/newsroom/releases/Documents/20141124-PR-23-14-BPA-Northwest-public-utilities-top-energy-saving-target.pdf.

[85] Northwest Power and Conservation Council, *Sixth Northwest Conservation and Electric Power Plan* (September 2011) *available at* http://www.nwcouncil.org/energy/powerplan/6/plan/.

[86] Austin Energy, *Austin Energy Annual Performance Report, Year Ended September 2012*, Tables 15 and 32 (July 26, 2013) *available at* https://austinenergy.com/wps/wcm/connect/8a6066f4-d774-490f-8ebd-e3de513b5745/2012AnnualPerformanceReport.pdf?MOD=AJPERES.

achieving meaningful savings. Maquoketa Valley Electric Cooperative achieved savings of 1.45 % and 1.87 % of their sales in 2011 and 2012 respectively, while staying within budget and close to or above their energy savings targets.[87]

It is also possible for municipal utilities and cooperative utilities in a region to work with a third party to provide energy efficiency programs region-wide, as is the case with Efficiency Vermont, which serves the entire state of Vermont, including the territories of 22 municipal, coop and investor-owned utilities. Efficiency Vermont has achieved significant savings over the last 14 years,[88] and its 2012-2014 plan includes approximately 2.2 % annual savings.[89] A study by the National Rural Electric Cooperative Association (NRECA) showed that over 90% of its member cooperatives offered at least one energy efficiency program, and over 70% of members planned to expand their energy efficiency programs further.[90]

The Tables below use EIA Form 861 Data (as before with investor-owned utilities), for municipal utilities, cooperatives, and political subdivisions.

Table 7.3: 2011 and 2012 Energy Savings for Leading Municipal Utilities.

Utility (Municipal)	State	2011 Savings (% of sales)	2012 Savings (% of sales)
City of Oberlin - (OH)	OH	0.44%	2.62%
City of Saint Peter	MN	0.00%	2.34%
City of Aspen- (CO)	CO	1.00%	2.24%
Rock Rapids Municipal Utility	IA	0.85%	2.18%
City of Burlington Electric - (VT)	VT	2.39%	1.87%
City of Wadena - (MN)	MN	0.37%	1.80%
Shakopee Public Utilities Comm	MN	2.12%	1.68%

[87] Maquoketa Valley Electric Cooperative, Summary of 2011 and 2012 Energy Efficiency Programs, (December 19, 2013).
[88] *See e.g.,* Efficiency Vermont Annual Reports (last visited December 1, 2014) *available at* https://www.efficiencyvermont.com/About-Us/Oversight-Reports-Plans/Annual-Reports-amp-Plans
[89] VT Public Service Board Docket EEU-2010-06, Order Entered 8/1/2011.
[90] NRECA, *Energy Efficiency* (last visited December 1, 2014) *available at* http://www.nreca.coop/nreca-on-the-issues/energy-operations/energy-efficiency/.

Utility (Municipal)	State	2011 Savings (% of sales)	2012 Savings (% of sales)
City of Chaska	MN	1.36%	1.63%
City of Benson - (MN)	MN	1.60%	1.62%
Rochester Public Utilities	MN	1.32%	1.58%
City of Greenfield - (IA)	IA	1.40%	1.58%
City of Fort Collins - (CO)	CO	1.06%	1.58%
City of Owatonna	MN	1.95%	1.41%
City of Austin - (MN)	MN	1.02%	1.40%
City of Seattle - (WA)	WA	1.12%	1.36%
City of Palo Alto - (CA)	CA	0.68%	1.32%
Fairmont Public Utilities Comm	MN	0.69%	1.31%
Princeton Public Utils Comm	MN	0.86%	1.30%
City of Azusa	CA	1.15%	1.28%
City of Laurens - (IA)	IA	0.42%	1.28%
City of Remsen - (IA)	IA	NA	1.23%
City of Glendale	CA	1.08%	1.22%
City of Marshfield - (WI)	WI	0.83%	1.11%
City of Algona - (IA)	IA	0.50%	1.11%
City of Jackson - (MN)	MN	NA	1.05%
City of East Grand Forks - (MN)	MN	1.24%	1.04%
City of Anaheim - (CA)	CA	0.65%	1.02%
City of Tacoma - (WA)	WA	1.29%	1.01%
City of Pasadena - (CA)	CA	1.19%	1.00%
City of Riverside - (CA)	CA	1.03%	0.99%
City of Burbank Water and	CA	1.09%	0.98%

Utility (Municipal)	State	2011 Savings (% of sales)	2012 Savings (% of sales)
Power			
City of Arlington - (MN)	MN	0.29%	0.97%
City of Marquette - (MI)	MI	0.57%	0.95%

Table 7.4: 2011 and 2012 Energy Savings for Leading Cooperative Utilities.

Utility (Cooperatives)	State	2011 Savings (% of sales)	2012 Savings (% of sales)
Barron Electric Coop	WI	0.12%	2.55%
Franklin Rural Electric Coop - (IA)	IA	1.57%	1.40%
Piedmont Electric Member Corp	NC	0.98%	1.19%
Southern Maryland Elec Coop Inc	MD	0.92%	1.14%
Henry County Rural E M C	IN	0.96%	1.03%
Kauai Island Utility Cooperative	HI	1.03%	0.99%

Table 7.5: 2011 and 2012 Energy Savings for Leading Political Subdivision Utilities.

Utility (Political Subdivisions)	State	2011 Savings (% of sales)	2012 Savings (% of sales)
Columbia River Peoples Ut Dist	OR	1.17%	2.21%
Salt River Project	AZ	1.46%	2.21%
Truckee Donner P U D	CA	2.27%	1.88%
Sacramento Municipal Util Dist	CA	1.64%	1.57%

Snohomish County PUD No 1	WA	1.18%	1.35%
Tillamook Peoples Utility Dist	OR	0.92%	1.34%
PUD No 1 of Clark County - (WA)	WA	1.51%	1.31%
PUD No 2 of Grant County	WA	1.24%	1.20%

7.3.2 *Adoption of improved building codes and increased compliance with codes could add between an additional 0.87 - 2.5 % per year in 2030.*

***Recommendation**: Increased compliance with building codes (0.87% per year in 2030) should be included in the potential emissions reductions in the BSER for Block 4 and both increased compliance and adoption of updated building codes by states and local governments should be credited in state plans.*

Buildings account for 40% of US primary energy use, 70% of electricity use, and 39% of carbon dioxide emissions.[91] Increasing energy efficiency in buildings represents a significant opportunity to reduce emissions from the electricity sector. Building codes have proven to be one of the most effective policy tools for increasing energy efficiency in new construction and major renovations, thereby reducing emissions and resulting in cost-effective energy savings for consumers. Codes can also affect fairly minor remodels, such as a new tenant moving into a commercial building and installing new lighting.

There are several ways that utilities, program administrators, and EGUs can affect the energy savings achieved from buildings codes, including affecting the stringency of codes during code development, influencing the code adoption process, and ensuring that adopted codes are complied with.[92] This section presents potential savings that could be achieved by increasing compliance with currently adopted building codes and through both updating codes and increasing compliance. We recommend that, at a minimum, savings achievable through increased compliance be included in the potential emissions reductions used in the BSER for Block 4 and should be credited in state plans. Programs for increased compliance can be implemented by the state, local governments

[91] Pacific Northwest National Laboratory, *Building Energy Codes Resource Guide for Policy Makers*, PNNL-SA-81023 (June 2011) *available at* http://www.energycodes.gov/sites/default/files/documents/BECP_Policy_Maker_Resource%20Guide_June2011_v00_lores.pdf.

[92] NEEP, IMT, and IEE, *Attributing Building Energy Code Savings to Energy Efficiency Programs,* Final Report (February 2013) *available at* http://www.neep.org/file/964/download?token=fdJXry0p.

or the utilities, or a wide variety of third party providers or energy service companies without the involvement of government, and credits developed for compliance by EGUs directly. Including updated code adoption and future code improvements by state or local governments will lead to significant additional savings and should also be credited in state plans.

7.3.2.1 *Building Energy Codes Have a Long History of Cost-effective Energy Savings.*

Energy efficient building codes have been a successful policy tool for reducing energy use in new buildings and major renovations since the 1970s. Building energy codes ensure that minimum levels of energy efficiency are achieved at the time when they are easiest and cheapest to implement: during construction. In addition to reducing national energy use and consequently emissions, building energy codes result in cost-effective energy bill savings for consumers, increased comfort in buildings, reductions in peak electricity load, and job creation, as energy bill savings are spent on other goods throughout the economy.[93]

The Pacific Northwest National Laboratory (PNNL) estimates that the Department of Energy Building Energy Codes Program has achieved significant energy savings since its inception in 1992. Specifically, PNNL estimates that the following savings can be attributed to the Building Energy Codes Program:

- Cumulative savings from 1992 to 2012: 4 quadrillion BTU primary energy savings, $44.6 net present value (NPV) energy cost savings, and 300 million metric tons carbon dioxide.

- Annual Savings in 2012: 0.5 quads of primary energy savings, $4 billion NPV energy cost savings, and 36 MMT CO_2.[94,95]

That building codes have resulted in energy savings to date is supported by additional research. A 2009 report that assessed the impact of residential building energy codes on state electricity use found that building codes had a detectable effect on per capita

---

[93] Pacific Northwest National Laboratory, *Building Energy Codes Resource Guide for Policy Makers*, PNNL-SA-81023 (June 2011) *available at* http://www.energycodes.gov/sites/default/files/documents/BECP_Policy_Maker_Resource%20Guide_June2011_v00_lores.pdf.

[94] Livingston et al, *Building Energy Codes Program: National Benefits Assessment, 1992-2040* (March 2014) *available at* http://www.energycodes.gov/sites/default/files/documents/BenefitsReport_Final_March20142.pdf.

[95] Note that these savings are the savings from codes that can be attributed to the actions of the BECP and therefore do not represent the total savings achieved to date from building codes.

electricity consumption, ranging from a reduction of 0.3 to 5%, depending on the state. The same study estimated aggregate national savings of 2.09 to 4.98% for the year 2006.[96]

While building codes can result in incremental construction costs, the energy savings from codes have been shown to be cost-effective. For example, the Building Codes Assistance Project (BCAP) analysis of the 2009 International Energy Conservation Code (IECC) found that it have an average simple payback to the homeowner of 3.45 years Research by PNNL found that American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) Standard 90.1-2010 was cost-effective compared to ASHRAE 90.1-2007 for representative building prototypes and climate zones.[97] Additional research by DOE found that both the 2009 IECC and the 2012 IECC were cost-effective in all climate zones compared the 2006 IECC.[98]

7.3.2.2 *Code Development, Adoption, Enforcement and Compliance.*

Building codes in the United States are adopted and enforced at the state and local level, rather than at the national level. Most states adopt model codes that are developed by two non-profit organizations: the International Code Council (ICC) and ASHRAE. These organizations develop the IECC and ASHRAE Standard 90.1, respectively. The IECC covers all residential and commercial building types and incorporates ASHRAE Standard 90.1 by reference; ASHRAE 90.1 covers nonresidential construction over three stories. Both of these codes are updated every three years with the input of stakeholders. Once a new edition of the code is finalized, the Department of Energy makes a determination as to whether the code saves energy compared to the previous edition of the code. If the Secretary of Energy finds that the new codes save energy, states are directed to consider adoption of the new code.

Actual adoption of building energy codes varies state by state. As can be seen from Figures 7.6 and 7.7, most states have adopted recent energy codes, while other states have not adopted energy codes or have energy codes that predate the 2006 IECC or

[96] Aroonruengsawat, Auffhammer, and Sanstad, *The Impact of State Level Building Codes on Residential Electricity Consumption*, Lawrence Berkeley National Lab (November 25, 2009) *available at* http://urbanpolicy.berkeley.edu/greenbuilding/auffhammer.pdf.

[97] Thornton et al, *National Cost-effectiveness of ASHRAE Standard 90.1-2010 Compared to ASHRAE Standard 90.1-2007 (*November 2013.) *available at* http://www.pnnl.gov/main/publications/external/technical_reports/pnnl-22972.pdf.

[98] US Department of Energy, *National Energy and Cost Savings for New Single- and Multifamily Homes: A Comparison ofthe 2006, 2009, and 2012 Editions of the IECC* (last visited December 1, 2014) *available at* http://www.energycodes.gov/sites/default/files/documents/NationalResidentialCostEffectiveness.pdf.

ASHRAE 90.1-2004. Some states, such as California and Washington, develop and adopt their own codes rather than relying on the IECC and ASHRAE 90.1 codes.

Figure 7.6: Residential Energy Code State Adoption Map.[99]

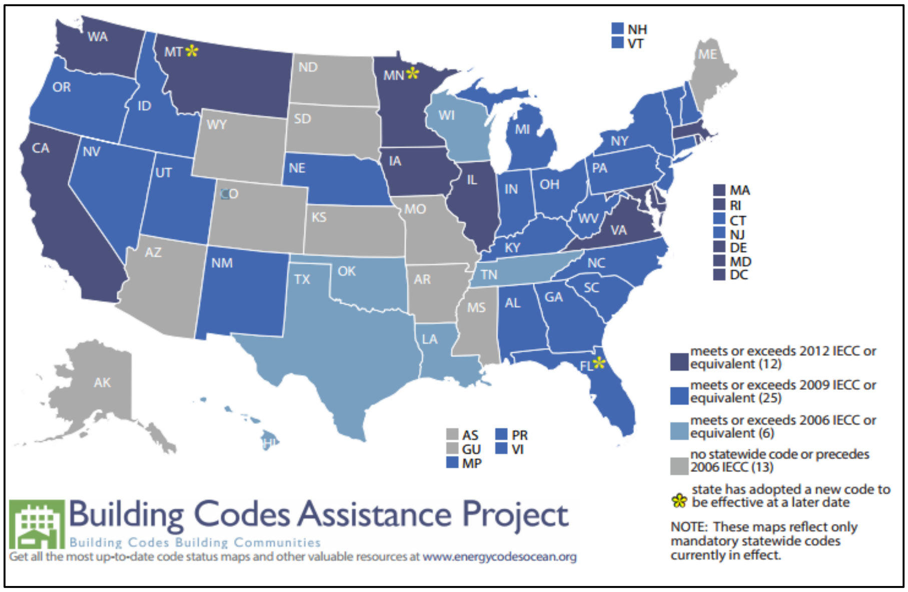
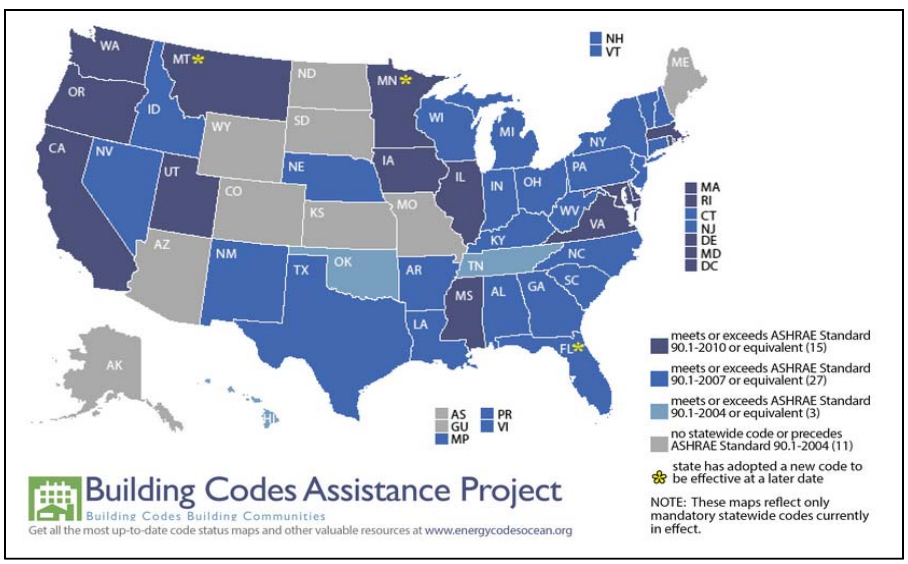


Figure 7.7: Commercial Energy Code State Adoption Map.[100]



---

[99] Online Code Environment & Advocacy Work, Building Codes Assistance Project, *Code Status: Residential* (last visited December 1, 2014) *available at* http://energycodesocean.org/code-status-residential.
[100] Online Code Environment & Advocacy Work, Building Codes Assistance Project, (last visited December 1, 2014) *available at* http://energycodesocean.org/sites/default/files/Commercial%201pager%20Nov14.jpg, Accessed 11/12/2014.

Utilities can play an important role in the development, adoption, and enforcement of building energy codes. There is history of utility involvement in every stage of the building code process with established mechanisms for crediting energy savings from this activity.[101] Specifically, utilities can:

- Participate in the code development process to strengthen the efficiency of building energy codes
- Provide technical assistance to state and local agencies in both the adoption and implementation of building codes
- Directly advocate for state and local adoption of codes
- Conduct studies to assess compliance
- Train building industry professionals to improve compliance
- Directly support third-party compliance

In order to achieve energy savings, adopted codes must be enforced and energy efficiency measures implemented in the field. While there is varying data quality on compliance rates by state, studies of compliance in the US have found that compliance is significantly less than 100 %.[102] A 2013 Institute for Market Transformation (IMT) study that surveyed existing compliance studies for 45 states and estimated energy savings from increased compliance found that compliance rates varied significantly across the US, ranging from as low as zero compliance to over 90 % compliance.[103] Unfortunately, data on compliance is limited due to the cost and resources to conduct compliance studies. The IMT report surveyed compliance literature spanning two decades. Unfortunately, the compliance studies done to date and surveyed in the IMT report do not use consistent methodologies and therefore findings for compliance rates across states are not necessarily comparable. In 2010, DOE published a methodology for determining compliance rates which should alleviate these inconsistencies for future compliance studies.[104]

---

[101] *See* NEEP, IMT and IEE, *Attributing Building Energy Code Savings to Energy Efficiency Programs*, (February 2013).
[102] Sarah Stellberg, *Assessment of Energy Efficiency Achievable from Improved Compliance with U.S. Building Energy Codes: 2013 – 2030* (2013).
[103] *Id*.
[104] DOE, *Measuring State Energy Code Compliance* (March 2010).

In its analysis, IMT looked at a range of scenarios to assess potential savings from increasing compliance with code: a low existing compliance scenario of 25% and a high existing compliance scenario of 75%. Below, we present a middle scenario that conservatively assumes that existing compliance rates are 50%. While the data on existing compliance rates may be limited, there is significant consensus that compliance in most jurisdictions is less than 100% and often much lower. IMT also found that every dollar spent to improve compliance yields $6 in energy savings.[105]

7.3.2.3 *Potential Electricity Emissions Reduction from Increased Compliance and Adoption of 2012 IECC and ASHRAE 90.1-2010.*

History has shown continual improvement in building energy codes and further progress beyond current codes is likely. Recent energy codes have made significant progress in energy efficiency. Figures 7.8 and 7.9 present the history of improvements in ASHRAE Standard 90.1 between 1975 and 2010 and the IECC between 1975 and 2012. These figures show that there has both been continual improvement in building energy codes and also recent significant improvements. Notably, both the ASHRAE 90.1-2013 code and the IECC 2015 make further improvements upon the codes shown in these charts. Given that many states have yet to adopt the most recent codes, this indicates a significant potential for energy savings. Additionally, technologies exist today to achieve even deeper levels of energy savings than are captured by current codes. Even further energy savings will therefore be possible through the adoption and implementation of future code additions.

[105] Sarah Stellberg, *Assessment of Energy Efficiency Achievable from Improved Compliance with U.S. Building Energy Codes: 2013 – 2030* (2013).

Figure 7.8: Model Commercial Energy Code Improvements between 1975 and 2010[106]

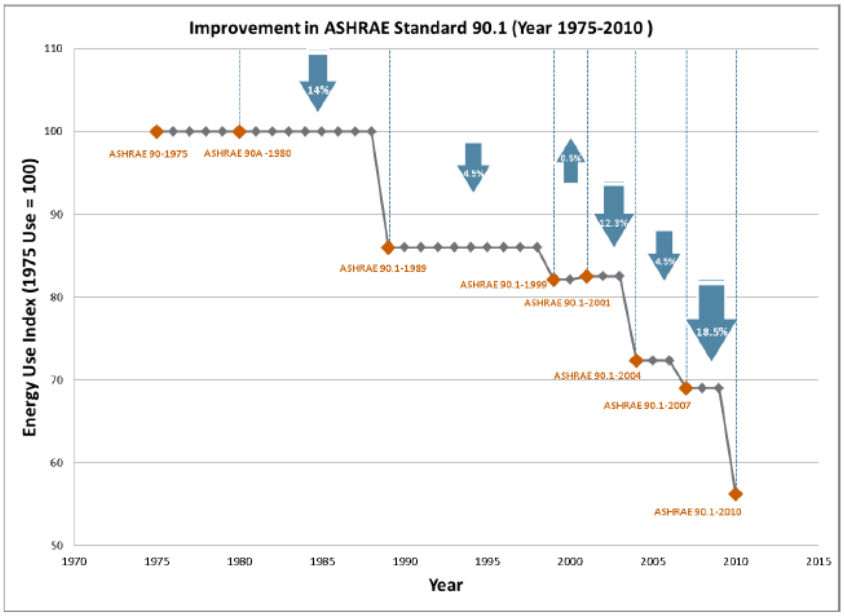


Figure 3.1. ASHRAE Standard 90.1 Improvement Index

Figure 7.9: Model Residential Energy Code Improvements between 1975 and 2012[107]

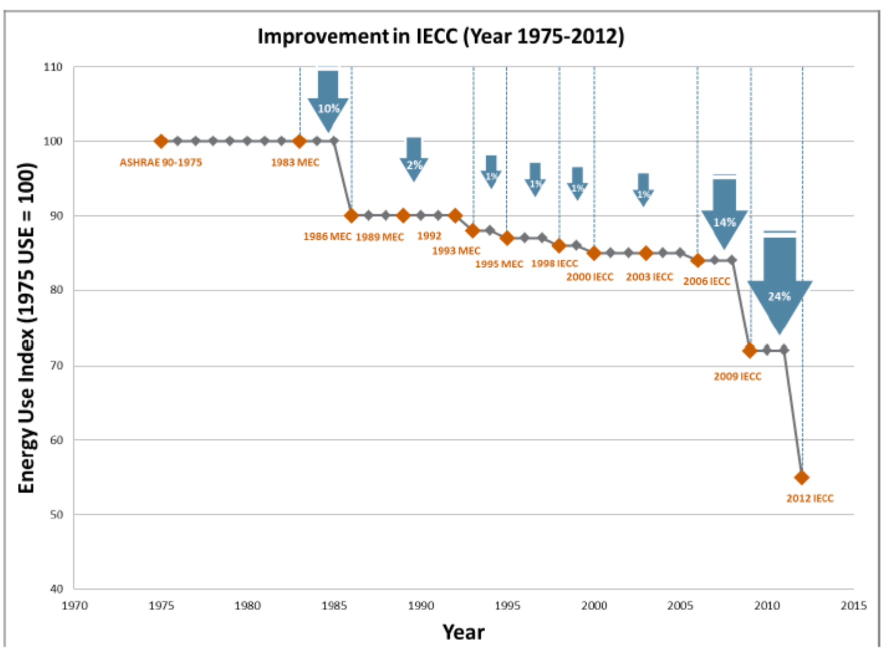


Figure 4.1. IECC Residential Energy Improvement Index

[106] Livingston et al, *Building Energy Codes Program: National Benefits Assessment, 1992-2040* (March 2014).

[107] *Id.*

Significant electricity emissions reductions are possible from increasing code compliance and adoption of updated building codes. Several studies have projected significant future savings potential from building codes. An IEE study found that adoption of improved building codes could save 123 to 129 TWH annually by 2025.[108] PNNL also found significant future savings from the Building Energy Codes Program, and projects that future savings between 2013-2040 would be 40.1 quads cumulatively, 2.2 quads annually in 2040, $185.7 billion cumulatively, $5.2 billion annually, 3,178 MMT CO2 cumulatively by 2040, and 185 MMT CO2 annually in 2040.[109] A 2014 ACEEE report[110] found that state adoption of updated building codes could yield annual electricity savings of 155 TWH in 2030, equal to 4.2 % of electricity consumption in 2012. The ACEEE analysis assumed two rounds of code adoption: adoption of ASHRAE 90.1-2010 and 2012 IECC in 2016 and adoption of updated ASHRAE and IECC codes in 2020, which achieve 50 % savings relative to the 2004 and 2006 versions of those codes, respectively.

IMT conducted analysis following the methodology in its 2013 compliance assessment that looked at the potential electricity savings from increased code compliance and the adoption of the 2012 IECC and ASHRAE 90.2010 by state.[111] This study assumed an existing compliance rate of 50 %, a conservative assumption, and assumed that non-compliant buildings "failed" the code by 15 %. The IMT analysis looked at two scenarios: improving compliance with the state's existing code to 100 % and improving compliance to 100 % plus adoption of the 2012 IECC and 2010 ASHRAE 90.1 Standards. Primary data sources for the IMT analysis include: US Census Bureau construction projection data, EIA RECS and CBECS building energy consumption data, and AEO price projections.

The state-by-state potential savings found in the IMT analysis are presented in Figures 7.10 and 7.11. These savings represent a very conservative estimate of the potential savings from adoption and compliance with building codes. As noted above, the 50 % baseline compliance rate is a conservative assumption: in many states compliance rates are far below 50 %. Additionally, this analysis does not assume any future building code

[108] IEE, *Assessment of Electricity Savings in the US Achievable through New Appliance/Equipment Efficiency Standards and Building Efficiency Codes (2010-2025)* (2011).
[109] Livingston et al, *Building Energy Codes Program: National Benefits Assessment, 1992-2040* (March 2014).
[110] Sara Hayes et al, *Change is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution* (April 2014) Report E1401.
[111] IMT, "Assessment of Energy Efficiency Achievable from Improved Compliance with U.S. Building Energy Codes: 2013 – 2030."

efficiency improvements, despite the fact that these future improvements are likely.[112] Finally, this analysis is only based on savings from new construction; additional savings would be achieved from codes effecting renovations.

On a national basis, improved compliance with existing building energy codes *alone* has the potential to save:

- In 2020, assumed to be the first year of full compliance, predicted annual energy savings exceed 19,000,000 MWh, with cost savings of over $1 billion
- In 2025, annual energy savings would exceed 21,000,000 MWh, with cost savings of over $2.4 billion
- By 2030, annual energy savings would exceed 33,800,000 MWh, with cost savings of over $3.9 billion

Potential national savings from *both* adoption of the 2010 IECC and ASHRAE 90.1-2010 *and* increased compliance are as follows:

- In 2020, assumed to be the first year of full compliance, predicted annual energy savings exceed 26,000,000 MWh, with cost savings of over $2.7 billion
- In 2025, annual energy savings would exceed 60,700,000 MWh, with cost savings of over $6.6 billion
- By 2030, annual savings would exceed 97,800,000 MWh, with cost savings of over $10.8 billion

[112] Notably, the performance path of the IECC 2015 and the new ASHRAE 90.1-2013 offer substantial (more than 15%) additional savings, with the potential that during the post-2020 continued code updates will further expand the easily-achieved efficiency potential.

Figure 7.10: State by state potential savings from adoption of 2012 IECC and ASHRAE 90.1-2010 and full compliance.

Savings from Adoption and Compliance				
	Annual Electricity Savings ($)		Annual Electricity Savings (kWh)	
	2025	2030	2025	2030
Northeast				
Connecticut	$70,882,853	$115,200,116	442,307,576	703,113,798
Delaware	$9,177,341	$15,269,681	71,895,821	117,215,491
District of Columbia	$14,147,021	$23,053,980	119,660,251	190,467,859
Maine	$30,524,406	$51,216,384	216,160,488	354,101,133
Maryland	$49,428,269	$80,576,464	425,503,756	677,959,488
Massachusetts	$40,206,653	$65,187,093	272,427,292	432,569,901
New Hampshire	$28,205,588	$46,468,770	186,157,907	299,676,480
New Jersey	$199,467,789	$329,218,307	1,344,132,687	2,167,130,951
New York	$362,773,208	$593,568,064	2,166,385,604	3,466,501,845
Pennsylvania	$212,510,010	$350,585,761	1,895,523,155	3,049,057,135
Rhode Island	$5,169,080	$8,345,997	40,371,345	63,781,036
Vermont	$8,986,713	$15,105,490	52,748,965	86,713,458
Midwest				
Illinois	$45,405,700	$73,718,960	502,475,506	796,344,009
Indiana	$125,130,788	$204,644,868	1,247,272,739	1,995,088,365
Iowa	$14,688,084	$24,174,021	155,219,711	249,147,021
Kentucky	$86,762,634	$144,299,324	905,603,997	1,474,515,302
Michigan	$164,925,959	$270,898,017	1,312,686,696	2,104,321,015
Minnesota	$173,148,023	$287,586,365	1,640,854,655	2,659,525,738
Missouri	$110,139,628	$179,869,867	1,201,093,188	1,916,566,653
Nebraska	$57,121,465	$94,605,383	593,878,169	961,075,767
North Dakota	$56,704,604	$96,256,752	602,391,640	1,001,786,168
Ohio	$175,240,272	$283,757,409	1,691,944,647	2,679,269,437
South Dakota	$35,716,257	$60,653,065	349,094,543	580,010,781
West Virginia	$46,664,347	$79,467,817	355,885,808	592,119,798
Wisconsin	$116,463,016	$191,906,763	1,088,163,058	1,759,612,584
Southeast				
Alabama	$164,760,385	$273,371,402	1,424,422,668	2,313,818,789
Florida	$478,536,494	$771,797,562	4,615,752,418	7,286,836,008
Georgia	$415,724,232	$688,249,850	3,842,036,804	6,217,602,246
Mississippi	$68,536,795	$116,802,847	643,398,637	1,074,101,985
North Carolina	$207,769,515	$346,358,781	2,112,976,860	3,444,670,343
South Carolina	$243,058,663	$407,290,040	2,119,503,944	3,469,611,915
Tennessee	$282,897,111	$470,972,424	2,646,996,546	4,321,238,384
Virginia	$85,859,058	$141,648,551	885,305,252	1,423,921,537
South Central				
Arkansas	$98,607,605	$164,932,385	1,080,251,447	1,765,934,743
Kansas	$80,708,111	$133,618,560	756,527,220	1,223,495,847
Louisiana	$136,520,017	$231,674,922	1,575,147,853	2,618,119,734
Oklahoma	$111,026,372	$184,245,798	1,263,799,931	2,046,390,858
Texas	$890,819,325	$1,470,578,215	9,111,304,700	14,669,375,627
Northwest				
Alaska	$25,856,457	$43,310,212	147,325,895	241,158,725
Idaho	$24,579,274	$40,518,568	310,447,292	499,578,074
Montana	$14,243,008	$23,471,537	142,403,995	229,637,703
Oregon	$46,421,394	$78,186,688	470,499,052	775,118,906
Washington	$46,195,871	$76,256,974	546,166,726	882,152,514
Wyoming	$14,358,693	$24,274,150	144,452,954	239,537,152
Southwest				
Arizona	$272,614,534	$445,561,549	2,586,426,413	4,132,881,113
California	$225,929,007	$364,932,925	1,569,986,811	2,482,631,887
Colorado	$138,833,243	$225,412,437	1,345,759,543	2,136,598,170
Hawaii	$72,857,127	$119,117,692	193,971,395	310,557,839
Nevada	$141,275,166	$227,605,402	1,472,413,310	2,320,258,715
New Mexico	$30,561,019	$50,745,381	282,343,176	457,887,145
Utah	$54,048,636	$90,986,483	548,046,743	901,850,642
U.S. Total	$6,612,186,818	$10,897,556,052	60,717,506,788	97,862,637,813

Figure 7.11: State by state potential savings from increasing compliance with existing state building codes alone.[113]

	Savings from Compliance Only			
	Annual Electricity Savings ($)		Annual Electricity Savings (kWh)	
	2025	2030	2025	2030
Northeast				
Connecticut	$21,513,112	$34,317,067	134,691,085	214,105,430
Delaware	$10,449,179	$17,144,074	87,196,663	142,956,991
District of Columbia	$13,696,615	$21,873,872	119,660,251	190,467,859
Maine	$8,132,598	$13,388,338	57,846,307	94,838,336
Maryland	$52,704,567	$84,429,542	444,151,856	709,172,925
Massachusetts	$42,812,159	$68,238,888	284,616,685	453,009,006
New Hampshire	$8,858,588	$14,291,117	58,269,660	93,664,947
New Jersey	$58,245,835	$94,127,704	390,925,909	629,748,427
New York	$109,882,992	$176,190,467	611,645,762	977,944,689
Pennsylvania	$61,817,350	$99,932,350	558,150,497	896,227,611
Rhode Island	$5,773,075	$9,151,636	41,496,296	65,673,540
Vermont	$2,682,530	$4,422,658	15,735,190	25,876,013
Midwest				
Illinois	$46,103,728	$73,249,928	496,926,970	787,043,800
Indiana	$41,078,150	$65,956,192	392,711,250	628,847,823
Iowa	$19,067,997	$30,896,891	173,416,807	279,681,806
Kentucky	$22,127,971	$35,946,180	222,679,511	361,189,894
Michigan	$46,127,472	$74,071,759	377,871,802	603,754,920
Minnesota	$40,674,038	$65,761,122	361,319,002	581,536,623
Missouri	$42,044,468	$67,851,780	379,568,153	610,608,354
Nebraska	$17,435,845	$28,257,391	162,424,626	262,091,970
North Dakota	$11,052,468	$18,340,726	103,481,960	171,461,561
Ohio	$54,548,240	$86,674,629	515,477,411	816,343,236
South Dakota	$7,425,848	$12,330,665	67,025,880	111,012,683
West Virginia	$9,647,429	$16,071,015	73,815,353	122,204,498
Wisconsin	$29,219,652	$46,860,731	277,296,878	446,056,990
Southeast				
Alabama	$44,071,723	$71,584,457	385,520,632	625,298,345
Florida	$199,471,538	$320,035,193	1,905,736,455	3,047,960,996
Georgia	$126,282,703	$205,115,866	1,104,653,511	1,788,280,982
Mississippi	$19,480,348	$31,809,939	171,767,139	280,180,392
North Carolina	$93,638,106	$153,826,650	937,284,829	1,535,838,135
South Carolina	$62,972,496	$103,204,078	544,085,486	888,497,312
Tennessee	$61,120,346	$99,076,903	567,589,669	920,070,483
Virginia	$102,404,748	$166,614,343	1,012,792,196	1,637,856,387
South Central				
Arkansas	$21,366,985	$34,763,203	229,328,528	371,889,953
Kansas	$22,110,747	$35,774,238	192,044,162	309,717,020
Louisiana	$30,149,978	$49,875,261	303,913,561	502,238,224
Oklahoma	$28,341,443	$45,773,749	297,163,709	478,545,355
Texas	$252,390,151	$408,765,420	2,591,187,242	4,169,493,230
Northwest				
Alaska	$6,666,080	$10,885,775	34,353,892	55,962,272
Idaho	$8,891,858	$14,354,511	97,457,984	156,634,252
Montana	$4,028,889	$6,505,048	39,790,415	64,115,289
Oregon	$22,855,462	$37,081,494	234,337,412	378,829,606
Washington	$45,078,831	$72,916,645	537,035,217	866,842,000
Wyoming	$3,311,140	$5,480,698	30,924,575	51,044,518
Southwest				
Arizona	$72,871,990	$116,299,623	650,333,663	1,035,695,878
California	$280,533,207	$443,559,507	1,569,986,811	2,482,631,887
Colorado	$42,737,084	$68,074,810	379,834,442	603,488,950
Hawaii	$19,655,633	$31,592,976	54,119,341	86,857,836
Nevada	$45,061,811	$71,046,998	434,109,541	683,464,141
New Mexico	$10,623,276	$17,240,842	85,301,518	138,002,205
Utah	$24,090,241	$38,852,686	243,563,398	391,056,048
U.S. Total	$2,433,328,719	$3,919,887,639	21,042,617,093	33,826,011,629

[113] Note that the numbers in Figures 7.10 and 7.11 are not directly comparable. Figure 7.10 includes updated assumptions for the underlying data used in the 2013 IMT report. Due to time constraints, Figure 7.11 is drawn directly from the 2013 IMT report and does not include these same updates.

7.3.3 *Savings from ESCO Projects Can Add an Additional .025% per-year*

> ***Recommendation:*** *Savings from ESCOs that correct for any duplication with other programs should be included in the BSER and credited in state plans.*

The energy service company (ESCO) industry is a large and fast growing industry. Lawrence Berkeley National Laboratory (LBNL) projects that the industry will gross $10 to 15 billion in annual sales by 2020.[114] The ESCO industry is dominant especially in the municipal, university, schools, and hospitals markets. In a 2013 study, LBNL estimates the current and potential ESCO industry market penetration in these sectors (see Figure 7.12 below).[115] It is likely that the ESCO industry will continue to grow and will provide a significant source of savings over the 2020-2030 time period. As long as savings from ESCO projects are shown to not be duplicative of other savings claimed in state plans, these savings should be credited. From recently-released LBNL research[116], we estimate the incremental electricity savings of public sector ESCO projects undertaken in 2012 without utility incentives to be 1.15 TWh,[117] or around .027 % of 2012 electricity sales.[118] In setting its best practices level of energy efficiency performance, EPA should take into account the opportunity of ESCO projects to be part of a state plan or generate savings credits that could be distributed to or purchased by EGUs. We recommend EPA raise the best practices level by .025 % per year to account for this opportunity.

---

[114] Stuart, Elizabeth, Peter H. Larsen, Charles A. Goldman, and Donald Gilligan*. Current Size and Remaining Market Potential of the U.S. Energy Service Company Industry*, 2013.

[115] *Ibid*.

[116] J.P. Carvalho, P.H. Larsen and C.A. Goldman. *Estimating customer electricity savings from projects installed by the U.S. ESCO industry*. Berkeley, CA: Lawrence Berkeley National Laboratory (November 2014) *available at* http://emp.lbl.gov/publications/estimating-customer-electricity-savings-projects-installed-us-esco-industry.

[117] Estimated annual incremental savings average about ~2.4 TWh/year for all ESCO projects, 75% of incremental savings from new projects were in the public sector, and 64% of public sector projects did not rely on utility incentives. *Id*. at 5.

[118] 2012 Retail Sales of Electricity totaled 4,208,939,885 MWh. Energy Information Administration, Form 861, 2012, retail Sales spreadsheet.

Figure 7.12: ESCO Market Potential.

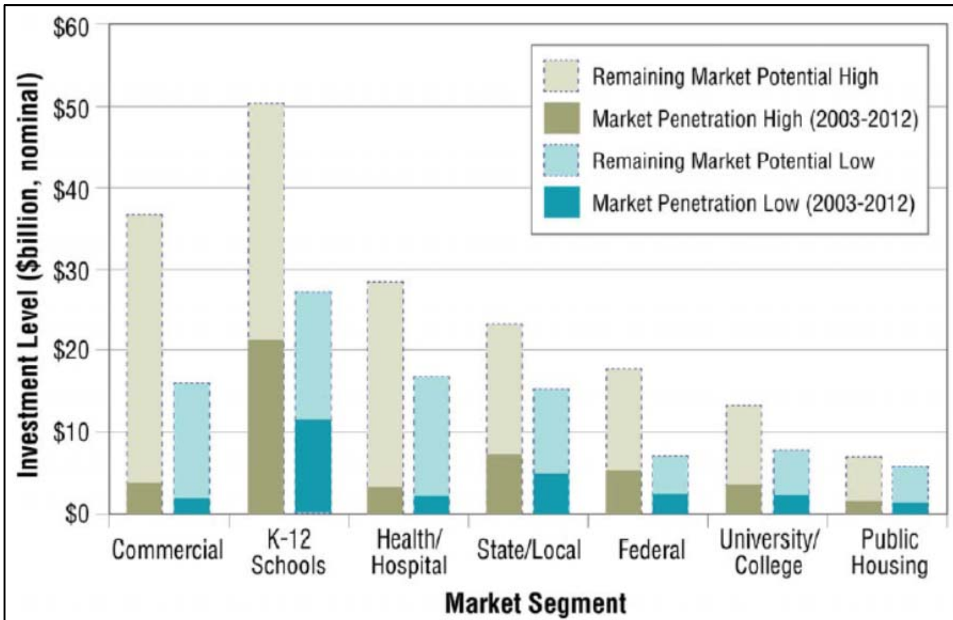


Figure ES- 3. Range of estimated existing ESCO market penetration (2003-2012) and remaining ESCO market potential by customer market segment

7.3.4 *Savings from transmission and distribution system efficiency investments that reduce utility losses or reduce the energy used by appliances and devices by optimizing voltage can add an additional .2 % per-year.*

Recommendation: *Savings from transmission and distribution efficiency improvements should be included in the BSER for Block 4 and credited in state plans.*

The electricity sector is the second largest electricity-consuming industry in the U.S., consuming 11 % of electricity in production and delivery.[119] About 6.3 % of that is used in transmission and distribution (T&D), and the rest is related to power production. More efficient T&D systems would directly reduce the amount of generation needed (and thus GHG emissions). There are many cost-effective energy savings opportunities available today. An Electric Power Research Institute study estimates the potential to reduce electricity use in this area is about 10-15 %. Even a 10 % reduction is enough to power 3.9 million homes.[120]

[119] The EPRI Technical Report *Program on Technology Innovation: Electricity Use in the Electric Sector: Opportunities to Enhance Electric Energy Efficiency in the Production and Delivery of Electricity.* EPRI, Palo Alto, CA: 2011. 1024651 (EPRI 2011).
[120] EPRI 2011.

Electricity losses in the distribution system can be reduced substantially through the use of efficient transformers, improved voltage control, phase balancing, and balancing of reactive power needs. In the transmission system, opportunities include voltage overlays, voltage and line efficiency. These measures can enhance not only the efficiency, but also the flexibility and reliability of the electric system, facilitating integration of renewables into the system.

Volt VAR Optimization/Conservation Voltage Reduction

EPA's analysis of the potential of demand-side energy efficiency improvements to reduce emissions excluded Volt VAR Optimization/Conservation Voltage Reduction, a cost-effective option for states and utilities to save energy and reduce pollution. Maintaining proper voltage levels thought the electric distribution system is one of the most important challenges utilities face: ANSI standard C84.1 specifies that the voltage provided to customers should be between 114 volts and 126 volts.[121] Maintaining voltage in the lower half of the 114-126 volt range saves energy, because reducing voltage reduces the energy used by customer appliances and equipment.

Actual voltage supplied to customers varies throughout the day because of changing customer loads. Utilities have in the past regulated voltage on a circuit by setting the voltage at the beginning of the circuit high enough so that voltage at the end of the circuit remained within acceptable limits.[122] But recent advances in sensors, communication, and information processing and control techniques make it possible for utilities to monitor voltage levels throughout the distribution circuit and communicate that information to voltage regulation devices and capacitor banks. The utility can then use these devices to make quick adjustments in response to actual conditions on the circuit,[123] a process termed "Volt Var Optimization." Using these technology and practices, a utility need not adopt a strategy of "setting voltage high enough:" it can supply the voltage required to maintain consumer voltage service standards. When these practices are implemented over a period of time to save energy, it is termed "Conservation Voltage Reduction."

[121] US Department of Energy Office of Electricity Delivery and Energy Reliability, *Application of Automated Controls for Voltage and Reactive Power Management – Initial Results* (December 2012) at 2, Section 1.2. (U.S. DOE 2012).
[122] AEP-Ohio, Final Technical Report, Gridsmart Demonstration Project, June 2014, at 217, Section 6.2. (AEP-Ohio 2014).
[123] *Ibid* U.S. DOE 2012.

Utilities have known about and piloted Conservation Voltage Reduction for a long time,[124] but the new sensor, communications, and information processing and control technologies that allow a utility to understand voltage in near real-time along a distribution feeder are prompting more utilities to consider implementing VVO and CVR. Twenty-six projects funded by the Smart Grid Investment Grants through the American Recovery and Reinvestment Act implemented VVO or CVR.[125] AEP-Ohio implemented VVO on 17 circuits, which yielded a 3 % reduction in residential customer energy use during the test period (measured for those customers with AMI meters).[126] This 3 % reduction is corroborated by other experience, including a large pilot in the Pacific Northwest, the Distribution Efficiency Initiative Project, which tested conservation voltage reduction practices on a variety of different distribution circuits that served a variety of loads. The evaluation of the project stated, "performing system improvements and operating the distribution feeder voltage in the lower half of the ANSI standard can be done cost-effectively, saves energy, and reduces kW and kvar demand without negatively impacting service to customers."[127] Average energy savings using end-of-line voltage regulation was between two and three %. Voltage regulation with minor system improvements saved one to two % of energy use.[128] The Regional Technical Forum of the Northwest Power & Conservation Council isdeveloping a protocol for measuring the savings from Conservation Voltage Reduction.[129]

Conservation Voltage Reduction has the potential to serve as a significant source of demand-side energy efficiency for states, and EPA should encourage its use. It is one of the excluded opportunities whose potential inclusion in state plans supports raising the energy efficiency target to three % annual savings. We recommend EPA raise the best practices level of energy efficiency by .2 % per year, to account for the savings from conservation voltage reduction and other transmission and distribution system investments. In developing EM&V Guidance, EPA's designated entity (discussed more in Appendix 7B), should consider developing or validating a protocol for estimating savings

[124] D. Lauria, *Conservation Voltage Reduction (CVR) at Northeast Utilities*, IEEE Transactions on Power Delivery, 1987, Volume 2, Issue 4, pp. 1186-119; D. Kirshner, *Implementation of Conservation Voltage Reduction at Commonwealth Edison*, IEEE Transactions on Power Systems, 1990, Volume 5, Issue 4, pp. 1178-1182. B. Kennedy and R. Fletcher, *Conservation Voltage Reduction (CVR) at Snohomish County PUD*, IEEE Transactions on Power Systems, 1991, Volume 6, Issue 3, pp 986-998.
[125] *Id.* U.S. DOE 2012, page ii.
[126] *Id.* AEP-Ohio 2014, page 225, Section 6.5.1.6.
[127] Leidos, *Distribution Efficiency Initiative Project Final Report,* Northwest Energy Efficiency Alliance (December 2007) Page 5-1, Section 5.1.
[128] *Id.* page 4-7.
[129] *See generally* Regional Technical Forum, Automated Conservation Voltage Reduction (CVR) Control, *available at* http://rtf.nwcouncil.org/subcommittees/cvr/.

from Conservation Voltage Reduction and transmission and distribution system that reduce line losses. As with other efficiency projects, entities saving energy with transmission and distribution projects that reduce losses should show that savings are above a “business as usual” baseline.

7.4 In the state planning process, EPA should recognize a variety of energy savings practices.

7.4.1 *Energy efficiency in affordable multi-family housing can provide significant savings.*

Recommendation: *Savings from affordable multi-family housing programs should be credited in state plans.*

More than 20 million American households, almost 18 % of the nation’s total, live in apartments and condominium communities described as multifamily buildings containing five or more housing units. Energy efficiency is a key resource for maintaining and improving quality of life for residents and owners of affordable housing. The affordable multi-family sector is also a critical untapped resource for achieving widespread energy demand reductions, and thus emissions reductions, in the residential sector.

According to a widely cited 2009 report by the Benningfield Group, an energy consulting and software development firm, multifamily housing stock could feasibly become 28.6 % more energy efficient by 2020. This increased efficiency would translate into a savings of at least 51,000 gigawatt hours of electricity and more than 2,800 million therms of natural gas, which amounts to $9.2 billion at today’s residential energy prices. Similarly, a 2009 study by McKinsey & Company estimated that the capital required to unlock energy efficiency opportunities in our nation’s low-income residential buildings between 2009 and 2020 is approximately $46 billion, and would provide a present value of $80 billion in savings. Almost a quarter of this energy efficiency potential is in multifamily buildings, accounting for approximately $16 billion in savings[130].

On average, multifamily housing is older than single-family housing and has less efficient heating, cooling, plumbing, and lighting systems. An Energy Programs Consortium analysis found that 85 % of multifamily units were built before 1990, leaving room for substantial savings—anywhere from 30 to 75 %—from energy efficiency improvements.

---

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

Despite that reality, multifamily housing has many characteristics that make it especially amenable to energy retrofits. One is that it is inherently more energy efficient than single-family housing due to size per unit, exterior exposure, and other structural differences.

In addition to the potential energy savings, improving the energy efficiency of multifamily housing also improves the stability of vulnerable households. Most multifamily households (88 %) are renters, whose average annual income ($31,000) is just over half that of homeowners ($61,000)[131]. This means that nationally, the burden of the untapped savings in the older and less energy-efficient multifamily housing stock is being borne by the families with the fewest resources. As a result, renters typically pay a higher percentage of their income for energy. This lowers their discretionary income and makes them more vulnerable to fluctuations in energy prices, which are increasing at a faster rate than housing costs: between 2001 and 2009, renters in multifamily units faced an average rent increase of 7.6 %, while energy costs for these renters rose by 22.7 %[132]. Thus, efficiency gains from multifamily retrofits have the concurrent benefit of relieving low- and middle-income families of some of their financial strain and uncertainty.

Unfortunately, only a fraction of the potential energy savings in the multifamily sector has been realized, despite the economies of scale not available in single-family homes. It is easier to coordinate retrofits for multiple units that are contiguous, and a single intervention (for example, HVAC replacement) can improve efficiency in every unit in the building. This fact is critical when we consider that the EPA underestimates the potential for energy efficiency by assuming that states will only be able to ramp up energy efficiency programs extremely slowly. By investing more resources into the multi-family sector, states can scale up energy efficiency programs much more rapidly than previously imagined, quickly enabling real energy savings.

---

[131] *See* Benningfield Group. 2009. *U.S. Multifamily Energy Efficiency Potential by 2020*, at 3–9 (October 27, 2009) *available at* http://www.benningfieldgroup.com/docs/Final_MF_EE_Potential_Report_Oct_2009_v2.pdf.

[132] *See generally* Joint Center for Housing Studies, *America's Rental Housing: Meeting Challenges, Building on Opportunities*, Harvard University (April 26, 2011) *available at* http://www.jchs.harvard.edu/research/publications/americas-rental-housing-meeting-challenges-building-opportunities.

7.4.2 *Behavioral Programs, Financing, City Programs, And Other Voluntary Programs Can Also Provide Substantial Savings.*

Recommendation: *A wide range of programs including behavioral programs, financing programs, city programs, and other voluntary programs should be credited in state plans.*

We support the current proposal to credit a range of efficiency programs, including both utility and non-utility programs, as long as all measures included in the state plans include the same standards for EM&V (for those states using the rate-based approach). Programs that should be credited include but are not limited to the following:

- Behavioral-based programs that show persistent, measurable savings. Rigorous experimental design has been used in many places in the country to show savings on the order of 2 % annually for participants in energy usage bill information programs in the residential sector,[133] and a range of operations-based and occupant behavior-driven savings opportunities are available in the commercial and industrial sectors.

- Savings from local, city, and regional efforts. Many cities and regions are innovators in tapping into energy efficiency as a resource.[134] Savings from these efforts should be credited as long as they are included in the state plan and coordinated with other programs so as not to double count savings.

- Financing programs to enable energy efficiency improvements should also be included. There is a range of financing options available including revolving loan funds, state green banks funds, on-bill financing programs,[135] property-assessed clean energy programs (PACE),[136] and others that result in implementation of energy efficient measures.

[133] *See, e.g.,* "Social norms and energy conservation." Hunt Allcott, Journal of Public Economics Volume 95, Issues 9–10, October 2011.

[134] For example, the City Energy Project is a joint initiative of NRDC and the Institute for Market Transformation. *See* http://www.cityenergyproject.org/

[135] Twenty-three states have implemented or are about to implement on-bill financing programs, many of which (Illinois, Hawaii, Oregon, Kentucky, Georgia, South Carolina, Michigan, and New York) have legislation in place that supports adoption. *See* http://www.aceee.org/sector/state-policy/toolkit/on-bill-financing .

[136] Local PACE programs are currently operating in at least nine states (California, Connecticut, Florida, Maine, Michigan, Minnesota, Missouri, New York and Wisconsin) and the District of Columbia. *See* http://www.dsireusa.org/solar/solarpolicyguide/?id=26.

- Strategic Energy Management programs that follow the template laid out by the Consortium for Energy Efficiency.[137] These programs can be operated by utilities, governments, or an industrial companies. The savings can be calculated using the methods of ISO Standards 50001 and verified by third-party audits as required by DOE's Superior Energy Performance program. Strategic Energy management programs recognize savings both from behavior and from capital investments and process changes. As these programs require a commitment by a company to improve its energy performance by a fixed target every year, the savings can compound strongly over 10 years.

A range of other programs may also contribute to energy savings, and EPA should consider a variety of options as long as they are initiated within the state (i.e. not federal programs such as federal appliance and equipment standards), have the appropriate EM&V, and avoid double counting savings.

7.4.3 *Efficiency Opportunities In The Industrial Sector Will Help Achieve Strong Efficiency Performance in States*.

Recommendation: *Industrial energy efficiency should be credited in state plans.*

The industrial sector in the United States has significant untapped energy efficiency potential. Like many other forms of energy efficiency, efficiency in the industrial sector is a component of the BSER. As industrial users install and implement energy efficiency measures that reduce their electricity consumption, they would reduce the demand for generation from EGUs, resulting in emissions reductions.[138]

According to a number of studies and analyses, the industrial sector in the United States likely has potential for energy efficiency in the vicinity of 15-20 % of current electricity usage, primarily from equipment upgrades. Nearly all of this potential is cost-effective, with attractive payback for investments (by one estimate 4:1 return on investment).[139]

---

[137] *See* CEE, *CEE Industrial Strategic Energy Management Initiative* (February 11, 2014) *available at* http://library.cee1.org/content/cee-industrial-strategic-energy-management-initiative/.
[138] 79 Fed. Reg. at 34,871.
[139] McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy* (July 2009) *available at* http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/~/media/mckinsey/dotcom/client_service/epng/pdfs/unlocking%20energy%20efficiency/us_energy_efficiency_full_report.ashx ; McKinsey and Company, *The Untapped Energy Efficiency Opportunity in the U.S. Industrial Sector* (2007) report prepared for DOE's Office of Energy Efficiency and Renewable Energy; Interlaboratory Working Group on Energy-Efficient and Clean Energy Technologies, Oak Ridge National Laboratory and Lawrence Berkeley National Laboratory, *Scenarios for a Clean Energy Future* (November 2000) ORNL/CON-476 and LBNL-44029, *available at* http://web.ornl.gov/sci/eere/cef/; National Research

Both state and international assessments and experiences bear out the finding that the industrial sector has significant untapped energy efficiency potential. Industries like iron and steel, cement, chemicals, pulp and paper, and refining likely have the highest energy savings potential, but savings can be found in a wide range of industrial sectors.[140] The technical potential in the industrial sector is much larger (35-70 % by some estimates)[141], and while some of that is not cost-effective now, it will become cost-effective over time, especially with a management focus on energy efficiency (as summarized below).

Industrial energy efficiency can be realized in a number of ways. Equipment-based improvements constitute one approach, but 20-70 % of the energy used (depending on the industrial sub-sector) is associated with the industrial processes themselves.[142] The practice of strategic energy management enables the right decision makers to be at the right place at the right time, making industrial processes more efficient, improving operations and behaviors, and magnifying equipment-based energy efficiency improvements on a continual and ongoing basis. Process- and operations-based efficiency initiatives, despite recent evidence that they save even more than equipment based initiatives, only constitute a minority in the potential studies cited above (suggesting that the actual efficiency potential may indeed be larger). Finally, Combined Heat and Power (CHP) is a specific energy efficiency technology that can significantly increase the efficiency with which the required energy at an industrial facility is generated.[143]

Council, *Real Prospects for Energy Efficiency in the United States,* pages 192-198, *available at* http://www.nap.edu/openbook.php?record_id=12621 .

[140] Intergovernmental Panel on Climate Change (IPCC), contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, B. Metz, O.R.Davidson, P.R. Bosch, R. Dave, L.A. Meyer, editors, *Mitigation of Climate Change* (2007); International Energy Agency*, Tracking Industrial Energy Efficiency and* CO_2 *Emissions* (2007); KEMA, Inc., Final Report to Pacific Gas and Electric Company, prepared with assistance from Lawrence Berkeley National Laboratory and Quantum Consulting, Arnhem, The Netherlands, *California Industrial Existing Construction Energy Efficiency Potential Study, Volumes 1 and 2*, 2006; Optimal Energy, Inc., prepared for the New York State Energy Research and Development Authority, *Energy Efficiency and Renewable Energy Resource Development Potential in New York State* (August 2003); Senternovem (now known as NL Agency), from a presentation by Ronald Vermeeren in Dublin, Ireland, *Realising the Potential – Making Energy Management Systems deliver* (November 2009); David B. Goldstein, Aimee McKane, and Deann Desai, *ISO 50001: Energy Management Systems: A Driver for Continual Improvement of Energy Performance* (July 2011) presented at 2011 ACEEE Summer Study on Energy Efficiency in Industry.

[141] McKinsey & Company, *Unlocking Energy Efficiency in the U.S. Economy* (July 2009) available as above.

[142] *Id*.

[143] NRDC, *Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings, and Other Facilities* (April 2013) *available at* http://www.nrdc.org/energy/combined-heat-and-power-systems.asp; DOE and EPA, *Combined Heat and Power: A Clean Energy Solution* (August

Companies are able to and indeed do realize energy efficiency potential themselves. However, both large and smaller companies face similar barriers to energy efficiency, including imperfect information about opportunities and available solutions, lack of well-trained and technically capable staff, reactive rather than strategic decision making, perceived risk of making efficiency investments, split incentives, constrained access to capital, and lack of corporate or executive support. Smaller companies tend to be more adversely affected by these barriers than larger companies. [144] However, the most energy-efficient companies do take effective steps to overcome these barriers and capture efficiency potential, by establishing corporate buy-in for and visibility to energy issues, hiring energy managers, providing appropriate incentives including for identifying efficiency opportunities, tracking energy use in real-time, aligning facility equipment replacement schedules with utility incentives, and, in aggregate, institutionalizing principles of strategic energy management (sometimes known as continuous energy improvement). Specific efficiency improvements include installing variable frequency drives, retrocommissioning HVAC systems, improving recycling or air, and implementing waste heat recovery.[145] Companies[146] such as 3M[147], Allergan,

---

2012) *available at* www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf.

[144] Daniel Trombley, American Council for an Energy-Efficiency Economy, *One Small Step for Energy Efficiency: Targeting Small and Medium-Sized Manufacturers* (January 2014) *available at* http://www.aceee.org/research-report/ie1401; Steve Sorrell, Alexandra Mallett, and Sheridan Nye, United Nations Industrial Development Organization (UNIDO), *Barriers to industrial energy efficiency: A literature review* (October 2011) *available at* http://www.unido.org//fileadmin/user_media/Publications/Research_and_statistics/Branch_publications/Research_and_Policy/Files/Working_Papers/2011/WP102011%20Barriers%20to%20Industrial%20Energy%20Efficiency%20-%20A%20Literature%20Review.pdf .

[145] EPA ENERGY STAR® for Industry, *Profiles in Leadership, 2014 ENERGY STAR Award Winners* (2014) *available at* http://www.energystar.gov/sites/default/uploads/about/old/files/POY_2014_Profiles_508(1).pdf ; EPA ENERGY STAR® for Industry, *Profiles in Leadership, 2013 ENERGY STAR Award Winners* (March 2013) *available at* http://www.energystar.gov/ia/partners/publications/pubdocs/POY%202013%20Profiles%20508%20compliant.pdf?eecf-4b2e ; EPA ENERGY STAR® for Industry, *Profiles in Leadership, 2012 ENERGY STAR Award Winners* (March 2012) *available at* http://www.energystar.gov/ia/partners/pt_awards/documents/2012_profiles_in_leadership.pdf?ba29-a120 ; U.S. DOE, Better Plants, *Progress Update Fall 2014* (2014) *available at* http://www.energy.gov/sites/prod/files/2014/09/f18/Better%2520Plants%2520Progress%2520Update%25202014.pdf .

[146] Same as immediately previous reference, supplemented by following references for particular companies.

[147] 3M, *SEP and ISO 50001 at 3M Canada's Brockville Plant* (2014) *available at* http://www.energy.gov/sites/prod/files/2014/09/f18/SEP_3M_Canada_Andrew_Hejnar%20v2.pdf .

ArcelorMittal, BPM Inc.[148], CalPortland, Colgate Palmolive, Eastman Chemical, Freescale Semiconductor[149], General Dynamics[150], General Motors, Hanesbrands, Kettle Foods[151], Merck, Nissan[152], PepsiCo, Purdy[153], Raytheon, Saint Gobain, Boeing, and Toyota, espouse many of these "best practices".[154]

In the context of overcoming barriers, government agencies,[155] NGOs, and utility-sponsored programs can provide considerable assistance in helping companies achieve energy savings.

Utility-sponsored programs for the industrial sector tend to require more specificity and customization based on sub-sectors as compared to programs for residential and commercial sectors. Nonetheless, well designed industrial efficiency programs like those administered by the Energy Trust of Oregon, Bonneville Power Administration, Efficiency Vermont and Wisconsin Focus on Energy consistently contribute about one-sixth to one-third of the overall annual energy savings (this is clearly dependent on the region's industrial base as well). Such efficiency programs that include effective industrial sector offerings would constitute one of the "best practices" for demand-side energy efficiency.[156]

---

[148] Focus on Energy (Wisconsin), *Peshtigo's BPM, Inc. Earns Recognition from U.S. Department of Energy for Leadership in Energy Efficiency* (October 2013) *available at* https://focusonenergy.com/about/news-room/peshtigo%E2%80%99s-bpm-inc-earns-recognition-us-department-energy-leadership-energy .

[149] U.S. DOE, Energy Efficiency & Renewable Energy, *Freescale Semiconductor Successfully Implements an Energy Management System* (June 2011) *available at* http://www.energy.gov/sites/prod/files/2014/05/f16/freescale_case_study.pdf .

[150] General Dynamics, *Global Energy Management System Implementation: Case Study*, *available at* http://www.energy.gov/sites/prod/files/2014/09/f18/GSEP_EMWG-GD_casestudy.pdf .

[151] Energy Trust of Oregon, *Strategic Energy Management*, http://energytrust.org/industrial-and-ag/industry/strategic-energy-management/# (accessed October 2014).

[152] Nissan, *Global Energy Management System Implementation: Case Study*, *available at* http://www.energy.gov/sites/prod/files/2014/09/f18/GSEP_EMWG-Nissan_casestudy.pdf ; Nissan,*ISO50001 – What Counts!* (October 2012) *available at* http://www.energy.gov/sites/prod/files/2014/07/f17/nissan_weed_2012.pdf .

[153] Energy Trust of Oregon, *Strategic Energy Management*, *available at* http://energytrust.org/industrial-and-ag/industry/strategic-energy-management/# (accessed October 2014).

[154] 79 Fed. Reg. at 34872.

[155] Peter Therkelsen, Aimee McKane, Ridah Sabouni, and Tracy Evans, *Assessing the Costs and Benefits of the Superior Energy Performance Program* in American Council for an Energy-Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Industry, 2013.

[156] 79 Fed. Reg. at 34872.

Short summaries of these programs follow[157]:

- Bonneville Power Administration (BPA): BPA is a federally owned interstate wholesale electric power utility, which sells power (mostly hydropower) to 135 retail electricity utilities in the Northwest. BPA offers the Energy Smart Industrial program, with a variety of options for different industry types and sizes, such as providing an energy expert and single point-of-contact, encouraging strategic energy management including funding for energy managers, training and support, and support for specific efficiency measures. In 2010, the industrial sector contributed about 17% of BPA's efficiency savings.[158]

- Efficiency Vermont: Efficiency Vermont handles the energy efficiency efforts of almost all of Vermont's utilities. Efficiency Vermont's programs include a variety of offerings including prescriptive and custom incentives, technical assistance, energy management training and building energy efficiency awareness. In 2013, electric savings from large industrial companies contributed about 16% of Efficiency Vermont's total energy savings. [159]

- The Energy Trust of Oregon (ETO): ETO provides technical services and cash incentives to help industrial and agricultural businesses of all types and sizes identify and implement electric and natural gas energy efficiency projects and practices. This includes technical expertise, training, funding, and promoting behavioral changes and strategic energy management. Between 2010 and 2013, the industrial sector contributed 27-35% of ETO's efficiency savings. In 2013, the cost to ETO for realizing the industrial sector energy savings was 2.1 cents per kilowatt-hour, cheaper than for savings from the residential and commercial sectors.[160]

---

[157] State and Local Energy Efficiency Action Network (SEE Action), *Industrial Energy Efficiency: Designing Effective State Programs for the Industrial Sector* (March 2014) prepared by Prepared by A. Goldberg, R. P. Taylor, and B. Hedman, Institute for Industrial Productivity, *available at* http://energy.gov/eere/amo/articles/designing-effective-state-programs-industrial-sector-new-see-action-publication.

[158] Bonneville Power Administration, *2012 Update to the 2010-2014 Plan for Energy Efficiency* (March 2012) *available at* http://www.bpa.gov/EE/Policy/EEPlan/Documents/BPA_Action_Plan_FINAL_20120301.pdf .

[159] Efficiency Vermont, *Savings Claim Summary: 2013* (April 2014) *available at* https://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_summaries/2013_savingsclaim_summary.pdf .

[160] Energy Trust of Oregon, *2013 Annual Report to the Oregon Public Utility Commission and Energy Trust Board of Directors* (April 2014) *available at* http://energytrust.org/about/policy-and-reports/reports.aspx; Energy Trust of Oregon, *2012 Annual Report to the Oregon Public Utility Commission* (April 2013) *available as above*; Energy Trust of Oregon, *2011 Annual Report to the Oregon Public Utility Commission*" (April

- Wisconsin Focus on Energy (WFE): WFE consolidates all of the state's utility-related energy efficiency programs into a statewide program. WFE's industrial programs offer assistance to all eligible customers, and include prescriptive and custom incentives, feasibility studies, staffing grants, and (for larger customers) customized assistance for systematic energy management approaches. In 2013, the non-residential programs (servicing commercial, industrial, schools, government, and agricultural customers) contributed just over half of all electricity savings.[161]

EPA has set state targets in part based on achievable savings from state utility efficiency programs, of 1.5 %.[162] This was based on the efficiency performance of 12 leading states that have either achieved or plan to achieve such efficiency levels. In our assessment, and as described below, the efficiency potential from the industrial sector and recent demonstrated savings strongly support this level of energy reduction from efficiency and provides additional evidence for at least 2 %.

First, assessing actions by industrial companies directly, a number of well-established and prominent companies have been able to achieve energy savings greaterthan 2 % per year over a sustained period of time. Companies such as 3M, BPM Inc., General Motors, HanesBrands, PepsiCo, Raytheon, Saint Gobain, and Toyota have achieved average savings greater than 2 % per year%over a period of five years or more, with some companies achieving rates greater than 3 % per year.[163] Several other examples of efficiency successes in industrial companies exist, which amply demonstrate that industrial sector companies have the ability to do their part to sustain or even exceed annual energy efficiency savings of 1.5 %.

Second, the value of utility-sponsored efficiency programs for the industrial sector may be reviewed. In this regard, studying the Midwest can be instructive given the prevalence of manufacturing and, as a consequence, large industrial sector efficiency potential.[164]

2012) *available as above*; Energy Trust of Oregon, *Getting More for our Energy: 2010 Annual Report, available as above*.

[161] Wisconsin Focus on Energy, *Calendar Year 2013 Evaluation Report* (May 2014) prepared by The Cadmus Group, Inc., Nexant, Inc., TecMarket Works, St. Norbert College Strategic Research Institute, prepared for the Public Service Commission of Wisconsin, *available at* https://focusonenergy.com/about/evaluation-reports .

[162] 79 Fed. Reg. at 34,872.

[163] References as previously detailed for efficiency activities of various companies.

[164] James Bradbury, Nate Aden, Amir Nadav and John Cuttica, World Resources Institute, *Midwest Manufacturing Snapshot: Energy Use and Efficiency Policies* (February 2012) *available at* http://www.wri.org/publication/midwest-manufacturing-snapshot.

In 2012, among the Midwest states, Iowa, Michigan, Minnesota and Wisconsin, achieved efficiency savings of between 1 and 1.5%.[165] From our analysis, these states have reasonably well-structured utility-sponsored programs for the industrial sector; these programs result in measurable and verifiable savings that likely play a strong role in helping the states achieve their noteworthy annual savings.These programs, especially with continued refinements and increased participation from industrial companies, should help these states meet and exceed the 1.5% and 2.0% efficiency guideposts that inform the states' emissions targets.

Other Midwest states such as Illinois, Indiana, Kansas, Missouri, and Ohio achieved efficiency savings of less than 1% in 2012.[166] From our analysis, while Illinois has reasonably strong programs comparable to those discussed above, the other four states have either no industrial programs (Indiana, Kansas), or have industrial programs with the option for companies to opt-out with little oversight (Missouri, Ohio).[167] As such, the industrial program offerings can be strengthened considerably in order to increase participation from industrial companies and achieve meaningful and verifiable sectoral savings, which should help these states meet and exceed the 1.5% and 2.0% efficiency guidepost that informs the states' emissions targets.

Broadening the lens beyond the Midwest, it can be noted that Oregon and Vermont have achieved remarkable industrial sector energy savings. The Energy Trust of Oregon has realized energy savings in the industrial sector of approximately 1.8% of current industrial energy usage; efficiency performance of the industrial sector is outperforming other sectors.[168] In Vermont, energy efficiency performance in the industrial sector was greater than 2.2% on average in 2013, outperforming the 1.8% savings for all customer classes.[169] Utility-sponsored industrial sector programs in these states (as described earlier) are widely regarded as among the best in the country. Furthermore,

[165] EPA, Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants, Docket ID No. EPA-HQ-OAR-2013-0602, Table 5-8, page 5-33; Table 5-4, pages 5-17 to 5-19 (June 10, 2014).
[166] *Id*.
[167] It is a possibility that higher participation and removal of "opt-out" provisions will allow greater efficiency savings from the industrial sector and in the states overall.
[168] According to analysis obtained via email communication with the Energy Trust of Oregon in November 2014. The analysis shows that energy savings from industrial facilities in the Portland General Electric and Pacific Power territories are approximately 1.8% of annual energy usage currently.
[169] According to analysis obtained via email communication with Vermont Energy Investment Corporation in November 2014. The findings were based on custom analyses of 68 industrial sites and their savings in 2013. The 68 sites saved 19.3 million kWh in 2013.

demonstrated international experience from the Netherlands has achieved 30% savings over a 15-year period, more than 2% per year.[170]

From a national perspective, EIA Form 861 data suggests that nearly half of all energy efficiency (or load management) programs are devoid of industrial sector contribution, and, as discussed in the context of the Midwest states, driving participation where programs are available is yet another matter.[171]

While better data and focused analyses are needed as verification, in reviewing these state utility-sponsored programs, there appears to exist at least a loose correlation between states that have strong overall efficiency performance and ones that have strong industrial sector efficiency programs.

Accordingly, efficiency savings in the industrial sector may either be occurring outside of utility-sponsored programs, or if included as part of utility programs, are likely underrepresented currently vis-à-vis efficiency from other sectors. In either case, as significant savings are possible from the industrial sector, going forward, it should be able to play a strong role in improving states' efficiency performance.

7.4.4 *State Appliance And Efficiency Standards Provide Substantial Cost-Effective Savings*.

> ***Recommendation:*** *State appliance and efficiency standards should be credited in state compliance plans.*

State appliance and equipment standards have a history of success in many states, and new state appliance and efficiency standards should be considered in setting the BSER. States can choose to adopt efficiency standard for those products not yet covered under the federal appliance and efficiency standards. The Appliance Standards Awareness Project (ASAP) reports that 16 states have adopted state standards since 2001; these states are AZ, CA, CT, DC, GA, MA, MD, NH, NJ, NV, NY, OR, RI, TX, VT, WA.[172] These

---

[170] Senternovem (now known as NL Agency), from a presentation by Ronald Vermeeren in Dublin, Ireland, *Realising the Potential – Making Energy Management Systems deliver* (November 2009); David B. Goldstein, Aimee McKane, and Deann Desai, *ISO 50001: Energy Management Systems: A Driver for Continual Improvement of Energy Performance* (July 2011) presented at 2011 ACEEE Summer Study on Energy Efficiency in Industry.

[171] Nate Aden, Anna Chittum, and James Bradbury, *Anchoring costs: the role of industry programs in U.S. ratepayer-funded energy efficiency*, presented at ECEEE Industrial Summer Study on Energy Efficiency in the Netherlands, June 2014; based on DOE, EIA, "Annual Electric Power Industry Report (Form 861)", 2013.

[172] Appliance Standards Awareness Project , *State Adoption of Energy Efficiency Standards*, *available at* http://www.appliance-standards.org/sites/default/files/State_status_grid_Feb_2014.pdf

states have adopted standards on products such as battery chargers, TVs, pool pumps, DVD players and vending machines. California has been a leader in state standards, and just this year the California Energy Commission announced that it will establish new energy efficiency standards for 15 product categories, ranging from water faucets to the light bulbs that go into small recessed cans, and consumer electronics like computers, monitors, modems and Wi-Fi routers. Once in full effect, these standards will save an estimated $2 billion in avoided annual electricity bills and avoid the need to build three new large power plants.[173] Not every state will choose to adopt state appliance and equipment standards, but adding this as an option will further increase the flexibility states have in reaching their targets.

7.4.5 *Savings from CHP Systems Can serve as a valuable tool for compliance.*

> ***Recommendation:*** *EPA should provide appropriate and comprehensive guidance on how CHP systems can participate under a variety of compliance scenarios.*

Combined Heat and Power (CHP) systems are typically used in an industrial facility or a commercial building (and less often in agricultural or residential establishments). A CHP system would be used for both electricity and thermal needs, and, as such, it would displace (or supplement) the thermal energy system at the site. CHP's energy efficiency benefits are derived from the simultaneous generation of electricity and thermal energy, provided the system is properly designed to the energy needs of the facility, well-maintained, and operated judiciously. Currently, approximately 85 GW of CHP are installed in the U.S., but there remains additional technical potential of 65-200 GW, around 6 GW of this potential has strong potential economic payback;[174] at least 65 GW of additional potential remains in the industrial sector.[175] However, there remain numerous market and policy barriers that hinder this potential from being realized

[173] Pierre Delforge, NRDC, *California Moving Forward on 15 New Appliance Efficiency Standards* (March 19, 2014) *available at* http://switchboard.nrdc.org/blogs/pdelforge/california_moving_forward_on_1.html.

[174] Hedman, et al., *The Opportunity for CHP in the United States*, ICF International, Prepared for the American Gas Association (May 2013) Page ES-3, Table ES-1. The study includes a state-by-state assessment of CHP potential.

[175] DOE and EPA, *Combined Heat and Power: A Clean Energy Solution* (August 2012) *available at* www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_clean_energy_solution.pdf. Going beyond the currently installed capacity, the remaining technical potential of CHP systems (where they are technically feasible and favorable to deploy) in the industrial and commercial/institutional sectors is roughly 65 GW each. However, the 65 GW of remaining industrial technical potential accounts only for systems with sizes constrained such that they do not have excess power to export to the grid. But if systems can be sized to enable export of power (which needs supportive regulations) to the grid, then the remaining industrial technical potential doubles, to 130 GW.

appreciably.[176] A recent report (published before the release of EPA's Clean Power Plan proposal) suggested that a policy based on regulating emissions from existing power plants could have a modest beneficial effect on CHP deployment.[177]

While there are different methodologies for calculating electricity-related emissions from CHP systems, the higher energy efficiency of CHP systems compared to separate heat and power systems (e.g., central power plant for electricity and onsite boiler for thermal needs), translates to fewer emissions associated with electricity produced from CHP systems.[178] This leads to reduced emissions from EGUs when CHP systems are used onsite at industrial facilities. Accordingly, we support the consideration of industrial CHP systems as a potential approach to avoid affected EGU emissions.[179] Going further, we also supportconsidering CHP systems that lie outside of the industrial sector, for exactly the same reasons. (We note that the approaches discussed here may also be applicable to other low-emissions systems besides CHP, which are used at third-party facilities.)

In the context of the proposed Clean Power Plan, the primary issue is the emissions benefits of CHP. There are two main output-based approaches for calculating emissions reductions. The first is the equivalence approach proposed by EPA. The second is the avoided emissions approach, which calculates emissions reductions derived from using a CHP system in place of a "counterfactual" thermal system (e.g., boiler). Appendix 7A details these two approaches.

EPA has requested comment on the "range of two-thirds to 100 % credit for useful thermal output," as applicable in the equivalence approach.[180]

We, instead, strongly advocate for the use of the avoided emissions approach to calculate the emissions benefits from CHP systems. As detailed in Appendix 7A, mainly for reasons of accuracy, reasonable simplicity, and potentially greater relevance in this

---

[176] State and Local Energy Efficiency Action Network (SEE Action) *Guide to the Successful Implementation of State Combined Heat and Power Policies* (March 2013) prepared by B. Hedman, A. Hampson, J. Rackley, E. Wong, ICF International; L. Schwartz and D. Lamont, Regulatory Assistance Project; T. Woolf, Synapse Energy Economics; and J. Selecky, Brubaker & Associates, *available at* https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies .
[177] Center for Clean Air Policy, *Expanding the Solution Set* (May 2014) *available at* http://ccap.org/resource/expanding-the-solution-set-how-combined-heat-and-power-can-support-compliance-with-111d-standards-for-existing-power-plants/ .
[178] NRDC, *Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings, and Other Facilities* (April, 2013) *available at* http://www.nrdc.org/energy/combined-heat-and-power-systems.asp .
[179] 79 Fed. Reg. at 34,924.
[180] 79 Fed. Reg. at 34,914.

particular regulatory context, we recommend the use of the avoided emissions approach.

If EPA wishes to provide guidance for the equivalence approach (for instance, if states adopt this approach), we would encourage using a thermal credit that matches the actual design and operation of a particular CHP system, which have a strong bearing on system performance. This is in contrast to using one thermal credit value for all types and sizes of CHP systems. We note that the system-specific thermal credit could exceed the proposed 75% value.

As for assessing performance, for either the equivalence or avoided emission approaches, the same measurements of fuel input and useful electric and thermal outputs would be needed. Robust evaluation, measurement and verification of CHP system performance would increase confidence in the efficiency benefits of the systems – for instance, the thermal output from CHP systems should not be wasted or dissipated, but actually put to productive use. Accordingly, we strongly support the use of independent verification (as done in other energy efficiency contexts) to develop an accurate picture of the realized emissions benefits from CHP systems.

Finally, EPA should provide appropriate and comprehensive guidance on how CHP can serve as a valuable compliance option towards meeting the goals of the Clean Power Plan. CHP systems may be directly affected or non-affected, which would result in different practical considerations (e.g., how to account for onsite emissions of non-affected CHP systems). Moreover, states may choose to adopt state-based or mass-based approaches to comply with the Clean Power Plan. EPA's guidance will be necessary and helpful to help states navigate the many options for compliance.

7.5 Evaluation, measurement, and verification.

> ***Recommendation:*** *EPA's EM&V guidance should ensure states establish a process that produces reasonably accurate, unbiased, and consistent estimates of savings from demand-side energy efficiency measures used in a state plan: EM&V that addresses and accounts for major sources of uncertainty and is consistent across program administrators and states. In particular, EPA should publish detailed guidance establishing an EM&V framework that includes standards and requirements for state reporting of EM&V plans, EM&V actions, savings estimates, and program details; encourage regional collaboration on EM&V; encourage states to subject savings estimates to peer review; commit to conducting a thorough review of state EM&V plans; and require states to certify savings estimates in an open and transparent regulatory process.*

The EPA proposes that states whose state plans include enforceable demand-side energy efficiency measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of those measures will be determined over the plan period.[181] Note that these requirements, except reporting requirements, are most relevant for rate-based policy approaches (as a opposed to mass-based). This plan would specify the analytic methods, assumptions, and data sources the state will employ during the state plan performance period to determine the energy savings related to demand-side energy efficiency measures, and would be subject to EPA approval as part of a state plan. EPA is planning to establish guidance to states for acceptable quantification, monitoring, and verification of demand-side energy efficiency measures for an approvable state plan, and EPA seeks comment on critical features of such guidance, including scope, applicability, and minimum requirements, as well as the basis for and technical resources used to establish such guidance.[182]

There is no technical impediment to the establishment of a national standard for estimating savings from energy efficiency programs. There has simply been no reason to develop a national EM&V standard prior to now. Customer-funded energy efficiency programs are regulated by state public utility commissions and implemented for a variety of purposes: to support state carbon reduction policies, to delay or avoid expensive new power plants, distribution and transmission systems, and to reduce customer bills. Carbon pollution standards under this Rule provide a new impetus for customer-funded energy efficiency programs and a clear policy motivation for EM&V standardization across states and regions: the savings from a LED light bulb should be measured similarly in Arizona and Wisconsin (although they may produce different results).

As explained below, EPA's EM&V guidance should ensure states establish a process that produces reasonably accurate, unbiased, and consistent estimates of savings from demand-side energy efficiency measures used in a state plan: EM&V that addresses and accounts for major sources of uncertainty and is consistent across program administrators and states. EPA can take several actions to achieve this goal:

- Promulgate detailed guidance establishing an EM&V framework (including definitions, evaluation methods and key assumptions, roles and responsibilities, peer review requirements, and transparency and reporting requirements) that – if used by states to estimate savings from demand-side energy efficiency

[181] 79 Fed. Reg. at 34,920,VIII.F.4.
[182] 79 Fed. Reg. at 34,920, VIII.F.4.

measures – allows resulting savings estimates to be used to demonstrate compliance with a state plan or to modify an emissions rate

- Create standards and requirements for state reporting of EM&V plans, EM&V actions, savings estimates, and program details that allow easy comparison of savings estimates across program administrators and states

- Encourage regional collaboration on EM&V, so that more states use similar analytic methods, assumptions, and data sources, and states can share the burden of developing resource-intensive inputs

- Encourage states to subject savings estimates to peer review

- Commit to conducting a thorough review of state EM&V plans, ensuring they comport with EM&V Guidance, and on to ensuring that states follow EM&V plans to estimate savings.

- Require states to certify savings estimates in an open and transparent regulatory (adjudicated if requested by parties) process .

- EPA should consider supporting the development of a national EE registry.

Our recommendations on EM&V are further detailed in Appendix 7B. NRDC, along with 14 other organizations including Northeast Energy Efficiency Partnerships and ACEEE, submitted Joint Energy Efficiency Stakeholder Comments in this docket on November 26, 2014. Appendix 7B adds further detail to issues discussed in the joint comments.

7.6 Compliance Issues.

7.6.1 *Start Date/Early Action Credit*.[183]

> ***Recommendation:*** *States should be able to claim credit for the post-2020 emission reduction impact of energy efficiency measures installed after the date the rule was proposed.*

Energy efficiency measures installed between now and 2020 will reduce greenhouse gas emissions between now and 2020, and the measures remaining during the 2020-2029 compliance period will reduce emissions during the compliance period. In the Proposed Rule , EPA seeks comment on the point in time after which installed energy efficiency measures should be able to qualify for use as emission-reducing measures during a plan

[183] 79 Fed. Reg. at 34918 and 34919.

performance period. EPA proposed to use the date this rule was proposed but also sought comment on additional options, including the date of rule promulgation, the start of the initial performance period, the end of the base period for the BSER-based analysis (2017 for Block 4), or the end of 2005. EPA also sought comment on an additional approach: applying emission reductions that existing state requirements, programs, and measures yield prior to the initial performance period toward meeting the required level of emission performance in a state plan.

As EPA states, there should generally be congruence between the forward-looking methodology that the EPA used to proposed state emission performance goals based on the BSER and state compliance options: states should not get emission-reduction credit for past actions already reflected in the BSER. Additionally, states should be encouraged to build the policy and programmatic infrastructure necessary to make meaningful progress toward targets during the initial performance period, while maintaining the environmental imperative to reduce emissions intensity of electric power production.

These goals can best be balanced by allowing states to use energy efficiency measures installed after the date the rule was proposed to be used against observed emissions rates at affected EGUs during the performance period . This would encourage states to launch or maintain energy efficiency efforts ahead of the compliance period, and recognize early action by states to reduce greenhouse gas emissions. However, allowing states to use pre-2020 emission reductions in the compliance period would conflict with the purpose of the rule – reducing the emissions intensity of electric power production – allowing states to trade early performance for later performance.

7.6.2 *Addressing Federal Appliance And Efficiency Standards.*

> ***Recommendation:*** *Federal appliance and equipment energy efficiency standards should not be included in state plans, but if states request to include them in state plans, they will need to work with EPA to adjust their targets accordingly.*

Federal appliance and equipment standards are important contributors to improvements in national energy efficiency. ASAP and ACEEE estimate that just those federal efficiency standards adopted through 2011 will save about 7% of U.S. electricity by 2010, and about 15% per year by 2025.[184] Standards enacted since 2011 and those currently planned will further increase the savings from federal standards. To put this

[184] A. Lowenberger, et al. *The Efficiency Boom? Cashing In on the Savings from Appliance Standards.* Washington, DC: ACEEE and Boston, MA: ASAP (March 2012) *available at* http://www.aceee.org/sites/default/files/publications/researchreports/a123.pdf.

into the Clean Power Plan context, ASAP and ACEEE also estimate that energy savings from the existing and pending federal standards will average about 0.70% of electricity sales for each year over 2020-2030.[185]

The EPA's proposed rule does not include federal standards in setting state targets, nor does it suggest they could be used for compliance in state plans. We agree that, because federal standards are outside of the jurisdiction of states and are not enforceable by states, they should not be included in targets nor used as a means of compliance. We recommend that the EPA clarify this in the final rule. However, if states do request to include federal standards in their plans, they should work with EPA to tighten their targets accordingly.

There is strong evidence that states will be able to meet their targets without including federal standards in their plans. The EPA's own analysis of the savings that could be reasonably expected from states used sources of data that did not include savings from federal standards. We argue for a savings level of at least 2% of annual retail sales which does not include savings from federal standards.

The treatment of federal standards for states using the rate-based approach is clear, i.e. the MWhs of savings from federal standards would not be added to the denominator of the rate equation. However, the EPA will need to make an adjustment to give equal treatment to mass-based states. We recommend that the EPA use the most updated EIA Annual Energy Outlook Reference Case to better address the impact of the most recent federal standards.

---

[185] *See* ACEEE's 111d comments for this analysis, which is based on a 2012 report by the American Council for an Energy-Efficient Economy. *The Efficiency Boom: Cashing in on the Savings from Applicance Standards* (March 8, 2012) *available at* http://aceee.org/research-report/a123.

8.0 Analysis and Modeling of NRDC's Recommended Changes to the CPP

8.1 Summary and Methodology

NRDC's technical comments focus on how EPA can strengthen the Clean Power Plan and make even deeper cuts to dangerous carbon pollution. In this section, we present our analyses of several different policy scenarios, and associated sensitivity analyses. We demonstrate that there is ample room to strengthen the CPP and achieve even deeper emissions reductions at reasonable costs, and that the benefits consistently outweigh the costs by a wide margin. It is important to note that we examined a few illustrative policy scenarios which do not reflect our full set of recommendations for strengthening the Clean Power Plan, and that there are some additional pieces of analysis still under development (we will submit additional material to the docket in the coming weeks). Appendix B provides a comprehensive summary of our analyses developed to date.

The EPA's Clean Power Plan establishes state-specific emission rate targets based on a technical and economic assessment of each state's opportunities to reduce emissions from its electricity sector. The EPA found that by 2020, the power sector could reduce its emissions by 26 percent below 2005 levels under the Clean Power Plan, costing between $5.5 billion and $7.5 billion annually.[1,2] However, the assumptions incorporated into EPA's analysis are noticeably conservative and outdated, particularly with respect to the costs and performance of renewable energy and energy efficiency. To correct this, we updated these assumptions and re-evaluated the Clean Power Plan's proposed state targets. Our analysis found that the agency overstates the costs of compliance—the amount the power sector would pay to implement the Clean Power Plan as proposed—by $10 billion in 2020 – this correction turns compliance costs into savings. These savings mean the power sector would spend less to meet the Clean Power Plan targets, which would result in larger net savings for customers on their utility bills. Moreover, by overstating the costs, the EPA missed an opportunity to make even deeper carbon reductions while keeping costs reasonable.

NRDC updated these cost and performance numbers and provided the assumptions to ICF International. NRDC engaged ICF to run the Integrated Planning Model (IPM®), the same model that EPA uses. IPM determines a least cost compliance pathway through both re-dispatch of existing resources and capacity expansion of new resources. Using IPM, NRDC asked ICF to model several policy scenarios based on NRDC assumptions, presented throughout this section.

---

[1] All compliance costs throughout this section are reported in 2011$.

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

First, we examined compliance with EPA's state targets, and then performed the same analysis with updated cost and performance data for renewables and efficiency. These IPM runs are referred to as "Updated Costs and Performance" runs.

Second, the "Updated Cost and Performance" runs demonstrate that EPA can strengthen state targets to achieve deeper emissions reductions at reasonable cost, and NRDC analyzed potential strengthening of state targets based primarily on the ideas put forth in EPA's October 28, 2014 Notice of Data Availability (NODA). Our recommendations for this approach to state target-setting, in which the formula is adjusted to reflect real-world displacement of fossil emissions, can be found in more detail (in Section 3) The methodology for deriving new state targets can also be found in that chapter.

We evaluated compliance for the resulting set of state targets under both approaches described in the NODA. These model runs are described below as "NODA Dirtiest First" and "NODA Pro Rata" cases. Under both "NODA Dirtiest First" and "NODA Pro Rata" target-setting approaches, we also analyzed a second list of state targets that accounts for a minimum generation conversion from higher-emitting sources to lower-emitting sources. These are referred to as "NODA Dirtiest First + Min Gen Conversion" and "NODA Pro Rata + Min Gen Conversion."

Third, EPA recently issued guidance and illustrative examples of how to convert state rate targets into emissions mass caps. As discussed in more detail in Section 9 many states may want to adopt mass caps because it can involve less administrative complexity, and may also make it easier for states to join existing regional trading programs. NRDC analyzed a case in which all states adopt EPA's mass caps, and then examined a similar case in which only Pennsylvania and New Mexico adopt rate targets. The comparison of these runs provides additional information on the potential for environmental leakage between states.

Finally, we performed two sets of sensitivity analyses on compliance with these state targets. The first sensitivity case examined the effects of including new natural gas units for compliance when those sources were not included in the target-setting calculation. The second sensitivity case examined a potential compliance pathway in which only half of the available energy efficiency is selected by utilities and states. These two sensitivity analyses are described further in Appendix 8A, attached to this section.

For the policy runs described in this section, NRDC relied on an endogenous approach to representing demand-side energy efficiency in the model using a simplified supply curve. We derived the energy efficiency supply curve from the total electricity demand reduction from energy efficiency projected by Synapse Energy Economics on the basis of the performance of leading state programs. We divided the total energy savings into three equal blocks, and assigned a utility program cost to each block. Also based on the Synapse study, the levelized cost of saving energy (LCOSE) of the middle block was assumed to be 4.7 cents/kWh from 2017-2019, 5.3 cents/kWh between 2020-2029, and 6.0 cents/kWh beginning in 2030. We note that these cost assumptions are conservative. The recently released study from Lawrence Berkeley National Laboratory (LBNL) examining costs of efficiency programs found a national savings-weighted average LCOSE for energy efficiency of 4.4 cents/kWh. In this analysis, we assumed that utility program costs and participant costs each make up 50 percent of the total LCOSE. The relative costs for the other two blocks were scaled on the basis of a generic cost curve given in a 2013 LBNL report on the projected costs and savings of utility-funded energy efficiency programs. In this analysis, we assumed the costs are uniform throughout the country, while the quantities of energy efficiency savings available vary by region in accordance with the Synapse assessment. In each region, the model selects the amount of energy efficiency to deploy based on a competitive assessment of its levelized cost relative to other resources. While the selection of the efficiency resource in the model is based on levelized utility program costs, we include the participant's contribution in the calculations of total compliance costs.

In Appendix B, Tables 8B.1 – 8B.3 present a summary of the cases analyzed and the inputs used in each case, along with more details about our updates to the energy efficiency and renewable energy assumptions.

8.2 Reference Cases

Our initial analysis was developed using the same cost assumptions and reference case as EPA, and is built around the economic forecasts developed by the Energy Information Administration in its 2013 Annual Energy Outlook (EIA AEO 2013). This reference case is called Reference Case 1 (or "RC1"). Our next round of analyses only updated the cost and performance assumptions for renewable energy technologies - to maintain comparability between these policy cases and the Reference Case, we also updated the Reference Case ("RC2").

We have also developed a reference case ("RC3") to reflect the most recent projections from EIA in its 2014 Annual Energy Outlook (AEO 2014). EIA AEO 2014 reflects recent trends such as continued fuel switching to natural gas and increasing levels of renewable energy. RC3 also contains adjustments such as updating existing CC heat rates to better align with NEEDS, and assumes a 60 year lifetime ceiling for existing nuclear units. The combinations of these dynamics results in a reference case with lower projected emissions compared to RC1, which was built on AEO 2013, as is demonstrated in Figure 8.2.

More details on each reference case and the corresponding assumptions can be found in the attached IPM files.

8.3 Updated Cost and Performance Cases

The Updated Costs and Performance cases evaluated the state emissions-rate targets the EPA has proposed and used the same modeling framework as the EPA's "Option 1 State" and "Option 1 Regional" policy cases. It is important to note that all modeling outcomes discussed throughout the remainder of this section are based on NRDC analysis, and results based on EPA assumptions may still differ slightly from those reported in EPA's RIA due to variations in modeled regions.

Simply by making the cost and performance parameters for renewable generation and energy efficiency consistent with today's data, NRDC has found that compliance with EPA's proposed targets could be achieved at a *savings* of $1.8 billion (Option 1 State) to $4.3 billion (Option 1 Regional) by 2020. For 2030, the savings are even larger: $6.4 billion (Option 1 State) or $9.4 billion (Option 1 Regional). There is a ***$10 billion*** difference in 2020 and a $17 billion difference in 2030 between model runs using EPA's assumptions and the Updated Costs and Performance assumptions. These substantial savings indicate that the standards could be strengthened and achieve significantly greater carbon reductions at a reasonable cost.

Further detail on this subject may be found in NRDC's November 2014 issue brief, titled, "The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030," available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf (attached as Appendix 8C).

8.4 NODA Dirtiest First Approach for Target-Setting Calculation

In its October 27, 2014, Notice of Data Availability (NODA), 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 necessary to ensure that the Clean Power Plan fully reflects the potential for emission reductions achievable under the best system of emission reduction.

EPA also requested comment on whether to include a "minimum level of generation shift from higher-emitting sources to lower-emitting sources for all states" (40 CFR Part 60, at 64549), which would cause building block 2 to be more consistent across states by assuming that new NGCC generation can be built in certain states that have little to no existing NGCC capacity. In our analysis, we have examined a very modest policy scenario in which a minimum generation shift of 20 percent over the ten year period is applied to each state. As demonstrated in the state targets table below, this only has a significant effect on states with little or no existing NGCC capacity.

We analyzed the impacts of the Clean Power Plan on the electric power sector, substituting the June 2014 proposed state targets for recalculated state targets using NRDC's preferred approach as described in the NODA: 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. The "NODA Dirtiest First" case analyzed the following state targets, calculated based on M.J. Bradley Associates' Clean Power Plan Evaluation Tool.

Table 8.1: State Targets for NODA Dirtiest First

		INTERIM GOAL			FINAL GOAL		
State	2012 Comp.	EPA	Policy	NODA BB3/4	EPA	Policy	NODA BB3/4
Alabama	1,444	1,147	1,147	1,041	1,059	1,059	852
Alaska	1,351	1,097	1,097	1,086	1,003	1,003	969
Arizona	1,453	735	735	709	702	702	662
Arkansas	1,640	968	968	855	910	910	709
California	698	556	556	517	537	537	484
Colorado	1,714	1,159	1,159	1,012	1,108	1,108	907
Connecticut	765	597	597	544	540	540	444
Delaware	1,234	913	913	873	841	841	782
Florida	1,200	794	794	759	740	740	693
Georgia	1,500	891	891	497	834	834	403
Hawaii	1,540	1,378	1,378	1,319	1,306	1,306	1,203
Idaho	339	244	244	26	228	228	0
Illinois	1,895	1,366	1,366	1,210	1,271	1,271	1,021
Indiana	1,923	1,607	1,607	1,561	1,531	1,531	1,453
Iowa	1,552	1,341	1,341	1,265	1,301	1,301	1,194
Kansas	1,940	1,578	1,578	1,472	1,499	1,499	1,341
Kentucky	2,158	1,844	1,844	1,796	1,763	1,763	1,702
Louisiana	1,466	948	948	821	883	883	653
Maine	437	393	393	325	378	378	286
Maryland	1,870	1,347	1,347	1,138	1,187	1,187	807
Massachuse	925	655	655	590	576	576	444
Michigan	1,696	1,227	1,227	1,092	1,161	1,161	957
Minnesota	1,470	911	911	726	873	873	619
Mississippi	1,130	732	732	719	692	692	668
Missouri	1,963	1,621	1,621	1,593	1,544	1,544	1,491

State	2012 Comp.	INTERIM GOAL EPA	INTERIM GOAL Policy	INTERIM GOAL NODA BB3/4	FINAL GOAL EPA	FINAL GOAL Policy	FINAL GOAL NODA BB3/4
Montana	2,245	1,882	1,882	1,827	1,771	1,771	1,671
Nebraska	2,009	1,596	1,596	1,531	1,479	1,479	1,354
Nevada	988	697	697	667	647	647	592
New Hampshire	905	546	546	436	486	486	306
New Jersey	932	647	647	571	531	531	342
New Mexico	1,586	1,107	1,107	933	1,048	1,048	795
New York	983	635	635	534	549	549	353
North Carolina	1,646	1,077	1,077	925	992	992	764
North Dakota	1,994	1,817	1,817	1,803	1,783	1,783	1,760
Ohio	1,850	1,452	1,452	1,355	1,338	1,338	1,168
Oklahoma	1,387	931	931	766	895	895	671
Oregon	717	407	407	227	372	372	123
Pennsylvania	1,540	1,179	1,179	1,024	1,052	1,052	751
Rhode Island	907	822	822	811	782	782	761
South Carolina	1,587	840	840	245	772	772	124
South Dakota	1,135	800	800	628	741	741	456
Tennessee	1,903	1,254	1,254	943	1,163	1,163	726
Texas	1,298	853	853	678	791	791	542
Utah	1,813	1,378	1,378	1,322	1,322	1,322	1,234
Virginia	1,297	884	884	745	810	810	645
Washington	763	264	264	54	215	215	27
West Virginia	2,019	1,748	1,748	1,729	1,620	1,620	1,566
Wisconsin	1,827	1,281	1,281	1,124	1,203	1,203	962
Wyoming	2,115	1,808	1,808	1,756	1,714	1,714	1,631
U.S.	1,497	1,068	1,068	959	990	990	824

We also analyzed the following state targets, based on adding a minimum conversion rate to lower-emitting generation of 20 percent over the period 2020-2029.

Table 8.2: State Targets for NODA Dirtiest First + Min Gen Conversion

		INTERIM GOAL			FINAL GOAL		
	2012			NODA			NODA
State	Comp.	EPA	Policy	BB3/4	EPA	Policy	BB3/4
Alabama	1,444	1,147	1,147	1,041	1,059	1,059	852
Alaska	1,351	1,097	1,097	1,086	1,003	1,003	969
Arizona	1,453	735	735	709	702	702	662
Arkansas	1,640	968	968	855	910	910	709
California	698	556	556	517	537	537	484
Colorado	1,714	1,159	1,159	1,012	1,108	1,108	907
Connecticut	765	597	597	544	540	540	444
Delaware	1,234	913	913	873	841	841	782
Florida	1,200	794	794	759	740	740	693
Georgia	1,500	891	891	497	834	834	403
Hawaii	1,540	1,378	1,410	1,261	1,306	1,215	1,083
Idaho	339	244	244	26	228	228	0
Illinois	1,895	1,366	1,362	1,205	1,271	1,242	984
Indiana	1,923	1,607	1,553	1,500	1,531	1,410	1,312
Iowa	1,552	1,341	1,341	1,264	1,301	1,292	1,184
Kansas	1,940	1,578	1,487	1,356	1,499	1,327	1,129
Kentucky	2,158	1,844	1,744	1,691	1,763	1,579	1,503
Louisiana	1,466	948	948	821	883	883	653
Maine	437	393	393	325	378	378	286
Maryland	1,870	1,347	1,325	1,086	1,187	1,103	677
Massachuse	925	655	655	590	576	576	444
Michigan	1,696	1,227	1,227	1,092	1,161	1,161	957
Minnesota	1,470	911	911	726	873	873	619
Mississippi	1,130	732	732	719	692	692	668
Missouri	1,963	1,621	1,598	1,568	1,544	1,465	1,402

State	2012 Comp.	INTERIM GOAL EPA	INTERIM GOAL Policy	INTERIM GOAL NODA BB3/4	FINAL GOAL EPA	FINAL GOAL Policy	FINAL GOAL NODA BB3/4
Montana	2,245	1,882	1,762	1,690	1,771	1,561	1,420
Nebraska	2,009	1,596	1,574	1,505	1,479	1,407	1,266
Nevada	988	697	697	667	647	647	592
New Hampshire	905	546	546	436	486	486	306
New Jersey	932	647	647	571	531	531	342
New Mexico	1,586	1,107	1,107	933	1,048	1,048	795
New York	983	635	635	534	549	549	353
North Carolina	1,646	1,077	1,077	925	992	992	764
North Dakota	1,994	1,817	1,699	1,681	1,783	1,572	1,538
Ohio	1,850	1,452	1,423	1,319	1,338	1,259	1,072
Oklahoma	1,387	931	931	766	895	895	671
Oregon	717	407	407	227	372	372	123
Pennsylvania	1,540	1,179	1,165	1,004	1,052	1,003	685
Rhode Island	907	822	822	811	782	782	761
South Carolina	1,587	840	840	245	772	772	124
South Dakota	1,135	800	800	628	741	741	456
Tennessee	1,903	1,254	1,230	910	1,163	1,089	619
Texas	1,298	853	853	678	791	791	542
Utah	1,813	1,378	1,378	1,322	1,322	1,322	1,234
Virginia	1,297	884	884	745	810	810	645
Washington	763	264	264	54	215	215	27
West Virginia	2,019	1,748	1,649	1,618	1,620	1,449	1,365
Wisconsin	1,827	1,281	1,281	1,124	1,203	1,203	962
Wyoming	2,115	1,808	1,702	1,641	1,714	1,521	1,416
U.S.	1,497	1,068	1,052	940	990	955	781

To summarize, we evaluated the impacts of these state targets based on the following model runs:

- Reference Case 3 (RC3)
- NODA Dirtiest First
- NODA Dirtiest First + Min Gen Conversion

Each of these model runs assumed state compliance. NRDC plans to analyze regional cooperation cases in the coming weeks.

Under the NODA Dirtiest First case, emissions fell to 1,693 million short tons in 2020, or 36 percent below 2005 and 24 percent below 2012 emissions levels. In 2030, emissions declined further to 1,495 million short tons, or 44 percent below 2005 levels and 33 percent below 2012 levels. Total annual compliance costs in 2020 were $7.7 billion, $4.3 billion in 2025, and $10.6 billion in 2030.

The NODA Dirtiest First + Min Gen Conversion case showed 1,705 million short tons in 2020, and declined further to 1,485 million short tons in 2030. On an annualized basis, compliance costs in the NODA Dirtiest First + Min Gen Conversion case totaled $6.5 billion in 2020, declined to $4.3 billion in 2025, and rose again to $10.5 billion in 2030.

These outcomes demonstrate that EPA can achieve significant emission reductions in the range of 44 percent below 2005 levels in 2030 at reasonable costs – similar to EPA's cost estimates for the proposed plan. EPA's Option 1 State analysis showed $7.5 billion in costs in 2020, and $8.8 billion in 2030. For these cases, we did not model regional compliance approaches, but we expect that in all the cases we have modeled compliance costs would be lower if states choose to take a regional approach.

Moreover, the value of the emission reduction benefits in these cases greatly exceeds the compliance costs. In 2030, the total benefits of the emission reductions, including reductions of SO_2 and CO_2, range between $73 and $119 billion, with the benefits outweighing the costs by $62 to $108 billion. For a comparison of the costs and benefits of the cases we analyzed, see the figure in the following section.

8.5 NODA Pro Rata Approach for Target-Setting Calculation

In addition to the NODA Dirtiest First cases, we analyzed the state targets based on the Pro Rata Approach, as described in the October 2014 NODA.[3] For this analysis, we compared:

- Reference Case 3 (RC3)
- NODA Pro Rata
- NODA Pro Rata + Min Gen Conversion

We analyzed each of these cases assuming state compliance. The state targets under the NODA Pro Rata Approach (also taken from the M.J. Bradley Associates' Clean Power Plan Evaluation Tool) were:

[3] We did not adjust the amount of existing NGCC available for redispatch as part of Block Two, although as we note in our discussion of the formula change in Section 3, EPA would need to make such a change if it adopted this approach.

Table 8.3: State Targets for NODA Pro Rata

		INTERIM GOAL			FINAL GOAL		
	2012			NODA			NODA
State	Comp.	EPA	Policy	BB3/4	EPA	Policy	BB3/4
Alabama	1,444	1,147	1,147	1,125	1,059	1,059	1,007
Alaska	1,351	1,097	1,097	1,086	1,003	1,003	969
Arizona	1,453	735	735	709	702	702	662
Arkansas	1,640	968	968	951	910	910	874
California	698	556	556	517	537	537	484
Colorado	1,714	1,159	1,159	1,097	1,108	1,108	1,021
Connecticut	765	597	597	544	540	540	444
Delaware	1,234	913	913	901	841	841	809
Florida	1,200	794	794	783	740	740	715
Georgia	1,500	891	891	738	834	834	621
Hawaii	1,540	1,378	1,378	1,338	1,306	1,306	1,233
Idaho	339	244	244	26	228	228	0
Illinois	1,895	1,366	1,366	1,269	1,271	1,271	1,107
Indiana	1,923	1,607	1,607	1,580	1,531	1,531	1,483
Iowa	1,552	1,341	1,341	1,291	1,301	1,301	1,229
Kansas	1,940	1,578	1,578	1,478	1,499	1,499	1,349
Kentucky	2,158	1,844	1,844	1,800	1,763	1,763	1,708
Louisiana	1,466	948	948	927	883	883	836
Maine	437	393	393	325	378	378	286
Maryland	1,870	1,347	1,347	1,184	1,187	1,187	879
Massachuse	925	655	655	590	576	576	444
Michigan	1,696	1,227	1,227	1,176	1,161	1,161	1,077
Minnesota	1,470	911	911	843	873	873	776
Mississippi	1,130	732	732	719	692	692	668
Missouri	1,963	1,621	1,621	1,607	1,544	1,544	1,514

		INTERIM GOAL			FINAL GOAL		
State	2012 Comp.	EPA	**Policy**	**NODA BB3/4**	EPA	**Policy**	**NODA BB3/4**
Montana	2,245	1,882	1,882	1,827	1,771	1,771	1,671
Nebraska	2,009	1,596	1,596	1,546	1,479	1,479	1,378
Nevada	988	697	697	667	647	647	592
New Hampshire	905	546	546	436	486	486	306
New Jersey	932	647	647	571	531	531	342
New Mexico	1,586	1,107	1,107	1,051	1,048	1,048	960
New York	983	635	635	535	549	549	354
North Carolina	1,646	1,077	1,077	1,011	992	992	900
North Dakota	1,994	1,817	1,817	1,803	1,783	1,783	1,760
Ohio	1,850	1,452	1,452	1,398	1,338	1,338	1,238
Oklahoma	1,387	931	931	896	895	895	844
Oregon	717	407	407	227	372	372	123
Pennsylvania	1,540	1,179	1,179	1,114	1,052	1,052	908
Rhode Island	907	822	822	811	782	782	761
South Carolina	1,587	840	840	428	772	772	221
South Dakota	1,135	800	800	713	741	741	586
Tennessee	1,903	1,254	1,254	1,055	1,163	1,163	870
Texas	1,298	853	853	809	791	791	710
Utah	1,813	1,378	1,378	1,359	1,322	1,322	1,288
Virginia	1,297	884	884	846	810	810	750
Washington	763	264	264	54	215	215	27
West Virginia	2,019	1,748	1,748	1,729	1,620	1,620	1,566
Wisconsin	1,827	1,281	1,281	1,222	1,203	1,203	1,103
Wyoming	2,115	1,808	1,808	1,759	1,714	1,714	1,637
U.S.	1,497	1,068	1,068	1,020	990	990	906

The following table shows the state targets resulting from the NODA Pro Rata Approach and the assumption that existing fossil steam generation converts to lower-emitting generation at a minimum level of 20 percent over the period from 2020-2029.

Table 8.4: State Targets for NODA Pro Rata + Min Gen Conversion

		INTERIM GOAL			FINAL GOAL		
State	2012 Comp.	EPA	Policy	NODA BB3/4	EPA	Policy	NODA BB3/4
Alabama	1,444	1,147	1,147	1,125	1,059	1,059	1,007
Alaska	1,351	1,097	1,097	1,086	1,003	1,003	969
Arizona	1,453	735	735	709	702	702	662
Arkansas	1,640	968	968	951	910	910	874
California	698	556	556	517	537	537	484
Colorado	1,714	1,159	1,159	1,097	1,108	1,108	1,021
Connecticut	765	597	597	544	540	540	444
Delaware	1,234	913	913	901	841	841	809
Florida	1,200	794	794	783	740	740	715
Georgia	1,500	891	891	738	834	834	621
Hawaii	1,540	1,378	1,410	1,285	1,306	1,215	1,126
Idaho	339	244	244	26	228	228	0
Illinois	1,895	1,366	1,362	1,265	1,271	1,242	1,082
Indiana	1,923	1,607	1,553	1,528	1,531	1,410	1,366
Iowa	1,552	1,341	1,341	1,291	1,301	1,292	1,221
Kansas	1,940	1,578	1,487	1,387	1,499	1,327	1,191
Kentucky	2,158	1,844	1,744	1,705	1,763	1,579	1,533
Louisiana	1,466	948	948	927	883	883	836
Maine	437	393	393	325	378	378	286
Maryland	1,870	1,347	1,325	1,152	1,187	1,103	805
Massachuse	925	655	655	590	576	576	444
Michigan	1,696	1,227	1,227	1,176	1,161	1,161	1,077
Minnesota	1,470	911	911	843	873	873	776
Mississippi	1,130	732	732	719	692	692	668
Missouri	1,963	1,621	1,598	1,585	1,544	1,465	1,436

State	2012 Comp.	INTERIM GOAL EPA	INTERIM GOAL Policy	INTERIM GOAL NODA BB3/4	FINAL GOAL EPA	FINAL GOAL Policy	FINAL GOAL NODA BB3/4
Montana	2,245	1,882	1,762	1,712	1,771	1,561	1,474
Nebraska	2,009	1,596	1,574	1,525	1,479	1,407	1,311
Nevada	988	697	697	667	647	647	592
New Hampshire	905	546	546	436	486	486	306
New Jersey	932	647	647	571	531	531	342
New Mexico	1,586	1,107	1,107	1,051	1,048	1,048	960
New York	983	635	635	535	549	549	354
North Carolina	1,646	1,077	1,077	1,011	992	992	900
North Dakota	1,994	1,817	1,699	1,687	1,783	1,572	1,552
Ohio	1,850	1,452	1,423	1,370	1,338	1,259	1,166
Oklahoma	1,387	931	931	896	895	895	844
Oregon	717	407	407	227	372	372	123
Pennsylvania	1,540	1,179	1,165	1,100	1,052	1,003	865
Rhode Island	907	822	822	811	782	782	761
South Carolina	1,587	840	840	428	772	772	221
South Dakota	1,135	800	800	713	741	741	586
Tennessee	1,903	1,254	1,230	1,036	1,163	1,089	815
Texas	1,298	853	853	809	791	791	710
Utah	1,813	1,378	1,378	1,359	1,322	1,322	1,288
Virginia	1,297	884	884	846	810	810	750
Washington	763	264	264	54	215	215	27
West Virginia	2,019	1,748	1,649	1,631	1,620	1,449	1,401
Wisconsin	1,827	1,281	1,281	1,222	1,203	1,203	1,103
Wyoming	2,115	1,808	1,702	1,657	1,714	1,521	1,455
U.S.	1,497	1,068	1,052	1,004	990	955	872

Under the NODA Pro Rata Approach state targets, we found that 2020 CO_2 emissions decline to 1,748 million short tons, or 34 percent below 2005 and 22 percent below 2012 emissions levels. The 2020 compliance costs for this scenario total $5.5 billion. In 2030, emissions in the NODA Pro Rata case decline to 1,592 million short tons, a reduction of 40 percent from 2005 levels and 29 percent from 2012 levels. Compliance costs in this scenario total $7.3 billion in 2030. In the NODA Pro Rata + Min Gen Conversion case (which assumes that new fossil generation is eligible for compliance), emissions total 1,759 million short tons, or 34 percent below 2005 and 21 percent below 2012, with compliance costs of $4.0 billion. The NODA Pro Rata + Min Gen Conversion case achieves a similar level of emissions reductions in 2030, with a compliance cost of $7.1 billion. These outcomes suggests that EPA could achieve 10 percent more emission reductions with 17 percent less in costs than set forth in the proposed standards.

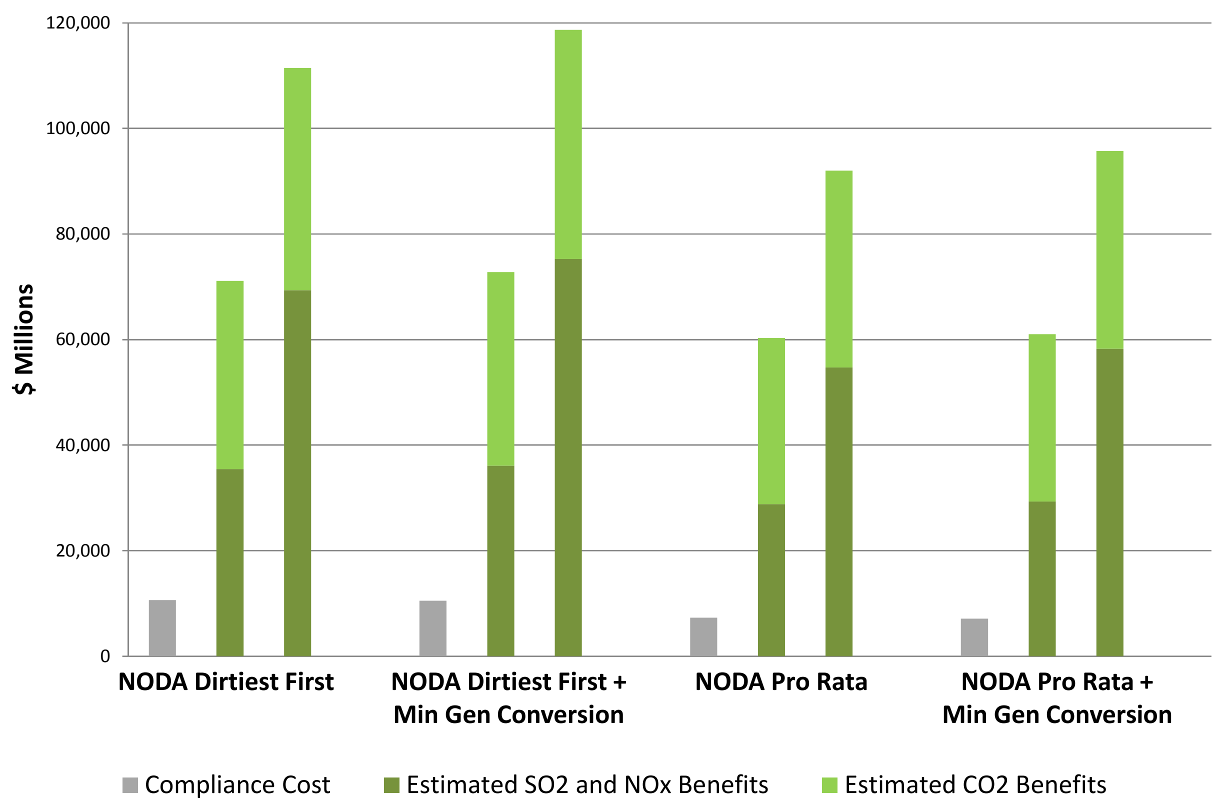
The values of the benefits in the NODA Pro Rata cases far outweigh the costs of compliance. The total benefits of the emission reductions, including reductions of SO_2 and CO_2, range between $61 billion and $96 billion, exceeding the costs of compliance by nearly nine times. The net benefits are valued between $54 and $89 billion in 2030. Figure 8.1 below compares the costs and benefits across the four NODA cases we analyze here.

The NODA Pro Rata cases we have analyzed here, in addition to the NODA Dirtiest First cases, illustrate compliance scenarios that achieve emission reductions reflecting significantly greater ambition than what EPA proposed. Still, compliance costs remain within the range of EPA's proposed estimates. Taken together, the four NODA cases we have analyzed support the recommendations we have made to strengthen the proposed standards in our technical comments. Note that these modeling runs only represent a portion of the opportunity for strengthening we have identified in in our comments and do not include stronger assumptions related to the quantity of energy efficiency and renewable energy.

8.6 Comparison of Results Across Scenarios

In the tables and figures throughout this section, we compare results for the four NODA cases discussed in section 8.5.

Figure 8.1: Compliance Costs and Net Benefits in 2030



NOTES

- Benefits from SO_2 and NO_x reductions are derived using the regional Benefits-per-ton estimates published in EPA's Regulatory Impact Analysis for the pollutant SO2 at a 3% discount rate.

- Lower carbon reduction benefit calculated with Social Cost of Carbon (SCC) of $43 (2012$) per short ton in 2020, reflecting the Administration's 3% discount rate case.

- Higher carbon benefit calculated with independently calculated SCC of $62 (2012$) per short ton in 2010, reflecting a 2% discount rate case.[4]

Figure 8.2. Historical and Projected Electricity Sector CO_2 Emissions

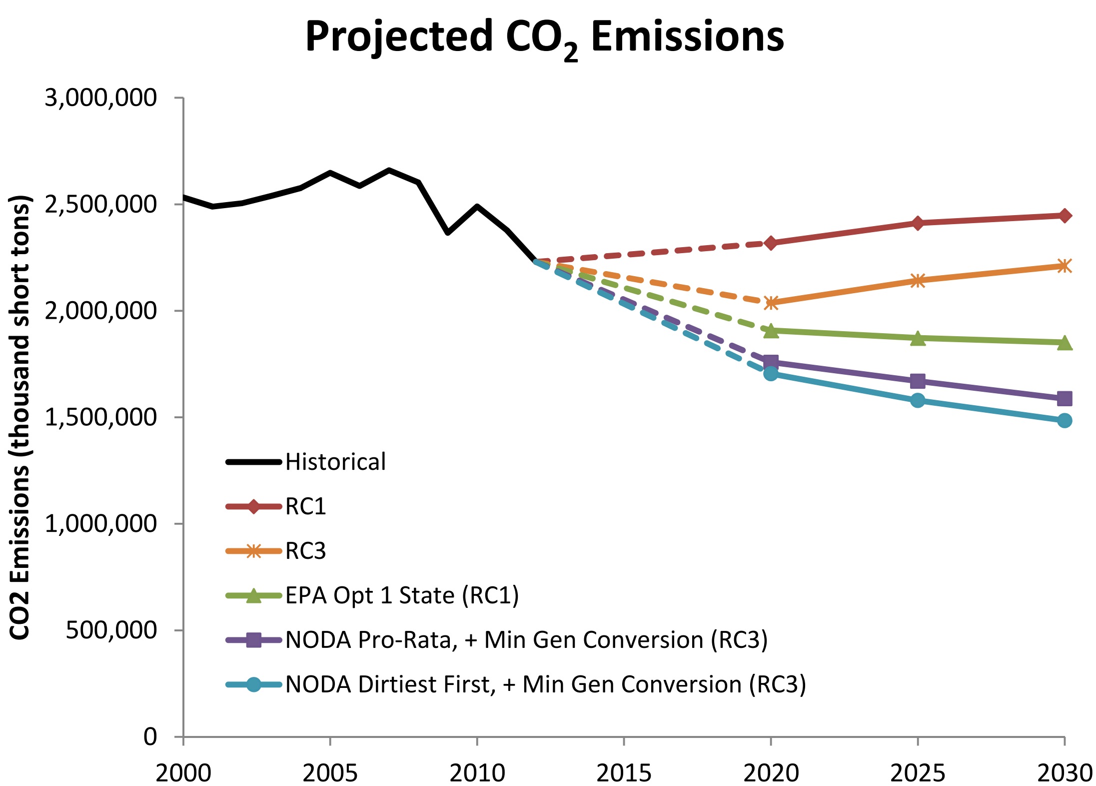


Table 8.5: Projected CO_2 Emissions

[4] The value of reducing carbon pollution is calculated in accordance with the Administrations' Social Cost of Carbon (SCC) of $43 (2012$) per short ton in 2020, reflecting the 3% discount rate case. For more details on the Administration's SCC, see the Interagency Working Group on Social Costs of Carbon's Technical Support Document, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013) *available at* http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf. The $62 (2012$) per short ton SCC is based on an independent estimate using the 2% discount rate case. See L. Johnson and C. Hope, The Social Cost of Carbon in U.S. Regulatory Impact Analyses: an Introduction and Critique," Vol 2. Issue 3, *Journal of Environmental Studies and Sciences,* 205 (Sept. 2012) *available at* http://link.springer.com/article/10.1007%2Fs13412-012-0087-7.

CO_2 Emissions (thousand short tons)					
Scenario	2005	2012	2020	2025	2030
Historical	2,647,835	2,229,622			
NRDC Reference Case 3			2,037,266	2,141,577	2,211,134
NODA Dirtiest First			1,692,837	1,581,877	1,495,354
NODA Dirtiest First, + Min Gen Conversion			1,704,524	1,579,002	1,484,894
NODA Pro Rata			1,748,285	1,660,326	1,591,852
NODA Pro Rata, + Min Gen Conversion			1,758,458	1,669,879	1,587,427

Table 8.6: Projected CO_2 Emissions, Relative to 2005 and 2012

CO_2 Emissions						
	% from 2005			% from 2012		
Scenario	2020	2025	2030	2020	2025	2030
NRDC Reference Case 3	-23%	-19%	-16%	-9%	-4%	-1%
NODA Dirtiest First	-36%	-40%	-44%	-24%	-29%	-33%
NODA Dirtiest First, + Min Gen Conversion	-36%	-40%	-44%	-24%	-29%	-33%
NODA Pro Rata	-34%	-37%	-40%	-22%	-26%	-29%
NODA Pro Rata, + Min Gen Conversion	-34%	-37%	-40%	-21%	-25%	-29%

Table 8.7: Projected SO_2 Emissions

SO_2 Emissions (thousand short tons)						
				Relative to BAU*		
Scenario	2020	2025	2030	2020	2025	2030
NRDC Reference Case 3	1,758	1,879	1,810	0%	0%	0%
NODA Dirtiest First	1,198	1,086	1,033	-32%	-42%	-43%
NODA Dirtiest First, + Min Gen Conversion	1,188	1,066	1,019	-32%	-43%	-44%
NODA Pro Rata	1,271	1,197	1,171	-28%	-36%	-35%
NODA Pro Rata, + Min Gen Conversion	1,280	1,200	1,160	-27%	-36%	-36%

Table 8.8: Projected NO_x Emissions

NO_x Emissions (thousand short tons)						
				Relative to BAU*		
Scenario	2020	2025	2030	2020	2025	2030
NRDC Reference Case 3	1,255	1,318	1,344	0%	0%	0%
NODA Dirtiest First	1,057	1,001	960	-16%	-24%	-29%
NODA Dirtiest First, + Min Gen Conversion	1,013	950	910	-19%	-28%	-32%
NODA Pro Rata	1,074	1,038	1,001	-14%	-21%	-26%
NODA Pro Rata, + Min Gen Conversion	1,040	997	971	-17%	-24%	-28%

Table 8.9: Projected Incremental Costs of Compliance

Total System Costs (Million 2011$)			
Scenario	2020	2025	2030
NRDC Reference Case 3	0	0	0
NODA Dirtiest First	7,508	4,202	10,424
NODA Dirtiest First, + Min Gen Conversion	6,376	4,212	10,305
NODA Pro Rata	5,418	2,682	7,160
NODA Pro Rata, + Min Gen Conversion	3,936	1,535	7,003

Table 8.10: Projected Wholesale Power Prices

Wholesale Power Price (% from BAU)			
Scenario	2020	2025	2030
NRDC Reference Case 3	0%	0%	0%
NODA Dirtiest First	17%	3%	6%
NODA Dirtiest First, + Min Gen Conversion	13%	2%	6%
NODA Pro Rata	15%	2%	1%
NODA Pro Rata, + Min Gen Conversion	10%	-1%	1%

Table 8.11: Projected Natural Gas Consumption

Natural Gas Consumption (trillion Btu)					
Scenario	2005	2012	2020	2025	2030
Historical	6,015	9,287			
NRDC Reference Case 3			7,374	7,429	8,429
NODA Dirtiest First			9,014	8,909	8,318
NODA Dirtiest First, + Min Gen Conversion			8,821	8,754	8,239
NODA Pro Rata			8,692	8,389	7,757
NODA Pro Rata, + Min Gen Conversion			8,459	8,211	7,695

Table 8.12: Projected Henry Hub Natural Gas Prices

Henry Hub Gas Price ($/MMBTU)			
Scenario	2020	2025	2030
NRDC Reference Case 3	4.6	5.4	5.6
NODA Dirtiest First	5.3	5.5	6.0
NODA Dirtiest First, + Min Gen Conversion	5.2	5.5	6.0
NODA Pro Rata	5.2	5.5	5.8
NODA Pro Rata, + Min Gen Conversion	5.1	5.4	5.8

Figure 8.3.a. EPA Base Case, 2030

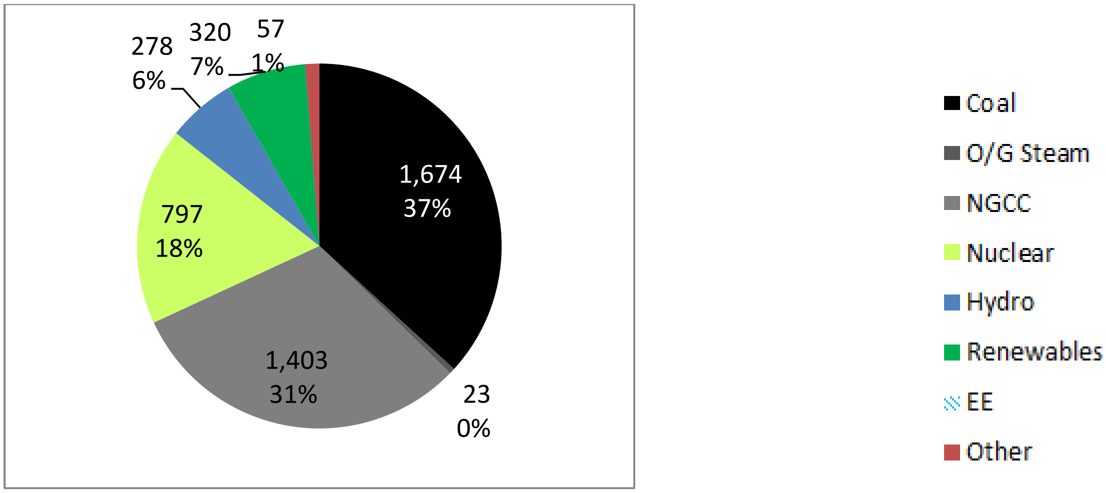


Figure 8.3.b. EPA Option 1 State, 2030

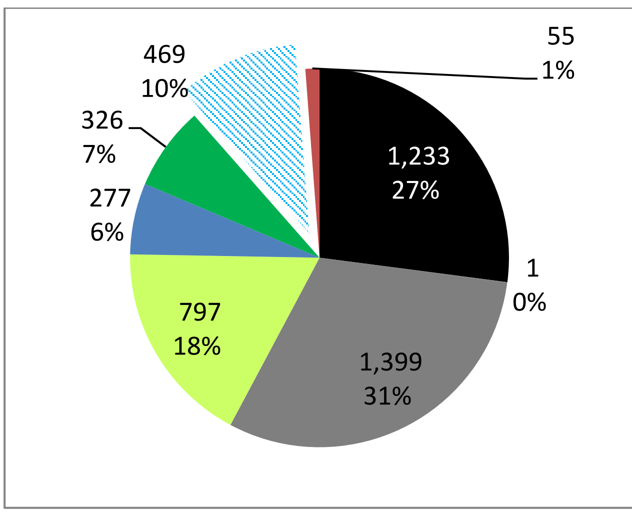


Figure 8.3.c. Updated Costs & Performance Opt 1 State, 2030

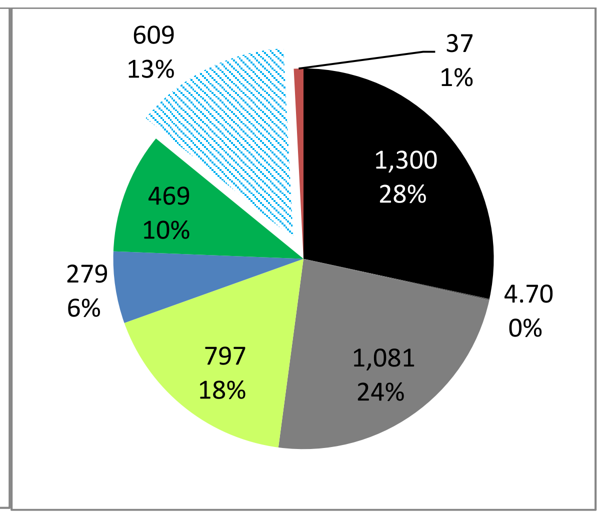


Figure 8.3.d. Reference Case 3, 2030

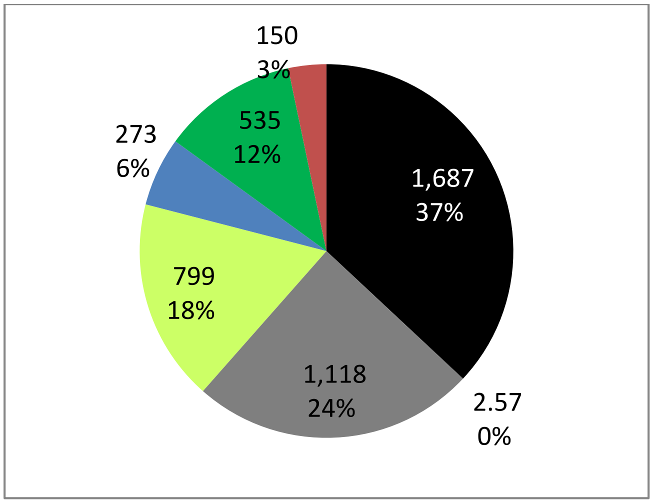


Figure 8.3.e. NODA Dirtiest-First + Min Gen Conversion, 2030

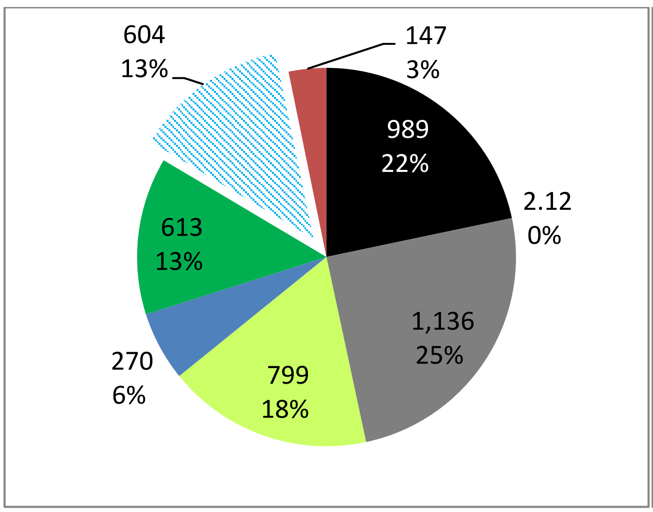


Figure 8.3.f. NODA Pro Rata + Min Gen Conversion, 2030

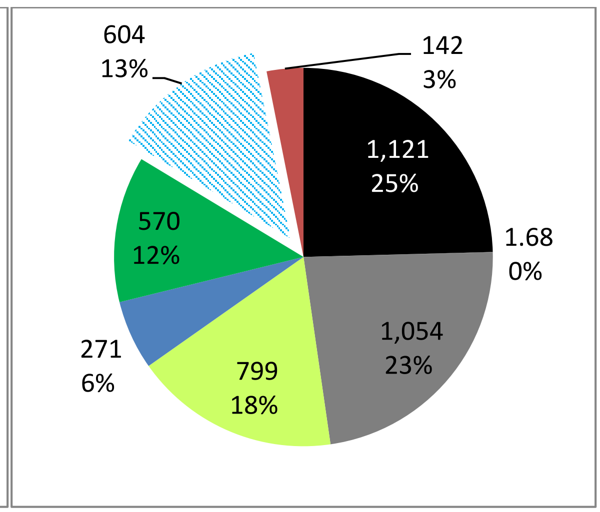


Table 8.13: Projected 2020 Generation Mix

2020 Generation Mix (TWh)							
	2005	2012	NRDC RC3	NODA Dirtiest First	NODA Dirtiest First, + Min Gen Conversion	NODA Pro Rata	NODA Pro Rata, + Min Gen Conversion
Coal Generation	2,013	1,514	1,578	1,147	1,172	1,222	1,249
NGCC Generation	568	1,015	983	1,229	1,213	1,163	1,151
Gas CT Generation	82	97	44	48	44	51	45
Generation - Oil/Gas Steam	122	23	2	3	2	3	2
Nuclear Generation	782	769	817	817	817	817	817
Generation - Hydro	270	276	270	272	272	271	270
Biomass Generation	30	58	39	42	41	42	40
Generation - All Renewables	33	161	458	508	508	497	491
Energy Efficiency Generation*	n/a	n/a	0	118	118	118	118
Generation - Other	129	270	40	45	45	45	44
Total Generation	4,029	4,183	4,232	4,230	4,231	4,229	4,228

*

Table 8.14: Projected 2025 Generation Mix

2025 Generation Mix (TWh)							
	2005	2012	NRDC RC3	NODA Dirtiest First	NODA Dirtiest First, + Min Gen Conversion	NODA Pro Rata	NODA Pro Rata, + Min Gen Conversion
Coal Generation	2,013	1,514	1,675	1,044	1,054	1,154	1,176
NGCC Generation	568	1,015	983	1,219	1,202	1,129	1,122
Gas CT Generation	82	97	50	51	50	50	45
Generation - Oil/Gas Steam	122	23	4	3	2	3	2
Nuclear Generation	782	769	822	822	822	822	822
Generation - Hydro	270	276	271	271	271	270	269
Biomass Generation	30	58	42	47	44	46	44
Generation - All Renewables	33	161	522	570	587	558	554
Energy Efficiency Generation*	n/a	n/a	0	333	333	333	333
Generation - Other	129	270	44	51	48	46	46
Total Generation	4,029	4,183	4,412	4,410	4,413	4,409	4,411

Table 8.15: Projected 2030 Generation Mix

2030 Generation Mix (TWh)							
	2005	2012	NRDC RC3	NODA Dirtiest First	NODA Dirtiest First, + Min Gen Conversion	NODA Pro Rata	NODA Pro Rata, + Min Gen Conversion
Coal Generation	2,013	1,514	1,687	994	989	1,121	1,121
NGCC Generation	568	1,015	1,118	1,141	1,136	1,047	1,054
Gas CT Generation	82	97	62	54	51	52	47
Generation - Oil/Gas Steam	122	23	3	3	2	3	2
Nuclear Generation	782	769	799	799	799	799	799
Generation - Hydro	270	276	273	271	270	272	271
Biomass Generation	30	58	44	48	45	47	45
Generation - All Renewables	33	161	535	595	613	574	570
Energy Efficiency Generation*	n/a	n/a	0	604	604	604	604
Generation - Other	129	270	44	52	51	51	50
Total Generation	4,029	4,183	4,564	4,562	4,560	4,570	4,562

8.7 Emissions Leakage

One matter that has been discussed among stakeholders in connection with the June 2014 proposal is the erosion of emission reductions ("emissions leakage" or simply, "leakage") under specific circumstances including: shifting levels of electricity imports and exports between states, mixing rate-based and mass-based policy designs, and inconsistent accounting of emissions from new fossil units. We have examined the dynamics of mixing rate-based and mass-based designs in our analysis and have found that emissions leakage can occur. The effects in our evaluation are significant but are constrained by economic and transmission factors. See Section 9 for a discussion of minimum state plan requirements to address leakage.

To examine the potential for emissions leakage, we analyzed two scenarios based on NRDC's Reference Case (RC3). In the first ("Mass Equivalents Case"), all states were assumed to adopt a mass-based program, reflecting the mass-based equivalents in the November 2014 Technical Support Document, "Translation of the Clean Power Plan Emission Rate-Based CO_2 Goals to Mass-Based Equivalents." In the second ("Leakage Case"), all states were assumed to adopt mass-based programs, except for Pennsylvania and New Mexico. Pennsylvania and New Mexico were assumed to adopt the proposed June 2014 rate-based state targets. These two states were selected for this study because they may represent pronounced opportunities for leakage in their respective interconnected grid systems. The rate-based targets in Pennsylvania and New Mexico exceed the emissions rate of new natural gas combined cycle units, and they are located in proximity to states participating in cap-and-trade programs like the Regional Greenhouse Gas Initiative (RGGI) and California's AB32, respectively. The combination of these effects mean that each state could choose to build significant amounts of new NGCC units and export some of this generation to neighboring states, while still complying with its own rate target.

In this analysis, we observed dynamics reflecting emissions leakage in Pennsylvania prior to the 2030 final compliance date. As noted above, Pennsylvania's rate-based state target is greater than the emission rate for new natural gas combined cycle units. The analysis showed 4.20 GW of new natural capacity added by 2020 in Pennsylvania, increasing to 5.25 GW added by 2030 in the Leakage Case compared with no new capacity added throughout the analysis period in the Mass Equivalents Case. In neighboring Ohio, we observed that net imports from Pennsylvania increased. This reduces the need for new low-emitting generation, and Ohio's wind capacity additions decline by approximately 41 MW (or 22 percent) in the Leakage Case compared with the Mass Equivalents Case. Led by the growth in natural gas generation from newly built gas units, emissions in Pennsylvania total 118 million short tons in 2020 in the Leakage Case, compared to 104 million short tons in Mass Equivalents Case; in 2030, however, this trend reverses with Pennsylvania emissions totaling 86 million short tons in the Leakage Case compared with 89 million tons in the Mass Equivalents Case. This is the result of increasing energy efficiency savings in neighboring states. For example, as Ohio develops its portfolio of energy efficiency programs in the Leakage Case, it depends less on electricity imports. Pennsylvania then ramps down its coal generation, resulting in a significant decline in total emissions in 2030. Total emissions in neighboring states, including Ohio, West Virginia, New York and New Jersey, do not show variability between the two cases, indicating that the increase in Pennsylvania's emissions does not result in emissions reductions elsewhere and therefore constitutes emissions leakage of 13 to 14 percent in the period from 2020-2025.

Table 8.16: Comparison of IPM Projections in Pennsylvania

Leakage: Pennsylvania Case Study			
	2020	2025	2030
	CO_2 Emissions (thousand short tons)		
Mass Equivalents	104,256	96,845	89,182
Leakage	117,681	110,988	86,173
	New NGCC Builds (GW)		
Mass Equivalents	0.0	0.0	0.0
Leakage	4.2	1.1	0.0
	NGCC Generation (TWh)		
Mass Equivalents	43	36	24
Leakage	75	92	85
	Total Generation (TWh)		
Mass Equivalents	226	219	208
Leakage	259	267	241

In New Mexico, we observed minimal emissions leakage. The Leakage Case showed no change in natural gas capacity from the Mass Equivalents Case in 2020, and an increase in natural gas capacity of 0.11 GW (or 11 percent) in 2025. By 2030, there were 1.31 GW of new natural gas capacity in both the Leakage Case and in the Mass Equivalents Case. New natural gas generation trends in New Mexico between the two scenarios are similar, as shown in the table below. Total emissions in New Mexico follow a similar pattern between the two cases. In this analysis, 2025 is the only reported model year in which emissions leakage is projected to occur in New Mexico. Total emissions in New Mexico in 2025 are 27.3 million short tons in the Leakage Case, compared with 27.1 million short tons in the Mass Equivalents Case, or a leakage rate of 0.7 percent.

Table 8.17: Comparison of IPM Projections in New Mexico

Leakage: New Mexico Case Study			
	2020	2025	2030
	CO_2 Emissions (thousand short tons)		
Mass Equivalents	24,996	27,078	27,390
Leakage	24,866	27,258	27,303
	New NGCC Builds (GW)		
Mass Equivalents	0.0	1.0	0.3
Leakage	0.0	1.1	0.2
	NGCC Generation (TWh)		
Mass Equivalents	10	16	17
Leakage	10	17	17
	Total Generation (TWh)		
Mass Equivalents	41	51	53
Leakage	41	51	53

Based on these observations, we conclude the potential for emissions leakage is significant and must be addressed by EPA and states in their plans. The potential for leakage may be sensitive to natural gas price differentials and transmission capacity between rate-based and mass-based states. See Section 9 for a discussion of minimum state plan requirements to address leakage.

8.8 Alternative Renewables Approach Runs

In its Alternative Approach to setting renewable energy targets under Building Block 3, EPA used IPM to determine the technically and economically achievable amount of renewable energy available to states. NRDC recommends that EPA adopt and strengthen this approach, and has conducted similar analysis using the updated cost and performance assumptions for renewable energy outlined above. Through this analysis, NRDC has demonstrated that there is nearly double the amount of renewable energy available for cost-effective emissions reductions than originally estimated by EPA. For more on this approach and the results of this modeling, see Section 6 of our comments.

We also include with our submission the results of the Integrated Planning Model runs detailed above in Microsoft Excel format.

9.0 State Goals, Plans and Policy Approaches

9.1 Strong interim targets, 5 year compliance periods, and program review.

Immediate carbon emission reductions are needed to address the impacts of climate change. EPA has proposed a ten-year averaging period between 2020 and 2029 for states to achieve the interim emission rate target. However, to ensure that states are making appropriate progress towards the interim target, EPA should instead provide two five-year interim compliance periods. Strong interim targets are essential to deliver near-term reductions in carbon pollution and to transition the power sector towards lower-polluting infrastructure, deploying investments in renewable energy and energy efficiency that will create jobs and increase economic activity. EPA itself noted that "certain emission reduction measures and programs … are generally easier to implement in the near term."[1] These two five-year periods will improve transparency by creating verifiable and enforceable short-term targets, while encouraging states and power companies to focus on those efficiency, renewable energy, and other clean-energy advancements which are immediately achievable.

In addition, EPA should commit to reevaluate the "best system of emission reduction" (BSER) over time, and the interim five-year compliance period would provide an ideal point for reevaluation. Reexamining the BSER at the mid-way point of the compliance period would ensure that it continues to reflect the system that can maximize reductions in carbon pollution considering cost, energy requirements, and impacts on other health and environmental outcomes, as required by the Clean Air Act.

EPA should commit to the first reevaluation of state targets by June 2020, (a) to review the targets for 2025 and 2030 and revising them as appropriate to reflect up-to-date data on the technological and economic reduce power sector CO2 emissions, and (b) to set appropriate targets for the five-year period beginning in 2035. By June 2025, EPA should complete a second review and revision cycle, reviewing the targets for 2030 and 3035 and setting targets for 2040, and so forth.

9.2 Portfolio approach and state commitments.

As noted in Section 2 of these comments, section 111(d)(1) provides that states shall submit "plan[s] which . . . establish standards of performance for any existing source" and "provide[] for the implementation and enforcement of such standards of performance."[2] EPA has observed that one acceptable form of state plans is one that establishes emission rate

[1] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, 34,906 (proposed June 18, 2014) (to be codified at 40 C.F.R. pt. 60).
[2] 42 U.S.C. § 7411(d)(1).

standards for each fossil-fueled EGU together with emission credit trading provisions, and that another acceptable form is a plan that establishes a mass-based limit and tradable emissions allowances. In addition, EPA requests comment on "the extent to which measures such as RE and demand-side EE may be considered implementing measures in state plans if they are not directly tied to emission reductions that affected sources are required to make through emission limits, and if they are requirements on entities other than the affected sources."[3]

NRDC believes that state plans may include "implementation" measures that do not directly reduce emissions from affected sources, as well as measures that regulate entities other than affected EGUs. But NRDC believes that any plan adopting these "portfolio" measures must also include federally enforceable emission limitations like those described in the previous paragraph, which require affected EGUs to demonstrate compliance with the relevant standards of performance in the event that the portfolio measures fail to deliver the required emission reductions. EPA may approve a state plan that includes portfolio measures, however, only if the plan also "provides for the … enforcement of [the] standards of performance" established for the affected sources.[4] Thus, even if a state intends to rely on portfolio measures to deliver the emission reductions required by its state target, its section 111(d) plan must provide for federal enforcement of the relevant standards of performance in the event that the portfolio measures fail to deliver the required emission reductions. The backstop would need to be designed to secure from affected EGUs any "missing" emission reductions from portfolio measures that fall short of their goals. The necessary provisions could take the form of a requirement that regulated EGUs make sufficient reductions or secure sufficient credits from redispatch, renewable energy generation, and energy efficiency activities to make up the shortfall within the same compliance year. The obligation to make up the shortfall could be allocated among sources in any manner acceptable to the state. The backstop would be included in the operating permits of the regulated entities, and would be federally enforceable by EPA under section 113 of the Clean Air Act, and by citizens under section 304 of the Act.[5]

9.3 Crediting biomass-burning EGUs.

EPA's proposed treatment of biomass with respect to CPP compliance is unclear and problematic. In the preamble to the proposed rule, the Agency states that it expects that "states likely will consider biomass-derived fuels in energy production as a way to mitigate the CO_2 emissions attributed to the energy sector and include them as part of their plans to meet

[3] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. at 34,903..
[4] 42 U.S.C. § 7411(d)(1)(B).
[5] See Section 2.2, *supra*.

the emission reduction requirements of this rule."[6] In the preamble to the June 2014 proposal, EPA committed to providing states with "a clear path" for "meet[ing] the emission reduction requirements of this rule" through the use of biomass.[7]

As noted in Section 6.1.2.7 of these comments, on November 19, EPA released a revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources*[8] ("Framework") and a memorandum from Acting Assistant Administrator Janet McCabe that accompanied the revised Framework (the "McCabe Memo").[9] Unfortunately, these offer little in the way of specific direction and what direction they do provide is illegal and ill-advised.

Two key features of the McCabe Memo are:

- A finding that the "use of waste-derived feedstocks and certain forest-derived industrial byproducts are likely to have minimal or no net atmospheric contributions of biogenic CO2 emissions, or even reduce such impacts, when compared with an alternate fate of disposal." Based on this finding, EPA "expects to recognize the biogenic CO2 emissions and climate policy benefits of waste-derived and certain forest-derived industrial byproducts based on the conclusions supported by a variety of technical studies, including the revised Framework" when implementing the Clean Power Plan ("CPP").[10]

- A statement that EPA also "expects that states' reliance specifically on sustainably-derived agricultural- and forest-derived feedstocks may also be an approvable element of their [CPP] compliance plans."[11]

The term "sustainable land management" covers an enormous variety of practices, as do the terms "sustainable forestry" and "sustainable agriculture." The McCabe Memo does not define these terms.

It would be arbitrary to approve a class of biomass fuel simply based on a generic claim of "sustainability." In addition to being an ambiguous standard, sustainability is not a measure of carbon impacts, however defined, nor is the term even mentioned in the EPA's revised framework. Even if fully specified to include considerations of forest growth and removals,

[6] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. at 34,924.
[7] *Id*.
[8] EPA, *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* (November 19, 2014) ("Revised Framework").
[9] Janet G. McCabe, Acting Assistant Administrator, EPA Office of Air and Radiation, "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" (November 19, 2014) ("McCabe Memo") at 2.
[10] Janet G. McCabe, Acting Assistant Administrator, EPA Office of Air and Radiation, "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" (November 19, 2014) ("McCabe Memo") at 2.
[11] *Id*.

sustainability criteria will fail to fully account for changes in carbon emissions, and cannot be justified as a proxy for carbon accounting. The fact that a regulated EGU burns only "sustainably-derived feedstocks" says very little, if anything, about the amount of biogenic CO2 emitted by the source or the net effect of those emissions on climate change.

Moreover, a robust definition of "sustainable" does not address the fact that there are very limited amounts of biomass. One needs only look at the growing loss of biodiversity and the loss of critical and imperiled forest types to know that even if EPA were to mistakenly substitute sustainability for carbon accounting, there would be a very limited supply of truly sustainable biomass.

Finally, the EPA proposal to judge sustainably-derived feedstocks in parallel with further work on the framework runs the risk of pre-empting the agency's technical review process by prematurely generating exemptions for broad categories of fuel types.

In sum, EPA's plan to effectively exempt from CPP scrutiny those emissions that occur when EGUs combust "sustainably-derived feedstocks" could result in a net increase of CO2 emissions for decades. Consequently, EPA cannot meet its obligations under CAA §111(d) by solely requiring affected sources to show that they rely on "sustainably-derived feedstocks." EPA should retract the McCabe memo and propose a scientifically and legally-sound methodology to measure the carbon from biomass burned at EGU as part of state compliance plans.

Oddly, in the context of compliance with the CPP, the McCabe memo makes only the glancing reference to the Framework quoted above. The Framework at least begins to provide a scientifically and legally sound approach to accounting and crediting carbon emissions from biomass-burning EGUs. Unfortunately, in most instances, the revised Framework catalogs the various options for analyzing biogenic emissions according to a set of relevant criteria but fails to signal a preference for one approach or another. Moreover, it is unclear how—or even if—the revised Framework will be of relevance to the ESPS, given that EPA "has not yet determined how the framework might be applied in any particular regulatory or policy contexts."[12]

If EPA chooses correctly among the options it catalogs in the revised Framework—*i.e.*, if the Agency requires states to account for biogenic emissions using anticipated future baselines, a compact (and policy-relevant) timescale for analysis, spatial scales that facilitate meaningful distinctions between biomass types, and mechanisms that address leakage—the resulting emissions modeling could reasonably simulate the effect that biogenic emissions will have on the atmosphere during the policy-relevant timeframe. But if EPA makes incorrect choices with

[12] Janet G. McCabe, Acting Assistant Administrator, EPA Office of Air and Radiation, "Addressing Biogenic Carbon Dioxide Emissions from Stationary Sources" (November 19, 2014) ("McCabe Memo") at 2.

respect to these analytic criteria (or allows states to make incorrect choices), the analyses that result will be inaccurate and highly misleading. For example, if EPA allows states to analyze biogenic emissions over a protracted timeframe—such as 50 years, which the Agency contemplates in Appendix B to the revised Framework[13]—affected sources would be free to burn biomass feedstocks that will produce significantly higher GHG emissions over the next several decades, including over the time period covered by the ESPS.

EPA should continue to develop a scientifically- and legally-valid framework for assessing biogenic CO2 emissions from EGUs under the ESPS program.

Specifically, the Agency should develop biogenic accounting factors (BAFs) that:

- Rely on an anticipated future baseline to model changes in stored carbon. Regulators must compare emissions from increased biomass harvesting added to a "business as usual" baseline to a scenario absent increased biomass demand for bioenergy. This approach will help ensure biomass carbon accounting results reflect what the atmosphere "sees" in terms of emissions from increased biomass harvesting.

- Utilize compact timeframes when analyzing the net emissions associated with the use of biomass. An analytic horizon of 10-20 years would align biogenic emissions accounting under the ESPS with other regulatory efforts designed to avoid the worst consequences of climate change; it would reduce modeling uncertainty, which can increase dramatically over longer time horizons; and it would model BAFs on approximately the same timeframe as industry planning horizons for long term-contracts and operations.

- Calculate biogenic emissions and reductions consistently, regardless of the spatial scale or region in which they occur. BAFs should be modeled in a way that is independent of the physical fuelshed area. Instead, data to inform BAFs—on fuel type, size class for woody biomass feedstocks, land use history, current harvest regime and alternate biomass uses in existing wood products markets—should be collected at the appropriate scale for each class of data.

- Address leakage by incorporating the following counterbalancing assumptions into the BAF analysis: first, that new biomass harvest displaces demand associated with other industries on a full 1-to-1 basis to a new, similar forest stand; second, that leakage is additive and "new" standing trees are cut in forests that are biologically and climatically identical to the original wood source to meet the original non-biomass needs.

---

[13] U.S. EPA, Office of Air and Radiation, Framework for Assessing Biogenic CO2 Emissions from Stationary Sources, Appendix B: Temporal Scale (November 2014)

- Categorize biomass feedstocks according to key physical and methodological characteristics. This process includes differentiating between different fuel types (e.g., boles versus branches/limbs), different size classes (e.g., large diameter versus small diameter), different land use histories (e.g., planted versus naturally regenerating); different harvest regimes (e.g., complete removal versus partial cuts); and different alternative fates (e.g., short-term uses versus long-term structural objects for merchantable and in situ burning versus decay for harvest residues).

- Use simple, precautionary assumptions that reduce the risk of undercounting emissions and ensure modeling uncertainties are resolved conservatively.

Most important, the agency must place the burden of proof on the states and the regulated entities to demonstrate that their claims and assumptions underlying the model are in fact true and accurate. Given the host of uncertainties underlying the modeling and the undue discretion afforded to the states in the revised Framework, the agency must set strict standards for documentation and verification of feedstock use, land use practices, regional scales, markets, and "leakage."

9.4 Net generation should be used for state goals and emission reporting requirements.

NRDC 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.[14] 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."[15] Using net generation as the basis for rate-based standards appropriately rewards efforts to increase the *useful* output of the power plants while avoiding increases in fuel consumption and emissions. In contrast, a rate-based standard based on gross generation would ignore differences in the efficiency of auxiliary equipment and pollution control systems among EGUs, and thus fail to fully incentivize the efficient generation of electricity. In addition, using net generation to set state goals is feasible, as EGUs already collect the necessary data[16] and report net generation data to the Energy Information Administration.[17]

---

[14] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. at 34,894 .

[15] Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 1430, 1448 (proposed January 8, 2014).

[16] *See* Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. at 34,894.

[17] *See* EIA, Form EIA-923: Power Plant Operations Report Instructions, OMB No. 1905-0129 (Exp. Dec. 31, 2015), at 14.

9.5 Rate to mass conversion.

In the proposed rule, EPA established a rate-based emission target, under which state goals are measured in pounds of CO_2 per megawatt-hour of electricity generated. EPA's Supplemental Notice proposed potential approaches for translating the emission rate-based goals to an equivalent mass-based metric.[18]

NRDC agrees that states should have the option of taking a mass-based approach to compliance. NRDC 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, if it is required for the conversion, EPA must define a uniform electricity demand growth projection that can be used in a rate-to-mass conversion (see discussion below). NRDC recommends that the Energy Information Agency (EIA) projections are the maximum demand growth that can be included.

In its rate-to-mass conversion Notice, EPA provides two options for conversion of a emission rate-based goal to a mass-based form.[19] The two approaches include one that provides "mass-based equivalent metrics that apply to existing affected EGUs only."[20] 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 9.8, similar leakage 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"[21] – 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 second 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

[18] Notice: Additional Information Regarding the Translation of Emission Rate-Based CO2 Goals to Mass-Based Equivalents. 79 Fed. Reg. 67,406 (November 13, 2014).
[19] *Id*. at 67,408.
[20] *Id*. (emphasis added).
[21] Notice: Additional Information Regarding the Translation of Emission Rate-Based CO2 Goals to Mass-Based Equivalents. 79 Fed. Reg. at 67,408 (emphasis added).

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.[22]

NRDC commissioned analysis from M.J. Bradley and Associates of past electricity demand and energy forecasts from a range of planning entities, including EIA, the California Energy Commission (CEC) and some of the ISO/RTOs. This analysis is presented in Appendix 9A. They summarize their findings as:

- Generally speaking, EIA, CEC and RTO's all consistently overestimate both demand and consumption, although estimates tend to get more accurate the closer the estimate is made to the target year.

- Forecasts made before 2009 tend to be several more percentage points off than later-year estimates, likely because they do not account for the economic downturn.

- For all RTOs/ISOs, both peak demand and annual consumption dropped markedly from 2008-2009.

- Forecasts for demand four years prior range from an overestimate of 14 percent to an underestimate of 1 percent; forecasts one year prior range from an overestimate of 11 percent to an underestimate of 6 percent.

- Forecasts four years prior overestimate annual consumption by 2 percent to 10 percent; forecasts one year prior range from an overestimate of 8 percent to an underestimate of 2 percent.

There are many reasons for utilities and system planners to overestimate energy growth. NRDC believes two primary drivers are: 1) a desire to ensure peak demand and energy use are easily accommodated (reliability) and 2) the opportunity to use demand and energy forecasts to justify new generation, transmission and distribution investments that increase a utility's rate base and increase earnings for shareholders.

---

[22] 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.

Regardless of the driver for chronic estimation of energy demand and consumption, this analysis shows that the use of energy forecasts in setting a mass-based target is extremely likely to increase the estimate of emissions in the future and lead EPA to establish a target that is inflated and easier to achieve than anticipated by EPA and their modelers.

EPA must adopt a consistent and unbiased demand growth projection, and NRDC suggests that EPA use current EIA projections. EPA should describe this forecast as conservative and not allow states and companies to develop alternative forecasts, which would provide significant opportunity for gaming and which EPA should assume are inflated in their current form.

In sum, NRDC supports the EPA's continued flexibility in the state emission reduction planning process under section 111(d). But EPA must clearly define the method for converting rate-based targets and requirements for existing source-only mass-based caps in order to ensure that equivalent emission reductions will be achieved.

9.6 State and regional plan policy options and criteria.

While we support EPA providing states with significant flexibility in the development of state plans, there is a clear need to provide guidance to states to help them through the planning process and also to describe 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 highly desired – but there are four categories of policies for which EPA should consider providing guidance on and must develop minimum criteria.

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 9.1, 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 stakeholder discussion of how the different approaches could work regionally and how interstate problems could develop if different policy approaches exist 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[23] 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 essential for EPA to proactively consider and address these issues. See also our comments in Section 9.8 on leakage.

The following are minimum criteria by policy type EPA should refine and include as further guidance on state plans is developed. We are suggesting this as additional criteria by policy approach, in addition to 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. Standard 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 to 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

[23] 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.

emissions reduction; however, 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. Standard 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 (with adjustment periods not to exceed 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), as previously discussed).

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. Standard 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; however, 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)), as previously discussed.

Table 9.1: 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 – however, all fossil ensures a level playing field among generators)	Fossil power plants (could be all fossil or just existing – however, all fossil ensures a level playing field among generators)	Fossil power plants (could be all fossil or just existing – however, all fossil ensures a level playing field among generators)	Load serving entity (those that deliver energy to customers, not necessarily the generator owners)
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.

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; an emissions credit (tons) is quite different from an emissions allowance (tons) and they are not necessarily tradable.	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; an emissions allowance (tons) is quite different from an emissions credit (tons) and they are not necessarily tradable.	The environmental agency estimates the carbon price needed to achieve the emissions goal and then they 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 receive additional revenue and become more competitive in comparison to high emitting resources; certificates could be banked (held) for future compliance periods. Energy efficiency is generally developed and tracked under the supervision of the public utility commission.

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 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 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 receive more revenue and increase their competitiveness in the market; 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 receive more revenue and increase their competitiveness in the market; 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.
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.			

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
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 (note that many non-emitting resources have low marginal costs and markets and operators will choose to run them regardless of their treatment).			
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) REMOVE OR REDUCE RELIABILITY CONCERNS - a larger market and additional flexibility further reduces reliability concerns.			

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) Standard 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;	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) Standard 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) Standard 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) Standard 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

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
	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 could still be used for RPS compliance).			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 levels (this requirement must include an enforcement mechanism on the fossil generators regulated under Sec. 111(d)).

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 would be necessary in most states to require load serving entities or distribution companies to procure specific resources over time.
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	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	NA

Policy Approach	Flexible Intensity-based	Mass-based with Trading	Carbon Fee	Portfolio / Resource Standards
		also be funded with auction revenue (see below).	worker transition assistance can also be funded with auction revenue (see below).	

9.7 Accounting for renewables and energy efficiency in a rate-based program.

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.

9.7.1 *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—and led the way in reducing carbon pollution. They have done so by deploying renewable energy, by harvesting demand-side energy efficiency resources, and by shifting utilization away from high-emitting toward lower-emitting power plants.

State and private sector leadership and early action in addressing pollution is something that should be recognized and supported. Action at the federal level to address climate-destabilizing pollution, on the other hand, 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—EPA should also 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 a very significant way, those early actions are indeed remedied by the Clean power Plan: because the standard only applies to fossil generators, 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 that 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 grow 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. The benefits that will accrue from those common sense actions lessen the need for credit for early action.

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. If crediting of early actions is allowed, the targets should also be strengthened in anticipation of that credit.

9.7.2 *Tracking & crediting for states employing a rate-based program*.

States employing rate-based compliance programs should credit renewable energy and energy efficiency in the form of tons of CO2 as opposed to trading credits of MWh through RECs or some other mechanism. Doing so 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 specific 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 a separate CO_2 credit tracking program (not the REC tracking system) as this is the system that will be used to determine whether or not a facility has met its CO_2 emissions obligation at the end of each compliance period. 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 to 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 plans, we recommend that EPA design and operate a tracking system that states can opt to use if they choose.

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 as a result of new carbon-free projects such as wind, solar, hydro, or nuclear uprates. In order to ensure that crediting reflects the emission reductions secured by these projects, we recommend that such projects are credited in an amount based on the emissions standard 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.

9.7.3 *Tracking and crediting from states employing a mass-based program.*

States employing mass-based compliance programs should not increase their cap in order to provide credit to new generation or efficiency projects, as so doing would compromise the emissions benefits of the program. However, they are welcome to incentivize such projects by providing them with free allowance allocations or allowance auction revenue from under their cap if they so choose.

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 or energy savings from neighboring mass-based states as emissions credit generators, they would effectively be double counting the emissions benefit.

Thus, EPA must establish a clear prohibition on rate-based states converting RECs and efficiency savings to emissions credits from mass-based states. Rate-based states can still purchase RECs from mass-based states for other renewables requirements like RES/RPSs, but not claim a carbon emissions benefit from those purchases.

9.8 Environmental leakage.

Whenever a shift in the deployment of generation assets is treated as delivering greater GHG emissions reductions than actually occur, overall 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 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. Some analysis has suggested that the threat of leakage could be in the range of 14-19% of total GHG emissions reductions required under the Clean Power Plan as proposed. 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 more stringent emissions rate standard to a state with a less stringent 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 and a decrease in the mass-based state.

Note, there is no threat of mass to mass leakage between different states. 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. (As noted in our discussion of rate-to-mass conversion, there is a risk of leakage to new in-state plants if those are not covered or properly accounted for.)

9.8.1 ***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 CO2/MWh and 1783 lbs CO2/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 CO_2 (about 9 tons of CO_2), even though the atmosphere would have not seen any reduction in actual CO_2 emissions.

The wider the gap in emissions targets, the greater the financial incentive for sources to shift generation away from states with stringent targets towards states with less stringent targets. Therefore, any action EPA takes to reduce the variation in state targets by increasing the GHG emissions reductions required in states that currently have less ambitious targets 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 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.

9.8.2 *Rate to mass leakage*.

Mass-based programs are superior to rate based programs for a number of reasons, including that: 1) they guarantee emissions reductions even if electric demand increases, 2) they significantly minimize reporting and verification needs for energy efficiency programs, which are a critical cost saving opportunity for state plans, and 3) 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 targets 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).

9.8.3 *NRDC modeling of leakage potential*.

NRDC has analyzed the potential for leakage using the IPM model. Results are shown in Section 8.

9.8.4 ***Policy options for states to address emissions 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. At a minimum we recommend that EPA describe a methodology for how they will measure and evaluate leakage over time. We recommend that the responsibility to address leakage be placed on the states that increase electricity production, as they are the states that otherwise benefit from their less stringent emissions rate. States employing a rate-based approach or a portfolio approach must 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 delivery approach

Under this approach to address emissions leakage, 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 absent the submission of emissions credits (note that this approach was first developed for California where the obligation could only be placed on the importer; we are recommending the rate-based exporting state or exporter be given the obligation).

The advantage to this approach is that it imposes the burden on the exporter and not on 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[24], 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 separately 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 any shifts through automatic ex-post adjustment of their GHG programs.

[24]RAP, David Farnsworth, Rachael Terada, Tracking Emissions Associated with Energy Serving Load in the Regional Greenhouse Gas Initiative (RGGI) States: A Feasibility Study (April 2013) *available at* www.raponline.org/document/download/id/6509.

This approach can address the threat of leakage over time through adjustments, but 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 statewide power sector performance against mass-based targets

As explained, there is no threat of emissions 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 less ambitious state emissions targets. This rate would apply to new fossil-based generation, new renewable generation, increased deployment of energy efficiency resources, as well as to significant increases in generation at existing power plants. In performing this analysis, EPA could use either the fuel-specific standard under 111(b) where it exists, or either the most or the least conservative emission standard for any new unit (coal or gas).

Again, these approaches are based on the fact that leakage would be caused by a shift in the net balance of imports and exports between states with disparate standards. However, in this ex ante approach, instead of applying an ex post adjustment at the state level, EPA 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. There is an advantage to placing them on plants whose generation increases: doing so avoids further penalizing plants that are already being outcompeted in the marketplace (and thus states whose in-state generation is decreasing). In addition, it 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.

9.9 Reliability.

There is no valid reason to doubt that system operators will be able to maintain system reliability as the Clean Power Plan is implemented.

The power grid has always adapted to changing state and national energy trends and will be able to do so to accommodate the Clean Power Plan. As described below, there is a strong federal and state structure in place to plan for and achieve adequate system reliability. In addition, maintaining reliability under the Clean Power Plan will be facilitated by the significant flexibility provided by the multi-year compliance period and the system-based compliance options. For example, plants needed for reliability may continue to operate as long as needed under a credit-based compliance program simply by obtaining a sufficient supply of low-emission credits from renewable energy, energy-efficiency or other lower emitting generation. Similarly, multi-year averaging compliance will allow a plant essential for maintenance of reliability to continue to operate even if there are not adequate credits available in a particular year so long as the average emission rate is met over the multi-year period.

9.9.1 *Maintaining and strengthening electric power grid reliability is the ongoing responsibility of both federal and state authorities*.

Under the Federal Power Act, electric system reliability is a coordinated effort among federal and state authorities. The Federal Energy Regulatory Commission (FERC) has the ultimate responsibility of ensuring the reliable operation of the bulk-power system (which includes the interconnected transmission network and the electric energy needed to maintain transmission reliability, but excludes facilities used for local electricity distribution).

FERC uses a number of tools to ensure grid reliability. For example, market tools such as forward capacity markets allow some grid operators to procure sufficient generating and demand side management to meet future reserve margins. FERC has approved day ahead and real-time energy and ancillary services markets in many areas of the county to manage the constant flow of power and improve grid efficiencies. FERC also can direct grid operators to take steps such as initiating processes to ensure adequate fuel delivery[25] and approving agreements to enable otherwise uneconomic power plants to continue operating to meet reliability needs. FERC also oversees the regional planning/reliability processes discussed below.

---

[25] *See, e.g.*, *ISO New England Inc.*, 148 FERC ¶ 61,179 (2014) (requiring a RTO to initiate a stakeholder process to develop a proposal to address winter reliability concerns and submit progress reports); *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145, (2014) (directing RTOs/ISOs to file reports on the status of their efforts to address fuel assurance issues).

One of FERC's critical responsibilities is to review and approve grid planning and operating standards created by the North American Electric Reliability Corporation (NERC), none of which would change under the Clean Power Plan. This comprehensive system of standards and regulatory oversight guides the efforts of electric utilities and grid operators to ensure reliable energy supplies. NERC works with eight regional reliability entities, whose participants include grid operators, utilities, generating companies, and other key stakeholders in the electric industry. Each monitors and enforces compliance with NERC's reliability standards, and assesses the maintenance of minimum target reserve margins, a key indicator of resource adequacy. All regions plan to have capacity above expected demand to accommodate unplanned power plant outages, transmission failures, unexpectedly high demand, or other contingencies. Most regions maintain minimum target reserve margins of about 15 percent above their forecast demand. This would continue to be the case under the Clean Power Plan

Finally, many states have authority to ensure resource adequacy, which directly affects grid reliability. States that exercise traditional regulation over vertically integrated electric companies often use integrated resource planning processes to ensure that electric distribution companies have sufficient resources available to meet projected load and reserve requirements at least cost.

9.9.2 *FERC's grid planning rules create a forum for states to craft and implement effective and reliable CPP state plans*.

The electric power system in the United States has proven to be a robust and reliable system even as technology, markets conditions, and regulations have evolved over time. FERC orders over the course of more than a decade reflect the evolving nature of the grid, moving from a largely one-way delivery system for electricity from power plants close to consumers and predictable growth in consumption, to one with variable renewable energy resources sometimes located far from consumers, a rise in rooftop solar and other distributed energy resources, dynamic price responsive demand, and more energy efficiency.

Among FERC's responsibilities is to regulate the transmission planning processes of FERC-jurisdictional public utility transmission providers. Transmission planning – an essential reliability mechanism – involves identifying short- and long-term grid needs arising from reliability, economic and public policy issues and implementing solutions. Effective planning can significantly improve environmental quality, support rather than frustrate economic development, and improve long-term grid reliability.

A key reason why transmission planning is useful for state compliance activities with the Clean Power Plan is that FERC requires transmission planners to consider cost-effective alternatives to building new transmission – like improving or increasing generation capacity through new power plants, energy efficiency, energy storage, distributed generation like rooftop solar, and demand response (customer reductions in electricity use based on price signals and directions from grid operators). Thus, the planning process helps link the system's physical/electrical needs to both transmission and "non-wires solutions" – which include onsite generation, demand response, and energy efficiency – that can identify and resolve reliability needs. From the states' perspective, the regional planning process can help states develop and implement a cost-effective and on-time state plan for the CPP.

9.9.2.1 *Key FERC transmission planning orders relevant to the CPP*.

Two recent FERC orders on transmission system planning are particularly relevant as states develop their state plans to implement the CPP. These FERC orders require every grid planner (including both individual public utility transmission providers and the regional grid planners) in every region of the country to:

1. Participate in a regional system planning process;
2. Create processes and forums for all stakeholders, including states, to consider such public policies as the CPP; and
3. Evaluate both transmission and non-wires solutions to meet system needs.

Order 890, issued in 2009, among other things requires that public utility transmission providers evaluate alternatives to transmission solutions in the planning process, such as new generation, energy efficiency, energy storage, and demand response. Grid planners must consider whether these non-transmission solutions can solve system reliability and other needs more quickly and cost-effectively, and on a comparable basis, than building transmission. These non-wires solutions almost always can be implemented more quickly than building new transmission capacity.

Order 1000, issued in 2011, further reformed the transmission planning process and builds on Order 890's requirement to consider non-wires solutions on a "comparable" basis with transmission solutions.

- First, Order 1000 requires all public utility transmission providers to participate in a regional planning process. As a result, the comparability requirement in Order 890 now applies to every region of the country.[26]

[26] Many large public power, cooperative, and municipal utilities, and federal power marketing authorities, although not subject to FERC jurisdiction, have joined or will join planning regions. Most recently, Basin Electric Cooperative and the Western Area Power Authority (eastern region) are planning to join the Southwest Power Pool next year,

- Second, Order 1000 requires each of these planning regions to consider the impacts of the "public policy requirements" on transmission system needs. Public policy requirements include state and federal energy and environmental policies such as renewable energy standards and the CPP; state energy efficiency resource standards; and any other federal, state, or municipal laws and regulations with the potential to affect grid needs. Order 1000 reflects the reality that the explosive growth in wind and solar power, combined with the energy saving effects of energy efficiency and demand response, are changing how grid operators plan for the future, and that new and upgraded transmission projects and other solutions may be necessary to meet these system needs, even in the absence of a purely reliability-based need. Denying these resources access to the grid could amount to undue discrimination under the Federal Power Act.
- Third, Order 1000 requires every planning region to coordinate their planning with neighboring regions. It has encouraged neighboring regions to plan jointly and to begin to study how regions can share the costs of new transmission projects benefitting both regions.

9.9.2.2 *Applying FERC-jurisdictional planning requirements to the Clean Power Plan.*

Section 111(d) of the Clean Air Act provides states with significant discretion in terms of how they comply with EPA's CO_2 performance targets. States can adopt market-based regulatory mechanisms, demand-side energy efficiency policies, renewable energy policies, or other programs and policies. Transitioning to a lower carbon-polluting energy system will be facilitated by a well-functioning bulk power transmission grid, and FERC's grid planning framework can help states meet CPP carbon reduction targets cost-effectively and on time.

In sum, Order 1000-compliant planning processes provide a forum for states, utilities, and other stakeholders to bring CPP compliance strategies for discussion and critical review. Working together, the grid planners and states can identify commonalities and conflicts among different state plans, and the grid planner can then create a regional transmission plan (updated on an annual basis) that helps to meet the states' CPP targets.

which means that power resources in their large regions can access a growing power market and take advantage of the economies of scale of regional dispatch and planning.

9.9.2.3 *Regional grid planners provide the information and guidance to help states craft and implement reliable, cost-effective plans.*

Broadly speaking, FERC-jurisdictional grid operators have at least two functional roles relevant to CPP plan development and implementation. First, they should provide whatever technical and analytical support the states require to help develop their plans. Given the wide range of compliance options in the CPP, states will have to evaluate many different potential compliance scenarios. Regional grid planners can provide meaningful technical guidance to states to help them assess options – guidance that otherwise is not readily available to the states.

Second, these FERC-jurisdictional bodies have the independent responsibility to plan and operate a reliable and cost-effective grid. Acting under Orders 890, 1000, and other FERC authorities, they regularly assess how state public policy requirements (*e.g.,* state renewable energy and energy efficiency standards, the forthcoming CPP) will affect system needs. Coordinated planning by states and these FERC-jurisdictional regions will produce greater environmental benefits and consumer savings at lower cost. The longer compliance horizons for the CPP should provide states and planning regions with more than sufficient time to utilize Order 1000-compliant frameworks to identify and agree on cost-effective compliance solutions.

Consider FERC's explanation in Order 1000 of the value of public policy requirements in the grid planning processes, which envisions complementary and mutually beneficial planning activities across regions:

> [I]t is not the transmission providers' function to decide on the merits of these federal or state requirements or to decide between wind and coal resources. *It is their function to help both sets of utilities comply with the laws they each face by considering in the transmission planning process,* but not necessarily including in the regional transmission plan, the new transmission facilities needed by both sets of utilities to meet their obligations, *and also to determine if these diverse objectives can be met more efficiently or cost-effectively through regional transmission planning than through individual utility planning.*[27]

The Western Electricity Coordinating Council (WECC), the regional reliability entity for the Western Interconnection, is an early adopter of coordinated state and grid planning, and is thus a model for useful regional planning processes under the CPP. In September 2014, in a preliminary study on the potential impacts of the CPP on its system, WECC identified ways it could support state compliance activities, while also furthering its reliability goals, including:

[27] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, at P 327 (emphasis added).

- "Work with states and other stakeholders to continue to refine and adjust the underlying data sources that provide the analytical foundation for this report and future analyses;
- Provide data and information useful to the development of state compliance plans;
- Investigate potential reliability issues by conducting cross-functional analyses on potential or conceptual compliance plans using WECC's production cost model and powerflow model capabilities;
- Compare impacts of emission rate compliance with mass-based emission methods;
- Analyze possible multistate compliance options;
- Investigate how proposed state compliance plans could interact and impact one another; and
- Convene groups of stakeholders, such as impacted utilities and state officials, to inform them of analyses related to any of the above topics and discuss regional impacts of state compliance plans."[28]

These are precisely the functions of an Order 1000-compliant regional planning process: grid operators will provide the necessary information and guidance to states to allow them to determine how their state-jurisdictional CPP compliance solutions could better meet grid reliability needs and avoid or minimize the need to continue to run plants otherwise slated for retirement. Recent grid operator comments mistakenly suggesting that the CPP's deadlines are too onerous and risk triggering reliability issues underscore that reliability cannot be viewed in a vacuum; instead, grid operators are obligated and empowered under Order 1000 to use their planning tools to support state implementation of the CPP.

9.9.2.4 *States and utilities are responsible for vigorous, ongoing use of the regional grid planning process*.

From the states' perspective, especially that of air/environmental regulators, they can integrate the regional transmission planning process can be integrated into their ongoing CPP compliance in at least two major ways.

First, they can obtain ongoing system information and modeling projections to allow them to align their individual plans/goals more closely with regional needs.

[28] WECC, *EPA Clean Power Plan: Phase I – Preliminary Technical Report* (Sept 19, 2014), at 31, *available at* https://www.wecc.biz/Reliability/140912_EPA-111(d)_PhaseI_Tech-Final.pdf.

Second, they can direct utilities with state law obligations to engage more completely in the planning process, and direct them to provide accurate information to the grid planners on their state-jurisdictional activities so that the planners understand the effects of these activities on system needs. State public utilities laws typically provide state commissions with broad oversight authority, including authority to review resource plans and filings. Many state commissions review and approve utility demand side management programs. State commissions and other state entities are also responsible for implementing renewable energy standards. These laws often provide commissions or other state agencies with the legal authority that would allow the states to compel utilities to use the grid regions' planning processes to help design and implement CPP compliance pathways.

A good recent example of state partnership with a FERC-jurisdictional regional transmission organization (RTO) is in MISO, where MISO and the Organization of MISO States (OMS) recently amended the MISO tariff to include more specific opportunities for states to participate in MISO's 18-month regional transmission planning process. For example, the tariff makes clear that the OMS will have input into the planning process study scope, modeling inputs, and assumptions. Because of this cooperative arrangement, the states in MISO's footprint will be well-positioned to use the Order 1000 planning process to facilitate their development of CPP compliance strategies, either alone or in combination with other states.

9.9.3 *State plans should require that emissions from plants needed for grid reliability purposes are offset with emissions credits elsewhere*.

In January 2014, the ISO/RTO Council submitted comments to EPA urging the Agency to include a process to allow plants to obtain extensions of time to comply with the CPP state plan requirements should their planned closure trigger grid reliability issues. It explained that this process should "ensure that any federal CO_2 rule or related state plan includes a process to assess, and, as relevant, to mitigate, electric system reliability impacts resulting from related environmental compliance actions."[29] We understand that the ISO/RTO Council supports a "rolling" process for providing extensions of time to comply, available through 2030 and beyond, which it refers to as a "reliability safety valve."

We support RTO and other planning regions' overriding interest and mandate in preserving and enhancing grid reliability; however, the reliability safety valve as proposed by the ISO/RTO Council is unnecessary, and we urge EPA not to institute this unneeded mechanism. The CPP essentially has three "reliability safety valves" already embedded in the structure of the rule: i) flexibility to take advantage of a broad array of system resources, including both supply-side

[29] Comments of ISO/RTO Council to U.S. EPA on the Section 111(d) standards (January 2014).

and demand-side resources; ii) an extended compliance period spanning at least 10 years and multi-year averaging; and iii) compliance flexibility, including emissions trading and averaging to avoid mandating reductions at any individual plant, including reliability critical facilities, or at any specific period of time (e.g., during the summer peak demand period). With these flexible compliance options, implementation of the CPP will avoid reliability issues. Regardless, EPA should maintain final responsibility under its Clean Air Act authority as to whether to reject or adjust a state plan or targets on reliability or other grounds, based on input from FERC.

9.9.3.1 *The CPP provides the time and flexibility necessary to avoid reliability issues.*

Because of the long compliance period and range of resources available to achieve compliance, states and grid operators will have sufficient time to identify and avoid reliability issues associated with the CPP.

First, states will have 12 years or more under the CPP to achieve the final 2030 compliance deadline. This lengthy compliance period distinguishes the CPP from the MATS rule (which EPA promulgated in February 2012). MATS had a three-year compliance deadline, through April 2015. Up to two additional years are available for sources to comply: one year under section 112(i)(3)(B) of the Clean Air Act, and one year under an EPA administrative enforcement discretion policy.[30] In contrast to MATS, states will have more than twice as much time to achieve final compliance with the CPP.

Recognizing that strong interim targets are essential in order to deliver near-term reductions in carbon pollution, states can scale up energy efficiency, coal-to-gas conversions and redispatch, and other actions achievable in the next five years. Concurrently, states and grid operators can begin the process of identifying longer lead-time resources such as new transmission needed for expansion of wind and solar power. With this combination of short- and near-term compliance strategies, together with continuing technology advances and falling costs, states are well-positioned to meet the standards while preserving grid reliability.

A second compelling difference between the MATS and CPP standards is that states can meet the CPP standards with any electric system resources, including outside-the-fenceline strategies like efficiency and renewables, in addition to improving power plant emissions rates. As a result, reliability-critical power plants can continue to operate and the sources can reduce

[30] EPA, *Enforcement Response Policy for Use of Clean Air Act Section 113(a) Administrative orders in Relation To Electric Reliability and The Mercury and Air Toxics Standards* (Dec. 16, 2011). It is worth noting that to date EPA has considered only one request for the second year extension under the MATS rule (final compliance deadline April 2017), with only a handful of additional requests expected in the near future. See FERC, *Commission Comments on Kansas City Board of Public Utilities' Request for EPA Administrative Order*, Docket No. AD14-16-0000 (Nov. 20, 2014).

overall emissions through other resources – increasing the use of wind and natural gas generation, more efficiency, and demand response. Again, the regional grid planning process described above provides the forum and opportunities for the early and ongoing planning that is necessary to help identify the right mix of existing and new resources necessary to achieve CPP compliance and meet reliability needs.

Third, if a specific plant is required to be available beyond when a state's plan otherwise assumed it would reduce output or retire, the state should account for its emissions in its compliance plan. The state can draw on averaging or market-based approaches using allowances or emissions credits elsewhere in the system (whether in or out of state) or by other means to offset the excess emissions from the plant needed for reliability purposes.

9.9.3.2 *Early RTO reliability studies of the CPP have limited value.*

Several grid operators have conducted preliminary evaluations of the CPP's proposed standards. We encourage EPA to view these studies for what they are: a very preliminary look at proposed standards. To date, they suffer similar flaws, which is that they do not realistically model contributions from energy efficiency, demand response, and renewable energy in achieving compliance and maintaining grid reliability; and in some cases they force implementation of the EPA BSER building blocks rather than achieving the state goal at least cost. This is not surprising, since grid planning regions historically have focused on using transmission as the primary tool for maintaining reliability standards and are not as familiar with deploying demand side solutions. In addition, many of their models are ill-suited to longer-term environmental and resource planning.

The most glaring example of a deficient study is the Southwest Power Pool's reliability-only assessment in October 2014 of the CPP.[31] SPP unrealistically assumed the closure of thousands of megawatts of coal plants by 2020 but considered none of the replacement power resources which would occur during CPP implementation. To quote from its report, "due to time constraints [SPP] did not evaluate the viability or reliability impacts of any of the building blocks used to establish [the CPP's] proposed goals."[32] Those missing building blocks include new wind and solar, natural gas, and energy efficiency that states will add to their energy mix to meet those standards, plus any other state and regional compliance solutions. Not surprisingly, with that critical missing piece, SPP found reliability issues.

Other fundamental problems with SPP's study include:

[31] Letter from Southwest Power Pool to Gina McCarthy, U.S. EPA Administrator (Oct. 9, 2014) *available at* http://www.spp.org/publications/2014-10-09_SPP%20Comments_EPA-HQ-OAR-2013-0602.pdf.
[32] *Id*. at 2.

- Timetable errors: SPP's study assumes an inflexible final compliance deadline of 2020, even though that interim deadline allows averaging over the years 2020-2029, giving states substantial flexibility that SPP ignores.
- New generation ignored: SPP didn't add any new wind, solar, natural gas, or other generation solutions states might choose alone or together as a region to meet the standards. Although SPP did add some new wind and natural gas power, those plants are already in the development stage, and SPP assumed very low levels of new wind power. Essentially, SPP assumed that no new generation is built to meet load or to address any retirements.
- Efficiency ignored: SPP didn't consider whether any new energy efficiency, energy storage, demand response, or other similar customer-controlled solutions would make up part of states' compliance plans – even though these resources often cost far less than the price of new generation.

9.10 EPA should ensure that 111(d) standards do not create disincentives to transportation electrification.

Transportation electrification is well-recognized by experts, air regulators and others as a key strategy to reduce GHGs and other criteria pollutants.[33] Recognizing its importance, EPA and state air pollution regulators have programs to promote transportation electrification, such as EPA's light-duty vehicle GHG rules and state NAAQS attainment SIPs that include Zero-Emission Vehicle programs. EPA should ensure that the final rule is consistent with the goal of electrifying the transportation sector to reduce GHGs and other criteria pollutants.[34]

9.10.1 *Transportation electrification is a key strategy to reduce carbon pollution and criteria pollutants*.

Using electricity from today's grid, the electrification of the transportation sector can substantially reduce emissions of key pollutants, including greenhouse gases, reactive

[33] For the purposes of this section, transportation electrification includes both on-road vehicles (including light-, medium-, and heavy-duty vehicles) as well as off-road equipment (such as forklifts, commuter and transit rail, ship shore power, airport ground support equipment, truck stop electrification, and transportation refrigeration units).
[34] We recommend that EPA evaluate the appropriateness of allowing states choosing a mass-based equivalent goal that includes existing and new generation to adjust the goal consistent with the actual adoption of heat pump water, space heating, and potentially other increased electrification loads if they are found to substantially reduce GHG emissions. Note that NRDC believes mass-based targets should include existing and new sources and our recommendation applies only to such mass-based targets.

hydrocarbons, nitrogen oxides and particulate matter.[35] The proposed GHG standards for existing fossil fuel-fired electric generating units will further increase the air pollution benefits of transportation electrification.

Since the electricity sector has the potential for greater GHG emissions reductions through the transition of generation to renewable energy, electrifying vehicles is a key long-term strategy for deep GHG, as well as criteria pollutant emission, reductions in the transportation sector.[36] According to the International Energy Agency (IEA), achieving the climate stabilization goal of 450 ppm by the end of this century requires half of the global light-duty vehicle sold in 2050, about 100 million vehicles, to be battery electric or plug-in electric vehicles. The IEA's 2020 sales target for North America is about 1.5 million vehicles.[37] IEA calls this decade a "make or break" period for plug-in electric vehicles ("PEVs") and that "EV/PHEV sales must reach substantial levels by 2015 and rise rapidly thereafter."[38]

A recent study published in *Science* of the pathways for California to meet an 80 percent GHG reduction target by 2050 concluded "after other emission reduction measures were employed to the maximum feasible extent, there was no alternative to widespread switching of direct fuel uses (e.g., gasoline in cars) to electricity in order to achieve the reduction target."[39] Transportation electrification is also critical to the state's ability to meet federal ozone NAAQS attainment deadlines (both the old and new ozone standards). Air quality regulators in California estimate that reaching the longer-term 2032 ozone air quality standard and the 2050 climate goal requires nearly complete transformation of passenger vehicles to zero-emission technologies, approximately 80 percent of the truck fleet to zero-or near-zero technology, and nearly all locomotives operating in the South Coast air basin to be using some form of zero-

---

[35] Electric Power Research Institute and Natural Resources Defense Council, *Environmental Assessment of Plug-in Hybrid Electric Vehicles, Volume 1: National Greenhouse Gas Emissions, Final Report*, Electric Power Research Institute, Palo Alto, CA, July 2007; and National Research Council, *Overcoming Barriers to Electric-Vehicle Deployment: Interim Report*, Washington, DC: The National Academies Press, 2013.

[36] Yang, C., McCollum D., McCarthy, R., Leighty, W., *Meeting an 80% reduction in greenhouse gas emissions from transportation by 2050: a case study in California, Transportation Research Part D: Transport and Environment 14*, 2009; Melaina, M. Webster, K., Ro*le of fuel carbon intensity in achieving 2050 greenhouse gas reductions within the light-duty vehicle sector*, *Environmental Science and Technology 45 (9),* 2011; International Energy Agency, *Transport, Energy, and CO_2: Moving Towards Sustainability*, 2009; and National Research Council, *Transitions to Alternative Vehicles and Fuels*, Washington, DC: The National Academies Press (2013).

[37] International Energy Agency, *Technology Roadmap: Electric and Plug-in Electric Vehicles*, OECD/IEA, updated June 2011.

[38] *Id*.

[39] Williams et al., *The Technology Path to Deep Greenhouse Gas Emission Cuts by 2050: The Pivotal Role of Electricity*, Science, January 2012.

emission technology.[40] Recent studies have also found substantial opportunity in California and nationwide for electrification of non-road sources (including forklifts, commuter and transit rail, truck stop electrification, and cold ironing at ports) that can deliver additional GHG and criteria pollutant benefits.[41]

EPA has recognized the "game changing" nature of PEVs in reducing GHGs by providing two temporary incentives in its model year 2017 to 2025 light-duty vehicle ("LDV") GHG emission standard program.[42] First, it allows auto manufacturers to treat a certain number of electric vehicles, plug-in hybrid electric vehicles, and fuel cell vehicles as "zero emissions" by ignoring power plant and other upstream emissions. Second, it provides temporary sales multipliers for all battery electric vehicles, plug-in hybrid electric vehicles, and fuel cell vehicles sold in model years 2017 through 2021.[43]

Ten states have included PEVs in their state ozone SIPs, in the form of zero-emission vehicle ("ZEV") programs as part of their adoption of California's Low-Emission Vehicle Program ("CA LEV III").[44] California has utilized its unique authority under section 209 of the Clean Air Act to develop its Low-Emission Vehicle Program which includes a requirement for automakers to produce an increasing number of zero emission vehicles (ZEVs), a category that includes battery electrics, plug-in hybrid electric vehicles and fuel cell vehicles.[45] By adopting California's LEV III standards, including the ZEV requirement, under section 177 of the Clean Air Act, nine other states have included the deployment of ZEVs in their SIPs.[46] The California Air Resources Board projects that the state ZEV requirements of these ten states would result in 3.3 million ZEVs on

---

[40] California Air Resources Board, South Coast Air Quality Management District, and San Joaquin Valley Unified Air Pollution Control District, *Vision for Clean Air: A Framework for Air Quality and Climate Planning*, Public Review Draft, June 27, 2012.
[41] ICF International et al., California Transportation Electrification Assessment 5 (2014), *available at* http://www.caletc.com/wp-content/uploads/2014/09/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf and Innovation Electricity Efficiency, *Forecast of On-Road Electric Transportation in the U.S. (2010-2035),* IEE Whitepaper, April 2013
[42] See Environmental Protection Agency & Department of Transportation, *2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule*, 77 Fed. 62,650-51 (October 15, 2012).
[43] *Id.*
[44] California Air Resources Board, California's Zero Emission Vehicle Program (June 2009), *available at* http://www.arb.ca.gov/msprog/zevprog/factsheets/zev_tutorial.pdf and Center for Climate and Energy Solutions, *ZEV Program*, http://www.c2es.org/us-states-regions/policy-maps/zev-program (last visited Nov. 10, 2014).
[45] Center for Climate and Energy Solutions, *ZEV Program*, http://www.c2es.org/us-states-regions/policy-maps/zev-program (last visited Nov. 10, 2014).
[46] *Id.*

the road by 2025.[47] Clearly, ZEVs are an integral component of Clean Air Act emissions compliance generally.

9.10.2 *EPA should allow states to adjust their Mass-based Equivalent Target to account for transportation electrification.*

To help ensure continued promotion of transportation electrification, we recommend that EPA allow states that choose a mass-based equivalent target to adjust the target consistent with the actual transportation electrification load if appropriate. Unless an adjustment is allowed, transportation electrification would make it harder for states to meet their mass-based emission reduction goals because the growth in electricity demand from vehicles would reduce the emission reductions achieved through others measures, including energy efficiency, renewable energy and increase dispatch of natural gas.

Note that since NRDC does not support a mass-based program for only existing sources as stated previously, our recommendations for treatment of transportation electrification apply only to the mass-based program option that includes both existing and new generation.

For states that choose to include new sources, EPA proposes allowing for growth in load based on AEO 2013 in setting the mass-based equivalent goal. However, AEO 2013 has a very conservative projection of electric vehicle penetration. It projects the total U.S. stock of battery-powered electric and plug-in hybrid electric vehicles in 2025 to be 2.03 million.[48] In contrast, the CARB estimates that in the ten states with ZEV programs alone would result in the cumulative sales 3.1 million battery electric and plug-in electric vehicles between model years 2017 and 2025.[49] Navigant Research projects the 2023 stock of battery electric and plug-in electric vehicles will be 2.75 million.[50] However because energy forecasts tend to over-predict overall energy and demand growth, a portion (or potentially all) of new transportation electrification load may be accommodated in the overall forecast.

We recommend that EPA allow states that choose the mass-based equivalent goal compliance option that includes existing and new generation to adjust the mass-based target to account for

---

[47] California Air Resources Board, "Governor Announces Bold Initiative to Put 3.3 Million Zero-Emission Vehicles on Road by 2025", October 24, 2013, press release, *available at* http://www.arb.ca.gov/newsrel/newsrelease.php?id=520 .

[48] Energy Information Administration, *Annual Energy Outlook 2013,* April 2013.

[49] NRDC calculation based on California Air Resources "ZEV Calculator" spreadsheet, *available at* https://www.google.com/url?q=http://www.arb.ca.gov/msprog/clean_cars/clean_cars_ab1085/zevcalculator.xlsx&sa=U&ei=c5RmVInzNoa4yQTerIGQAQ&ved=0CBIQFjAI&client=internal-uds-cse&usg=AFQjCNEnGDncVLMmQqSBrE5A1BIfGMjMAg.

[50] Shepard, Scott and Gartner, John, *Electric Vehicle Geographic Forecasts: Plug-In Electric Vehicle Sales Forecasts for North America and Select European and Asia Pacific Cities by State/Province, Metropolitan Area, City, and Selected Utility Service Territories*, published 2Q 2014.

the actual transportation electrification load using the following formula for each period (the goal is to adjust for the difference between forecast and actual transportation electrification load):

$$MBEG_{adjusted\ final} = MBEG_{final} + TE_{additional} * ERBG$$

Where:

$MBEG_{adjusted\ final}$ is the adjusted final Mass-based Equivalent Goal,

$MBEG_{final}$ is the final Mass-based Equivalent Goal adopted by EPA in its final rule,

$TE_{additional}$ is the actual transportation electrification load in excess of the transportation electrification load already included in the load forecast used to determine the Mass Equivalent Generation Level, and

ERBG is the Emission Rate-Based Goal.

9.11 Federal plan.

As noted above, EPA should develop more detailed guidance on state and regional policy approaches. We believe EPA should develop a rate-based and a mass-based approach that can also become the federal plan(s) if a state fails to develop a compliant state plan. EPA should release these model plans or guidance around the same time as the guidelines are finalized (June 2015).

9.12 Environmental Justice and Conventional Air Pollution Implications of the Clean Power Plan.

EPA's Clean Power Plan proposal projects that there will be sharp reductions in overall emissions of CO_2 and co-pollutants (including SO2, NOx, ozone, PM2.5, and hazardous air pollutants (HAPs) such as mercury and hydrochloric acid) as a result of the proposed emission guidelines for existing fossil fuel-fired EGUs. The proposal also acknowledges, however, that there may be increases in these pollutants in certain areas. 79 Fed. Reg. at 34,949. These pollutants can cause serious health impacts, and EPA should undertake further and more detailed analysis to determine what, if any, areas of the country may experience these pollution increases.

We recognize that existing modeling platforms may not be capable of effectively modeling the response of particular EGUs to different potential state 111(d) plans. But to the extent that EPA is able to do so, EPA should attempt to characterize and identify the following information:

1) The location of potential EGUs (coal- and gas-fired) that could increase emissions based upon increased utilization of more efficient coal units or lower-GHG emitting gas units;
2) The potential magnitude of emissions increases from such units;

3) The result of offsetting emissions decreases from EGUs located upwind from or in the same vicinity of the prior universe of EGUs;
4) The availability of state and federal clean air authorities to control or prevent such emissions increases.
5) The availability of state and federal monitoring and reporting authorities available to inform citizens of potential emissions increases;
6) Specific guidance that EPA might provide state and local authorities in the preamble to a final Clean Power Plan to address such emissions increases, if and when they arise.

9.12.1 Estimated Air Pollution Reductions

EPA estimates that the Clean Power Plan will reduce SO_2, NO_x, ozone, $PM_{2.5}$, and hazardous air pollutants (HAPs) such as mercury and hydrochloric acid by more than 25 percent in 2030.[51] This translates to up to 6,600 lives saved per year, and over one hundred thousand less asthma attacks in children. These statistics show that on the whole, EPA's Clean Power Plan will have a real and measurable positive impact on air quality across the nation. If EPA strengthens the state targets based on the analyses presented elsewhere in these comments, the health benefits, in terms of the number of lives saved and asthma attacks avoided, will increase markedly.

Other federal rulemakings that have recently been proposed or finalized will work in concert with the Clean Power Plan to further drive down emissions of air pollution from the electric power sector. For example, EPA's final Mercury and Air Toxics Standards, requirements to reduce the interstate transport of ozone, Regional Haze rules, and updated NAAQS for ozone, SO_2 and particulate matter will work to drive significant improvements in air quality both in advance of 2030, and after. However, there are many additional steps that the Agency could take to continue to continue to cut these deadly emissions. In particular, EPA should finalize strong health standards for ozone at 60 parts per billion in its 2015 NAAQS review, and should draft a future transport rule to address the 2011 $PM_{2.5}$ NAAQS and 2008 ozone NAAQS.

Even though EPA has made great strides in reducing air pollution, according to the American Lung Association, 47 percent of Americans "live where pollution levels are too often dangerous to breathe."[52] What's more, the report found that "[o]zone was much worse in 2010-2012 compared to 2009-2011, likely due to warmer temperatures, especially in 2012." As such, the Clean Power Plan is a critical piece in reducing dangerous pollution levels, and independent studies bear out EPA's own estimates of the conventional air pollution benefits of the CPP.

A recent study performed by researchers at Harvard and Syracuse modeled a number of policy approaches to reducing carbon dioxide emissions from the U.S. power sector. Their modeling took place in advance of EPA's proposal, but the researchers found that their "Scenario 2",

---

[51] U.S. EPA, Fact Sheet: Clean Power Plan, available at: http://www2.epa.gov/carbon-pollution-standards/fact-sheet-clean-power-plan (last accessed 11/25/14).
[52] American Lung Association, 2014 State of the Air, available at: http://www.stateoftheair.org/2014/key-findings/

which consists of state-based CO_2 emission targets, flexible compliance options, and significant program investments in new end-user energy efficiency, most closely approximated EPA's proposed Clean Power Plan.[53] Importantly, they found that Scenario 2 resulted in the greatest air pollution reductions.[54]

Scenario 2 results in an "estimated 24% decrease in U.S. power plant carbon emissions from the 2020 reference case (Driscoll et al. 2014). This is equivalent to a 35% decrease from 2005 levels, the baseline year used by EPA in the Clean Power Plan." For other air pollutants, Scenario 2

> results in an estimated decrease in power plant emissions from the 2020 reference case of 27% for SO_2, 22% for NO_x, and 27% for Hg. The decrease in emissions in Scenario 2 results in widespread air quality improvements of up to 1.35 micro-grams per cubic meter (µg/m3) for annual average $PM_{2.5}$ and up to 3.6 parts per billion (ppb) for the 8-hour maximum summertime ozone by 2020.[55]

The study also estimates health benefits from these reductions, and finds that Scenario 2 would result in "3,500 premature deaths avoided each year []… 1,000 hospital admissions avoided from heart and lung disease each year, [and] 220 heart attacks prevented each year," with all states receiving benefits from the standards.[56] While others of the Scenarios outlined in the report, certain negative health endpoints can be observed from different policy choices, but that is not the case with Scenario 2. As we detail below, EPA and states must similarly guard against negative health endpoints as they work to develop plans to meet the goals of the Clean Power Plan.

9.12.2 Potential Scenarios Resulting in Increased Emissions under the Clean Power Plan

EPA describes two situations in which localized emissions increases could occur as a result of the Clean Power Plan: 1) situations in which power plants "become dispatched more intensively than in the past because they become more fuel efficient," and 2) situations involving "increased utilization of other, unmodified EGUs with relatively low GHG emissions per unit of electrical output, in particular high-efficiency gas-fired EGUs." *Id.* We address these scenarios in turn.

- Increased Dispatch Due to Unit Upgrades

EPA states that for any "modifications" whose emissions increases trigger new source review (NSR) permitting, permitting authorities "will ensure that there are no [national ambient air

---

[53] Joel Schwartz, et al., Health Co-benefits of Carbon Standards for Existing Power Plants: Part 2 of the Co-benefits of Carbon Standards Study, page 2 (September 30, 2014) *available at* http://www.chgeharvard.org/sites/default/files/userfiles2/Health%20Co-Benefits%20of%20Carbon%20Standards.pdf [Hereinafter "Harvard Co-benefit study"].

[54] *Id.*

[55] *Id.*

[56] *Id.* at 3.

quality standard] NAAQS violations and that no existing NAAQS violations are made worse." 79 Fed. Reg. at 34,949.

This explanation glosses over several concerns with the adverse impacts of potential emissions increases in local areas. First, as EPA well knows, it is possible that power plant operators undertaking upgrades could increase local emissions *and* avoid New Source Review (NSR) permitting by invoking exemptions (*e.g.*, for routine maintenance, repair or replacement) or exclusions (*e.g.*, the "demand growth" exclusion[57]) in the NSR regulations. Any unit that escapes NSR permitting may increase its hours of operation and resulting emissions significantly. In those cases in which a modified unit does undergo NSR permitting (a rare situation, based on historic experience), the unit would be subject to BACT and a local air quality impact analysis would be performed.

It is inadequate, however, for EPA to contend that the mere absence of NAAQS violations would mitigate any adverse impacts of local emissions increases based on the numerous permitting exemptions baked into NSR. Even in attainment areas that are currently meeting the NAAQS, air quality can be degraded, even without actual NAAQS violations. Moreover, many of the pollutants at issue are "non-threshold," as EPA itself has recognized, meaning that even

[57] The "demand growth" exclusion was adopted in the Bush administration's 2002 NSR reform rulemaking and allows a plant operator to undertake substantial physical changes at an emissions unit, and project that any significant emissions increases from that change will result from increased demand for its product (i.e., electricity) rather than from the physical changes themselves. The consequence is that the construction project avoids NSR permitting and the resulting significant emissions increases are not subject to best available control technology (BACT).

Further, a recent court decision, *United States v. DTE Energy Co.*, 711 F.3d 643 (6th Cir. 2013) held that the NSR rules allow only a cursory review by EPA of the plant operator's demand growth claim, and disallow EPA from second-guessing those claims. Second, the court held that if the company's projections are later proven incorrect, EPA can bring an enforcement action whenever emissions increase – but not until *6 years* later. The EPA regulations presume that any emissions increases after 5 years are unrelated to the project, but the court said EPA could attempt to overcome that presumption. The court was untroubled by EPA's protests in the case (an enforcement action) that a company could just hold down emissions increases for 5 years, only to increase them after the 5-year presumption period had passed.

Finally, this negative court ruling is made even more alarming in the context of another line of cases finding that a failure to obtain a NSR preconstruction permit is a one-time violation, and EPA must bring any enforcement cases against alleged violations within 5 years or else be barred by the 5-year federal statute of limitations. While there has been no court decision examining the implications of the 6th Circuit's "demand growth" holdings with the consequences of the statute of limitations cases, there is an alarming prospect that these two lines of cases combined could make it impossible for EPA, states and citizens to enforce NSR modification violations resulting from false demand growth claims whose incorrectness may not be proven earlier than 6 years after the violation, outside the statute of limitations.

For these and other reasons, NRDC believes that EPA should undertake a rulemaking to overhaul this problematic Bush-era "demand growth" exclusion. Undertaking such a rulemaking would have benefits both in the climate and conventional air pollution contexts.

degradation of air quality in attainment areas can result in serious health impacts.[58] And in nonattainment areas, even lawfully increasing emissions would result in exacerbation of ongoing health-based NAAQS violations.

- Increased Utilization Due to Redispatch

EPA also notes that power plant operators have the legal right to increase utilization of modified or unmodified EGUs and therefore increase emissions from these units, so long as they are not avoiding NSR permitting or other restrictions through noncompliance. It is in this scenario that EPA identifies the potential for emissions increases. The agency notes that states "can take steps to avoid increased utilization,"[59], but it does not specify those possible steps. NRDC does not believe states have legal authority under current regulations to prevent increased utilization under all circumstances. Again, this means that local emissions could increase.

First, EPA says increased utilization "generally would not cause higher peak concentrations of $PM_{2.5}$, NO_x or ozone around such EGUs than is already occurring, because peak hourly or daily emissions generally would not change, but increased utilization may make periods of relatively high concentrations more frequent."[60] This response is inadequate; the increased frequency of high concentrations of $PM_{2.5}$, NO_x and ozone may very well be cause for health concerns in specific local areas. NAAQS have averaging periods from one to eight to twenty-hours because for certain pollutants we are concerned about short-term peak concentrations *and* longer exposure periods—especially when longer exposures are to high peak concentrations.

EPA anticipates that increased utilization is most likely to happen with natural gas plants. It is true that natural gas plants experiencing higher utilization rates will emit far lower levels of primary particulate matter, SO_2 and HAPs than coal-fired EGUs.[61] Thus, the reductions in regional upwind sources from lower generation at coal-fired EGUs could exceed local emission increases, resulting in better local air quality. But there remain potential local health concerns if emissions from natural gas plants increase, primarily from ozone, NO_x and particulate matter emissions in the form of nitrates (rather than sulfates). Natural gas plants also emit far lower amounts of these pollutants than coal units so with respect to these pollutants it is also possible that regional improvements from lower coal generation could lead to net improvement in local air quality. Moreover, EPA is also right that most new combined cycle natural gas units built within the past two decades are more likely to have modern NO_x pollution control than an average coal EGU.

---

[58] $PM_{2.5}$ is one of these pollutants. See, *e.g.*, http://switchboard.nrdc.org/blogs/jwalke/2-3-12%20EPA%20letter%20to%20Upton%20re%20PM%20benefits.pdf (EPA recognizing that the "scientific literature provides no evidence of a threshold below which health effects associated with exposure to fine particles – including premature death – would not occur.")
[59] 79 Fed. Reg. 34,830, 34,949.
[60] 79 Fed. Reg. 34,830, 34,950.
[61] *Id*.

Nonetheless, these comparisons are very general and simplistic, and are not adequate responses to legitimate health concerns over the significant increases in NO_x emissions that could result from increased utilization of natural gas units. Gas units today operating around 30% capacity due primarily to economic considerations (where they bid in auctions) could see increased utilization to an average of 70%, according to EPA, but even higher than that depending upon reasonable scenarios.[62] Accordingly, there are valid concerns about increases in NO_x emissions even from natural gas units equipped with BACT.[63]

EPA offers to work with states to address this problem as follows:

> the state may be able to predict which EGUs and communities may be in this type of situation and to address any concerns about localized NO2 concentrations in the design of the CAA section 111(d) program, or separately from the CAA section 111(d) program but before its implementation. In any case, existing tracking systems will allow states and the EPA to be aware of the EGUs whose utilization has increased most significantly, and thus to be able to prioritize our efforts to assess whether air quality has changed in the communities in the vicinity of such EGUs. There are multiple mechanisms in the CAA to address situations in which air quality has degraded significantly.[64]

It is important that states and EPA track just such increases but EPA has not identified adequate, available remedies to address the possibility of local NOx emissions increases from significantly increased utilization by natural gas units. At a minimum, EPA should analyze whether any local NOx pollution increases are likely to be offset in the same locales by reductions achieved at upwind plants.

---

[62] EPA assumes a 65 to 70% capacity rate for natural gas. See also, e.g., RIA at 3-25 (table 3-10)(showing capacity factor of natural gas units at close to 60% in a slightly different policy scenario)

[63] EPA's RIA estimates that "NOx emissions from a NGCC unit [are] approximately 10 times lower than a subcritical or supercritical coal-fired boiler. Many are also very well controlled for emission of NOx through the application of after combustion controls such as selective catalytic reduction, although not all gas-fired sources are so equipped."

[64] 79 Fed. Reg. 34,830, 34,950.

10.0 Signature and NRDC CPP Comment Author and Editor Acknowledgements

The foregoing comments are respectfully submitted on behalf of NRDC.

Signed: *s/ David Doniger*

David Doniger
Director, Climate and Clean Air Program
Natural Resources Defense Council
1152 15th Street NW
Washington DC 20012

The following members of the NRDC team contributed to the writing and editing of these comments. Questions on the comments should be directed to Ben Longstreth (blongstreth@nrdc.org), Derek Murrow (dmurrow@nrdc.org), and Starla Yeh (syeh@nrdc.org).

David Baake
Merrian Borgeson
Sheryl Carter
Jennifer Chen
Emily Davis
David Doniger
Vignesh Gowrishankar
Nathanael Greene
Lindsay Hall
David Hawkins
Laurie Johnson
Kit Kennedy
Gabriel Levine
Andrea Leshak
Noah Long
Ben Longstreth
Mathew McKinzie
Peter Miller
Jackson Morris
John Moore
Derek Murrow
Richard Robinson
Khalil Shahyd
Walton Shepherd
Kevin Steinberger
Dylan Sullivan
Meg Waltner
Starla Yeh

Many of the sections were also drafted by or in collaboration with colleagues at the Environmental Defense Fund.

Appendix 6A: Renewables – Recommended Changes to the Proposed Approach

While 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 and their indication of political feasibility. However, the Proposed 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.

A1.1 *EPA Should Update the 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.

A1.2. *EPA should eliminate the growth rate constraint, and choose the best of: existing generation, existing state RPS requirement, or state goal based on the regional RPS average*

We support a regional analysis and 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. Each state's existing 2014 generation (see Section 6.1.x for more details) should 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 would indicate a lower level of emissions reductions than is available to the state. While using modeled or average emissions reductions is appropriate in states that have minimal experience in minimizing emissions, to ignore demonstrated capability for emissions reductions would be both unnecessary and contrary to the requirement of the law.

There is also no reason to use average renewable energy standards to derive a regional growth rate, and recommend instead that EPA use average regional renewable targets to set targets for all states in each region – all states should meet the regional targets without being constrained by a growth rate.

EPA used unnecessary constraints that limited the pace of renewable energy growth; in doing so, it selected 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. 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 (see Appendix 5).[1] 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 (see Section 3.2 for more details). It is not clear what technical or economic limit is reflected by EPA's use of regional growth rates that is not more accurately reflected in the average RPS. 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.[2] Each state can and should be expected to achieve more from its renewables building block, such that national average growth rates more closely resemble the impressive growth from leading states during the last decade.

A1.3 *EPA should remove biopower from state targets*

---

[1] Generation data compiled and analyzed by NRDC from U.S. EIA, Electricity Generation Data, *available at* http://www.eia.gov/electricity/data/browser/.

[2] NREL/LBNL, *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards* (May 2014) *available at* http://www.nrel.gov/docs/fy14osti/61042.pdf.

While individual renewable energy technologies are not specifically identified as justifying the state targets under the proposed approach, EPA should explicitly exclude biopower from the justifications for the targets. As noted in Section 6.1.2.7, the available supply of low-carbon biomass is likely to be limited. As detailed in our own IPM modeling and further supported in Section 6.1.3, other renewables provide more than enough potential to justify stricter targets and actually reduce carbon pollution in the atmosphere in the same timeframe as this regulation. As a result, if EPA adopts the proposed approach, it should explicitly state that it is not assuming any additional biopower in setting the targets.

We provide more detail on how EPA should assess biopower included as part of state compliance plans in Section 9.

Appendix 6B: IPM Results

The IPM results in 2030 from our RE Market Potential run, including distributed solar generation are presented here. However, as discussed in more detail in Section 6.1.2.8, we recommend that EPA use a regionalization technique to better reflect renewable energy markets, and present some options for doing so in Appendix 6C.

Comparison of RE Target-Setting Approaches				
	2012 Generation*	EPA Proposed	EPA Alternative	NRDC Alternative w/ DG
Total U.S.	**159,918**	**522,723**	**524,065**	**973,354**
AL	0	14,293	682	4,808
AK		163		
AZ	1,487	3,663	3,318	14,399
AR	0	4,709	4,057	5,031
CA	23,656	41,151	30,983	119,546
CO	6,134	10,840	17,639	19,676
CT	0	3,114	637	1,541
DE	26	1,038	111	536
FL	194	22,110	2,540	11,874
GA	3	12,231	1,547	1,714
HI		1,047		
ID	1,965	3,197	10,611	8,584
IL	7,757	17,818	23,706	93,679
IN	3,210	7,547	21,951	43,696
IA	14,032	8,566	30,040	26,671
KS	5,195	8,885	50,895	24,920
KY	0	1,714	2,033	1,459
LA	0	6,892	1,823	5,777
ME	887	3,612	4,477	22,891
MD	344	5,982	790	2,282
MA	119	8,613	810	4,309
MI	1,132	8,056	10,862	41,856
MN	7,615	7,889	18,647	21,651
MS	0	5,458	2,506	82
MO	1,245	2,764	12,075	4,614
MT	1,262	2,723	10,206	12,327
NE	1,284	3,819	21,174	3,264
NV	2,950	6,406	3,856	9,738
NH	209	4,822	1,615	4,717
NJ	316	10,147	1,361	3,947

NM	2,560	4,722	16,441	21,749
NY	3,044	24,262	7,317	47,253
NC	139	11,668	2,483	6,392
ND	5,275	5,460	14,862	10,013
OH	1,022	13,776	14,786	73,276
OK	8,158	15,579	24,259	44,932
OR	6,376	12,567	8,196	19,729
PA	2,161	35,331	9,650	8,447
RI	1	476	437	1,197
SC	0	9,676	1,405	3,576
SD	2,915	1,819	19,156	13,808
TN	60	4,306	128	4,175
TX	32,332	85,963	78,438	129,011
UT	1,040	2,373	3,983	4,734
VA	0	11,192	5,497	3,763
WA	6,601	17,726	8,047	14,834
WV	1,286	10,273	4,274	5,049
WI	1,558	6,859	5,954	7,510
WY	4,369	9,428	7,801	38,314

*2012 RE generation here refers to the sum of each state's generation from onshore wind, solar PV and CSP, and geothermal energy only.

Appendix 6C: Renewables – Regionalization Approach

There are many approaches that EPA may choose to represent the regional nature of Renewable Energy markets. In its Notice of Data Availability, EPA discusses REC markets in its request for comment on a regional approach to Building Block 3 target-setting. We have focused on existing REC markets to guide our re-distribution of IPM results to reflect the regional nature of renewable energy. We have used the markets defined in the map below, and have placed individual states (NC, NV, and TX), into their neighboring REC markets, as shown in Figure 6C.1.

The RE targets are then calculated as:

$$Regional\ RE = Sum\ of\ State\ RE\ generation\ in\ IPM, within\ each\ region$$

$$Regional\ emissions = Sum\ of\ 2012\ State\ emissions, all\ sources, within\ each\ region$$

$$State\ RE\ Target = \left(\frac{State\ emissions, all\ sources}{Regional\ emissions}\right) * Regional\ RE$$

Figure 6C.1: REC Trading Markets[1]

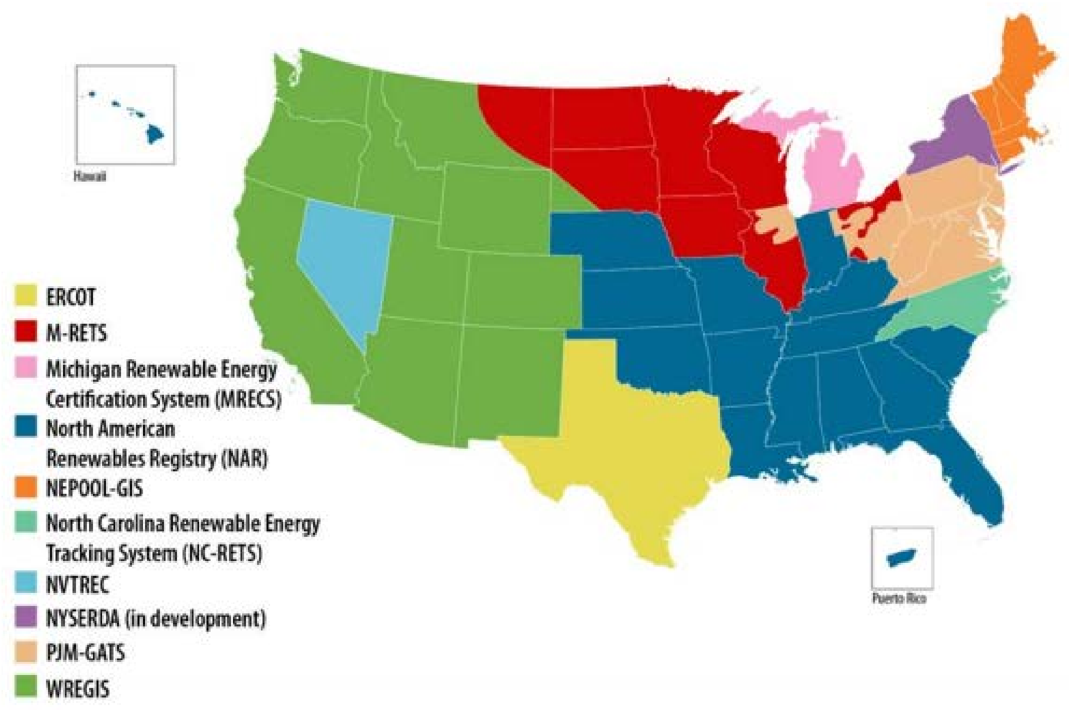


Table 6C.1: Regional Aggregation for Target-Setting

REC Trading Region Aggregation		
Markets	Number	States
NAR, ERCOT, NC-RETS	1	AL, AR, FL, GA, KS, KY, LA, MS, MO, NE, NC, OK, SC, TN, TX
PJM-GATS	2	DE, MD, NJ, OH, PA, VA, WV
NEPOOL-GIS, NYGATS	3	CT, ME, MA, NH, NY, RI
M-RETS, MIGATS	4	IL, IN, IA, MI, MN, ND, SD, WI
WREGIS, NVTREC	5	AZ, CA, CO, ID, MT, NM, NV, OR, UT, WA, WY

Alternatively, renewable energy targets can be re-distributed along transmission regions, or along the NERC regions used in EPA's Proposed Approach. In Table 6C.1, we demonstrate

[1] NREL, *Status and Trends in the U.S. Voluntary Green Power Market* (October 2013) *available at* http://www.nrel.gov/docs/fy14osti/60210.pdf.

regionalized targets for EPA's Alternative Approach and NRDC's Alternative Approach (including distributed solar PV generation (DG)), aligned along NERC regions and REC markets.

We recommend that EPA set targets based on the full suite of compliance options available to states. If states can comply with their targets through purchases of renewable electricity (or bundled RECs), then target-setting should be based on electricity trading regions (NERC regions). If unbundled RECs are available as a compliance option, then targets should be based on REC trading regions. In Tables 6C.2 and 6C.3 below, the effects of these different regionalization approaches are compared for the EPA Alternative Approach and the NRDC Alternative Approach (with Distributed Generation).

Table 6C.2. Regionalization of EPA's Alternative Approach

Comparison of different regionalization methodologies (2030 Targets, in GWh)					
	Regions				
	None	NERC Regions	NERC Regions	REC Regions	REC Regions
State	EPA Targets	Generation-weighted	Emissions-weighted	Generation-weighted	Emissions-weighted
Total U.S.	524,065	524,065	524,065	524,065	524,065
AL	682	2,186	1,974	17,711	15,056
AZ	3,318	16,155	17,609	16,155	17,609
AR	4,057	15,558	16,113	7,531	7,927
CA	30,983	33,924	20,957	33,924	20,957
CO	17,639	8,936	18,440	8,936	18,440
CT	637	2,209	1,575	2,209	1,575
DE	111	517	493	517	493
FL	2,540	3,161	3,096	25,614	23,610
GA	1,547	1,748	1,642	14,169	12,522

ID	10,611	2,635	306	2,635	306
IL	23,706	42,384	30,803	44,732	33,832
IN	21,951	24,606	32,464	25,969	35,656
IA	30,040	12,159	12,258	12,832	13,463
KS	50,895	10,633	13,908	5,147	6,842
KY	2,033	1,286	2,387	10,421	18,204
LA	1,823	24,749	19,724	11,980	9,704
ME	4,477	882	425	882	425
MD	790	2,264	2,066	2,264	2,066
MA	810	2,214	3,107	2,214	3,107
MI	10,862	23,205	22,329	24,491	24,525
MN	18,647	11,197	8,985	11,817	9,868
MS	2,506	780	677	6,324	5,161
MO	12,075	19,695	25,074	10,635	15,576
MT	10,206	4,728	7,803	4,728	7,803
NE	21,174	8,190	10,999	3,964	5,411
NV	3,856	5,980	6,739	5,980	6,739
NH	1,615	1,178	1,099	1,178	1,099
NJ	1,361	3,908	1,329	3,908	1,329
NM	16,441	3,893	7,546	3,893	7,546
NY	7,317	8,303	8,203	8,303	8,203
NC	2,483	1,668	1,531	13,517	11,677
ND	14,862	7,750	10,702	8,179	11,755
OH	14,786	7,769	10,484	7,769	10,484
OK	24,259	18,644	21,364	9,024	10,510
OR	8,196	10,360	3,337	10,360	3,337
PA	9,650	13,378	11,876	13,378	11,876
RI	437	508	884	508	884
SC	1,405	1,383	938	11,209	7,152

SD	19,156	2,582	1,067	2,725	1,172
TN	128	1,111	1,077	9,004	8,216
TX	78,438	102,871	98,537	49,793	48,477
UT	3,983	6,174	13,413	6,174	13,413
VA	5,497	4,236	2,813	4,236	2,813
WA	8,047	19,865	3,174	19,865	3,174
WV	4,274	4,396	7,408	4,396	7,408
WI	5,954	13,675	13,571	14,432	14,906
WY	7,801	8,431	21,758	8,431	21,758

Table 6C.3. Regionalization of NRDC's Alternative Approach, with Distributed Generation

Comparison of different regionalization methodologies (2030 Targets, in GWh)					
		Regions			
State	None IPM Results	NERC Regions Generation-weighted	NERC Regions Emissions-weighted	REC Regions Generation-weighted	REC Regions Emissions-weighted
Total U.S.	973,354	973,354	973,354	973,354	973,354
AL	4,808	5,591	5,051	21,630	18,387
AZ	14,399	37,844	41,249	37,844	41,249
AR	5,031	18,340	18,993	9,197	9,681
CA	119,546	79,465	49,091	79,465	49,091
CO	19,676	20,932	43,196	20,932	43,196
CT	1,541	11,829	8,437	11,829	8,437
DE	536	1,379	1,314	1,379	1,314
FL	11,874	8,085	7,920	31,281	28,834
GA	1,714	4,473	4,201	17,304	15,292
ID	8,584	6,173	717	6,173	717

IL	93,679	71,020	51,614	79,767	60,330
IN	43,696	41,230	54,397	46,308	63,582
IA	26,671	20,373	20,539	22,883	24,008
KS	24,920	12,533	16,394	6,285	8,356
KY	1,459	3,289	6,107	12,726	22,232
LA	5,777	29,174	23,250	14,630	11,851
ME	22,891	4,726	2,276	4,726	2,276
MD	2,282	6,041	5,513	6,041	5,513
MA	4,309	11,856	16,642	11,856	16,642
MI	41,856	38,883	37,416	43,672	43,734
MN	21,651	18,762	15,055	21,073	17,598
MS	82	1,996	1,731	7,723	6,303
MO	4,614	33,001	42,014	12,989	19,023
MT	12,327	11,074	18,277	11,074	18,277
NE	3,264	9,653	12,965	4,841	6,608
NV	9,738	14,009	15,787	14,009	15,787
NH	4,717	6,310	5,885	6,310	5,885
NJ	3,947	10,427	3,547	10,427	3,547
NM	21,749	9,118	17,676	9,118	17,676
NY	47,253	44,467	43,933	44,467	43,933
NC	6,392	4,267	3,917	16,508	14,260
ND	10,013	12,986	17,933	14,585	20,961
OH	73,276	20,729	27,973	20,729	27,973
OK	44,932	21,976	25,183	11,021	12,836
OR	19,729	24,268	7,816	24,268	7,816
PA	8,447	35,695	31,685	35,695	31,685
RI	1,197	2,721	4,736	2,721	4,736
SC	3,576	3,538	2,399	13,689	8,734
SD	13,808	4,326	1,788	4,859	2,090

TN	4,175	2,842	2,756	10,997	10,033
TX	129,011	121,259	116,151	60,811	59,203
UT	4,734	14,463	31,419	14,463	31,419
VA	3,763	11,302	7,505	11,302	7,505
WA	14,834	46,534	7,436	46,534	7,436
WV	5,049	11,729	19,765	11,729	19,765
WI	7,510	22,914	22,741	25,736	26,581
WY	38,314	19,750	50,967	19,750	50,967

Appendix 6D: Renewables – Distributed Solar Projections from NREL's Sunshot Vision Study

As described in Section 6.1.2.6., distributed solar PV is a unique, customer-sited generation resource, and therefore it may be difficult to represent in a wholesale power model such as IPM. Instead, we have relied on NREL's own modeling using its 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 widely expected price declines. In our IPM modeling, we have used NREL's projections for the -62.5% price sensitivity scenario, in which commercial systems decline to an installed price of $1880/kWdc by 2020, and residential systems decline to an installed price of $2250/kWdc by 2020. We have approximated a growth pathway between 2014 installed capacity and NREL's 2030 projections.

However, we note that these projections may be conservative for the purposes of establishing BSER in several ways. First, NREL's October 2014 Sunshot pricing update indicates that system prices are in fact on track to meet the full -75% price reduction by 2020, which would result in higher demand for distributed solar systems than this projection. Second, NREL's analysis assumes no further price declines after 2020, when in fact many analysts expect that prices will continue to decline. And third, this analysis does not assume any carbon price or incentives for renewable energy, beyond those already in place in 2012.[1] Therefore, an analysis that includes an application of a $30/MWh cost reduction or similar incentive for zero-carbon technologies would lead to even higher levels of distributed solar deployment.

Table 6D: DOE/NREL Sunshot, Distributed solar capacity projections for -62.5% price sensitivity case[2]

Distributed Solar Projections (GWdc)				
	2014	2020	2025	2030
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

[1] NREL's analysis assumed that the PTC and ITC expired in 2012 and 2016, respectively.
[2] NREL, *Sunshot Vision Study* (February 2012) *available at* http://www1.eere.energy.gov/solar/pdfs/47927.pdf.

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 6E: Renewables – Renewable Energy Growth Rates[1]

Table 6E.1: Growth in Solar PV Generation

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%

Table 6E.2: Growth in Onshore Wind Generation

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%

[1] Generation data compiled and analyzed by NRDC from U.S. EIA, Electricity Generation Data, *available at* http://www.eia.gov/electricity/data/browser/.

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%

Appendix 6F: Renewables – Capital Cost Adders

As discussed in section 6.1.2.4, the installed capacity bounds and capital cost adders used by EPA are not reflective of recent industry progress for both onshore wind and solar PV. In Table 6F below, we have updated these figures through the following methodology:

$$Step1, 2016_{NRDC} = Installed\ capacity, 2011 - 2012$$
$$Step2{,}2016_{NRDC} = \left(\frac{Step1{,}2016_{NRDC}}{Step1{,}2016_{EPA}}\right) * Step2{,}2016_{EPA}$$

And the same scaling factor was applied for all steps and cost adders in 2018 – 2030:

$$Step_{NRDC} = \left(\frac{Step1{,}2016_{NRDC}}{Step1, 2016_{EPA}}\right) * Step_{EPA}$$
$$Cost\ adder_{NRDC} = \left(\frac{Base\ cost_{NRDC}}{Base\ cost_{EPA}}\right) * Cost\ adder_{EPA}$$

Table 6F: Capital Cost Adders for EPA (in blue) and NRDC (in green)

		2016			2018			2020			2025			2030		
		Step1	Step2	Step3	Step1	Step2	Step3	Step1	Step2	Step3	Step1	Step2	Step3	Step1	Step2	Step3
Solar PV	Upper Bound (MW)	286	190	-	571	381	-	571	381	-	1,428	952	-	1,428	952	-
	Adder ($/KW)	-	1,025	2,651	-	1,025	2,651	-	1,025	2,651	-	1,025	2,651	-	1,025	2,651
	Base Cap Costs ($/KW)	3364			3281			3217			3027			2859		
Onshore Wind	Upper Bound (MW)	11,618	7,746	-	23,237	15,491	-	23,237	15,491	-	58,092	38,728	-	58,092	38,728	-
	Adder ($/KW)	-	694	1,794	-	694	1,794	-	694	1,794	-	694	1,794	-	694	1,794
	Base Cap Costs ($/KW)	2258			2250			2220			2123			2039		
Solar PV	Upper Bound (MW)	4,658	3,094	-	9,316	6,216	-	9,316	6,216	-	23,291	15,527	-	23,291	15,527	-
	Adder ($/KW)	0	539	1,395	0	511	1,321	0	478	1,236	0	423	1,095	0	359	927
	Base Cap Costs ($/KW)	1770			1635			1500			1250			1000		
Onshore Wind	Upper Bound (MW)	14,172	9,449	-	28,345	18,896	-	28,345	18,896	-	70,863	47,241	-	70,863	47,241	-
	Adder ($/KW)	0	538	1,390	0	540	1,395	0	547	1,414	0	572	1,479	0	596	1,540
	Base Cap Costs ($/KW)	1750			1750			1750			1750			1750		

Appendix 7A: Thermal Credit for CHP

Combined Heat and Power (CHP, or cogeneration) is a technology that produces electricity and thermal energy together by the burning of a single fuel. (A variant of CHP is Waste Energy Recovery.)

The energy efficiency benefits of CHP derive from the generation of both useful electricity and thermal energy together. Significant efficiency gains are possible. This typically leads to energy savings, reduced emissions over the entire energy system, as well as potentially various other advantages, such as local grid benefits and increased reliability and resiliency.[1] As such, we support the inclusion of CHP technologies among the portfolio of energy efficiency and cleaner energy technologies that may help comply with the Clean Power Plan. A recent report (published before the release of EPA's Clean Power Plan proposal) suggested that a policy based on regulating emissions from existing power plants could have a modest beneficial effect on CHP deployment.[2]

For the purposes of EPA's Clean Power Plan, we are concerned mainly with the emissions benefits of using CHP. (We note that the approaches discussed below may be applicable to other low-emissions systems besides CHP, which are used at third-party facilities.) At a typical facility, which may be a factory or a commercial building (or even an agricultural or residential establishment), a CHP system would be used for both electricity and thermal needs. As such, the CHP system would be displacing (or supplementing) the thermal energy system at the site. In general, the energy savings and system-wide emissions benefits of CHP accrue when CHP is properly designed to the energy needs of a facility, well-maintained, and operated judiciously. The emissions benefits of CHP can be measured in different ways, most accurately using output-based emissions measures. Two such output-based approaches are the equivalence approach and the avoided emissions approach, described below, which measure emissions associated with electricity from CHP. The emissions benefits are then obtained when contrasted with separate heat and power systems.

Possible approaches to measure emissions associated with CHP systems

<u>Equivalence approach:</u> This is the approach as proposed by the EPA in its Clean Power Plan proposal. In this approach, the effective emissions rate (lbs/MWh) of the CHP system is obtained by taking the full emissions output of the CHP system (lbs) and dividing that by the sum of the (used and) useful electricity (MWh) and thermal energy appropriately converted (MMBtu converted to MWh).[3] For this method, measurements of the input fuel, and used and useful thermal and electric outputs of the CHP system are needed.

---

[1] NRDC, "Combined Heat and Power Systems: Improving the Energy Efficiency of Our Manufacturing Plants, Buildings, and Other Facilities", April 2013, available at http://www.nrdc.org/energy/combined-heat-and-power-systems.asp

[2] Center for Clean Air Policy, "Expanding the Solution Set", May 2014, available at http://ccap.org/resource/expanding-the-solution-set-how-combined-heat-and-power-can-support-compliance-with-111d-standards-for-existing-power-plants/

[3] This is the approach that EPA adopted in the proposed 111(b) rule for new power plants and previously in NSPS for utility boilers (40 CFR Part 60 Subparts Da and Db) and for stationary gas turbines (40 CFR Part 60, Subpart KKKK).

The equivalence method can be relatively straightforward because the regulating authority does not *need* to consider details about the boiler or other thermal energy system (or part thereof) that was displaced by the CHP system. However, consideration can indeed be made of the boiler that was displaced or otherwise made unnecessary, which would make this approach more closely mirror the reality at a facility. Further, the concept of a thermal credit has sometimes been used by the EPA to account for differences in the thermodynamic factors between CHP's electric output, its thermal output and separate heat and power. In fact, the thermal credit concept can be used to make considerations of the displaced boiler, by appropriately crediting the thermal output in order to convert it to "equivalent" electric output in the calculation of the effective emissions rate. A cautionary note is that the requisite conversion of thermal output to equivalent electric output could introduce debate in the regulatory process.

Emissions rate (lbs/MWh) =

[total emissions from CHP system] / [useful electricity (MWh) + useful thermal output (MMBtu converted to MWh)]

<u>Avoided emissions approach:</u> In this approach, the effective emissions rate (lbs/MWh) of the CHP system is obtained by dividing emissions (lbs) attributable to electricity generation by the electricity output (MWh). One way of thinking about emissions attributable to electricity generation is total measured CHP system emissions, less the emissions that would have been emitted by the now unneeded conventional thermal system, typically boiler (such a boiler is often referred to as the "counterfactual boiler"). As for the previous method, the same three measurements are needed for this method as well – measurements of the input fuel, and (used and) useful thermal and electric outputs of the CHP system. Additionally, consideration is needed on the type and performance of the boiler that is displaced by the CHP system.

Emissions rate (lbs/MWh) =

[emissions from CHP system (lbs) – emissions from counterfactual thermal system (lbs)] / [useful electricity (MWh)]

<u>Comparing the two approaches</u>

There are both similarities and differences between the approaches and their implications. Both approaches have been used in output based emissions standards at the federal and state level. [4] Key similarities are that:

- The same measurements are needed under both approaches.
- The CHP emissions associated with electric output are calculated by multiplying the effective emissions rate (lbs/MWh) in either approach, by the total electricity output of the CHP system. As an equation:

  CHP emissions associated with electric output = useful electricity (MWh) x emissions rate (lbs/MWh)

[4] U.S. EPA, "Output-Based Regulations: A Handbook for Air Regulators", August 2014

- The emissions benefits of electricity generation from CHP systems are then obtained by contrasting CHP emissions with emissions from separate heat and power systems.

However, the avoided emissions approach is arguably a more accurate representation of the emissions that may be associated with electricity production.[5] This approach is also rooted in how a typical CHP system would actually be implemented; accordingly, it conceptualizes the CHP system as one that comprises a thermal component and an electric component working cooperatively together. The emissions associated with the thermal component are estimated by considering what would have happened had the CHP system not been in place (i.e., through consideration of a counterfactual boiler). Based on these emissions, the emissions associated with the electric component can be obtained. In doing so, the approach directly relates the thermal-related emissions to the emissions avoided (system-wide) through the use of the CHP system.

While consideration of a boiler's performance is needed, such consideration can be site-specific (based on historic data) or a regional average or even a standard based on attainable future goals for boilers. However, there is nothing inherently difficult in this approach. This is potentially an area that a state may have final authority over.
The equivalence approach could be simpler to implement in certain circumstances (because the counterfactual boiler is ignored). However, it has its own drawbacks. Primarily, the conversion of thermal output to electric output necessitates making assumptions about the underlying thermodynamic efficiency and emissions associated with generating these two forms of energy. As such, depending on what factor is used to convert the thermal output to "equivalent" electrical output, the equivalence approach will diverge more or less from the (more accurate) avoided emissions approach. EPA proposes a thermal credit of 75 percent in its proposal, which is an example of a factor needed to convert thermal output to electrical equivalents.

Finally, the equivalence approach explicitly includes the thermal output (in the denominator) and adds it to the electric output, in order to calculate the effective CHP-system electricity-related emission rate. In contrast, the avoided emissions approach calculates the CHP-system electricity-related effective emissions rate solely based on the electric output (in the denominator), by accounting for and excluding the emissions associated with the thermal output (in the numerator). As the framework proposed by EPA pertains solely to the electric output of existing power plants, the (latter) avoided emissions approach may be a more straightforward one in this context. .

As such, mainly for reasons of accuracy, reasonably simplicity, and potentially greater relevance in this particular regulator context, we recommend the use of the avoided emissions approach.

---

[5] EPA has recognized that the avoided emissions approach "provides for a more complete accounting of the environmental benefits of CHP by including the emissions avoided by the CHP system's secondary output in the calculation." See U.S. EPA, CHP Partnership, "Accounting for CHP in Output-Based Regulations", February 2013, available at http://www.epa.gov/chp/documents/accounting.pdf.

However, EPA may wish to provide guidance on the use of the equivalence approach or states may choose to adopt this approach. A side-by-side comparison between the equivalence and avoided emissions approaches is site-specific and depends on the overall efficiency of the CHP system, the relative amounts of electricity and thermal energy produced, and the emissions characteristics of the counterfactual boiler. If using a thermal credit to convert thermal output to electric equivalents, from our internal analysis of the emission benefits of typical CHP systems in operation, thermal credits that closely match the results of the more accurate avoided emissions approach would range from 60 percent to 100 percent, assuming natural gas boilers and CHP systems[6]. Thermal credits of 80-90 percent are reasonable for the most widely used CHP system configurations. We would encourage using a thermal credit that matches the actual design and performance of a particular CHP system. This could exceed the proposed 75 percent, as the case may be.[7,8]

Finally, regardless of the approach, it is important that CHP receive incentives or credit based on the actual performance of the system, not according to projected or anticipated levels. Clearly, only a properly performing CHP system can yield actual efficiency and emission benefits. Also important in this regard, is that policies to promote CHP systems incentivize efficiency if efficiency is desired, rather than some other metric. For instance, a report on CHP systems in California[9] found that the actual performance of CHP systems at certain early facilities was different from the anticipated performance based on design. Consequently, one of the report's findings was that proper operation and maintenance of CHP systems was essential for high-performing CHP systems. However, another key finding was that California's policy in this case was not emphasizing efficient performance; it was instead trying to solve for power shortages with less regard to efficient performance. As such, two aspects are critical: policies should adequately incentivize desired outcomes (in this case, efficient performance and emissions reductions), which engenders appropriate CHP design; and credits should be based on actual performance. Accordingly, under the EPA Clean Power Plan, both the equivalence approach and the avoided emissions approach, in principle, could drive efficient CHP systems – although we recommend the avoided emissions approach for reasons described earlier. As for

[6] The appropriate thermal credit may be even higher than 100 percent if a coal boiler is displaced by (or compared with) a natural gas CHP system. This may indeed happen, but the appropriate counterfactual boiler from a policy perspective may nonetheless justifiably be a natural gas-fired one (especially if future upgrades are considered). Conversely, the appropriate thermal credit could be lower if a natural gas boiler is replaced by (or compared with) a coal-fired CHP system; this situation is perhaps less common.

[7] In previous use of the equivalence approach, EPA has applied a range of credits to CHP thermal output, ranging from 75 percent in EPA's New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units (40 CFR Part 60, Subpart Da) to recognizing 100 percent of thermal output in the NSPS for Stationary Combustion Turbines. See U.S. EPA, "New Source Performance Standard (NSPS) for Stationary Combustion Turbines", 40 CFR Part 60, Subpart KKKK, which credits100 percent of thermal output; U.S. EPA, "New Source Performance Standard (NSPS) for Electric Utility Steam Generating Units", 40 CFR Part 60, Subpart Da, which credits 75 percent of thermal output from CHP systems.

[8] A 100 percent credit has likewise been applied in several states that have used the equivalence approach in their regulations. See U.S. EPA, CHP Partnership, "Accounting for CHP in Output-Based Regulations" , February 2013, pages 7-9 cite California's multi-pollutant regulations and Texas permit by rule and standard permitting program., available at http://www.epa.gov/chp/documents/accounting.pdf.

[9] Itron, Inc., "CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation: Final Report", July 2011, report prepared for PG&E and The Self-Generation Incentive Program Working Group.

ensuring performance, for either the equivalence or avoided emission approaches, the same measurements of fuel input and useful electric and thermal outputs would be needed. Robust evaluation, measurement and verification of CHP system performance would increase confidence in the efficiency benefits of the systems – for instance, the thermal output from CHP systems should not be wasted or dissipated but actually put to productive use.[10] Accordingly, we strongly support the use of independent verification (as done in other energy efficiency contexts) to develop an accurate picture of the realized emissions benefits from CHP systems.

Treatment of CHP systems to account for their efficiency and emissions benefits

CHP systems depending on the size and power output may be directly covered or not-covered by the EPA rule. In either case, the principles for crediting CHP should be the same.

In the case of covered CHP units, all of the electric output should be taken into consideration. The emissions from the CHP system associated with such electric output may be calculated using the approaches discussed earlier.

In the case of non-covered CHP units, in principle, this approach would not change. In other words, all of the electric output and the emissions associated with such electric output would be needed.

However, as a practical matter, treatment of non-covered CHP units would need some additional procedural steps. A non-covered CHP system would likely be operating at a third-party facility. Accordingly, once the required measurements are made, consideration will need to be made for the emissions (associated with the electric output) that occur onsite, at the CHP facility. Such treatment is different from pure energy efficiency or renewable energy generation, which produce no onsite emissions. Nonetheless, this should not pose a barrier to accounting for and providing credit for the legitimate efficiency savings generated by CHP systems.

Two examples of possible approaches to account for onsite emissions are described below.

Situation 1: A particular state (or region) adopts a rate-based approach to comply with the EPA Clean Power Plan, wherein energy credits are provided for clean energy produced. In this case, a megawatt-hour of energy saved by traditional energy efficiency or produced by a renewable source such as wind or solar may be counted as one credit, because they would reduce power plant emissions associated with producing (and transporting) one megawatt-hour of energy, while producing no emissions onsite. In contrast, a megawatt-hour of electricity produced by CHP would, generally speaking, reduce system-wide emissions by a lesser amount, because while they would reduce power plant emissions associated with producing (and distributing) one megawatt-hour of energy, they would also have non-zero onsite emissions. Accordingly, it might be reasonable to provide credit to the CHP system proportional to the actual emissions

[10] Some state approaches recognize this potential pitfall. For instance, many state CHP regulations typically require at least 20 percent of the input fuel's recovered energy to be thermal and a minimum overall CHP system efficiency of 55 to 60 percent. Regardless, robust evaluation, measurement and verification of CHP system performance would increase confidence in the systems' efficiency benefits.

reduced across the entire system. For instance, compared to the power plant emissions, if a CHP system emits onsite 40 percent of the emissions per megawatt-hour from the power plant, then it would receive only 60 percent (100 less 40 percent) credit for each megawatt-hour generated. As discussed earlier, the emissions associated with electricity production can be obtained by using the equivalence approach or avoided emissions approach, although we recommend the latter.

Situation 2: A particular state (or region) adopts a mass-based approach to comply with the EPA Clean Power Plan, wherein all emissions and megawatt-hours are measured across the state to calculate the statewide emissions limit for compliance with EPA guidelines. In such a case, renewable energy and energy efficiency would contribute megawatt-hours while contributing no emissions. A CHP system, however, would add to the pool of megawatt-hours produced within the state, while also contributing some non-zero emissions to the pool of emissions present in the state. The presence of CHP systems would still be beneficial as they would typically produce fewer emissions per megawatt-hour than would a power plant.

There are likely to be other approaches or variations to the above approaches suggested, that are adopted by different states. Accordingly, EPA should provide appropriate and comprehensive guidance on how CHP can serve as a valuable compliance option towards meeting the goals of the Clean Power Plan. EPA acknowledges that it “intends to develop guidance for evaluation, monitoring, and verification (EM&V) of renewable energy and demand-side energy efficiency programs and measures incorporated in state plans.”[11] However, it is not clear whether this commitment encompasses approaches that advance CHP. In particular, states will need model rules detailing the best way to include CHP in rate-based or mass-based approaches, or in energy portfolio standards, along with guidance on how to appropriately credit CHP output. These written materials may be supplemented with stakeholder education and outreach, such as regional workshops or webinars.

[11] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 79 Fed. Reg. 34,830, June 18, 2014, at 34,909

Appendix 7B: Energy Efficiency Evaluation, Monitoring and Verification

1) Introduction

The EPA proposes that states whose state plans include enforceable demand-side energy efficiency measures must include an evaluation, measurement, and verification (EM&V) plan that explains how the effect of those measures will be determined over the plan period.[1] This plan would specify the analytic methods, assumptions, and data sources the state will employ during the state plan performance period to determine the energy savings related to demand-side energy efficiency measures, and would be subject to EPA approval as part of a state plan. EPA is planning to establish guidance to states for acceptable quantification, monitoring, and verification of demand-side energy efficiency measures for an approvable state plan, and EPA seeks comment on critical features of such guidance, including scope, applicability, and minimum requirements, as well as the basis for and technical resources used to establish such guidance.[2]

There is no technical reason why the techniques and process used to estimate savings from energy efficiency measures are not more consistent and standardized across the nation. Rather, customer-funded energy efficiency programs are regulated by state public utility commissions and implemented for a variety of purposes: to support state carbon reduction policies, to delay or avoid expensive new power plants, and to reduce customer bills. Carbon pollution standards provide a new impetus for customer-funded energy efficiency programs and a clear policy reason for EM&V consistency and standardization across states: the savings from a LED light bulb should be measured similarly in Arizona and Wisconsin.

As explained below, EPA's EM&V guidance should ensure states establish a process that produces reasonably accurate, unbiased, and consistent estimates of savings from demand-side energy efficiency measures used in a state plan: EM&V that addresses and accounts for major sources of uncertainty and is consistent across program administrators and states. EPA can take several actions to achieve this goal:

- Promulgate detailed guidance establishing an EM&V framework (including definitions, evaluation methods and key assumptions, roles and responsibilities, peer review requirements, and transparency and reporting requirements) that – if used by states to estimate savings from demand-side energy efficiency measures – allows resulting savings estimates to be used to demonstrate compliance with a state plan or to modify an emissions rate.

[1] VIII.F.4., 34920
[2] VIII.F.4.

- Create standards and requirements for state reporting of EM&V plans, EM&V actions, savings estimates, and program details that allow easy comparison of savings estimates across program administrators and states.

- Encourage regional collaboration on EM&V, so that more states use similar analytic methods, assumptions, and data sources, and states can share the burden of developing resource-intensive inputs.

- Encourage states to subject savings estimates to peer review.

- Focus scrutiny on EM&V plans, ensuring they comport with EM&V Guidance, and on making sure that states follow EM&V plans to estimate savings.

- Require states to certify savings estimates in an open and transparent (adjudicated if requested by parties) regulatory process.

- Consider supporting the development of an energy efficiency registry.

2) **EPA should promulgate detailed guidance establishing an EM&V framework**

EPA is planning to promulgate guidance to states for acceptable quantification, monitoring, and verification of demand-side energy efficiency measures for an approvable state plan, and EPA seeks comment on critical features of such guidance, including scope, applicability, and minimum requirements, as well as the basis for and technical resources used to establish such guidance. Guidance should establish a robust EM&V framework, sufficiently robust so that if states follow EPA's guidance, resulting savings estimates can be used alongside stack measurements of CO2 output to demonstrate compliance with a state plan. EPA guidance can help ensure that savings estimates are reasonably accurate and unbiased, that savings estimates are comparable across program administrators and states, and help EPA devote scrutiny to savings estimates.

EPA proposes three options for guidance for state plans that incorporate energy efficiency requirements, programs, and measures:[3]

- Establishing specific EM&V requirements with a level of defined rigor for all energy efficiency programs and measures.

[3] State Plan Considerations TSD, Page 55.

- Establish specific EM&V requirements for certain types of widely used energy efficiency programs and measures, while establishing a generalized EM&V approach that states can apply to programs that are relatively new, innovative, or untested.

- Establish a set of generalized, process-oriented EM&V requirements that apply to all energy efficiency programs and measures, while providing flexibility to customize EM&V approaches.

EPA's EM&V guidance should accommodate the spectrum of state experience and investment in energy efficiency, and innovation in the design and implementation of energy efficiency programs. These considerations argue for guidance that both establishes a generalized EM&V approach and specific requirements for widely-used measures. New or innovative programs for which there are not yet specific requirements can follow the generalized EM&V approach, until such time as a new EM&V methodology is developed in the formal protocol development and vetting process, described in section (2)(g)(i)below. This approach would codify what states and the energy efficiency industry already have learned about EM&V, while fostering innovation.

a) **EPA has ample basis for and technical resources to establish EM&V guidance and general reporting requirements**

In recent years, various authors and organizations have established frameworks for estimating savings, articulated necessary features of frameworks for estimating savings, developed methods for estimating savings from widely-used measures, defined key EM&V terms and concepts, and developed standardized program types, metrics, survey tools, and reporting tools that facilitate reporting, comparison, and analysis of energy efficiency programs. EPA can use this prior work, much of it performed in anticipation of electric system carbon pollution regulation or legislation, to establish EM&V guidance, supplementing this work with new resources. These existing resources include:

i) The Uniform Methods Project,[4] coordinated by the Department of Energy and managed by the National Renewable Energy Laboratory: an expert-developed, peer-reviewed framework and set of protocols for developing estimates of energy savings from a variety of specific energy efficiency

[4] http://www1.eere.energy.gov/office_eere/de_ump.html

measures. In developing guidance, the EPA can use the uniform methods as methods for estimating savings from widely-used measures.

ii) The Operative Guidelines,[5] developed by the Regional Technical Forum (RTF), an advisory committee established in 1999 to develop standards to verify and evaluate energy efficiency savings in the Pacific Northwest, describe how the RTF selects, develops, and maintains methods for estimating energy savings. Reviewed by technical experts that serve on the RTF, the Guidelines define key concepts, describe how measures are classified into one of four savings protocols, describe how to determine the baseline of a measure and how broadly a measure should be defined, describe how measures should be assessed, describe how the RTF operates, and include links to other important documents, including a measure assessment template and a standard information workbook that collects information used in a variety of savings estimates. In developing guidance, the EPA can use the Guidelines as a framework for estimating savings, as methods for estimating savings from widely-used measures, and as a source for definitions of key EM&V terms and concepts.

iii) The Energy Efficiency Program Impact Evaluation Guide[6] of the State and Local Energy Efficiency Action Network (SEE Action) defines a systematic evaluation planning and implementation process, describes several standard approaches for determining energy savings, defines key terms related to energy efficiency evaluation, and provides guidance on key evaluation issues. In developing guidance, the EPA can use the Impact Evaluation Guide as a framework for estimating savings, and as a source for definitions of key EM&V terms and concepts.

iv) The publication, National Energy Efficiency EM&V Standard: Scoping Study of Issues and Implementation Requirements,[7] is a scoping study that identifies

[5] Regional Technical Forum, Roadmap for the Assessment of Energy Efficiency Measures, June 17, 2014, available at: http://rtf.nwcouncil.org/subcommittees/guidelines/RTF%20Guidelines%20(revised%206-17-2014).pdf.

[6] State and Local Energy Efficiency Action Network, 2012, Energy Efficiency Program Impact Evaluation Guide, Prepared by Steven R. Schiller, Schiller Consulting, Inc., available at: www.seeaction.energy.gov.

[7] Schiller, S., Goldman, C., and Galawish, E., National Energy Efficiency Evaluation, Measurement and Verification (EM&V) Standard: Scoping Study of Issues and

issues with developing a national EM&V standard for demand-side energy efficiency activities. It provides a set of definitions applicable to an EM&V standard, a literature review, and an annotated list of issues that need to be considered as part of developing a national EM&V standard for energy efficiency. In developing guidance, the EPA can use the Scoping Study as a description of necessary features that should be included in EM&V guidance, and as a source of definitions of key EM&V terms and concepts.

v) The publication, Review of Evaluation, Measurement and Verification Approaches Used to Estimate the Load Impacts and Effectiveness of Energy Efficiency Programs,[8] reviews the strengths and weaknesses of EM&V methods and practices, reviews EM&V issues that need to be addressed to improve and scale-up EM&V activities, and suggests activities and projects that address these EM&V issues and support more consistent and standardized approaches to estimating savings. In developing guidance, the EPA can use the Review of EM&V approaches as a description of necessary features that should be included in EM&V guidance.

vi) The publication, Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations,[9] provides guidance and recommendations on methodologies that can be used for estimating energy savings impacts resulting from residential behavior-based efficiency programs. In developing guidance, the EPA can use the publication as a source of methods for estimating savings from behavior-based programs, and as a source of definitions for key EM&V terms and concepts.

Implementation Requirements, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-4265E, April 2011, available at: http://emp.lbl.gov/publications/national-energy-efficiency-evaluation-measurement-and-verification-emv-standard-scoping.

[8] Messenger, M., et al., Review of Evaluation, Measurement and Verification Approaches Used to Estimate the Load Impacts and Effectiveness of Energy Efficiency Programs, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-3277E, April 2010, available at: http://emp.lbl.gov/publications/review-evaluation-measurement-and-verification-approaches-used-estimate-load-impacts-an.

[9] State and Local Energy Efficiency Action Network, 2012, Evaluation, Measurement, and Verification (EM&V) of
Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations, Prepared by A. Todd, E.
Stuart, S. Schiller, and C. Goldman, Lawrence Berkeley National Laboratory, available at: http://behavioranalytics.lbl.gov.

vii) The publication, Energy Efficiency Program Typology and Data Metrics: Enabling Multi-State Analyses Through the Use of Common Terminology,[10] includes a typology of standardized energy efficiency program categories, as well as metrics and associated definitions for program characteristics, costs and impacts. In developing guidance, the EPA can use the publication's typology and data metrics as a source of definitions for key EM&V terms and concepts, and as a source of program types, and metrics.

viii) The publication, The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs,[11] comprehensively examines program administrator costs of savings energy using the LBNL DSM Program Impacts Database, which has grown to encompass data from more than 100 energy efficiency program administrators in 34 states, totaling 5,900 program years from 2009-2013.[12] To aggregate data and compare cost performance between program administrators, the authors had to develop a common lexicon for describing energy efficiency programs, their costs, and impacts. The Presentation[13] includes program data reporting guidelines. Appendix B includes a program data glossary, and Appendix C describes the authors' data collection processes. In developing guidance and reporting requirements, EPA can use the report's glossary and data collection processes as a source for key EM&V terms and concepts, and a source of data collection processes and practices, and its program data reporting guidelines to help develop program and portfolio reporting requirements.

---

[10] Hoffman, I., et al., Energy Efficiency Program Typology and Data Metrics: Enabling Multi-State Analyses Through the Use of Common Terminology, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-6370E, August 28, 2013, available at: http://emp.lbl.gov/sites/all/files/lbnl-6370e.pdf.

[11] Billingsley, M., et al., The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs, Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-6595E, March 2014, available at http://emp.lbl.gov/publications/program-administrator-cost-saved-energy-utility-customer-funded-energy-efficiency-progr.

[12] Hoffman, I., et al., The Total Cost of Saving Electricity Through Utility Customer-Funded Energy Efficiency Programs, Ernest Orlando Lawrence Berkeley National Laboratory, Presentation to National Association of Regulatory Utility Commissioners Annual Meeting, November 17, 2014, available at: http://emp.lbl.gov/publications/total-cost-saving-electricity-through-utility-customer-funded-energy-efficiency-program.

[13] Slide 36.

b) Scope, applicability, and minimum criteria of EM&V guidance

Guidance should establishing a robust EM&V framework, sufficiently robust so that if states follow EPA's guidance, resulting savings estimates can be used alongside stack measurements of CO2 output to demonstrate compliance with a state plan. The scope of the guidance should be broad: it should articulate an EM&V framework that states can use to estimate savings from all demand-side energy efficiency measures, both emerging and widely-used. EPA can rely on existing EM&V protocols and scoping studies[14] to inform the drafting of detailed guidance. The publication, National Energy Efficiency EM&V Standard: Scoping Study of Issues and Implementation Requirements, includes as an appendix a draft outline for an EM&V national standard[15] that describes the key features of an EM&V framework. The Operative Guidelines of the Regional Technical Forum includes a Roadmap for the Assessment of Energy Efficiency Measures[16] and detailed Guidelines for the Estimation of Energy Savings[17] that EPA can use as an example document.

i) Scope and minimum criteria
Below, in outline form, are the minimum topics and sections Guidance should include:[18]

(1) An executive summary that summarizes and describes the purpose of the document: to describe a process by which a state can produce reasonably accurate, unbiased, and consistent estimates of savings from demand-side energy efficiency measures included in a state plan (described below)

(2) An introduction that summarizes the role of energy efficiency in the Clean Power Plan and EM&V requirements for states that utilize demand-side energy efficiency measures in a state plan

(3) A scoping section that defines the demand-side energy efficiency measures covered by the guidance

[14] Ibid [scoping study].
[15] Ibid [scoping study], Appendix C.
[16] Ibid [operative guidelines], Page 1.
[17] Ibid [operative guidelines], Page 29.
[18] As described in Ibid [national EM&V standard], Appendix C.

(4) A definitions section that defines key EM&V terms and concepts that will be used throughout the guidance. This section can be informed by the definitions provided in the technical resources listed above. As discussed below, EPA should require savings to be estimated from a "beyond business as usual" baseline. Key EM&V terms and concepts that should be defined include: measure, baseline, savings (discussed below), lifetime savings, and statistical terms like bias, confidence, and precision

(5) A principles, objectives, and metrics section

(6) An evaluation cycle or timeline section that details when states need to file or update EM&V plans, implement evaluation activities, and report savings estimates

(7) A scale and certainty section that sets expectations for how states will address error and bias in estimating savings (discussed below)

(8) A reporting section that sets transparency requirements, an overall reporting schedule and how states will communicate the process and results of EM&V activities to EPA in a standardized manner

(9) An evaluation methods and key assumptions section (discussed below), including:

   (a) what impact evaluation methods will be used to estimate savings
   (b) the baseline against which savings will be measured
   (c) the use of deemed savings values and how values will be updated
   (d) how savings from the reduction of transmission and distribution line losses will be included

(10) A section addressing requirements for evaluators, including a definition for independent evaluation, a description of how evaluation contractors should be selected, and a description of skills and assurances required of evaluators

(11) Data management strategies

(12) Data submittal process

ii) Applicability

- Robust EM&V of demand-side energy efficiency measures is especially important for states that choose the rate-based option, as EGU emission rates will have to be adjusted to take into account energy savings. In states that choose the mass-based option, the impact of demand-side energy efficiency measures result in a reduction in the mass of CO_2 emitted by EGUs. Thus, regardless of federal enforceability, EPA EM&V guidance should apply to all states that use demand-side energy efficiency measures in a rate-based system. Some portions of the guidance should be applied to states that choose the mass-based option particularly requirements for reporting savings estimates. Even in states that choose the mass-based option, a State Plan has to show a clear connection between the mass-based target and the measures the state will use to reduce emissions. Reporting savings estimates will help measure progress toward the goal, and give states early warning about which measures are underperforming. Also, consistent reporting facilitates cross-state comparisons of savings estimates

c) The purpose of EM&V guidance should be to describe a process by which a state can produce reasonably accurate, unbiased, and consistent estimates of savings from demand-side energy efficiency measures

As described in the State Plan Considerations TSD,[19] all energy savings values from demand-side energy efficiency measures are estimates: savings cannot be directly measured because it is not possible to measure what would have happened had the energy efficiency measure not been implemented. Given this, energy savings estimates should be reasonably accurate (random error should be limited), unbiased (systematic biases should be limited), and consistent (savings from a LED light bulb should be estimated the same way in Mississippi and Minnesota). Guidance can limit random error by requiring savings to be reported at a set level of certainty, as required by ISO-New England. Guidance can limit systematic error by requiring evaluators to address self-selection bias in sampling, address data collection errors, and subject statistical and engineering models to peer review. Guidance can ensure consistent estimates by identifying estimation methodologies for widely-used measures and a general EM&V process applicable to both existing and emerging measures.

[19] State Plan Considerations TSD at 38.

d) **EM&V guidance should require savings to be estimated from a baseline of "what would have happened without the energy efficiency program"**

EPA requests comment on whether states should report net or "gross" savings.[20] Gross savings are the savings from an energy efficiency program, regardless of why the participant participated. "Net" savings are a subset of gross savings: those savings attributable to a particular energy efficiency program.[21] States vary in whether energy efficiency targets are articulated and savings reported in net or gross form. The use of net savings in theory encourages program administrators to focus on measures that are not otherwise being adopted in the marketplace. But in practice, evaluators do not employ reliable methods to determine why program participants participated in programs due to challenges in determining whether a customer purchased an efficient measure due to the program's marketing, or some other influence – which increases the uncertainty of a savings estimate.

EPA should consistently require states to measure savings from a baseline that takes into account what would have happened without the program or intervention, i.e., savings beyond business as usual or beyond common practice, sometimes called "adjusted gross" savings. This is the approach taken in the Regional Technical Forum's Operative Guidelines.[22] In the guidelines, each measure for which savings are estimated must have a clearly defined baseline condition, that is, either:

- Current practice, used if the measure affects systems, equipment, or practices that are at the end of their useful life or for measures delivering new systems, equipment, or practices. For these measures, current practice is defined as the typical choices of eligible customers in purchasing new equipment and services, or

- Pre-conditions, when the system, equipment, or practice affected by the measure still has remaining useful life. For these measures, the baseline is defined as the typical conditions of the affected system, equipment, or practice. The RTF adopted this decision because of recognition, noted by others in the efficiency industry[23] and in the SEE Action Energy Efficiency Program Impact

[20] State Plan Considerations TSD at 52.
[21] Ibid [SEE Action EM&V Guide], Page A-11.
[22] Ibid [operative guidelines], "1.3.2. Savings" and "3.2 Savings Baseline," Page 3 and 10
[23] Ridge, R., et al., Gross Is Gross and Net Is Net: Simple, Right?, 2013 International Energy Program Evaluation Conference, Chicago.

Evaluation Guide,[24] that using a “what would have happened anyway baseline” and an after-the-fact determination of the amount of savings directly attributable to the program potentially adds significant uncertainty, because the baseline already accounts for existing market activity.

By requiring states to carefully account for baseline conditions, and to measure savings from a clearly defined counterfactual baseline, EPA can better ensure reasonably accurate, unbiased estimates of energy savings. The use of a “what would have happened anyway” baseline ensures that only energy efficiency measures or programs that are additional to current market practices will generate emissions reductions credit.

e) **EM&V guidance should require savings estimates to address random and systematic sources of bias**

As discussed earlier, it is impossible to directly measure the energy savings of an energy efficiency measure, so the outputs of EM&V will always be estimates of energy savings. Evaluators can improve savings estimates by reducing random and systematic sources of error, and EPA EM&V guidance should require savings estimates to address both. Random errors are those that arise by “chance:”[25] the sample from which savings are estimated could be not representative of program participants, or changes in energy use could be due to unobserved influences instead of the influence of an energy efficiency program. Systematic errors, also called bias, arise because of the evaluator’s choices and procedures.[26] An evaluator may compare energy use of program participants to a group of non-participants, when the groups are not comparable. Data collection might not include a sample representative of program participants. Statistical models could be incorrect.

As described in the SEE Action Energy Efficiency Program Impact Evaluation Guide, random sources of error are typically the easiest to quantify, using confidence intervals and statistical significance tests. Systematic errors, on the other hand, are less susceptible to quantitative description, and thus are not typically described in evaluations. To limit systematic errors, evaluators can calibrate measurement devices, use experienced and trained personnel, use rigorous data analysis, develop and apply

[24] Ibid [SEE Action EM&V guide], Page 5-9.
[25] Ibid [SEE Action EM&V guide], Page 7-8.
[26] Id.

rigorous quality control procedures, employ peer review, and implement proper random sampling techniques.[27]

As random errors can be described quantitatively, EPA's EM&V guidance can and should specify a necessary level of accuracy and uncertainty for energy savings estimates. For systematic error, guidance can require an EM&V plan to address sources of systematic error. Systematic error could also be a focus of those assigned to review savings estimates, either at EPA or peer reviewers at the state or regional level who review savings estimates before submission to EPA.

EPA could use the same formal stakeholder process used to determine acceptable evaluation approaches (explained below) to develop evaluation rigor requirements and required actions to limit bias.

f) EM&V guidance should include transparency and reporting requirements, and encourage states to subject savings estimates to peer review

Estimating savings from demand-side energy efficiency measures inevitably involves the application of judgment. To ensure credible savings estimates, evaluator judgment should be applied transparently and reported to other stakeholders. Subjecting savings estimates to peer review by collaborative groups of technical experts can further increase the credibility and accuracy of savings estimates. EPA guidance should include minimum transparency and reporting requirements, and encourage states to subject savings estimates to peer review.

i) Transparency requirements

EM&V guidance should require states to publicly post savings estimates in draft form, for public comment. Evaluators should be required to explain how and why comments were or were not incorporated into final savings estimates.

ii) Reporting requirements

EPA summarizes existing state practices for reporting savings estimates,[28] notes significant variation in state practices, and asks:

[27] Id. at 7-9.
[28] State Plan Considerations TSD at 76-77.

- Are reporting processes, timeframes, and documentation required by state PUCs sufficient and appropriate for state plans?

- Should lead state agencies that oversee energy efficiency programs be required to certify reported energy efficiency savings impacts on behalf of the state, potentially including certification that the values are appropriate and conservative, and meet their approval?

Existing state reporting practices vary significantly, and thus there is wide variation in how savings estimates, program costs, and program details are reported across and even within states. For example, savings estimates, program costs, and program details in Illinois are reported in a standard format by investor-owned electric and natural gas utilities: standardization that was facilitated by the state's Stakeholder Advisory Group.[29] In Ohio, in contrast, each investor-owned electric utilities presents savings estimates in a different format, making comparing program performance difficult. In the context of the proposed rule, the current variation in state and program administrator reporting is problematic, as it makes comparing savings estimates among and within states difficult and laborious, and complicates aggregate analyses of important energy efficiency topics, like program costs.[30]

EPA should require states to present EM&V plans and savings estimates in a consistent format that allows viewers to easily understand what EM&V activities were undertaken and the key assumptions and methods used by evaluators. The above-referenced Energy Efficiency Program Typology and Data Metrics, and its glossary, and the previously-referenced Appendix C to The Program Administrator Cost of Saved Energy for Utility Customer Funded Energy Efficiency Programs report could serve as technical bases for this consistent format. In addition, the following documents can inform EPA reporting requirements:

- The Model EM&V Methods Standardized Reporting Forms for Energy Efficiency,[31] a project of the Regional Evaluation, Measurement, and

[29] http://www.ilsag.info/
[30] See, for example, Slides 33 to 38 of the Presentation, Ibid [The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs].
[31] Regional Evaluation Measurement & Verification Forum, Model EM&V Methods Standardized Reporting Forms for Energy Efficiency, facilitated and managed by Northeast Energy Efficiency Partnerships, July 2014, available at: http://www.neep.org/resources.

Verification Forum, facilitated and managed by the Northeast Energy Efficiency Partnerships, is a model template that supports greater transparency of program administrator and state EM&V practices used to estimate savings by using a standardized EM&V methods check list. The forms allow for easy understanding of the key assumptions and methods used in a savings estimate. The forms could be modified and expanded for use in a state EM&V plan and for reporting.

- The Energy Information Administration's Form 861, Annual Electric Power Industry Report, includes a section that requires respondents to report savings estimates, as described in the form's instructions[32]

- The Consortium for Energy Efficiency's Annual State of the Energy Efficiency Program Industry report is based on a standardized form sent to program administrators

- The presentation that accompanies the previously-referenced report on the program administrator cost of saved energy includes a set of program data reporting guidelines.[33]

EPA's proposed rule and technical support documents are unclear on what energy efficiency reporting requirements will be required of different types of states and state plans.[34] EPA should require consistent reporting of savings estimates from all states that propose to use energy efficiency measures – either directly or indirectly – to reduce emissions from affected EGUs, for two reasons. First, even in mass-based states, a State Plan has to show a clear connection between the mass-based target and the strategies a state will use to reduce emissions. To the extent a state uses energy efficiency measures to reduce emissions, reporting on the estimated savings from those energy efficiency measures will help measure progress, and give states early warning about which measures are underperforming. Second, mandatory reporting of savings estimates will enable cross-state comparisons of savings estimates. Such comparisons will be more

---

[32] http://www.eia.gov/survey/form/eia_861/instructions.pdf

[33] Slide 36, Presentation, Ibid [The Program Administrator Cost of Saved Energy for Utility Customer-Funded Energy Efficiency Programs].

[34] Compare State Plan Considerations TSD at 75 and 35. The former states that reporting may be necessary for energy efficiency actions in states that use a portfolio mass-based approach, while the latter implies that EM&V is not necessary in states that choose any type of mass-based approach.

difficult and less comprehensive if data from states that choose the mass-based approach are not available.

In EM&V Guidance, EPA should require all states to report savings estimates and evaluation activities, program costs, and program details in a standardized manner that facilitates easy understanding of savings estimates, as well as key EM&V assumptions and methods.

iii) **Peer Review**

Peer review is one technique used in the sciences to evaluate and improve the quality and veracity of scientific research and analysis (other techniques include pre-registration of study designs and replication). Peer review is well suited to energy efficiency evaluation, which incorporates both social science and engineering methods. A diverse peer review panel can help to ensure that efficiency analyses and estimates are thoroughly vetted and credible. Peer review can also serve to integrate dispersed knowledge among engineers, analysts, and implementers into efficiency evaluation.

State use of technically-rigorous, transparent peer review can increase the credibility, accuracy, and consistency of savings estimates. This approach has been demonstrated in leading states and regions, and can be deployed in states or regions nationwide. Collaborative EM&V efforts include:

- The Regional Technical Forum (RTF): an advisory committee, established in 1999 pursuant to federal legislation.[35] It advises the Northwest Power and Conservation Council, the Bonneville Power Administration (BPA), the region's utilities, and other organizations, such as the Northwest Energy Efficiency Alliance and the Energy Trust of Oregon, on technical matters related to conservation and renewable resources development. The RTF is primarily funded by BPA, regional utilities, and the Energy Trust of Oregon. The RTF is composed of 20-30 members[36] who are selected on the basis of their expertise and experience in the areas of economic and engineering analysis and the planning, implementation, and evaluation of energy efficiency programs and renewable resource projects.

[35] http://rtf.nwcouncil.org/
[36] An NRDC scientist has been a member of the RTF since January 2013.

The primary responsibility of the RTF is the development of standardized protocols for verifying and evaluating savings from demand-side energy efficiency measures. The RTF has adopted two approaches for developing savings estimation methods. For common measures, it approves savings estimates that can be directly adopted. For more complex measures and program-impact evaluation methods, the RTF provides guidance that program operators can use to develop savings estimates. The RTF has developed savings estimates for dozens of measures and standard protocols for determining savings from a number of additional more complex measures. RTF savings estimates are widely adopted throughout the four northwest states, both by public utilities and by private utilities in state PUC proceedings.

- The Northeast Energy Efficiency Partnership (NEEP) EM&V Forum[37] was established in 2008 and now includes representatives from ten states in the Northeast and mid-Atlantic region. The Forum is managed by a steering committee,[38] which includes air and utility regulators, and is funded by state energy agencies and participating utilities. Recent projects include a review of cost-effectiveness methods, a study of estimating savings from codes and standards, research on load shapes and incremental costs, and development of a common energy efficiency database.

- The California Technical Forum (CalTF)[39][40] is a panel of technical experts who use independent professional judgment in a transparent and technically rigorous process to develop and review energy savings and other measure parameters (such as measure costs and expected useful lives) and other technical information related to the California energy efficiency portfolio. The initial focus of the Cal TF was the development of savings estimates for new measures. The scope is now being expanded to address existing measures and other technical information needed to support California's energy efficiency programs.

[37] http://neep.org/emv-forum/about-emv-forum
[38] http://neep.org/emv-forum/steering-committees
[39] http://switchboard.nrdc.org/blogs/pmiller/new_organization_could_help_pu.html
[40] http://www.caltf.org/

EPA should encourage states to engage technical experts in the review of savings estimates by making peer review a factor in determining how closely EPA will scrutinize a savings estimate, as discussed below. EPA should also explore providing technical assistance for the development of regional EM&V peer review groups similar to the NEEP EM&V Forum and the RTF.

g) **EM&V guidance should include an evaluation methods and key assumptions section**

The use of consistent evaluation methods and key assumptions for similar measures or program types is essential to the development of consistent savings estimates across states and program administrators. EPA proposes to not limit the types or programs of demand-side energy efficiency measures that can be included in a state plan, provided that supporting EM&V is rigorous, complete, and consistent with EPA guidance.[41] EPA also proposes that the level and type of EM&V documentation for energy efficiency measures be categorized in a qualitative hierarchy, from those measures where EM&V protocols are well-established (and where EPA presumably applies less scrutiny to savings estimates, provided they were generated with the well-established protocol) to those measures for which EM&V protocols are not well-established. NRDC supports the use of such a hierarchy in scrutinizing savings estimates, provided EPA is flexible in the definition of a well-established EM&V protocol. For example, the protocol for measuring savings from opt-out behavioral programs is well-established.[42] An evaluations methods and key assumption section of EM&V guidance should address at minimum the following topics:

i) Acceptable impact evaluation approaches for measures

EPA EM&V guidance should outline acceptable impact evaluation approaches for widely-used measures, referencing existing uniform methods where appropriate. For measures that do not have a widely-accepted EM&V protocol (city benchmarking efforts, increasing building code compliance, for example), guidance should outline acceptable evaluation approaches, such as the use of randomized controlled trials, quasi-experimental design or natural experiments, or the undertaking of a code compliance study at program launch. EM&V for measures without a widely-accepted protocol should pay particularly close attention to baseline issues, ensuring savings are measured compared to a "what

[41] VIII.F.4.
[42] Ibid [SEE Action behavioral EM&V paper].

would have happened anyway," and that evaluations minimize systematic biases like self-selection.

EPA should convene an independent entity or task force of EM&V experts as soon as possible to develop a list of acceptable EM&V methods and industry-accepted protocols, and identify gaps where protocols do not exist or need additional development. Such a protocol process should identify appropriate existing and/or new EM&V methods protocols for determining baselines, verification of installations, and estimating EE savings and measure persistence, and other identified areas for specific program types or projects (e.g., building code programs). The process for identifying industry-accepted best practices should largely focus on citing existing protocols that are already in use by states, or that have recently developed for the purpose of documenting best practices in EM&V.

ii) Baseline issues, as described above

iii) The use of deemed savings or unit energy saving values as savings estimates

Deemed savings values are stipulated savings estimates "based on historical and verified data, in some cases using the results of prior M&V studies. Similarly, deemed savings calculations are standardized algorithms" for the development of a savings estimate for a particular measure.[43] The use of deemed savings can reduce the cost and uncertainty of EM&V: evaluators focus on verifying measure installation rather than determining a measure's energy savings. States should be able to use deemed savings values, provided they are subject to peer review, comport with a "what would have happened anyway" baseline, and are regularly updated based on new evaluations. Some state databases of savings estimates, known as Technical Reference Manuals, may not be sufficient. EPA should explore providing technical assistance for the creation of regional deemed savings databases. EPA EM&V guidance should address criteria for the use of deemed savings values, rather than approving default savings values for use in state plans.

iv) Other details, like how savings from the reduction of transmission and distribution line losses, or the optimization of customer voltage, will be treated.

[43] Ibid [SEE Action EM&V guide], Page xviii.

3) EPA should create standards for state reporting of EM&V plans, EM&V actions, and savings estimates that allow easy comparison across program administrators and states

As described in section 2(f) above, it can currently be difficult to compare and understand energy savings estimates across program administrators and states. Promulgating detailed EM&V guidance, as described above, will increase the consistency and comparability of savings estimates and methodologies. EPA should also include in its final rule requirements for state reporting of EM&V plans, EM&V actions, savings estimates, program costs, and program details.

4) EPA should focus scrutiny on state EM&V plans, ensuring they comport with EM&V Guidance, and on making sure that states follow EM&V plans in estimating savings

Promulgating detailed EM&V guidance can help EPA manage its limited regulatory resources. Rather than reviewing every savings estimate for specific demand-side energy efficiency measures or programs in a state, EPA can instead review state EM&V plans to ensure they comport with EPA's guidance, approving or modifying accordingly. As states use energy savings to generate emissions reductions credits, EPA should ensure that savings estimates were generated according to the state's EM&V plan.

5) EPA should require lead state agencies that oversee energy efficiency programs to certify savings estimates in an open and transparent process, before they are used to modify an emissions rate

EPA asks "whether lead state agencies that oversee energy efficiency programs should be required to certify reported energy efficiency savings impacts on behalf of the state, potentially including certification that the values are appropriate and conservative, and meet their approval."[44] EPA should require lead state agencies that oversee energy efficiency programs, or the regulators responsible for submitting and implementing a state plan, to certify that savings estimates are appropriate, reasonably accurate, and unbiased, before these savings estimates are used to modify an emissions rate or used to show progress toward a mass-based goal. The application by states of EPA's EM&V guidance will help ensure that savings estimates meet these criteria, but an open and transparent process (adjudicated if requested by parties) provides an important opportunity for citizens to ensure that savings estimates reflect actual emission

[44] State Plan Considerations at 78.

reductions, and to enforce a state's regulatory commitment to only issue properly verified credits.

6) EPA should consider supporting the development of a national energy efficiency registry.

EPA should consider supporting the development of a national EE registry (e.g., The Climate Registry proposed EE Registry[45]) where such a registry can support state documentation of EE savings, underlying EM&V methods used and level of rigor (e.g., confidence/precision level and treatment of systemic error), and associated avoided emissions. Such a registry could also provide the basis for support of the exchange of tradable efficiency credits across states and help avoid double-counting of EE credits.

[45] See http://www.theclimateregistry.org/downloads/2014/09/TCR_An-EE-Registry.pdf

Appendix 8A: IPM Sensitivity Analysis

This Appendix includes data tables that detail model outputs for two sensitivity analyses that NRDC performed, based on the NODA Pro Rata cases. Additional model runs using the NODA Dirtiest First approach are currently under development, and will be published at a later date.

New Units for Compliance

In this analysis, NRDC examined the effects of including new units for compliance in the NODA Pro Rata case. As described above, we examined a case in which all state targets are based on a minimum level of generation shift from higher-emitting sources to lower-emitting sources. In the analysis of the "NODA, minimum generation shift" case, to maintain symmetry between target-setting and compliance, new fossil sources are allowed to count for compliance with state targets. In this sensitivity analysis, we examine the impacts of allowing new sources for compliance even when it is not used in target-setting.

The following tables summarize the results of this sensitivity case.

Constrained Energy Efficiency

In Section 7, we demonstrate that even more energy efficiency can be achieved and sustained than the 1.5 % annual savings EPA included in the proposed rule. Energy efficiency programs can also ramp up more quickly than EPA assumed. The data we present in Section 7 shows that energy efficiency savings can expand at a rate of at least 0.25 % of annual retail electric sales per year and can reach and sustain a level of energy efficiency savings of 2 % annually. And the same data also shows that it is even easier to achieve and sustain 1.5 % annual savings.

But some commenters continue to express concerns that achieving energy efficiency may be difficult. These concerns are not, in our view, supported by any substantial evidence. Nonetheless, we have analyzed a scenario in which less energy efficiency was available.

Specifically, for this sensitivity analysis NRDC analyzed a case with a constrained amount of demand-side energy efficiency, using state targets derived based on the pro rata displacement approach described in the November 2014 NODA, with 20 percent new natural gas used in setting the targets. NRDC plans also to analyze a constrained efficiency case using state targets derived based on the second approach described in the NODA, under which fossil steam is displaced first for the purposes of the target-setting calculation. These results could differ from those presented here, and we plan to submit these results once they are available in a supplemental filing.

The following tables summarize the results of the above sensitivity cases:

Table 8A.1: Projected CO_2 Emissions

CO_2 Emissions (thousand short tons)					
Scenario	2005	2012	2020	2025	2030
Historical	2,647,835	2,229,622			
NRDC Reference Case 3			2,037,266	2,141,577	2,211,134
NODA Pro-Rata, Incl New Sources			1,767,731	1,683,938	1,606,581
NODA Pro-Rata + Min Gen Conversion, Constrained EE			1,760,535	1,693,978	1,653,696

Table 8A.2: Projected CO_2 Emissions, Relative to 2005 and 2012 levels

CO_2 Emissions						
	% from 2005			% from 2012		
Scenario	2020	2025	2030	2020	2025	2030
NRDC Reference Case 3	-23%	-19%	-16%	-9%	-4%	-1%
NODA Pro-Rata, Incl New Sources	-33%	-36%	-39%	-21%	-24%	-28%
NODA Pro-Rata + Min Gen Conversion, Constrained EE	-34%	-36%	-38%	-21%	-24%	-26%

Table 8A.3: Projected SO_2 Emissions

SO_2 Emissions (thousand short tons)						
				Relative to BAU*		
Scenario	2020	2025	2030	2020	2025	2030
NRDC Reference Case 3	1,758	1,879	1,810	0%	0%	0%
NODA Pro-Rata, Incl New Sources	1,303	1,225	1,195	-26%	-35%	-34%
NODA Pro-Rata + Min Gen Conversion, Constrained EE	1,260	1,165	1,130	-28%	-38%	-38%

Table 8A.4: Projected NO_x Emissions

NO_x Emissions (thousand short tons)						
				Relative to BAU*		
Scenario	2020	2025	2030	2020	2025	2030
NRDC Reference Case 3	1,255	1,318	1,344	0%	0%	0%
NODA Pro-Rata, Incl New Sources	1,051	1,014	982	-16%	-23%	-27%
NODA Pro-Rata + Min Gen Conversion, Constrained EE	1,054	1,017	986	-16%	-23%	-27%

Table 8A.5: Projected Incremental Costs of Compliance

Total System Costs (Million 2011$)			
Scenario	2020	2025	2030
NRDC Reference Case 3	0	0	0
NODA Pro-Rata, Incl New Sources	3,654	1,353	6,015
NODA Pro-Rata + Min Gen Conversion, Constrained EE	5,969	4,332	9,945

Table 8A.6: Projected 2020 Generation Mix

2020 Generation Mix (TWh)					
	2005	2012	NRDC RC3	NODA Pro-Rata, Incl New Sources	NODA Pro-Rata + Conv, Constrained EE
Coal Generation	2,013	1,514	1,578	1,261	1,231
NGCC Generation	568	1,015	983	1,140	1,212
Gas CT Generation	82	97	44	45	43
Generation - Oil/Gas Steam	122	23	2	2	2
Nuclear Generation	782	769	817	817	817
Generation – Hydro	270	276	270	270	271
Biomass Generation	30	58	39	40	41
Generation - All Renewables	33	161	458	490	510
Energy Efficiency Generation*	n/a	n/a	0	118	59
Generation – Other	129	270	40	44	45
Total Generation	4,029	4,183	4,232	4,229	4,230

Table 8A.7: Projected 2025 Generation Mix

2025 Generation Mix (TWh)					
	2005	2012	NRDC RC3	NODA Pro-Rata, Incl New Sources	NODA Pro-Rata + Conv, Constrained EE
Coal Generation	2,013	1,514	1,675	1,196	1,156
NGCC Generation	568	1,015	983	1,101	1,246
Gas CT Generation	82	97	50	45	45
Generation - Oil/Gas Steam	122	23	4	2	2
Nuclear Generation	782	769	822	822	822
Generation – Hydro	270	276	271	269	271
Biomass Generation	30	58	42	44	46
Generation - All Renewables	33	161	522	553	608
Energy Efficiency Generation*	n/a	n/a	0	333	168
Generation – Other	129	270	44	46	45
Total Generation	4,029	4,183	4,412	4,410	4,408

Table 8A.8: Projected 2030 Generation Mix

2030 Generation Mix (TWh)					
	2005	2012	NRDC RC3	NODA Pro-Rata, Incl New Sources	NODA Pro-Rata + Conv, Constrained EE
Coal Generation	2,013	1,514	1,687	1,150	1,093
NGCC Generation	568	1,015	1,118	1,028	1,305
Gas CT Generation	82	97	62	47	48
Generation - Oil/Gas Steam	122	23	3	2	1
Nuclear Generation	782	769	799	799	799
Generation – Hydro	270	276	273	271	272
Biomass Generation	30	58	44	45	47
Generation - All Renewables	33	161	535	567	637
Energy Efficiency Generation*	n/a	n/a	0	604	304
Generation – Other	129	270	44	50	51
Total Generation	4,029	4,183	4,564	4,562	4,557

Appendix 8B: Full IPM Summary Tables

Table 8B.1: Summary and descriptions of all IPM runs presented in NRDC's technical comments

Summary and Descriptions of IPM Runs				
Scenario	EE Assumptions	RE Assumptions	EIA AEO Year	Other notes
Reference Case 1	**N/A**	**EPA**	**2013**	
EPA Option 1 State	Hard-wired	EPA	2013	EPA's Option 1 State targets
EPA Option 1 Regional	Hard-wired	EPA	2013	EPA's Option 1 Regional targets
$40/ton	Hard-wired	EPA	2013	$40/ton carbon price applied during 2020-2030 period
Reference Case 2	**N/A**	**NRDC Updates**	**2013**	
NRDC Option 1 State	Supply Curve	NRDC Updates	2013	EPA's Option 1 State targets
NRDC Option 1 Regional	Supply Curve	NRDC Updates	2013	EPA's Option 1 Regional targets
RE Market Potential	Supply Curve	NRDC Updates	2013	Applied $30/MWh cost reduction to RE
RE Market Potential w/ DG, Ambitious Solar	Supply Curve	NRDC Updates, + Ambitious Solar	2013	Same as above, but includes dist. Solar and assumes Sunshot goal reached by 2030
Reference Case 4	**N/A**	**NRDC Updates**	**2014**	Updated CC heat rates; 60-year nuclear retirements
NODA Dirtiest First	Supply Curve	NRDC Updates	2014	Updated state targets using the formula change presented in the NODA, backing out highest-emitting sources first
NODA Dirtiest First, + Min Gen Conversion	Supply Curve	NRDC Updates	2014	Same as above, and assumes 20% minimum generation conversion from higher to lower emitting sources
NODA Pro-Rata	Supply Curve	NRDC Updates	2014	Updated state targets using the formula change presented in the NODA, backing out fossil sources on a pro-rata basis
NODA Pro-Rata, + Min Gen Conversion	Supply Curve	NRDC Updates	2014	Same as above, and assumes 20% minimum generation conversion from higher to lower emitting sources
NODA Pro-Rata, Incl New Sources	Supply Curve	NRDC Updates	2014	NODA Pro-Rata, with new fossil sources allowed for compliance

NODA Pro-Rata, + Min Gen Conversion, Constrained EE	Supply Curve	NRDC Updates	2014	NODA Pro-Rata + min gen conversion, constrained EE sensitivity case
EPA Mass Caps	Supply Curve	NRDC Updates	2014	EPA mass caps based on November Supplemental TSD
Leakage Case	Supply Curve	NRDC Updates	2014	EPA mass caps, except PA and NM have their proposed rate targets

In Tables B.2 and B.3, we present the renewable energy and energy efficiency assumptions used in many of the IPM analyses. These assumptions are fully documented in Sections 6 and 7, respectively, and are also detailed in NRDC's Issue Brief, titled, "The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030," available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf. The Issue Brief has also been submitted as attachment 8C.

Table 8B.2: Renewable Energy Cost and Performance

Renewable Energy Cost and Performance Assumptions				
	Installed Costs ($/kW)		Average Capacity Factor	
	Wind	Solar	Wind	Solar
EIA AEO 2013	2213	3098	35%	20%
Updated EE & RE Costs	1750	1770	44%	16%

Table 8B.3: Energy Efficiency Assumptions in NRDC Updated Costs and Performance Runs vs. EPA Runs

Energy Efficiency Assumptions						
	Modeling Approach	Start Year	Ramp-up	Average Cost ($/MWh)		
				2020	2025	2030
EPA EE & RE Costs	Hard-wired	2017	1.5%/year	$85/MWh	$89/MWh	$90/MWh
Updated EE & RE Costs	Supply Curve	2017	2%/year	$47/MWh	$53/MWh	$53/MWh

Table 8B.4: Projected CO_2 Emissions

CO_2 Emissions (thousand short tons)					
Scenario	2005	2012	2020	2025	2030
Historical	2,647,835	2,229,622			
EPA Reference Case (1)			**2,318,135**	**2,411,723**	**2,446,977**
EPA Option 1 State			1,907,158	1,871,866	1,850,836
EPA Option 1 Regional			1,926,222	1,891,162	1,876,419
$40/ton Carbon Price			1,470,024	1,381,565	1,334,736
NRDC Reference Case (Updated RE) (2)			**2,190,466**	**2,315,171**	**2,365,674**
NRDC Option 1 State (Updated EE/RE)			1,881,987	1,842,400	1,797,163
NRDC Option 1 Regional (Updated EE/RE)			1,928,145	1,903,737	1,868,378
NRDC Reference Case (AEO 2014, Updated RE) (3)			**2,037,266**	**2,141,577**	**2,211,134**
NODA Dirtiest First			1,692,837	1,581,877	1,495,354
NODA Dirtiest First, + Min Gen Conversion			1,704,524	1,579,002	1,484,894
NODA Pro-Rata			1,748,285	1,660,326	1,591,852
NODA Pro-Rata, + Min Gen Conversion			1,758,458	1,669,879	1,587,427
NODA Pro-Rata, Incl New Sources			1,767,731	1,683,938	1,606,581
NODA Pro-Rata + Min Gen Conversion, Constrained EE			1,760,535	1,693,978	1,653,696

Table 8B.5: Projected CO_2 Emissions, Relative to 2005 and 2012 levels

Projected CO_2 Emissions						
	% Rel. to 2005			% Rel to 2012		
Scenario	2020	2025	2030	2020	2025	2030
EPA Reference Case (1)	-12%	-9%	-8%	4%	8%	10%
EPA Option 1 State	-28%	-29%	-30%	-14%	-16%	-17%
EPA Option 1 Regional	-27%	-29%	-29%	-14%	-15%	-16%
$40/ton Carbon Price	-44%	-48%	-50%	-34%	-38%	-40%
NRDC Reference Case (Updated RE) (2)	-17%	-13%	-11%	-2%	4%	6%
Updated Costs & Performance Option 1 State	-29%	-30%	-32%	-16%	-17%	-19%
Updated Costs & Performance Option 1 Regional	-27%	-28%	-29%	-14%	-15%	-16%
NRDC Reference Case (AEO 2014, Updated RE) (3)	-23%	-19%	-16%	-9%	-4%	-1%
NODA Dirtiest First	-36%	-40%	-44%	-24%	-29%	-33%
NODA Dirtiest First, + Min Gen Conversion	-36%	-40%	-44%	-24%	-29%	-33%
NODA Pro-Rata	-34%	-37%	-40%	-22%	-26%	-29%
NODA Pro-Rata, + Min Gen Conversion	-34%	-37%	-40%	-21%	-25%	-29%
NODA Pro-Rata, Incl New Sources	-33%	-36%	-39%	-21%	-24%	-28%
NODA Pro-Rata + Min Gen Conversion, Constrained EE	-34%	-36%	-38%	-21%	-24%	-26%

Table 8B.6: Projected SO2 Emissions

SO_2 Emissions (thousand short tons)			
Scenario	2020	2025	2030
EPA Reference Case (1)	1,792	1,885	1,862
EPA Option 1 State	1,337	1,338	1,332
EPA Option 1 Regional	1,362	1,358	1,335
$40/ton Carbon Price	899	775	699
NRDC Reference Case (Updated RE) (2)	1,726	1,843	1,823
Updated Costs & Performance Option 1 State	1,390	1,346	1,348
Updated Costs & Performance Option 1 Regional	1,467	1,462	1,474
NRDC Reference Case (AEO 2014, Updated RE) (3)	1,758	1,879	1,810
NODA Dirtiest First	1,198	1,086	1,033
NODA Dirtiest First, + Min Gen Conversion	1,188	1,066	1,019
NODA Pro-Rata	1,271	1,197	1,171
NODA Pro-Rata, + Min Gen Conversion	1,280	1,200	1,160
NODA Pro-Rata, Incl New Sources	1,303	1,225	1,195
NODA Pro-Rata + Min Gen Conversion, Constrained EE	1,260	1,165	1,130

Table 8B.7: Projected NO_x Emissions

NO_x Emissions (thousand short tons)			
Scenario	2020	2025	2030
EPA Reference Case (1)	1,312	1,345	1,327
EPA Option 1 State	976	956	947
EPA Option 1 Regional	1,013	995	976
$40/ton Carbon Price	596	528	478
NRDC Reference Case (Updated RE) (2)	1,213	1,273	1,270
Updated Costs & Performance Option 1 State	988	959	934
Updated Costs & Performance Option 1 Regional	1,053	1,038	1,000
NRDC Reference Case (AEO 2014, Updated RE) (3)	1,255	1,318	1,344
NODA Dirtiest First	1,057	1,001	960
NODA Dirtiest First, + Min Gen Conversion	1,013	950	910
NODA Pro-Rata	1,074	1,038	1,001
NODA Pro-Rata, + Min Gen Conversion	1,040	997	971
NODA Pro-Rata, Incl New Sources	1,051	1,014	982
NODA Pro-Rata + Min Gen Conversion, Constrained EE	1,054	1,017	986

Table 8B.8: Projected Compliance Costs

Total System Compliance Costs (2011$)			
Scenario	2020	2025	2030
EPA Reference Case (1)	**0**	**0**	**0**
EPA Option 1 State	8,357	3,432	10,529
EPA Option 1 Regional	6,859	2,367	9,200
$40/ton Carbon Price	26,287	21,869	26,688
NRDC Reference Case (Updated RE) (2)	**0**	**0**	**0**
Updated Costs & Performance Option 1 State	-1,784	-4,643	-6,431
Updated Costs & Performance Option 1 Regional	-4,294	-6,566	-9,441
NRDC Reference Case (AEO 2014, Updated RE) (3)	**0**	**0**	**0**
NODA Dirtiest First	7,508	4,202	10,424
NODA Dirtiest First, + Min Gen Conversion	6,376	4,212	10,305
NODA Pro-Rata	5,418	2,682	7,160
NODA Pro-Rata, + Min Gen Conversion	3,936	1,535	7,003
NODA Pro-Rata, Incl New Sources	3,654	1,353	6,015
NODA Pro-Rata + Min Gen Conversion, Constrained EE	5,969	4,332	9,945

Table 8B.9: Projected Wholesale Power Prices

Wholesale Power Price (Relative to BAU)			
Scenario	2020	2025	2030
EPA Reference Case (1)	**0%**	**0%**	**0%**
EPA Option 1 State	16%	-3%	0%
EPA Option 1 Regional	15%	-3%	0%
$40/ton Carbon Price	68%	42%	37%
NRDC Reference Case (Updated RE) (2)	**0%**	**0%**	**0%**
Updated Costs & Performance Option 1 State	7%	1%	-3%
Updated Costs & Performance Option 1 Regional	3%	-1%	-8%
NRDC Reference Case (AEO 2014, Updated RE) (3)	**0%**	**0%**	**0%**
NODA Dirtiest First	17%	3%	6%
NODA Dirtiest First, + Min Gen Conversion	13%	2%	6%
NODA Pro-Rata	15%	2%	1%
NODA Pro-Rata, + Min Gen Conversion	10%	-1%	1%
NODA Pro-Rata, Incl New Sources	10%	-1%	-1%
NODA Pro-Rata + Min Gen Conversion, Constrained EE	12%	2%	6%

Table 8B.10: Projected Electricity Sector Natural Gas Consumption

Natural Gas Consumption (trillion BTU)			
Scenario	2020	2025	2030
EPA Reference Case (1)	**8,814**	**9,135**	**10,088**
EPA Option 1 State	10,280	9,844	9,818
EPA Option 1 Regional	10,131	9,773	9,750
$40/ton Carbon Price	12,252	12,334	12,612
NRDC Reference Case (Updated RE) (2)	**8,180**	**8,386**	**9,367**
Updated Costs & Performance Option 1 State	8,874	8,573	7,763
Updated Costs & Performance Option 1 Regional	8,617	8,227	7,327
NRDC Reference Case (AEO 2014, Updated RE) (3)	**7,374**	**7,429**	**8,429**
NODA Dirtiest First	9,014	8,909	8,318
NODA Dirtiest First, + Min Gen Conversion	8,821	8,754	8,239
NODA Pro-Rata	8,692	8,389	7,757
NODA Pro-Rata, + Min Gen Conversion	8,459	8,211	7,695
NODA Pro-Rata, Incl New Sources	8,404	8,086	7,528
NODA Pro-Rata + Min Gen Conversion, Constrained EE	8,782	8,956	9,288

Table 8B.11: Projected Henry Hub Natural Gas Prices

Henry Hub Gas Price ($/MMBTU)			
Scenario	2020	2025	2030
EPA Reference Case (1)	**5.1**	**5.8**	**6.0**
EPA Option 1 State	5.9	5.6	6.0
EPA Option 1 Regional	5.9	5.6	6.0
$40/ton Carbon Price	6.6	6.4	6.5
NRDC Reference Case (Updated RE) (2)	**4.8**	**5.6**	**5.8**
Updated Costs & Performance Option 1 State	5.1	5.6	5.7
Updated Costs & Performance Option 1 Regional	4.9	5.6	5.4
NRDC Reference Case (AEO 2014, Updated RE) (3)	**4.6**	**5.4**	**5.6**
NODA Dirtiest First	5.3	5.5	6.0
NODA Dirtiest First, + Min Gen Conversion	5.2	5.5	6.0
NODA Pro-Rata	5.2	5.5	5.8
NODA Pro-Rata, + Min Gen Conversion	5.1	5.4	5.8
NODA Pro-Rata, Incl New Sources	5.0	5.4	5.7
NODA Pro-Rata + Min Gen Conversion, Constrained EE	5.2	5.6	6.1

Appendix 8C: NRDC Issue Brief, The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030

NOVEMBER 2014
IB:14-11-A

The EPA's Clean Power Plan Could Save Up to $9 Billion in 2030

Up-to-Date Cost Data For Clean Energy Resources Mean Lower Costs, Greater Potential for Carbon Reductions

INTRODUCTION

The U.S. Environmental Protection Agency's (EPA) Clean Power Plan is an essential step toward ending unlimited dumping of carbon pollution into our atmosphere from the largest source in the United States—existing power plants. It sets the first-ever limits on how much carbon pollution the country's existing power plants can release, and is a groundbreaking step toward combating climate change before it's too late to avoid the worst impacts. Still, the EPA can and should strengthen the proposal by requiring more reductions of dangerous carbon pollution. It can accomplish this at reasonable costs with stronger contributions from energy efficiency and renewable energy.

The EPA's Clean Power Plan establishes state-specific emission rate targets based on a technical and economic assessment of each state's opportunities to reduce carbon emissions from its electricity sector. The EPA found that by 2020, the power sector could reduce its emissions by 26 percent below 2005 levels under the Clean Power Plan, costing between $5.5 billion and $7.5 billion annually.[1,2] But because the EPA uses conservative and outdated assumptions, the agency overstates the costs of compliance—the amount the power sector would pay to implement the Clean Power Plan—by $9 billion in 2020—a correction would turn compliance costs into savings. These savings mean the power sector would spend less to meet the Clean Power Plan targets, which would result in utility bill savings for customers. There are large net savings after accounting for the significant health and environmental benefits in both the EPA's analysis as well as the one presented here. Moreover, by overstating the costs, the EPA missed an opportunity to make even deeper carbon reductions at a much lower cost than its projections suggested were attainable.

Simply by making the cost and performance parameters for renewable generation and energy efficiency consistent with today's technologies, NRDC has found that compliance with EPA's proposed limits could be achieved at a savings of between $1.8 and $4.3 billion in 2020. Using the same model as the EPA, NRDC constructed the "Updated Costs and Performance" runs, reproducing the EPA's compliance scenarios with updated assumptions to reflect current trends in energy efficiency and renewable energy technologies. Additionally, our analysis improved on the EPA's approach of subtracting pre-determined energy efficiency savings from the load forecast by using a simplified supply curve, allowing the model to choose energy efficiency on an economic basis.

In summary our findings are:

- The EPA used outdated renewable energy cost and performance numbers, including levelized costs for both wind and solar energy that are 46 percent above current average costs.[3]
- The EPA used extremely conservative energy efficiency costs that are 68–81 percent higher than current average costs.
- NRDC updated these cost and performance numbers and provided the data to ICF International. NRDC engaged ICF to run the Integrated Planning Model (IPM®), the same model that EPA uses, with the updated data. IPM® determines a least cost compliance pathway through both re-dispatch of existing resources and capacity expansion of new resources. The analysis showed:
  - Total savings of $1.8 billion to $4.3 billion in 2020, compared to the EPA's estimated compliance costs of $5.5 billion and $7.5 billion;

NRDC

For more information, please contact:

Starla Yeh
syeh@nrdc.org
switchboard.nrdc.org/blogs/syeh

- Total savings of $6.4 billion to $9.4 billion in 2030, compared to the EPA's estimated costs of $7.3 billion and $8.8 billion;
- A national total of 469 TWh of renewable generation compared with the EPA's 278 TWh in 2030; and
- Energy efficiency savings of 609 TWh in 2030, compared with 469 TWh in the EPA's analysis.

These results —which used the most recent publicly available cost and performance data for renewable energy and energy efficiency—show that the EPA can strengthen its state-by-state carbon pollution targets and achieve more pollution reductions at lower cost than projected in the original proposal.

This issue brief provides an overview of these topics, which will be addressed in further detail along with many other recommendations in NRDC's technical comments in response to the Clean Power Plan (planned for submission on December 1, 2014).

THE JUNE 2014 EPA ANALYSIS OVERESTIMATES THE COMPLIANCE COSTS OF THE PROPOSED CLEAN POWER PLAN, LARGELY DUE TO OUTDATED DATA ON COSTS AND PERFORMANCE OF EFFICIENCY AND RENEWABLES

In its Integrated Planning Model (IPM®) Base Case v5.13,[4] the EPA adopts load forecasts and new technology costs from the Energy Information Administration's (EIA) Annual Energy Outlook 2013 (AEO2013).[5] More recent industry data demonstrate that modeling assumptions used for the cost and performance characteristics of new generating technologies are significantly out of date. The cost estimates are especially important because the costs for new generation technologies drive the costs of the overall compliance costs of the Clean Power Plan Proposal.

AEO2013's assumptions were based on projects completed in 2012, and may reflect pricing contracts signed several years prior to project completion.[6] 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.[7] The capital cost of developing onshore wind turbines has also declined, from $2260/kW to $1750/kW on average.[8] Moreover, technology improvements have produced 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.[9]

In its analysis, the EPA estimates the cost of energy efficiency savings as 8.5 to 9.0 cents/kWh—an overly conservative estimate. In discussing the costs of energy efficiency programs, the EPA directly acknowledged that the "range of LCOSE [Levelized Cost of Saved Electricity] is notably conservative (leading to higher costs) in comparison with most utility and state analysis."[10] EPA overstated the cost of energy efficiency by almost twice what has been demonstrated; NRDC corrects for this by incorporating costs that accurately reflect current practice. Numerous state programs have demonstrated consistently that energy efficiency programs cost significantly less than the estimate EPA relied on in its analysis. The Updated Costs and Performance analysis presented here relies on costs ranging from 4.7 cents/kWh to 6.4 cents/kWh[11] based on estimates from Synapse Energy Economics (Synapse) and supported by LBNL. LBNL researchers found a savings-weighted average LCOSE for energy efficiency of 4.4 cents/kWh.[12]

*The **$9 billion dollar** difference between the 2020 savings in the Updated Costs and Performance assessment and the EPA's estimates indicates that the proposal could achieve significantly greater carbon reductions at a reasonable cost.*

Additionally, the EPA represents energy efficiency in the model by reducing the assumed load forecast by the amount of energy savings delivered by efficiency programs. The Updated Costs and Performance analysis reflects the available energy savings from efficiency programs at three different costs. Using this method, energy efficiency is an available technology and the model determines whether to include efficiency in the economically optimized generation mix. Table 2 compares the EPA and Updated Costs and Performance approaches to reflecting energy efficiency in the model assumptions.

In order to accurately reflect the costs and performance of energy efficiency programs, wind, and solar technologies, NRDC asked ICF to reconstruct the EPA's base case scenario in IPM® based on publicly available assumptions, replacing AEO2013 wind and solar cost and performance estimates with more up-to-date publicly available estimates as described above. Table 1 below compares these updated estimates with those in AEO2013. The Updated Costs and Performance analysis assumed that states will begin making additional investments in energy efficiency in 2017. The model can choose energy savings up to 2 percent of previous year's sales at an average utility program cost of 2.7 cents/kWh.[13] Energy efficiency participant costs were assumed to be equal to utility program costs, and are included in the total cost calculations in the Updated Costs and Performance analysis.

The EPA analyzed its proposed Clean Power Plan in two compliance scenarios[14]: Option 1 State (in which states comply individually) and Option 1 Regional (in which states form regional compliance agreements).[15] The EPA projects its proposal could lead the power sector to reduce its dangerous carbon emissions by 26 percent below 2005 levels to 1959 million short tons by 2020 in the Option 1 State scenario, at a cost of $7.5 billion with net benefits valued at $27 to

Table 1: Comparison of Wind and Solar Cost and Performance Characteristics: Updated Costs and Performance vs. AEO2013				
Renewable Energy Cost and Performance Assumptions				
	Installed Costs ($/kW)		Average Capacity Factor	
	Onshore Wind	Solar PV[17]	Onshore Wind	Solar PV[18]
EIA AEO 2013[19]	2213	3098	35%	20%
Updated Costs and Performance	1750[20]	1770[21]	45%[22]	16%[23]

Table 2: Comparison of Energy Efficiency Approaches from EPA analysis and Updated Costs and Performance Assessments						
Energy Efficiency Assumptions						
	Modeling Approach	Start Year	Ramp-up	Average Cost ($/MWh)		
				2020	2025	2030
EPA	Hard-wired	2017	1.5%/year	8.5	8.9	9.0
Updated Costs and Performance[24]	Supply Curve	2017	2%/year	4.7	5.3	5.3

$50 billion.[16] The Option 1 Regional scenario was projected to lead to a similar level of carbon pollution reductions and associated benefits, but with compliance costs of about $5.5 billion by 2030—or $2.0 billion less than if states were to comply independently.

The Updated Costs and Performance cases evaluated the state emissions-rate targets the EPA has proposed and used the same modeling framework as the EPA's "Option 1 State" and "Option 1 Regional" policy cases. It is important to note that all modeling outcomes discussed throughout the remainder of this issue brief are based on NRDC analysis, and results based on EPA assumptions may still differ from those reported in EPA's RIA due to variations in modeled regions.

Simply by making the cost and performance parameters for renewable generation and energy efficiency consistent with today's data, NRDC has found that compliance with EPA's proposed targets could be achieved at a savings of $1.8 billion (Option 1 State) to $4.3 billion (Option 1 Regional) by 2020. For 2030, the savings are even larger: $6.4 billion (Option 1 State) or $9.4 billion (Option 1 Regional). There is a $10 billion difference in 2020 and a $17 billion difference in 2030 between model runs using EPA's assumptions and the Updated Costs and Performance assumptions. These substantial savings indicate that the standards could be strengthened and achieve significantly greater carbon reductions at a reasonable cost.

Figure 1 illustrates the impact of updated cost and performance data on the incremental system cost of compliance with the proposed standard in 2020. Using the EPA's cost assumptions for energy efficiency and renewable energy technologies, the policies result in incremental costs of $8.4 billion in 2020 for Option 1 State and $6.9 billion for Option 1 Regional (shown in gray). After updating the Energy Efficiency and Renewable Energy cost assumptions, the total system costs of the Reference Case decline. This is shown by the dotted horizontal line labeled, "Cost-Adjusted Baseline" in Figure 1. Compared to the updated Reference Case (shaded green), the policy cases still result in savings of $1.8 billion for Option 1 State and $4.3 billion for Option 1 Regional. The conservative AEO2013 assumptions led the EPA to overestimate compliance costs by $9 billion dollars. The EPA could use the proposed Clean Power Plan to achieve even more significant emission reductions from the power sector while maintaining compliance costs within the predicted range.

Figure 1: 2020 Incremental Compliance Costs (+) or Savings (-) ($ Billion) of Clean Power Plan Proposal[25]

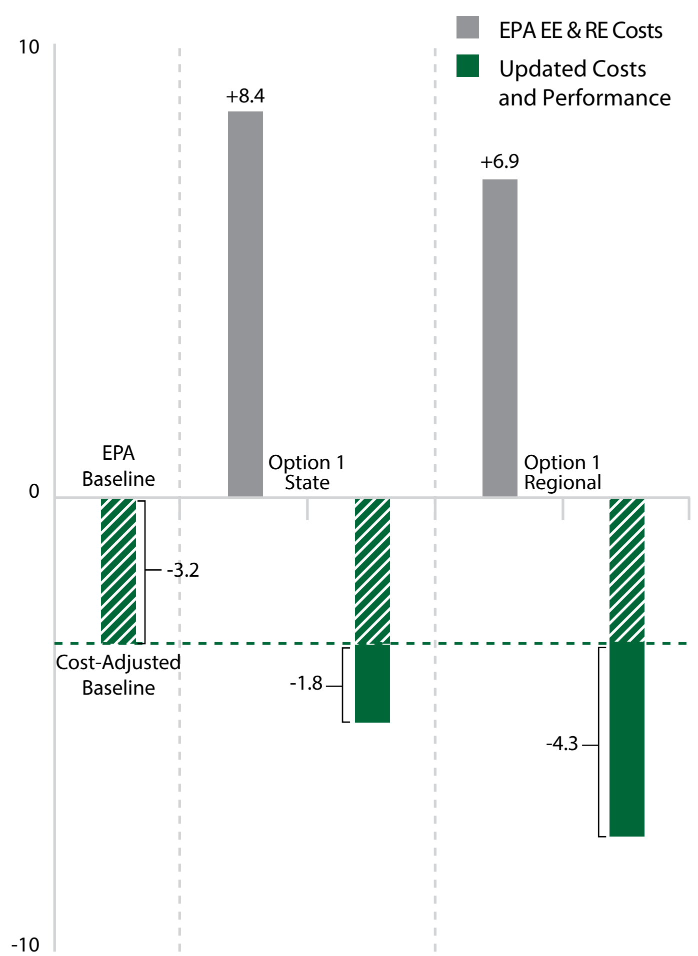


Table 3: Comparison of Incremental Compliance Costs (+) or Savings (-) of Clean Power Plan Proposal with EPA assumptions vs. Updated Costs and Performance assumptions						
Incremental System Costs ($ Billion)[26]						
	2020		2025		2030	
	Option 1 State	Option 1 Regional	Option 1 State	Option 1 Regional	Option 1 State	Option 1 Regional
EPA EE & RE Costs	8.4	6.9	3.4	2.4	10.5	9.2
Updated Costs and Performance	-1.8	-4.3	-4.6	-6.6	-6.4	-9.4

ENERGY EFFICIENCY AND RENEWABLE ENERGY COULD FEATURE MORE HEAVILY IN THE COMPLIANCE FUEL MIX THAN THE EPA'S REGULATORY IMPACT ANALYSIS SUGGESTS

Using the outdated costs and performance characteristics assumed in AEO2013 in the EPA's modelling of the Clean Power Plan proposal results in underestimating the role of energy efficiency and renewable generation technologies in meeting the EPA's proposed state targets. Renewable energy generation in the Updated Costs and Performance assessment exceeds EPA case by 60 percent by 2020 and 44 percent by 2030. Figure 2 shows the difference between generation trajectories for renewable energy (wind and solar combined)[27] using EPA's assumptions compared to the same policy scenario using the Updated Cost and Performance assumptions, relative to the historical growth of renewable energy.

Figure 2: Renewable Energy Generation Projections in EPA and Updated Costs and Performance Assessments[28]

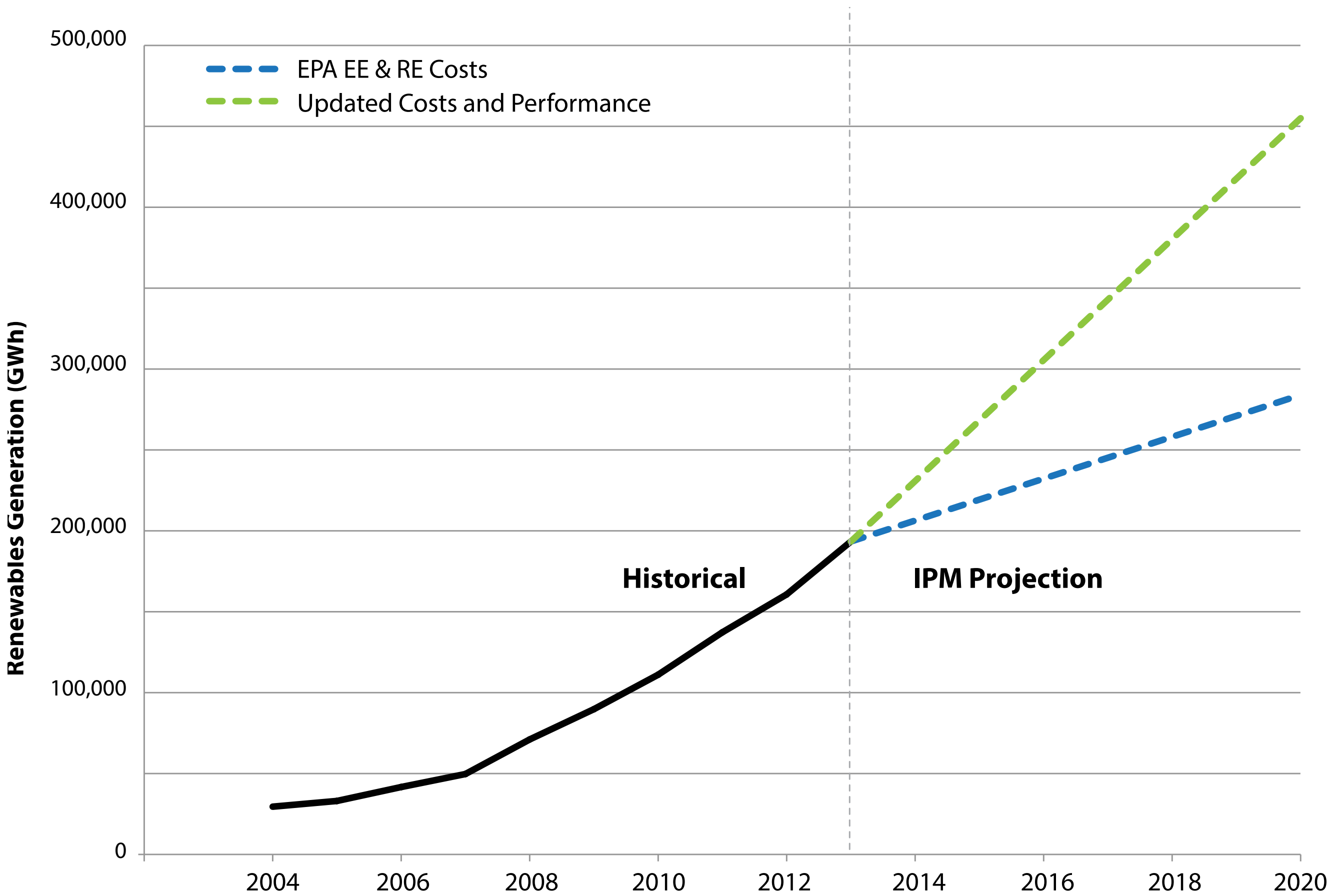


Table 4: Comparison of Total Renewable Generation[29]

Generation - All Renewables (TWh)			
Scenario	2020	2025	2030
EPA Reference Case	272	301	320
EPA Option 1 State	284	308	326
EPA Option 1 Regional	282	305	322
Reference Case - Updated Costs and Performance	428	445	453
Option 1 State - Updated Costs and Performance	455	465	469
Option 1 Regional - Updated Costs and Performance	432	441	441

Total renewable generation in the Updated Cost and Performance case exceeds the EPA case by 171 TWh in 2020, an amount equivalent to the annual electricity consumption of about *16 million homes*.[30]

Correcting the efficiency and renewables assumptions to match current data shows that renewable energy is a viable and economical compliance option. Figure 3 illustrates the compliance generation mixes in the EPA and Updated Costs and Performance cases. Note the more prominent role of energy efficiency and renewable generation in 2030.

CONCLUSION

The EPA's analysis of its Clean Power Plan proposal relies on outdated estimates of the costs and performance of renewable energy-generating technologies and an overly conservative outlook on the cost of energy efficiency. As a result, the EPA overestimates the costs of compliance and undervalues the potential for resources like renewable energy and energy efficiency as compliance pathways.

NRDC re-evaluated the Clean Power Plan proposal using the same model that the EPA uses to reproduce its base case and policy cases, updating cost and performance assumptions for energy efficiency, wind and solar energy-generating technologies. We found that the Clean Power Plan would actually save the power sector between $1.8 and $4.3 billion in 2020, and $6.4 and $9.4 billion in 2030, with energy efficiency, wind energy, and solar energy occupying a greater share of the generation mix than in the EPA's analysis. While the EPA estimates the net benefits to be valued at $27 to $50 billion in 2020 and $49 to $84 billion in 2030, this analysis shows that compliance with the proposed targets will actually produce a savings rather than a cost for the electricity system and that the net benefits will be even higher than what EPA estimates by $9 billion in 2020, and $15 billion in 2030.[31]
The EPA has room to strengthen the proposed Clean Power Plan while keeping costs reasonable, and can count on clean generation technologies to lead the way toward substantially reducing emissions of climate-changing carbon pollution from the nation's largest emitting sector. We can do so and save money even as we protect our health, our communities and future generations.

Figure 3: 2030 Generation Mix (TWh) in EPA and Updated Costs and Performance Assessments[32]

Figure 3a: EPA Base Case

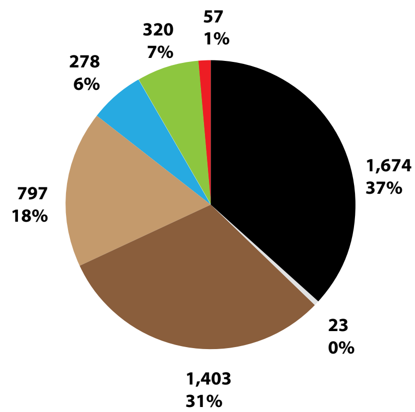


Figure 3b: EPA Option 1 State

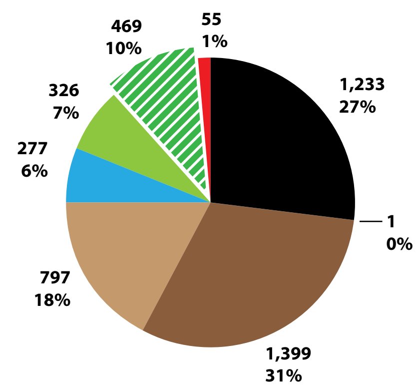
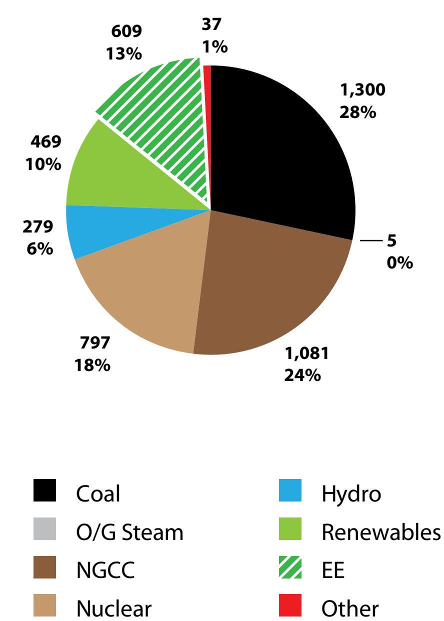


Figure 3c: Updated Costs and Performance Option 1 State



ENDNOTES

1 All compliance costs throughout this issue brief are reported in 2011$.

2 EPA Regulatory Impact Analysis of the Clean Power Plan, June 2014. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

3 EPA's cost and performance assumptions lead to an average LCOE of $224/MWh for solar and $95/MWh for wind. Updating those assumptions (see table 1) leads to an average LCOE of $153/MWh for solar and $65/MWh for wind.

4 EPA's Base Case v5.13, based on EPA's application of the Integrated Planning Model (IPM), is the basis for analysis of the impact of air emission standards on the U.S. electric sector. It serves as a starting point against which policy scenarios are compared. Base Case v5.13 is a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2013. Documentation describing assumptions, updates, and changes are available at: http://www.epa.gov/powersectormodeling/BaseCasev513.html.

5 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.

6 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). NRDC will include more detail on this matter in its technical comments.

7 Range of estimates based on data from the following sources. *See* Bottom-up modeling estimates in: 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.

8 Lawrence Berkeley National Laboratory. "2013 Wind Technologies Market Report". August 2014, available at: http://emp.lbl.gov/publications/2013-wind-technologies-market-report.

9 Discussions with American Wind Energy Association and updated industry data, and: 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-Between-Renewables-and-Natural-Gas.

10 EPA, "GHG Abatement Measures," Technical Support Document at page 5-51, available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf.

11 This refers to the total resource cost of energy efficiency programs, including two components: utility program costs and participant costs.

12 Lawrence Berkeley National Laboratory. "The Total Cost of Saving Electricity Through Utility Customer-Funded Energy Efficiency Programs." November 17, 2014 Presentation, available at: http://emp.lbl.gov/cost-saved-energy.

13 Based on Synapse Energy Economics, "Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011," available at: http://www.civilsocietyinstitute.org/media/pdfs/Toward%20a%20Sustainable%20Future%2011-16-11.pdf and LBNL, "The Total Cost of Saving Electricity Through Utility Customer-Funded Energy Efficiency Programs." November 17, 2014 Presentation, available at: http://emp.lbl.gov/cost-saved-energy.

14 In its Clean Power Plan proposal, EPA sets forth a Best System of Emission Reduction (BSER) goal approach referred to as Option 1, and takes comment on a second approach referred to as Option 2. Each of these goal approaches uses the four building blocks at different levels of stringency. Option 1 involves higher deployment of the four building blocks but allows a longer timeframe to comply (2030) whereas Option 2 has a lower deployment over a shorter timeframe (2025). This discussion focuses on Option 1. NRDC will address Option 2 in its comments.

15 EPA proposes as part of the Clean Power Plan that states would have the discretion to choose between regional or state compliance approaches. In a state compliance approach, states are assumed to comply with the guidelines by implementing measures solely within the state and emissions rate averaging is limited to intrastate affected sources. Under the regional approach, groups of states collaborate to comply with the guidelines.

16 EPA Regulatory Impact Analysis of the Clean Power Plan, June 2014. EPA estimates using the Administration's estimate for the Social Cost of Carbon. Estimates for both climate benefits and health co-benefits use a discount rate of 3%.

17 Cost and performance assumptions for solar are given in terms of kWdc. EIA's assumptions are converted from AC to DC using a 0.8 derate factor.

18 *Ibid.*

19 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.

20 Lawrence Berkeley National Laboratory. "2013 Wind Technologies Market Report". August 2014.

21 Range of estimates based on data from range of bottom-up modeling sources. See Endnote 7.

22 Discussions with American Wind Energy Association and updated industry data.

23 Solar performance estimates are based on the simple average of performance at each TMY3 weather station in each state as modeled using PVWatts in NREL's System Advisor Model (SAM). Data provided by Solar Energy Industries Association. Through innovation such as oversized inverters, individual projects have reported capacity factors of up to 30%, but we are not aware of publicly available data that captures this trend at a national level. Our performance data relies on NREL's PVWatts model, which has been recently updated to better reflect today's capacity factors. We performed a sensitivity case using these updated performance numbers, but it did not significantly affect results.

24 LBNL and Synapse.

25 Lawrence Berkeley National Laboratory. "2013 Wind Technologies Market Report". August 2014.

26 All system costs in Table 4 and in Figure 1 are developed using NRDC's IPM results. Due to variations in modeled regions, cost estimates using EPA assumptions differ from those reported in EPA's Regulatory Impact Analysis.

27 This also includes marginal amounts of solar thermal and geothermal energy generation.

28 Endnote 21 also applies for Figures 2 and 3, and Table 4: The EPA trajectory and generation mix represents NRDC's analysis of EPA's proposal using the same assumptions as EPA, but results may differ from EPA's own IPM results due to variation in modeled regions.

29 Id at 28.

30 *See* Energy Information Administration Average Annual Household Electricity Consumption, available at: *http://www.eia.gov/tools/faqs/faq.cfm?id=97&t=3*.

31 The comparison here is between the EPA's estimates in its RIA and our Updated Costs and Performance modeling for Option 1 State.

32 Id at 28.

Appendix 9A: M.J. Bradley and Associates, U.S. Electricity Consumption & Peak Demand: Comparison of Forecasts to Actual

U.S. Electricity Consumption & Peak Demand

COMPARISON OF FORECASTS TO ACTUAL
JUNE 2014

Chris Van Atten
+ 1 978 405 1264
vanatten@mjbradley.com

Purpose

- Evaluate the accuracy of load (mW) and consumption (mWh) forecasts used to make investment decisions in the electric sector
- Compare actual load and consumption in a given year to forecasts for that year made in the prior four years
- Evaluated forecasts by:

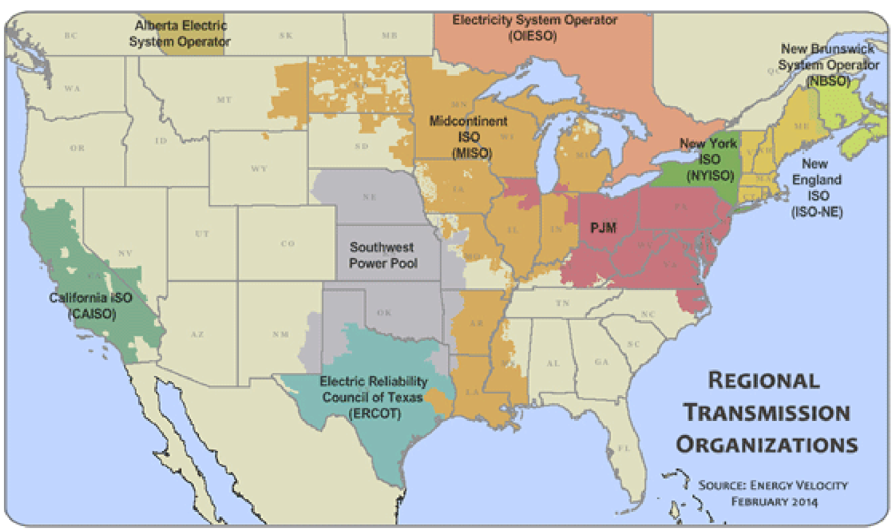
Government:	Energy Information Administration [EIA] - US California Energy Commission [CEC] - CA
Regional RTOs[1]	ISO-NE, NYISO, PJM
Utilities[2]	Florida Power & Light

[1] *Data is not publicly available from MISO or CAISO*
[2] *This is the only utility found that makes comprehensive data available publicly*

Data Availability

- Load forecast data for utilities was found to be very limited as many utilities consider this information to be confidential and do not make it publicly available. Some utilities only issue forecasts every three to four years or as part of an integrated resource plan. Because the scope of this analysis is limited to the years 2008-2012, this intermittent data could not be used to produce meaningful results.
- For this analysis, MJB&A examined over 20 utilities for load forecast data. Of these, Florida Power & Light was the only utility for which complete data was available. All other utilities either do not make forecast data publicly available or only had data for one or two years.
- MJB&A is still waiting to hear back from several state regulatory agencies that may have data for individual utilities. If this information becomes available, MJB&A will provide it to NRDC in the same format as the information included in this presentation.

U.S. Regional Transmission Organizations



Source: Federal Energy regulatory Commission

MJB & A
M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

Summary

- Generally speaking, EIA, CEC and RTO's overestimate both demand and consumption, although estimates tend to get more accurate the closer the estimate is made to the target year
- Forecasts made before 2009 tend to be several more percentage points off than later-year estimates, likely because they do not account for the economic downturn.
  - For all RTOs/ISOs, both peak demand and annual consumption dropped markedly from 2008-2009.
- Forecasts for demand four years prior range from an underestimate of 1 percent to an overestimate of 14 percent; forecasts one year prior range from an underestimate of 6 percent to an overestimate of 11 percent.
- Forecasts four years prior overestimate annual consumption by 2 percent to 10 percent; forecasts one year prior range from an underestimate of 2 percent to an overestimate of 8 percent.

Average Overestimation of RTO/ISO Forecasts

	Same Year	1 Year	2 Years	4 Years
Demand	+1.05%	+3.12%	+3.83%	+5.44%
Consumption	+1.91%	+3.67%	+4.62%	+6.58%

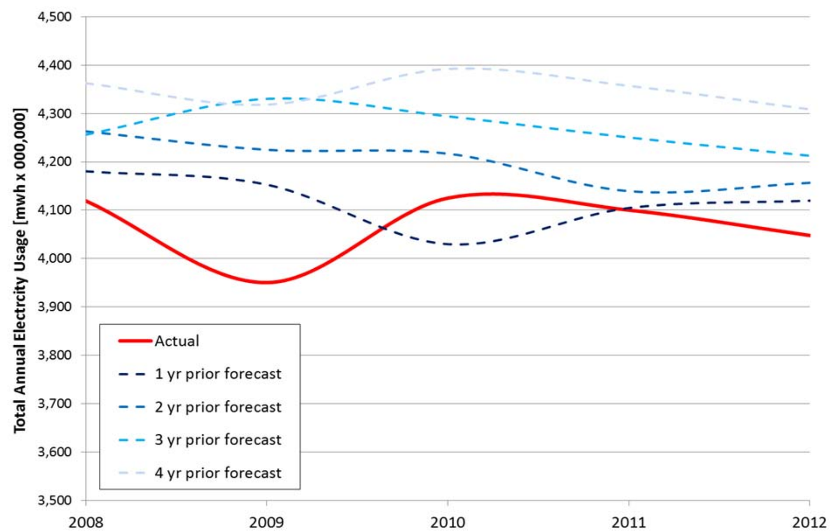
Demand includes forecasts from CEC, ISONE, NYISO and PJM. Generation includes forecasts from CEC, EIA, ISONE, NYISO and PJM

EIA – Summary

- EIA consistently over-estimates U.S. electricity consumption. Forecasts four years prior over-estimate consumption by 6 to 9% and three years prior over-estimate consumption by 3 to 10%.
- The one case where EIA under-predicted was in its 2009 forecast for 2010 consumption (2010 was the first year that the U.S. economy experienced economic growth after the financial crisis).
- Forecasts steadily become more accurate as they approach the actual year of consumption.

EIA U.S. TOTAL Electricity Consumption

Actual vs Four Years of Forecasts



EIA – *Total U.S. Electricity Consumption (mWh)*

EIA, U.S. Total Electricity Usage (mWh)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**4,119,387,760**	**3,950,330,926**	**4,125,059,899**	**4,100,140,925**	**4,047,765,262**
2012 forecast					4,119,794,922
2011 forecast				4,104,608,887	4,156,676,758
2010 forecast			4,029,760,000	4,139,360,000	4,212,500,000
2009 forecast		4,152,840,000	4,216,890,000	4,250,460,000	4,308,530,000
2008 forecast	4,180,500,000	4,224,930,000	4,294,130,000	4,357,170,000	
2007 forecast	4,263,010,000	4,330,290,000	4,392,230,000		
2006 forecast	4,256,210,000	4,318,240,000			
2005 forecast	4,362,540,000				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	101%	105%	98%	100%	102%
2 year prior	103%	107%	102%	101%	103%
3 year prior	103%	110%	104%	104%	104%
4 year prior	106%	109%	106%	106%	106%

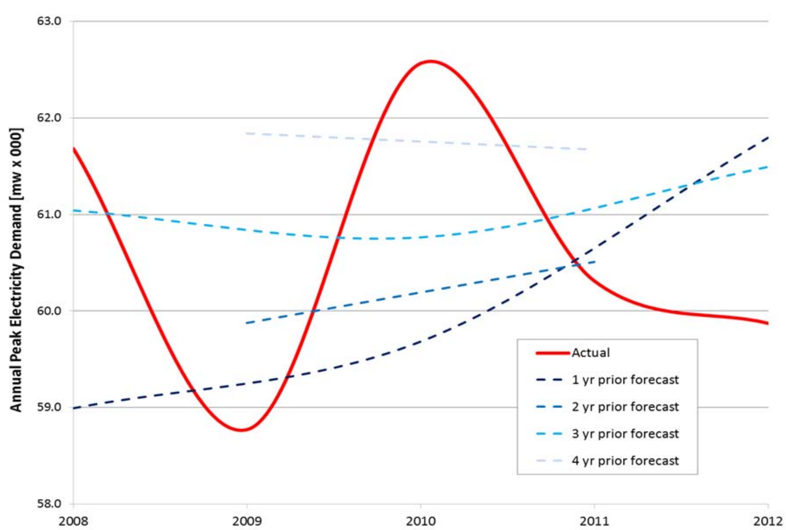
California Energy Commission (CEC) – Summary

- CEC peak demand and consumption forecasts were only available every other year.
- Consumption forecasts became more accurate as they approached the year being forecast. Four year projections overestimated consumption by as much as ten percent, while one year forecasts accurately predicted actual consumption.
- Peak demand in California fluctuated both up and down from 2008-2012, leading forecasts –which predicted stable growth –to both under and overestimate actual peak demand.

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

CEC Electricity Peak Demand

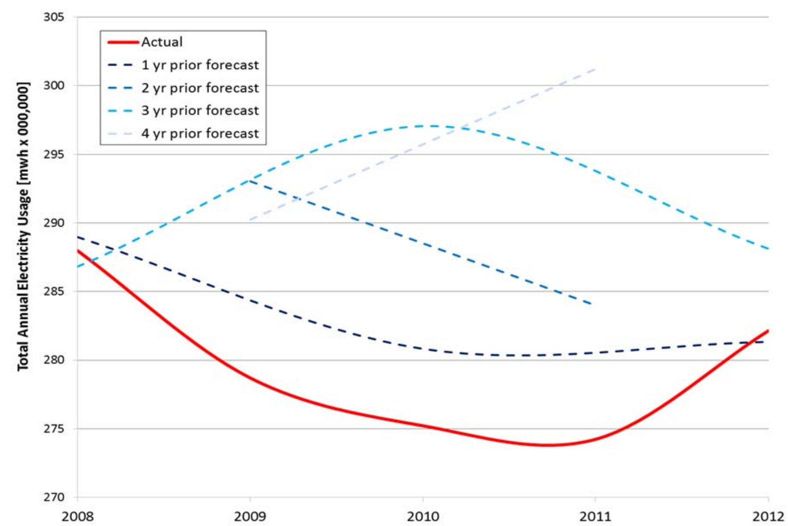
Actual vs Four Years of Forecasts



MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

CEC Electricity Consumption

Actual vs Four Years of Forecasts



M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

CEC – *Peak Electricity Demand (mW)*

CEC, Total Demand (mW)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**61,681**	**58,771**	**62,564**	**60,310**	**59,872**
2012 forecast					61,796
2011 forecast					
2010 forecast			59,681	60,510	61,494
2009 forecast					
2008 forecast	58,990	59,875	60,762	61,673	
2007 forecast					
2006 forecast	61,042	61,841			
2005 forecast					
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	96%	0%	95%	0%	103%
2 year prior	0%	102%	0%	100%	0%
3 year prior	99%	0%	97%	0%	103%
4 year prior	0%	105%	0%	102%	0%

M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

CEC – *Total Electricity Consumption (mWh)*

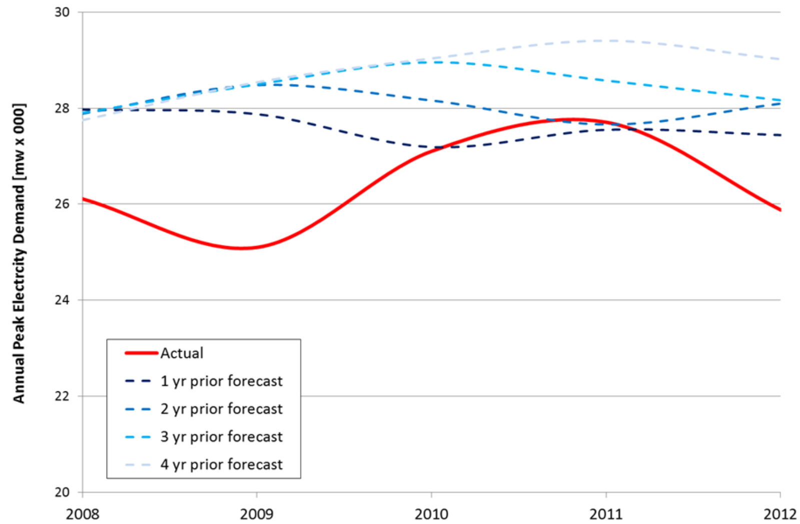
CEC, Total Electricity Usage (mWh)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**287,982,124**	**278,707,353**	**275,220,046**	**274,235,285**	**282,140,844**
2012 forecast					281,347,000
2011 forecast					
2010 forecast			280,843,000	284,001,000	288,123,000
2009 forecast					
2008 forecast	288,976,000	293,021,000	297,062,000	301,230,000	
2007 forecast					
2006 forecast	286,813,000	290,230,000			
2005 forecast					
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	100%	0%	102%	0%	100%
2 year prior	0%	105%	0%	104%	0%
3 year prior	100%	0%	108%	0%	102%
4 year prior	0%	104%	0%	110%	0%

ISO-NE – Summary

- ISO-NE consistently over-estimates electricity consumption and peak demand. Consumption forecasts four years prior over-estimate consumption by 5 to 9%, and peak demand predictions are over-estimated by 6 to 14%. Even two years prior, consumption is over-estimated by up to 8% and peak demand is over-estimated by 13% for 2009.
- Forecasts one year prior are notably more accurate than previous years, though ISO-NE typically still overestimated consumption and peak demand in these predictions.
- Uncertainties in economic conditions and effective roll-out of energy efficiency programs may have contributed to the notable over-predictions of peak demand.

ISO-NE Electricity Peak Demand

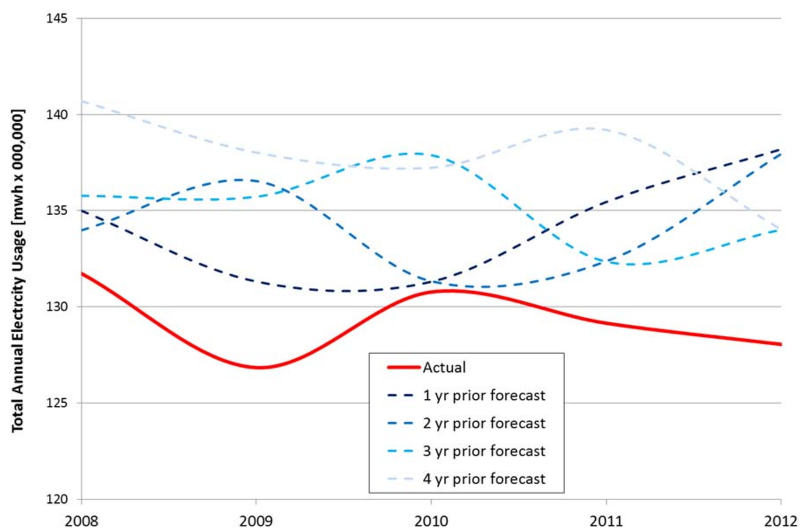
Actual vs Four Years of Forecasts



MJB&A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

ISO-NE Electricity Consumption

Actual vs Four Years of Forecasts



MJB&A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

ISO-NE – *Peak Electricity Demand (mW)*

ISO-NE, Peak Demand (mW)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**26,111**	**25,100**	**27,102**	**27,707**	**25,880**
2012 forecast					27,440
2011 forecast				27,550	28,095
2010 forecast			27,190	27,660	28,165
2009 forecast		27,875	28,160	28,575	29,020
2008 forecast	27,970	28,480	28,955	29,405	
2007 forecast	27,885	28,495	29,035		
2006 forecast	27,900	28,540			
2005 forecast	27,750				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	107%	111%	100%	99%	106%
2 year prior	107%	113%	104%	100%	109%
3 year prior	107%	114%	107%	103%	109%
4 year prior	106%	114%	107%	106%	112%

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

ISO-NE – *Total Electricity Consumption (mWh)*

ISO-NE, Total Electricity Usage (mWh)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**131,735,000**	**126,840,000**	**130,771,000**	**129,146,000**	**128,047,000**
2012 forecast					138,195,000
2011 forecast				135,455,000	137,955,000
2010 forecast			131,305,000	132,370,000	134,005,000
2009 forecast		131,315,000	131,330,000	132,350,000	134,015,000
2008 forecast	135,000,000	136,540,000	137,885,000	139,195,000	
2007 forecast	133,980,000	135,725,000	137,235,000		
2006 forecast	135,775,000	138,020,000			
2005 forecast	140,700,000				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	102%	104%	100%	105%	108%
2 year prior	102%	108%	100%	102%	108%
3 year prior	103%	107%	105%	102%	105%
4 year prior	107%	109%	105%	108%	105%

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

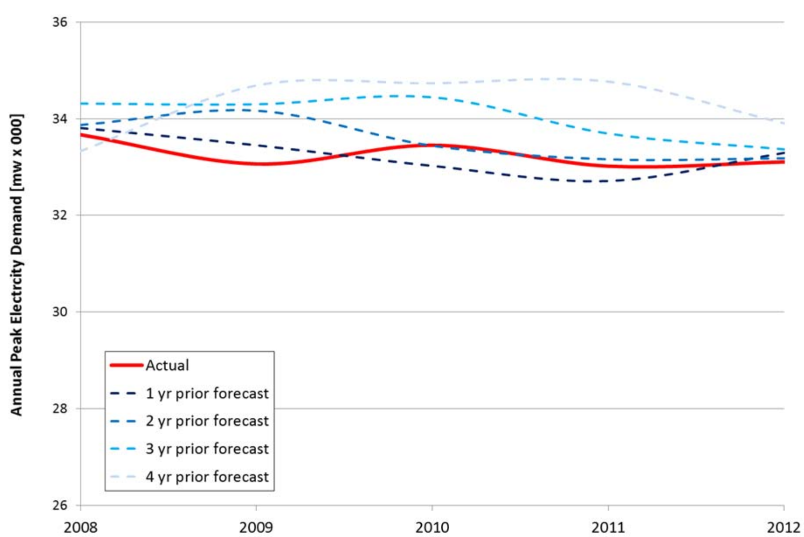
NY ISO – Summary

- NY ISO generally overestimates U.S. electricity consumption. Forecasts four years prior overestimate consumption by three percent to eight percent. One year forecasts are more accurate, ranging from an underestimate of one percent to an overestimate of two percent.
- Electricity consumption dropped significantly from 2008-2009 but then grew gradually through 2012.
- NY ISO demand forecasts are generally high but improve as forecasts approach the target year.

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

NY ISO Electricity Peak Demand

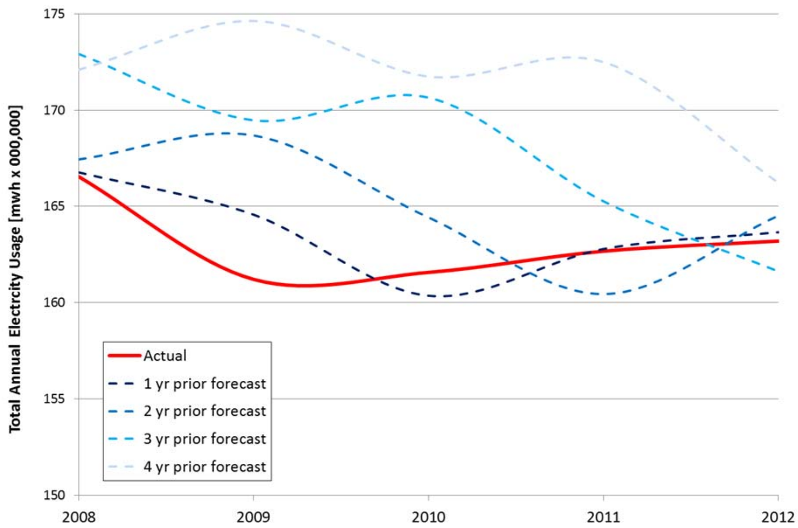
Actual vs Four Years of Forecasts



MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

NY ISO Electricity Consumption

Actual vs Four Years of Forecasts



MJB & A

M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

NY ISO – *Peak Electricity Demand (mW)*

NYISO, Total Demand (mW)	Calendar Year 2008	2009	2010	2011	2012
Actual	**33,670**	**33,065**	**33,452**	**33,019**	**33,106**
2012 forecast					33,295
2011 forecast				32,712	33,182
2010 forecast			33,025	33,161	33,367
2009 forecast		33,452	33,441	33,693	33,906
2008 forecast	33,809	34,167	34,444	34,768	
2007 forecast	33,871	34,300	34,734		
2006 forecast	34,314	34,688			
2005 forecast	33,330				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	100%	101%	99%	99%	101%
2 year prior	101%	103%	100%	100%	100%
3 year prior	102%	104%	103%	102%	101%
4 year prior	99%	105%	104%	105%	102%

MJB & A

M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

NY ISO – *Total Electricity Consumption (mWh)*

NYISO, Total Electricity Usage (mWh)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**166,547,000**	**161,207,000**	**161,571,000**	**162,672,000**	**163,199,000**
2012 forecast					163,659,000
2011 forecast				162,787,000	164,521,000
2010 forecast			160,358,000	160,446,000	161,618,000
2009 forecast		164,568,000	164,423,000	165,263,000	166,221,000
2008 forecast	166,767,000	168,683,000	170,649,000	172,493,000	
2007 forecast	167,440,000	169,470,000	171,744,000		
2006 forecast	172,916,000	174,634,000			
2005 forecast	172,100,000				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	100%	102%	99%	100%	100%
2 year prior	101%	105%	102%	99%	101%
3 year prior	104%	105%	106%	102%	99%
4 year prior	103%	108%	106%	106%	102%

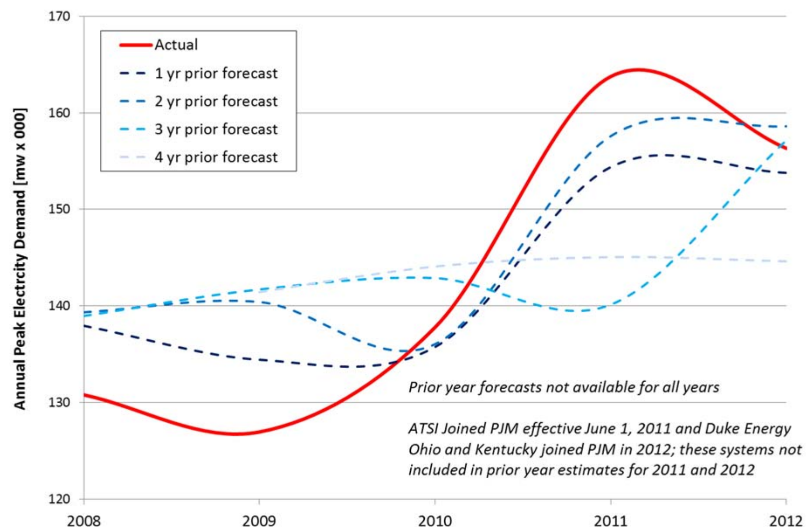
PJM - Summary

- Both demand and consumption estimates overestimate actual results in four year forecasts but became more accurate as the forecast year approached.
- Demand forecasts ranged from an 11 percent overestimation in four year prior forecasts to a six percent underestimation in one year forecasts.
- All PJM consumption predictions overestimated actual consumption, with four year prior forecasts off by as much as ten percent and one year prior forecasts off by up to four percent.
- In a number of forecasts, PJM underestimated peak demand but overestimated annual generation.
- American Transition Systems Inc. (ATSI) and Duke Energy Ohio and Kentucky joined PJM during the timeframe of this analysis. Efforts were taken to ensure that actual demand/consumption data and forecasts correspond with the same size service area.

MJB & A
M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

PJM Electricity Peak Demand

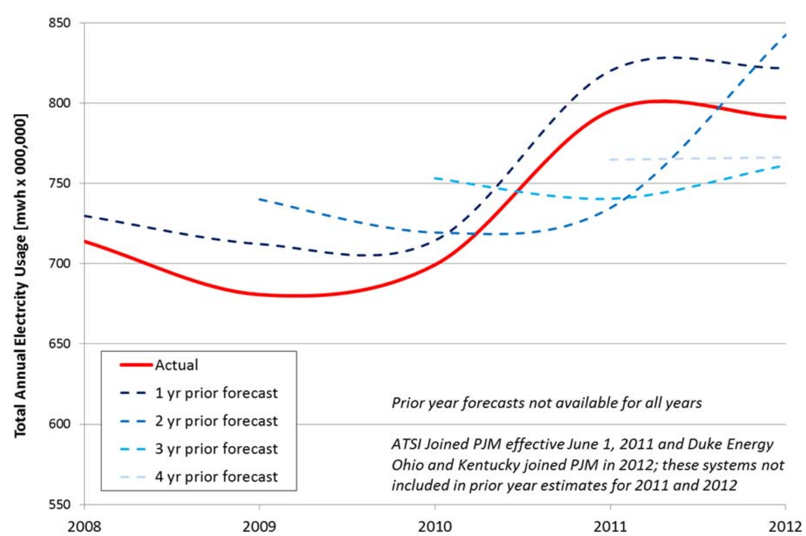
Actual vs Four Years of Forecasts



M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

PJM Electricity Consumption

Actual vs Four Years of Forecasts



M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

PJM – *Peak Electricity Demand (mW)*

PJM, Total Demand (mW)	Calendar Year 2008	2009	2010	2011	2012
Actual	**130,792**	**126,944**	**137,788**	**163,762**	**156,319**
Actual-w/out DEOK&ATSI				**144,088**	**137,358**
2012 forecast					153,782
2011 forecast				154,383	158,603
2010 forecast			135,750	157,589	157,167
2009 forecast		134,428	136,038	140,132	144,613
2008 forecast	137,948	140,407	142,884	145,061	
2007 forecast	139,342	141,710	144,082		
2006 forecast	138,962	141,430			
2005 forecast	Not Avail				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	105%	106%	99%	94%	98%
2 year prior	107%	111%	99%	96%	101%
3 year prior	106%	110%	104%	97%	101%
4 year prior	NA	111%	103%	101%	105%

ATSI Joined PJM effective June 1, 2011 and Duke Energy Ohio and Kentucky joined PJM in 2012

Numbers in RED include ATSI and DEOK, others do not

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

PJM – *Total Electricity Consumption (mWh)*

PJM, Total Electricity Usage (mWh)	Calendar Year 2008	2009	2010	2011	2012
Actual	**713,910,000**	**680,767,000**	**699,331,000**	**795,160,000**	**791,018,000**
Actual-w/out DEOK&ATSI				**698,678,000**	**695,165,000**
2012 forecast					821,786,000
2011 forecast				820,128,000	842,634,000
2010 forecast			714,440,000	734,738,000	761,364,000
2009 forecast		712,236,000	719,433,000	740,423,000	766,257,000
2008 forecast	729,819,000	740,048,000	753,214,000	764,785,000	
2007 forecast	Not Avail	Not Avail	Not Avail		
2006 forecast	Not Avail	Not Avail			
2005 forecast	Not Avail				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	102%	105%	102%	103%	104%
2 year prior	NA	109%	103%	105%	107%
3 year prior	NA	NA	108%	106%	110%
4 year prior	NA	NA	NA	109%	110%

ATSI Joined PJM effective June 1, 2011 and Duke Energy Ohio and Kentucky joined PJM in 2012

Numbers in RED include ATSI and DEOK, others do not

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

Florida Power & Light - Summary

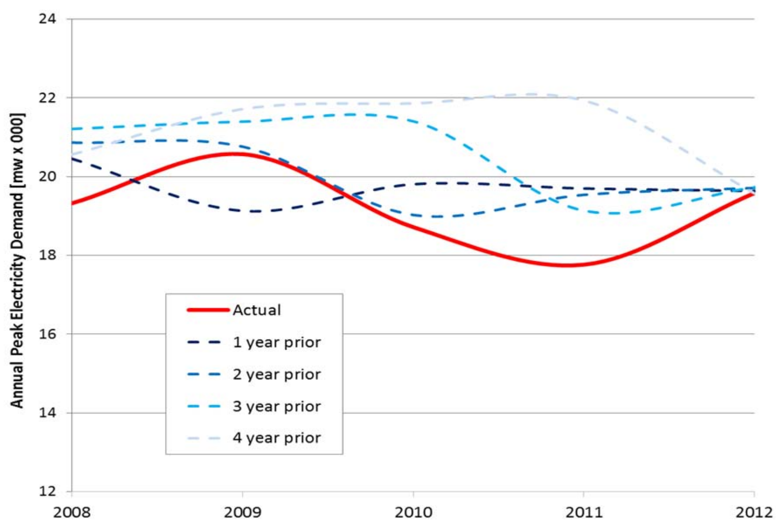
- FP&L's actual demand and consumption were not impacted by the recession in the same manner as RTOs/ISOs.
  - Consumption continued to increase from 2008-2010 before decreasing in the final two years examined.
- As with RTOs/ISOs, FP&L's longer-term forecasts overestimated both demand and consumption but improved forecast accuracy in next-year forecasts.
- Demand projections for four year prior forecasts overestimated demand by up to 23 percent, while one year prior forecasts ranged from an underestimation of seven percent to an overestimation of 11 percent.
- Consumption from four year prior forecasts ranged from 103 percent to 117 percent of actual consumption, while one year prior forecasts ranged from 96 percent to 107 percent of actual consumption.

Average Overestimation of FP&L Forecasts

	Same Year	1 Year	2 Years	4 Years
Demand	+3.2%	+4.4%	+7.4%	+10.4%
Consumption	0%	+3%	+7.2%	+11.8%

MJB & A
M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

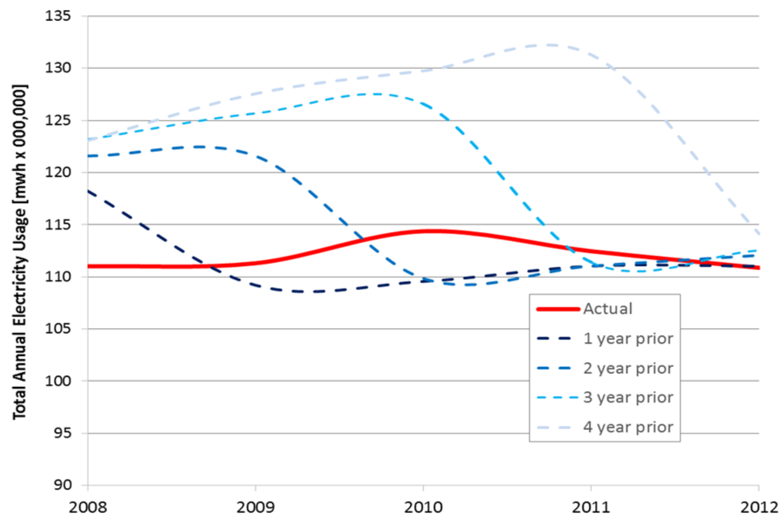
Florida Power & Light Electricity Peak Demand
Actual vs Four Years of Forecasts



MJB & A
M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

Florida Power & Light Electricity Consumption

Actual vs Four Years of Forecasts



MJB & A M.J. Bradley & Associates LLC (978) 369 5533 / www.mjbradley.com

Florida Power & Light – *Peak Electricity Demand (mW)*

FP&L, Total Demand (mW)	Calendar Year				
	2008	2009	2010	2011	2012
Actual	**19,327**	**20,573**	**18,720**	**17,767**	**19,586**
2012 forecast					19,632
2011 forecast				19,697	19,712
2010 forecast			19,805	19,540	19,732
2009 forecast		19,128	19,028	19,132	19,576
2008 forecast	20,448	20,758	21,408	21,927	
2007 forecast	20,862	21,401	21,857		
2006 forecast	21,216	21,714			
2005 forecast	20,566				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	106%	93%	106%	111%	100%
2 year prior	108%	101%	102%	110%	101%
3 year prior	110%	104%	114%	108%	101%
4 year prior	106%	106%	117%	123%	100%

MJB & A M.J. Bradley & Associates LLC (978) 369 5533 / www.mjbradley.com

Florida Power & Light – *Total Electricity Consumption (mWh)*

FP&L, Total Electricity Usage (mWh)	Calendar Year				
	2008	**2009**	**2010**	**2011**	**2012**
Actual	**111,004,000**	**111,304,000**	**114,373,000**	**112,454,000**	**110,866,000**
2012 forecast					111,021,000
2011 forecast				111,028,000	112,041,000
2010 forecast			109,552,000	111,021,000	112,540,000
2009 forecast		109,192,000	109,816,000	111,386,000	114,119,000
2008 forecast	118,225,000	121,586,000	126,595,000	131,305,000	
2007 forecast	121,596,000	125,707,000	129,764,000		
2006 forecast	123,203,000	127,571,000			
2005 forecast	123,062,000				
Forecast Accuracy	**2008**	**2009**	**2010**	**2011**	**2012**
1 year prior	107%	98%	96%	99%	100%
2 year prior	110%	109%	96%	99%	101%
3 year prior	111%	113%	111%	99%	102%
4 year prior	111%	115%	113%	117%	103%

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com

Contact MJB&A

MJB & A

Concord, MA
Headquarters
47 Junction Square Drive
Concord, Massachusetts
United States

Tel: 978 369 5533
Fax: 978 369 7712

www.mjbradley.com

Washington, DC

325 7th Street NW, Suite 225
Washington, DC
United States

Tel: 202 525 5770
Fax: 202 525 5774

MJB & A M.J. Bradley & Associates LLC
(978) 369 5533 / www.mjbradley.com