NRDC REPORT

MARCH 2013
R: 12-11-A

Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters

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Acknowledgments

The Authors of this report would like to thank the following people, organizations and their staff for valuable assistance and insights: ICF International, Inc., Synapse Energy Economics, Inc., Environmental Defense Fund, and David Schoengold. For their review and thoughtful comments on this report, we thank Dallas Burtraw, Dale Bryk, Megan Ceronsky, David Hawkins, Geoff Keith, Derek Murrow, George Peridas, Andy Stevenson, and John Walke.

We are grateful to The Energy Foundation, The Wallace Genetic Foundation, and The William and Flora Hewlett Foundation. This analysis would not have been possible without their generous support.

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Cover photo: istockphoto.com

TABLE OF CONTENTS

1. Executive Summary....3
2. Policy and Legal Basis for Setting Power Plant Carbon Dioxide Standards....6
3. NRDC Proposed Performance Standards for Existing Sources: Policy Description 13
4. Proposed Implementation Guidance for End-Use Energy Efficiency Credits Under Section 111(d) 15
A. Source (Enforceability)....15
B. Baseline (Surplus)....16
C. Quantification/Permanence 16
D. Demonstrating Additionality or Surplus....16
E. Energy Savings Based on Transparent Methodologies and Independent.... 16
F. Avoiding the Pitfalls of a Private Energy Efficiency Credit Program 17
5. Modeling Approach and Platform: Integrated Planning Model (IPM®)....19
6. Environmental Modeling....22
7. Key Assumptions 23
8. CO_2 Emission Reductions 25
9. Compliance Costs....29
10. The Economic Benefits of Emissions Reductions....30
A. Nitrogen Oxides (NOx) and Sulfur Dioxide (SO_2)....30
B. Carbon Dioxide (CO_2) 30
C. Total Benefits vs. Total Costs....31
11. Wholesale Electricity Prices 33
12. Demand-Side Management is The Most Cost-Effective Emission Reduction Option 35
A. Demand Response and Energy Efficiency Assumptions....36
B. Synapse Transition Scenario....36
C. Resource Adequacy 39
13. Projected Generation Changes in the U.S. Power Sector 42
A. Generation Changes....42
B. Retirements, New Builds, and Capacity Changes....45
14. Conclusion....47
Appendix I: NRDC Environmental Policy Assumptions 48
Appendix II. Demand-Side Management Assumptions 57
Appendix III. NRDC Market Assumptions....61
Appendix IV. Additional Notes on IPM® 68
Appendix V. Supply-Side Efficiency Assumptions 69
Appendix VI. Modeled and Reported Regions for CO_2 Rate-Averaging 72
Appendix VII. Supplemental Analysis of Weaker Standard and Weaker Standard - No DSM Cases....73
Appendix VIII. Henry Hub Natural Gas Prices....82
Endnotes 83

LIST OF FIGURES

Figure 8.1: Historical CO_2 Emissions and NRDC Projected CO_2 Emissions (in million short tons) 26
Figure 8.2: U.S. Fossil and Compliance CO_2 Emission Rates 26
Figure 8.3: Reference Case Regional Fossil and Electric System CO_2 Emission Rates 27
Figure 8.4: NRDC Regional Fossil and Compliance CO_2 Emission Rates 28
Figure 10.1: NRDC Case Estimated U.S. Benefits from Reductions in SO_2, NOx, and CO_2 in 2020 32
Figure 11.1: Wholesale Power Prices, Generation-Weighted Average of Five Regions 33
Figure 11.2: Projected Wholesale Electricity Prices (NRDC Case, 2010$) 34
Figure 12.1: NERC Regional Reserve Margin Estimates and Targets for Summer 2012 39
Figure 13.1: Age and Average Capacity Factors of the Current U.S. Coal-Fired Generation Plant 42
Figure 13.2: Projected 2020 Generation Changes in the U.S. Power Sector 43
Figure 13.3: Projected 2020 Capacity Changes in the U.S. Power Sector 46
Figure I.1 Renewable Portfolio Standards 52
Figure VII.1 Historical CO_2 Emissions and NRDC Projected CO_2 Emissions (in million tons) 74
Figure VII.2 U.S. Fossil and Compliance CO_2 Emission Rates 74
Figure VII.3 WS Regional Fossil and Compliance Emission Rates 75
Figure VII.4 WS–No DSM Regional Fossil and Compliance Emission Rates 75
Figure VII.5 WS–No DSM Case Estimated U.S. Benefits from Reductions in SO_2, NOx, and CO_2 in 2020 77
Figure VII.6 WS Case Estimated U.S. Benefits from Reductions in SO_2, NOx and CO_2 in 2020 77
Figure VII.7. Wholesale Electricity Prices in All Scenarios (Generation-Weighted Average of Five Regions) 78
Figure VII.8 Projected 2020 Generation Changes in the U.S. Power Sector 79
Figure VII.9 Projected Capacity Changes in the U.S. Power Sector 80
Figure VIII.1: Henry Hub Gas Prices in All Cases, 2012-2020 82

LIST OF TABLES

Table 3.1: List of Model Runs for NRDC CO_2 Pollution Standard for Existing Sources 14
Table 8.1: Summary of CO_2 Emissions Results (in million tons) 25
Table 8.2: Summary of Reference Case and NRDC Fossil and Compliance CO_2 Emission Rates 27
Table 9.1: NRDC Compliance Costs (compared with Reference Case) 29
Table 10.1: Social Cost of Carbon Values 32
Table 12.1: Synapse Demand Response Penetration Compared with 2009 FERC Brattle Study of Potential 37
Table 12.2: Energy Efficiency Assumptions 38
Table 12.3: Demand Response Assumptions 38
Table 12.4: Reserve Margin Target Levels 40
Table 12.5: Reserve Margins in the NRDC Case: Mothballed (Temporarily Inactive) Capacity Excluded 40
Table 13.1: Comparison of Renewable Energy Generation in Multiple Studies 44
Table I.1 Environmental Regulations: SO_2, NOx 48
Table I.2 Environmental Regulations: Hazardous Air Pollutants 49
Table I.3 State-specific Hg Regulations 50
Table I.4 Environmental Regulations: Regional GHG NSPS 51
Table I.5 Ash and Water Regulations 52
Table I. 6 Existing Coal Retrofit Cost and Performance 53
Table I.7 Mercury Controls for Coal 54
Table I.8 CCS for Existing Coal 54
Table I.9 Particulate Controls for Coal 55
Table I.10 Dry Sorbent Injection 55
Table I.12 Cooling Tower Costs 55
Table I.13 Technology Limits 56
Table II.1 Synapse Demand Response 57
Table II.2 Dispatchable vs Non-dispatchable DR 58
Table II.3 Delta - MW (Synapse - Reference) 58
Table II. 4 Synapse - Energy Efficiency, GWH 59
Table II. 5 Synapse - Energy Efficiency, Peak Load reduction 60
Table III.1 Representative Minemouth Coal Prices (2010$) 61
Table III.2 Domestic ($/MMBtu) 62
Table III.3 Gross Peak and Energy Demand 63
Table III.4 Reference Case Demand Response 65
Table III.5 Dispatchable vs Non-dispatchable DR 65
Table III.6 Net Peak and Energy Demand - Reference Case 66
Table IV.1 Zones Modeled Within IPM® for NRDC Regions of Focus 68
Table V.1 Supply-Side Efficiency Assumptions 69
Table V.2 Compilation of Select Heat Rate Improvement Options for Coal-Fired Power Plants 70
Table VI.1 NRDC Alt. NSPS Regional CO_2 Groups 72
Table VII.1 Summary CO_2 Emissions Results (in million tons)—United States and by Focal Region 73
Table VII.2 Summary of WS and WS - No DSM Fossil and Compliance Emission Rates in 2020 76
Table VII.3 WS - No DSM Compliance Costs (compared with Reference Case) 76
Table VII.4 WS Compliance Costs (compared with Reference Case) 77

CHAPTER 1: EXECUTIVE SUMMARY

Power plants in the United States released almost 2.4 billion tons of carbon dioxide in 2011, more than any other source of this dangerous heat-trapping pollutant. The Environmental Protection Agency is responsible for setting standards to reduce these emissions. This report describes and analyzes a flexible and highly cost-effective approach to setting power plant carbon pollution standards that would clean up and modernize America's aging electric power system.

In April 2012, the Environmental Protection Agency (EPA) proposed the Carbon Pollution Standard for new power plants under Section 111(b) of the Clean Air Act (the Act). The proposed standard states that each new plant will need to meet a specified emission rate performance standard of 1,000 pounds of carbon dioxide (CO_2) per megawatt-hour (lbs/MWh) of electricity produced. New coal plants would have the option to time-average emission rates over the first 30 years of operation for added compliance flexibility. The proposal marks the first uniform national limits on carbon dioxide emissions from new fossil fuel–fired electric power plants and is a critical step forward. EPA also has a legal obligation to issue carbon pollution standards for existing power plants under Section 111(d) of the Clean Air Act. EPA should move expeditiously to finalize carbon pollution standards for new power plants as well as to propose and, following a period for public comment, finalize standards that achieve significant carbon dioxide emission reductions from existing power plants in a cost-effective and legally robust manner.

NRDC has conducted an analysis of how CO_2 pollution standards for existing fossil fuel–fired power plants under Section 111(d) could affect the power sector, emissions levels, and electricity costs for consumers. The policy proposal set forth in this report will decrease levels of CO_2 emissions and encourage the power sector's transition to cleaner, lower-emitting generation with increased deployment of both supply- and demand-side energy efficiency. NRDC proposes that EPA set state-specific performance standards for existing power plants, using national average emission rate benchmarks and the state-specific generation mix in a baseline period to produce state average fossil fuel emission rate standards. Each of these standards—called an "emission guideline" under EPA's Section 111(d) regulations—would serve as a template for acceptable state plans, a yardstick to evaluate alternative plans that states may propose, and an advance notice of the federal plan that EPA must issue if states do not submit approvable plans.

NRDC's performance standard proposal begins with determining each state's generation mix during a baseline period (we used the average for 2008 through 2010 in this analysis). Then a target fossil-fleet average emission rate for 2020 is calculated for each state, using the state's baseline coal and oil/gas generation fractions and an emission rate benchmark of 1,500 lbs/MWh for coal-fired units and 1,000 lbs/MWh for oil- and gas-fired units on a net basis. States with more carbon-intensive fleets would have higher target emission rates but greater differentials between their starting and target emission rates. NRDC's proposal is designed to give power plant owners freedom to choose how they would achieve the required emission reductions, giving credit for increases in energy efficiency and electricity generation using renewable sources and allowing emission-rate averaging among fossil fuel–fired power plants. States would also have the freedom to design their own approach, as long as it achieved equivalent emission reductions.

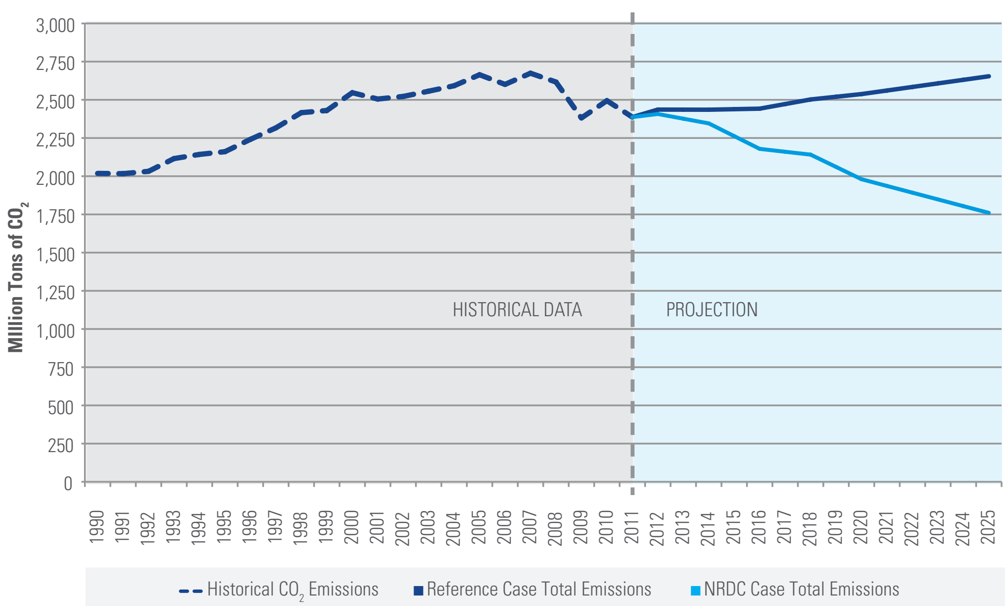
NRDC compared this performance standard with a Reference Case representing expected trends in the absence of such standards. NRDC also tested the sensitivity of the electric power grid's response to the stringency of emission rate targets and energy efficiency penetration in two additional scenarios.

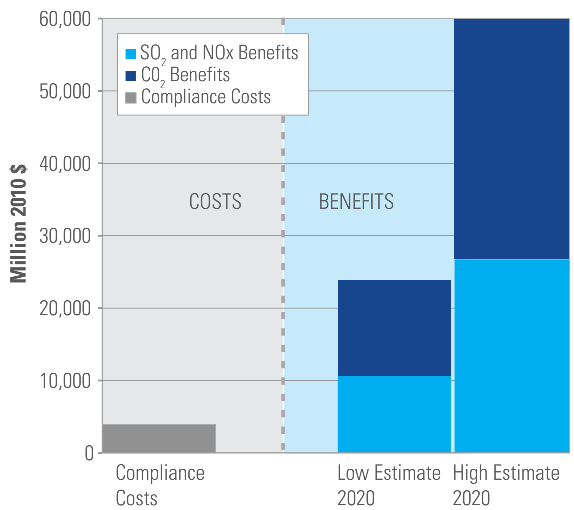
The analysis demonstrates that this recommended approach would reduce power plants' carbon pollution in an efficient and affordable way. It would reduce CO_2 emissions from the fossil generating fleet by 26 percent from 2005 levels by 2020, with annualized costs of approximately $4 billion in 2020 and benefits of $25 billion to $60 billion. The benefits come from saving lives and reducing the risks of catastrophic climate change. Reducing carbon pollution is valued at $26 to $59 per ton; reducing sulfur dioxide and oxides of nitrogen emissions beyond the levels that would be reached under other standards is valued by using an EPA-approved model of the health benefits on a regional basis. This recommended proposal can deliver the health and environmental benefits of reducing emissions from power plants without interfering with reliable and affordable electricity supplies. Establishing such CO_2 emission standards now will boost investments in energy efficiency and will give the power industry the investment certainty it needs to avoid billions of dollars of stranded investment in obsolete power plants.

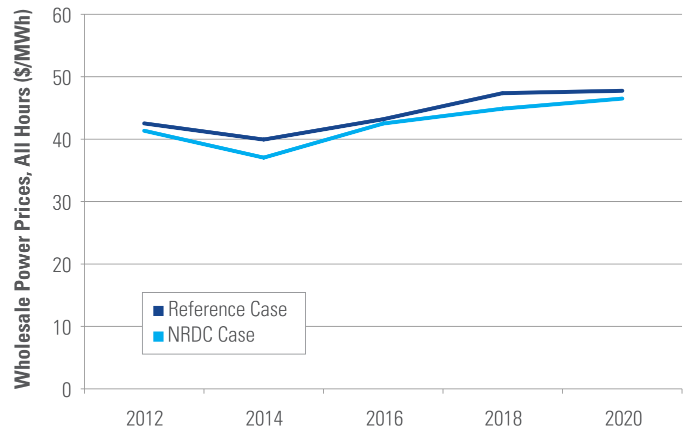
NRDC retained ICF International to conduct a modeling analysis of NRDC's recommended policy approach using the Integrated Planning Model (IPM®) and NRDC assumptions. ICF's IPM® power model is widely accepted by both public- and private-sector clients including the federal government, rating agencies, investment banking institutions, utilities, and independent power producers (IPPs). Based on the results, NRDC calculated the effects of the proposal on the U.S. power system, including air emissions, power plant investment and retirement decisions, and estimated economic costs as well as economic and public-health benefits.

Among the key findings of the analysis are these:

- NRDC's recommended performance standards will achieve considerable emissions reductions through 2020 with manageable costs to the electric power sector.







Note: Generation-weighted average of PJM, Southeast (excluding Florida), MISO, NYISO, ISO-NE, accounting for 60 percent of national generation.

- The value of societal benefits could reach $60 billion in 2020, as much as 15 times the costs of compliance.
- The recommended approach will lower wholesale electricity costs.
- Adequate electricity resources are available to assure a reliable supply as emissions standards are met.

NRDC's recommended CO_2 performance standards will achieve considerable emission reductions through 2020 with manageable costs to the electric power sector. The analysis shows that the proposed policy approach will reduce CO_2 emissions by 26 percent from 2005 levels by 2020, and 34 percent by 2025, with $4 billion in annualized compliance costs in 2020. These reductions will be achieved through a combination of demand-side and supply-side efficiency improvements, increased investment in renewable energy capacity, and an increased market share for lower-emitting generation sources.

The value of societal benefits could reach $60 billion in 2020, as much as 15 times the costs of compliance. NRDC estimates that in 2020 the societal, public health, and economic benefits of reducing emissions of particulate matter or soot, including precursor pollutants, SO_2 and NOx, will be $11 billion to $27 billion, while the benefits of reducing CO_2 will be $14 to $33 billion. The range in total benefits is $25 billion to $60 billion, or roughly 6 to 15 times the costs of compliance. The benefits accounted for in the valuation of avoided particulate and SO_2 emissions include avoided mortality, heart attacks, asthma attacks, hospital visits, respiratory symptoms, and lost workdays.

The recommended approach will lower wholesale electricity costs. NRDC's analysis indicates that, under the recommended approach, wholesale power prices would be 4 percent lower than under the Reference Case in 2020. Meanwhile, energy efficiency improvements in households and businesses would reduce electricity consumption, lowering electricity bills and emissions at the same time.

Adequate electricity resources are available to assure a reliable supply as emissions standards are met. Energy efficiency and demand response measures adopted in reaction to the incentives created by NRDC's proposed carbon pollution standard would lower energy costs for households and businesses while also reducing strain on the electric power grid during peak hours. Demand-side resources have the potential to add flexibility and efficiency to energy consumption patterns, diversify the resource mix, reduce emissions, and lower energy costs.

The body of this report begins with the policy and legal basis for setting carbon pollution standards for existing power plants under the Clean Air Act and the importance of action in the short term. The paper then sets out the details of the recommended approach and the basic premises of the modeling analysis using ICF International's proprietary Integrated Planning Model (IPM®) and NRDC assumptions. A discussion of the implementation strategy for the proposed standard follows. Finally, the discussion examines the emissions reductions, associated costs, and broader power-sector shifts that are projected to occur as a result of the recommended CO_2 pollution standards. The Appendices provide additional details and a discussion of sensitivity analyses.

CHAPTER 2: POLICY AND LEGAL BASIS FOR SETTING POWER PLANT CARBON DIOXIDE STANDARDS

The United States electric power sector[1] released almost 2.4 billion short tons of harmful CO_2 pollution into the atmosphere in 2011.[2] This accounts for almost 40 percent of the nation's total 2011 CO_2 emissions, more than any other industry.[3]

In the absence of carbon pollution standards, the Energy Information Administration's Annual Energy Outlook for 2011 (AEO2011) Reference Case forecast projects that energy-related CO_2 emissions will grow by an average of 0.4 percent per year from 2010 to 2035. More recent projections suggest nearly flat emissions, with an annual growth rate of 0.1 percent per year over the same period due to relatively low-cost natural gas and the growth of energy efficiency programs that are reducing electricity demand. The starting point for NRDC's analysis is the AEO2011 Reference Case because it was the latest forecast available at the time the analysis began.

While the AEO2012 forecast projects slower growth in emissions than in previous decades, the amount of CO_2 released into the atmosphere remains unsustainably high. Curbing dangerously high CO_2 emissions levels from fossil-fueled power plants is necessary to protect public health and welfare from the dangerous consequences of climate change, including death and disease triggered or exacerbated by heat waves, droughts, floods, and other extreme weather events made worse by heat-trapping pollution.

The Supreme Court ruled in April 2007 that greenhouse gases (GHGs), including carbon dioxide, plainly meet the definition of "air pollutants" under the Clean Air Act. The U.S. Environmental Protection Agency (EPA) identified numerous ways in which carbon dioxide and other heat-trapping pollution endanger public health and welfare. Among the most important, EPA concluded that these pollutants and the climate change they fuel can be reasonably anticipated to cause:

- deaths and illnesses from more severe heat waves,
- deaths and illnesses from more intense smog,
- deaths and illnesses from temperature and rainfall changes that spread infectious and insect-borne diseases,
- deaths, injuries, and illnesses from more frequent and severe storms, flooding, and drought.[4]

The United States has experienced these effects firsthand over the past several years. Extreme heat killed at least 74 people during the first half of 2012,[5] and superstorm Sandy tragically demonstrated the implications of more severe storms, with a death toll of more than 100 Americans.[6] Climate change-related mortality in 2012 is only one part of a deadly trend. In 2011, at least 206 people died from extreme heat alone, up from 138 fatalities in 2010 and nearly double the 10-year average, according to the National Oceanic and Atmospheric Administration.[7] In a study published in the journal *Health Affairs*, a team of scientists from NRDC collaborated with university economists to investigate the health costs of six climate change-related events expected to worsen with climate change in ways likely to harm human health, including ozone smog pollution, heat waves, hurricanes, mosquito-borne infectious disease, river flooding and wildfires. As an indication of the threats we will increasingly face under a warming climate, they estimated the human health costs to be over $14 billion (in 2008 U.S. dollars).[8] The health and economic burden of climate change will only increase if global warming continues unchecked.

In setting carbon pollution standards, EPA is acting under the law of the land, in conformity with the U.S. Supreme Court, based on an enormous scientific record.

The Clean Air Act has been very successful in reducing life-threatening pollution over its 40-year history, but old power plants have largely escaped modern pollution control requirements. There is no doubt that power plants significantly contribute to many forms of air pollution, including about 40 percent of CO_2 in the U.S. and one-third of total U.S. greenhouse gas emissions. Indeed, more than 500 power plants operating in the United States were built before the Clean Air Act was written[9] and have been allowed to continue emitting excessive quantities of mercury, acid gases, sulfur dioxide, nitrogen oxides, and carbon dioxide into the air for decades. This is a major loophole that is costing thousands of lives each year and driving up health care costs. EPA is finally moving to close this loophole so that all electricity generators, including new clean technologies, can compete on a level playing field.

Some big polluters have characterized EPA's plans to set standards for carbon dioxide, mercury, and other pollutants as a train wreck for both power grid economics and reliability. Nothing could be farther from the truth. These standards are achievable, affordable, and long overdue, and they will prevent thousands of deaths and millions of diseases. For instance, the EPA estimates that reduced emissions of mercury, particulate matter and acid gases as a result of the Mercury and Air Toxics Standards will prevent as many as 11,000 premature deaths, 130,000 asthma attacks, 5,700 hospital visits, 4,700 heart attacks, 2,800 cases of chronic bronchitis and prevent up to 540,000 missed work or "sick" days each year starting in 2016. The public health improvements are valued at $37 billion to $90 billion.[10]

The Clean Air Act requires EPA to set standards to reduce carbon dioxide pollution from power plants in order to protect public health and the environment. EPA is also obligated to set standards, in partnership with the states, to clean up and modernize the aging, inefficient, and polluting fleet of existing electricity-generating units.

In April 2012, EPA took an important step forward by proposing the first national standard to limit carbon dioxide (CO_2) pollution from new power plants, under Section 111 of the Clean Air Act.[11] EPA issued the proposed power plant standard in response to the Supreme Court's landmark 2007 decision in *Massachusetts v. EPA* that carbon dioxide and other heat-trapping gases are air pollutants under the Clean Air Act, that EPA must make a science-based determination as to whether they endanger public health or welfare, and that the agency must issue standards if it finds that they do.[12] In 2009 EPA made the scientific determination that these pollutants endanger our health and welfare.[13]

Section 111 of the Clean Air Act gives EPA the responsibility to set emission performance standards for categories of stationary sources that contribute to dangerous air pollution. Performance standards under Section 111 are the principal tool for addressing carbon pollution from industrial facilities. For pollutants like carbon dioxide, standards are required for both new and existing sources.

A. SECTION 111 OVERVIEW

Section 111 directs EPA to set "standards of performance," usually in the form of a maximum emission rate, for categories of stationary sources (e.g., industrial facilities) emitting air pollutants that endanger public health or welfare.[14] EPA sets federal performance standards covering *new* and *modified* sources under Section 111(b). EPA and the states share the job of implementing performance standards for *existing* sources of pollutants like CO_2 under Section 111(d).

In brief, Section 111 creates criteria, procedures, and timetables for:

- identifying the *categories* of facilities that contribute to dangerous air pollution,
- setting performance standards for *new* and *modified* sources in those categories, and
- setting performance standards for *existing* sources.

Categories. EPA must publish and periodically revise a list of categories of stationary sources that the agency judges "cause [], or contribute [] significantly, to air pollution which may reasonably be anticipated to endanger public health or welfare."[15] Power plants have been on this list since 1971. EPA has broad discretion to group sources into categories based on the functions they serve, and to decide whether to establish subcategories with different control requirements.[16] In the April 2012 proposal for new sources, EPA defined the category to include all fossil fuel–fired power plants—both natural gas–fired and coal-fired—that serve the function of generating electricity to meet base load or intermediate load demand.[17] (The power plant category is known as Category TTTT.) EPA expressly relies on its 2009 determination that greenhouse gas air pollution, including CO_2, endangers public health and welfare. EPA also found that power plants, which release more than two billion tons of CO_2 per year and account for 40 percent of U.S. CO_2 emissions, contribute significantly to that air pollution.

Standards for New Sources. The next step is to propose a performance standard for new sources within the category under Section 111(b). Then EPA must issue a final standard within a year of the proposal, after considering public comments.[18] The Clean Air Act defines a performance standard as

> *a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.*[19]

EPA refers to these criteria by the shorthand term "best system of emission reduction" (BSER).

Congress intended these standards to be "technology forcing" and to drive down emissions of dangerous air pollutants from industrial sources of pollution. The Senate Committee Report on the 1970 Clean Air Act stated:

"Standards of performance should provide an incentive for industries to work toward constant improvement in techniques for preventing and controlling emissions from stationary sources."[20] The Senate Report also stated that emerging control technology used as the basis for standards of performance need not "be in actual routine use somewhere."[21] Court cases confirm the intended technology-forcing character of these standards. As the D.C. Circuit Court of Appeals stated in *Portland Cement Association v. Ruckelshaus*, "Section 111 looks toward what may fairly be projected for the regulated future, rather than the state of the art at present."[22]

In the April 2012 proposal, EPA proposed to find that new plants in the base-load and intermediate-load category could meet a carbon dioxide standard of 1,000 lbs/MWh using the BSER. The reasoning was that (1) the proposed standard can be met by new natural gas combined-cycle (NGCC) plants at no additional cost, and that (2) market trends, primarily the price and availability of natural gas, are expected to cause firms to build exclusively NGCC plants. Since construction of new coal-fired plants is not expected to occur even absent any carbon standard, EPA found that no additional costs will be incurred by applying the proposed standard to the entire category.[23]

EPA recognized that the same emission rate can be met by new coal-fired plants capable of carbon capture and storage. EPA noted that a number of carbon capture and storage projects may go forward with the assistance of federal or state subsidies or other incentives. To help encourage such projects, EPA proposed a flexible 30-year averaging compliance pathway for them.[24]

EPA is currently responding to public comments on the proposal, and a final standard is expected to be issued soon.

Standards for Existing Sources. For pollutants such as carbon dioxide, Section 111 also requires EPA to set standards for existing power plants.[25] Specifically, when EPA issues a performance standard for new sources under Section 111(b), Section 111(d) mandates the regulation of existing plants in the same category. Section 111(d) gives EPA and the states shared responsibility to set these existing plant standards, through a state implementation process resembling the one used to curb pollutants like soot and smog.

The process starts with EPA's issuance of an "emission guideline," a recommended or presumptive standard of performance for states to apply to their sources. Then each state adopts and submits to EPA a plan containing an emission standard and compliance schedule for each existing source in the category. EPA either approves the state plan or, if it cannot be approved, issues a federal plan.

SECTION 111(d): A CLOSER LOOK

Specifically, Section 111(d)(1) requires EPA to issue regulations that create "a procedure similar to that provided by Section 110 of this title under which each State shall submit to the Administrator a plan" that (1) "establishes standards of performance" for the existing sources in the category, and (2) "provides for [their] implementation and enforcement." Section 111(d)(1) further states that the regulations have to allow each state "to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

In 1975, EPA issued Section 111(d) regulations that set up a default implementation framework for existing sources, described below. The regulations expressly state, however, that EPA may modify this framework as appropriate when proposing and promulgating the specific emission guideline that will apply to a particular category of existing sources.[26]

The framework regulations provide for EPA to issue an "emission guideline document" setting forth the performance level (called the "emission guideline") that reflects the "best system of emission reduction" (BSER) for existing sources.[27] Similar to the Section 111(a)(1) definition of a standard of performance for new sources, the emission guideline must:

> reflect[] the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with emission standards of equivalent stringency can be achieved.[28]

Each state then has a period of time (nine months, unless EPA prescribes a different period for a particular category[29]) to adopt and submit to EPA a state plan that includes an emission standard and compliance schedule for each source in the category.[30]

Returning to the statute, Section 111(d)(2) provides that, just as under Section 110, EPA has the backup responsibility to establish federal plans containing acceptable performance standards if state plans are not submitted on time or if they do not meet requirements for EPA approval.[31]

Updating Standards and Adding New Pollutants. The final relevant statutory provision is the requirement that at least every eight years, EPA must review the performance standards for each category and, if appropriate, revise them following the same procedures as for initial adoption.[32] Historically, during such reviews EPA considers whether to add emission limits for pollutants that were not covered by the previous standards.

When EPA reviewed the Section 111 standards for power plants in 2006, however, the agency refused to add limits on carbon dioxide, taking the mistaken view that CO_2 was not an air pollutant under the Clean Air Act. States and environmental organizations, including NRDC, challenged that view in two cases, one concerning motor vehicles (*Massachusetts v. EPA*) and one concerning power plants (*New York v. EPA*). In 2007 the Supreme Court decided the question in *Massachusetts*, rejecting EPA's position and holding (1) that greenhouse gases including CO_2 are air pollutants subject to the Clean Air Act, (2) that EPA must make a science-based decision regarding whether they endanger public health or welfare, and (3) that EPA must issue standards if the endangerment decision was in the affirmative. Ruling in the *New York* case, the D.C. Circuit Court of Appeals then ordered EPA to reconsider its refusal to curb carbon emissions from power plants. In 2011 the Supreme Court confirmed EPA's responsibility to address carbon pollution from power plants under Section 111 in another climate change decision, *American Electric Power v. Connecticut*.[33]

In 2011 the parties reached a settlement agreement in the *New York* case with a schedule for EPA to act on CO_2 standards for both new and existing power plants.[34] Although EPA has fallen behind the settlement schedule, the agency proposed a carbon pollution standard for new plants in April 2012. This is an important step toward EPA's meeting its statutory duties, but action is still required on the existing power plants, the largest contributor of carbon pollution in America.

B. USING SECTION 111(d) TO REDUCE CARBON POLLUTION FROM EXISTING POWER PLANTS

This paper recommends a specific approach to setting standards for existing power plants under Section 111(d)—an approach that is consistent with the statute and allows EPA and the states to make substantial and cost-effective reductions in carbon pollution from the nation's highest-emitting sector.

As explained above, the Section 111(d) regulatory process begins with EPA's issuance of an "emission guideline document" for existing power plants in the category covered by the new source standard.[35] As permitted by EPA's framework regulations, we recommend that EPA modify the default approach in several respects in order to most cost-effectively achieve significant carbon dioxide reductions from this sector.

The Emission guideline Document. The emission guideline document that we recommend would:

- **Serve as a template for approvable plans.** The guideline document would serve as a programmatic template that states can follow to prepare an approvable plan. It would set forth a state-specific CO_2 emission rate standard and a range of methods for demonstrating compliance. If a state plan adopts the emission rate standard and accompanying compliance provisions set forth in the guideline document, the state will know that its plan will be approved.
- **Act as a yardstick for alternative plans.** Our recommended approach would allow states to adopt plans of different design, provided they achieve equal or better CO_2 emission reductions from the power sector. For this purpose, the guideline document would serve as a yardstick to evaluate such state plans, and it would spell out the steps states could take to demonstrate equivalence. For example, some states that already have programs limiting total power sector emissions may want to submit plans based on that design, rather than on emission rate limits. The guideline document would signal that EPA will approve such a plan if the state demonstrates that the CO_2 emissions from its power sector will not exceed the total emissions expected under a program that followed the template.
- **Provide advance notice of FIP.** The guideline document would serve as advance notice of the contents of a federal implementation plan (FIP) if that step should be necessary. In other words, if a state fails to submit a plan or submits one that is not approvable, the state and its power sector would know in advance that EPA will issue a FIP based on the template.

Structure of the Emission Guideline. We recommend that the emission guideline document follow a regulatory design, elaborated below, intended to obtain the largest CO_2 emission reduction achievable at reasonable cost.

The "emission guideline"—the presumptive emissions standard contained within the guideline document—will not be the same as the new source standard. The new source standard governs plants that owners and operators have not yet built, and the proposed 1,000 lbs/MWh limit on CO_2 emissions can be easily met by the kinds of plants they are expected to choose in the baseline forecast for the next 20 years.

In contrast, the emission guideline will apply to the fleet of power plants now operating. In delineating the best system of emission reduction (BSER) for existing plants, the guideline must take into account the important characteristics of the existing fleet of fossil fuel–fired power plants, and the opportunities to reduce emissions from that fleet as cost-effectively as possible.

The most important existing fleet characteristics and emission control opportunities are these:

- The mix of fossil fuel–fired steam generators and natural gas combined-cycle plants differs from state to state, varying from almost entirely coal to almost entirely natural gas.
- Compared with other categories of industrial sources, the power plant fleet is operated to a unique extent as an integrated system on a state or regional basis, with interdependent management decisions on when to operate, build, upgrade, and retire individual units.
- Depending on their type and starting point, existing generating units can reduce their own CO_2 emission rates by improving generation efficiency (improving heat rates) or by switching to or co-firing with lower-emitting fuels (e.g., natural gas or biomass).
- Covered units within a state or group of states can reduce their average emission rates through additional tools, including dispatch shifts (e.g., running lower-emitting plants more and higher-emitting plants less).
- Covered units can reduce their emissions by increasing generation from renewable and other non-emitting plants.
- Covered units can reduce their emissions by increasing end-use electrical energy efficiency.

These system-wide compliance options can allow more substantial emission reductions—at lower overall cost—than the restricted set of measures that individual units can take on their own.

NRDC recommends that the emission guideline capture these salient fleet characteristics and emission control opportunities in its delineation of the best system of emission reduction (BSER) that is technically feasible and economically reasonable for existing plants. Under NRDC's proposal the fleet average emission rate for each state would be derived as follows:

(1) Calculate each state's baseline fossil fleet generation mix of coal- and gas-fired plants for 2008 through 2010.[36]

(2) Establish nominal emission rate targets for coal- and gas-fired units for each compliance year.

(3) Determine each state's emission rate standard by calculating the fossil fleet average emission rate limit from the nominal targets weighted by the state's generation mix during the baseline period.[37]

   a. In NRDC's proposal the 2020 standard for each state is calculated by applying a nominal emission rate of 1,500 lbs/MWh to the fraction of the state's baseline-period generation from coal units and a 1,000 lbs/

MWh nominal emission rate to the fraction of the state's baseline-period generation from oil and gas units.

b. Similarly, each state's fossil fleet average standard for 2025 is obtained by applying a nominal emission rate of 1,200 lbs/MWh to the fraction of the state's baseline-period generation from coal and a 1,000 lbs/MWh rate to the fraction of the state's baseline-period generation from oil and gas units. An example calculation is given in the description of NRDC's proposed policy approach in Chapter 3 below.

(4) Allow the use of emission rate averaging across fossil fuel–fired units, and credit the emission reductions achieved through displacement of fossil fuel–fired generation via different classes of electricity service resources (including demand-side efficiency projects) to enable cost-effective compliance options that can be taken across the integrated electricity system. In other words, emission reductions achieved by shifting dispatch to lower-emitting plants, by increasing dispatch from non-emitting plants, and by increasing end-use energy efficiency would be credited (per ton of CO_2 avoided), and those credits could be used by a regulated unit to achieve the required emission rate. Emission reduction credits not needed for compliance in a given year could also be retained ("banked") for use later.

(5) Permit states by mutual consent to combine their fleets of fossil fuel generating units into a multistate region for compliance purposes, and/or permit states to trade emission credits on a multistate exchange, thus allowing states to choose whether to spread the geographic range of compliance options beyond their borders.

Conformity with Section 111(d). Section 111(d) requires states to establish emission standards for existing sources of certain pollutants for which EPA has issued standards under section 111(b). EPA is required to approve or disapprove such state emission standard programs and to adopt federal emission standards for states whose programs are not approved. NRDC's proposal is consistent with all of the legal requirements of Section 111(d).

First, the proposal provides a process for each state (or EPA if necessary) to establish a standard of performance applicable to each source in the category. The proposal follows the state-by-state structure of Section 111(d), which calls for each state to develop and submit to EPA a plan that places enforceable emission standards on each source in the category located within that state. Under the proposal the basis for an EPA approval/disapproval action is whether the state's program achieves emission levels from the regulated sector consistent with the emission rate target established by EPA after considering statutorily pertinent factors. Further, each state is responsible for adopting and enforcing its own implementation plan.

Second, under the recommended program, an enforceable emission rate standard, in pounds of CO_2 emissions per megawatt-hour of electricity produced, applies to each source in the TTTT category.[38] While each source has several compliance options, an enforceable emission limit applies to each source.

Third, the recommended program gives each source several ways to comply.

- A source may comply by meeting the emission rate standard on its own.
- A set of sources may comply by averaging their emission rates. For example, a coal plant may average with a gas plant, such that their total emissions divided by their combined electricity output meets the applicable state standard.
- A source may comply by acquiring qualifying credits derived from low- or zero-emitting electricity generation. For example, an NGCC plant would earn credits reflecting the difference between the required state fleet average standard and its emissions per megawatt-hour. A wind plant would earn larger per-MWh credits, reflecting the difference between the state standard and its zero-emission rate.
- Finally, a source may comply by acquiring qualifying energy efficiency credits, reflecting incremental reductions in power demand (sometimes called "negawatt-hours"), which earn credits at the same rate as other zero-emission sources listed above.

The EPA emission guideline document would need to specify the rules and protocols for these compliance options. Because the compliance responsibility remains with the sources in the regulated category, and because all of the eligible compliance measures reduce or avoid emissions from covered sources in that category, these compliance options are fully compatible with the definition of a standard of performance.[39]

The recommended program structure allows, but does not require, states to reach agreements to allow sources in more than one state to average their emissions, or to use compliance credits generated in another state.

Building these types of emission reduction options into the emission guideline for compliance serves several important functions:

- It expands the range of compliance techniques available to each covered unit.

- It provides an incentive for early action because measures that reduce emission rates any time after the end of the baseline period automatically count toward compliance.
- It taps the most economically efficient means of reducing emissions, including energy efficiency and non-fossil supply options.
- It reduces the overall system cost of achieving any specified percentage improvement in sources' emission rates, thus allowing achievement of the greatest possible pollution reduction within any given cost constraints.
- It equalizes the marginal cost of emission reductions for owners and operators of different types of plants within a state and eliminates the need for different standards for different types of power plants, given the ability to use emissions averaging and/or emission reduction credits, rather than meeting the standard on site.

Whether a standard of performance set at a particular level is achievable at a reasonable cost must be assessed taking into consideration all of the permissible means of compliance. An emission rate may be unreasonably expensive to achieve if the source's only options are measures taken at the source itself to reduce its direct emission rate. If the standard allows sources the option of additional means of compliance, as this proposal does, through averaging and crediting mechanisms, then the source's cost of compliance will be substantially lower. Thus, EPA needs to analyze the cost and achievability of potential standards on the basis of all the compliance options that are available to plant owners and operators, including these emission credit compliance options.Based on this program structure, EPA would determine the appropriate emission rates to be met in each state. The emission rate for each state must reflect the *best* system of emission controls that has been adequately demonstrated, taking cost into account. In this context, the key question is the impact on the *integrated system* of electric generating units within a state.

We recommend that the guideline reflect the different improvement potentials for coal-fired and gas-fired plants, using all available compliance techniques. On the one hand, coal-fired units start from a higher emission rate than gas-fired units. On the other hand, while both kinds of unit can make use of compliance credits from qualifying increases in renewables generation or demand-side energy efficiency, coal-fired units have a cost-effective compliance option that gas-fired units do not: shifting dispatch from coal- to gas-fired units. Coal-fired plants may also have more scope to improve their generation efficiency (reduce their heat rate) than natural gas plants. Taking these factors into account, the guideline recommended here would establish a more lenient state average emission rate for states with a higher fraction of coal-fired power in their baseline generation mix than for states with more gas-fired power. At the same time, states more dependent on coal-fired power in the baseline period would be expected to make a greater percentage improvement in their average emission rate, because those states have greater access to the cost-effective compliance options of improving the operation of their plants and shifting dispatch to gas-fired units.[40] In other words, each state's emission reduction obligation would reflect its mix of generation from coal-fired and gas-fired units during the baseline period.

CHAPTER 3: NRDC PROPOSED PERFORMANCE STANDARDS FOR EXISTING SOURCES: POLICY DESCRIPTION

In this report, NRDC proposes a carbon pollution standard for existing fossil-fueled electricity generation sources under Section 111(d) of the Clean Air Act crafted to achieve significant near and mid-term CO_2 reductions. The primary goals of the proposal are threefold: (1) to decrease the average emission rate of the fossil generating fleet significantly by 2020, (2) to accomplish this objective cost-effectively, and (3) to establish a robust framework that is technically, legally, and politically defensible.

NRDC's performance standard proposal for existing sources under Section 111(d) begins with determining each state's generation mix during a baseline period (we used the average for 2008 through 2010 in this analysis). Then, a target fossil-fleet average emission rate for 2020 is calculated for each state, using the state's baseline coal and oil/gas generation fractions and an emission rate benchmark of 1,500 lbs/MWh for coal-fired units and 1,000 lbs/MWh for oil and gas-fired units. Consequently, those states with more carbon-intensive fleets would have higher target emission rates, but greater differentials between their starting emission rates and their targets.

The range of compliance options under this proposal includes (i) intrastate averaging among all fossil units,[41] (ii) emissions credits for reduced emissions from fossil fuel–fired units achieved via demand-side energy efficiency programs and incremental electricity generation from renewable sources, (iii) use of banked compliance credits, (iv) shifts in utilization to lower-emitting units, and (v) supply-side efficiency improvements. (NRDC also modeled less stringent standards, both with and without end-use energy efficiency as a compliance option, as described further in Appendix VII.)

The baseline regional generation shares used in the calculation of the program standards were developed from the share of fossil generation attributable to coal and the share attributable to combined oil and gas generation, based on historical generation data for the years 2008 through 2010. These shares were determined at the state or model region level, consistent with the model regions currently used in IPM®.

The emission rate for each state/region was calculated by applying two uniform emission rate benchmarks (one for the coal-fired baseline generation share and a second for the oil/gas-fired baseline generation share) to the baseline state/

regional share of generation of each fuel over the period 2008 through 2010, using the following equation:

a. For 2015–2019, state/regional rate = [1,800 lbs/MWh] × [baseline coal generation share of state/region] + [1,035 lbs/MWh] × [baseline oil/gas generation share of state/region]

b. For 2020–2024, state/regional rate = [1,500 lbs/MWh] × [baseline coal generation share of state/region] + [1,000 lbs/MWh] × [baseline oil/gas generation share of state/region]

c. For 2025 and thereafter, state/regional rate = [1,200 lbs/MWh] × [baseline coal generation share of state/region] + [1,000 lbs/MWh] × [baseline oil/gas generation share of state/region]

Based on national EPA data for the period 2008–2010, the baseline national CO_2 emission rates are calculated as 2,063 lbs/MWh for coal-fired generation sources and 1,065 lbs/MWh for oil and gas–fired generation sources. The 2020 benchmark for coal units is a 27 percent reduction from the baseline coal emission rate, and the 2020 gas benchmark is a 6 percent reduction.

To illustrate the target emission rate calculations, consider two hypothetical jurisdictions: The first is a high-carbon-intensity jurisdiction where 90 percent of the electricity generation is coal-fired and the remaining 10 percent is gas-fired, and the second is a lower-carbon-intensity jurisdiction where gas-fired units generate 90 percent of the electricity with coal-fired generation making up the other 10 percent. In the **coal-heavy jurisdiction**, the 2020 emission rate standard calculation is given by:

(1,500 lbs/MWh* 0.90)+(1,000 lbs/MWh* 0.10)
= 1,450 lbs/MWh

In **the gas-heavy jurisdiction**, the 2020 emission rate standard calculation is given by:

(1,500 lbs/MWh* 0.10)+(1,000 lbs/MWh* 0.90)
= 1,050 lbs/MWh

NRDC's analysis of its proposed CO_2 pollution standards for existing power plants consisted of four IPM® model runs, identified as follows:

- Reference Case: No CO_2 pollution standards and EIA AEO2011 Reference Case demand;
- NRDC Policy Case ("NRDC"): CO_2 pollution standards as described above, with energy efficiency allowed to count toward compliance and demand levels resulting from energy efficiency represented by the Transition Scenario in the November 2011 report "Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011," published by Synapse Energy Economics, Inc.[42]
- Weaker Standard Case ("WS"): Less stringent CO_2 pollution standards reflecting a 5 percent reduction by 2016 and a 15 percent reduction by 2020 in the benchmark emission rate for coal, and a 2.5 percent reduction by 2016 and a 5 percent reduction by 2020 in the benchmark emission rate for gas, with energy efficiency allowed to count toward compliance using the same assumptions as in the NRDC Policy Case.
- Weaker Standard, No Demand-Side Management ("WS–No DSM"): Less stringent CO_2 pollution standards as in the Weaker Standard Case, with no credit toward compliance for energy efficiency and EIA AEO2011 Reference Case demand.

Table 3.1 below summarizes the characteristics of the four cases modeled in this analysis. This discussion will refer to the cases by their respective shorthand titles, indicated in parentheses. The Reference Case and the NRDC Policy Case are covered in the body of the text, while details on the WS and WS – No DSM cases are contained in Appendix VII.

Table 3.1. List of Model Runs for NRDC CO_2 Pollution Standard for Existing Sources

	CO_2 POLICY (2020)	DEMAND	RATE AVERAGING	EE COMPLIANCE
Reference Case	None	AEO2011	No	No
NRDC Policy Case (NRDC)	1,500 lbs/MWh coal; 1,000 lbs/MWh gas	Synapse Transition	State/Regional	Yes
Weaker Standard (WS)	1,754 lbs/MWh coal; 1,012 lbs/MWh gas	Synapse Transition	State/Regional	Yes
Weaker Standard, No DSM (WS–No DSM)	1,754 lbs/MWh coal; 1,012 lbs/MWh gas	AEO2011	State/Regional	No

CHAPTER 4: PROPOSED IMPLEMENTATION GUIDANCE FOR END-USE ENERGY EFFICIENCY CREDITS UNDER SECTION 111(d)

End-use energy efficiency is cheaper, cleaner, and faster at providing energy services to electricity customers than building and operating power plants and power lines.[43] Efficiency improvements can save a typical household more than $700 per year, or roughly one-third of the $2,200 average annual utility bill.[44] Savings are even higher for commercial and industrial consumers, and there is abundant untapped cost-effective potential for all sectors and in all states.[45]

The recommended program under Section 111(d) allows certain end-use energy efficiency savings to count as a flexible compliance option—specifically, those generated from qualifying state and local regulator-approved energy efficiency programs or from improved building and appliance standards. Allowing these programs and standards as compliance options for existing power plants could help spur additional energy efficiency investments, improve the cost-effectiveness of the standard, and result in net economic savings to the system. By its nature, however, energy efficiency cannot easily be measured directly like the output of a power plant, and so the "emission guideline document" that EPA issues under Section 111(d) must provide clear guidance to ensure that savings and associated emission reductions are permanent, quantifiable, surplus, and enforceable.[46]

The energy efficiency compliance option proposed here would be relevant for states that adopt the template program based on state-specific emission rate standards. It would not apply in states adopting alternative programs such as the Regional Greenhouse Gas Initiative (RGGI) and California's AB32, which use cap-and-trade systems. In those systems, the effects of energy efficiency and renewables are already accounted for in the emissions of the capped sector, and an energy efficiency credit system is unnecessary (and would result in double counting).

EPA should include the following principles in its guidance to states regarding the design and creation of the energy efficiency compliance option.

PRINCIPLES

Credits must represent emission reductions that are permanent, quantifiable, surplus, and enforceable.

A. SOURCE (ENFORCEABILITY)

- Compliance credits should be generated from end-use energy efficiency programs approved by state or local energy regulators or from improved mandatory building and appliance efficiency standards.
- CO_2 credits should be generated from electricity savings that state or local energy regulators verify have been achieved by such programs or standards.
- The state air regulator would be responsible for converting the savings reported by the state and local energy regulators into CO_2 credits. The state air regulator would also be responsible for issuing and tracking CO_2 credits to ensure enforceability, avoid double counting, and lower transaction costs and complexity.
- Qualifying energy savings (in MWh) should be converted to emission credits (in tons) by multiplying by the state's applicable emission rate standard.[47]
- Each state would be free to determine its own process for distributing emission credits to generators, but NRDC recommends that states auction these credits and use the revenue to pay for the implementation of the energy efficiency programs, codes, and standards that generate the credits. Any extra revenue could be used to expand these programs, make other clean energy investments, or otherwise benefit electricity customers.[48]

B. BASELINE (SURPLUS)

- Energy savings used for compliance must be verified by the state or local energy regulator, and must be additional or surplus beyond a specified baseline.
- The baseline should be the average annual electricity savings from state and local programs, and codes and standards during the baseline period (e.g., 2008-2010).[49] This level of savings should be assumed to continue in subsequent years in the baseline, and annual savings above that level would be eligible to create CO_2 compliance credits. This requirement ensures that compliance credit is given only for improvements in energy savings levels. Due to the dramatic growth in energy efficiency investments, this baseline will need to be revisited when the program is put into place.

C. QUANTIFICATION/PERMANENCE

- Qualifying energy savings must be quantified through transparent methodologies, must meet EPA-established guidelines, and must be independently verified.
- The state plan should provide for the administrators of energy efficiency programs approved by energy regulators to submit savings using measurement and verification processes that employ independent verification, and that are in compliance with EPA guidelines.
- The cost of measurement and verification requirements should be balanced with the value it provides by giving guidance on acceptable levels of uncertainty.

D. DEMONSTRATING ADDITIONALITY OR SURPLUS

The number of states with investor-owned or publicly owned electric utility energy efficiency programs has increased over the last 30 years to the point where nearly every state includes such programs in its regulatory process. As of 2011, 24 states had established an energy efficiency resource standard (EERS), with 17 states adopting savings requirements of at least 1 percent of total annual sales per year.[50] Forty-four states plus the District of Columbia have billpayer-funded energy efficiency programs. Between 2007 and 2011, American electric efficiency program budgets more than doubled, from $2.7 billion to $6.8 billion.[51] These growth trends are expected to continue.

The program recommended here will encourage the continued growth and success of these programs by setting the savings actually achieved during a fixed retrospective period as the baseline. While some of these savings would have occurred in the absence of a 111(d) policy, and thus are not strictly surplus, this should be accounted for by making the overall emission rate standard more stringent to reflect the number of efficiency credits anticipated to be available for compliance purposes.

E. ENERGY SAVINGS BASED ON TRANSPARENT METHODOLOGIES AND INDEPENDENT VERIFICATION

The emission reductions from end-use energy efficiency can be calculated with reasonable accuracy based on the energy saved by the efficiency program or standard. Experience across the country over the past 30 years has shown that energy savings can be estimated accurately enough to warrant tens of billions of dollars in investments in efficiency programs, and an industry of experts has developed best practices for measuring and verifying energy savings. There will always be a degree of uncertainty in estimating a reduction in energy consumption relative to a hypothetical "business as usual" scenario, but this uncertainty is relatively small and can be accounted for with conservative quantification. There is abundant evidence that efficiency saves tremendous amounts of energy and money and results in real, substantial avoided investments in power plants and other electric system infrastructure.[52]

The recommended Section 111(d) program requires each fossil-fueled power plant to meet the applicable emission rate. For this reason, it is necessary to convert the CO_2 reductions achieved by the energy efficiency savings into a CO_2 credit, so that power plant operators can use energy efficiency as a compliance option. A compliance credit system will require rigorous evaluation, measurement and verification (EM&V), reporting and accounting[53] of the efficiency savings to provide adequate certainty and precision needed to create the credits. Many states already have adequate EM&V processes and protocols in place and in operation, but a few do not. Creating such a system will modestly increase the transaction costs, but clear guidance from EPA could help mitigate these costs and simplify compliance.

Currently there is no national standard to measure energy savings from energy efficiency programs. Instead, each state commission (or utility board in the case of publicly owned utilities) develops its own measurement and verification protocols. While there is some variation in the methods used, there is sufficient reason to believe the savings from these programs are being adequately evaluated. According to a recent ACEEE survey, nearly all states take their responsibility for billpayer protection very seriously, and it is unlikely that any other aspect of a utility's operations is scrutinized so closely.[54] Thus, as long as states rely on transparent, consistent methodologies and employ independent verification, it should be possible to meet the enforceability and quantification requirements for the credits produced. In order to avoid reinventing the wheel for states that already have an adequate EM&V system, and to avoid requiring two layers of measurement and verification processes, state commissions and air regulators should communicate to determine how to use the information currently produced as the result of energy efficiency programs and what modifications/additions might be needed to both streamline EM&V and ensure that it is not subject to gaming in the face of the added incentive to create efficiency credits.[55]

F. AVOIDING THE PITFALLS OF A PRIVATE ENERGY EFFICIENCY CREDIT PROGRAM

The challenges of determining surplus savings and ensuring transparent, independent EM&V for quantification and determination of permanence become much more pronounced when the benefits of energy savings are turned into a credit intended for use as a compliance mechanism. The transaction costs that come with the more stringent EM&V that is required, as well as the additional reporting and accounting costs, can be kept within reasonable bounds if sensible limits are placed on the types of entities that are eligible to generate credits.[56]

The policy direction of a significant portion of state energy efficiency program investments is increasingly focused on longer-term, more comprehensive investments that achieve deep savings. Efforts that are not well coordinated with these programs would likely focus on easy savings, would undermine this policy trend, and would leave savings opportunities behind that would otherwise be cost-effective.

State regulators should be solely responsible for determining the type and quantity of energy savings that qualify to generate emission credits. Only approved CO_2 credits should be tradeable; energy savings themselves should not be tradeable. Once state air regulators convert these qualified energy savings into emission credits (using the state's applicable emission rate standard), the resulting emission credits (measured in tons) would be usable for compliance in combination with any other source of emission credits (e.g., credits from generating electricity at an emission rate below the applicable standard, or from qualifying renewable energy generation). If the state decides to allow third-party-funded and implemented efficiency program savings to qualify for credits, these programs must use the same independently verified EM&V methodologies and assumptions as the regulator-approved programs.

PROPOSED ENERGY EFFICIENCY PROCESS

1. State air regulator (in consultation with the public utility commission and other relevant state/local agencies) determines the energy efficiency savings baseline. State or local energy regulators establish qualifying energy efficiency programs and standards that will generate savings above the baseline and estimate the savings. State air regulator submits the baseline and qualifying programs and standards with savings estimates to EPA as part of the state's Section 111(d) plan.
2. Savings are generated through state or local regulator-approved energy efficiency programs and state or local building codes or standards, using independently verified measurement methodologies and assumptions approved by EPA.
3. EM&V is conducted and verified savings are submitted to state air regulator by the administrator of the qualifying state or local energy efficiency programs and standards.
4. State air regulator establishes emission credits (tons) by multiplying the verified energy savings above the baseline (MWh) by the applicable state emissions standard (tons/MWh) in accordance with EPA guidelines.
5. These emission credits are distributed to sources that need them through a process determined by the state. NRDC advocates auctioning these credits, with the revenue reinvested in additional energy efficiency or clean-energy programs, as the most efficient, transparent, and effective distribution method.
6. Credits submitted by power plant owners as part of their compliance demonstration are retired by state air regulator.

BASELINE AND CO_2 EMISSION CREDIT CALCULATION EXAMPLE

The following hypothetical, simplified example illustrates how the energy efficiency used to create CO_2 credits is determined to be additional or surplus for State X, and at the same time how the baseline calculation is structured so it does not bog down in the ambiguities regarding estimations of attribution.

1) The **baseline** is established by calculating the average first-year MWh savings from energy efficiency programs, codes, and standards for the years 2008–2010.[57]

   279,000 MWh (2008 savings of 0.5%) + 278,000 MWh (2009 savings of 0.5%) + 531,000 MWh (2010 savings of 0.95%) = 1,088,000 MWh/3 = 363,000 MWh (**baseline savings**)

2) It is assumed that this level of first-year savings would continue to be achieved in subsequent years in the baseline; anything over and above that level of savings each year is eligible to be used in the creation of CO_2 credits.

3) The **adjusted savings** used in the **credit calculation** is determined by taking the first-year savings actually achieved in each year (see section on Quantification/Permanence), subtracting the baseline savings, accruing annual savings over the lifetime of the energy efficiency measures,[58] and converting to CO_2 emissions avoided (1 ton = 1 credit).

   a) 806,000 MWh (2011 actual savings) – 363,000 MWh (baseline savings) = 444,000 MWh (2011 **adjusted savings)**

   b) 2011 energy efficiency investments are assumed to achieve 444,000 MWh of savings each year from 2011 through 2022 (444,000 × 12 years = 5,326,000 MWh **lifetime savings** from 2011 measures)[59]

   c) Creditable savings in each year are the sum of creditable savings from measures installed in all previous years that persist through that year. So creditable savings in 2016 are 444,000 MWh (from 2011 measures) + 522,000 MWh (from 2012) measures + 593,000 MWh from 2013 measures + 616,000 MWh (from 2014 measures) + 652,000 MWh (from 2015 measures) + 652,000 MWh (from 2016 measures) = 3,488,000 MWh.

   d) Once the savings have been measured and verified, the CO_2 emission credits from the creditable savings could then be generated. Assuming the state's target emission rate is 1,500 lbs/MWh in 2016, the energy efficiency credits would be 3,488,000 MWh × 1,500 lbs/MWh = 5,232,000,000 lbs /2,000 lbs/ton = 2,616,000 tons (**credits produced** from energy efficiency savings realized in 2016)

CHAPTER 5: MODELING APPROACH AND PLATFORM: INTEGRATED PLANNING MODEL (IPM®)

The analysis has been conducted using ICF's IPM®, a power sector production cost linear optimization model that integrates wholesale power, system reliability, environmental constraints, fuel choice, transmission, capacity expansion, and all key operational elements of generators on the power grid. Developed by ICF, IPM® is a multiregional, dynamic, linear programming model of the North American electric power sector including all major generators. The model is used to determine the least-cost means of meeting electric generation energy and capacity requirements while complying with specified air pollution regulations and other constraints.

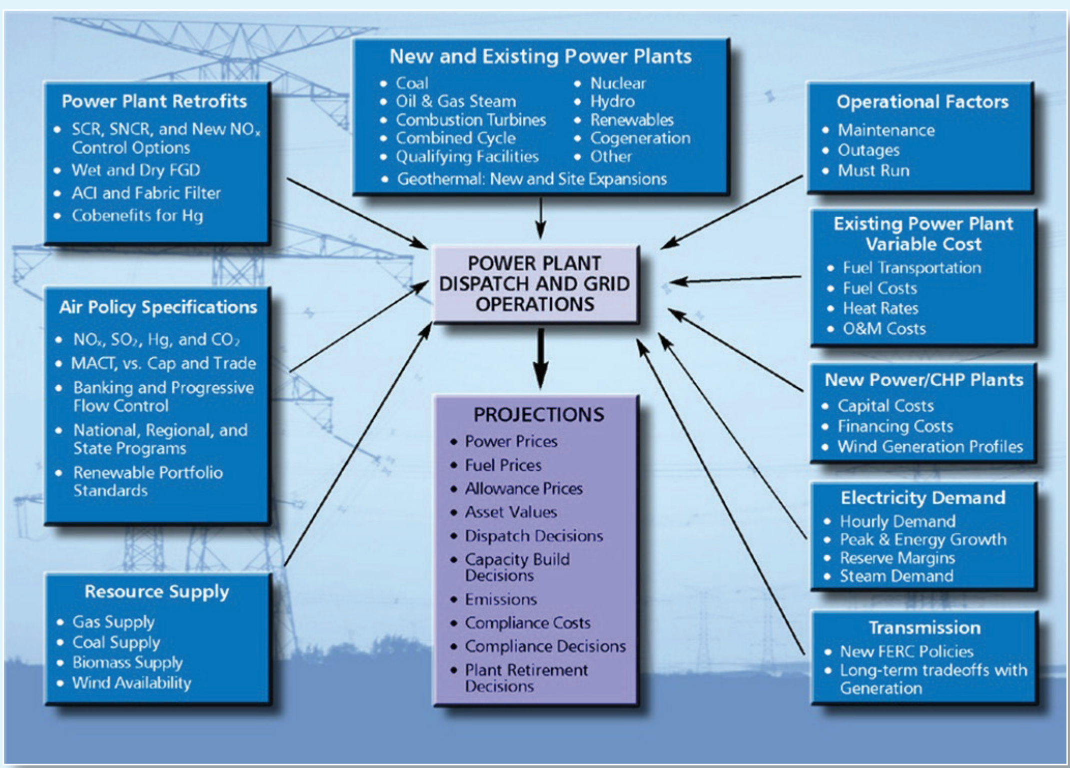
For this analysis, NRDC specified critical assumptions, including environmental policy assumptions, peak and energy demand levels, demand-side management (DSM) levels and DSM costs. The modeling effort focused on five power market regions in the Eastern Interconnect: the New York Independent System Operator (NYISO), New England Independent System Operator (ISO-NE), Midwest Independent System Operator (MISO), Pennsylvania-Jersey-Maryland (PJM), and the Southeast region, excluding Florida. These regions make up approximately 65 percent of the total electricity generated in the United States. The IPM® analysis also produces national results, with less-detailed analysis outside the five focal regions.

IPM® analyzes wholesale power markets and assesses competitive market prices of electrical energy, based on an analysis of supply and demand fundamentals (see diagram below). IPM® projects zonal wholesale market power prices, power plant dispatch, fuel consumption and prices, interregional transmission flows, environmental emissions and associated costs, capacity expansion and retirements, and retrofits based on an analysis of the engineering economic fundamentals. The model does not extrapolate from historical conditions, but rather provides a least-cost optimization projection for a given set of future conditions that determine how the industry will function (i.e., new demand, new power plant costs, new fuel market conditions, new environmental regulations, etc.). The optimization routine has dynamic effects (i.e., it looks ahead at future years and simultaneously evaluates decisions over a specified time horizon). All major factors affecting wholesale electricity prices are explicitly modeled, including detailed modeling of existing and planned units, with careful consideration of fuel prices, environmental allowance and compliance costs, transmission constraints, and operating constraints.

Based on the supply/demand balance in the context of the various factors discussed above, IPM® projects hourly spot prices of electric energy within a larger wholesale power market. IPM® also projects an annual "pure" capacity price.

While this assessment focuses on five key regions (ISO-NE, NYISO, PJM, MISO, and the Southeast)[60] in the Eastern Interconnect, these regions have been modeled as part of the larger North American power system with more than 100 zonal markets. The benefit of this greater geographic scope and granularity is that the model covers the regions of focus, the details of the national environmental regulations, and transmission congestion across major interfaces. This also allows for properly capturing coal usage and pricing through use of coal supply curves. Appendix IV contains more information on the zones modeled within IPM®.

IPM® Modeling Structure



EPA's analysis of the proposed Mercury and Air Toxics Standards published in the March 2011 Regulatory Impact Analysis (RIA) was also performed using IPM® but incorporates EPA's own economic, market, and financial assumptions. EPA's model and the one used for this analysis take the same analytical approach, with some variances in the regional mapping of energy zones.[61] For example, EPA's version of IPM® in its Base Case v.4.10 was modeled on a total of 32 regions nationally and included Canada, Alaska, Hawaii, Puerto Rico, and the U.S. Virgin Islands. The version of IPM® used in this analysis counted more than 100 regions across the country. NRDC specified separate financial, environmental policy, and electricity demand growth[62] assumptions, as well as parameters for aggregation schemes, run years, retrofit costs, trading, and banking.

CHAPTER 6: ENVIRONMENTAL MODELING

The NRDC analysis incorporates constraints on emissions of NOx, SO_2, Hg, CO_2, and other pollutants into its optimization process. Constraints are specified on the basis of target rates, cap-and-trade policies, $/ton emitted tariffs, or technology requirements and are applied to individual generating units or groups of units. Units subject to constraints have a variety of compliance options (including a combination of options), depending on how the policy is specified:

- **Improve Heat Rates.** For all coal units that do not retire, NRDC assumes varying levels of potential heat rate improvements depending on their relative heat rate performance ranking. Since information on actual implemented heat rate improvement programs at specific units is not publicly available, relative heat rate performance was used as a basis to determine efficiency improvement potential. Each coal unit was ranked within its appropriate category (e.g., subcritical vs. supercritical) by full-load heat rate data, which in large part was obtained from EPA's Continuous Emission Monitoring Systems (CEMS). Units with relatively poor heat rate performance are expected to be able to realize the maximum 600 Btu/kWh heat rate improvement, based on implementing a suite of heat rate reduction measures.[63] On the opposite extreme, units that are "best-in-class" are expected to realize no further improvements. Based on this off-line assessment, the improvements determined are then directly applied in IPM®, with implementation assumed to be spread over the period 2014 to 2018. The assumptions regarding supply-side efficiency improvements are described in Appendix V.
- **Reduce Dispatch.** In order to comply with policies that limit total emissions, a unit can limit its operational hours.
- **Switch Fuels.** Coal-fired units can choose from a variety of coals of different sulfur and mercury contents to minimize emissions and allowance cost impacts. The demand for these lower-content coals results in premiums paid for those coals relative to coals with higher pollutant content, although that premium may shrink if, for example, control becomes the dominant compliance option and higher-content coals can be burned by controlled units. Oil-fired units are generally offered fuels with different sulfur contents as well. A system may also switch from coal-fired generation to gas-fired generation, for example, to address CO_2 emissions requirements.
- **Retrofit.** For NOx, SO_2, and mercury, a variety of retrofit technologies are available to reduce emissions. In the case of CO_2, IPM® includes potential carbon capture and sequestration technology retrofits that can be applied to both new and existing units. Repowering with carbon capture and sequestration (CCS) or integrated gasification combined cycle (IGCC) was also included as a retrofit option for coal-fired units.
- **Purchase Credits.** By solving for a CO_2 credit price, IPM® is implicitly assuming that some units are sellers of pollution credits and others are buyers. NRDC assumed that credits are bankable.
- **Retire.** Units can be retired on the basis of specified assumptions, or given the economic option to do so if it cannot cover its operating costs going forward.
- **Transmission.** There is no dynamic modeling of the transmission system in this analysis. Transmission capabilities (for energy and capacity transfers) between IPM® regions reflect the existing transmission system as well as the major transmission projects approved by the respective ISO regions at the time the assumptions for this analysis were developed. Enhancements to transmission and distribution would likely facilitate greater penetration of renewable energy sources in the generation mix, but this was not within the scope of this analysis.

CHAPTER 7: KEY ASSUMPTIONS

Each of the four cases in this report incorporated assumptions specified by NRDC for the pollution standards that EPA has proposed or finalized over the past 24 months. These include: the Mercury and Air Toxics Standards (MATS), proposed on March 16, 2011, and finalized February 16, 2012; the Cross-State Air Pollution Rule (CSAPR), proposed on July 7, 2011, and published in the Federal Register on February 21, 2012;[64] the requirements for cooling water intake structures under Section 316(b) of the Clean Water Act; and standards for coal ash, or coal combustion residuals (CCR), under Subtitle D of the Resource Conservation and Recovery Act (RCRA). It is important to note that the policy assumptions regarding EPA rules that are not yet finalized were based on NRDC's assessment of plausible outcomes, and do not necessarily reflect NRDC's position on these proposals or EPA's subsequent proposals or final rules.

Below is a description of key modeling assumptions as specified by NRDC. Additional details on the individual model runs and the underlying assumptions are available in the Appendices.

- **Natural Gas Prices.** For the purposes of this assessment, natural gas prices are a function of NRDC's assumed gas supply fundamentals and projected power sector gas demand resulting from the specified assumptions. Natural gas supply curves for years across the time horizon of this analysis were developed based on the amount of resource available and the Exploration and Production (E&P) finding and development costs (fixed and variable costs for exploration, development, and Operations and Maintenance (O&M)) associated with the different types of gas resources across the U.S. and Canada, accounting for LNG imports and exports. Regional gas prices reflect forecasted basis differentials from Henry Hub, with delivered prices reflecting various sources of supply, gas pipeline transportation costs, local distribution charges, and potential gas pipeline congestion. The gas supply curves and basis differentials used for this analysis were developed in 2011.
- **Coal Prices.** Delivered coal prices vary by plant as a function of supply options and associated commodity coal prices and transportation options and associated transportation rates. Power plants in the regions of focus largely burn a combination of central and northern Appalachian coal, Illinois Basin coal, Powder River Basin coal, and imported coal. Given assumed coal supply fundamentals and projected demand from the power sector, IPM projects a decrease in prices in real terms through 2016 due to a number of stabilizing supply factors (including production costs, environmental costs, and productivity improvements).
- **Gross Peak Demand (MW).** For all regions in the model, this analysis relied on Reference Case projections for peak demand from the Energy Information Administration's (EIA's) Annual Energy Outlook (AEO) 2011. Peak demand growth rates average approximately 1 percent on an annual average basis across the five focal regions over the 2012–2020 period. In the cases featuring energy efficiency as a compliance pathway, the energy efficiency contribution to peak load reduction was assumed to be 0.15 kW for each MWh saved.
- **Net Energy Demand (GWh).** Similar to peak demand, energy demand reflects EIA's AEO 2011 Reference Case. Energy figures were specified by EIA on a net basis; that is, they incorporate the effect of existing energy efficiency (EE) programs. The average annual net energy growth rates for the five focal regions over the 2012–2020 period is approximately 0.8 percent. Net energy demand in the cases incorporating energy efficiency for compliance was calculated by subtracting the MWh of energy efficiency from the gross energy demand assumptions.
- **DSM.** NRDC specified demand response (DR) levels based on levels reported by ISOs or NERC (as specified in NERC ES&D 2011). No additional energy efficiency

(EE) has been assumed over AEO2011 assumptions in the Reference Case and in the WS–No DSM Case, where energy efficiency does not count toward compliance. Energy efficiency and demand response penetration levels of the Synapse Transition scenario were adopted in the cases with energy efficiency counting toward compliance.

- **Firm Builds.** Firm builds across the five regions largely reflect projects currently under construction. In a few cases, we include projects in an advanced stage of development, i.e., with financing, permits, and/or power purchase agreements (PPAs) secured. In total, we assume 14 GW of thermal builds (including coal, oil and gas, and natural gas capacity) across the 2011–2013 period, made up of 9.4 GW of natural gas combined cycle (NGCC) capacity, 2.9 GW of natural gas combustion turbine (NGCT) capacity, and 1.5 GW of coal capacity with carbon capture and sequestration (CCS). There is no conventional coal capacity in the firm builds forecast. Firm builds also include 8 GW of renewable builds. On a derated capacity basis, this reflects approximately 4 to 5 percent of peak demand.
- **New Entrant Costs.** New entrant costs vary by region as a function of varying ambient temperature (costs are expressed on a summer- and altitude-adjusted basis), labor costs, materials costs, etc. The range for new combined cycle plants in 2016 is from a low of approximately $1,300/kW in the Southeast to approximately $2,700/kW in New York City (NYC). Similarly, for combustion turbine plants in 2016, the range is from $900/kW in the Southeast to $1,500/kW in NYC. For new entrant financing costs, NRDC assumed 50/50 and 42.5/57.5 debt/equity share for CCs and CTs, 12.8 percent return on equity, and 7.1 to 7.6 percent debt rates. Capital charge rates further reflect property taxes and insurance, which vary by region.
- **Reserve Margin Target.** The target reserve margin level determines the point at which new builds are required to maintain reliability. The target reserve margin level ranges from 15 to 18 percent across the focal regions. All regions (in aggregate) commence at significantly higher actual reserve margin levels, indicative of excess capacity.
- **Retirement Limits.** The model projects economic retirements for plants in the system by comparing going-forward revenues and going-forward costs. In the short term (prior to 2017), NRDC limited the total amount of retirements achievable to simulate practical limits associated with reliability considerations, economic and regulatory uncertainty, lead time requirements for replacement capacity, transmission expansion, etc. Cumulative retirements across the U.S. are limited to 20 GW by 2014 and 50 GW by 2016.
- **Supply-Side Efficiency Improvements.** NRDC specified supply-side efficiency (heat rate) improvements for the U.S. coal units as a function of their relative heat rate performance ranking. Units with relatively poor heat rate performance were assumed to undertake a set of measures (combustion optimization software/controls, replacement of steam turbine blades, precombustion drying of moist coal, fuel gas system modification, optimization of soot-blowing, etc.) to realize up to a 600 Btu/kWh heat rate improvement in the 2014 to 2018 period. Units that are deemed to be "best in class" are assumed to realize no further improvements. The coal fleet was categorized to better ascertain best-in-class and worst-in-class rankings on the basis of boiler type (subcritical or supercritical) and type of coal used (bituminous or sub-bituminous). These assumptions for supply-side efficiency improvements were incorporated into the Reference Case as a compliance option for MATS, and in the policy scenarios for both MATS and the CO_2 standard.

CHAPTER 8: CO_2 EMISSION REDUCTIONS

The modeling results show that there are ample opportunities to improve power plant performance and reduce carbon dioxide emissions without adverse economic impacts.

Reference Case. In the Reference Case, CO_2 emissions in the U.S. increase 4 percent from 2012 through 2020, although 2020 emissions remain 5 percent below 2005 levels. Without a specific CO_2 pollution standard to discourage emissions, CO_2 reductions in the Reference Case are a by-product of market dynamics. Emissions increase despite the retirement of some high-emitting units because of demand growth and increased utilization of the remaining high-emitting units.

NRDC Case. The carbon dioxide emissions standards in the NRDC Case reduce national CO_2 emissions 22 percent in 2020 below Reference Case levels. On a regional basis, the CO_2 emission reductions in 2020 range from 16 percent in the Southeast to 29 percent in MISO. Figure 8.1 below illustrates the emissions in the NRDC Case compared with the Reference Case.

The emission rate standards specified in the NRDC Case are intended to reflect BSER.[65] The NRDC Case shows substantial reductions are feasible and cost-effective, resulting in 563 million tons of avoided CO_2 emissions in 2020. In this case total emissions are projected to be just under 2 billion tons, or 26 percent below 2005 levels. The most significant reductions of power sector emissions come from the retirement and reduced dispatch of coal-fired generation driven by energy efficiency. Under the NRDC Case assumptions, emissions are projected to decline further to 34 percent below 2005 levels by 2025. Beyond 2020, however, EPA could revisit the policy and impose tighter standards for future periods to support continued emissions reductions from the electric system.

Table 8.1: Summary CO_2 Emissions Results (in million tons)—U.S. and by Focal Region

MILLION TONS CO_2	2012	2014	2016	2018	2020	2012-2020 % CHANGE
REFERENCE CASE						
US	2,435	2,435	2,458	2,508	2,543	4.4%
ISO-NE	43	43	44	47	46	4.8%
NYISO	40	40	41	47	47	18.2%
MISO	537	546	557	564	571	6.3%
PJM	488	490	482	491	500	2.4%
Southeast	404	394	397	405	412	2.1%
NRDC						
US	2,407	2,346	2,179	2,141	1,980	-17.7%
ISO-NE	41	38	36	37	35	-14.9%
NYISO	36	34	36	39	38	5.2%
MISO	533	527	460	452	406	-23.8%
PJM	485	480	440	430	400	-17.6%
Southeast	404	394	393	364	348	-13.9%

Figure 8.1. Historical CO_2 Emissions and NRDC Projected CO_2 Emissions (in million short tons)

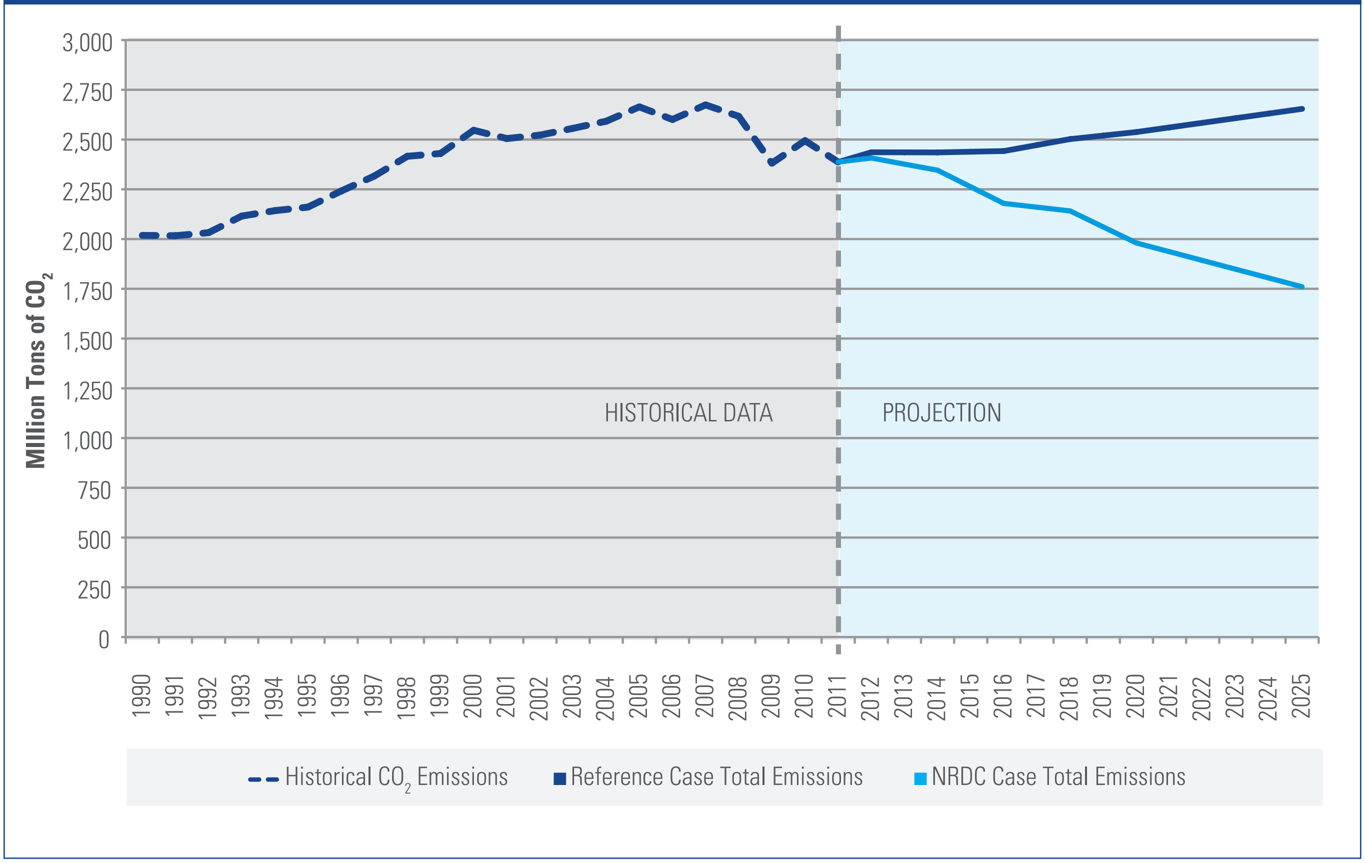
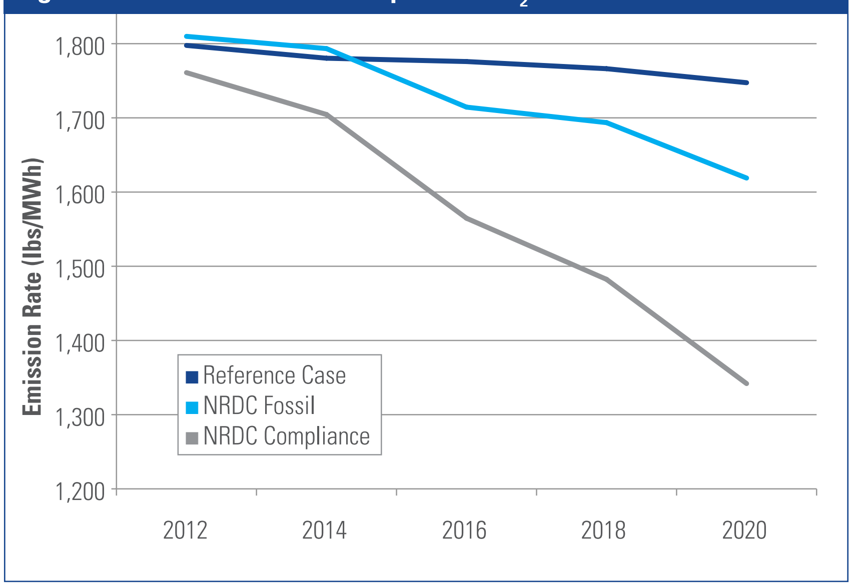


Figure 8.2. U.S. Fossil and Compliance CO_2 Emission Rates



Emission Rate Profiles. The effects of the available compliance options are also evident in the overall emission rates achieved nationally and in each region. For this analysis we calculated the "fossil emission rate" and "compliance emission rate." The fossil emission rate was computed as the total CO_2 emissions from fossil sources in pounds divided by the sum of generation in MWh from fossil sources. The compliance emission rate was defined as the total CO_2 emissions in pounds divided by the sum of generation in MWh from fossil sources, *incremental* energy efficiency, and *incremental* renewable generation.

The differences between the fossil emission rates and compliance emission rates at the national level are shown in Figure 8.2. The national fossil emission rate declines slightly in the Reference Case and by 11 percent in the NRDC Case between 2012 and 2020. The compliance emission rate shows a much greater reduction of 24 percent.

Figures 8.3 and 8.4 illustrate the fossil and electric system emission rates in the focal regions individually by case. In the ISO-NE region, the fossil emission rate hovers consistently in the range of 1,100 to 1,200 lbs/MWh in all cases. The compliance emission rate in ISO-NE declines sharply in the NRDC Case to approximately 820 lbs/MWh as a consequence of increases in energy efficiency and renewable generation in 2020. In NYISO, the fossil emission rate remains in the range of 1,700 to 1,800 lbs/MWh in both the Reference and NRDC Cases, but the compliance emission rate falls to 1,054 lbs/MWh by 2020 in the NRDC Case, 36 percent lower than in the Reference Case. Across all cases in NYISO, capacity shifts are insignificant, but the addition of energy efficiency counting toward compliance drives a decrease in generation from NGCC in the NRDC Case.

In the regions that start out with a higher coal market share—MISO, PJM, and the Southeast—the fossil and compliance emission rates demonstrate again the effect of the CO_2 policy approach, with energy efficiency reducing CO_2 emissions significantly. In the NRDC Case, MISO's fossil emission rate declines 13 percent relative to the Reference Case in 2020. The

Figure 8.3 Reference Case Regional Fossil Emission Rates

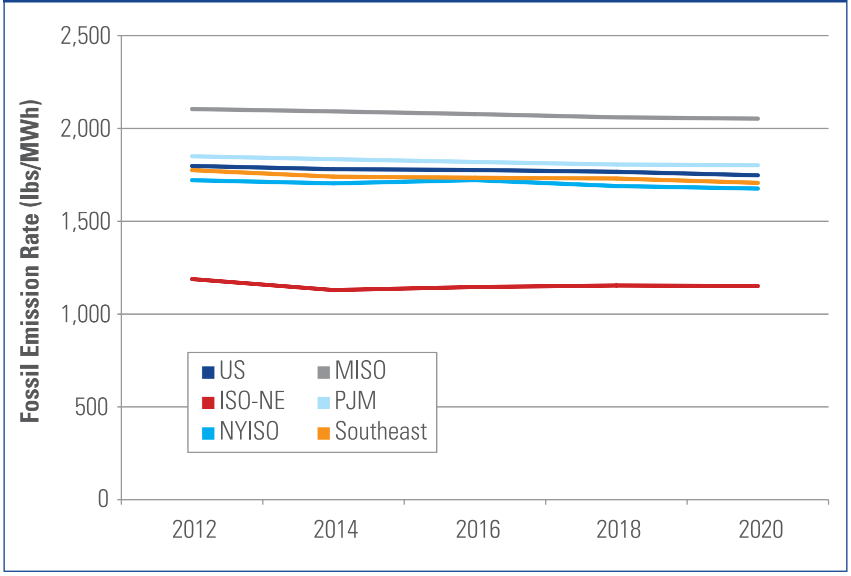
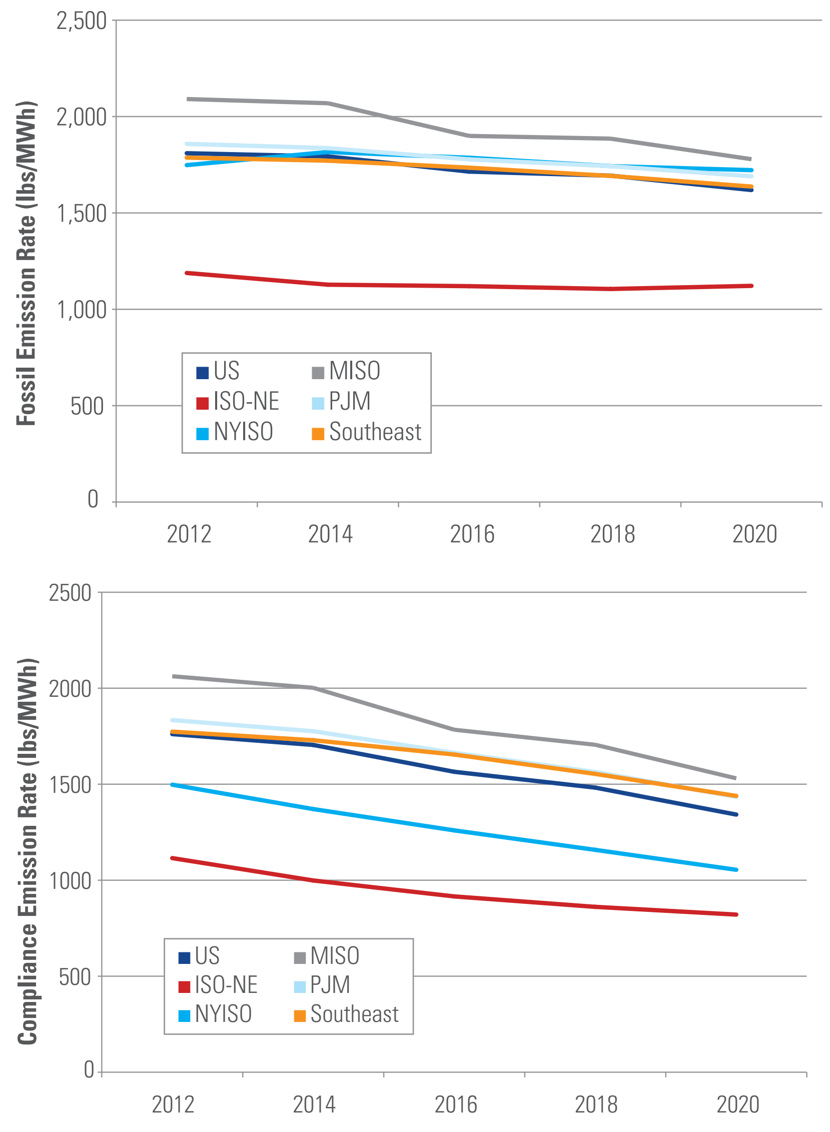


Table 8.2 Summary of Fossil and Compliance Emission Rates in 2020

REFERENCE CASE (LBS/MWH IN 2020)	FOSSIL EMISSION RATE	COMPLIANCE EMISSION RATE
US	1,747	1,747
ISONE	1,151	1,145
NYISO	1,676	1,647
MISO	2,052	2,053
PJM	1,802	1,802
Southeast	1,707	1,708
NRDC (LBS/MWH IN 2020)	**FOSSIL EMISSION RATE**	**COMPLIANCE EMISSION RATE**
US	1,619	1,342
ISO-NE	1,122	821
NYISO	1,722	1,054
MISO	1,779	1,530
PJM	1,690	1,434
Southeast	1,637	1,439

Figure 8.4 NRDC Regional Fossil and Compliance Emission Rates



2020 NRDC Case compliance emission rate in MISO is 25 percent below the Reference Case. In PJM, the fossil emission rate in the NRDC Case declines 6 percent relative to the Reference Case by 2020, while the compliance emission rate in 2020 is 20 percent lower than the Reference Case. In the Southeast, the 2020 fossil emission rate declines a mere 1 percent between the NRDC Case and the Reference Case, but the NRDC Case 2020 compliance emission rate in the Southeast is 16 percent lower than in the Reference Case. Changes in the Southeast emission rates are attributable to sharper declines in coal generation driven by the recommended CO_2 policy approach. IPM projects no increase in renewable energy capacity in the Southeast, so compliance with the CO_2 standards happens primarily through energy efficiency replacing coal generation.

CHAPTER 9: COMPLIANCE COSTS

Compliance costs measure the annualized costs to the electric power system of complying with the standards. It includes fuel expenses and operations and maintenance (O&M) costs for existing and new units, costs for capital recovery for new units and environmental retrofits, and demand-side management (DSM) costs based on the Synapse cost curve.

Table 9.1 below illustrates the compliance costs for the NRDC Case. There is a significant decrease in fuel and capital costs relative to the Reference Case. Lower fuel costs in the NRDC Case are driven by lower generation requirements and lower natural gas prices. Similarly, lower capital costs are the result of lower net peak demand levels and, consequently, fewer unplanned builds. Costs for demand response and energy efficiency offset the decreasing fuel and capital costs. Compared with the Reference Case, the NRDC Case incurs annualized compliance costs of $4 billion in 2020 (see Table 9.1 below).

Note that the compliance costs shown in Table 9.1 include the estimated total resource costs of achieving the energy efficiency improvements incorporated in the NRDC Case, which include both the costs of energy efficiency programs borne by utilities and the incremental costs borne by customers to acquire more efficient equipment. Synapse estimates that utilities bear 55 percent of the total resource costs of energy efficiency. Considering only these utility system costs, the annualized total in the NRDC Case is $6.6 billion lower than in the Reference Case in 2020.

Table 9.1 NRDC Compliance Costs (compared with Reference Case)

DELTA NRDC - REFERENCE CASE							
[MMUS$]	**2012**	**2014**	**2016**	**2018**	**2020**	**2025**	**2030**
Variable O&M	(86)	(248)	(144)	(456)	(677)	(1,299)	(1,384)
Fixed O&M	(84)	(716)	(2,074)	(4,222)	(4,777)	(5,963)	(7,002)
Fuel	(2,809)	(6,893)	(4,950)	(9,992)	(13,642)	(27,026)	(47,479)
Capital	381	276	219	(49)	631	(2,188)	(6,108)
CO2 Transport & Storage	-	-	-	-	(212)	(207)	(188)
DR	-	-	503	694	806	2,226	3,368
EE	2,389	5,543	9,868	15,366	21,949	44,051	59,040
DSM (DR+EE)	2,389	5,543	10,371	16,060	22,754	46,277	62,409
HR Efficiency Improvement	-	(643)	(643)	(643)	-	-	-
TOTAL	**(209)**	**(2,681)**	**2,779**	**697**	**4,077**	**9,594**	**248**

CHAPTER 10: THE ECONOMIC BENEFITS OF EMISSION REDUCTIONS

Air pollution from fossil-fueled electric power generation is harmful to public health, causing a variety of illnesses including asthma, heart attacks, stroke, and even death. These pollutants, including sulfur and nitrogen oxides, affect not only those who live in proximity to power plants but also those who live downwind, often hundreds and even thousands of miles from the plant's actual location.[66] Coal-fired power plants in the United States release enough of these pollutants into the atmosphere each year to cause more than 13,000 premature deaths and hundreds of thousands of asthma attacks.[67] The aggregate toll caused by these harmful health impacts, and the resulting medical bills and lost wages, can exceed $100 billion in one year.[68] This section will describe the economic benefits of reducing SO_2, NOx, and CO_2 emissions from power plants resulting from the NRDC recommended approach for setting carbon pollution standards for existing sources.

A. NITROGEN OXIDES (NOx) AND SULFUR DIOXIDE (SO_2)

Nitrogen oxides (NOx) and sulfur oxides (SOx) are dangerous air pollutants produced by burning coal. NOx, which is also produced by natural gas–fired power plants, can have toxic effects on airways, leading to inflammation, asthmatic reactions, and worsening of allergies and asthma symptoms.[69] In addition, NOx reacts with volatile organic compounds (VOCs) in sunlight to form ground-level ozone, a principal component of smog. This layer of brown haze contributes to decreased lung function, increased respiratory problems, asthma attacks, emergency room visits, hospital admissions, and premature deaths. Ozone can also cause irreversible changes in lung structure, eventually leading to chronic respiratory illnesses such as emphysema and bronchitis. Sulfur dioxide (SO_2), part of the group of air pollutants known as sulfur oxides (SOx), reacts chemically in the air to produce acids that irritate the airways, often causing aggravated respiratory symptoms for those with asthma, particularly children.[70] Exposure to SO_2 is also linked to preterm births, increases in premature mortality, and emergency hospitalizations for respiratory disease in the elderly.[71] Sulfur dioxide and nitrogen oxides both contribute to the secondary formation of fine particulate matter (PM) in the atmosphere in addition to directly emitted fine PM. Numerous studies have linked a wide range of adverse health impacts to exposure to PM, including increased rates of cardiovascular disease and respiratory illness. Exposure to PM has also been linked to birth defects, low birth weight and premature births.

The NRDC Case avoids between 2,900 and 7,300 deaths, 4,755 hospital visits, and approximately 2.6 million incidences of poor health in 2020 due to reductions in SO_2 and NOx emissions, compared with the Reference Case. The economic value of the benefits of NOx and SO_2 reductions from the NRDC recommended approach for carbon pollution standards is estimated to be between $10.6 and $26.3 billion in 2020.[72] For the 730,000 tons of SO_2 and 419,000 tons of NOx reduced, this amounts to $25,000 to $63,000 per ton avoided. These benefits include value from avoided mortality, acute and chronic bronchitis, asthma exacerbation, heart attacks and emergency room visits, hospital admissions, upper and lower respiratory symptoms, and restricted activity days.

B. CARBON DIOXIDE (CO_2)

The NRDC proposal is projected to reduce carbon dioxide emissions by 563 million tons in 2020 compared with the Reference Case. Depending upon the assumed discount rate (discussed further below) and corresponding estimates of the social cost of carbon (SCC), the economic value of this decrease in CO_2 pollution was estimated to be between $14.1 billion and $33 billion.

The SCC methodology has been used to estimate the benefits associated with CO_2 emission reductions in several recent EPA rulemakings, including the Mercury and Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSPAR), and the industrial boilers major and area source rules. The SCC is an estimate of monetized damages associated with an incremental increase in CO_2 emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damage from increased flood risk, and the value of ecosystem services due to climate change.[73]

The SCC values that EPA uses in its regulatory impact analyses were developed in February 2010 through an interagency process that included EPA and other executive-branch entities. EPA used these SCC estimates in the first greenhouse gas rulemaking , issued jointly by EPA and the Department of Transportation, the Light-Duty Vehicle Greenhouse Gas Emissions Standards and Corporate Average Fuel Economy Standards. The SCC Technical Support Document (SCC TSD) provides a complete discussion of the methods used to develop these SCC estimates.[74]

In this analysis, we estimated carbon reduction benefits for NRDC's recommended CO_2 policy using EPA's mid-range SCC for 2020 of $26 per metric tonne of CO_2, derived from a 3 percent discount rate. We also estimated benefits at an alternative midpoint of 2 percent, based upon a literature review cited in official guidelines of the Office of Management and Budget finding inter-generational discount rates ranging from 1 to 3 percent. We use estimates from Johnson and Hope (2012),[75] who re-ran EPA's model at lower rates, finding values of $266 and $62 at 1 and 2 percent, respectively. Importantly, their estimates are conservative in that they are 2010 values, in contrast to the 2020 estimate we used for EPA's 3 percent discount rate case (the SCC grows over time as carbon emissions have larger and larger effects). Johnson and Hope only estimated EPA's model for 2010; as such we were limited to that year at the 1 and 2 percent rates.

Multiple discount rates are used in SCC analysis because the SCC is very sensitive to the discount rate assumption,[76] and because there is no consensus on the appropriate rate to use. In contrast to our SCCs, the interagency group estimates use discount rates of 2.5, 3, and 5 percent. The 2020 SCCs corresponding to these are, respectively, $7, $26, and $42. EPA also recommends an additional estimate of $81 for sensitivity analysis, derived from the 95th percentile of the SCC at the 3 percent discount rate.

Table 10.1 summarizes the SCC values over our alternative range (1 to 3 percent) and midpoint, translating the SCC estimates from 2007 dollars per metric tonne to 2010 dollars per short ton, the units used to present this analysis. Total

CALCULATING THE BENEFITS FROM REDUCING SO_2 AND NO_x EMISSIONS]

The value of reduced emissions of SO_2 and NOx were derived from Abt Associates' extensively peer-reviewed dispersion model developed to estimate health impacts from power plants for EPA. Specifically, Abt Associates followed the sequence of calculations below:

Step 1: Calculating Regional Impact Coefficients

Regional coefficients were calculated using Abt Associates' Powerplant Impact Estimator tool. This tool calculates the health impacts of power plant emissions by combining emissions with weather patterns to determine pollutant concentrations at a county-by-county level. These concentrations are combined with the Pope and Laden dose-response curves to determine the health impacts of a given level of emissions. The mortality range is based on the application of Pope and Laden as alternative dose-response functions. The model was run three times for each region—once to determine coefficients for SO_2, once to determine coefficients for NOx, and once to determine coefficients for particulate matter. The coefficients derived from this modeling tell us the health impact of a ton of emissions nationally and in each of the focal regions.

Step 2: Health Impacts of Regional Emission Reductions

For the cases evaluated, the regional impact coefficients calculated in step one were applied to the emission reduction results of the IPM® model runs to determine the health benefits related to each case. Emission reductions for all the cases were assumed to be uniform (percentage-wise) across the different plants, though the percentage reduction varied from case to case. The dispersion pattern remains constant due to plant-level uniformity, so recalculation is unnecessary.

Step 3: Valuation of Health Impacts

The health impacts were monetized using EPA's estimates for the valuation per unit of impact. For the most part, these valuations are constant across the entire U.S. However, for several of the impacts that involve regional differences, such as the value of lost work days, county-level valuations are applied.

CO_2 benefits corresponding to EPA's $26 per metric ton ($25 per short ton) equal $14 billion, while those corresponding to our $62 per metric ton estimate ($59 per short ton) equal $33 billion. Total benefits discussed in the next section across all pollutants are based upon these two figures.

Economic benefits would be still greater at NRDC's recommended discount rate of 0.7 percent, as submitted in the comments to EPA's proposed Clean Air Act Section 111(b) New Source Performance Standards for new power plants.[77] NRDC maintains that the administration relies on discount rates that are unjustifiably high[78] and recommends 0.7 percent as the appropriate discount rate. This recommendation was based upon multiple factors associated with climate change, including risks that entail potentially irreversible damages over very long time horizons (for further discussion, see Johnson and Hope (2012)).

C. TOTAL BENEFITS VS. TOTAL COSTS

Figure 10.1, below, illustrates the comparison between the total compliance costs of the recommended policy approach and the total benefits, representing the sum of the benefits from SO_2 and NOx reduction and the CO_2 reduction benefits.

Figure 10.1. NRDC Case Estimated U.S. Benefits From Reductions in SO_2, NOx, and CO_2 in 2020

In 2020, for a compliance cost of $4 billion, NRDC estimates health and economic benefits in the range of $25 to $60 billion. The cost per ton of CO_2 emissions avoided in the NRDC scenario is $7.24. This suggests that the benefits outweigh the compliance costs of the policy by a factor of 6 to 15.

Figure 10.1 NRDC Case Estimated U.S. Benefits From Reductions in SO_2, NO_x, and CO_2 in 2020

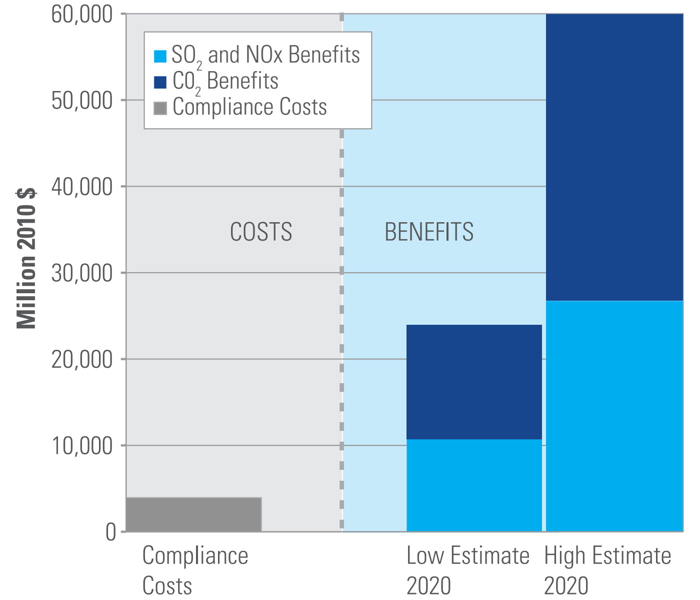


Table 10.1 Social Cost of Carbon Values

DISCOUNT RATE	2007 $/METRIC TONNE	2010 $	SHORT TONS	FOR NRDC ANALYSIS
1.0%	266.00	279.75	253.79	$254/ton
2.0%	62.00	65.21	59.15	$59/ton
3.0%	26.30*	27.66	25.09	$25/ton

* This value is the Administration's 3 percent discount rate estimate of the SCC for 2020. The marginal damages from carbon emissions increase over time.

CHAPTER 11: WHOLESALE ELECTRICITY PRICES

Average wholesale electricity prices in the NRDC Case are expected to be below Reference Case levels (Figure 11.1), and regional wholesale prices are expected to be below Reference Case levels in each region in most years.

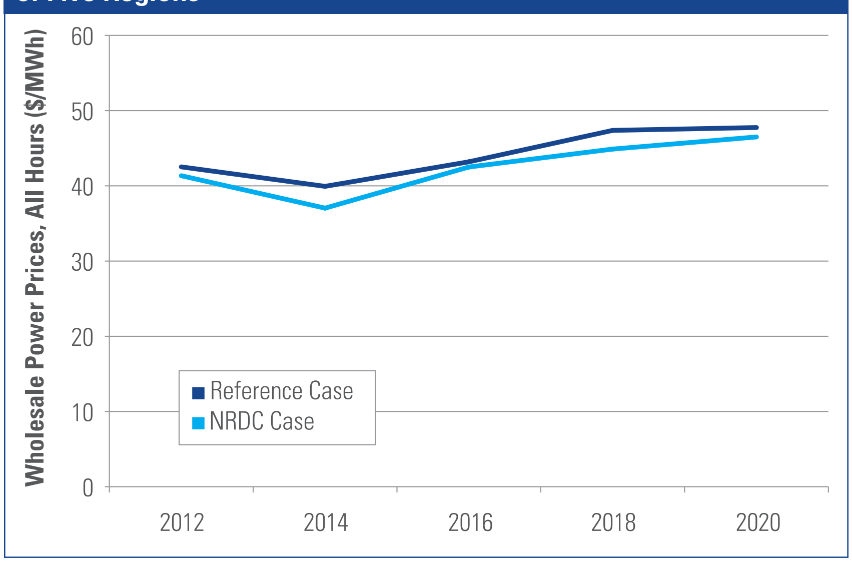
IPM®'s assessment of power prices comprises two components—energy and capacity. The energy price generally reflects the short-run variable cost of the marginal unit (i.e., the last unit dispatched to meet hourly load requirements) including fuel, variable O&M (startup fuel, consumables, etc.), and emission costs. The capacity price reflects the incremental costs necessary to maintain system reliability and reserve margin target levels. In a situation of excess capacity, capacity prices are largely correlated to the fixed going-forward costs of the marginal units remaining in the system to ensure reliability. In equilibrium, capacity prices generally reflect the annualized capital and fixed cost of new units that come on line to meet incremental need, net of energy margin. The energy margin reflects the profit that a unit makes for dispatching and selling electricity. It is calculated as the revenue from electricity sales minus fuel, emission, and other nonfuel costs.

IPM®'s energy and capacity price methodology maps closely to the market structure in ISO-NE, NY-ISO, PJM, and MISO. IPM® maintains the analytic structure of energy and capacity price components even for markets where there is no formal/centralized capacity market structure (such as TVA, Southern, and Entergy). In these markets, the capacity price component manifests in the volatility or scarcity component of the firm power price.

Historical Energy Prices. Figure 11.2 summarizes historical and projected annual average all-hours (around the clock) energy prices for ISO-NE, NY-ISO, PJM, MISO, and the Southeast market (defined as TVA, Southern, and Entergy) over the 2007–2010 period, along with projections for the NRDC Case. For ISO-NE, NY-ISO, and PJM, the historical prices shown reflect pricing in the energy market. In the case of MISO and the Southeast, the price shown reflects the firm bundled price. Assuming there has been little capacity value in these markets in the 2007–2010 period, the firm price may be considered similar to the energy component of price.

Historical energy prices have been influenced primarily by fuel prices, but also by electricity demand levels, which are in turn affected by weather and economic conditions. In regions like ISO-NE, NY-ISO, and Eastern PJM, where the supply is dominated by gas-fired units, energy prices are largely influenced by natural gas prices. Coal prices determine energy prices in coal-dominated regions of MISO, Western PJM, and most of the Southeast, particularly during off-peak

Figure 11.1 Wholesale Power Prices, Generation-Weighted Average of Five Regions



Note: Generation-weighted average of PJM, Southeast (excluding Florida), MISO, NYISO, ISO-NE, accounting for 60 percent of national generation.

hours. Even in these regions, however, peak energy prices are influenced by natural gas on the margin during some hours. From 2007 to 2008, Henry Hub gas prices increased by 24 percent and all-hours electricity prices in ISO-NE and NYISO increased by approximately 20 percent, but MISO electricity prices were largely unaffected. PRB coal prices (the main source of coal for MISO coal-fired units) remained relatively constant between 2007 and 2008. Between 2008 and 2009, when gas prices more than halved, energy prices across all regions also plummeted. In this period, the increase in eastern coal prices was offset by lower demand, resulting in energy price decreases in both gas- and coal-dominated regions.

Based on the energy and capacity price outputs of the model, IPM® projected firm power prices for each region, representative of wholesale electricity prices. The firm power price includes the cost of energy and capacity price components of power. The all-hours firm power price in \$/MWh is calculated as:

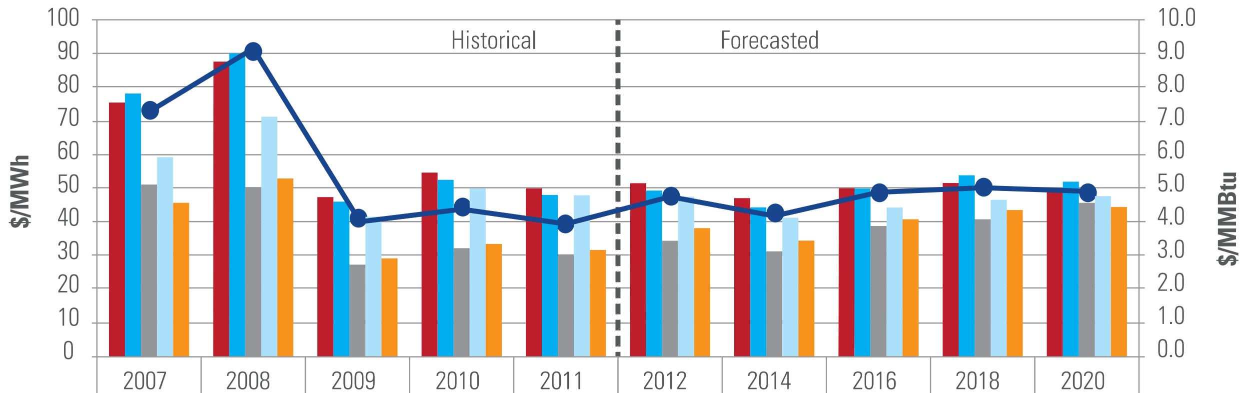
Energy price (\$/MWh) + Capacity price ((\$/kw-year)/8.760)

The firm power price is correlated with retail electricity prices but does not include such costs as transmission and distribution charges and taxes.

Electricity demand is also an important driver for electricity prices. From 2009 to 2010, for example, natural gas prices increased by approximately 10 percent but energy prices in ISO-NE, NYISO, and PJM increased by almost 20 percent as a result of higher-than-normal electricity demand in the Northeast, which was due, in turn, to partial economic recovery and extreme weather. Other factors such as significant generation-capacity or transmission-expansion projects (and retirements) can also significantly influence energy prices.

These modeling results demonstrate that NRDC's recommended policy approach reduces CO_2 emissions from the power sector at modest costs,[79] with the potential for consumer electricity price savings.

Figure 11.2 Projected Wholesale Electricity Prices (NRDC Case, 2010$)



	2007	2008	2009	2010	2011	2012	2014	2016	2018	2020
ISO-NE	75	87	47	54	50	51	47	50	52	49
NYISO	78	90	46	52	48	49	44	50	54	52
MISO	51	50	27	32	30	35	31	39	41	46
PJM	59	71	42	50	48	47	41	44	47	47
Southeast	45	53	29	33	32	38	34	41	43	44
Henry Hub	7.3	9.1	4.0	4.4	3.9	4.7	4.2	4.9	5.1	4.9

FIRM POWER PRICES, ALL HOURS (\$/MWH): DELTA NRDC - REFERENCE CASE

	2012	2014	2016	2018	2020
ISO-NE	-3.8%	-8.4%	-5.5%	-10.4%	-11.8%
NYISO	-3.7%	-10.4%	-3.6%	-7.0%	-8.8%
MISO	-4.3%	-8.9%	-4.5%	-5.1%	-3.4%
PJM	-1.6%	-6.0%	0.6%	-1.0%	-1.8%
Southeast	-1.7%	-5.7%	0.6%	-8.9%	-5.5%

Note: Delta = (NRDC Case Firm Power Price– Reference Case Firm Power Price)/Reference Case Firm Power Price.

CHAPTER 12: DEMAND-SIDE MANAGEMENT IS THE MOST COST-EFFECTIVE EMISSION REDUCTION OPTION

Demand-side management is a significant low-cost driver of emission reductions in the NRDC Case. This section describes the assumptions for demand-side management and the associated implications for the recommended policy approach.

Much of the research by utility sector equity analysts in recent months has focused on the uncertainties that utility companies face with respect to carbon dioxide emissions regulation and the impacts of EPA rules on the nation's fossil fuel generating fleet. Even with the shifting regulatory landscape, there are available resources that can be deployed to mitigate impacts of the environmental regulations and deliver even greater emission reductions. Demand-side management resources (including demand response and energy efficiency) are cost-effective solutions for power plants that would make electricity generation cleaner, more flexible, and more efficient, and are valuable resources for meeting the nation's energy needs.

End-Use Energy Efficiency. End-use energy efficiency, or demand-side energy efficiency, refers to programs and standards that encourage improvements that reduce energy demand while producing the same or greater output or service. A McKinsey analysis of the national economic potential for demand-side energy efficiency indicates that energy efficiency improvements could reduce demand by more than 2 percent each year.[80] Existing state programs, such as Vermont's, are already achieving this level of demand reductions.[81] Four states (including Vermont) have policies that include binding annual energy savings targets of 2 percent or above: Massachusetts (2.4%), Vermont (2.25%), Arizona (2.2%), and Rhode Island (2.0%).[82] Because the cost savings are associated with lower energy bills, investments in energy efficiency are cost effective (that is, they have a positive net present value). The McKinsey study found that, after accounting for the up-front costs of administering energy efficiency programs and installing efficiency improvements, the efficiency measures they identified would save American families and businesses $500 billion over 10 years. In addition, the study estimated that it would require 600,000 to 900,000 additional workers during that period to develop, produce, and implement efficiency improvements, administer the programs, and verify the results.

Demand Response. FERC defines "demand response" to mean "changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[83] By lowering the demand for peak energy, demand response programs reduce the need to construct costly new generation units and increase overall system flexibility with ramping capabilities that can support greater levels of variable renewable generation.

Demand response can be both dispatchable and non-dispatchable. "Dispatchable demand response" refers to planned changes in consumption that the customer agrees to make in response to direction from someone other than the customer. It includes direct load control of customer appliances such as air conditioners and water heaters, directed reductions in return for lower rates (called curtailable or interruptible rates), and a variety of wholesale programs offered by RTOs/ISOs that compensate participants who reduce demand when directed for either reliability or economic reasons. "Non-dispatchable demand response" refers to programs and products in which the customer decides whether and when to reduce consumption based on a retail rate design that changes over time, such as dynamic pricing programs that charge more during high-demand hours and less during off-peak hours.

Accelerating deployment of low-cost demand response and end-use energy efficiency provides the capability to meet growing electricity service needs without creating a significant need for new capacity through 2020, saving the industry billions of dollars in new construction costs, ensuring affordable energy for American households and decreasing carbon dioxide emission levels.

A. DEMAND RESPONSE AND ENERGY EFFICIENCY ASSUMPTIONS

NRDC collaborated with Environmental Defense Fund (EDF) to evaluate and specify the demand response and energy efficiency assumption levels for this analysis. The analysis indicates these ubiquitous resources can achieve important reductions in carbon pollution and other airborne contaminants while saving families and businesses money. A body of research conducted by utilities, the Electric Power Research Institute, McKinsey, the American Council for an Energy Efficient Economy, Synapse, Analysis Group, and others, as well as extensive programs long administered by states, power companies, the private sector, and efficiency innovators have demonstrated the considerable economic, energy security and environmental benefits that result from deploying today's available electricity resources more efficiently including: reductions in carbon pollution and other air pollutants, electricity bill savings for American families and businesses, expansive consumer choice, job creation, enhanced electric grid reliability and resilience, and smoother integration of renewable energy into grid dispatch.[84]

The demand response and energy efficiency assumptions are based on the penetration levels in the Transition Scenario presented in the November 2011 report "Toward a Sustainable Energy Future for the U.S. Power Sector: Beyond Business as Usual 2011," issued by Synapse Energy Economics, Inc. Synapse adopted fundamental power sector assumptions in its Reference Case, including energy demand growth, peak load growth, technology cost, and performance from EIA AEO 2011.

B. SYNAPSE TRANSITION SCENARIO

Synapse designed the Transition Scenario by adjusting demand forecasts to simulate the effects of more aggressive deployment of energy efficiency and demand response programs nationwide in 10 regions aggregated from those modeled in AEO. The energy use forecast in AEO accounts for the near-term effects of efficiency codes and standards, but it does not include the effects of future modifications to those codes and standards or the much larger impact of utility or third-party efficiency programs. Transition Scenario adjustments were based on data from energy efficiency programs currently being implemented across the country and on a number of studies of efficiency potential. Synapse assumed that by 2020 all regions achieve savings equivalent to 2 percent of the previous year's electricity sales, consistent with the results of the leading efficiency programs in recent years. Synapse applied this level of savings from energy efficiency for each year through 2050. Each region begins the ramp-up to 2 percent from its current average level of savings. Synapse assumed that the average cost of efficiency increases from 4.7 cents per kWh saved in the 2011–2020 period to 5.3 cents per kWh saved in the 2021–2030 period. These figures are derived from evaluations of very aggressive state efficiency programs and represent the total resource costs of acquiring energy efficiency, assuming that utilities bear 55 percent of these total costs while customers bear the remaining 45 percent of the cost in their share of the incremental energy efficient equipment. Thus the 4.7 cents per kWh total cost of energy efficiency corresponds to 2.6 cents/kWh utility program costs.

For demand response, this report finds the potential for peak electricity demand reductions across the country to be between 38 GW and 188 GW, up to 20 percent of national peak demand, depending on how extensively demand response is applied. Synapse cites the Achievable Participation scenario in the June 2009 report prepared by the Brattle Group for the Federal Energy Regulatory Commission (FERC), "A National Assessment of Demand Response Potential."

To develop peak load forecasts for the Transition Scenario, Synapse adjusted the AEO regional peak loads to account for the effects of energy efficiency by reducing peak loads by 0.15 kW for each MWh saved. This factor is an average based on a Synapse evaluation of state and utility efficiency programs. To simulate growth of demand response programs and the associated effects on peak load forecasts, Synapse reduced peak load in each region by an estimate of relative DR potential in different regions derived from the FERC Brattle study.[85] Synapse followed the 2019 DR levels in the FERC Brattle Achievable Participation scenario but expanded the deployment horizon, assuming that each region reaches DR penetration at or slightly below the Achievable Participation level in 2050. Synapse also assumed that the cost of DR rises in each region as time goes on and that greater amounts of DR substitute for generating capacity. Table 12.1, below, illustrates the relationship between the FERC Brattle Achievable Participation (AP) scenario and the Synapse Transition Scenario.

The Transition Scenario data lowers the overall net peak and generation requirements in the NRDC Case for the purposes of this analysis. Tables 13.2 and 13.3 illustrate, respectively, the amount of energy demand reduced by energy efficiency (in TWh) and the effect of demand response on peak load (in GW) between the Reference Case and the NRDC Case. This analysis assumes that energy efficiency reduces peak load by a factor 0.15 kW for each MWh saved. On average, in the five focal regions and across the U.S., energy efficiency levels (in TWh terms) reflect 1 percent of energy demand in 2012, increasing to 10 percent in 2020. In MW terms, energy efficiency levels reflect 1 percent of peak demand in 2012, increasing to 9 percent in 2020 for the five focal regions. DR levels in these cases are identical to the Reference Case in the 2012 to 2014 period but are higher by 9 to 11 percent on average thereafter, across the five focal regions. Energy efficiency levels vary by region, with higher levels in ISO-NE and NYISO on a percent of gross demand basis. For demand response, the increase is higher in MISO, NYISO, and the Southeast and lowest in ISO-NE.

Appendix III contains full details on the net energy and peak demand assumptions

Table 12.1 Synapse Demand Response Penetration Compared to 2009 FERC Brattle Study of Potential

	FERC BRATTLE	SYNAPSE TRANSITION SCENARIO			
	2019 (AP)	2020	2030	2040	2050
Arizona/New Mexico	16%	1%	4%	10%	15%
Rocky Mountains	9%	4%	4%	7%	9%
Northwest	11%	1%	1%	1%	1%
California	7%	1%	3%	5%	7%
Northeast	7%	1%	3%	5%	7%
Southeast	12%	1%	4%	8%	10%
Eastern Midwest	9%	1%	4%	7%	9%
Western Midwest	8%	1%	3%	5%	7%
South Central	13%	2%	5%	10%	12%
Texas	14%	1%	5%	9%	14%

Table 12.2 Energy Efficiency Assumptions

REDUCTIONS FROM ENERGY EFFICIENCY (TWH) AND PERCENTAGE OF GROSS ENERGY DEMAND						
YEAR	ISO-NE	MISO	NYISO	PJM	SE	U.S.
2012	4 (3.2%)	7 (1.0%)	5 (3.5%)	7 (0.8%)	3 (0.5%)	51 (1.2%)
2013	6 (4.6%)	11 (1.6%)	8 (5.0%)	11 (1.4%)	6 (1.0%)	81 (1.9%)
2014	8 (6.2%)	17 (2.4%)	10 (6.6%)	17 (2.2%)	10 (1.6%)	118 (2.8%)
2015	11 (7.8%)	23 (3.3%)	13 (8.4%)	25 (3.1%)	15 (2.3%)	161 (3.8%)
2016	13 (9.3%)	30 (4.4%)	16 (10.1%)	33 (4.1%)	21 (3.2%)	210 (4.8%)
2017	15 (10.9%)	39 (5.6%)	19 (11.8%)	43 (5.3%)	29 (4.2%)	265 (6.0%)
2018	18 (12.3%)	49 (6.9%)	22 (13.4%)	55 (6.7%)	37 (5.4%)	327 (7.4%)
2019	20 (13.8%)	60 (8.4%)	24 (15.0%)	68 (8.2%)	46 (6.8%)	394 (8.8%)
2020	22 (15.1%)	72 (9.9%)	27 (16.6%)	82 (9.9%)	57 (8.2%)	467 (10.3%)

Note: Values in parentheses are the % change in generation in each of the five regions and the U.S. for each year. This table shows reductions from energy efficiency assumed in the Synapse Transition Scenario incremental to AEO2011, which accounts for savings associated with current codes and standards. End-use energy efficiency refers to programs and standards that reduce energy demand for the same or greater amount of output.

Table 12.3 Demand Response Assumptions

DEMAND RESPONSE (MW) AND PERCENTAGE OF GROSS PEAK LOAD						
YEAR	ISO-NE	MISO	NYISO	PJM	SE	U.S.
2012	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)
2013	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)
2014	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)
2015	122 (0.5%)	616 (0.5%)	162 (0.5%)	716 (0.5%)	579 (0.5%)	4,264 (0.6%)
2016	146 (0.6%)	740 (0.6%)	195 (0.6%)	859 (0.6%)	695 (0.6%)	5,116 (0.7%)
2017	171 (0.7%)	863 (0.7%)	227 (0.7%)	1,002 (0.7%)	811 (0.7%)	5,969 (0.8%)
2018	195 (0.8%)	986 (0.8%)	260 (0.8%)	1,145 (0.8%)	926 (0.8%)	6,822 (0.9%)
2019	220 (0.9%)	1,110 (0.9%)	292 (0.9%)	1,288 (0.9%)	1,042 (0.9%)	7,675 (1.0%)
2020	244 (1.0%)	1,233 (1.0%)	325 (1.05)	1,431 (1.0%)	1,158 (1.0%)	8,527 (1.1%)

Note: Values in parenthesis are the % change in peak load in each of the five regions and the U.S. for each year. This table shows peak load reductions from demand response assumed in the Synapse Transition Scenario incremental to what was reported in the NERC ES&D 2011, as well as by independent system operators NYISO and PJM. Demand response refers to those programs that decrease demand for peak energy, reducing the need for additional capacity in the system.

C. RESOURCE ADEQUACY

Electric system reliability is defined as the degree to which the performance of the elements of an electric system results in power being delivered to consumers in demand centers within accepted standards and in the amount of time desired. Reliability is generally made up of two aspects: adequacy and security. Adequacy refers to the sufficiency of generation and transmission resources installed and available to meet projected load plus reserves for contingencies. Security refers to the degree to which a system has available operating capacity even after outages or equipment failure. This section of the discussion deals exclusively with generation adequacy, showing that NRDC's recommended policy approach will not materially constrain the resource aspect of reliability. Security and localized reliability impacts are beyond the scope and capabilities of IPM® and this analysis.

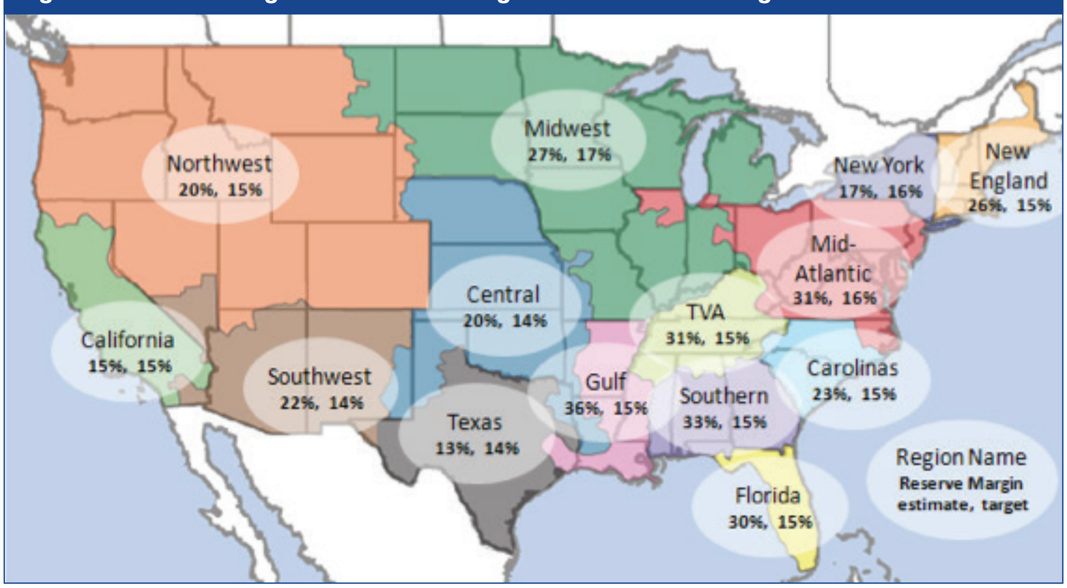
The electric utility system strives to maintain more available electricity supply than is required. This is the simple basis for system reliability. However, it can be difficult to predict future electricity demand, and building new generating capacity to meet increasing load in the short term is impracticable because permitting, construction, and activation often take several years. The industry regularly monitors electricity supply in relation to demand using a metric called reserve margin. Regional estimates of reserve margins are compared with predetermined target levels to assess supply adequacy. Reserve margin is calculated as capacity minus demand, divided by demand, where "capacity" is the expected maximum available supply and "demand" is the expected peak demand. It is calculated for electric systems or for regions made up of a number of electric systems. For instance, a reserve margin of 15 percent means that an electric system has excess capacity in the amount of 15 percent of expected peak demand. The map in Figure 12.1, below, shows 14 regional reserve margin estimates and the target reserve margins for summer 2012, which are derived from the North American Electric Reliability Corporation's (NERC) recently released 2012 Summer Short-Term Reliability Assessment.[86] NERC Regional Entities set their region's target reserve margin.

The reserve margin estimates exceed the target in nearly every region except in ERCOT (most of Texas), where reserve margins could be inadequate, and in California, where reserve margin estimates meet the target. Southeastern and Mid-Atlantic regions currently have reserve margins well above their region's target level, indicating significant excess capacity.

In this analysis, target reserve margins in the five regions of focus between 2010 and 2030 were modeled according to the following, taken from Independent System Operator (ISO) information as of March 2012.

IPM® optimizes new build capacity according to target reserve margins in each region, taking into account import and export transactions in a region. The results include units in each region that are "mothballed," or temporarily withdrawn from the system because of low capacity prices. Each region and the U.S. as a whole maintain reserve margins comfortably above targets through 2020 in the NRDC Case. This indicates that there is substantial excess capacity in

Figure 12.1 NERC Regional Reserve Margin Estimates and Targets for Summer 2012



Source: U.S. EIA, based on NERC 2012 Summer Short Term Reliability Assessment, May 2012. http://www.eia.gov/todayinenergy/detail.cfm?id=6510

Table 12.4 Reserve Margin Target Levels					
2010	15.4%	18.0%	20.0%	15.0%	15.5%
2011	15.7%	18.0%	17.0%	15.0%	15.5%
2012	16.0%	18.0%	13.0%	15.0%	15.5%
2013	16.2%	18.0%	16.0%	15.0%	16.2%
2014	16.5%	18.0%	16.0%	15.0%	15.3%
2015	16.2%	18.0%	16.0%	15.0%	15.5%
2016	15.9%	18.0%	16.0%	15.0%	15.5%
2017	15.5%	18.0%	16.0%	15.0%	15.5%
2018	15.2%	18.0%	16.0%	15.0%	15.5%
2019+	14.9%	18.0%	16.0%	15.0%	15.5%

Table 12.5 Local Reserve Margins in the NRDC Case (Excluding Net Imports and Exports): Mothballed (Temporarily Inactive) Capacity Excluded

REGION	GW	2012	2014	2016	2018	2020	2025	2030
ISO-NE	Gross Peak Demand	23	23	23	24	24	25	27
16%	*Avg. Annual GR*	*3.8%*	*1.0%*	*0.8%*	*1.1%*	*1.0%*	*0.8%*	*1.3%*
	RM Capacity (including DSM)	28	29	31	32	33	36	39
	DSM	3.2	5.0	6.2	7.2	8.1	10.3	11.7
	RM with DSM	24.0%	27.2%	32.1%	33.3%	35.3%	40.3%	42.5%
	RM wo DSM	9.9%	5.3%	5.8%	3.2%	1.9%	-0.4%	-0.8%
NYISO	Gross Peak Demand	31	31	32	32	32	34	35
18%	*Avg. Annual GR*	*4.8%*	*0.6%*	*0.6%*	*0.8%*	*0.6%*	*0.8%*	*0.8%*
	RM Capacity (including DSM)	32	33	34	36	37	41	43
	DSM	2.8	3.8	5.1	6.3	7.5	10.2	11.9
	RM Capacity (including DSM)	2.9%	4.6%	8.9%	12.5%	15.4%	20.4%	22.3%
	RM wo DSM	-6.3%	-7.6%	-7.4%	-7.3%	-7.5%	-9.6%	-11.4%
MISO	Gross Peak Demand	114	116	118	121	123	130	136
17%	*Avg. Annual GR*	*-4.6%*	*0.9%*	*0.8%*	*1.0%*	*1.1%*	*1.0%*	*1.0%*
	RM Capacity (including DSM)	142	138	140	139	143	157	170
	DSM	7.9	9.9	13.4	17.5	22.1	34.7	45.0
	RM with DSM	24.0%	18.5%	18.9%	15.6%	16.3%	21.1%	24.5%
	RM wo DSM	17.0%	9.9%	7.6%	1.1%	-1.7%	-5.7%	-8.5%
PJM-MAAC	Gross Peak Demand	45	46	46	47	48	50	53
16%	*Avg. Annual GR*	*3.6%*	*0.8%*	*0.7%*	*0.9%*	*0.8%*	*1.0%*	*1.0%*
	RM Capacity (including DSM)	53	54	55	57	59	65	70
	DSM	2.4	5.2	6.7	8.4	10.5	16.2	21.0
	RM with DSM	18.0%	18.8%	19.2%	20.7%	23.3%	28.8%	32.4%
	RM wo DSM	12.7%	7.5%	4.8%	2.8%	1.4%	-3.5%	-7.3%

REGION	GW	2012	2014	2016	2018	2020	2025	2030
PJM-RTO	Gross Peak Demand	88	90	91	93	95	100	106
16%	*Avg. Annual GR*	*-5.0%*	*1.1%*	*0.9%*	*1.0%*	*1.1%*	*1.1%*	*1.0%*
	RM Capacity (including DSM)	108	111	115	119	121	129	138
	DSM	4.6	9.8	12.5	15.5	19.0	29.2	37.6
	RM Capacity (including DSM)	22.5%	23.9%	25.2%	27.3%	27.0%	28.8%	31.0%
	RM wo DSM	17.3%	13.0%	11.6%	10.7%	7.0%	-0.3%	-4.6%
PJM	Gross Peak Demand	133	135	138	140	143	151	159
16%	*Avg. Annual GR*	*-2.3%*	*1.0%*	*0.8%*	*1.0%*	*1.0%*	*1.0%*	*1.0%*
	RM Capacity (including DSM)	161	166	170	176	180	194	208
	DSM	7.0	15.0	19.1	23.9	29.5	45.4	58.6
	RM with DSM	21.0%	22.2%	23.2%	25.1%	25.8%	28.8%	31.4%
	RM wo DSM	15.7%	11.1%	9.3%	8.0%	5.1%	-1.4%	-5.5%
SE	Gross Peak Demand	109	111	113	114	116	121	126
15%	*Avg. Annual GR*	*3.1%*	*0.9%*	*0.7%*	*0.7%*	*0.8%*	*0.9%*	*0.8%*
	RM Capacity (including DSM)	127	130	132	134	138	151	163
	DSM	5.8	7.5	10.7	14.1	18.3	30.7	41.3
	RM with DSM	16.7%	17.2%	17.7%	17.9%	19.6%	25.2%	29.4%
	RM wo DSM	11.4%	10.5%	8.2%	5.5%	3.8%	-0.2%	-3.4%
US	Gross Peak Demand	728	744	758	773	788	828	868
15%	*Avg. Annual GR*	*0.7%*	*1.1%*	*0.9%*	*1.0%*	*1.0%*	*1.0%*	*1.0%*
	RM Capacity (including DSM)	866	877	901	924	951	1,027	1,100
	DSM	45.3	67.2	91.5	117.9	147.4	227.5	292.3
	RM with DSM	18.9%	17.9%	18.9%	19.5%	20.6%	24.1%	26.7%
	RM wo DSM	12.7%	8.8%	6.8%	4.3%	1.9%	-3.4%	-7.0%

Table 12.5 ***(Continued) Local Reserve Margins in the NRDC Case (Excluding Net Imports and Exports): Mothballed (Temporarily Inactive) Capacity Excluded***

Notes: Imports and exports are not included in these reserve margin calculations. Only capacity counting toward reserve margins is represented above. Reserve Margin with DSM is defined as ((RM capacity + DSM)/Gross Peak Demand) –1.

the system as a result of energy and demand response resources, with the environmental standards and NRDC's recommended CO_2 policy approach in place.

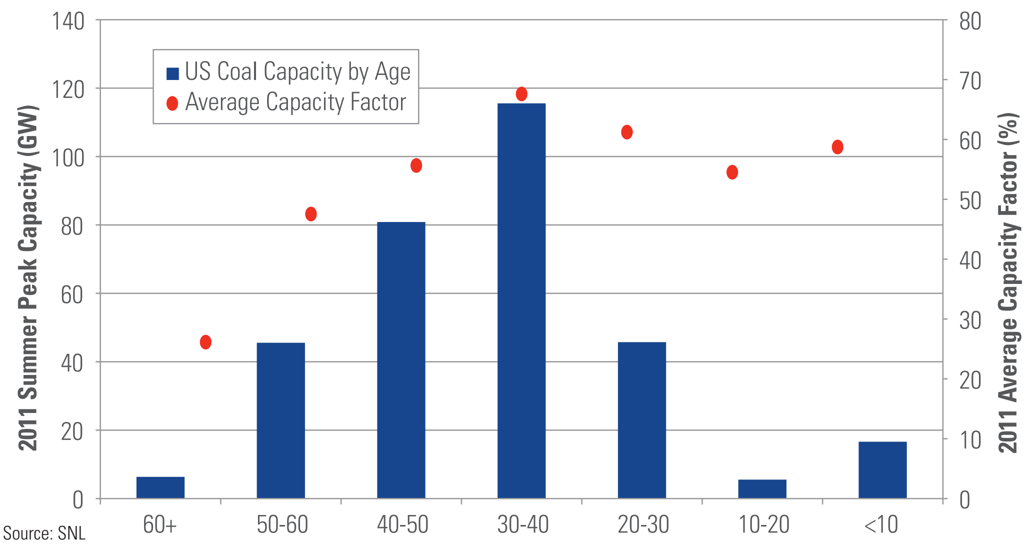
If mothballed capacity were to be excluded from reserve margins, four of the five focal regions, including ISO-NE, PJM, Southeast, and MISO, would still have excess capacity in each of the model years. The exception is NYISO, where reserve margins excluding imported and mothballed capacity are projected to miss targets until 2020. However, NYISO commonly imports capacity from regions with high reserve margins.

NRDC has observed in this analysis that increasing end-use energy efficiency is the most economical way to reduce emissions and decrease overall electricity demand, and that accelerating deployment of demand response is a low-cost option for adding flexibility to the power grid while avoiding significant capacity additions across the nation. Demand response and energy efficiency can be powerful resources in transitioning the fuel mix away from dirty, polluting power plants while maintaining system reliability in accordance with the objectives of a performance standard for CO_2 emissions.

CHAPTER 13: PROJECTED CAPACITY AND GENERATION CHANGES IN THE U.S. POWER SECTOR

The IPM® results show that the proposed carbon standards would begin to modernize and clean up America's electricity sector. Energy efficiency programs adopted in response to the incentives created by the approach would cause overall demand to decline by 4 percent, rather than increase by 7 percent. Meanwhile, coal-fired generation would drop 21 percent from 2012 to 2020 instead of increasing by 5 percent without the proposed carbon standard. Natural gas generation would rise by 14 percent, while renewables rise by about 30 percent (assuming no new state or federal policies to expedite an increase in market share for renewables).

Figure 13.1 Age and Average Capacity Factors of the Current U.S. Coal-Fired Generation Fleet



Source: SNL

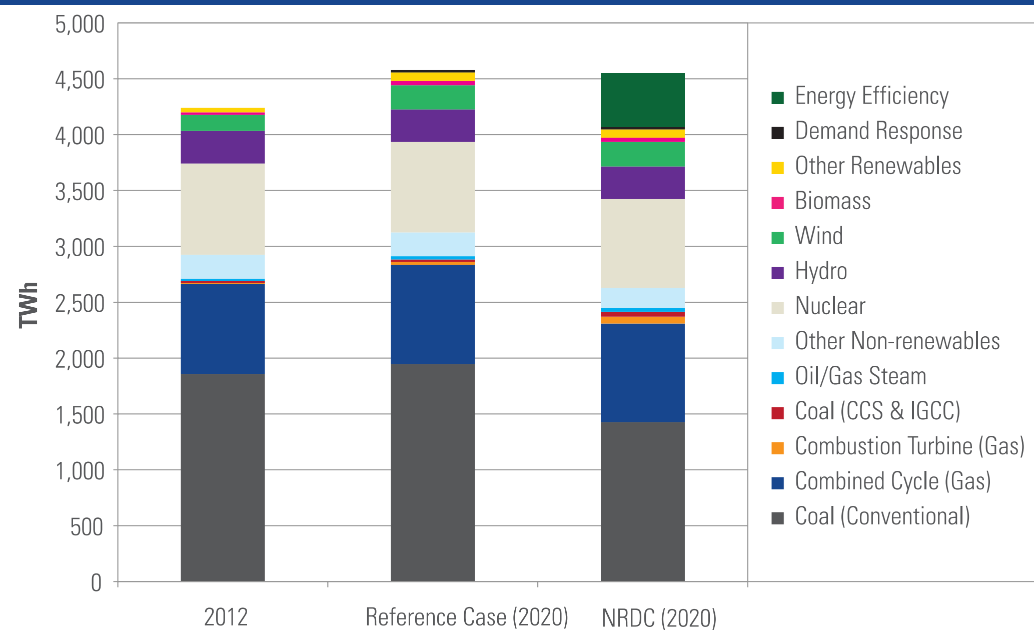
It is helpful to consider the current state of the electric generating capacity in the United States to supplement the interpretation of this analysis. The U.S. power generation fleet is aging as a whole. Almost two-thirds of the base-load coal fleet is more than 30 years old. Figure 13.1 illustrates the coal capacity in the United States by age, along with the average capacity factors for each age group. Consistent with the Reference Case for this analysis, this figure suggests that in the absence of CO_2 emission standards, a substantial share of the existing coal capacity could retire without producing substantial CO_2 emission reductions if that generation were replaced by increased utilization of the remaining coal-fired power plants. For example, if the oldest 80 GW of coal units retire because they are economically unviable, the generation from those units could be replaced by raising the capacity factors of the remaining units by an average of 12.4 percent.

A. GENERATION CHANGES

Generation refers to how much electricity a generator produces and customers consume over a specific period of time, measured in MWh. Capacity is a measure of how much electricity a generator can produce under certain conditions, representing a power plant's potential to generate electricity in MW. Changes in capacity are not necessarily reflected equally in the generation mix. For example, retiring 20 percent of the coal capacity in the generating fleet could mean losing only 9 percent of coal generation. This section describes the changes in the generation mix and is followed by a discussion of the capacity shifts observed in this analysis.

The shift in generation mix resulting from NRDC's proposed policy is driven primarily by energy efficiency replacing deactivated coal generation. NRDC also analyzed a case, presented in Appendix VII, which demonstrates that assuming the same penetration of energy efficiency with weaker emission rate targets leads to efficiency replacing a mix of natural gas and coal generation, rather than primarily coal generation as found in the NRDC Case. The CO_2 standard has the effect of ensuring that the energy efficiency savings displace higher-emitting coal generation rather than natural gas. The result of the CO_2 policy is to reduce both total generation and the market share of coal, while increasing the market share of natural gas and renewables generation. Coincidentally, the increased market share of natural gas

Figure 13.2 Projected 2020 Generation Changes in the U.S. Power Sector



TWH	2012	REFERENCE CASE (2020)	NRDC (2020)
Combined Cycle (Gas)	804	889	883
Combustion Turbine (Gas)	25	40	62
Coal (Conventional)	1,859	1,946	1,426
Coal (CCS & IGCC)	5	8	44
Oil/Gas Steam	18	29	31
Nuclear	816	809	793
Hydro	292	292	292
Wind	144	216	220
Biomass	23	38	38
Other Renewables	40	98	95
Other Nonrenewables	214	213	183
Demand Response	0	0	0
Energy Efficiency	0	0	482
TOTAL	**4,239 (4,239)**	**4,578 (4,578)**	**4,550 (4,068)**

Note: Values for 2012 are not historical, but modeled in IPM® and may differ from actual due to factors including gas prices, demand, etc. Parenthetical values show actual physical generation.

generation in the NRDC Case is almost exactly offset by the reduction in overall demand, leading to an absolute level of natural gas generation in the NRDC Case almost identical to that in the Reference Case. Figure 13.2, below, shows the resulting generation mixes in 2020 across the cases analyzed.

Reference Case. Both coal- and gas-fired generation increases from 2012 to 2020 in the Reference Case. Relative to 2012, gas generation increases by 11 percent, and coal generation increases by 5 percent in 2020. Electricity generation with renewable resources increases by almost 30 percent between 2012 and 2020. Total generation from all sources in 2020 equals 4,578 TWh, an increase of 8 percent from 2012. In the absence of CO_2 standards in the Reference Case, coal generation is competitive on the basis of variable costs, and the average capacity factor for coal units nationwide rises from 66 percent in 2012 to 80 percent in 2020. Average capacity factors for gas units escalate at a slower rate, from 55 percent in 2012 to 58 percent in 2020. As a result, the market shares of coal and gas change little, ending up at 43 percent and 19 percent, respectively, in 2020. The market share of renewable energy increases from 12 percent to 14 percent.

NRDC Case. In the NRDC Case, energy efficiency contributes substantially to the decrease in overall generation requirements, while coal remains a substantial part of the generation mix. By 2020, energy efficiency makes up 11 percent of the generation mix, as represented by the gray shaded area in Figure 13.2. As in the Reference Case, natural gas generation increases modestly to 883 TWh by 2020, a mere 1 percent below the Reference Case level. Not counting energy efficiency in the total, natural gas's market share of generation rises to 23 percent in 2020. Coal generation in 2020 is 27 percent lower in the NRDC Case compared with the Reference Case, with a market share equal to 36 percent of actual generation. As with natural gas, renewable generation is about the same in the NRDC Case as it is in the Reference Case, but this represents an increase in market share to 16 percent by 2020.

Perspectives on Generation from Renewable Energy Sources. Results for the NRDC Case show limited incremental builds of renewable energy capacity through 2025 compared with the Reference Case. In both cases, increases in renewable energy generation are driven primarily by existing state renewable portfolio standards. Given the relatively conservative assumptions about the costs of renewable energy built into the model, the added value provided to renewables in the NRDC Case is apparently not enough to close the price gap between renewables and natural gas. NRDC did not attempt to develop more optimistic cost projections for renewable resources or assume increases in state renewable energy requirements in response to the carbon standards, hence the generation share results for low- and zero-carbon resources are a function of the comparative cost curves used to drive the model. These results should not be regarded as a firm projection of the market shares for renewable energy sources. In practice, the NRDC approach is structured with an economic incentive for all low- and zero-carbon resources to be used more extensively. The ultimate market share will be determined largely by the rate of cost improvement for these competing resources.

While the growth of renewables' market share is limited, increased renewable generation still represents 47 percent of the total increase in generation between 2012 and 2020 in the Reference Case. In the NRDC Case, total generation declines due to energy efficiency while renewable generation increases at the same rate as in the Reference Case. Renewables play a more significant role in some regions. For example, wind generation is projected to increase 23 TWh (51 percent) in MISO by 2020, when it will constitute about 10 percent of total MISO generation in the Reference Case. In the NRDC Case, wind generation in MISO increases by 25 TWh despite a decrease in total generation, resulting in an increase in wind's market share to 11 percent. PJM will experience an 80 percent increase in wind generation from 2012 to 2020, but wind will make up only 3 percent of total generation in 2020. Total wind generation in the Southeast is negligible in both the Reference Case and in the NRDC Case.

These projections of renewable capacity and generation are conservative in comparison with some other recent analyses that suggest the potential for greater renewables penetration, so a parallel review is instructive. The table below compares the renewable generation results of the NRDC Case with the predictions in the AEO2011 Reference Case (AEO2011), the AEO2012 Reference Case (AEO2012), the AEO2012 Extended Policies Case (AEO2012 EP), the Constrained Nuclear scenario in Senator Jeff Bingaman's May 2012 Clean Energy Standard proposal (BCES CN), and

Table 13.1 Comparison of Renewable Energy Generation in Multiple Studies

	GENERATION (TWH) 2012	GENERATION (TWH) 2020
NRDC Reference Case	498 (11.9%)	644 (14.1%)
NRDC Case	497 (11.7%)	645 (15.9%)
AEO 2011	450 (11.9%)	521 (13.0%)
AEO 2012	444 (11.7%)	544 (13.0%)
AEO EP	444 (11.7%)	526 (13.7%)
BCES CN	443 (11.8%)	661 (16.7%)
BCES	443 (11.8%)	643 (16.1%)
Synapse BAU (2010, 2020)	414 (10.0%)	606 (13.7%)
Synapse Transition (2010, 2020)	414 (10.0%)	720 (17.9%)

Note: Values in parentheses represent the percentage of the generation mix made up of renewable energy sources in each case.

finally, the Synapse Transition Scenario (Synapse). The table also shows each study's respective base case in order to provide context.

Reference Case. Because this analysis relies on AEO2011 for its energy and peak demand assumptions, it is helpful to compare the two renewable generation profiles. NRDC adopted AEO2011 as a basis for the Reference Case in this analysis because AEO2012 was not released until after the assumptions were designed, and also because the Energy Efficiency and Demand Response assumptions taken from the Synapse Transition scenario were based on AEO2011. AEO2011's 2020 projection for electricity generation from renewable energy sources is on average 24 percent lower than both the Reference Case and the NRDC Case.

AEO2012 Reference Case and *AEO2012 Extended Policies Case.*[87] The NRDC Case projects 19 percent more electricity from renewable generation than in AEO2012, and 23 percent more in 2020 than in AEO2012 EP. As shown in Table 13.1 above, the 35 percent increase in renewable generation in the NRDC Case from 2012 to 2020 exceeds the increase in renewable generation in the AEO2012 cases over the same period.

Synapse Transition Scenario. The projection of utility-scale renewables in the Synapse Transition Scenario is in line with the IPM® results in this analysis. However, Synapse also projects 102 TWh of distributed renewables.[88] In sum, the total renewable generation in the Synapse Transition Scenario in 2020 is 720 TWh, or 18 percent of total generation. Compared with 16 percent in the NRDC Policy Case, this is substantially more aggressive, representing 12 percent more renewable energy generation.

Bingaman Clean Energy Standard—Constrained Nuclear Case. The Clean Energy Standard proposed by Senator Jeff Bingaman, chairman of the Senate Committee on Energy and Natural Resources (BCES), consists of a crediting system for renewable energy sources, including hydropower and nuclear, with a 24 percent target share of retail electricity sales beginning in 2015, increasing to 84 percent in 2035. EIA's analysis of the BCES showed significant expansion of nuclear generating capacity through 2035. In addition, EIA analyzed a scenario limiting nuclear generation, increasing penetration of renewable energy sources in the generation mix. Renewable generation in the NRDC Case projections is 2.5 percent lower than in the Constrained Nuclear scenario of the Bingaman CES proposal in 2020.

The results of the NRDC analysis on the share of renewable energy sources in the generation mix are moderate and in the range of publicly available projections. They are closer to the conservative projections in the AEO releases than to the more optimistic outlooks for renewable generation presented in the BCES and Synapse Transition Scenario.

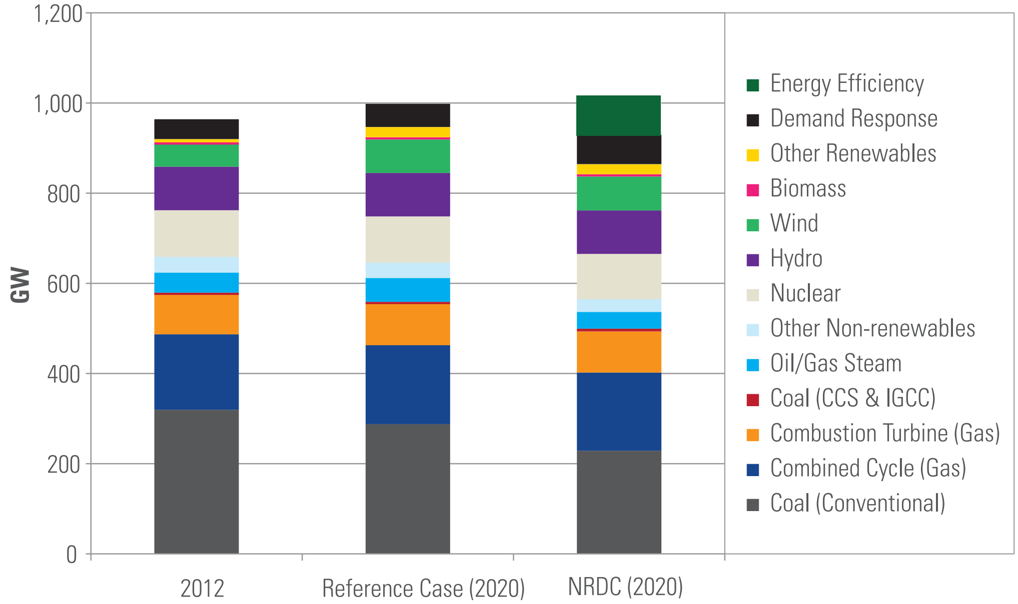
B. RETIREMENTS, NEW BUILDS, AND CAPACITY CHANGES

Retirements are economically projected by IPM® when forward revenues are deemed insufficient to cover forward costs. For this analysis, NRDC has applied some constraints to this basic economic function by assuming that the magnitude of retirements may be practically limited in the 2013–2016 period due to factors including (i) reliability considerations, (ii) lead time required for replacement capacity and transmission upgrades where required, and (iii) operation already assumed due to participation in forward auctions. Specifically, NRDC assumed a U.S.-wide limit of 20 GW of unplanned retirements in the 2013–2014 period and a cumulative limit of 50 GW of unplanned retirements in the 2013–2016 period.

Reference Case. In the Reference Case, there are a total of 12.5 GW of coal unit retirements projected through 2014 in the five focal regions and another 5.1 GW of coal units retired nationally. The model projects a further 10.7 GW to retire by 2016, totaling 28.3 GW of coal retired by 2020. These retirements reflect the inefficient units with high fixed costs that retire due to uncompetitive economics as well as units for which it is not economic to install air, ash, and water controls to comply with the assumed environmental standards for CSAPR, MATS, ash, and water intake. Even though the ash and water rules would require compliance investments after 2016, the retirement decisions look ahead to those provisions and are made in advance of the implementation of MATS in 2015–2016. The absence of 111(d) CO_2 pollution standards in the Reference Case leads to lower variable costs for coal plants. In the five focal regions, the model projects 50 GW of capacity builds over the 2012–2020 period, or 59 percent of the national total.

NRDC Case. Significant levels of DSM in the NRDC Case lead to lower net peak and energy requirements than in the Reference Case. Through 2020, a total of 80 GW of coal capacity is retired nationwide in the NRDC Case. Of the 52 GW of additional coal capacity retired beyond the Reference Case, 19 GW are in MISO, 13 GW are in PJM and 8 GW are in the Southeast. In total, three-quarters of the incremental capacity retired in the NRDC Case beyond the Reference Case are located in these three regions, with the remaining quarter retiring in the rest of the country. NGCC capacity between the two cases stays relatively static, with 174 GW of capacity in the NRDC Case compared with 175 GW in the Reference Case. As illustrated in Figure 13.3, below, the 89 GW of capacity contributed by energy efficiency in the NRDC Case effectively decreases coal capacity without affecting natural gas capacity.

Figure 13.3 Projected 2020 Capacity Changes in the U.S. Power Sector



GW	2012	REFERENCE CASE (2020)	NRDC PROPOSAL (2020)
Combined Cycle (Gas)	167	175	173
Combustion Turbine (Gas)	91	95	91
Coal (Conventional)	319	288	229
Coal (CCS & IGCC)	1	1	6
Oil/Gas Steam	45	53	37
Nuclear	104	103	101
Hydro	97	96	96
Wind	51	74	75
Biomass	3	5	5
Other Renewables	7	23	23
Other Nonrenewables	35	34	28
Demand Response	44	51	65
Energy Efficiency	0	0	89
TOTAL	**964 (920)**	**998 (947)**	**1,019 (864)**

Note: CC and CT exclude capacity that becomes temporarily inactive (mothballed capacity) and later returns to the system. Parenthetical values show actual physical generation.

CHAPTER 14: CONCLUSION

EPA should use its existing authority to regulate greenhouse gases under the Clean Air Act to propose a standard that requires highly polluting fossil-fueled power plants to make substantial emission reductions. EPA should finalize its proposed standard for new fossil fuel generating units and proceed to promptly propose and promulgate standards for existing units.

NRDC recommends that EPA adopt an approach to crafting a performance standard for CO_2 emissions from existing power plants based on each state's baseline fossil fleet generation mix of coal- and gas-fired plants. Then, by applying the nominal emission rate benchmarks for coal- and gas-fired units weighted by the generation mix in the baseline period, each state determines its emission rate standard. NRDC's recommended nominal target rates for use in the emission guidelines are: 1,800 lbs/MWh in 2016, 1,500 lbs/MWh in 2020, and 1,200 lbs/MWh in 2025 for the baseline coal generation share; and 1,035 lbs/MWh in 2016 and 1,000 lbs/MWh in 2020 and thereafter for the baseline gas generation share. This approach allows the use of emission rate averaging and crediting among different classes of electricity service resources in order to enable cost-effective compliance options like energy efficiency and demand response. Additionally, states would have the authority to combine jurisdictions and/or authorize interstate credit trading to expand the geographic range of compliance options.

The NRDC approach to setting carbon pollution standards for existing power plants set forth in this report is technically and legally robust and is sound policy. It would reduce carbon dioxide emissions from the power sector to more than 25 percent below 2005 levels by 2020 without imposing excessive burdens on any region. By taking advantage of the most cost-effective emission reduction opportunities, including energy efficiency improvements and a shift to lower-emission generating units, these reductions would be achieved at an annualized compliance cost of only $4 billion, while yielding social benefits valued up to $60 billion.

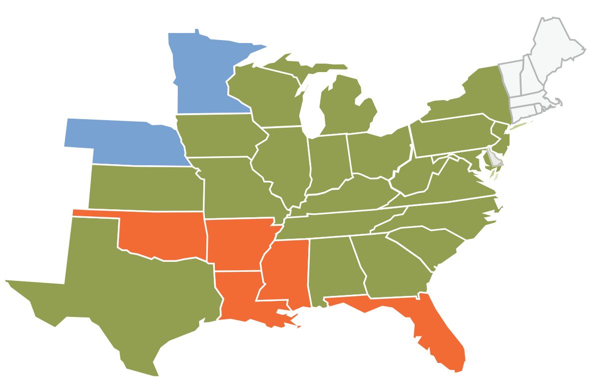
APPENDIX I: NRDC ENVIRONMENTAL POLICY ASSUMPTIONS

Policy assumptions regarding potential outcomes of forthcoming EPA rules were provided by NRDC based on our assessment of plausible outcomes of each EPA rulemaking process, and do not necessarily reflect NRDC's positions with respect to these rules. Economic assumptions were based on consultation with industry participants and private-sector investors active in the power sector, with the exception of the enhanced demand response and energy efficiency case assumptions. The energy efficiency and demand response data were based on the Transition Scenario presented in "Toward A Sustainable Future for the U.S. Power Sector: Beyond Business-as-Usual 2011," published in November 2011 by Synapse Energy Economics, Inc., and reflect all current laws, including state mandates and EERS provisions at the time the analysis was done. The analysis was conducted for NRDC by ICF International using ICF's Integrated Planning Model (IPM®) platform. NRDC is solely responsible for the assumptions used in this analysis.

Table I.1 Environmental Regulations: SO_2, NOx

		Annual	Ozone Season
CAIR for SO_2 and NOx (2010-2011)	25 States + DC Retirement ratio: 2:1 Existing Title IV for unaffected states	25 States + DC 1.522 million tons	25 States + DC 0.568 million tons
Cross-State Air Pollution Rule (CSAPR) for SO_2 and NOx (with proposed adjustments) (2012 onward)	23 States State emission budgets, with in-state and limited interstate trading in each of 2 groups Group 1 2012: 2.54 MMTons 2014: 1.36 MMTons Group 2 2012: 0.93 MMTons 2014: 0.86 MMTons Existing Title IV for unaffected states	23 States State emission budgets, with in-state and limited interstate trading 2012: 1.26 MMTons	26 States State emission budgets, with in-state and limited interstate trading 2012: 0.62 MMTons

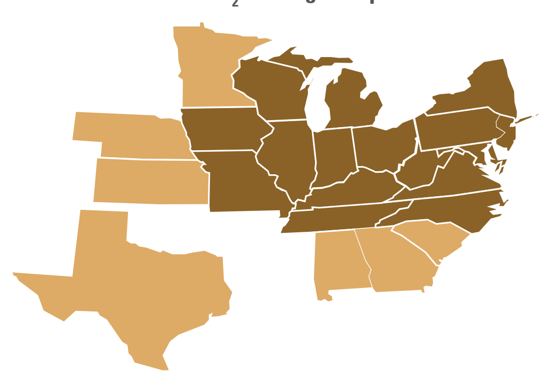
CSAPR-Affected States



- Annual SO_2 and NO_X; Ozone Season NO_X
- Annual SO_2 and NO_x
- Ozone season NO_x

* The map reflects the addition of six states to the ozone season NO_x program, as proposed by EPA in July.

CSAPR SO_2 Trading Groups



- SO_2 Group 1
- SO_2 Group 2

Table I.2 Environmental Regulations: Hazardous Air Pollutants

PROGRAMS	START YEAR	NRDC TREATMENT
State Level Hg	Vary by State	Final state level programs.
HAPs	2015/2016	As-specified by NRDC (Appendix II of proposal) Units not already controlled for acid gases must install a scrubber or DSI; applicability based on EPA's modeling of the final MATS Rule; FF required with DSI Units without a wet FGD must be equipped with ACI Units without FF must install FF or upgrade ESP; applicability based on EPA's IPM modeling of final MATS Rule

Table I.3 State-specific Hg Regulations

STATE	PERFORMANCE STANDARD	ALTERNATE REGULATION
CT	Yes	90% removal or 0.6 lb/Tbtu at the unit level by 7/2008.
DE	Yes	Unit-level regulation: Phase 1 (2009): 80% capture or rate limit of 1.0 lb/TBtu; Phase 2 (2013): 90% capture or rate limit of 0.6 lb/TBtu
IL	Yes	0.008 lb Hg/GWh or 90% removal by 2009; Ameren, Dynegy: unit-level controls and plan-level reduction of 90% by 2012; Midwest Generation: 90% removal at all plants by 2009
MA	Yes	Facility-level: 85% Hg removal or 0.0075 lb/GWh by 2008 and 95% Hg removal or 0.0025 lb/GWh by 2012.
MD	Yes	Facility-level: Phase 1 (2010): 80% removal; Phase 2 (2013): 90% removal
ME	Yes	Facility-level: limit of 50 lbs/yr; drops to 35 lb/yr in 2007 and 25 lb/yr in 2010
MI	Yes	Phase 1 (2010): CAMR levels; Phase 2 (2015): 90% reduction. System-wide averaging .
MN	Yes	90% removal for facilities over 500 MW; reductions required by 2010 for dry PM units and 2014 for wet PM units.
NH	Yes	Unit level: 80% removal via scrubber installation by 7/1/2013. SO2 emission credits for early Hg reductions.
NJ	Yes	Unit level: 90% removal or 3.0 mg/MWh by 2008; compliance extended to 2012 with multi-pollutant controls.
NM	No	Facility level: Adopts CAMR budgets; unused allowances (inc. new source set-aside) are retired annually.
NY	Yes	Facility level: Phase 1 (2010-2014): limits based on CAMR budget. Phase 2 (2015): limit of 0.6 lbs/MMBtu
OR	Yes	State standards (12/2006): 90% removal or 0.60 lb/TBtu by 7/2012 (one year extension possible).
PA	Yes	Unit level: 80% reduction by 2010, 90% reduction by 2015
WI	No	Facility level: Adopts CAMR standards & schedule.
RI	No	Only new sources will be subject to CAMR.
WA	Yes	Facility level: 2013: 0.008 lb/GWh (existing sources) and 0.0066 lb/GWh (new sources); plants must be in compliance by 2017

Table I.4 Environmental Regulations: Regional GHG NSPS

Policy as defined by NRDC

CO_2 emission rate standards by state/region (consistent with IPM region structure)

NSPS standards are a function of the historical fossil fuel generation mix in each region and national historical emission rates.

State/regional generation mix – Using historical generation data from EPA and FERC for the years 2008 to 2010, ICF calculated the average share of fossil generation attributable to coal and to combined oil and gas generation. These shares were developed at the state or model region level, consistent with the model regions currently used in IPM©.

N**ational coal and oil/gas CO_2 emission rates** –Based on national EPA data for the period 2008 to 2010, ICF calculated the average emission rate, in lbs/MWh, for coal-fired generation and for combined oil- and gas-fired generation at 2063 lbs/MWh and 1065 lbs/MWh, respectively.

NRDC specified the initial emission rates for use in the development of the standard for each state/region as the average national emission rate for coal and oil/gas, weighted by the share of generation of each fuel by region over the 2008-2010 period, based the following formula:

Initial Regional Rate = [National coal CO_2 emission rate * coal generation share by region] + [National oil/gas CO^2 emission rate * oil/gas generation share by region]

For each compliance period, the standard for each region in the NRDC Policy Case will be the percentage share of coal and oil/gas of each states total fossil generation in the baseline period multiplied by the target rates for coal and oil/gas.

For 2015-2019, the annual emission rate used for the coal share is 1,800 lbs/MWh is and the rate used for oil and gas is 1,035 lbs/MWh. The annual rate standards are flat during this 5-year period.

For 2020-2024, the annual emission rate used for the coal share is 1,500 lbs/MWh and the rate used for oil and gas is 1,000 lbs/MWh. The annual rate standards are kept flat during this 5-year period.

For 2025 and onwards, the annual emission rate used for the coal share is 1,200 lbs/MWh and the rate used for oil and gas is 1,000 lbs/MWh.

For each compliance period, the standard for each region in the Weaker Standard cases will be the percentage share of coal and oil/gas of each states total fossil generation in the baseline period multiplied by the target rates for coal and oil/gas.

For 2015-2019, the annual emission rate used for the coal share is 1,959 lbs/MWh is and the rate used for oil and gas is 1,035 lbs/MWh. The annual rate standards are flat during this 5-year period.

For 2020-2024, the annual emission rate used for the coal share is 1,754 lbs/MWh and the rate used for oil and gas is 1,012 lbs/MWh. The annual rate standards are kept flat during this 5-year period.

Table I.5 Ash and Water Regulations	
WATER INTAKE REGULATIONS	
Plants with once-through cooling systems that withdraw >50 million gallons per day	As-specified by NRDC 46 of the largest facilities drawing on tidal water sources must be equipped with cooling towers (2% efficiency penalty) No requirements for low capacity factor (CT, oil/gas steam) units Compliance spread equally over years 2018-2022, with order determined randomly by plant"
Re-circulating systems with cooling pond/canal are exempted	
COAL COMBUSTION RESIDUALS REGULATIONS	
Units with surface-based impoundment	(1) Dry collection modifications (2) Close/cap ash pond (3) New wastewater treatment facilities
Units that landfill	Upgrade wastewater treatment facilities for scrubbed units only (in response to effluent guidelines)
Ash is not treated as hazardous	
Beneficial use of ash continues	

Figure I.1 Renewable Portfolio Standards

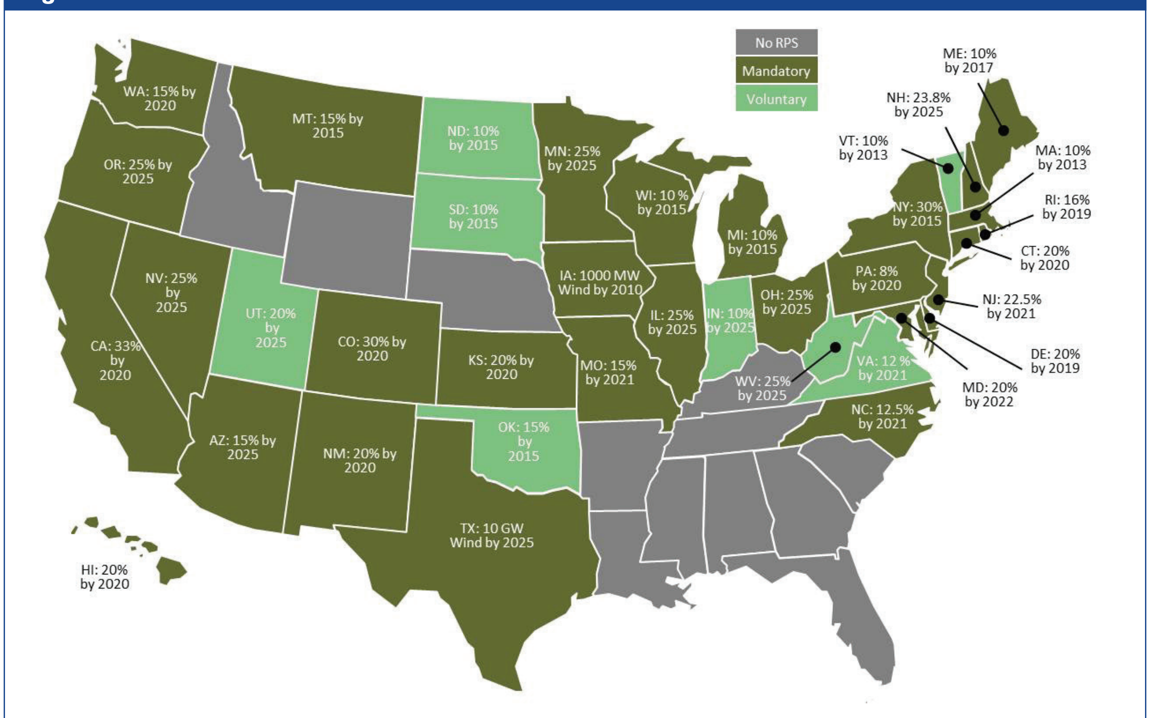


Table I. 6 Existing Coal Retrofit Cost and Performance

CONTROL TYPE	EFFICIENCY	HEAT RATE (BTU/KWH)	CAPACITY PENALTY (%)	HEAT RATE PENALTY (%)	VARIABLE O&M ($/MWH)	CAPACITY (MW) 100 CAPITAL COSTS ($/KW)	100 FIXED O&M ($/KW-YR)	300 CAPITAL COSTS ($/KW)	300 FIXED O&M ($/KW-YR)	500 CAPITAL COSTS ($/KW)	500 FIXED O&M ($/KW-YR)	700 CAPITAL COSTS ($/KW)	700 FIXED O&M ($/KW-YR)	1000 CAPITAL COSTS ($/KW)	1000 FIXED O&M ($/KW-YR)
LSFO															
Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming 3 lb/MMBtu SO_2 Content Bituminous Coal"	SO_2: 98% down to 0.06 lbs/MMBtu	9,000	-1.50	1.53	1.74	781	23.5	572	11.0	495	8.2	450	7.5	406	6.2
		10,000	-1.67	1.70	1.92	819	23.8	599	11.3	519	8.4	472	7.7	426	6.4
		11,000	-1.84	1.87	2.12	854	24.3	625	11.5	541	8.6	491	7.9	444	6.6
LSD															
Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming 2 lb/MMBtu SO_2 Content Bituminous Coal"	SO_2: 93% down to 0.065 lbs/MMBtu	9,000	-1.18	1.20	2.23	670	17.1	490	8.5	425	6.4	403	5.5	403	5.1
		10,000	-1.32	1.33	2.47	701	17.5	513	8.7	443	6.6	421	5.8	421	5.3
		11,000	-1.45	1.47	2.72	730	17.8	534	8.9	462	6.8	439	6	439	5.4
SCR															
Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NOx rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu"	NOx: 90% down to 0.06 lb/MMBtu	9,000	-0.54	0.54	1.2	231	2.6	185	0.8	170	0.7	162	0.5	154	0.4
		10,000	-0.56	0.56	1.3	251	2.6	202	0.8	186	0.7	177	0.5	169	0.4
		11,000	-0.58	0.59	1.39	270	2.6	219	0.8	202	0.7	192	0.5	184	0.4
SNCR - Non-FBC															
Minimum Cutoff: ≥ 25 MW Maximum Cutoff: < 200 MW Assuming Bituminous Coal NOx rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu"	NOx, 35%	9,000	-0.05	0.05	0.92	47	1								
		10,000	-0.05	0.05	1.02	49	1								
		11,000	-0.05	0.05	1.13	50	1								
SNCR - FBC															
Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal NOx rate: 0.5 lb/MMBtu SO_2 rate: 2.0 lb/MMBtu"	NOx, 50%	9,000	-0.05	0.05	0.92	36	0.9	19	0.4	15	0.2	12	0.2	9	0.1
		10,000	-0.05	0.05	1.02	37	0.9	20	0.4	15	0.2	13	0.2	10	0.1
		11,000	-0.05	0.05	1.13	38	0.9	20	0.4	15	0.2	13	0.2	10	0.1

Source: EPA - http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter5.pdf

Table I.7 Mercury Controls for Coal														
CONTROL TYPE			**CAPACITY (MW)**											
			100			**300**			**500**			**700**		
Minimum Cutoff: ≥ 25 MW Maximum Cutoff: None Assuming Bituminous Coal	**CAPACITY PENALTY (%)**	**HEAT RATE PENALTY (%)**	**CAPITAL COSTS ($/KW)**	**FIXED O&M ($/KW-YR)**	**VARIABLE O&M ($/MWH)**	**CAPITAL COSTS ($/KW)**	**FIXED O&M ($/KW-YR)**	**VARIABLE O&M ($/MWH)**	**CAPITAL COSTS ($/KW)**	**FIXED O&M ($/KW-YR)**	**VARIABLE O&M ($/MWH)**	**CAPITAL COSTS ($/KW)**	**FIXED O&M ($/KW-YR)**	**VARIABLE O&M ($/MWH)**
MPAC - Existing BH	-0.43	0.43	3	0.10	0.17	3	0.10	0.17	3	0.10	0.17	3	0.10	0.17
MPAC- Existing CESP	-0.43	0.43	8	0.10	0.6	8	0.10	0.6	8	0.10	0.6	8	0.10	0.6
SPAC - Existing BH	-0.43	0.43	5	0.10	0.23	5	0.10	0.23	5	0.10	0.23	5	0.10	0.23
SPAC - Existing ESP	-0.43	0.43	28	0.52	2.39	28	0.52	2.39	28	0.52	2.39	28	0.52	2.39
SPAC+FF - Existing ESP	-0.43	0.43	281	4.5	2.55	281	4.5	2.55	281	4.5	2.55	281	4.5	2.55

Source: EPA - http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter5.pdf

LEGEND:

ACI Activated carbon injection
BH Baghouse
Bit Bituminous coal
CFB Circulating fluidized-bed boiler
CESP Cold-side electrostatic precipitator
FGC Flue gas conditioning
HESP Hot-side electrostatic preciptator
Lig Lignite
MPAC Modified powdered activated carbon
SPAC Standard powdered activated carbon
Sub Subbituminous coal

Notes:
If the existing equipment provides 90% Hg removal, no ACI system is required.
"--" means that the category type has no effect on the ACI application.

Table I.8 CCS for Existing Coal		
APPLICABILITY (ORIGINAL MW SIZE)	**450-750 MW**	**> 750 MW**
Incremental Capital Cost ($/kW)	2,062	1,672
Incremental FOM ($/kW-yr)	3.14	2.07
Incremental VOM ($/MWh)	2.46	2.46
Capacity Penalty (%)	25%	25%
Heat Rate Penalty (%)	33%	33%
CO_2 Removal (%)	90%	90%

Source: EPA - http://www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter6.pdf

Table I.9 Particulate Controls for Coal														
	CAPACITY PENALTY (%)	HEAT RATE PENALTY (%)	CAPACITY (MW)											
			100			300			500			700		
			CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	VARIABLE O&M ($/MWH)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	VARIABLE O&M ($/MWH)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	VARIABLE O&M ($/MWH)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	VARIABLE O&M ($/MWH)
Fabric Filter	0	0	259	4.5	0	195	2.5	0	170	1.9	0	156	1.6	0
ESP Upgrade	0	0	65	1.1	0	49	0.6	0	43	0.5	0	39	0.4	0

Table I.10 Dry Sorbent Injection												
	CAPACITY PENALTY (%)	HEAT RATE PENALTY (%)	CAPACITY (MW)									
			100		300		500		700		1000	
			CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)	CAPITAL COSTS ($/KW)	FIXED O&M ($/KW-YR)
DSI-FF	0	0	130	2.4	59	0.9	42	0.6	32	0.4	32	0.4

Source: EPA v4.10, Proposed Toxics Rule analysis United Conveyor Corporation presentation & NRDC

Table I.11 Trona VOM by SO_2 Content		
SO_2 CONTENT (LB/MMBTU)	VOM ($/MWH)	
	BIT COAL	SUB, LIG COAL
0.50	--	1.3
0.75	--	1.9
1.00	5.0	2.5
1.25	6.2	3.1
1.50	7.5	3.7
1.75	8.7	4.2
2.00	10.0	4.8
2.25	11.2	5.4
2.50	12.4	6.1

Table I.12 Cooling Tower Costs	
CAPACITY (MW)	CAPITAL COSTS ($/KW)
100	342
150	280
200	244
250	219
300	200
350	186
400	174
450	164
500+	150

Also includes a 2% capacity derate and heat rate increase (NRDC).
Source: 2010 NERC Report

Table I.13 Technology Limits

NATIONAL NEW NUCLEAR CAPACITY LIMITS, CUMULTIVE GW	
CALENDAR YEAR	CAPACITY LIMIT
2020	3.3
2025	12.1
2030	23.1
2035	35.2
2040	55
2045	77

NATIONAL NEW CCS CAPACITY LIMITS, CUMULTIVE GW	
CALENDAR YEAR	CAPACITY LIMIT
2020	3
2025	11
2030	24
2035	42
2040	65
2045	90

REGIONAL NEW NUCLEAR CAPACITY LIMITS, CUMULATIVE GW	
REGION	CAPACITY LIMIT
MISO	4.4
NYISO	1.1
ISO-NE	2.2
PJM	11
Southeast	7.7
Rest of US	28.6
Total US	55.0

APPENDIX II: DEMAND-SIDE MANAGEMENT ASSUMPTIONS

Table II.1 Synapse Demand Response

PEAK LOAD REDUCTION DR (MW)												
	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US		
2011	2,937	8,174	2,219	2,959	5,898	5,276	1,484	3,146	6,099	38,192	735,870	5.2%
2012	2,896	8,178	2,219	7,047	6,351	5,649	1,526	3,269	6,846	43,981	742,712	5.9%
2013	3,349	8,183	2,219	9,282	6,559	5,976	1,572	3,390	7,252	47,782	751,184	6.4%
2014	4,145	8,185	2,219	14,118	6,705	6,017	1,623	3,441	7,539	53,992	754,993	7.2%
2015	4,267	8,803	2,381	14,834	7,533	6,372	2,038	3,745	8,863	58,836	760,742	7.7%
2016	4,291	8,928	2,414	14,977	7,786	6,493	2,172	3,825	9,326	60,212	766,576	7.9%
2017	4,316	9,053	2,446	15,120	7,947	6,614	2,311	3,938	9,964	61,709	773,869	8.0%
2018	4,340	9,178	2,479	15,263	8,081	6,788	2,458	4,049	10,239	62,876	781,740	8.0%
2019	4,365	9,304	2,511	15,406	8,224	6,960	2,612	4,150	10,577	64,109	790,025	8.1%
2020	4,389	9,429	2,544	15,549	8,360	7,131	2,774	4,260	10,868	65,305	798,008	8.2%
2021	4,446	9,777	2,617	16,040	8,771	7,371	3,093	4,431	10,932	67,478	805,960	8.4%
2022	4,503	10,123	2,691	16,531	9,159	7,508	3,404	4,603	11,414	69,935	813,725	8.6%
2023	4,559	10,469	2,764	17,022	9,547	7,645	3,715	4,774	11,896	72,391	825,312	8.8%
2024	4,616	10,815	2,837	17,513	9,935	7,782	4,027	4,945	12,378	74,848	834,117	9.0%
2025	4,673	11,161	2,911	18,004	10,323	7,918	4,338	5,116	12,861	77,304	842,805	9.2%
2026	4,730	11,506	2,984	18,495	10,711	8,055	4,649	5,287	13,343	79,761	851,621	9.4%
2027	4,787	11,852	3,058	18,986	11,099	8,192	4,960	5,459	13,825	82,217	860,468	9.6%
2028	4,844	12,198	3,131	19,477	11,487	8,329	5,271	5,630	14,307	84,674	869,482	9.7%
2029	4,901	12,544	3,204	19,968	11,874	8,466	5,583	5,801	14,790	87,131	878,318	9.9%
2030	4,957	12,890	3,278	20,459	12,262	8,603	5,894	5,972	15,272	89,587	887,986	10.1%
2031	5,026	13,301	3,360	21,062	12,848	8,770	6,252	6,253	16,195	93,069	897,335	10.4%
2032	5,095	13,712	3,443	21,664	13,434	8,938	6,611	6,534	17,118	96,550	906,506	10.7%
2033	5,164	14,124	3,526	22,267	14,021	9,105	6,970	6,815	18,041	100,032	915,038	10.9%
2034	5,232	14,535	3,608	22,870	14,607	9,273	7,328	7,096	18,964	103,514	923,942	11.2%
2035	5,301	14,946	3,691	23,473	15,193	9,441	7,687	7,378	19,887	106,995	932,511	11.5%
Average	**4,485**	**10,855**	**2,830**	**16,736**	**9,949**	**7,547**	**4,014**	**4,932**	**12,352**	**73,699**		

ELCC (Reserve Margin Contribution) for DR -- 75% Dispatchable and 100% No Dispatchable

Sources: **ISONE:** ISONE Forward Capacity Auctions (FCA#2, FCA#3, FCA#4, FCA#5) for the period 2011-2014. Post-2014 assumed in cremental targets as per Synapse assumptions .

PJM: The demand reponse for period 2011-2014 represents the amount cleared in PJM cpaacity auctions . Post -2014, it has been assumed that the DR will increase as per additional DR targets assumed by Synapse.

Other Markets: The demand response reflects Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak-Pricing (CPP) with Control , Load as a Capacity Resource, Demand Response used for Reserves - Spinning, Demand Response used for Reserves - Non-Spinning, Demand Response used for Regulation, Demand Response used for Energy, Voluntary - Emergency and Demand Response Expected On-Peak as reported in NERC ES&D 2011 for the forecast period of 2011-2021. After 2021, DR has been increased assuming the additional DR targets as per Synapse.

Table II.2 Dispatchable vs Non-dispatchable DR

	NON DIS-PATCHABLE DR %	DIS-PATCHABLE DR %
2011	22%	78%
2012	24%	76%
2013	27%	73%
2014	31%	69%
2015	36%	64%
2016	42%	58%
2017	49%	51%
2018	54%	46%
2019	59%	41%
2020	59%	41%
2021	59%	41%
2022	59%	41%
2023	59%	41%
2024	59%	41%
2025	59%	41%
2026	59%	41%
2027	59%	41%
2028	59%	41%
2029	59%	41%
2030	59%	41%

Source: NRDC

Table II.3 Delta - MW (Synapse - Reference)

PEAK LOAD REDUCTION DR (MW)										
	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0
2015	122	616	162	716	579	291	359	237	1,181	4,264
2016	146	740	195	859	695	349	431	285	1,418	5,116
2017	171	863	227	1,002	811	407	503	332	1,654	5,969
2018	195	986	260	1,145	926	465	575	379	1,890	6,822
2019	220	1,110	292	1,288	1,042	523	647	427	2,126	7,675
2020	244	1,233	325	1,431	1,158	581	719	474	2,363	8,527
2021	301	1,579	398	1,922	1,546	718	1,030	645	2,845	10,984
2022	358	1,925	472	2,413	1,934	855	1,341	817	3,327	13,441
2023	414	2,271	545	2,904	2,322	992	1,652	988	3,809	15,897
2024	471	2,617	618	3,395	2,710	1,129	1,964	1,159	4,292	18,354
2025	528	2,963	692	3,886	3,098	1,265	2,275	1,330	4,774	20,810
2026	585	3,309	765	4,377	3,486	1,402	2,586	1,501	5,256	23,267
2027	642	3,654	839	4,868	3,874	1,539	2,897	1,673	5,738	25,723
2028	699	4,000	912	5,359	4,262	1,676	3,208	1,844	6,221	28,180
2029	756	4,346	985	5,849	4,649	1,813	3,520	2,015	6,703	30,636
2030	812	4,692	1,059	6,340	5,037	1,950	3,831	2,186	7,185	33,093
2031	881	5,103	1,141	6,943	5,623	2,117	4,189	2,467	8,108	36,575
2032	950	5,514	1,224	7,546	6,209	2,285	4,548	2,748	9,031	40,056
2033	1,019	5,926	1,307	8,149	6,796	2,452	4,907	3,029	9,954	43,538
2034	1,087	6,337	1,389	8,752	7,382	2,620	5,265	3,310	10,877	47,020
2035	1,156	6,748	1,472	9,355	7,968	2,788	5,624	3,592	11,800	50,501
Average	**470**	**2,661**	**611**	**3,540**	**2,884**	**1,129**	**2,083**	**1,258**	**4,422**	**19,058**

ELCC (Reserve Margin Contribution) for DR -- 75% Dispatchable and 100% No Dispatchable

Table II. 4 Synapse - Energy Efficiency

	ENERGY EFFICIENCY[1] (GWH)									
	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	2,703	3,537	3,320	3,101	1,208	6,532	1,395	462	4,992	27,249
2012	4,404	6,834	5,411	6,543	3,263	10,582	2,950	1,247	9,599	50,835
2013	6,333	11,183	7,781	11,287	6,307	15,123	5,084	2,411	15,616	81,126
2014	8,475	16,537	10,413	17,282	10,317	20,127	7,777	3,943	23,064	117,935
2015	10,806	22,931	13,277	24,572	15,324	25,245	11,058	5,857	31,991	161,060
2016	13,117	30,450	16,116	33,121	21,314	30,336	14,908	8,147	42,449	209,957
2017	15,404	39,157	18,926	43,154	28,459	35,390	19,427	10,877	54,550	265,343
2018	17,669	49,039	21,709	54,652	36,742	40,410	24,603	14,043	68,073	326,941
2019	19,912	60,066	24,465	67,580	46,141	45,396	30,426	17,636	82,773	394,395
2020	22,132	71,859	27,192	81,896	56,631	50,342	36,873	21,645	98,423	466,993
2021	24,332	83,721	29,895	96,653	68,044	55,248	43,498	26,008	114,736	542,133
2022	26,511	95,458	32,572	111,249	79,361	60,113	50,046	30,333	130,931	616,574
2023	28,672	107,096	35,227	125,697	90,585	64,941	56,543	34,623	147,013	690,397
2024	30,818	118,675	37,865	140,025	101,722	69,739	62,972	38,880	162,985	763,681
2025	32,326	129,544	39,717	153,750	112,690	73,005	69,119	43,072	177,931	831,155
2026	33,729	139,859	41,440	166,728	123,091	76,002	74,930	47,047	192,097	894,923
2027	35,012	149,631	43,017	178,969	132,915	78,756	80,410	50,802	205,471	954,982
2028	36,189	158,821	44,463	190,467	142,179	81,294	85,573	54,343	218,093	1,011,423
2029	37,265	167,450	45,786	201,239	150,889	83,627	90,434	57,672	229,949	1,064,311
2030	38,258	175,531	47,005	211,313	159,066	85,942	94,995	60,797	241,062	1,113,970
2031	39,272	183,035	48,251	220,721	166,718	88,312	99,263	63,722	251,414	1,160,708
2032	40,308	189,940	49,524	229,362	173,775	90,739	103,197	66,419	260,967	1,204,231
2033	41,360	196,245	50,817	237,239	180,236	93,211	106,777	68,889	269,820	1,244,593
2034	42,430	201,989	52,131	244,400	186,140	95,730	110,021	71,146	278,137	1,282,125
2035	43,519	207,369	53,469	250,877	191,508	98,292	112,943	73,197	286,033	1,317,207

Source: Synapse Cumulative EE Assumption as provided by NRDC
1 This represents the sensitivity assumptions for Energy Efficiency.

Table II.5 Synapse - Energy Efficiency

PEAK LOAD REDUCTION[2] - EE CONTRIBUTION (MW)										
	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	405	531	498	465	181	980	209	69	749	4,087
2012	661	1,025	812	981	489	1,587	443	187	1,440	7,625
2013	950	1,678	1,167	1,693	946	2,268	763	362	2,342	12,169
2014	1,271	2,480	1,562	2,592	1,548	3,019	1,167	592	3,460	17,690
2015	1,621	3,440	1,992	3,686	2,299	3,787	1,659	879	4,799	24,159
2016	1,968	4,567	2,417	4,968	3,197	4,550	2,236	1,222	6,367	31,494
2017	2,311	5,874	2,839	6,473	4,269	5,308	2,914	1,632	8,183	39,801
2018	2,650	7,356	3,256	8,198	5,511	6,061	3,690	2,107	10,211	49,041
2019	2,987	9,010	3,670	10,137	6,921	6,809	4,564	2,645	12,416	59,159
2020	3,320	10,779	4,079	12,284	8,495	7,551	5,531	3,247	14,763	70,049
2021	3,650	12,558	4,484	14,498	10,207	8,287	6,525	3,901	17,210	81,320
2022	3,977	14,319	4,886	16,687	11,904	9,017	7,507	4,550	19,640	92,486
2023	4,301	16,064	5,284	18,855	13,588	9,741	8,481	5,193	22,052	103,560
2024	4,623	17,801	5,680	21,004	15,258	10,461	9,446	5,832	24,448	114,552
2025	4,849	19,432	5,958	23,062	16,904	10,951	10,368	6,461	26,690	124,673
2026	5,059	20,979	6,216	25,009	18,464	11,400	11,240	7,057	28,815	134,238
2027	5,252	22,445	6,452	26,845	19,937	11,813	12,062	7,620	30,821	143,247
2028	5,428	23,823	6,669	28,570	21,327	12,194	12,836	8,151	32,714	151,713
2029	5,590	25,117	6,868	30,186	22,633	12,544	13,565	8,651	34,492	159,647
2030	5,739	26,330	7,051	31,697	23,860	12,891	14,249	9,120	36,159	167,096
2031	5,891	27,455	7,238	33,108	25,008	13,247	14,889	9,558	37,712	174,106
2032	6,046	28,491	7,429	34,404	26,066	13,611	15,480	9,963	39,145	180,635
2033	6,204	29,437	7,622	35,586	27,035	13,982	16,016	10,333	40,473	186,689
2034	6,364	30,298	7,820	36,660	27,921	14,360	16,503	10,672	41,721	192,319
2035	6,528	31,105	8,020	37,632	28,726	14,744	16,941	10,980	42,905	197,581

2 The energy efficiency contribution to peak load reduction has been assumed as 0.15kW for each MWh saved.

Note:
For base case it has been assumed the AEO 2011 refrence energy load already includes the existing EE (Source: Synapse Report)

APPENDIX III: NRDC MARKET ASSUMPTIONS

Table III.1 Representative Minemouth Coal Prices (2010$)				
	DOMESTIC ($/TON)			
	NORTHERN APPALACHIA	CENTRAL APPALACHIA	POWDER RIVER BASIN	ILLINOIS BASIN
LBS SO_2/MMBTU:	**2.7**	**1.7**	**0.8**	**6.0**
MMBTU/TON:	**25.5**	**24.2**	**17.2**	**22.5**
2011	70.7	65.8	13.9	57.0
2012	72.3	65.9	13.9	56.8
2013	67.5	62.3	13.9	51.1
2014	62.6	58.6	13.9	45.3
2015	60.6	57.6	13.5	44.1
2016	58.7	56.5	13.0	42.9
2017	57.3	56.1	13.1	42.3
2018	55.9	55.8	13.3	41.8
2019	55.7	55.0	13.4	41.7
2020	55.5	54.2	13.5	41.6
2021	55.6	54.3	13.5	41.5
2022	55.7	54.4	13.6	41.4
2023	55.9	54.5	13.6	41.3
2024	56.0	54.6	13.6	41.2
2025	56.2	54.7	13.7	41.1
2026	56.3	55.0	13.7	41.0
2027	56.5	55.3	13.7	40.9
2028	56.6	55.5	13.7	40.8
2029	56.8	55.8	13.7	40.7
2030	56.9	56.1	13.7	40.6
Average 2010-2030"	**59.0**	**56.9**	**13.6**	**43.7**

Notes:
[1] Coal prices delivered to plant vary by source, location, and transportation option(s).
[2] Coal prices are solved dynamically within the model and may be slighter different from those reported above.

Table III.2 Domestic ($/MMBtu)				
DOMESTIC ($/TON)				
	NORTHERN APPALACHIA	CENTRAL APPALACHIA	POWDER RIVER BASIN	ILLINOIS BASIN
LBS SO_2/MMBTU	2.7	1.7	0.8	6.0
MMBTU/TON	25.5	24.2	17.2	22.5
2011	2.8	2.7	0.8	2.5
2012	2.8	2.7	0.8	2.5
2013	2.6	2.6	0.8	2.3
2014	2.5	2.4	0.8	2.0
2015	2.4	2.4	0.8	2.0
2016	2.3	2.3	0.8	1.9
2017	2.2	2.3	0.8	1.9
2018	2.2	2.3	0.8	1.9
2019	2.2	2.3	0.8	1.9
2020	2.2	2.2	0.8	1.8
2021	2.2	2.2	0.8	1.8
2022	2.2	2.2	0.8	1.8
2023	2.2	2.3	0.8	1.8
2024	2.2	2.3	0.8	1.8
2025	2.2	2.3	0.8	1.8
2026	2.2	2.3	0.8	1.8
2027	2.2	2.3	0.8	1.8
2028	2.2	2.3	0.8	1.8
2029	2.2	2.3	0.8	1.8
2030	2.2	2.3	0.8	1.8
Average 2010-2030"	**2.3**	**2.4**	**0.8**	**1.9**

Notes:
[1] Coal prices delivered to plant vary by source, location, and transportation option(s).
[2] Coal prices are solved dynamically within the model and may be slighter different from those reported above.

Table III.3 Gross Peak and Energy Demand

ENERGY DEMAND[1] GROWTH (%)										
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	133710	674734	153480	777760	631936	289060	361270	228920	918041	4168911
2012	1.6%	0.4%	1.4%	0.6%	2.1%	0.8%	2.0%	1.4%	1.7%	1.3%
2013	0.9%	1.3%	0.4%	1.1%	1.4%	0.6%	1.0%	0.4%	0.9%	1.0%
2014	0.5%	0.2%	0.3%	0.1%	0.1%	0.4%	0.2%	0.6%	0.3%	0.2%
2015	1.0%	1.1%	0.7%	1.0%	1.2%	0.9%	1.3%	1.0%	1.0%	1.0%
2016	1.0%	0.7%	0.8%	0.7%	0.8%	1.2%	0.8%	1.1%	1.0%	0.8%
2017	0.9%	0.7%	0.8%	0.7%	0.6%	1.1%	0.8%	1.0%	1.0%	0.8%
2018	1.1%	0.9%	0.8%	0.8%	0.7%	1.2%	0.8%	1.1%	1.0%	0.9%
2019	1.0%	0.9%	0.8%	0.8%	0.8%	1.1%	0.9%	1.1%	1.0%	0.9%
2020	1.0%	1.1%	0.6%	0.8%	0.9%	1.0%	0.9%	1.0%	1.0%	0.9%
2021	0.9%	0.8%	0.9%	0.8%	0.9%	1.0%	0.8%	1.0%	1.0%	0.9%
2022	1.0%	0.8%	0.8%	0.8%	1.0%	1.0%	0.7%	1.2%	1.1%	0.9%
2023	1.0%	1.0%	0.9%	0.9%	1.0%	1.0%	1.0%	1.3%	3.7%	1.6%
2024	1.2%	1.3%	1.0%	1.0%	0.9%	1.1%	0.8%	1.4%	1.1%	1.1%
2025	1.1%	1.1%	0.9%	0.8%	0.8%	1.0%	0.7%	1.2%	1.0%	0.9%
2026	1.2%	1.1%	0.9%	0.9%	0.8%	1.1%	0.8%	1.3%	1.0%	1.0%
2027	1.3%	1.2%	0.9%	0.9%	0.8%	1.2%	1.0%	1.3%	1.0%	1.0%
2028	1.4%	1.0%	1.0%	0.9%	0.8%	1.3%	1.0%	1.4%	1.0%	1.0%
2029	1.2%	0.8%	0.8%	0.7%	0.7%	1.2%	1.0%	1.2%	1.0%	0.9%
2030	1.3%	1.0%	0.9%	0.9%	0.9%	1.3%	1.1%	1.4%	1.1%	1.1%
2031	1.2%	1.0%	0.9%	0.9%	0.8%	1.3%	1.0%	1.3%	1.1%	1.0%
2032	1.2%	1.0%	0.9%	0.9%	0.8%	1.3%	1.0%	1.4%	1.1%	1.0%
2033	1.0%	0.8%	0.7%	0.7%	0.7%	1.1%	0.6%	1.1%	0.9%	0.8%
2034	1.1%	0.9%	0.8%	0.8%	0.8%	1.2%	0.7%	1.2%	1.0%	0.9%
2035	1.1%	0.9%	0.8%	0.8%	0.8%	1.0%	0.6%	1.2%	1.0%	0.9%
Annual Avg	**1.1%**	**0.9%**	**0.8%**	**0.8%**	**0.9%**	**1.1%**	**0.9%**	**1.1%**	**1.1%**	**1.0%**

Gross Peak and Energy Demand

ENERGY DEMAND[1] (GWH) LEVELS (GWH)										
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	133,710	674,734	153,480	777,760	631,936	289,060	361,270	228,920	918,041	4,168,911
2012	135,870	677,286	155,630	782,365	644,965	291,410	368,540	232,050	933,481	4,221,596
2013	137,130	686,087	156,310	791,191	654,170	293,140	372,330	233,070	941,818	4,265,247
2014	137,760	687,463	156,730	792,325	655,119	294,280	373,010	234,510	944,330	4,275,527
2015	139,170	694,889	157,750	800,032	662,864	296,940	377,700	236,740	953,858	4,319,943
2016	140,580	699,721	159,030	805,577	667,966	300,580	380,670	239,410	963,119	4,356,653
2017	141,900	704,886	160,240	811,236	672,223	304,010	383,630	241,780	972,581	4,392,487
2018	143,400	711,284	161,590	817,848	677,117	307,560	386,770	244,320	982,535	4,432,425
2019	144,790	717,963	162,870	824,585	682,291	311,050	390,300	246,960	992,830	4,473,639
2020	146,220	725,554	163,910	831,413	688,309	314,240	393,750	249,470	1,003,187	4,516,053
2021	147,490	731,287	165,440	838,379	694,351	317,300	396,980	252,010	1,012,948	4,556,186
2022	148,900	737,364	166,740	845,135	701,024	320,340	399,930	255,150	1,023,673	4,598,256
2023	150,390	744,568	168,180	852,425	707,889	323,520	404,090	258,440	1,061,731	4,671,233
2024	152,140	753,897	169,780	860,785	714,571	327,020	407,310	262,000	1,073,363	4,720,866
2025	153,780	762,162	171,240	868,083	720,442	330,280	410,360	265,170	1,084,060	4,765,576
2026	155,690	770,908	172,790	875,729	726,314	333,770	413,630	268,530	1,095,075	4,812,436
2027	157,670	780,126	174,410	883,539	732,055	337,680	417,590	271,960	1,106,271	4,861,301
2028	159,820	787,539	176,130	891,274	738,023	342,210	421,850	275,740	1,117,692	4,910,279
2029	161,780	794,015	177,540	897,791	743,302	346,210	426,010	279,050	1,128,412	4,954,110
2030	163,930	801,842	179,150	905,964	749,905	350,770	430,740	282,860	1,141,049	5,006,211
2031	165,890	809,685	180,700	914,157	755,976	355,390	435,080	286,610	1,153,035	5,056,523
2032	167,890	817,484	182,250	922,254	762,118	359,980	439,570	290,520	1,165,228	5,107,295
2033	169,560	824,270	183,510	929,150	767,469	363,960	442,320	293,840	1,176,045	5,150,124
2034	171,380	831,799	184,890	936,877	773,525	368,180	445,500	297,490	1,188,140	5,197,780
2035	173,300	838,915	186,290	944,379	779,443	372,030	448,380	301,080	1,199,786	5,243,603
Annual Avg	**152,006**	**750,629**	**169,063**	**856,010**	**708,135**	**326,036**	**405,092**	**261,107**	**1,053,292**	**4,681,370**

Source: Annual Energy Outlook 2011, EIA Reference Case

1Gross Energy Demand represents Net Energy for Load and Generation for Own Use . It includes the inter-regional tranmission losses.

Table III.3 (Coninued) Gross Peak and Energy Demand

PEAK DEMAND (MW)										
GROWTH (%)										
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	21784	119667	29398	135967	105748	52518	66025	42661	162102	735870
2012	3.8%	-4.6%	4.8%	-2.3%	3.1%	2.7%	3.4%	1.9%	3.4%	0.9%
2013	1.3%	1.3%	0.8%	1.4%	1.3%	0.7%	1.1%	1.1%	0.9%	1.1%
2014	0.7%	0.4%	0.4%	0.6%	0.4%	0.4%	0.3%	1.0%	0.6%	0.5%
2015	0.8%	0.8%	0.5%	0.9%	0.8%	0.6%	0.4%	1.0%	0.8%	0.8%
2016	0.7%	0.8%	0.7%	0.8%	0.6%	1.0%	0.3%	1.1%	0.9%	0.8%
2017	1.0%	1.0%	0.8%	0.9%	0.6%	1.3%	0.5%	1.2%	1.2%	1.0%
2018	1.1%	1.1%	0.8%	1.0%	0.7%	1.2%	0.7%	1.1%	1.2%	1.0%
2019	0.9%	1.1%	0.8%	1.0%	0.8%	1.2%	1.0%	1.2%	1.3%	1.1%
2020	1.0%	1.2%	0.5%	0.9%	0.8%	1.2%	0.8%	1.1%	1.2%	1.0%
2021	0.7%	1.0%	0.8%	1.0%	0.8%	1.0%	0.7%	1.2%	1.1%	1.0%
2022	0.7%	1.0%	0.8%	1.0%	0.8%	1.0%	0.6%	1.4%	1.1%	1.0%
2023	0.8%	1.0%	0.8%	1.1%	0.9%	1.0%	0.6%	1.5%	3.0%	1.4%
2024	0.9%	1.1%	0.9%	1.1%	0.9%	1.0%	0.6%	1.5%	1.2%	1.1%
2025	1.0%	1.0%	0.8%	1.0%	0.9%	1.0%	0.7%	1.5%	1.3%	1.0%
2026	1.3%	1.0%	0.9%	1.0%	0.8%	1.1%	0.6%	1.5%	1.2%	1.0%
2027	1.2%	1.0%	0.9%	1.0%	0.8%	1.2%	0.6%	1.4%	1.3%	1.0%
2028	1.2%	1.0%	0.9%	1.0%	0.8%	1.4%	0.6%	1.5%	1.2%	1.0%
2029	1.4%	0.9%	0.8%	1.0%	0.8%	1.2%	0.6%	1.4%	1.2%	1.0%
2030	1.3%	1.0%	0.8%	1.0%	0.9%	1.3%	0.8%	1.5%	1.3%	1.1%
2031	1.0%	1.0%	0.8%	1.0%	0.8%	1.3%	0.7%	1.5%	1.3%	1.1%
2032	1.1%	0.9%	0.7%	0.9%	0.8%	1.2%	0.8%	1.4%	1.3%	1.0%
2033	1.0%	0.8%	0.6%	0.9%	0.7%	1.1%	0.7%	1.3%	1.2%	0.9%
2034	0.9%	0.9%	0.6%	0.9%	0.8%	1.1%	0.8%	1.3%	1.2%	1.0%
2035	1.1%	0.8%	0.6%	0.9%	0.8%	1.0%	0.7%	1.3%	1.1%	0.9%
Annual Avg	**1.1%**	**0.7%**	**0.9%**	**0.8%**	**0.9%**	**1.1%**	**0.8%**	**1.3%**	**1.3%**	**1.0%**

Source: Annual Energy Outlook 2011, EIA Reference Case

Gross Peak and Energy Demand

PEAK DEMAND (MW)										
LEVELS (MW)										
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	21,784	119,667	29,398	135,967	105,748	52,518	66,025	42,661	162,102	735,870
2012	22,609	114,199	30,797	132,850	109,030	53,915	68,287	43,492	167,534	742,712
2013	22,903	115,715	31,039	134,689	110,487	54,285	69,048	43,984	169,035	751,184
2014	23,061	116,192	31,160	135,433	110,975	54,480	69,279	44,421	169,992	754,993
2015	23,256	117,171	31,324	136,590	111,821	54,812	69,533	44,844	171,392	760,742
2016	23,423	118,059	31,532	137,647	112,507	55,341	69,736	45,315	173,015	766,576
2017	23,665	119,200	31,792	138,951	113,192	56,073	70,118	45,852	175,025	773,869
2018	23,934	120,512	32,062	140,342	113,977	56,771	70,615	46,375	177,151	781,740
2019	24,155	121,858	32,308	141,763	114,881	57,453	71,300	46,923	179,383	790,025
2020	24,392	123,292	32,479	143,109	115,797	58,119	71,866	47,428	181,525	798,008
2021	24,573	124,575	32,738	144,591	116,754	58,707	72,402	48,008	183,610	805,960
2022	24,755	125,760	32,986	146,042	117,727	59,282	72,802	48,675	185,696	813,725
2023	24,963	127,016	33,260	147,578	118,775	59,879	73,220	49,384	191,236	825,312
2024	25,189	128,438	33,565	149,199	119,866	60,493	73,645	50,109	193,612	834,117
2025	25,429	129,724	33,844	150,745	120,915	61,124	74,133	50,839	196,052	842,805
2026	25,752	131,051	34,144	152,328	121,901	61,767	74,611	51,579	198,488	851,621
2027	26,049	132,370	34,445	153,882	122,866	62,488	75,073	52,323	200,971	860,468
2028	26,370	133,677	34,747	155,448	123,837	63,337	75,514	53,095	203,458	869,482
2029	26,729	134,920	35,022	156,947	124,798	64,126	75,986	53,861	205,929	878,318
2030	27,079	136,214	35,295	158,509	125,935	64,985	76,616	54,656	208,696	887,986
2031	27,337	137,510	35,590	160,135	126,997	65,803	77,161	55,463	211,337	897,335
2032	27,625	138,760	35,849	161,622	128,053	66,617	77,756	56,242	213,982	906,506
2033	27,899	139,904	36,076	163,000	128,997	67,382	78,306	56,988	216,486	915,038
2034	28,163	141,115	36,302	164,413	130,027	68,146	78,939	57,744	219,094	923,942
2035	28,484	142,303	36,532	165,834	131,039	68,801	79,474	58,500	221,542	932,511
Annual Avg	**25,183**	**127,568**	**33,372**	**148,305**	**119,076**	**60,268**	**73,258**	**49,950**	**191,054**	**828,034**

Table III.4 Reference Case Demand Response

	PEAK LOAD REDUCTION DR (MW)									
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	2,937	8,174	2,219	2,959	5,898	5,276	1,484	3,146	6,099	38,192
2012	2,896	8,178	2,219	7,047	6,351	5,649	1,526	3,269	6,846	43,981
2013	3,349	8,183	2,219	9,282	6,559	5,976	1,572	3,390	7,252	47,782
2014	4,145	8,185	2,219	14,118	6,705	6,017	1,623	3,441	7,539	53,992
2015	4,145	8,186	2,219	14,118	6,954	6,081	1,679	3,508	7,681	54,572
2016	4,145	8,188	2,219	14,118	7,091	6,144	1,741	3,540	7,908	55,095
2017	4,145	8,190	2,219	14,118	7,136	6,207	1,808	3,606	8,310	55,740
2018	4,145	8,192	2,219	14,118	7,155	6,323	1,883	3,670	8,348	56,054
2019	4,145	8,194	2,219	14,118	7,182	6,437	1,965	3,723	8,450	56,434
2020	4,145	8,196	2,219	14,118	7,202	6,550	2,055	3,786	8,506	56,777
2021	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2022	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2023	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2024	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2025	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2026	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2027	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2028	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2029	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2030	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2031	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2032	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2033	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2034	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
2035	4,145	8,198	2,219	14,118	7,225	6,653	2,063	3,786	8,087	56,494
Average	**4,015**	**8,193**	**2,219**	**13,196**	**7,064**	**6,418**	**1,931**	**3,675**	**7,930**	**54,641**

ELCC (Reserve Margin Contribution) for DR -- 75% Dispatchable and 100% No Dispatchable

Sources: **ISONE:** ISONE Forward Capacity Auctions (FCA#2, FCA#3, FCA#4, FCA#5) for the period 2011-2014. Base case assumes flat DR after 2014.

PJM: The demand reponse for period 2011-2014 represents the amount cleared in PJM cpaacity auctions . Post -2014, flat DR has been assumed for the base case..

Other Markets: The demand response reflects Direct Control Load Management, Contractually Interruptible (Curtailable), Critical Peak-Pricing (CPP) with Control, Load as a Capacity Resource, Demand Response used for Reserves - Spinning, Demand Response used for Reserves - Non-Spinning, Demand Response used for Regulation, Demand Response used for Energy, Voluntary - Emergency and Demand Response Expected On-Peak as reported in NERC ES&D 2011 for the forecast period of 2011-2021. After 2021, Base case DR has been assumed flat.

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Table III.5 Dispatchable vs Non-dispatchable DR

	NON DIS-PATCHABLE DR %	DIS-PATCHABLE DR %
2011	22%	78%
2012	24%	76%
2013	27%	73%
2014	31%	69%
2015	36%	64%
2016	42%	58%
2017	49%	51%
2018	54%	46%
2019	59%	41%
2020	59%	41%
2021	59%	41%
2022	59%	41%
2023	59%	41%
2024	59%	41%
2025	59%	41%
2026	59%	41%
2027	59%	41%
2028	59%	41%
2029	59%	41%
2030	59%	41%

Source: NRDC

Table III.6 Net Peak and Energy Demand - Reference Case

ENERGY DEMAND (GWH)										
GROWTH (%)										
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	133,710	674,734	153,480	777,760	631,936	289,060	361,270	228,920	918,041	4,168,911
2012	1.6%	0.4%	1.4%	0.6%	2.1%	0.8%	2.0%	1.4%	1.7%	1.3%
2013	0.9%	1.3%	0.4%	1.1%	1.4%	0.6%	1.0%	0.4%	0.9%	1.0%
2014	0.5%	0.2%	0.3%	0.1%	0.1%	0.4%	0.2%	0.6%	0.3%	0.2%
2015	1.0%	1.1%	0.7%	1.0%	1.2%	0.9%	1.3%	1.0%	1.0%	1.0%
2016	1.0%	0.7%	0.8%	0.7%	0.8%	1.2%	0.8%	1.1%	1.0%	0.8%
2017	0.9%	0.7%	0.8%	0.7%	0.6%	1.1%	0.8%	1.0%	1.0%	0.8%
2018	1.1%	0.9%	0.8%	0.8%	0.7%	1.2%	0.8%	1.1%	1.0%	0.9%
2019	1.0%	0.9%	0.8%	0.8%	0.8%	1.1%	0.9%	1.1%	1.0%	0.9%
2020	1.0%	1.1%	0.6%	0.8%	0.9%	1.0%	0.9%	1.0%	1.0%	0.9%
2021	0.9%	0.8%	0.9%	0.8%	0.9%	1.0%	0.8%	1.0%	1.0%	0.9%
2022	1.0%	0.8%	0.8%	0.8%	1.0%	1.0%	0.7%	1.2%	1.1%	0.9%
2023	1.0%	1.0%	0.9%	0.9%	1.0%	1.0%	1.0%	1.3%	3.7%	1.6%
2024	1.2%	1.3%	1.0%	1.0%	0.9%	1.1%	0.8%	1.4%	1.1%	1.1%
2025	1.1%	1.1%	0.9%	0.8%	0.8%	1.0%	0.7%	1.2%	1.0%	0.9%
2026	1.2%	1.1%	0.9%	0.9%	0.8%	1.1%	0.8%	1.3%	1.0%	1.0%
2027	1.3%	1.2%	0.9%	0.9%	0.8%	1.2%	1.0%	1.3%	1.0%	1.0%
2028	1.4%	1.0%	1.0%	0.9%	0.8%	1.3%	1.0%	1.4%	1.0%	1.0%
2029	1.2%	0.8%	0.8%	0.7%	0.7%	1.2%	1.0%	1.2%	1.0%	0.9%
2030	1.3%	1.0%	0.9%	0.9%	0.9%	1.3%	1.1%	1.4%	1.1%	1.1%
2031	1.2%	1.0%	0.9%	0.9%	0.8%	1.3%	1.0%	1.3%	1.1%	1.0%
2032	1.2%	1.0%	0.9%	0.9%	0.8%	1.3%	1.0%	1.4%	1.1%	1.0%
2033	1.0%	0.8%	0.7%	0.7%	0.7%	1.1%	0.6%	1.1%	0.9%	0.8%
2034	1.1%	0.9%	0.8%	0.8%	0.8%	1.2%	0.7%	1.2%	1.0%	0.9%
2035	1.1%	0.9%	0.8%	0.8%	0.8%	1.0%	0.6%	1.2%	1.0%	0.9%
Avg	**1.1%**	**0.9%**	**0.8%**	**0.8%**	**0.9%**	**1.1%**	**0.9%**	**1.1%**	**1.1%**	**1.0%**

Net Peak and Energy Demand - Reference Case

ENERGY DEMAND (GWH)										
LEVELS (GWH)										
YEAR	ISONE	MISO	NYISO	PJM	SE	CAISO	ERCOT	FLORIDA	REST OF US	US
2011	133,710	674,734	153,480	777,760	631,936	289,060	361,270	228,920	918,041	4,168,911
2012	135,870	677,286	155,630	782,365	644,965	291,410	368,540	232,050	933,481	4,221,596
2013	137,130	686,087	156,310	791,191	654,170	293,140	372,330	233,070	941,818	4,265,247
2014	137,760	687,463	156,730	792,325	655,119	294,280	373,010	234,510	944,330	4,275,527
2015	139,170	694,889	157,750	800,032	662,864	296,940	377,700	236,740	953,858	4,319,943
2016	140,580	699,721	159,030	805,577	667,966	300,580	380,670	239,410	963,119	4,356,653
2017	141,900	704,886	160,240	811,236	672,223	304,010	383,630	241,780	972,581	4,392,487
2018	143,400	711,284	161,590	817,848	677,117	307,560	386,770	244,320	982,535	4,432,425
2019	144,790	717,963	162,870	824,585	682,291	311,050	390,300	246,960	992,830	4,473,639
2020	146,220	725,554	163,910	831,413	688,309	314,240	393,750	249,470	1,003,187	4,516,053
2021	147,490	731,287	165,440	838,379	694,351	317,300	396,980	252,010	1,012,948	4,556,186
2022	148,900	737,364	166,740	845,135	701,024	320,340	399,930	255,150	1,023,673	4,598,256
2023	150,390	744,568	168,180	852,425	707,889	323,520	404,090	258,440	1,061,731	4,671,233
2024	152,140	753,897	169,780	860,785	714,571	327,020	407,310	262,000	1,073,363	4,720,866
2025	153,780	762,162	171,240	868,083	720,442	330,280	410,360	265,170	1,084,060	4,765,576
2026	155,690	770,908	172,790	875,729	726,314	333,770	413,630	268,530	1,095,075	4,812,436
2027	157,670	780,126	174,410	883,539	732,055	337,680	417,590	271,960	1,106,271	4,861,301
2028	159,820	787,539	176,130	891,274	738,023	342,210	421,850	275,740	1,117,692	4,910,279
2029	161,780	794,015	177,540	897,791	743,302	346,210	426,010	279,050	1,128,412	4,954,110
2030	163,930	801,842	179,150	905,964	749,905	350,770	430,740	282,860	1,141,049	5,006,211
2031	165,890	809,685	180,700	914,157	755,976	355,390	435,080	286,610	1,153,035	5,056,523
2032	167,890	817,484	182,250	922,254	762,118	359,980	439,570	290,520	1,165,228	5,107,295
2033	169,560	824,270	183,510	929,150	767,469	363,960	442,320	293,840	1,176,045	5,150,124
2034	171,380	831,799	184,890	936,877	773,525	368,180	445,500	297,490	1,188,140	5,197,780
2035	173,300	838,915	186,290	944,379	779,443	372,030	448,380	301,080	1,199,786	5,243,603
Avg	**152,006**	**750,629**	**169,063**	**856,010**	**708,135**	**326,036**	**405,092**	**261,107**	**1,053,292**	**4,681,370**

***Table III.6 (Continued)* Net Peak and Energy Demand - Reference Case**

PEAK DEMAND (MW)										
GROWTH (%)										
YEAR	**ISONE**	**MISO**	**NYISO**	**PJM**	**SE**	**CAISO**	**ERCOT**	**FLORIDA**	**REST OF US**	**US**
2011	18,847	111,493	27,179	133,009	99,850	47,242	64,541	39,515	156,003	697,678
2012	4.6%	-4.9%	5.1%	-5.4%	2.8%	2.2%	3.4%	1.8%	3.0%	0.2%
2013	-0.8%	1.4%	0.8%	-0.3%	1.2%	0.1%	1.1%	0.9%	0.7%	0.7%
2014	-3.3%	0.4%	0.4%	-3.3%	0.3%	0.3%	0.3%	1.0%	0.4%	-0.3%
2015	1.0%	0.9%	0.6%	1.0%	0.6%	0.6%	0.3%	0.9%	0.8%	0.7%
2016	0.9%	0.8%	0.7%	0.9%	0.5%	1.0%	0.2%	1.1%	0.9%	0.8%
2017	1.3%	1.0%	0.9%	1.1%	0.6%	1.4%	0.5%	1.1%	1.0%	0.9%
2018	1.4%	1.2%	0.9%	1.1%	0.7%	1.2%	0.6%	1.1%	1.3%	1.1%
2019	1.1%	1.2%	0.8%	1.1%	0.8%	1.1%	0.9%	1.2%	1.3%	1.1%
2020	1.2%	1.3%	0.6%	1.1%	0.8%	1.1%	0.7%	1.0%	1.2%	1.0%
2021	0.9%	1.1%	0.9%	1.1%	0.9%	0.9%	0.8%	1.3%	1.4%	1.1%
2022	0.9%	1.0%	0.8%	1.1%	0.9%	1.1%	0.6%	1.5%	1.2%	1.0%
2023	1.0%	1.1%	0.9%	1.2%	0.9%	1.1%	0.6%	1.6%	3.1%	1.5%
2024	1.1%	1.2%	1.0%	1.2%	1.0%	1.2%	0.6%	1.6%	1.3%	1.1%
2025	1.1%	1.1%	0.9%	1.1%	0.9%	1.2%	0.7%	1.6%	1.3%	1.1%
2026	1.5%	1.1%	0.9%	1.2%	0.9%	1.2%	0.7%	1.6%	1.3%	1.1%
2027	1.4%	1.1%	0.9%	1.1%	0.8%	1.3%	0.6%	1.6%	1.3%	1.1%
2028	1.5%	1.1%	0.9%	1.1%	0.8%	1.5%	0.6%	1.6%	1.3%	1.1%
2029	1.6%	1.0%	0.8%	1.1%	0.8%	1.4%	0.6%	1.6%	1.3%	1.1%
2030	1.5%	1.0%	0.8%	1.1%	1.0%	1.5%	0.9%	1.6%	1.4%	1.2%
2031	1.1%	1.0%	0.9%	1.1%	0.9%	1.4%	0.7%	1.6%	1.3%	1.1%
2032	1.2%	1.0%	0.8%	1.0%	0.9%	1.4%	0.8%	1.5%	1.3%	1.1%
2033	1.2%	0.9%	0.7%	0.9%	0.8%	1.3%	0.7%	1.4%	1.2%	1.0%
2034	1.1%	0.9%	0.7%	0.9%	0.8%	1.3%	0.8%	1.4%	1.3%	1.0%
2035	1.3%	0.9%	0.7%	0.9%	0.8%	1.1%	0.7%	1.4%	1.2%	1.0%
Avg	**1.1%**	**0.8%**	**1.0%**	**0.5%**	**0.9%**	**1.1%**	**0.8%**	**1.4%**	**1.3%**	**1.0%**

Includes the effect of EE and DSM

Net Peak and Energy Demand - Reference Case

PEAK DEMAND (MW)										
LEVELS (MW)										
YEAR	**ISONE**	**MISO**	**NYISO**	**PJM**	**SE**	**CAISO**	**ERCOT**	**FLORIDA**	**REST OF US**	**US**
2011	18,847	111,493	27,179	133,009	99,850	47,242	64,541	39,515	156,003	697,678
2012	19,713	106,021	28,578	125,803	102,679	48,266	66,761	40,223	160,688	698,732
2013	19,554	107,533	28,820	125,407	103,928	48,309	67,476	40,594	161,783	703,402
2014	18,916	108,007	28,941	121,315	104,270	48,463	67,656	40,980	162,453	701,001
2015	19,111	108,984	29,105	122,472	104,867	48,731	67,854	41,336	163,711	706,170
2016	19,278	109,871	29,313	123,529	105,416	49,197	67,995	41,775	165,106	711,480
2017	19,520	111,010	29,573	124,833	106,056	49,866	68,310	42,246	166,715	718,129
2018	19,789	112,320	29,843	126,223	106,822	50,448	68,732	42,705	168,803	725,686
2019	20,010	113,664	30,089	127,644	107,699	51,016	69,335	43,200	170,932	733,591
2020	20,247	115,096	30,260	128,991	108,595	51,569	69,811	43,642	173,019	741,231
2021	20,428	116,378	30,519	130,473	109,529	52,054	70,339	44,222	175,524	749,466
2022	20,610	117,562	30,767	131,923	110,502	52,629	70,739	44,889	177,610	757,231
2023	20,818	118,818	31,041	133,459	111,550	53,226	71,157	45,598	183,149	768,818
2024	21,044	120,240	31,346	135,080	112,641	53,840	71,582	46,323	185,526	777,623
2025	21,284	121,526	31,625	136,627	113,690	54,471	72,070	47,053	187,965	786,311
2026	21,607	122,853	31,925	138,209	114,676	55,114	72,548	47,793	190,402	795,127
2027	21,904	124,173	32,226	139,763	115,641	55,835	73,010	48,537	192,884	803,974
2028	22,225	125,479	32,528	141,329	116,612	56,684	73,451	49,309	195,371	812,988
2029	22,584	126,722	32,803	142,829	117,573	57,473	73,923	50,075	197,842	821,824
2030	22,934	128,016	33,076	144,391	118,710	58,332	74,553	50,870	200,610	831,492
2031	23,192	129,313	33,371	146,017	119,772	59,150	75,098	51,677	203,250	840,840
2032	23,480	130,562	33,630	147,504	120,828	59,964	75,693	52,456	205,895	850,012
2033	23,754	131,706	33,857	148,882	121,772	60,729	76,243	53,202	208,399	858,544
2034	24,018	132,917	34,083	150,295	122,802	61,493	76,876	53,958	211,007	867,448
2035	24,339	134,105	34,313	151,716	123,814	62,148	77,411	54,714	213,456	876,016
Avg	**21,168**	**119,375**	**31,153**	**135,109**	**112,012**	**53,850**	**71,327**	**46,276**	**183,124**	**773,393**

APPENDIX IV: ADDITIONAL NOTES ON IPM® REGIONS

In some markets, modeling of zones for energy and capacity may be different as a function of market structure. For example, for energy purposes, the New York market is modeled as five aggregate zones (A-E, F, G-I, J, and K); for capacity purposes, New York is modeled in a way that is consistent with the capacity market structure, with three zones: New York City, Long Island, and the rest of the state. The table below summarizes energy zones in the focal regions used in this analysis within the IPM® modeling framework.

Table IV.1 Zones Modeled Within IPM® for NRDC Regions of Focus

ISO-NE	NY-ISO	PJM	MISO	SOUTHEAST
BHE (North East Maine)	Upstate (Zones A-E)	AE (Atlantic Electric)	MAPP (West, North, South)	Entergy Associated
ME (Western and Central Maine)	Zone F	AEP	MAIN ILMO	Entergy North
SME (Southeastern Maine)	Downstate NY (Zones G-I)	APS	MAIN WUMS	Entergy Central
NH (New Hampshire)	NYC (Zone J)	BG&E	ECAR MECS	Entergy West
Boston (Greater Boston)	LILCO (Zone K)	ComEd	Cinergy	Entergy South
CMA/NEMA (Central Mass/Northeaster Mass)		Dominion		TVA
WMA (Western Mass)		DPL (Delmarva Power & Light)		Southern
SEMA (Southeastern Mass)		Jersey Central Power & Light (East, Central)		
RI (Rhode Island)		PECO		
CT (Connecticut)		PEPCO		
SWCT (Southwest CT)		PSEG (North, South)		
NOR (Norwalk/ Stamford CT)		Penelec		
		West Central (MetEd and PPL)		
		First Energy / ATSI		
		Duke (OH+KY)		

APPENDIX V: SUPPLY-SIDE EFFICIENCY ASSUMPTIONS

From "Coal-Fired Power Plant Heat Rate Reductions," Sargent & Lundy LLC, January 22, 2009:

Table V.1 Supply-Side Efficiency Assumptions

PROCESS	CAPACITY MW	PLANT TYPE	ASSUMED CYCLE EFF %	TYPICAL HEAT RATE BTU/KWH	HEAT RATE BENEFIT %	HEAT RATE REDUCTION BTU/KWH	CAPITAL COST $ MILLION	FIXED COST $000/YR	CAPITAL COST $/KW	FIXED COST $/KW-YR
1) Combustion Optimization Software & Controls										
Sargent & Lundy, 2009	500	generic	0.34	10,000	0.65%	65	0.75	50	2	0.1
2) Replace steam turbine blading										
Sargent & Lundy, 2009	500	generic	0.34	10,000	2.00%	200	12	0	24	0
3) Pre-combustion drying of moist coal										
		The Sargent & Lundy report does not cover this particular method								
4) Flue gas System -										
a) Heat recovery										
		The Sargent & Lundy report does not cover this particular method								
b) Replace radial with axial fan + VFD										
Sargent & Lundy, 2009	500	generic	0.34	10,000	1.00%	100	10	38	20	0.08
c) Upgrade economizers										
Sargent & Lundy, 2009	500	generic	0.34	10,000	0.75%	75	4.5	100	9	0.2
5) Optimization of Soot Blowers										
Sargent & Lundy, 2009	500	generic	0.34	10,000	0.60%	60	0.5	50	1	0.1
6) Tuning Steam Condenser - cleaning										
Sargent & Lundy, 2009	500	generic	0.34	10,000	0.50%	50	0	60	0	0.12
7) Boiler Feed Pump Upgrades										
Sargent & Lundy, 2009	500	generic	0.34	10,000	0.50%	50	0.6	60	1	0.12
TOTAL										
Sargent & Lundy, 2009						**600**	**28**	**358**	**57**	**0.72**

Table V.2 Compilation of Select Heat Rate Improvement Options for Coal-Fired Power Plants

PROCESS	CAPACITY MW	PLANT TYPE	NET CAPACITY INCREASE MW	ASSUME CYCLE EFF %	TYPICAL HEAT RATE BTU/KWH	HEAT RATE BENEFIT %	CYCLE EFFICIENCY BENEFIT %	HEAT RATE REDUCTION BTU/KWH	CAPITAL COST $ MILLION	FIXED COST $000/YR	CAPITAL COST ($/KW)	FIXED COST ($KW/YR)
Combustion Optimization Software& Controls												
Sargent&Lundy, 2009	500	generic		0.34	10,000	0.65%		65	0.75	50	1.5	0.1
Power Engineering, July 2008	500	generic		0.34	10,000		5.00%	1278	0.2		0.4	
NETL Improving Efficiency, 2008							0.35-2.84%					
Replace steam turbine blading												
Sargent & Lundy, 2009	500	generic	10	0.34	10,000	2.00%		200	12	0	24	0
Power Engineering, July 2008	500	generic		0.34	10,000		4.00%	1049	27	0	54	0
NETL Improving Efficiency, 2008	500	generic					0.8-2.6%					
Pre-combustion drying of moist coal												
NETL Fact Sheet, 2009	546	Coal Creek		0.34	10,000	3.00%		300	31.5	0	58	0
NETL Improving Efficiency, 2008	500	generic					0.1-1.8%					
Flue Gas System												
4a) Heat recovery												
NETL Improving Efficiency, 2008	500	generic					0.3-1.5%					
4b) replace radial with axial fan + VFD												
Sargent & Lundy, 2009	500	generic		0.34	10,000	1.0%		100	10	38	20	0.08
4c) upgrade economizers												
Sargent & Lundy, 2009	500	generic		0.34	10,000	0.75%		75	4.5	100	9	0.20
Optimization of Soot Blowers												
Sargent & Lundy, 2009	500	generic		0.34	10,000	0.6%		60	0.5	50	1	0.10
NETL Fact Sheet, 2008	445	Big Bend		0.34	10,000		0.30%	87	27	0	61	0
NETL Improving Efficiency, 2008							0.1-0.65%					
Tuning Steam Condenser - cleaning												
Sargent & Lundy, 2009	500	generic		0.34	10,000	0.5%		50	0	60	0	0.12
NETL Improving Efficiency, 2008	500	generic					0.7-2.4%					
Boiler Feed Pump Upgrades												
Sargent & Lundy, 2009	500	generic		0.34	10,000	0.5%		50	0.6	60	1.2	0.12
Power Engineering, July 2008	500	generic		0.34	10,000		2.50%	683	1.75	0	3.5	0

Sum of S&L Options	600	Btu/kWh
Sum of Power Eng Options	3010	Btu/kWh

The schedule for the groupings of heat rate improvements implemented is given below. Units with relatively poor heat rate performance (from the fifth to tenth decile) would receive the full measure of options (i.e., 600 Btu/kWh). Units that are “best-in-class” (the first decile) would receive no further improvements. Units within the second to fourth decile would receive 50% reductions.

The analysis assumes efficiency improvement options that provide a 600 Btu/KWh improvement, though in practice, it is possible that heat rate improvements could be as high as 1,000 Btu/kWh for some plants.

DECILE	HEAT RATE IMPROVEMENT
First	0%
Second	50%
Third	50%
Fourth	50%
Fifth	100%
Sixth	100%
Seventh	100%
Eighth	100%
Ninth	100%
Tenth	100%

APPENDIX VI: MODELED AND REPORTED REGIONS FOR CO_2 RATE-AVERAGING

Table VI.1 NRDC Alt. NSPS Regional CO_2 Groups

REPORTING REGION	CALIFORNIA	TEXAS	FLORIDA	MISO	NEW ENGLAND	NEW YORK	PACIFIC NORTHWEST	PJM CENTRAL / WEST	PJM EAST / SOUTH	SERC-CENTRAL	SERC-DELTA	SERC-GATEWAY	SERC-SOUTHEAST	SPP	OTHER WEST
Modeled Region	California ISO	ERCOT	FRCC	WUMS	Maine	NYISO	Other WA	AEP	BG&E	TVA	Entergy Associated	Southern Illinois	Southern	SPP - Southeast (Louisiana)	Rocky Mountain Power / Xcel Colorado
				MECS	Vermont		Other ID	APS	Dominion	SERC KY	Entergy North		Duke Carolinas	SPP - Other (AR, OK, TX, NE)	Arizona
				Cinergy	New Hampshire		Other OR	ComEd	DPL (Delmarva Power & Light)		Entergy Central		SCEG		Other Nevada
				NIPSCO	Mass.		NWPPA	First Energy / Penelec	PECO		Entergy West		Other North Carolina		Other New Mexico
				MAPP - North	Rhode Island			West Central (MetEd and PPL)	PEPCO		Entergy South				Other Montana
				MAPP - West	Connecticut			First Energy / ATSI	New Jersey		Missouri/ Kansas				Southwestern Public Service
				MAPP - SE				Duquesne							
				MAPP -											

APPENDIX VII: SUPPLEMENTAL ANALYSIS OF WEAKER STANDARD AND WEAKER STANDARD–NO DSM CASES

CO_2 Emission Reductions. In the specifications for the WS and WS–No DSM cases, state standards are based on a nominal 15 percent reduction in the average emission rate for coal generation by 2020 compared with the baseline average emission rate from 2008 through 2010. WS–No DSM total emissions from coal generation decline to 1.80 billion tons in 2016 and to 1.74 billion tons in 2020, which amounts to reductions of 10 percent and 14 percent below the Reference Case. The lower net energy demand growth and the addition of energy efficiency in the WS case, where energy efficiency counts toward compliance, result in lower emissions trajectories for CO_2. At the national level in 2020, efficiency projects contribute roughly 1.5 billion kWh toward load and provide more than enough emission reduction credits to offset the 1.0 billion kWh of coal-fired generation that emits in excess of regional target rates. The lower demand growth and efficiency overwhelm the CO_2 requirements (making them nonbinding) and reduces gas-fired generation, CO_2 emissions, and the need for new capacity. WS power sector CO_2 emissions in the U.S. fall by 14 percent relative to the Reference Case in 2020.

The WS–No DSM case shows that total CO_2 emissions from the power sector in the United States would decrease 12 percent below 2005 levels in 2020, to 2.34 billion tons. The potential for more pronounced low-cost reductions rests with complementary state and federal policies to further reduce electricity demand through improved energy efficiency, as evidenced by the results of the WS case (and the NRDC Case described in the body of this report). Adding energy efficiency as a compliance option leads to more pronounced reductions, with national CO_2 emissions in WS decreasing to 2.18 billion tons in 2020, 18 percent below 2005 levels. The state efficiency policies assumed to be induced by making energy efficiency a compliance option in the WS case produce a net reduction in compliance costs and electric services emission rates below the standard. This indicates that the standards specified in the WS model run do not reflect the economically justified best system of emission reductions.

Emission Rate Profiles. The WS case produced the second-lowest compliance emission rate, but the WS fossil emission rate is closer to the Reference Case fossil emission rate than to the fossil emission rate for WS–No DSM. This result is driven by the effect of energy efficiency in the WS case. While coal-fired generation is similar in WS and WS–No DSM, in WS there is substantially less fossil fuel generation overall, with less natural gas generation needed to meet demand due to efficiency gains that have decreased energy demand. Thus, the decreased overall generation is a result of less natural gas generation, which is, in turn, a result of efficiency gains offsetting energy demand. The lower level of natural gas generation in WS is reflected in reduced NGCC capacity factors and fewer new capacity builds compared with the WS–No DSM case. In WS, the average NGCC capacity factor for the U.S. is 50 percent in 2020 with 9.4 GW of total NGCC builds, compared with 61 percent and 25.2 GW, respectively, in WS–No DSM. Hence, the fossil fuel emission rate is higher in WS than in WS–No DSM, while total emissions are lower.

Table VII.1 Summary CO_2 Emissions Results (in million tons)—United States and by Focal Region

MILLION TONS CO2	2012	2014	2016	2018	2020	2012-2020 % CHANGE
WS						
US	2,412	2,363	2,279	2,250	2,184	-9.5%
ISONE	41	38	37	38	35	-15.7%
NYISO	37	35	35	40	37	1.6%
MISO	536	539	529	519	503	-6.2%
PJM	486	483	445	438	434	-10.7%
Southeast	405	390	374	359	350	-13.8%
WS - No DSM						
US	2,432	2,435	2,336	2,393	2,345	-3.6%
ISONE	43	43	44	47	45	4.9%
NYISO	39	39	41	46	46	18.2%
MISO	537	536	511	520	501	-6.7%
PJM	489	491	462	470	474	-3.2%
Southeast	403	400	400	405	403	0.1%

Figure VII.1 Historical CO_2 Emissions and NRDC Projected CO_2 Emissions (in million tons)

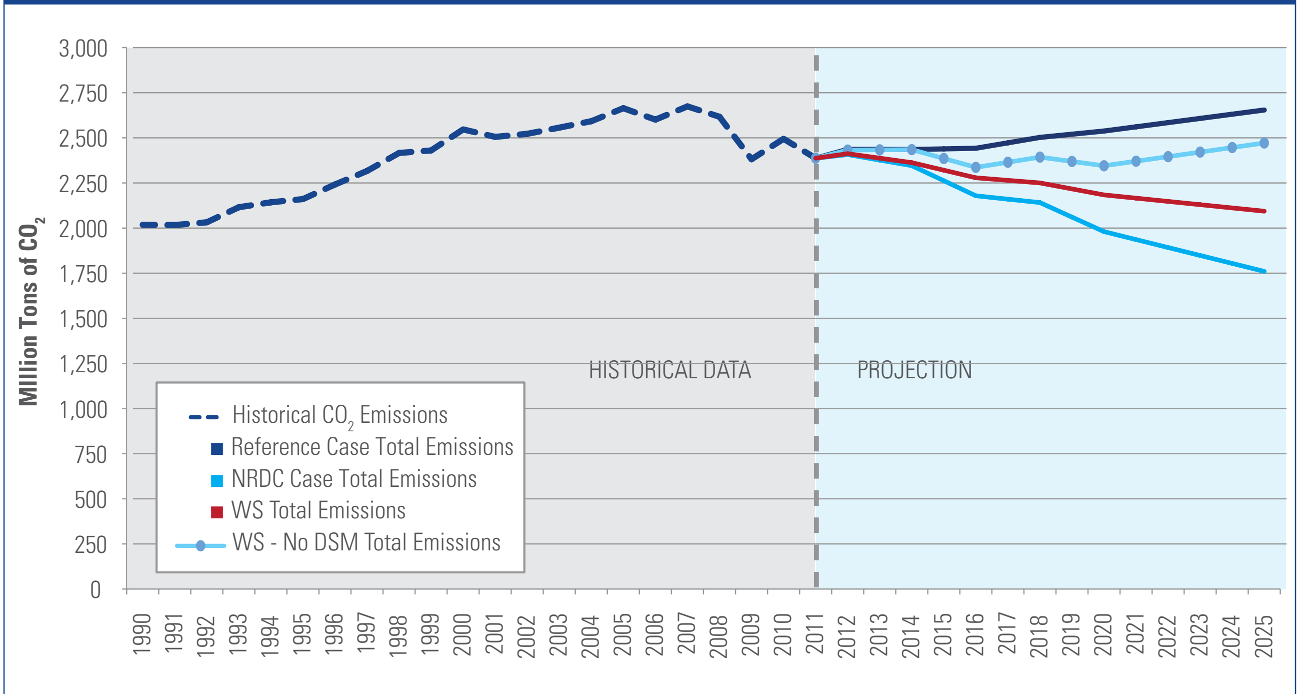


Figure VII.2 U.S. Fossil and Compliance CO_2 Emission Rates

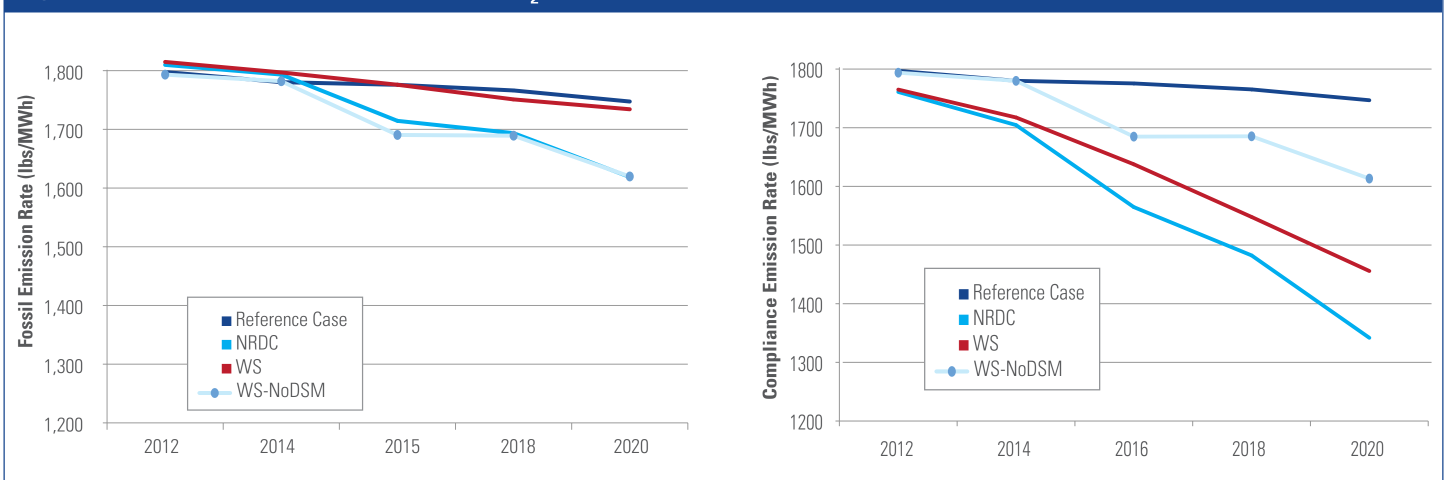


Figure VII.3 WS Regional Fossil and Compliance Emission Rates

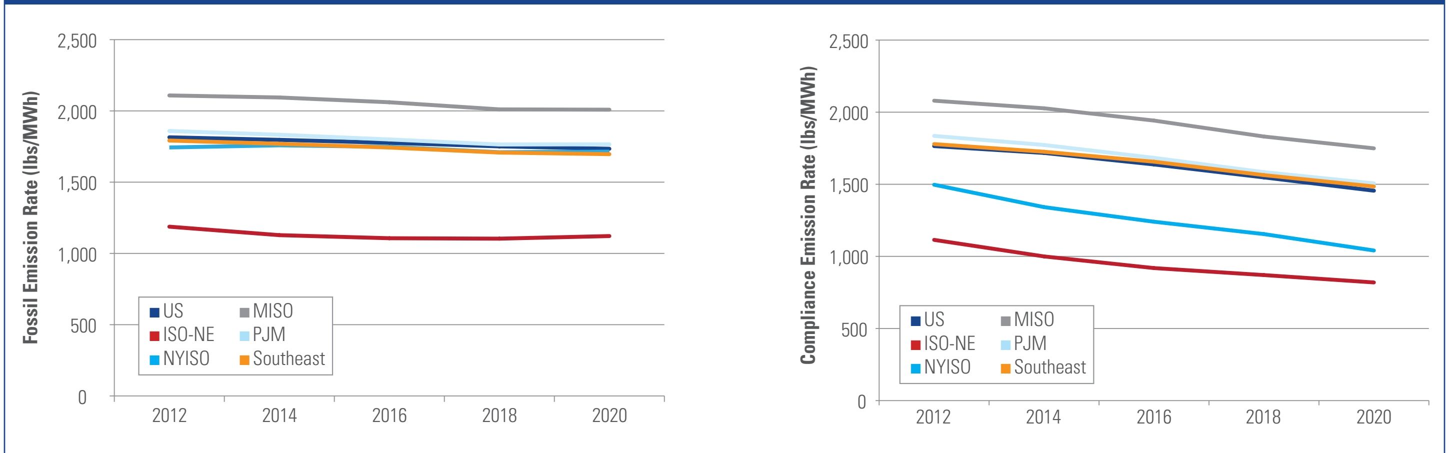
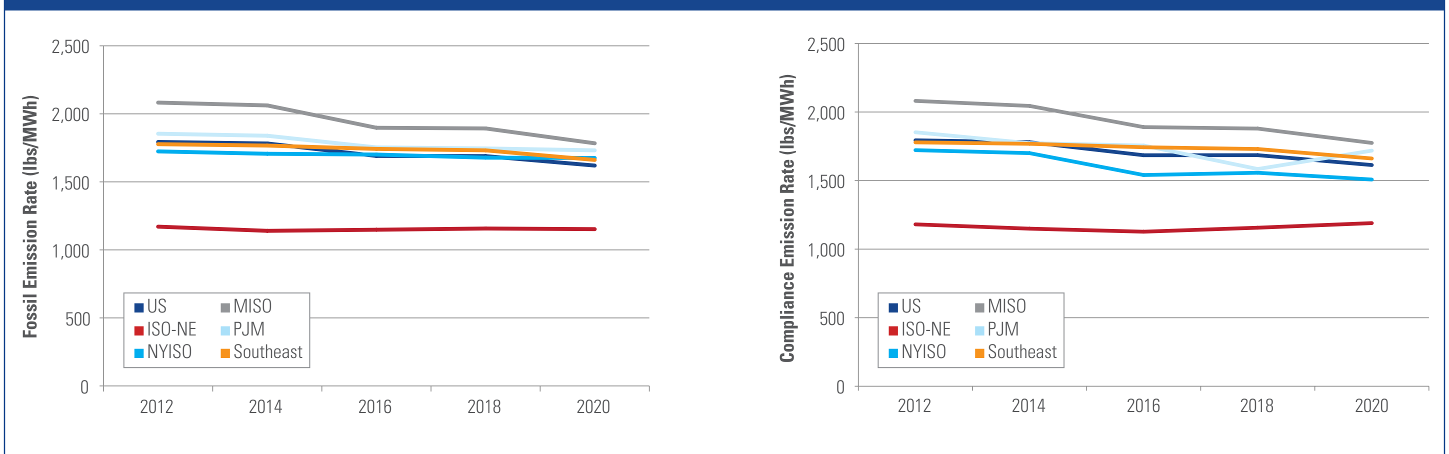


Figure VII.4 WS–No DSM Regional Fossil and Compliance Emission Rates



Compliance Costs. For WS–No DSM, the model estimates compliance costs of $10.2 billion (2010$) incremental to the Reference Case in 2020 for reducing CO_2 emissions by 8 percent, or 203 million short tons. Between WS–No DSM and the Reference Case, there is a significant difference in fuel and capital costs. Lower fuel costs in the Reference Case can be attributed to lower gas prices and higher coal generation. Lower capital costs in the Reference Case are due to lower gas prices and fewer coal retirements that result in fewer new units as replacement capacity. Higher fixed O&M costs in the Reference Case are associated with greater coal capacity staying in the system, as fixed O&M costs of coal plants are generally higher than for new gas plants. Additionally, heat rate improvement costs are slightly higher in the Reference Case. With fewer coal plant retirements, more coal units undertake efficiency improvements, resulting in higher capital expenses. The incremental differences between WS–No DSM and the Reference Case are shown in Table VII.2, below.

By contrast, the WS case demonstrates net savings to the system. Compared with WS–No DSM, there is a significant decrease in fuel costs, attributed to lower generation requirements and lower natural gas prices, and a similar decline in capital costs as a result of lower net peak demand levels and significantly fewer unplanned builds. Offsetting this decrease in fuel and capital costs is a significant increase

Table VII.2 Summary of WS and WS - No DSM Fossil and Compliance Emission Rates in 2020		
WS (LBS/MWH IN 2020)	**FOSSIL EMISSION RATE**	**COMPLIANCE EMISSION RATE**
US	1,734	1,456
ISO-NE	1,122	819
NYISO	1,714	1,041
MISO	2,008	1,749
PJM	1,765	1,507
Southeast	1,697	1,485
WS - NO DSM (LBS/MWH IN 2020)	**FOSSIL EMISSION RATE**	**COMPLIANCE EMISSION RATE**
US	1,620	1,613
ISO-NE	1,152	1,190
NYISO	1,676	1,508
MISO	1,783	1,775
PJM	1,732	1,719
Southeast	1,661	1,661

Table VII.3 WS - No DSM Compliance Costs (compared with Reference Case)							
DELTA WS - NO DSM - REFERENCE CASE							
[MMUS$]	**2012**	**2014**	**2016**	**2018**	**2020**	**2025**	**2030**
Variable O&M	(99)	(110)	(232)	(218)	(262)	(242)	(297)
Fixed O&M	39	(58)	(651)	(627)	(520)	(524)	(392)
Fuel	(220)	(209)	5,359	5,452	8,423	6,466	5,769
Capital	(20)	25	946	946	2,853	3,507	3,556
CO_2 Transport & Storage	-	-	-	-	(259)	(257)	(265)
DR	-	-	-	-	-	-	-
EE	-	-	-	-	-	-	-
DSM (DR+EE)	-	-	-	-	-	-	-
HR Efficiency Improvement	-	(149)	(149)	(149)	-	-	-
TOTAL	**(301)**	**(501)**	**5,272**	**5,404**	**10,235**	**8,950**	**8,371**

in the costs of deploying demand-side management (DSM), which includes both energy efficiency and demand response. Even with the DSM costs, the net savings to the system in WS are $3.6 billion below the Reference Case and $13.8 billion below WS–No DSM in 2020. These net savings suggest that the overall electric generating system has overcomplied with the standards, as a result of the high levels of end-use energy efficiency and demand response resources.

The Economic Benefits of Emission Reductions
Examining the corresponding comparison of total compliance costs and total benefits in the WS and WS–No DSM cases illustrates the magnitude of benefits and cost reductions delivered by energy efficiency in the NRDC Case. The annualized compliance costs of the WS–No DSM case in 2020 amount to $10.2 billion,[89] more than two times that of the NRDC Case, and the benefits total $8.6 billion to $23.4 billion. At the low end of the benefits range in WS–No DSM, the costs exceed the benefits by nearly 20 percent. The high benefits estimate for WS–No DSM outweighs the compliance costs by roughly a factor of two. For more than twice the cost of NRDC's recommended policy approach, the WS–No DSM case achieves roughly one-third the benefits. In the WS case,

the total costs of compliance are substantially lower than in the NRDC Case, resulting in a net savings to the system of $3.6 billion. The range of benefits in the WS case is $13.5 billion to $37.0 billion, greater than WS–No DSM, but still 40 percent below what is achieved in the NRDC Case. This indicates that the effect of introducing energy efficiency as a compliance mechanism under the target emission rates in the WS cases increases the benefits by more than 50 percent. The more stringent target emission rate scheme in the NRDC Case further builds on the range of benefits and accomplishes the optimal outcome with the maximum benefits and emission reductions for the median cost among these scenarios.

Wholesale Electricity Prices
Figure VII.7. Wholesale Electricity Prices in All Scenarios (Generation-Weighted Average of Five Regions)

Generation Changes. The CO_2 policy approach in these cases tends to mitigate coal generation to the benefit of natural gas–fired generation. National coal and gas generation in

Table VII.4 WS Compliance Costs (compared with Reference Case)

DELTA WS - REFERENCE CASE							
[MMUS$]	**2012**	**2014**	**2016**	**2018**	**2020**	**2025**	**2030**
Variable O&M	38	(147)	(48)	(259)	(491)	(637)	(958)
Fixed O&M	(156)	(1,098)	(2,561)	(4,343)	(5,404)	(7,134)	(7,987)
Fuel	(2,430)	(6,234)	(8,646)	(13,709)	(18,762)	(36,913)	(51,599)
Capital	358	292	(248)	(798)	(1,655)	(5,565)	(8,999)
CO_2 Transport & Storage	-	-	-	-	-	-	-
DR	-	-	503	694	806	2,226	3,368
EE	2,389	5,543	9,868	15,366	21,949	44,051	59,040
DSM (DR+EE)	2,389	5,543	10,371	16,060	22,754	46,277	62,409
HR Efficiency Improvement	-	(422)	(422)	(422)	-	-	-
TOTAL	**199**	**(2,066)**	**(1,553)**	**(3,471)**	**(3,558)**	**(3,972)**	**(7,134)**

Figure VII.5 WS–No DSM Case Estimated U.S. Benefits from Reductions in SO_2, NOx, and CO_2 in 2020

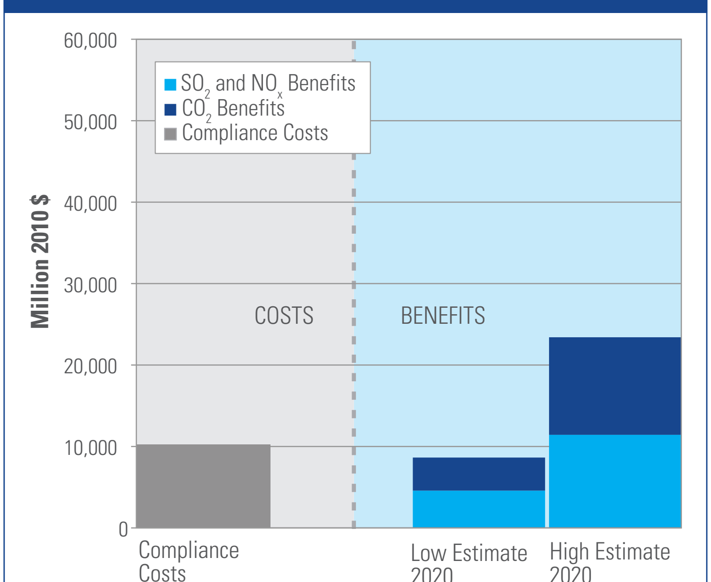


Figure VII.6 WS Case Estimated U.S. Benefits from Reductions in SO_2, NOx and CO_2 in 2020

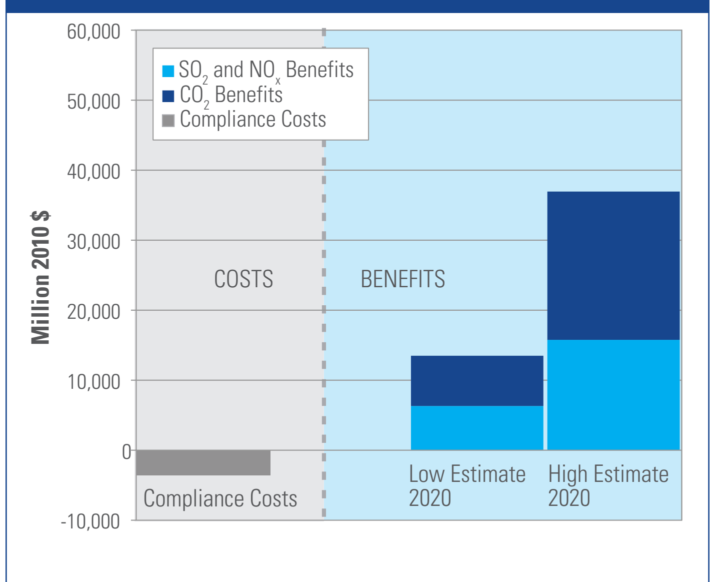
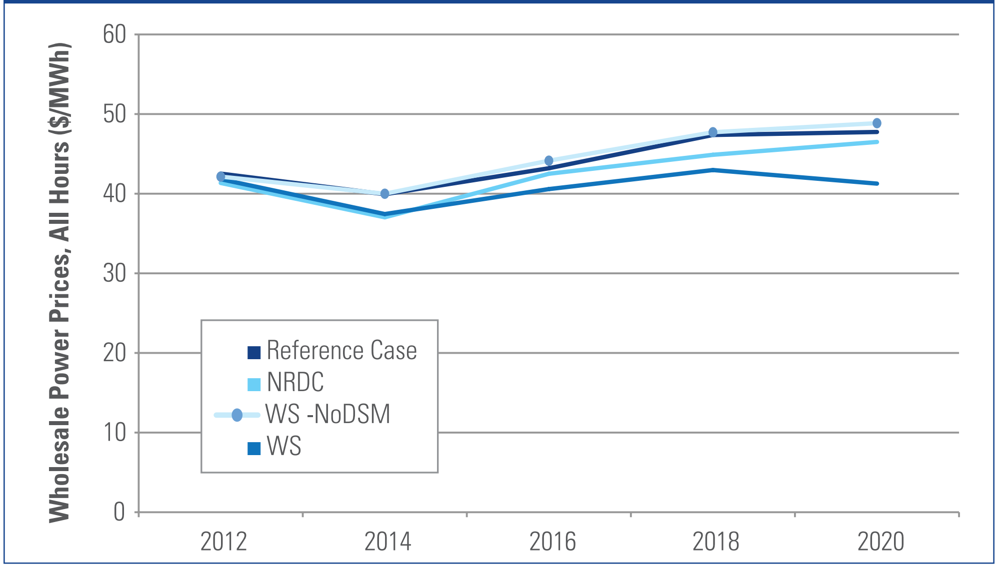


Figure VII.7. Wholesale Electricity Prices in All Scenarios (Generation-Weighted Average of Five Regions)



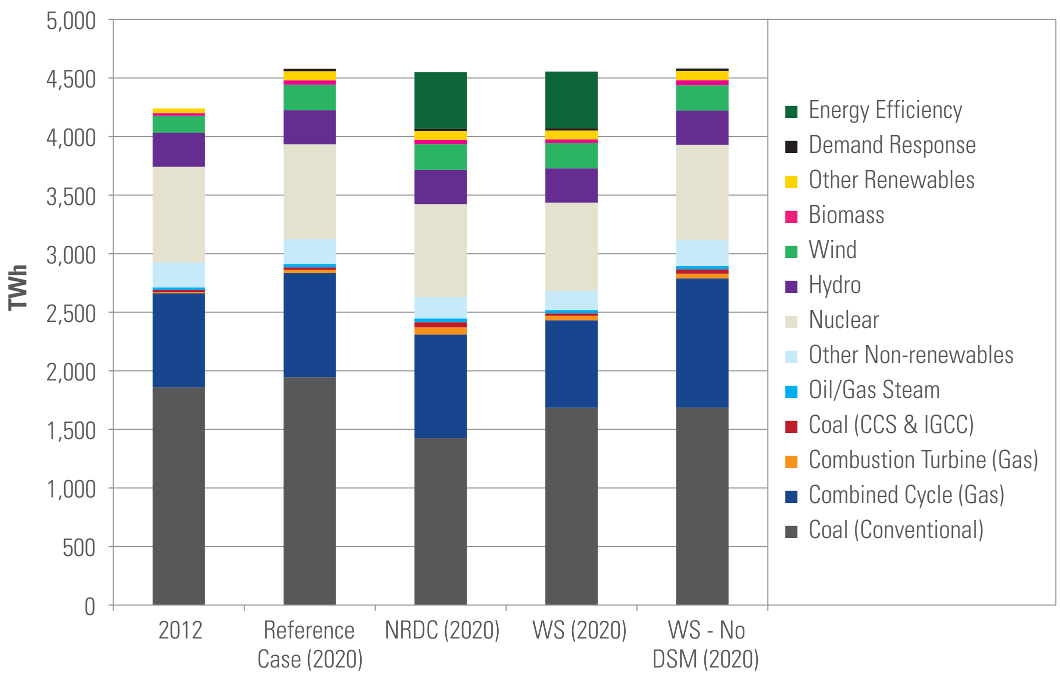
the WS case decline 13 percent and 16 percent, respectively, relative to the Reference Case in 2020.

As in the WS case, U.S. coal generation in WS–No DSM decreases 13 percent relative to the Reference Case in 2020. However, U.S. combined-cycle gas-fired generation in WS–No DSM increases 24 percent in 2020 compared with the Reference Case. Natural gas generation replaces the energy efficiency share of the generation mix in WS–No DSM, and consequently, average U.S. capacity factors for natural gas units increase from 56 percent to 68 percent. Coal has a market share of 37 percent of the generation mix in WS–No DSM, compared with 43 percent in the Reference Case. The market share of natural gas generation in WS–No DSM is 24 percent, compared with 19 percent in the Reference Case. In the WS case, the market share of coal is 42 percent, slightly lower than the Reference Case share of 43 percent, while the market share of natural gas generation is 20 percent, slightly higher than in the Reference Case.

Retirements, New Builds, and Capacity Changes. There are roughly 15.3 GW of coal unit retirements projected through 2014 and another 3.0 GW of oil/gas steam unit retirements across the five regions of focus in WS–No DSM, driven primarily by relatively low gas prices. In the 2015–2016 period, there are an additional 15.6 GW of coal units retired. These retirements coincide with the start date of MATS and the 111(d) CO_2 pollution standard. Due to the large number of older, uncontrolled coal units in the five focal regions—particularly MISO, PJM, and Southeast—the retirements in these regions make up the majority of the retirements at the national level. In the 2013–2020 time frame, the retirements in the five focal regions represent 68 percent of the national retirements. In terms of new builds in the WS–No DSM case, the model projects 32.8 GW of thermal capacity builds through 2020 nationally. Nearly 20 GW of these, or 60 percent, are in the five focal regions, with the majority anticipated in MISO. An additional 61.8 GW of renewable builds is projected nationwide through 2020, with 11 GW of that contributing to reserve margins. These renewable builds are anticipated largely to meet state RPS requirements. Thermal builds are almost exclusively in the form of combined cycle builds to meet intermediate and base load needs. Renewable builds are dominantly wind builds, although the model also projects solar, biomass, and landfill builds, particularly in PJM, ISO-NE, and NYISO.

As a result of the reduced need for generation and capacity (particularly for older, fossil-fired generation) and lower energy prices in WS relative to WS–No DSM, plant retirements are higher in WS. Through 2020, in the WS case, 92 GW of capacity retires nationwide. Retirements of coal-fired capacity make up two-thirds of that total, with retirements of oil/gas steam units and nuclear units making up the remainder. This total is 36 GW higher than in WS–No DSM, with coal capacity driving half of that difference. Retirements in the five focal regions account for more than 60 percent of the increase from WS–No DSM by 2020. The bulk of incremental coal retirements are centered in PJM and

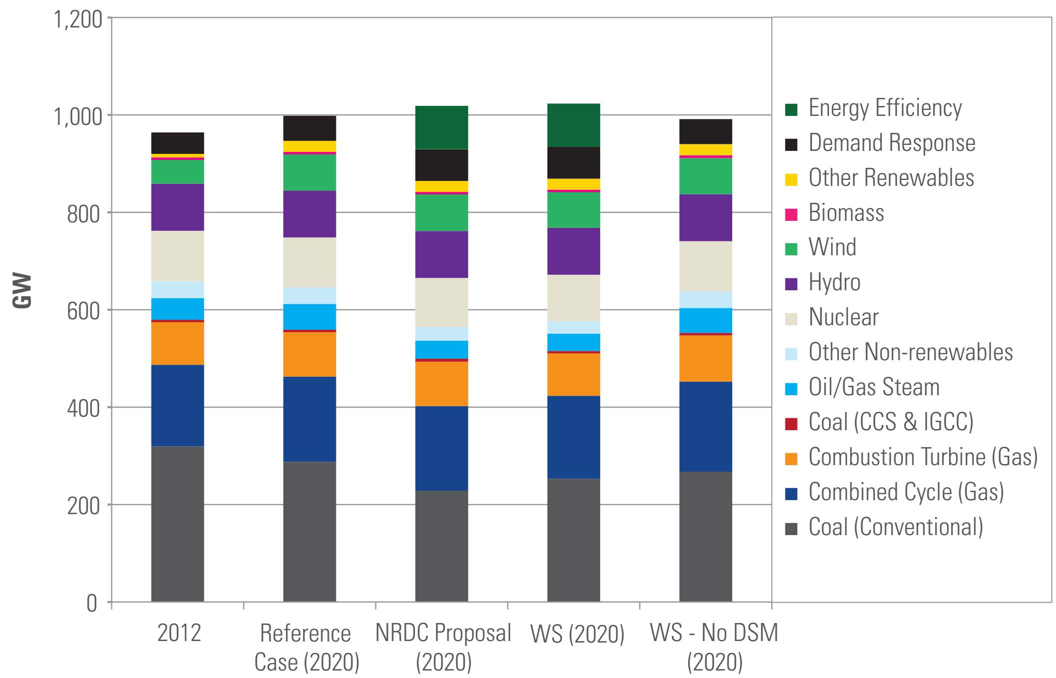
Figure VII.8 Projected 2020 Generation Changes in the U.S. Power Sector



TWH	2012	REFERENCE CASE (2020)	NRDC (2020)	WS (2020)	WS - No DSM (2020)
Combined Cycle (Gas)	804	889	883	747	1,103
Combustion Turbine (Gas)	25	40	62	51	39
Coal (Conventional)	1,859	1,946	1,426	1,684	1,686
Coal (CCS & IGCC)	5	8	44	8	38
Oil/Gas Steam	18	29	31	28	30
Nuclear	816	809	793	752	813
Hydro	292	292	292	294	293
Wind	144	216	220	216	217
Biomass	23	38	38	31	43
Other Renewables	40	98	95	96	99
Other Non-renewables	214	213	183	164	221
Demand Response	*0*	*0*	*0*	*0*	*0*
Energy Efficiency	*0*	*0*	*482*	*482*	*0*
TOTAL	**4,239 (4,239)**	**4,578 (4,578)**	**4,550 (4,068)**	**4,554 (4,071)**	**4,580 (4,582)**

Note: Parenthetical values show actual physical generation.

Figure VII.9 Projected Capacity Changes in the U.S. Power Sector



GW	2012	REFERENCE CASE (2020)	NRDC PROPOSAL (2020)	WS (2020)	WS - No DSM (2020)
Combined Cycle (Gas)	167	175	173	171	185
Combustion Turbine (Gas)	91	95	91	91	95
Coal (Conventional)	319	288	229	253	268
Coal (CCS & IGCC)	1	1	6	1	5
Oil/Gas Steam	45	53	37	36	51
Nuclear	104	103	101	95	103
Hydro	97	96	96	96	96
Wind	51	74	75	74	74
Biomass	3	5	5	4	6
Other Renewables	7	23	23	23	23
Other Non-renewables	35	34	28	26	34
Demand Response	*44*	*51*	*65*	*65*	*51*
Energy Efficiency	*0*	*0*	*89*	*89*	*0*
TOTAL	**964 (920)**	**998 (947)**	**1,019 (864)**	**1,023 (870)**	**991 (940)**

Note: CC and CT exclude capacity that becomes temporarily inactive (mothballed capacity) and later returns to the system. Parenthetical values show actual physical generation.

meet intermediate and base load needs. Renewable builds are dominantly wind builds, although the model also projects solar, biomass, and landfill builds, particularly in PJM, ISO-NE, and NYISO.

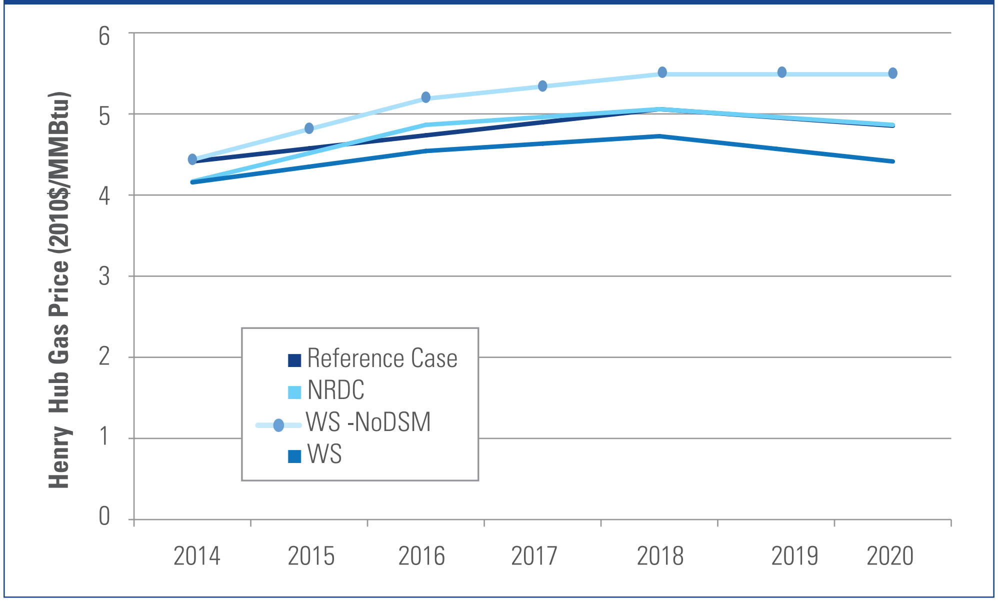
As a result of the reduced need for generation and capacity (particularly for older, fossil-fired generation) and lower energy prices in WS relative to WS–No DSM, plant retirements are higher in WS. Through 2020, in the WS case, 92 GW of capacity retires nationwide. Retirements of coal-fired capacity make up two-thirds of that total, with retirements of oil/gas steam units and nuclear units making up the remainder. This total is 36 GW higher than in WS–No DSM, with coal capacity driving half of that difference. Retirements in the five focal regions account for more than 60 percent of the increase from WS–No DSM by 2020. The bulk of incremental coal retirements are centered in PJM and the Southeast, while nuclear retirements are more evenly distributed.

The more stringent emission rate standards and the lower demand in the NRDC Case lead to more coal unit retirements relative to the WS and WS–No DSM cases. Through 2020, 18 GW and 37 GW of coal units retire in the NRDC Case that were not projected to retire in WS and WS–No DSM, respectively, across the U.S. The bulk of the incremental coal retirements compared with the WS case—11 GW of the 18 GW—occurs in the MISO region, and half of the remainder comes in the other target regions. It is notable that NGCC capacity in 2020 is lower than in the Reference Case in both the NRDC and WS cases. Additionally, through 2025, 5 GW of additional IGCC/CCS capacity over the Reference Case is added in the NRDC scenario.

A crucial feature of the NRDC Case is the role of energy efficiency as a compliance pathway and as a replacement for deactivated coal generation. The WS case analyzed an approach similar to the NRDC Case, but with less stringent nominal target emission rates. The WS results showed that the more lenient nominal targets coupled with energy efficiency drove the system into a state of overcompliance, with modest emission reductions at a net savings. WS–No DSM evaluated the impact of removing energy efficiency from the universe of possible compliance options, and the results showed the least emission reductions accompanied by the highest costs.

APPENDIX VIII: HENRY HUB GAS PRICES

Figure VIII.1: Henry Hub Gas Prices in All Cases, 2012-2020



Endnotes

1 The electric power industry includes all grid-connected power producers, both regulated utilities and other entities (e.g., independent power producers and cogenerators). Total U.S. emissions depend on the amount of electricity generated and the mix of fuels used to produce the electricity. AEO2012 indicates that fossil fuel combustion, including coal, petroleum, and natural gas, made up approximately 67 percent of the nation's electricity generation in 2012.

2 Energy Information Administration, *Monthly Energy Review,* October 2011, Table 12.6.

3 EIA, *Monthly Energy Review*, October 2011, Tables 12.1 and 12.6.

4 www.epa.gov/climatechange/endangerment/; "Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation,"Special Report of the Intergovernmental Panel on Climate Change, 2012. Available at: www.ipcc-wg2.gov/SREX/images/uploads/SREX-All_FINAL.pdf.

5 usnews.nbcnews.com/_news/2012/07/08/12624445-us-heat-wave-eases-but-death-toll-rises?lite.

6 www.latimes.com/news/nation/nationnow/la-na-nn-hurricane-sandy-deaths-climb-20121103,0,6945430.story.

7 *See* www.nws.noaa.gov/os/hazstats/heat11.pdf

8 Knowlton K, Rotkin-Ellman M, Geballe L, Max W, Solomon G. 2011. Health costs of six climate change-related events in the United States, 2002-2009. *Health Affairs*, 2011; 30(11) p.2167-2176.

9 SNL Financial, Power Plant Units Database.

10 *See* EPA Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, December 2011, available at: www.epa.gov/ttn/ecas/regdata/RIAs/matsriafinal.pdf

11 EPA, Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources, Electric Utility Generating Units, Proposed Rule, 77 Fed. Reg. 22,392 (April 13, 2012).

12 *Massachusetts v. EPA,* 549 U.S. 497 (2007). *Massachusetts* directly concerned carbon pollution from motor vehicles. In a companion case stemming out of a 2006 EPA decision refusing to issue standards for CO_2 from power plants, the U.S. Court of Appeals for the District of Columbia Circuit directed EPA to take action on power plants in light of the *Massachusetts* decision. *State of New York et al. v. EPA*, No. 06-1322 (Order, Sept. 24, 2007). In 2011 the parties reached a settlement agreement in the *New York* case with a schedule for EPA to act on CO_2 standards for both new and existing power plants. www.epa.gov/airquality/cps/settlement.html. In 2011 the Supreme Court confirmed EPA's responsibility to address carbon pollution from power plants under Section 111 in another climate-change case, *American Electric Power v. Connecticut*, 131 S.Ct. 2527 (2011). Although EPA has fallen behind the settlement schedule, the agency proposed the standard for new plants in April 2012.

13 74 Fed. Reg. 66,496 (Dec. 15, 2009). EPA's endangerment determination was upheld by a unanimous panel of the D.C. Circuit Court of Appeals in June 2012. *Coalition for Responsible Regulation v. EPA*, 684 F.3d 102 (D.C. Cir. 2012).

14 Section 111 does not apply to new or existing sources that emit "hazardous" air pollutants (a group of especially toxic pollutants), which are covered by Section 112 of the Act. It also doesn't apply to existing sources that emit so-called criteria pollutants, which are covered by Section 110 of the Act. Section 111 applies to both new and existing sources of greenhouse gases because they are neither "hazardous" nor "criteria" pollutants.

15 Section 111(b)(1)(A).

16 Section 111(b)(2).

17 77 Fed. Reg. at 22,410-11.

18 Section 111(b)(1)(B).

19 Section 111(a)(1).

20 S. Rep. No. 91-1196, at 17 (1970).

21 *Id.* at 16.

22 486 F.2d 375, 391 (D.C. Cir. 1973). *See also Sierra Club v. Costle*, 657 F.2d 298, 364 (D.C. Cir. 1981). ("[W]e believe EPA does have authority to hold the industry to a standard of improved design and operational advances, so long as there is substantial evidence that such improvements are feasible.")

23 77 Fed. Reg. at 22,398-99, 22,410-11.

24 77 Fed. Reg. at 22,406-07.

25 Section 111(d) applies only where there are no other provisions that control the emissions from existing stationary sources. If the pollutant is covered by a national ambient air quality standard (NAAQS) set under Section 109, then existing sources are controlled through state implementation plan (SIPs) under Section 110. If the pollutant is a hazardous air pollutant, then existing sources are controlled under Section 112. Because carbon dioxide and other greenhouse gases are neither NAAQS pollutants nor hazardous air pollutants, the existing source requirements of Section 111(d) apply.

26 *See, e.g.,* 40 C.F.R. § 60.24, describing factors that states may consider "[u]nless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities." "Applicable subpart" is the emission guideline regulations issued for a particular source category.

27 40 C.F.R. § 60.22. The regulation states that the emission guideline shall be issued simultaneously with or following the promulgation of the new source standard.

28 40 C.F.R. § 60.22(b)(5). In parallel to Section 111(b)'s provision for new sources, the guideline regulations give EPA broad discretion regarding the establishment of subcategories for existing sources. 40 C.F.R. § 60.22(b)(5) ("The Administrator will specify different emission guidelines or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.")

29 40 C.F.R. § 60.23(a).

30 40 C.F.R. § 60.24. This regulation provides certain default approaches for states to consider the costs of applying standards to particular sources which apply "[u]nless otherwise specified in the applicable subpart," i.e., in the emission guideline regulations issued for a particular source category. In the approach recommended in this paper, the emission guideline regulations for this category would supersede these default approaches for considering costs by incorporating cost considerations directly into the design of the standard of performance, through the availability of alternate compliance options. See Section B, below.

31 Section 111(d)(2) states that EPA: "shall have the same authority … to prescribe a plan for a State in cases where the State fails to submit a satisfactory plan as [it] would have under section 110(c) of this title in the case of failure to submit an implementation plan."

32 Section 111(b)(1)(B).

33 131 S.Ct. 2527 (2011).

34 www.epa.gov/airquality/cps/settlement.html.

35 In EPA's proposal for new sources, the agency proposed to cover all intermediate and base-load electric generating units, but not units designed to serve peak load. Joint environmental commenters have recommended that EPA include all fossil fuel generating units as covered sources, with a separate new source standard for units that serve only peak load. If EPA follows this recommendation in its final new source standard, then the covered sources under the standard for existing plants would be all fossil fuel–fired generators.

36 An updated baseline time period could be considered, depending on when the standard is proposed and finalized.

37 The emission rate standard for each state is obtained by summing the product of the nominal emission rate target for coal and coal's generation share in the state during the baseline period with the product of the nominal emission rate target for gas and the generation share of gas in the state during the baseline period.

38 Section 111(d)(1)(A) requires that each state plan contain "standards of performance" for any existing source within the category. Section 111(a)(1) defines a "standard of performance" as "a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." As noted above, EPA's emission guideline regulations (40 C.F.R. § 60.22(b)(5)) use substantially the same language.

39 Additional support for these compliance credit approaches can be found in Section 110(a)(2) of the Act, which authorizes state plans to use "enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emission rights)."

40 The distribution of compliance costs within states will be determined by the details of each state's implementation plan. State environmental and utility regulators have a variety of options for distributing these costs among and between power plant owners and utility customers. Any approach deemed appropriate by the state is acceptable, provided that it doesn't interfere with attainment of the state's emission rate standard.

41 For modeling purposes, some adjustments had to be made to this proposed state-by-state structure in order to reflect the subregions as defined in the IPM®. The modeling for the intrastate averaging feature was performed on the IPM® region level, which roughly approximates state boundaries, and aggregated to the ISO level for reporting. The modeled regions and aggregated regions are shown in Appendix VI.

42 G. Keith, B. Biewald, E. Hausman, "Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011," prepared for the Civil Society Institute by Synapse Energy Economics, Inc., Nov. 16, 2011. Available at: www.civilsocietyinstitute.org/media/pdfs/Toward%20a%20Sustainable%20Future%2011-16-11.pdf.

43 Helping customers improve efficiency generally costs utilities less than 4 cents per kilowatt-hour (kWh), which is less than half the cost of the equivalent power from a power plant. See also ACEEE on utility efficiency programs (in 14 states, energy efficiency costs utilities an average of 2.5 cents per kWh, as opposed to 8 to 14 cents per kWh for new plants).

44 EPA, ENERGY STAR, "Where Does My Money Go?" www.energystar.gov/index.cfm?c=products.pr_where_money, accessed April 2010.

45 See ACEEE; see also the discussion in Goldstein, D., *Invisible Energy: Strategies to Rescue the Economy and Save the Planet*. Point Richmond, California: Bay Tree Publishing, 2010, Chapter 3.

46 EPA has taken a great first step in issuing its draft "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State Implementation Plans/Tribal Implementation Plans"; however, the voluntary/emerging measures and the weight of evidence determination pathways to compliance as currently presented in the EPA Roadmap should be examined more closely before being relied upon to generate credits for the purposes of Section 111(d) to ensure the savings will be real, verifiable and surplus.

47 This reflects the additional emissions that would have been allowed if those MWh were generated instead of saved.

48 In the case of non-state/local funded third-party programs, revenues from auction would go back to the entities that produced the savings.

49 This baseline period could be updated, depending on when the standard is issued.

50 See ACEEE.

51 Consortium for Energy Efficiency (CEE) 2011 Annual Industry Report.

52 The utility industry regularly invests much larger sums of money in the face of significantly more uncertainty. Utilities invest in or contract for generation, transmission, and distribution that often last for decades on the basis of many assumptions, including future demand, fuel availability and price, and future regulations. These analyses have tremendous uncertainty, but that does not stop utilities and their regulators from investing, just as the uncertainty surrounding the exact amount of energy savings should not prevent investments in efficiency.

53 "An EM&V system for [energy efficiency credits] requires the fundamental elements of an EM&V system for any regulated energy efficiency program, but must also…be rigorous enough to ensure real, verifiable energy savings…while simultaneously being flexible and efficient enough to minimize transaction costs." S. Meyers and and S. Kromer. "Measurement and Verification Strategies for Energy Savings Certificates: Meeting the Challenges of an Uncertain World. *Energy Efficiency* (2008) 1:313-321.

54 See ACEEE.

55 See ACEEE.

56 This type of market trading for energy efficiency is often referred to as a "white tags program" and requires establishing not only a whole new infrastructure but a new market as well.

57 This can be expressed in MWh savings, as is done in this example, or in percent reduction in total load.

58 Savings from energy efficiency measures continue to deliver savings beyond the first year just like a power plant. The average lifetime commonly used is 12 years.

59 This is a simplified example and does not include adjustments that might be made in the measurement and verification process. For example, it does not include any adjustments to account for persistence, or how long the efficiency measure continues to deliver energy savings.

60 NRDC selected these five focal regions because the EPA standards assumed in the analysis are expected to drive the most significant generation shifts in these regions.

61 Documentation for EPA'S Base Case v.4.10 in IPM® is available at: www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation.

62 NRDC collaborated with the Environmental Defense Fund (EDF) on structuring the demand-growth assumptions for the model runs that feature energy efficiency as a compliance mechanism for the CO_2 pollution standards.

63 This assumption is based on the options for heat rate improvement detailed in "Coal-Fired Power Plant Heat Rate Reductions," Sargent & Lundy, 2009. The Sargent & Lundy study provides over twenty supply options for coal plants. Some options have very low or negligible capital costs, e.g. for a generic 500 MW coal-fired power plant, frequent cleaning of the steam condenser tubing could provide on average of approximately 50 points in heat rate improvement for no additional capital cost and with $50,000 in additional fixed maintenance fees. A more substantial improvement may be realized through upgrading steam turbine blading for approximately $12 million or $24/kW to provide an additional 200 points in heat rate improvement. The turbine upgrade tends to be at the upper end of feasible improvements. If the full range of measures were implemented on a generic plant, the heat rate could be reduced by approximately 600 Btu/kWh (or 6%) or from 10,000 Btu/kWh to 9,400 Btu/kWh, for example. With additional options, it is possible that heat rate improvements could be as high as nearly 1000 Btu/kWh for some plants but barriers such as regulatory incentives and potential NSR triggers tend to limit them.

64 CSAPR was vacated by a panel of the D.C. Circuit on August 21, 2012. This analysis was developed before the legal proceedings took place, and it assumes that units begin complying with CSAPR in 2013, as contemplated in the final rule. On October 5, 2012, EPA and other litigants petitioned the D.C. Circuit Court of Appeals to rehear the CSAPR case. There is no guarantee that the rule will be reinstated upon rehearing.

65 Due to resource constraints, NRDC did not conduct as extensive a set of analyses as we would expect EPA to conduct to determine the level of stringency that reflects BSER, but our analysis suggests that the specifications for the NRDC Case meet the criteria for BSER.

66 Environmental Health & Engineering Inc. "Emissions of Hazardous Air Pollutants from Coal-Fired Power Plants." Prepared for American Lung Association, March 7, 2011.

67 Clean Air Task Force. "Toll from Coal." www.catf.us/resources/publications/view/138 , accessed June 2012.

68 Clean Air Task Force. "Toll from Coal." www.catf.us/resources/publications/view/138, accessed June 2012.

69 U.S. EPA, "Integrated Science Assessment for Oxides of Nitrogen—Health Criteria and Annexes," July 11, 2008. Available at: www.epa.gov/ncea/isa/soxnox.htm, accessed June 21, 2012.

70 Nicolai, T. "Environmental Air Pollution and Lung Disease in Children." *Monaldi Archives of Chest Disease* 54 (1999): 475-478.

71 Hu, W., et al., 2008. "Temperature, Air Pollution and Total Mortality During Summers in Sydney, 1994-2004." *International Journal of Biometeorology* 52:689-696. Shah, P.S., et al., 2011. "Air Pollution and Birth Outcomes: A Systematic Review. *Environment International* 37:498-516. Sousa, S.I.V., et al., 2012. "Short-term Effects of Air Pollution on Respiratory Morbidity at Rio de Janeiro—Part II: Health Assessment." *Environment International* 43:1-5.

72 Benefits from SO_2 and NOx reductions estimated by extensively peer-reviewed dispersion model developed by Abt Associates to estimate health impacts from power plants for EPA. Lower and higher estimates based on different statistical relationships between pollution concentrations and health effects that are used by EPA. Value of statistical lives lost is the primary component of the monetary value of the estimated benefits.

73 U.S. EPA. Technical Support Document, "Social Cost of Carbon for Regulatory Impact Analysis," under Executive Order 11866, Interagency Working Group on Social Cost of Carbon, United State Government, February 2010: 1.

74 Docket ID EPA-HQ-OAR-2009-0472-114577. Technical Support Document, "Social Cost of Carbon for Regulatory Impact Analysis," under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, with participation by Council of Economic Advisers, Council on Environmental Quality, Department of Agriculture, Department of Commerce, Department of Energy, Department of Transportation, Environmental Protection Agency, National Economic Council, Office of Energy and Climate Change, Office of Management and Budget, Office of Science and Technology Policy, and Department of Treasury (February 2010). Available at: www.epa.gov/otaq/climate/regulations.htm.

75 Johnson, L.T., and Hope, C., 2012. "The Social Cost of Carbon in U.S. Regulatory Impact Analyses: An Introduction and Critique." *Journal of Environmental Studies and Sciences* 2(3). Available at: "http://www.springerlink.com/content/863287021p06m441/" www.springerlink.com/content/863287021p06m441/.

76 For example, the administration's lowest discount rate of 2.5 percent per year would value $100,000 worth of climate damages happening 30 years from now at approximately $48,000 (and at 100 years roughly $8,500). Alternatively, using the highest discount rate of 5 percent, $100,000 in 30 years would be approximately $23,000 today (and at 100 years $760). More details available at: "http://switchboard.nrdc.org/blogs/ljohnson/co2pollutioncost_part1.html" switchboard.nrdc.org/blogs/ljohnson/co2pollutioncost_part1.html and "http://switchboard.nrdc.org/blogs/ljohnson/co2pollutioncost_part2.html" switchboard.nrdc.org/blogs/ljohnson/co2pollutioncost_part2.html.

77 Comments on Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed. Reg. 22,392 (April 13, 2012). Comments on the Benefits of Carbon Reductions from the Proposed Power Plant New Source Performance Standards, submitted by Natural Resources Defense Council, Sierra Club, Earthjustice. June 25, 2012. Available at: "http://www.nrdc.org/air/air_12062601.asp" www.nrdc.org/air/air_12062601.asp. Docket No. EPA-HQ-OAR-2011-0660, via regulations.gov.

78 As discussed above, the government used discount rates of 2.5, 3, and 5 percent, specifying the estimate corresponding to the 3 percent rate as its primary one. Rates of 5 percent are typically applied to *intra*-generational costs and benefits that affect primarily the current generation. However, for intergenerational benefit-cost analysis, the Office of Management and Budget guidelines permit agencies to use rates ranging from 1 to 3 percent, based upon a review of the economics literature. See p. 36 of OMB Circular A-4 guidelines, available at: "http://www.whitehouse.gov/sites/default/files/omb/assets/omb/circulars/a004/a-4.pdf" www.whitehouse.gov/sites/default/files/omb/assets/omb/circulars/a004/a-4.pdf.

79 Firm power prices do not include the costs of demand-side management. These costs are, however, reflected in compliance costs.

80 McKinsey, "Unlocking Energy Efficiency in the U.S. Economy" (2009). Available at: www.mckinsey.com/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.aspx. EPRI's 2009 analysis of the economic potential for demand-side energy efficiency, though more limited in scope than McKinsey's, found that the interventions to capture the economic energy efficiency potential could generate a 0.9 percent reduction in energy demand per annum—eliminating projected demand growth. EPRI, "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. (2010-2030)" (2009). Available at:www.edisonfoundation.net/iee/reports/EPRI_AssessmentAchievableEEPotential0109.pdf.

81 Efficiency Vermont, "Year 2010 Savings Claim" (April 1, 2011) at 3. Available at: www.efficiencyvermont.com. Energy efficiency programs in Nevada, Hawaii, Rhode Island, Minnesota, and Vermont all achieved energy demand reductions equivalent to 1 percent or more of electricity sales in 2009. American Council for an Energy-Efficiency Economy, "2011 State Scorecard" (2011) at 17. Available at: www.aceee.org/research-report/e115.

82 American Council for an Energy-Efficiency Economy, "2011 State Scorecard" (2011) at 21-22. Available at: www.aceee.org/research-report/e115.

83 See www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp.

84 *See, e.g.*, Brown, R., Borgeson, S., Koomey, J. and Biermayer, P., *U.S. Building-Sector Energy Efficiency Potential*, LBNL Report 1096E, Berkeley, CA: Lawrence Berkeley National Laboratory (2008); Committee on America's Energy Future, *Real Prospects for Energy Efficiency in the United States*, Washington, DC: National Academies Press (2010); Electric Power Research Institute, *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* (2010-2030) (2009), available at: http://www.edisonfoundation.net/iee/reports/EPRI_AssessmentAchievableEEPotential0109.pdf; Energy Center of Wisconsin and American Council for an Energy-Efficient Economy, *A Review and Analysis of Existing Studies of the Energy Efficiency Resource Potential in the* Midwest, ECW Report No. 247-1 (2009), available at: http://www.midwesterngovernors.org/Energy/EEResourcePotential.pdf; Friedrich, K., Eldridge, M., York, D., Witte, P. and Kushler, M, *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs*, Washington, DC: American Council for an Energy-Efficient Economy (2009); Global Energy Partners, *Tennessee Valley Authority Potential Study: Final Report*, Report No. 1360 (December 21, 2011), available at: http://www.tva.gov/news/releases/energy_efficiency/GEP_Potential.pdf; *Granade*, H., Creyts, J., Derkach, A., Farese, P., Nyquist, S., and Ostrowski, K, *Unlocking Energy Efficiency in the U.S. Economy*, McKinsey & Company (2009), available at: http://www.mckinsey.com/insights/mgi/research/technology_and_innovation/the_social_economy; Hibbard, P., Tierney, S., Okie, A. and Darling, P, *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States*, Boston, MA: The Analysis Group (2011), available at: http://www.analysisgroup.com/uploadedfiles/publishing/articles/economic_impact_rggi_report.pdf; Keith, G., Biewald, B., and Hausman, E., "Toward a Sustainable Future for the U.S. Power Sector: Beyond Business-as-Usual 2011," Prepared for the Civil Society Institute by Synapse Energy Economics, Inc., (November 16, 2011), available at: http://www.civilsocietyinstitute.org/media/pdfs/Toward%20a%20Sustainable%20Future%2011-16-11.pdf; Laitner, J., Nadel, S., Elliott, R., Sachs, H. and Kahn, S, *The Long-Tern Energy Efficiency Potential: What the Evidence Suggests*, Washington, DC: American Council for an Energy-Efficient Economy (2012); Lung, R., McKane, A., Leach, R. and Marsh, D., "Ancillary Benefits and Production Benefits in the Evaluation of Industrial Energy

Efficiency Measures," In *Proceedings of the 2005 Summer Study on Energy Efficiency in Industry*, Washington, D.C.: American Council for an Energy-Efficient Economy (2005); Watson, D. et al., *Fast Automated Demand Response to Enable the Integration of Renewable Resources*, Lawrence Berkeley National Laboratory (June 2012), available at http://drrc.lbl.gov/sites/drrc.lbl.gov/files/LBNL-5555E.pdf; Worrell, E., Laitner, J., Ruth, M. and Finman, H, "Productivity Benefits of Industrial Energy Efficiency Measures," *Energy*, 28, 1081-98 (2003).

85 "A National Assessment of Demand Response Potential," Federal Energy Regulatory Commission Staff Report, prepared by the Brattle Group, Freeman, Sullivan & Co., Global Energy Partners, June 2009.

86 U.S. Energy Information Administration, based on North American Electric Reliability Corporation, 2012 Summer Short-Term Reliability Assessment, May 2012, available at: /www.nerc.com/files/2012SRA.pdf.

87 The AEO2012 Extended Policies case assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs), those that involve extensive regulatory analysis, such as CAFE improvements and periodic updates of efficiency standards, and extension of tax credits for blenders and other biofuels. AEO2012 EP also assumes an increase in capacity limitations on the ITC and extension of the program, additional rounds of efficiency standards for residential and commercial products, and new standards for products not yet covered. It also adds multiple rounds of national building codes by 2026 and increases LDV fuel economy standards in the transportation sector to 62 miles per gallon in 2035.

88 End-use PV accounts for a share of this (34 TWh, or 33 percent), but the largest contributor is biomass CHP (60 TWh, or 59 percent). The BAU case also features this level of biomass end-use generation.

89 The cost per ton of CO_2 emissions avoided in the WS–No DSM case is \$51.69.

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