Implementing EPA's Clean Power Plan:

A Menu of Options

NACAA
national association of clean air agencies

May 2015

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Acknowledgements

On behalf of the National Association of Clean Air Agencies (NACAA), we are pleased to provide *Implementing EPA's Clean Power Plan: A Menu of Options*. Our association developed this document to help state and local air pollution control agencies identify technologies and policies to reduce greenhouse gases from the power sector. We hope that states and localities, as well as other stakeholders, find this document useful as states prepare their compliance strategies to achieve the carbon dioxide emissions targets set by the EPA's Clean Power Plan.

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This document is available on the NACAA website at: www.4cleanair.org.

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Table of Contents

List of Figures

List of Tables

Acronym List

AB Assembly Bill
ACEEE American Council for an Energy-Efficient Economy
ACP Alternative Compliance Payment
ADB Asian Development Bank
AEC Alternative Energy Certificate
AEPS Alternative Energy Portfolio Standard
ARB (California) Air Resources Board
ARRA American Recovery and Reinvestment Act
ASAP Appliance Standard Awareness Project
ASHRAE American Society of Heating, Refrigeration, and Air Conditioning Engineers
AVERT Avoided Emissions and Generation Tool
BAA Balancing Authority Area
BACT Best Available Control Technology
BC British Columbia
BCR Benefit-Cost Ratio
BPA Bonneville Power Administration
BRA Base Residual Auction
BSER Best System of Emission Reduction
BTU British Thermal Unit
C Celsius
C&S Codes and Standards
CAA Clean Air Act
CAAAC Clean Air Act Advisory Committee
CAES Compressed air energy storage
CAIR Clean Air Interstate Rule
CAISO California Independent System Operator
CASE Codes and Standards Enhancement
CBSM Community-Based Social Marketing
CCS Carbon Capture and Sequestration
CDM Clean Development Mechanism
CEMS Continuous Emissions Monitoring System
CFL Compact Fluorescent Light (Bulb)
CHP Combined Heat and Power
CITSS (California) Compliance Instrument Tracking System Service
CO Carbon Monoxide
CO_2 Carbon Dioxide
CO_2e CO_2 equivalent
COATS (RGGI's) CO_2 Allowance Tracking System
CPP Clean Power Plan
CRC Carbon Reduction Credit
CREZ Competitive Renewable Energy Zones
CRS Congressional Research Service
CSE Cost of Saved Energy
CVR Conservation Voltage Regulation
D Darcy
DC Direct Current
DEQ (Michigan) Department of Environmental Quality
DER Distributed Energy Resource
DG Distributed Generation
DOC Department of Commerce
DOE (US) Department of Energy
DPHE (Colorado) Department of Public Health and Environment
DR Demand Response
DSIP Distributed System Implementation Plan
DSM Demand-Side Management
DSP Distributed System Platform
DY Delivery Year
EEM Energy Efficient Mortgage
EERS Energy Efficiency Resource Standard
eGRID Emissions & Generation Resource Integrated Database
EGU Electric Generating Unit
EIA (U.S.) Energy Information Administration
EIM Energy Imbalance Market
EIPC Eastern Interconnection Planning Collaborative
EM&V Evaluation, Measurement, and Verification
EOR Enhanced Oil Recovery
EPA (U.S.) Environmental Protection Agency
EPC Energy Performance Contracts
EPRI Electric Power Research Institute
EPS Emissions Performance Standard
ERCOT Electric Reliability Council of Texas
ESCO Energy Service Company
ESPC Energy Savings Performance Contract
ETS Emissions Trading System
EU ETS European Union's Emissions Trading System
EU European Union
EV Electric Vehicle
F Fahrenheit
FCM Forward Capacity Market
FERC Federal Energy Regulatory Commission
FIT Feed-In Tariff
GAO Government Accountability Office
GDP Gross Domestic Product
GHG Greenhouse Gas
GRE Great River Energy
GS Geologic Sequestration
Gt Gigaton
GW Gigawatt
GWh Gigawatt Hour
HHV Higher Heating Value
IA Incremental Auction
ICE Internal Combustion Engine
ID Induced Draft
IEA International Energy Agency
IECC International Energy Conservation Code
IEEE Institute of Electrical and Electronics Engineers
IGCC Integrated Gasification Combined Cycle
IMPEAQ Integrated Multi-Pollutant Planning for Energy and Air Quality
IoT Internet of Things

IOU	Investor-Owned Utility
IPL	Indianapolis Power & Light Company
IPM	Integrated Planning Model
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	Independent System Operator – New England
JI	Joint Implementation
kV	Kilovolt
kVA	Kilovolt-Ampere
kW	Kilowatt
kWh	Kilowatt Hour
lb/MMBTU	Pounds per Million BTU
lb/MWh	Pounds per Megawatt-Hour
LBNL	Lawrence Berkeley National Laboratory
lbs/MWh	Pounds per MWh
LCOE	Levelized Costs of Energy
LEED	Leadership in Energy and Environmental Design
LSE	Load-Serving Entity
MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MBTU	One Millions BTUs
mD	Millidarcy
MISO	Midcontinent Independent System Operator
MMBTU	Million British Thermal Units
MOU	Memorandum of Understanding
Mt	Millions of tons
MVP	Multi-Value Transmission Projects
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standard
NACAA	National Association of Clean Air Agencies
NAECA	National Appliance Energy Conservation Act of 1987
NEDRI	New England Demand Response Initiative
NEEP	Northeast Energy Efficiency Partnership
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NESCAUM	Northeast States for Coordinated Air Use Management
NESHAPS	National Emission Standards for Hazardous Air Pollutant Standards
NETL	National Energy Technology Laboratory
NGCC	Natural Gas-Fired Combined-Cycle
NOI	Notice of Inquiry
NOMAD	Normally Occurring Market Adoption
NOx	Nitrogen Oxide
NPV	Net Present Value
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standard
NSR	New Source Review
NTA	Non-Transmission Alternative
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O&M	Operation & Maintenance
OBR	Output-Based Regulation
ORNL	Oak Ridge National Laboratory
PACE	Property-Assessed Clean Energy
PGE	Portland General Electric
PGW	Philadelphia Gas Works
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM Interconnection
PM	Particulate Matter
ppm	Parts per million
PRB	Powder River Basin
PSC	(Michigan) Public Service Commission
PSD	Prevention of Significant Deterioration
PSE	Puget Sound Energy
PUC	Public Utility Commission
PURPA	Public Utility Regulatory Policy Act of 1978
PV	Photovoltaic
QA/QC	Quality Assurance/Quality Control
QF	Qualifying Facility
RCRA	Resource Conservation and Recovery Act
RE	Renewable Energy
REC	Renewable Energy Credit
REED	Regional Energy Efficiency Database
RETI	Renewable Energy Transmission Initiative
REZ	Renewable Energy Zone
RGGI	Regional Greenhouse Gas Initiative
RGOS	Regional Generator Outlet Study
RIIO	Revenues = Incentives plus Innovation plus Outputs
RMI	Rocky Mountain Institute
RPM	Reliability Pricing Model
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCC	Social Cost of Carbon
SEE Action	State and Local Energy Efficiency Action Network
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
TIC	Turbine Inlet Cooling
TOU	Time-Of-Use
TPO	Third-Party Ownership
TRM	Technical Reference Manual
TSD	Technical Support Document
TVA	Tennessee Valley Authority
US	United States
UIC	(Federal) Underground Injection Control
UMTDI	Upper Midwest Transmission Development Initiative
USGS	United States Geological Survey
V	Volt
V2G	Vehicle-to-Grid
VAR	Volt-Ampere Reactive
VER	Variable Energy Resource
VFD	Variable Frequency Drives
VOST	Value of Solar Tariff
W_{DC}	Dollars per Watt
WECC	Western Electric Coordination Council
WHP	Waste Heat to Power
WREZ	Western Renewable Energy Zone
ZNE	Zero Net Energy

Executive Summary

On June 25, 2013, President Obama announced a Climate Action Plan to (1) reduce US greenhouse gas (GHG) emissions; (2) adapt to the impacts of global warming; and (3) participate in international efforts to address global warming. The Climate Action Plan commits to reducing US GHG emissions to 17 percent below 2005 levels by 2020. Reducing carbon dioxide (CO_2) emissions from new and existing power plants is key to achieving that commitment, and a Presidential Memorandum released with the Climate Action Plan directed the US Environmental Protection Agency (EPA) to do so.

The EPA proposed CO_2 emissions standards for existing power plants on June 2, 2014 under Section 111(d) of the Clean Air Act. The final rule is expected in the summer of 2015. States will be expected to develop implementation plans consistent with the federal rule as early as June 2016. Consistent with the Clean Air Act Section 111, the proposed standards reflect the degree of emissions limitation achievable through the "best system of emission reduction" (BSER) that the EPA determined has been adequately demonstrated for fossil fuel-fired electric generating units (EGUs).

The EPA proposed emissions rate standards, or targets, for each state based on a BSER determination comprised of four *building blocks:* onsite heat rate improvements, redispatch to natural gas, renewable and nuclear energy, and energy efficiency. It is important to note, however, that states will not be limited in selecting compliance options to reduce emissions only from these building blocks. Rather, a state can choose any combination of measures in the building blocks, as well as other options that reduce CO_2 emissions, to achieve compliance with the emissions rate standards.

This report begins with 25 detailed chapters, each of which explores various approaches to GHG reduction in the electric sector. The *Menu of Options* looks first at proven *technologies* for reducing emissions, and then at various *policies* that have been demonstrated to promote or facilitate emissions reductions.

Each chapter starts with a profile, that is, a short description of the pros and cons of the approach. Next, a description of the regulatory backdrop, policy underpinnings, implementation experience, and GHG reduction potential associated with the approach are discussed. Each chapter then looks at co-benefits of the approach, including benefits to society and the utility system. Costs and cost-effectiveness are also explored. Finally, in Chapter 26, the *Menu of Options* more briefly explores a variety of emerging technologies and other important policies that regulators may wish to consider as they formulate plans to reduce power sector GHG emissions.

An overview of the 26 chapters is presented below.

Chapter 1 — Optimize Power Plant Operations

Boiler optimization and improved thermal efficiency are standard procedures that have been used for many decades. The recent development and maturity of artificial intelligence and neural networks to automatically adjust key variables and parameters de-emphasize the role of human intervention and help to ensure optimal boiler performance. Chapter 1 explores techniques to permit a plant to improve thermal efficiencies by up to four to seven percent, reducing coal combustion and GHG emissions by an equivalent quantity.

Chapter 2 — Implement Combined Heat and Power in the Electric Sector

One strategy for reducing CO_2 emissions from electric generating units is to capture their waste heat as a secondary output to serve other purposes, typically central heating and cooling or industrial processes in neighboring facilities. Combined heat and power, also known as CHP or cogeneration, is the term used to describe this variety of technology configurations that sequentially generates both electric and useful thermal output from a single fuel source. CHP provides a cost-effective, commercially available solution for near-term reductions in GHG emissions, with large technical potential distributed across the country. CHP results in direct energy savings to the user and offers a host of wider societal benefits, including reductions in air pollution, enhanced grid reliability, low-cost capacity additions, and improved resiliency of critical infrastructure. Chapter 2 focuses on CHP at central station EGUs as a means of reducing the carbon emissions of the power sector. This chapter also discusses the different types of CHP, how the Clean Power Plan would affect existing CHP and new opportunities, the variety of technologies that CHP can be based on, and examples of CHP projects.

Chapter 3 — Implement Combined Heat and Power in Other Sectors

This chapter discusses how CHP technologies in the commercial, institutional, and manufacturing sectors can reduce CO_2 emissions across the economy through system-wide gains in energy efficiency that improve economic competitiveness. Although CHP can take the form of large capacity power producers that sell bulk electricity to the grid, it can also be installed at facilities with onsite demand for both heating (or cooling) and electricity, like manufacturing facilities, universities, hospitals, and multifamily residential complexes, among others. While CHP is a technologically mature, cost-effective, and near-term strategy for environmental compliance, grid-tied CHP facilities can be complex, site-specific installations that carry significant technical and administrative burdens. Chapter 3 addresses a number of regulatory drivers currently affecting CHP, namely issues in utility and/or air pollution regulation, national and state CHP capacity targets, and grid reliability and resilience. This chapter also provides examples of CHP units that are designed primarily to meet onsite or nearby energy needs, rather than to supply electricity to the grid.

Chapter 4 — Improve Coal Quality

Power plant boilers are designed to accommodate a wide range of types of coal. However, within this range, variations in coal properties can affect performance and efficiency. A boiler designed to burn a high rank bituminous coal is going to perform quite differently if lower rank sub-bituminous coal is introduced, and properties such as high ash or sulfur content can impair not only the thermal performance of the boiler, but also associated systems, including duct work, steam temperature control, bottom and fly ash removal, pulverizers, burners, and combustion controls.

To maintain coal quality within specified ranges and meet boiler performance objectives, coals with different properties can be blended, either by the coal producer or at a power plant. Another option for meeting coal quality specifications is through "beneficiation," the industry's term for any of several processes and treatments that improve coal quality and have the potential to provide economic, energy, and environmental benefits for some units, depending on unit-specific design. Even small reductions in coal consumption on the order of one to two percent, for the same generating output, improve the profit margin of the power plant, extend the life of pollution controls, reduce the quantity of water and solid waste discharged, and reduce GHG, criteria pollutant, and mercury emissions. This chapter discusses different coal types and beneficiation options, examples of different types of beneficiation in practice, and the resulting GHG and environmental impacts of such actions.

Chapter 5 — Optimize Grid Operations

Electricity networks are changing today in ways that fundamentally challenge traditional grid reliability and planning tools. There is a long and growing list of system capabilities that can improve grid reliability, increase efficiency, reduce cost, and enhance operating performance. Each of these opportunities also typically reduces CO_2 emissions as a result of less – or lower-emitting – generation being needed. This is true at both the level of the transmission grid and the distribution system.

"Optimizing grid operations" refers to activities to improve the performance and efficiency of electricity transmission and distribution systems by grid operators. Performance improvements include better and lower-cost levels of grid reliability, more efficient delivery of electricity, reduced system losses, and increased capacity utilization for more efficient use of assets. The list of emerging strategies discussed in this chapter includes innovative applications of conservation voltage reduction, power factor optimization, phase balancing, the strategic use of electrical and thermal storage capabilities, and focused use of demand response capabilities. This chapter provides a brief overview of these strategies, the regulations that affect their implementation, and examples from around the United States.

Chapter 6 — Increase Generation from Low-Emissions Resources

More than two-thirds of the electricity generated in the United States is produced from fossil-fueled generators that emit substantial amounts of CO_2 and other GHGs, as well as many criteria and hazardous air pollutants. However, nearly all of the other technologies used to generate electricity produce far fewer emissions than fossil fuel technologies, or produce no emissions at all, including mature technologies like hydroelectric and nuclear power technologies, and resources like wind and solar. The potential for this wide range of zero- and low-emissions technologies is extremely large.

The GHG reduction benefits of zero-emissions generating resources are obvious and substantial, but will vary in the short-term depending on which higher-emitting resources are displaced (i.e., dispatched less often) owing to the availability of a zero-emissions alternative. The principal challenge associated with increased generation from zero- and low-emissions resources, aside from cost considerations, is likely to be that of integrating inflexible or non-dispatchable resources into the grid and balancing generation with demand on a real-time basis. This chapter analyzes the state of low-emissions resources in the United States and the policies that affect their deployment, and provides an overview of state implementation of these resources.

Chapter 7 — Pursue Carbon Capture and Utilization or Sequestration

Carbon capture and utilization and/or storage refers to a two-pronged approach to reduce CO_2 emissions from fossil fuel-fired EGUs and other CO_2-emitting facilities. At EGUs, CO_2 can be collected before or after combustion of fuel using various approaches. Following capture, the CO_2 can be compressed and transported to an injection site for underground storage, or used for productive purposes.

Carbon capture offers the potential to prevent the emissions of millions of tons of CO_2 into the atmosphere. The extent to which that potential is leveraged will be determined by our ability to overcome the technical and economic hurdles that confront this technology. It remains to be seen whether federal action – including potential regulatory requirements, like New Source Performance Standards for electric power plant GHG emissions and the US Department of Energy's research and development efforts in carbon capture – will spur sufficient interest and investment to make it a commercial technology. This chapter explains the process of carbon capture and storage/utilization in detail, describes the state of projects throughout the United States, and details the regulatory backdrop for this technology.

Chapter 8 — Retire Aging Power Plants

Although retiring aging coal-fired EGUs is becoming more and more prevalent, these decisions remain a sensitive topic. Despite the likely environmental benefits, retiring an aging EGU has the potential to produce significant economic impacts for utility ratepayers, companies, and the community where the unit is located. However, when weighed against various policy alternatives, retiring an aging EGU may be a lower-cost solution to the challenge of emissions reductions and worthy of inclusion in a state's Clean Power Plan compliance strategy.

There are various regulatory contexts in which states can review proposals to close power plants. There are also numerous factors that can affect decisions to keep a plant running or to retire it, including forward-looking market considerations, environmental regulatory requirements, and the ability to recover past plant-related investments. States that consider plant closure as a compliance option will have to consider these issues, as well as the varying degree to which these factors support such a decision. However, states that do engage in this effort will be better prepared to evaluate a wider array of potential compliance options and better able to strike their preferred balance between costs and other policy goals, including the most affordable and reliable compliance scenarios allowable under the EPA's Clean Power Plan. This chapter explores the various decision metrics that affect whether a unit is retired and provides examples of how retirement decisions have been carried out in select jurisdictions.

Chapter 9 — Switch Fuels at Existing Power Plants

An option for reducing CO_2 emissions from EGUs is to switch to a lower-emitting fuel. Fuel switching is perhaps the most familiar and most proven method for reducing GHG emissions from existing EGUs. The technological challenges are familiar and manageable, the co-benefits can be substantial, and the costs are generally lower than for other technology options. This chapter details three distinct strategies to accomplish fuel switching: using a lower-emitting backup fuel and decreasing the use of a higher-emitting primary fuel, blending or co-firing a lower-emitting fuel with a higher-emitting fuel, or repowering the

EGU to accommodate the use of a lower-emitting fuel not previously used.

Fuel switching in its various forms offers a proven emissions reduction strategy that will be feasible to a lesser or greater extent for many covered sources. Literally thousands of EGUs in the United States already have the capability to fire multiple fuels, and many more could be candidates for a repowering project. The primary limitation on this strategy is not technical, but economic. Most EGUs that are not already using low-emitting fuels as a primary energy source are using higher-emitting fuels for economic reasons. Fuel switching could increase the operating costs, and possibly add capital costs, for these sources. However, the underlying economics will change when new mandatory CO_2 emissions limits are in place. Generation owners will then want to reconsider the relative costs of different fuels and determine if fuel switching is their best compliance option.

Chapter 10 — Reduce Losses in the Transmission and Distribution System

Electricity losses occur at each stage of the power distribution process, beginning with the step-up transformers that connect power plants to the transmission system, and ending with the customer wiring beyond the retail meter. These electricity losses are often referred to generically as "line losses," even though the losses associated with the conductor lines themselves represent only one type of electricity loss that occurs during the process of transmitting and distributing electricity. System average line losses are in the range of six to ten percent.

Reducing line losses in the electrical transmission and distribution system is a readily available option to enhance electrical efficiency and reduce generation-related emissions. Advances in technology and understanding have made significant efficiency gains possible through investments in improved grid components and, on the demand side, in load management at peak levels. As with several other options, the primary limitation on this strategy is economic, not technical. It is essential that new system builds take advantage of more efficient components.

Upgrades and/or replacement of the broad electrical distribution infrastructure now in place, however, will remain a significant obstacle. Changes in the electric power industry, declining electrical demand in many areas, and increasingly competitive distributed generation alternatives, may make the financing of new, more efficient grid infrastructure challenging. The advent of mandatory CO_2 emissions reduction requirements will improve the payback of such improvements, but will simultaneously motivate more efficient end-use equipment and clean distributed generation as well. Each component of the distribution system can be optimized to reduce line losses. This chapter discusses each component, and how equipment choices can affect efficiency and, by extension, GHG emissions.

Chapter 11 — Establish Energy Savings Targets for Utilities

"Energy efficiency" is a term used to describe technologies, equipment, operational changes, and in some cases behavioral changes that enable our society to enjoy equal or better levels of energy services while reducing energy consumption. Energy efficiency is a low-cost, low-risk resource that compares favorably to all supply-side alternatives. It is also a proven and effective means of reducing air pollution emissions, increasingly recognized and encouraged by the EPA and state air pollution control agencies. By leveraging several policy mechanisms, chiefly an Energy Efficiency Resource Standard, states can make significant reductions in CO_2 emissions while stimulating job growth and their economies.

This chapter focuses on policies that establish mandatory energy savings targets for electric utilities, the achievement of which is generally funded through revenues collected from customers themselves. Ratepayer-funded energy efficiency programs have expanded significantly over the past decade, yielding significant economic and environmental benefits. Nevertheless, the potential to achieve even greater energy savings exists across the country, perhaps even more so in states that have a shorter history with energy efficiency programs or have historically invested less money in energy efficiency.

Chapter 12 — Foster New Markets for Energy Efficiency

This chapter builds on Chapter 11 by focusing on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency (i.e., technologies, equipment, operational changes, and in some cases behavioral changes that help produce equal or better levels of energy services while reducing energy consumption) as an alternative or supplement to government-mandated programs or regulatory requirements.

Investments in end-use energy efficiency have proven to be a low-cost option for states to achieve carbon reductions, and this option provides the longest and most robust list of co-benefits of all the options described in this document. But despite the fact that energy efficiency provides numerous benefits to utilities, their customers, and society, this option is frequently undervalued and underused.

This chapter discusses encouraging or facilitating the use of energy auditing and energy savings contracts between consumers and third-party energy service companies; improving consumer access to affordable private financing or providing tax incentives for energy efficiency improvements; creating voluntary energy consumption labeling and benchmarking programs for appliances and buildings; and allowing energy efficiency to compete for compensation in wholesale electricity markets.

Chapter 13 — Pursue Behavioral Efficiency Programs

Some energy efficiency programs use information dissemination, social interaction, competition, and/or potential rewards, rather than direct financial incentives, as the primary mechanisms for changing energy consumption behavior. These programs are known as “behavioral energy efficiency programs.” To date, most energy efficiency programs have focused on realizing savings through technical approaches, such as replacements, upgrades, and modifications to equipment and buildings. However, program administrators are increasingly considering behavioral energy efficiency programs for inclusion in their portfolios, and these programs are becoming more mainstream. This chapter discusses in more detail the types, benefits, and limitations of behavioral energy efficiency programs, as well as states’ experiences in addressing barriers to implementing them.

Chapter 14 — Boost Appliance Efficiency Standards

Appliance standards set minimum energy and water efficiency requirements for selected appliances and equipment — where cost-effective — and prohibit the production, import, or sale of appliances and equipment that do not meet those requirements. Although states cannot set efficiency standards for federally regulated products, they can and do adopt standards for products not covered by federal standards. Appliance standards have been one of the most cost-effective policies to generate significant energy and emissions reductions in the United States and could be an effective policy option to reduce CO_2 at the lowest possible cost. This chapter discusses in more detail the benefits to be gained from appliance standards, as well as states’ experiences in addressing political and other barriers to implementation.

Chapter 15 — Boost Building Energy Codes

Approximately half of US energy use is in buildings, and much of this is consumed in the heating, cooling, and lighting of those buildings, all of which are addressed by building energy codes. Building codes establish mandatory requirements for the building shell, mechanical equipment, and lighting systems, which can have a very significant impact on building energy use and associated carbon emissions.

Building codes establish minimum efficiency requirements for new and renovated residential and commercial buildings. They lock in future energy savings during the building design and construction phase, rather than through later, more expensive renovations. Building codes also capture energy savings that are more cost-effective than the more limited retrofit opportunities that are available after a building has been constructed. Up-to-date energy efficiency codes can reduce building energy use dramatically; the most recent national code would reduce usage by about 30 percent below conventional building standards. Innovative “Zero Net Energy” codes can reduce net building use to zero. This chapter analyzes different types of building codes and other mandatory building efficiency policies and provides examples of programs and codes that cities and states have enacted.

Chapter 16 — Increase Clean Energy Procurement Requirements

Increasing the proportion of zero- and low-emissions resources in the electricity supply portfolio is one of the most promising ways to reduce carbon emissions from the levels currently produced by a fossil-fuel-heavy portfolio. Although energy efficiency provides the most cost-effective path with the longest list of co-benefits for meeting energy portfolio requirements, the technical potential for renewable technologies is considerable, especially for wind and solar, exceeding existing electric demand by orders of magnitude.

Procurement policies for electric utilities and competitive retail suppliers to acquire clean energy have been found to be very successful in accelerating deployment of clean energy technologies on a large “utility” scale. The last decade has been marked by the widespread introduction and expansion of renewable and clean energy procurement requirements, in particular Renewable Portfolio Standard policies, which now exist in a majority of states.

In most cases, regulated entities have shown a willingness and ability to comply with procurement requirements, and evidence suggests that where policies have caused retail electricity rates to increase these increases have been less than two percent. Program costs are generally driven by three factors: (1) the availability of clean resources; (2) the targets themselves; and (3) the availability of cost-mitigation strategies, such as an alternate compliance payment framework. This chapter explores a variety of policies that can be adopted to increase clean energy procurement. Also featured in this chapter are various regulatory frameworks that can be used as a complement to procurement frameworks to help reduce barriers to participation by independent power producers.

Chapter 17 — Encourage Clean Distributed Generation

"Distributed generation" (DG) is a widely used term that has been defined and interpreted in different ways across federal, state, and local jurisdictions. For the purposes of this document, clean DG refers to generating facilities with a rated capacity of 20 megawatts or less that are interconnected to the distribution system. This is intended to encompass all DG technologies that contribute to reducing GHG emissions in the power sector, such as solar photovoltaics, wind, biomass, anaerobic digestion, geothermal, fuel cell, and efficient combined heat and power technologies.

Because clean DG can displace the need for some fossil fuel-based, central station generation, it can be a viable option for complying with the Clean Power Plan. Most forms of DG also reduce emissions of other air pollutants. The benefits of clean DG are amplified to some extent by the fact that it avoids most or all of the transmission and distribution line losses that are associated with central station generation. DG systems can also be deployed in much smaller increments than utility-scale, central station generation, which reduces the risk and expense of developing more capacity than utility customers need.

Clean DG technologies are cost-competitive in some states today and are becoming increasingly competitive as technology costs decline, technology performance improves, grid modernization better allows the potential value of local DG to be captured, and state policies toward DG evolve. This chapter discusses how improvements in interconnection policies, effective tax and incentive policies, state policies preferring clean energy sources, such as Renewable Portfolio Standard policies, and the terms and conditions of tariffs and contracts can each contribute to increasing the deployment of clean distributed generation.

Chapter 18 — Revise Transmission Planning and Cost Allocation

Transmission lines are an essential component of the modern electric grid, but one that is perhaps little understood by many regulators as the lines themselves do not emit air pollution. Although transmission lines do not directly reduce GHG emissions, they enable many reliable and cost-effective choices that can reduce GHG emissions. Some of the low-emissions generation technologies, like wind, solar, and geothermal technologies, are already cost-effective (compared to fossil fuel generation technologies) when sited in optimal locations. However, if those optimal locations are far from load centers, transmission is a necessary complement to developing these resources. In some cases, the best sites for these technologies simply cannot be developed at all unless new transmission lines are built. And in other cases, improvements to the transmission system are necessary (or will be) to enable grid operators to integrate greater amounts of variable energy resources while maintaining system reliability.

Transmission planning processes can identify the best options for tapping the potential of low-emitting electric generation resources, while maintaining reliability and containing costs. Some transmission options that facilitate GHG emissions reductions will make economic sense, even if those reductions are not needed or are considered to have no value. But other options may only be considered cost-effective when the value of GHG emissions reductions is considered along with all other relevant costs and benefits. Good planning processes will not only consider all of the costs and benefits of transmission, including GHG benefits, they will also allocate costs fairly to all beneficiaries. In addition, they will identify the potential to meet customer demand through non-transmission alternatives, such as energy efficiency, which also reduce GHG emissions and are more cost-effective. This chapter discusses the issues and challenges affecting transmission planning and cost allocation, regulatory rules affecting these issues, and how states have addressed these issues.

Chapter 19 — Revise Capacity Market Practices and Policies

In some parts of the United States, "capacity markets" have been established as a mechanism for promoting competition in the electric power sector while ensuring reliable electric service. This chapter explains what capacity markets are, where they have been instituted, and – most importantly – how capacity market rules can have an impact on GHG emissions.

It is important to understand that the existence of a capacity market does not, by itself, imply reduced GHG emissions, and establishing a capacity market is not necessarily a policy tool for reducing emissions. However, where capacity markets exist, the specific practices and policies (i.e., market rules) can and do affect GHG emissions, so it is legitimate to consider capacity market rule reforms as a tool for supporting and enhancing other GHG emissions reduction strategies. This chapter identifies some capacity market rules that support emissions reductions and should be emulated, as well as some market rules that can inhibit emissions reductions and should be changed.

Chapter 20 — Improve Integration of Renewables Into the Grid

The universal availability of reliable, affordable electric service is considered to be a high priority throughout the United States because of the central role that electricity plays in public health, social welfare, and economic productivity. This chapter focuses on a suite of policies and mechanisms that can help ensure continued electric system reliability as the electric system changes to include a higher penetration of variable energy resources, particularly wind and solar EGUs.

These policies and mechanisms do not reduce GHG emissions in and of themselves, but they are necessary complements to many GHG-reducing actions because they enable the electric system to continue to function reliably with a portfolio of much lower GHG-emitting generation resources.

Chapter 21 — Change the Dispatch Order of Power Plants

One option for reducing CO_2 emissions in the power sector is to change the order in which power plants are dispatched, so lower-emitting power plants operate more frequently and higher-emitting power plants operate less frequently. A number of different policies can accomplish this goal. Some jurisdictions have adopted emissions pricing policies to reduce CO_2 emissions. These policies include emissions taxes or, more commonly in the United States, emissions trading programs that directly or indirectly place a price on emissions. An alternative to emissions pricing that also shifts the dispatch order toward lower-emitting EGUs is "environmental dispatch." Environmental dispatch is a policy in which the system operator explicitly considers environmental criteria (primarily air pollution emissions) when making dispatch decisions, even if the environmental impacts do not lead to an actual regulatory compliance cost. These policies, implementation experiences, and associated GHG reductions are discussed in detail in this chapter.

Chapter 22 — Improve Utility Resource Planning Practices

This chapter focuses on the potential for utility resource planning processes to support the efforts of states to reduce GHG emissions from the electric power sector. At the heart of this discussion is a particular type of planning process, called integrated resource planning. This particular process, as well as any plan produced by the process, is commonly referred to by the acronym IRP. An IRP is a long-range utility plan for meeting the forecasted energy demand within a defined geographic area through a combination of supply-side resources (i.e., those controlled by the utility) and demand-side resources (i.e., those controlled by utility customers). Generally speaking, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system. This chapter explores IRP policies and the process to implement them, as well as implementation scenarios from around the United States.

Chapter 23 — Improve Demand Response Policies and Programs

Demand response (DR) refers to the intentional modification of electricity usage by end-use customers during periods of system stress, system imbalance, or in response to market prices. DR policies and programs were initially developed to help support electric system reliability by reducing load during peak hours. More recently, technical innovations have made it possible to expand DR capabilities to provide an array of ancillary reliability services. DR is also capable of promoting overall economic efficiency, particularly in regions that have wholesale electricity markets. DR programs can mitigate the cost impacts of GHG reduction efforts to make them more acceptable to consumers and policymakers. In addition, under certain circumstances, DR programs can reduce net emissions of GHGs and other air pollutants from existing sources. Finally, and perhaps even more importantly, DR programs can facilitate the use of various emissions reductions strategies, such as the integration of renewable energy into the grid, while ensuring reliable electric service. This chapter reviews the many forms of DR and the scale of energy savings and emissions reductions it can produce.

Chapter 24 — Adopt Market-Based Emissions Reduction Programs

One of the ways to reduce GHG emissions is to effectively place a price on emissions, and then rely on market forces that incentivize and reward innovation, competition, and customized solutions to reducing costs. A price can be directly imposed through a tax (as discussed in Chapter 25), or indirectly imposed through a market-based program, such as those described in this chapter. The most familiar market-based program is the cap-and-trade system. Cap-and-trade systems have been successfully used for two decades to control air pollution from electric power plants in the United States. These systems can be simple, transparent, and relatively straightforward to implement. This chapter explains market-based emissions reduction programs types, describes programs that have been implemented worldwide, and provides examples of successful programs in the United States.

Chapter 25 — Tax Carbon Dioxide Emissions

Pricing mechanisms can be an important element in any effort to reduce electric-sector GHG emissions. Pricing will be most effective when combined with related policies to encourage the use of other, less carbon-intensive resources. Policies that provide a real or implicit price of carbon internalize the cost of carbon emissions and can make renewables or other low-carbon resources more cost-competitive with other energy sources. This in turn creates incentives for producers and consumers to invest in low-GHG products, technologies, and processes. Policies that provide a carbon price can also serve as a source of revenue for funding low-carbon technologies and programs. This chapter explores different types of carbon taxes, and provides examples of how they have been implemented worldwide.

Chapter 26 — Consider Emerging Technologies and Other Important Policies

The 25 previous chapters offer a wide array of options to reduce GHG emissions from the electric power sector through existing technology-based and policy-oriented solutions. The electric sector is undergoing dramatic change, however, morphing from a one-direction analog system with centralized EGUs providing electricity to end-users through radial transmission and distribution networks, where supply is managed to meet demand, into a digital, distributed network system, where both supply and demand are managed through two-way communications and smart devices. These changes will profoundly alter the electric power system. Although the outcomes of these changes are not possible to fully predict, there are nonetheless technology and policy trends and developments that are increasingly evident. Some may not achieve significant penetration in the existing electric power system for a decade or more, but others are already becoming widely commercialized. It is important to consider these developments in air quality planning processes. This chapter provides a brief introduction to several of these emerging technology and policy considerations, including electricity storage, smart grid, electric vehicles, device-to-device communications (often called the "internet of things"), the water-energy nexus, reliability, rate design and pricing, new utility business models, carbon offsets, and multi-pollutant planning.

Introduction

About NACAA

The National Association of Clean Air Agencies (NACAA) is a national, nonpartisan, nonprofit association of air pollution control agencies in 41 states, the District of Columbia, four territories, and 116 metropolitan areas. NACAA seeks to encourage the exchange of information, to enhance communication and cooperation among federal, state, and local regulatory agencies, and to promote good management of our air resources. NACAA has prepared this *Menu of Options* to assist state and local air pollution control officials in developing strategies for reducing greenhouse gas (GHG) emissions, particularly carbon dioxide (CO_2) emissions, from the power sector in order to comply with the US Environmental Protection Agency's (EPA) Clean Power Plan (CPP).

The Clean Power Plan

On June 25, 2013, President Obama announced his Climate Action Plan, a multipronged approach to address global warming by reducing US GHG emissions, adapting to the effects of global warming, and participating in international efforts to address global warming.[1] The Climate Action Plan reflects a commitment to reduce GHG emissions to 30 percent below 2005 levels by 2030. Central to achieving that target is an Administration proposal to reduce CO_2 emissions from new and existing power plants, and in a Presidential Memorandum released alongside the Action Plan, the President directed the EPA to undertake rulemaking to do so.[2]

On June 2, 2014, the EPA proposed CO_2 emissions standards for existing power plants using its authority under Section 111(d) of the Clean Air Act (CAA). The agency expects to issue a final rule during the summer of 2015. States will be expected to develop implementation plans consistent with the federal rule as early as June 2016. Consistent with the requirements of CAA Section 111, the proposed standards are intended to reflect the degree of CO_2 emissions limitation achievable through the application of the "best system of emission reduction" (BSER) that the EPA has determined has been adequately demonstrated for existing fossil fuel-fired units, taking into account the cost of achieving such reduction and any non-air-quality health and environmental impacts and energy requirements.[3]

The EPA maintains that the CPP as proposed would continue progress already underway to reduce CO_2 emissions from the electric power sector in the United States, including promoting greater reliance on renewable energy sources, modernizing the US electric grid, increasing investments in technologies that reduce the GHG impacts of fossil fuels, and conducting a periodic strategic energy policy planning process.[4]

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1 The President's Climate Action Plan is available at: https://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf. Additional information about President Obama's climate change actions is available at: https://www.whitehouse.gov/climate-change.

2 The President's Memorandum to the EPA, *Presidential Memorandum – Power Sector Carbon Pollution Standards,* is available at: https://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

3 US Environmental Protection Agency. (2014, June 18). *40 CFR Part 60. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule*. Federal Register Vol. 79, No. 117, p 34834. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

4 The Obama Administration has also proposed a $1 billion climate resilience fund to mitigate the effects of climate change through research and community adaptation projects. In addition, the EPA has already adopted several regulations to reduce GHG emissions, including regulations to limit GHG emissions from motor vehicles, mandatory GHG reporting requirements, and GHG permitting regulations.

The Challenge

In 2009, the EPA Administrator issued an Endangerment Finding under CAA Section 202(a)(1).[5] In the Endangerment Finding, which focused on public health and public welfare impacts within the United States, the Administrator found that elevated concentrations of GHGs in the atmosphere could reasonably be anticipated to endanger public health and welfare.

The EPA determined that climate change caused by human emissions of GHGs threatens public health in multiple ways. It can be expected to raise average temperatures, increasing the likelihood of heat waves, which are associated with increased deaths and illnesses. The EPA also found that climate change can be expected to increase ozone pollution over broad areas of the United States, including in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk for morbidity and mortality. In addition, the EPA concluded that, because of projected increases in the intensity or frequency of extreme weather associated with climate change, public health will be threatened from the effects of increased hurricane intensity, increased frequency of intense storms, and heavy precipitation.

The Power Sector

Fossil fuel-fired electric generating units (EGUs) are the largest emitters of GHGs, primarily in the form of CO_2, among stationary sources in the United States. Among fossil fuel-fired units, coal-fired units are by far the largest emitters. The EPA prepares the official *US Inventory of Greenhouse Gas Emissions and Sinks* to comply with commitments under the United Nations Framework Convention on Climate Change.[6] The inventory is organized by industrial sectors and contains information on total US anthropogenic GHG emissions, including CO_2 emissions, for the years 1990, 2005, and 2012. Total fossil energy-related CO_2 emissions (including both stationary and mobile sources) are the largest contributor to total US GHG emissions, representing 77.7 percent of total 2012 GHG emissions. In 2012, fossil fuel combustion by the electric power sector (entities that burn fossil fuel and whose primary business is the generation of electricity) accounted for 38.7 percent of all energy-related CO_2 emissions.

Electricity in the United States is produced by an assortment of generation types – from power plants that use fossil fuels like coal, oil, and natural gas, to non-fossil sources, such as nuclear, solar, wind, and hydroelectric power. In 2013, more than 67 percent of electric power in the United States was generated from the combustion of coal (40 percent), natural gas (26 percent), and other fossil fuels (1 percent).[7] More recently, the amount of renewable generation being used has increased significantly. For example, approximately 38 percent of new generating capacity built in 2013 (more than 5 GW out of 13.5 GW) relied on renewable generation technologies.[8]

Reducing Power Sector CO_2 Emissions

To determine the BSER for reducing CO_2 emissions at affected EGUs, the EPA considered numerous measures that are either already being implemented or could be implemented more broadly to improve emissions rates and to reduce overall CO_2 emissions from fossil fuel-fired EGUs. The EPA defined BSER based on a range of measures that fall into four main categories, or "building blocks":[9]

1. Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements;
2. Reducing emissions from the most carbon-intensive affected EGUs in the amount that results from substituting generation at those EGUs with generation from less carbon-intensive affected EGUs (including

5 Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act. 74 FR 66496. (2009, December 15). (Endangerment Finding).

6 US Environmental Protection Agency. (2014, April 15). *Inventory of US Greenhouse Gas Emissions and Sinks: 1990 – 2012.* Report EPA 430-R-14-003. Available at: http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Main-Text.pdf

7 US Energy Information Administration. (2014, April 25). *Table 7.2b Electricity Net Generation: Electric Power Sector.* Data from April 2014 Monthly Energy Review. Available at: http://www.eia.gov/totalenergy/data/browser/xls.cfm?tbl=T07.02B&freq=m

8 Based on Table 6.3 (New Utility Scale Generating Units by Operating Company, Plant, Month, and Year) of the US Energy Information Administration's Electric Power Monthly, data for December 2013, for the following renewable energy sources: solar, wind, hydro, geothermal, landfill gas, and biomass. Available at: http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_03

9 Supra footnote 3 at p. 34835.

natural gas-fired combined-cycle units under construction);

3. Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation.
4. Reducing emissions from affected EGUs in the amount that results from the use of demand-side energy efficiency that reduces the amount of generation required.

The EPA developed proposed Section 111(d) emissions rate standards for each state by applying the BSER to the specific circumstances in the power sector of each state. However, the proposed Section 111(d) rule reinforces the important fact that states would not be required to use the BSER building blocks to reduce emissions, but could instead use any combination of those building blocks and other options that reduce CO_2 emissions to achieve compliance with the emissions rate standards.

The *Menu of Options*

This report contains 26 detailed chapters, 25 of which explore various approaches to reducing GHG emissions in the electric sector. The *Menu of Options* looks first at proven *technologies* for reducing emissions, and then at various *policies* that have been demonstrated to promote or facilitate emissions reductions.

Each chapter starts with a profile, that is, a short description of the pros and cons of the approach. Next, a description of the regulatory backdrop, the policy underpinnings, implementation experience, and GHG reduction potential associated with the approach are discussed. Each chapter then examines the co-benefits of the approach, including benefits to society and the utility system, and explores the costs and cost-effectiveness of the option. Finally, in the twenty-sixth chapter, the *Menu of Options* addresses a variety of emerging technologies and other important policies that regulators may wish to consider as they formulate plans to reduce power sector GHG emissions. Table Intro-1 lists the technologies and policies addressed in the *Menu of Options*.

Although the focus of this *Menu of Options* primarily concerns federal efforts to reduce GHG emissions from the power sector, specifically the EPA's proposed CPP, many states and localities have already adopted plans or requirements for such reductions. Some may also choose to require greater reductions in GHG emissions than required by the CPP. These jurisdictions may also find the technology and policy options described in this Menu to be valuable in their consideration or implementation of state and local GHG reduction programs or goals.

In addition, while the *Menu of Options* principally targets technologies and policies to reduce GHG emissions, many of the options described – particularly those that enhance the efficiency of generation, transmission, distribution, or use of electricity – can be expected to reduce other, non-GHG pollutants as well, including key criteria pollutants regulated under Section 110 of the CAA. The CAA mandates that the EPA periodically review National Ambient Air Quality Standards and revise them, if warranted. It may therefore be in the best interest of regulators to consider GHG and other air quality goals in a more integrated fashion than has historically been the case, in order to identify and implement options that can provide broad emissions reduction benefits and reduce overall costs.[10]

10 For one example of how such integrated planning might be conducted, see: James, C., & Colburn, K. (2013, March). *Integrated, Multi-Pollutant Planning for Energy and Air Quality (IMPEAQ)*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6440

Table Intro-1

The Menu of Options		
Chapter Number	**Title**	**Description**
1	**Optimize Power Plant Operations**	Explores techniques to permit a plant to improve thermal efficiencies by up to four to seven percent, reducing coal combustion and GHG emissions by an equivalent quantity
2	**Implement Combined Heat and Power in the Electric Sector**	Focuses on combined heat and power at central electric generating units as a means of reducing the carbon emissions of the power sector
3	**Implement Combined Heat and Power in Other Sectors**	Discusses how combined heat and power technologies in the commercial, institutional, and manufacturing sectors can reduce CO_2 emissions across the economy through system-wide gains in energy efficiency that improve economic competitiveness
4	**Improve Coal Quality**	Discusses different coal types and beneficiation options, examples of different types of beneficiation in practice, and the resulting GHG and environmental impacts of such actions
5	**Optimize Grid Operations**	Discusses activities to improve the performance and efficiency of electricity transmission and distribution systems by grid operators
6	**Increase Generation from Low-Emission Resources**	Analyzes the state of low-emissions resources in the United States and the policies that affect their deployment, and provides an overview of state implementation of these resources
7	**Pursue Carbon Capture and Utilization or Sequestration**	Describes the process of carbon capture and storage/utilization, updates the state of projects throughout the United States, and details the regulatory backdrop for this technology
8	**Retire Aging Power Plants**	Explores the various decision metrics that affect whether a unit is retired and provides examples of how retirement decisions have been carried out in select jurisdictions.
9	**Switch Fuels at Existing Power Plants**	Explores fuel switching as an emissions reduction option, and outlines three strategies to accomplish fuel switching
10	**Reduce Losses in the Transmission and Distribution System**	Discusses how each component of the distribution system can be optimized, and how equipment choices can affect efficiency, and by extension, GHG emissions
11	**Establish Energy Savings Targets for Utilities**	Focuses on policies that establish mandatory energy savings targets for electric utilities
12	**Foster New Markets for Energy Efficiency**	Focuses on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency
13	**Pursue Behavioral Efficiency Programs**	Discusses the types, benefits, and limitations of behavioral energy efficiency programs, as well as states' experiences in addressing barriers to implementing them

Chapter Number	Title	Description
14	**Boost Appliance Efficiency Standards**	Discusses the benefits from appliance standards, as well as states' experiences in addressing political and other barriers to implementation
15	**Boost Building Energy Codes**	Analyzes different types of building codes and other mandatory building efficiency policies, and provides examples of programs and codes that cities and states have enacted
16	**Increase Clean Energy Procurement Requirements**	Explores a variety of policies that can be adopted to increase clean energy procurement
17	**Encourage Clean Distributed Generation**	Discusses how improvements in interconnection policies, effective tax and incentive policies, state policies preferring clean energy sources such as Renewable Portfolio Standards policies, and the terms and conditions of tariffs and contracts can each contribute to increasing the deployment of clean distributed generation
18	**Revise Transmission Planning and Cost Allocation**	Discusses the issues and challenges affecting transmission planning and pricing, regulatory rules affecting these issues, and how states have addressed these issues
19	**Revise Capacity Market Practices and Policies**	Identifies capacity market rules that support emissions reductions and should be emulated, as well as market rules that can inhibit emissions reductions and should be changed
20	**Improve Integration of Renewables Into the Grid**	Focuses on a suite of policies and mechanisms that can help to ensure continued electric system reliability as the electric system changes to include a higher penetration of variable energy resources, particularly wind and solar electric generating units
21	**Change the Dispatch Order of Power Plants**	Discusses various policies to influence dispatch order, implementation experiences, and associated GHG reductions
22	**Improve Utility Resource Planning Practices**	Explores utility planning policies and the process to implement them, as well as implementation scenarios from around the United States
23	**Improve Demand Response Policies and Programs**	Reviews the many forms of demand response and the scale of energy savings and emissions reductions it can produce
24	**Adopt Market-Based Emissions Reduction Programs**	Explains market-based emissions reduction programs, describes programs that have been implemented worldwide, and provides examples of successful programs in the United States
25	**Tax Carbon Dioxide Emissions**	Explores different types of carbon taxes and gives examples of how they have been implemented worldwide
26	**Consider Emerging Technologies and Other Important Policies**	Provides a brief introduction to several emerging technology and policy considerations

1. Optimize Power Plant Operations

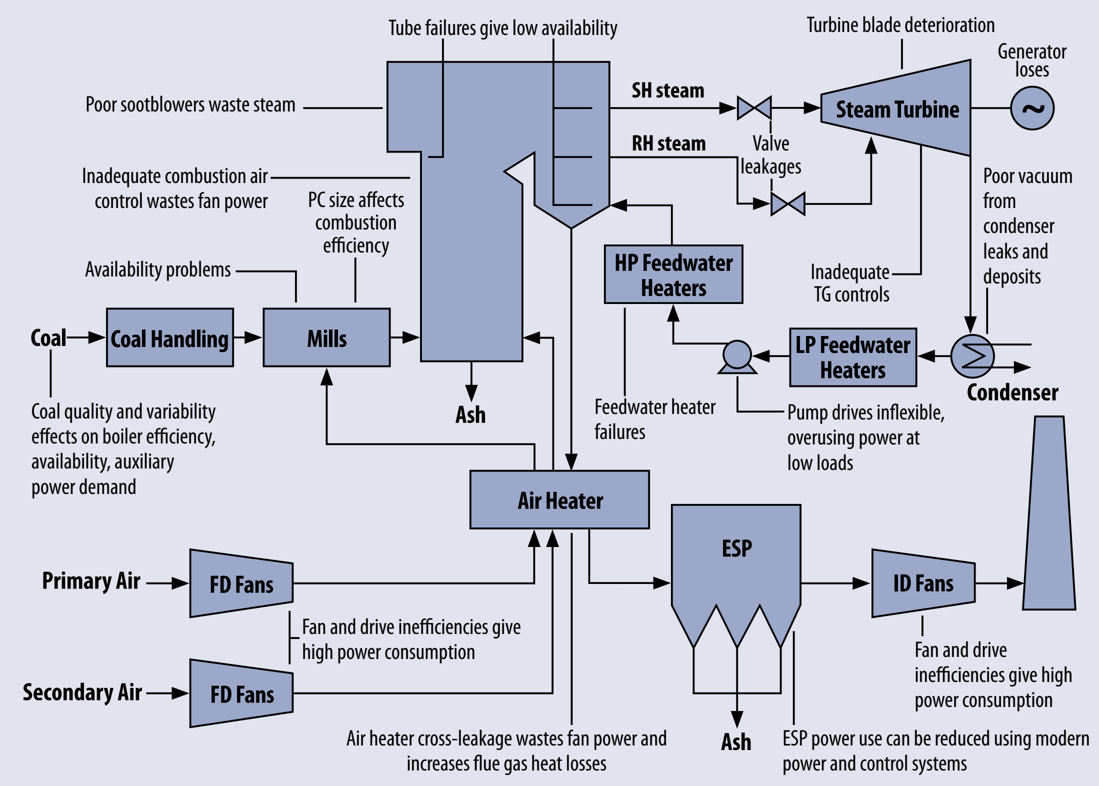
1. Profile

The average thermal efficiency of a coal-fired power plant in the United States across all classes of fuel is approximately 32 percent. This level has not changed in many years, as few new coal-fired power plants have been constructed in the last decade.[1] Figure 1-1 illustrates the various components of a power plant and factors that affect its thermal efficiency.

Operating experience reflects that the thermal efficiency of a power plant declines with use. Much of the efficiency degradation can be recovered during maintenance outages such that, over time, a unit's efficiency plotted versus time will have a sawtooth pattern. The level of maintenance undertaken will dictate the amount of efficiency loss that is recovered during each outage but, after a unit is 30 years old, even well-maintained equipment suffers from persistent degradation. Another contributing factor to the loss of efficiency over time is that older units are more likely to operate in a load-following mode, rather than a baseload mode, as newer units take their place

Figure 1-1

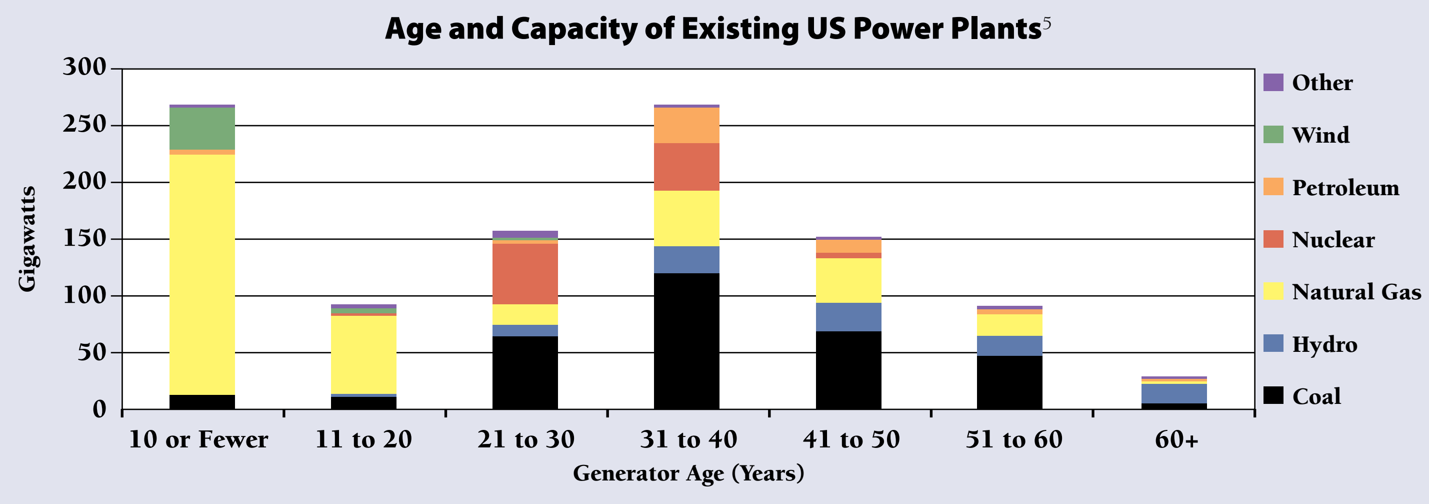
Areas of a Coal-Fired Power Plant That Give Rise to Efficiency Loss[2]



1 New coal-fired plants would not necessarily be more efficient than older coal-fired units. New units would be more likely to have high levels of emissions controls that increase the auxiliary load of the unit and reduce net output. New units may also have more restrictions on cooling water resulting in higher condenser pressure, and may be designed to operate flexibly rather than maximizing efficiency for one specific mode of operation. All of these factors would tend to have a negative impact on a unit's thermal efficiency.

2 Henderson, C. (2013, August). *Upgrading and Efficiency Improvement in Coal-Fired Power Plants*. International Energy Agency (IEA) Clean Coal Centre, CCC-221, ISBN 978-92-9029-541-9. Copies can be downloaded for free by member countries at: http://bookshop.iea-coal.org/publishor/system/component_viewbymedia.asp?logdocid=83186&MediaId=2. Registration required first.

Figure 1-2



in the dispatch order.[3] The increase in cycling that comes from following load can have a significant impact on overall operating efficiency. The thermal efficiency of an older plant can thus be significantly lower than that which existed at the time it commenced operation.[4] The average age of the US coal fleet is over 30 years, with up to one-third of the units over 50 years old in some regions. Figure 1-2 shows the ages of US fossil-fuel generation by ten-year increments, reflecting that approximately 500 gigawatts (GW) of total generation are produced by power plants that are 31 years old or older.

Using actual data from existing coal-fired power plants, the top ten percent of units have a thermal efficiency of 37.6 percent. This level is more than five percentage points higher than the average efficiency, and imputes a fuel consumption rate that is 15 percent lower than the average.[6] Table 1-1 breaks out unit level thermal efficiency by equal-weighted capacity deciles.[7] The table reflects that units with lower thermal efficiency have lower capacity factors, meaning that they operate for fewer hours in a given year, and that inefficient units are also smaller. Nearly 200 units comprise the least thermally efficient decile, whereas 53 units comprise the most thermally efficient decile. This profile suggests two key points: (1) inefficient units burn more fuel per megawatt hour (MWh) of generation and have higher fuel costs relative to other

3 "Baseload" generating units operate at fairly constant output levels near their maximum rated capacity, except when they are down for maintenance. These units tend to be the ones that are most thermally efficient or that have low operating costs for other reasons. "Load-following" generating units cycle their output levels up or down in response to a "dispatch" signal from a system operator, as needed to match total system-wide generation to the varying system-wide demand for electricity. Load-following units usually have higher operating costs than baseload units because they are less thermally efficient or for other reasons.

4 Boiler design is critical to the efficient operation of a power plant. Boiler design life is predicated on adherence to good fluid dynamics and heat transfer principles. Layout of the plant's ductwork and piping aims to minimize turns and bends and have large diameter ducts to minimize pressure drops, to maximize the thermal efficiency of the plant, and to avoid extra energy demand just to move flue gases from one point to another. Critical to this are well-mixed flue gases, which depend on adequate retention time in the combustion chamber to complete chemical reactions, achieve maximum heat transfer, and minimize the formation of air pollutants. Well-mixed flue gases also ensure that duct velocities are uniform from top to bottom and side-to-side. Doing so helps to assure that flue gas temperatures are as uniform as possible. Flue gas hot spots can cause duct deformation, and flue gas cold spots can cause corrosion if the temperatures drop below the acid dew point.

5 US Energy Information Administration (EIA). (2011, June 16). *Today in Energy.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

6 US Department of Energy (DOE). (2008, July). *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet*. National Energy Technology Laboratory (NETL), DOE/NETL-2008/1329. This report is no longer available online.

7 A decile is any one of nine numbers that divide a frequency distribution into 10 classes such that each contains the same number of individuals; also: any one of these 10 classes.

Table 1-1

Generation-Weighted Thermal Efficiency[9]

Decile	Number of Units	Capacity (GW)	Capacity Factor	2008 Total Generation (Billion kWh)[10]	2008 Generation-Weighted Efficiency (HHV)[11]
1	194	30.5	62%	165	27.6%
2	102	30.3	67%	179	29.9%
3	88	30.7	65%	176	30.8%
4	86	30.6	69%	185	31.6%
5	75	30.7	70%	189	32.2%
6	83	30.8	66%	178	32.9%
7	71	31.0	68%	186	33.8%
8	79	30.6	68%	183	34.7%
9	61	30.8	67%	181	35.7%
10	53	30.7	74%	201	37.6%
OVERALL	**892**	**307**	**69%**	**1823**	**32.5%**

units, and (2) less thermally efficient units operate more as peaking or cycling units.[8]

Onsite improvements to the power plant boiler and associated equipment can apply mature technologies and operating practices to reduce greenhouse gas (GHG) emissions by four to seven percent, on average. Older plants built between the 1950s and the 1970s have the greatest potential for improvement. Applications of these technologies also reduce fuel consumption, improve plant profitability, and reduce criteria pollutant emissions. Innovative new options have also been demonstrated that add onsite renewable generation to a coal-fired power plant site, further reducing GHG emissions by directly offsetting generation at the plant site or by using the renewable generation to help recover heat losses from the cooling system or flue gas.

The potential improvement that can be achieved by any given coal-fired generating unit will depend on at least three factors. First, some of the technologies and processes that improve thermal efficiency may be less feasible or effective owing to the design or operational requirements of the unit. For example, some of the possible improvements in steam turbine design will be less durable for units that operate with frequent start and stop cycles. Second, some units will have already implemented some of the available options and will have less room for improvement than an average unit. And third, the *capital* costs of improvement projects can be hard to recover through reduced *operating* costs for units that operate less frequently than an average unit. Nevertheless, there are many options to be considered.

This chapter explores a variety of boiler optimization technologies and processes, including those that:

- Optimize the combustion of coal;
- Recover waste heat from cooling systems;
- Recover waste heat from flue gases;

8 Very efficient units (e.g., supercritical units) require higher capital investments to build than less efficient units (e.g., subcritical units). The higher capital costs can be justified if the unit is expected to operate at a high capacity factor, whereas less efficient, less expensive designs make more sense when a unit is expected to operate at a lower capacity factor.

9 US DOE. (2010, February). *Technical Workshop Report: Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States.* National Energy Technology Laboratory. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf.

10 One thousand kilowatt hours (kWh) is equal to one megawatt hour (MWh).

11 Higher Heating Value (HHV) is one of two common ways to express the amount of heat released when a given amount of fuel is combusted. This column shows the efficiency based on HHV values.

- Optimize soot blower operation;
- Improve turbine design;
- Use turbine inlet cooling (TIC) technologies for natural gas-fired power plants;
- Supplement coal-fired generation with onsite renewable generation; and
- Reduce auxiliary power consumption (i.e., the electricity used onsite to operate the power plant – sometimes referred to as "house load").[12]

Another option to improve boiler efficiency — better coal quality through drying or other beneficiation techniques — is covered separately in Chapter 4.

2. Regulatory Backdrop

The emphasis of this GHG reduction option is to improve the heat rate and thermal efficiency of the power plant through techniques that optimize the operation of the boiler or reduce heat losses from the flue gas and cooling systems, or to complete other techniques that reduce fuel consumption or auxiliary equipment energy consumption.

The US Department of Energy (DOE) National Energy Technology Laboratory (NETL) found consistent support among utilities for implementing onsite efficiency improvements, as there are direct financial benefits that accrue to the plant itself after such improvements have been completed. Lower fuel costs mean improved profit margins for the utility or plant operator. Improved thermal efficiency results in lower heat rates (less fuel burned per kilowatt hour (kWh) of generation), and also improves the ability of an individual unit to be dispatched by the electricity grid operator, which again can help improve the profitability of the particular unit.[13] NETL further found that the five boiler optimization options it considered in the cited study can be completed without requiring additional legislation or regulations. However, these kinds of changes at a power plant may require the owner/operator to obtain a new or modified air pollution permit. NETL found that uncertainty and risk associated with the permitting process has been a barrier to higher penetration of boiler optimization projects.

Hesitancy exists among air pollution regulators as well. Despite the fact that Prevention of Significant Deterioration regulations require the applicant and the permitting authority to assess energy, environmental, and economic factors to establish Best Available Control Technology (BACT) emissions limits, states and the US Environmental Protection Agency (EPA) have not always taken advantage of the expansive definition of BACT to encourage new or modified power plants to operate as efficiently (thermally) as possible. Standard practice has instead been to set a specific point source concentration-based emissions limit grounded in an assessment of the boiler type and fuel combusted, for example, X pounds of nitrogen oxides (NO_X) per million British thermal units (BTU[14]) or Y parts per million (ppm) of NO_X. A few states have made more concerted efforts to incorporate thermal efficiency considerations in BACT analyses. For example, an advisory board to the Virginia Department of Environmental Quality issued a report in 2011 that lays out a recommended process for that state to follow in determining BACT for GHG emissions.[15]

The EPA has more explicitly considered thermal efficiency in a number of rulemakings over the last decade. To begin with, the New Source Performance Standards for Electric Utility Steam Generating Units now include output-based emissions standards for particulate matter (PM), NO_X, and sulfur dioxide (SO_2) that are expressed as "pounds per MWh" limits. Most older federal regulations included input-based emissions standards only, for example, standards limiting the pounds of emissions per million BTUs (MMBTU) of energy input into a coal-fired boiler. Output-based emissions standards inherently promote thermal efficiency because it is easier

12 Waste heat recovery strategies are also featured in Chapters 2 and 3 of this document. Here in Chapter 1, the discussion of waste heat recovery is limited to the potential to capture heat that is produced at power plants as an inherent byproduct of generating electricity, and then using the captured heat onsite to improve the net heat rate of the generating unit. Other applications of waste heat recovery are considered in Chapters 2 and 3.

13 Supra footnote 6.

14 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Farenheit.

15 State Advisory Board on Air Pollution. (2011, November). Energy Efficiency Measures as Best Available Control Technology for Greenhouse Gases. Available at: http://www.deq.virginia.gov/Programs/Air/StateAdvisoryBoardonAirPollution/StateAdvisoryBoardReports.aspx.

to comply with a "pounds per MWh" standard if less fuel is combusted to generate each MWh. With input-based standards, an inefficient boiler that requires more fuel (more BTUs) to generate each MWh can legally emit more pounds of air pollutant per MWh.

In September 2013, the EPA released proposed New Source Performance Standards similarly limiting GHG emissions from new electric generating units. The proposed rule would set separate, output-based standards for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined-cycle units. It would require affected natural gas combined-cycle units to meet output-based standards of 1000 pounds of carbon dioxide (CO_2) per gross MWh (for units with a heat input rating of greater than 850 MMBTU per hour) or 1100 pounds of CO_2 per MWh (for units smaller than 850 MMBTU per hour). The corresponding standards for fossil fuel-fired boilers and integrated gasification combined- cycle units would be set at 1100 pounds of CO_2 per MWh over any 12-month period, or 1000 to 1050 pounds of CO_2 per MWh over an 84-month period.[16]

In addition to this new emphasis on output-based emissions standards, the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Industrial Boilers rule that the EPA promulgated in 2012 requires affected facilities to complete energy assessments that produce "a comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments." The Industrial Boiler NESHAP does not specifically require facilities to act on the recommendations in these assessment reports. This energy assessment concept was not replicated in the EPA's 2012 NESHAP for Coal and Oil-Fired Electric Utility Steam Generating Units (also known as the Mercury and Air Toxics Standards, or MATS), but the MATS rule does rely on output-based standards and those standards, according to the EPA, were developed after consideration of the potential for thermal efficiency projects to reduce emissions.

Boiler optimization techniques are also a central component of the emissions guidelines for GHG emissions from existing power plants that the EPA proposed on June 2, 2014 (a.k.a. the Clean Power Plan). The EPA determined that the "best system of emissions reduction" for this category of sources is one that consists of a combination of four "building blocks" determined to have been adequately demonstrated to reduce CO_2 emissions, with due consideration for impacts on the cost of electricity and electricity system reliability. The first of those four building blocks consists of practices that reduce the output-based emissions rate (pounds of CO_2 per net MWh) of affected power plants through heat rate improvements. The proposed emissions guidelines include a GHG reduction obligation for each state that is based in part on the EPA's analysis that heat rates of coal-fired power plants can be improved by six percent on average.[17] This rate of improvement is based on analysis conducted on a suite of hundreds of coal-fired power plants. The EPA acknowledges that individual plant heat rate improvements will differ; some may achieve greater than a six-percent improvement and some may achieve less, based on the individual characteristics at each plant.

This chapter focuses on the state of power plant efficiency today to provide support for states that want to evaluate how improved thermal efficiency can be part of a GHG emissions reduction plan. It is worth noting, however, that the engineering consulting firm Sargent & Lundy, in a 2009 report to the EPA, found that regulatory and economic barriers tilt the dynamics toward replacing the entire power plant, rather than overhauling and rebuilding equipment at existing plants.[18] This conclusion

16 The proposed standards for natural gas combined-cycle plants are equivalent to or less stringent than the limits noted in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for some recently issued permits, viz. Calpine Russell City Energy Center, California (1100 lb/MWh); Interstate Power and Light, Marshalltown, Iowa (951 lb/MWh); or Berks Hollow Energy Associates, Ontelaunee, Pennsylvania (1000 lb/MWh). The proposed standards for coal-fired plants, however, are premised on the implementation of at least partial carbon capture and storage and are about one-half the value of the CO_2 limit in the draft permit for the Wolverine Power Supply Cooperative, Michigan (2100 lb/MWh). Wolverine was the only coal-fired unit included in the EPA RBLC as of July 3, 2014.

17 US EPA. (2014, June 18). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating#h-72 at Section VI(B)(2).

18 Sargent & Lundy. (2009, January). *Coal-Fired Power Plant Heat Rate Reductions.* SL-009597. Available at: http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.

would appear to be at odds with the conclusions the EPA reached in its analysis for the Clean Power Plan, although it is not clear whether Sargent & Lundy would reach the same conclusions today that it reached in 2009. In any event, it will not be surprising if, in response to the Clean Power Plan, some operators choose to completely replace power plants while others opt for just a subset of the boiler optimization options described here.

3. State and Local Implementation Experiences

Evidence of the effectiveness of boiler optimization projects can be found in the previously cited NETL reports. A power plant in the western United States completed upgrades to its turbines and control system. Its average thermal efficiency improved from 32 to 35 percent. A power plant in the northeastern United States also completed upgrades to its turbines and improved the performance of its fan blades and pumps. Each of the three units at this plant improved thermal efficiency by three to eight percent.[19] Although these are but a few examples of projects already undertaken, NETL has found that obtaining comprehensive, detailed, and robust data is difficult, as many utilities consider the results of such projects to be confidential.[20]

Nevertheless, the International Energy Agency's (IEA) Clean Coal Centre, based in London, United Kingdom, published a report that includes several more case studies from the United States. The JH Campbell plant in Michigan converted from burning Eastern bituminous coal to a blend of 30-percent Powder River Basin (PRB) subbituminous and 70-percent Eastern bituminous coal. A comprehensive overhaul of plant equipment was completed to adjust to the lower-sulfur, higher-ash PRB coal. Steps taken included: additional overfire air ports, new furnace roof tubes, new superheater and economizer surfaces, new primary air heaters, and new primary air fans. Prior to the upgrade, plant NO_X emissions were 2.42 pounds per MWh. After the changes were completed, NO_X emissions were reduced to 1.01 pounds per MWh. The IEA case study did not include information about heat rate improvements at this plant.[22]

The Dairyland Power Cooperative JP Madgett plant in Alma, Wisconsin, undertook a turbine retrofit project in 2004. During the same time period as a major boiler maintenance project, the turbine unit was retrofitted with new blades and inner casing. As a result, the efficiencies of the high-pressure turbine increased by eight to ten percent, that of the intermediate pressure turbine by two to four percent, and overall output of the plant increased by 20 to 27 MW.

Installation of a continuous combustion management system at the Progress Energy Crystal River plant in Florida improved boiler efficiency by 0.5 percent and also reduced the fan energy requirements.[23]

Intelligent soot blowing systems were installed at the 780-MW Jeffrey Energy Center in St. Marys, Kansas, and the 574-MW Allen King Unit 1 in Bayport, Minnesota. Both plants burn PRB coal. The heat rate was improved by 0.87 percent at the Jeffrey plant and by 1.8 percent at the Allen King plant.[24] A neural network soot blower optimization system installed at the Big Bend Power Project in Texas reduced CO_2 emissions by 58,400 tons per year and NO_X by 3000 tons per year. The Deseret Power Bonanza Station in Utah installed neural network controls on its burners to improve boiler efficiency by one percent.[25]

TIC refers to a suite of technologies that can be used to cool the ambient air before it enters a natural gas-fired power plant's combustion chamber. Gas turbines operate at high thermal efficiency at an ambient temperature of 59 degrees Fahrenheit (F) and 60 percent relative humidity (so-called "standard conditions"). Thermal efficiency losses

19 DiPietro, P. (2009, November). *Improving Efficiency of Coal-Fired Power Plants for Near-Term CO_2 Reductions.* National Energy Technology Laboratory. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ImprovEfficCFPPNearTermCO2Reduct.pdf.

20 Supra footnote 9.

21 Supra footnote 3. Note that a second phase of the JH Campbell plant included a conversion to 100-percent PRB coal and installation of Selective Catalytic Reduction for additional NO_X reductions.

22 Supra footnote 2.

23 Ibid.

24 Ibid.

25 Asia-Pacific Economic Cooperation (APEC) Energy Working Group, Expert Group on Clean Fossil Energy. (2005, June). *Costs and Effectiveness of Upgrading and Refurbishing Older Coal-Fired Power Plants in Developing APEC Economies.* Energy Working Group Project EWG 04/2003T. Available at: http://www.egcfe.ewg.apec.org/Documents/Costs%26EffectivenessofUpgradingOlderCoal-FiredPowerPlantsFina.pdf.

Figure 1-3

Cameo Generating Station, Grand Junction, Colorado, with Parabolic Solar Trough Installation

Photo: Xcel Energy, Public Service of Colorado, 2011.

increase with increased ambient temperature. Compared to standard conditions, turbine power output declines by 7 percent at an ambient temperature of 25 degrees Celsius (C) (77 F), and declines by 15 percent at an ambient temperature of 36 C (97 F).[26] In many parts of the United States, peak electricity demand occurs during periods of hot weather, when air conditioning demand from homes and businesses rapidly increases. TIC technologies include chillers, wet compression, fogging, and evaporative cooling.[27]

Fewer data are available on the potential to supplement coal-fired generation with onsite renewable generation, but at least one demonstrated example exists. The Xcel Energy Cameo plant near Grand Junction, Colorado, shown in Figure 1-3, installed parabolic trough concentrating thermal solar technologies to provide supplemental heat to the coal-fired power plant's heat exchanger. The Xcel project was performed as part of a demonstration with the National Renewable Energy Laboratory to show the potential to combine renewable technologies with coal-fired plants to improve their thermal efficiency and to reduce GHG and criteria pollutant emissions. The project lasted one year (2010) and produced positive results. No coal unit outages were experienced. The coal-based heat rate declined by more than one percent. Coal savings were calculated to be 524,760 pounds for the one-year test period.[28]

4. GHG Emissions Reductions

If all types of boiler optimization projects are completed, plant operators can improve a plant's thermal efficiency in the range of four to seven percent. Because improved thermal efficiency means lower fuel or auxiliary power consumption, these translate into a similar range of GHG reductions at the plant site. Supplementing coal-fired generation with renewable generation can further reduce emissions. The EPA's Clean Power Plan analysis for heat rate improvement found that best operating practices can improve the heat rate of coal-fired power plants by four percent on average and, in addition, upgrades to equipment can improve heat rate by up to two percent.[29]

It should be noted that the prime purpose of boiler optimization projects completed in the United States has been to reduce fuel consumption and criteria pollutant emissions. Although GHG emissions are also reduced, this result has not been a primary objective to date; GHG emissions reductions have been a co-benefit of projects designed to reduce NO_X or SO_2 emissions. This may change with the promulgation of the EPA's Clean Power Plan guidelines for existing power plants, and future optimization projects will more likely seek to jointly and simultaneously reduce criteria, toxic, and GHG emissions.

Three recent reports describe projects to improve boiler efficiency. Data from DOE's NETL and from the Xcel Energy solar demonstration project are summarized in Table 1-2.

A subsequent 2014 research report by NETL also examined the effects of "off the shelf" technology options for coal pulverizer and combustion control improvement, condenser improvement, and steam turbine upgrades on

26 Chacartegui, R. (2008, August). *Analysis of Combustion Turbine Inlet Air Cooling Systems Applied to an Operating Cogeneration Power Plant.* Energy Conversion and Management, Volume 49, Issue 8, 2130–2141.

27 Turbine Inlet Cooling Association. (2014, June). *Technology Options to Increase Clean Electricity Production in Hot Weather.*

28 Xcel Energy, Public Service of Colorado. (2011, March). *Final Report: Innovative Clean Technology: "The Colorado Integrated Solar Project."* Docket No. 09A-015E. Available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/09A-015E%20Final%20CISP%20Report%20Final.pdf.

29 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602.

Table 1-2

Reported Efficiency Increase from Actual Efficiency Improvement Projects[30]

Efficiency Improvement Technology	Description	Reported Efficiency Increase
Combustion Control Optimization	Combustion controls adjust coal and air flow to optimize steam production for the steam turbine/generator set. However, combustion control for a coal-fired EGU is complex and impacts a number of important operating parameters, including combustion efficiency, steam temperature, furnace slagging and fouling, and NO_X formation. The technologies include instruments that measure carbon levels in ash, coal flow rates, air flow rates, carbon monoxide levels, oxygen levels, slag deposits, and burner metrics as well as advanced coal nozzles and plasma-assisted coal combustion.	0.15% to 0.84%
Cooling System Heat Loss Recovery	Recover a portion of the heat loss from the warm cooling water exiting the steam condenser prior to its circulation through a cooling tower or discharge to a water body. The identified technologies include replacing the cooling tower fill (heat transfer surface) and tuning the cooling tower and condenser.[31]	0.2% to 1%
Flue Gas Heat Recovery	Flue gas exit temperature from the air preheater can range from 250° F to 350° F, depending on the acid dew point temperature of the flue gas, which is dependent on the concentration of vapor phase sulfuric acid and moisture. For power plants equipped with wet flue gas desulfurization systems, the flue gas is further cooled to approximately 125° F as it is sprayed with the flue gas desulfurization reagent slurry. However, it may be possible to recover some of this lost energy in the flue gas to preheat boiler feedwater through the use of a condensing heat exchanger.	0.3% to 1.5%
Soot Blower Optimization	Soot blowers intermittently inject high velocity jets of steam or air to clean coal ash deposits from boiler tube surfaces in order to maintain adequate heat transfer.[32] Proper control of the timing and intensity of individual soot blowers is important to maintain steam temperature and boiler efficiency. The identified technologies include intelligent or neural-network soot blowing (i.e., soot blowing in response to real-time conditions in the boiler) and detonation soot blowing.	0.1% to 0.65%
Steam Turbine Design	There are recoverable energy losses that result from the mechanical design or physical condition of the steam turbine. For example, steam turbine manufacturers have improved the design of turbine blades and steam seals, which can increase both efficiency and output (i.e., steam turbine dense pack technology).[33]	0.84% to 2.6%
TIC	Several technologies can be used to cool inlet air during hot weather to increase the thermal efficiency of a natural gas combined cycle plant. These include: chillers, wet compression, fogging, and evaporative coolers.	8% to 26%[34]
Integrated Renewable Energy and Coal	Parabolic solar thermal troughs provide supplemental heat to the plant's heat exchanger to improve thermal efficiency.	1.33%

30 Data in this table for Turbine Inlet Cooling are from: Turbine Inlet Cooling Association. (2012, July). *Turbine Installation Data.* Available at: http://www.turbineinletcooling.org/data/ticadatap.pdf. Data for Integrated Renewable Energy and Coal are from: Xcel Energy, Public Service of Colorado. (2011, March). Final Report: Innovative Clean Technology: *"The Colorado Integrated Solar Project."* Docket No. 09A-015E. Available at: http://www.xcelenergy.com/staticfiles/xe/Corporate/Environment/09A-015E%20Final%20CISP%20Report%20Final.pdf. All other data in this table are from: US DOE. (2008, July). *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet.* National Energy Technology Laboratory, DOE/NETL-2008/1329. The NETL study clarifies that reported efficiency improvement metrics are "adjusted to common basis by conversion methodology assuming individual component efficiencies for a reference plant as follows: 87 percent boiler efficiency, 40 percent turbine efficiency, 98 percent generator efficiency, and 6 percent auxiliary load. Based on these assumptions, the reference power plant has an overall efficiency of 32

two hypothetical coal-fired power plants. One of the hypothetical power plants was assumed to have a 1968-vintage, 550 MW unit with a heat rate of 10,559 BTU/kWh. The other hypothetical power plant also had a 550 MW unit, but was newer (1995-vintage) and more efficient (9,680 BTU/kWh heat rate). An emerging solar-assisted feedwater heating option was also evaluated.[35] NETL's 2014 report concluded that the "off the shelf" technologies could reduce CO_2 emissions at the two hypothetical power plants by 1.7 to 6.9 percent. Emissions at the retrofitted plants might be as little as one percent greater than the emissions expected from a new subcritical pulverized coal unit. In addition, the solar-assisted feedwater heating option could, by itself, potentially reduce CO_2 emissions 1.7 to 7.1 percent.

The IEA Clean Coal Centre report referenced earlier also provides data on the potential improvements in plant efficiency in several different areas, as shown in Table 1-3.

Sargent & Lundy's 2009 report to the EPA on possible projects to improve the heat rate at coal-fired power plants provides data based on small-, medium-, and large-sized electric generating units. These data, summarized in Table 1-4, represent a range based on Sargent & Lundy's industry surveys, discussions with equipment vendors, and review of operating experience at selected plants.[36]

For the data cited in Table 1-4, Sargent & Lundy used

Table 1-3

Potential Efficiency Improvements for Power Plants in the United States[37]

Area of Improvement	Efficiency increase, percentage points
Air heaters (optimise)	0.16–1.5
Ash removal system (replace)	0.1
Boiler (increase air heater surface)	2.1
Combustion system (optimise)	0.15–0.84
Condenser (optimise)	0.7–2.4
Cooling system performance (upgrade)	0.2–1
Feedwater heaters (optimise)	0.2–2
Flue gas moisture recovery	0.3–1.5
Flue gas heat recovery	0.3–1.5
Coal drying (installation)	0.1–1.7
Process controls (installation/improvement)	0.2–2
Reduction of slag and furnace fouling (magnesium hydroxide injection)	0.4
Soot blower optimisation	0.1–0.65
Steam leaks (reduce)	1.1
Steam turbine (refurbish)	0.84–2.6

percent and a net heat rate of 10,600 BTU/kWh. As a result, if a particular efficiency improvement method was reported to achieve a one-percent increase in boiler efficiency, it would be converted to a 0.37-percent increase in overall efficiency. Likewise, a reported 100-BTU/kWh decrease in net heat rate would be converted to a 0.30-percent increase in overall efficiency."

31 Replacing tower fill and tuning the tower and condenser improve the components' ability to reject heat to the atmosphere, thereby potentially reducing condenser backpressure and improving turbine thermal efficiency.

32 Soot blowers can also help clean the air preheater exchange surfaces.

33 Efficiency recovery from existing turbine components is also possible; this generally entails removing deposits from turbine blades, repairing damage to turbine blades, and straightening and sharpening packing teeth.

34 The reported data for turbine inlet cooling indicate the typical percentage power increase at specific plants. A few of the hundreds of power plants featured in the database reflect power increases greater or less than the range shown.

35 US DOE. (2014, April). *Options for Improving the Efficiency of Existing Coal-Fired Power Plants.* National Energy Technology Laboratory, DOE/NETL-2013/1611. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Efficiency-Upgrade-Final-Report.pdf.

36 Supra footnote 18.

37 Supra footnote 2.

Table 1-4

Potential Heat Rate Reductions (BTU/kWh) from System or Equipment Modifications for a Typical Coal-Fired Power Plant[38]

System or Equipment Modified	Power Plant Size 200 MW	500 MW	900 MW
Economizer	50–100	50–100	50–100
Neural Network	50–150	30–100	0–50
Intelligent Soot Blowers	30–150	30–90	30–90
Air Heater and Duct Leakage Control	10–40	10–40	10–40
Acid Dew Point Control	50–120	50–120	50–120
Turbine Overhaul	100–300	100–300	100–300
Condenser	30–70	30–70	30–70
Boiler Feed Pumps	25–50	25–50	25–50
Induced Draft (ID) Axial Fan and Motor	10–50	10–50	10–50
Variable Frequency Drives (VFD)	20–100	20–100	20–100
Combined VFD and Fan	10–150	10–150	10–150

an average boiler heat rate of 10,400 BTU/kWh. Although most of the above projects are discrete, the "combined VFD and fan" row represents a sum of the "ID axial fan" and the "VFD" projects. If all of the projects above were to be completed, and if all achieved the maximum possible heat rate improvement, thermal efficiencies could possibly be improved by more than ten percent. However, these data are based on discussions with equipment vendors. Sargent & Lundy was not able to exhaustively survey US coal-fired power plants and, like the NETL and IEA data cited earlier, was able to locate actual case examples for only a subset of the plant inventory.

5. Co-Benefits

In the examples described above, the prime purpose of boiler optimization projects was to reduce fuel consumption and criteria pollutant emissions. GHG reductions were a co-benefit of these projects. Boiler optimization projects, considered after EPA promulgates its Clean Power Plan emissions guidelines for existing power plants, are more likely to evaluate the benefits and compare tradeoffs between criteria, toxic, and GHG emissions.

The direct relationship between improved thermal efficiency and reduced fuel consumption reduces a plant's SO_2, NO_X, PM, and mercury emissions. Reductions in SO_2 and PM emissions will generally be proportional to the heat rate improvement, as the amount emitted is dictated by the sulfur and ash content of the fuel consumed. With NO_X emissions, nonlinear improvements are possible because most of the nitrogen comes from the combustion air rather than the fuel. For example, improvements in boiler efficiency achieved by replacing burners and installing new air supply can disproportionately reduce NO_X emissions. At a 550-MW plant, Siemens installed new burners and air supplies and saw NO_X emissions decrease from 1200 mg/m3 to 300 mg/m3. The plant also increased boiler efficiency by 0.42 percent and reduced fan power consumption by 900 kW.[39] The Deseret Power neural network controls reduced NO_X emissions by 20 percent and improved the plant's thermal efficiency by 1 percent, even with changes to different coals.[40]

The public health benefits associated with reductions in criteria and hazardous air pollutants are well documented across decades of published literature. In several recent rulemaking dockets, the EPA has consistently identified these co-benefits as constituting a substantial portion of the total benefits associated with reducing GHG emissions. For example, in the Regulatory Impact Analysis that the EPA published in conjunction with the Clean Power Plan proposal, air pollution health co-benefits represent more than half of the total calculated benefits under most of the analyzed scenarios.[41]

38 Supra footnote 18.

39 Supra footnote 2.

40 Supra footnote 25.

41 The EPA analyzed costs and benefits under a range of different assumptions. The results, summarized in Table ES-8 of the Regulatory Impact Analysis, show health benefits exceeding climate benefits in almost every scenario. Refer to: US EPA. (2014, June). *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants.* Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

Other types of co-benefits can also be significant. The full range of co-benefits that can be realized through boiler optimization are summarized in Table 1-5.

6. Costs and Cost-Effectiveness

It is difficult to make generalized statements about the cost of boiler optimization projects. Large utility-sized boilers are typically custom fabricated on a power plant site. The fuel handling system and boiler nozzles themselves are designed for particular fuel types. Coals – even within the same rank – have different properties, with varying heating values, ash content, and sulfur content. Also, the costs of many of the inputs used in boiler optimization projects, from copper wire and cement to the design and construction labor, can fluctuate significantly. Data confidentiality is often a further complication, as the cost of boiler optimization projects can be a sensitive topic. Consequently, much of the cost data cited herein comes from NETL, Sargent & Lundy, and the IEA Clean Coal Centre, and is based on generalized data from a broad range of coal-fired power plants. As a result, the cost data cited here should be interpreted as a guide or estimate only, and not strictly applicable to a particular future project.

Complete upgrades to a boiler to maximize efficiency improvement, including replacement of turbine blades, air preheaters, and all of the optimization tasks outlined in the IEA Clean Coal Centre report are estimated to range from \$100 to \$200 million.[42] However, boiler efficiency improvements of two to three percent can be achieved for a fraction of these costs through economizer, neural network, and intelligent soot blower projects.

Sargent & Lundy reflects that neural networks (artificial intelligence) have been installed at more than 300 US power plants. Boiler efficiencies have been improved by 0.3 to 0.9 percent, with an average improvement of 0.6 percent. Boilers using PRB coals have observed improvements of up to 1.5 percent. The average cost to install neural networks is \$300,000 to \$500,000, with annual operating costs of approximately \$50,000.[43] Actual experience has shown that, in order to sustain the improved levels of thermal efficiencies over the long-term, various equipment that was previously manually controlled or adjusted, such as actuators, must be controlled by instruments and routinely maintained.[44]

The Allen King Plant reported a payback period of less than six months to recover costs from the improved soot blowing system.[45] At the Big Bend example referenced earlier, the upgraded soot blowing system cost \$3 million and produced annual cost savings of \$908,000, resulting in a payback period of slightly more than three years.[46] The

Table 1-5

Types of Co-Benefits Potentially Associated With Boiler Operation

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_X	Yes
SO_2	Yes
PM	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Maybe
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	No
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Maybe
Other	

42 Supra footnote 2.

43 Supra footnote 18.

44 Personal communication, James Staudt, April 2014.

45 Supra footnote 2.

46 Supra footnote 25.

heat rate at this plant was improved by 0.1 to 0.4 percent.[47]

The APEC Energy Working Group report, from which some of the case examples described here have been extracted, provides methodologies to assess the costs and benefits of various types of boiler optimization projects. Sample spreadsheets include default assumptions for unit level data on operating and capital costs and electricity revenues. Results are provided in terms of increased electricity revenue, reductions in fuel and ash costs, and emissions reductions.[48]

Table 1-6

Capital, Fixed O&M, and Variable O&M Costs of Boiler Optimization Projects[49]

System or Equipment Modified	Cost Item	Power Plant Size 200 MW	500 MW	900 MW
Economizer	Capital ($ million)	2–3	4–5	7–8
	Fixed O&M ($/yr)	50,000	100,000	150,000
	Variable O&M ($/yr)	0	0	0
Neural Network	Capital ($ million)	0.5	0.75	0.75
	Fixed O&M ($/yr)	50,000	50,000	50,000
	Variable O&M ($/yr)	0	0	0
Intelligent Soot Blowers	Capital ($ million)	0.3	0.5	0.5
	Fixed O&M ($/yr)	50,000	50,000	50,000
	Variable O&M ($/yr)	0	0	0
Air Heater and Duct Leakage Control	Capital ($ million)	0.3–0.5	0.6–0.7	1–1.2
	Fixed O&M ($/yr)	50,000	75,000	100,000
	Variable O&M ($/yr)	0	0	0
Acid Dew Point Control	Capital ($ million)	1.5–3.5	2.5–10.0	3.5–18
	Fixed O&M ($/yr)	50,000	75,000	100,000
	Variable O&M ($/yr)	170,000–350,000	425,000–850,000	750,000–1,500,000
Turbine Overhaul	Capital ($ million)	2–12	4–20	5–25
	Fixed O&M ($/yr)	0	0	0
	Variable O&M ($/yr)	0	0	0
Condenser	Capital ($ million)	0	0	0
	Fixed O&M ($/yr)	30,000	60,000	80,000
	Variable O&M ($/yr)	0	0	0
Boiler Feed Pumps	Capital ($ million)	0.25–0.35	0.5–0.6	0.7–0.8
	Fixed O&M ($/yr)	0	0	0
	Variable O&M ($/yr)	0	0	0
Induced Draft (ID) Axial Fan and Motor	Capital ($ million)	6–6.5	9–11	15–16
	Fixed O&M ($/yr)	50,000	85,000	130,000
	Variable O&M ($/yr)	0	0	0
Variable Frequency Drives (VFD)	Capital ($ million)	1.5–2	3–4	5–6
	Fixed O&M ($/yr)	20,000	30,000	50,000
	Variable O&M ($/yr)	0	0	0
Combined VFD and Fan	Capital ($ million)	6–6.5	9–11	15–16
	Fixed O&M ($/yr)	25,000	38,000	60,000
	Variable O&M ($/yr)	0	0	0

47 US DOE. (2007, September). *Clean Coal Technology: Power Plant Optimization Demonstration Projects.* Topical Report Number 25. Available at: http://www.netl.doe.gov/File%20Library/Research/Coal/major%20demonstrations/ppii/topical25.pdf.

48 Supra footnote 25. Detailed examples are provided in Chapter 8 of this report.

49 Supra footnote 18.

Reduct, a consultancy focusing on improved utility boiler performance, indicates that their experience, based on a study of approximately 1150 power plants in North America, reflects that a one- to three-percent improvement in boiler efficiency can be achieved at savings equal to $600,000 to $1,700,000 for a 450-MW power plant.[50]

Sargent & Lundy also assessed the capital costs, fixed operations and maintenance (O&M) costs, and variable O&M costs associated with the boiler optimization projects identified in Table 1-4. These cost data are shown in Table 1-6.[51]

Finally, the previously cited 2014 NETL report examined the costs of efficiency retrofits and compared those to the cost of building a new power plant.[52] The combined retrofit cost for the "off the shelf" technologies studied in that report was found to be just over $36 million dollars, or $66/kW, for each of the two hypothetical power plants. Considering both the capital cost and the O&M costs, NETL concluded that the cost of electricity at each power plant could increase by nearly 1 percent in the worst case, or decrease by as much as 3.5 percent. But perhaps more importantly, NETL also determined that the cost of electricity that results from deploying these technologies at either the older or the newer hypothetical power plant is 22 to 25 percent below the cost of building and operating a new, subcritical pulverized coal unit. According to NETL, "This could be a strong incentive for performing efficiency upgrades at coal units, as a strategy for reducing CO_2 emissions from the existing power generation fleet."

Costs for TIC technology installed as retrofits to existing natural gas combined cycle plants range from $30/kW for wetted media to $375/kW for chillers. The Turbine Inlet Cooling Association estimates a cost of $28.1 million to install chillers at a 500-MW gas-fired power plant. The chillers are estimated to increase the capacity of the plant by 75 MW during periods of the highest ambient temperatures.[53]

7. Other Considerations

Improving the heat rate reduces fuel consumption and a plant's operating costs. Although improved profitability might be an incentive to significantly improve a plant's thermal efficiency, depending on the degree of changes made and their effects on emissions a plant may be subject to New Source Review permitting requirements, including BACT review. In some cases, the BACT process can stretch out for months, especially if the state does not receive a complete permit application from the source. If emissions decrease, as is typically the case shown with the examples provided in this chapter, then any changes to the boiler and associated equipment may only require adjustments to the plant's operating permit or may be considered a minor modification. The plant owner or operator would of course consult with the appropriate permitting authority before undertaking any significant changes to the plant. In states with vertically integrated utilities, the owner would also consult with the state public service commission to determine if any of the expenses associated with the improved thermal efficiency projects could be recovered through appropriate rate-making or cost-recovery proceedings under the Commission jurisdiction.

Although permitting issues can present challenges, reducing fuel costs and improving the dispatch ability of the plant are well understood by plant owners and operators as reasons to consider these techniques. Even a one-percent improvement in thermal efficiency can change the order in which a plant is dispatched by the regional transmission operator. Improved heat rates relative to other generating units reorder the dispatch stack; the unit that has upgraded its boiler has a higher probability of running, and can increase its capacity factor and its profitability.

Improved thermal efficiency also means less discharge to water and solid waste streams. Less coal burned per MWh of generation means less ash generation. The life of the associated emissions control equipment can also be extended, with less corrosion and fouling.

50 Reduct and Lobbe Technologies, British Columbia. More information at http://www.reduct.com.

51 Supra footnote 18.

52 Supra footnote 35.

53 Turbine Inlet Cooling Association. (2014, June). *FAQ About Turbine Inlet Cooling Technologies.* Note that the 500 MW plant in the example above would *not* have a peak capacity of 500 MW at an ambient temperature of 100 F. It is more likely that the capacity would be in the 400-425 MW range (reflecting a 15-20% loss of capacity), and that the TIC technologies would be one way to restore the capacity lost by natural gas combined-cycle plants during high ambient temperature conditions.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on boiler optimization:

- Campbell, R. (2013, December). *Increasing the Efficiency of Existing Coal-Fired Power Plants.* Congressional Research Service. Available at: http://www.fas.org/sgp/crs/misc/R43343.pdf.
- Henderson, C. (2013, August). *Upgrading and Efficiency Improvement in Coal-Fired Power Plants.* International Energy Agency (IEA) Clean Coal Centre, CCC-221, ISBN 978-92-9029-541-9.
- Sargent & Lundy. (2009, January). *Coal-Fired Power Plant Heat Rate Reductions.* SL-009597. Available at: http://www.epa.gov/airmarkets/resource/docs/coalfired.pdf.
- Storm, R., & Reilly, T. (1987). *Coal-Fired Boiler Performance Improvement Through Combustion Optimization.* Prepared for American Society of Mechanical Engineers. Available at: http://www.stormeng.com/pdf/Coal%20Fired%20Boiler%20Performance%20Improvement%20Through%20Combustion%20Optimization.pdf.
- US DOE. (2008, July). *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-Fired Power Plant Fleet.* National Energy Technology Laboratory, DOE/NETL-2008/1329. This report is no longer available online.
- US DOE. (2012, January). *Improve Your Boiler's Combustion Efficiency.* Advanced Manufacturing Office. Available at: http://www1.eere.energy.gov/manufacturing/tech_assistance/pdfs/steam4_boiler_efficiency.pdf.
- US DOE. (2014, April). *Options for Improving the Efficiency of Existing Coal-Fired Power Plants.* National Energy Technology Laboratory, DOE/NETL-2013/1611. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Efficiency-Upgrade-Final-Report.pdf.
- Doyle, B. W. (2003, June). *Combustion Source Evaluation Student Manual.* Air Pollution Training Institute, Course 427, Third Edition. Available at: http://www.4cleanair.org/APTI/427combined.pdf.
- US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-Fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

9. Summary

Boiler optimization and improved thermal efficiency are standard procedures that have been used for many decades. The recent development and maturity of artificial intelligence and neural networks to automatically adjust key variables and parameters de-emphasizes the role of human intervention, and helps to assure that the boiler performs at optimal efficiency levels at all times. Electricity load growth in the United States is at a steady one percent per year, and is expected by the Energy Information Administration to remain at those levels through 2040.[54] Energy efficiency continues to be the most cost-effective means to procure additional resources to meet electricity load growth. Thus there are few opportunities in the United States to construct new coal-fired power plants that achieve the thermal efficiency levels observed in China at their supercritical and ultra-supercritical power plants (up to 44- to 47-percent thermal efficiency, effectively combusting up to 50 percent less coal per MWh than the typical 32-percent thermal efficiency American plant). As a result, boiler optimization efforts in the United States must necessarily focus on ways to get the most generation (MWh) possible from each ton of coal combusted. The techniques described here will permit a plant to improve thermal efficiencies by up to four to seven percent, reducing coal combustion and GHG emissions by an equivalent quantity. Such techniques offer co-benefits in the form of lower criteria pollutant emissions, especially for NO_X and $PM_{2.5}$. Compared to previous performance at the same plant, reduced water and land discharges also result from improved efficiency. The interesting Colorado solar integration project showcases possibilities to achieve additional onsite efficiency improvements by using renewable technologies that provide supplemental heat to a plant heat exchanger.

54 US EIA. (2014, May). *Annual Energy Outlook 2014 – Market Trends: Electricity Demand.* Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm.

2. Implement Combined Heat and Power in the Electric Sector

1. Profile

One strategy for reducing carbon dioxide (CO_2) emissions is to capture the waste heat from electric generating units (EGUs) as a secondary output to serve other purposes, typically central heating and cooling or industrial processes in neighboring facilities. As described in the context of boiler optimization in Chapter 1, heat losses can be recovered from the flue gases or cooling system to improve plant efficiency (see Table 1-2). In addition to using waste heat to preheat boiler feedwater and meet other operational thermal requirements, plants can also capture and pipe heat locally to satisfy other co-located demand for thermal energy. Combined heat and power (CHP), also known as *cogeneration*, is the term used to describe this variety of technology configurations that sequentially generates both electric and useful thermal output from a single fuel source.

Generating only electricity, the average US coal-fired power plant has a conversion efficiency of 33 percent, which means that two-thirds of the energy input is lost through heat, largely in the condensation of steam.[1] CHP captures much of this waste heat as useful thermal output, substituting for heat that would have been produced separately.[2] Whereas generating electricity and thermal energy separately might have an overall efficiency ranging from 40 to 55 percent, CHP applications can achieve system efficiencies of 60 to 80 percent (Figure 2-1). These efficiency gains are accompanied by fuel savings that make CHP a cost-effective and commercially available solution for reducing CO_2 emissions. CHP both improves businesses' bottom lines and delivers system-wide benefits like reduced air pollution, improved grid reliability, and avoided electric losses on transmission and distribution networks. With CHP currently accounting for 8 percent of US generating capacity and 12 percent of electricity,[3] it is regarded as a widely underutilized opportunity for emissions reductions.[4] The US Department of Energy (DOE) has estimated that increasing CHP to 20 percent of electric power capacity by 2030 would reduce CO_2 emissions by more than 800 million metric tons per year.[5]

However, because the benefits of CHP accrue economy-wide and not just in the electric power sector, adequately

1 US Energy Information Administration. (2012). *Electric Power Annual Report, Table 8.1. Average Operating Heat Rate for Selected Energy Sources.* Available at: http://www.eia.gov/electricity/annual/html/epa_08_01.html

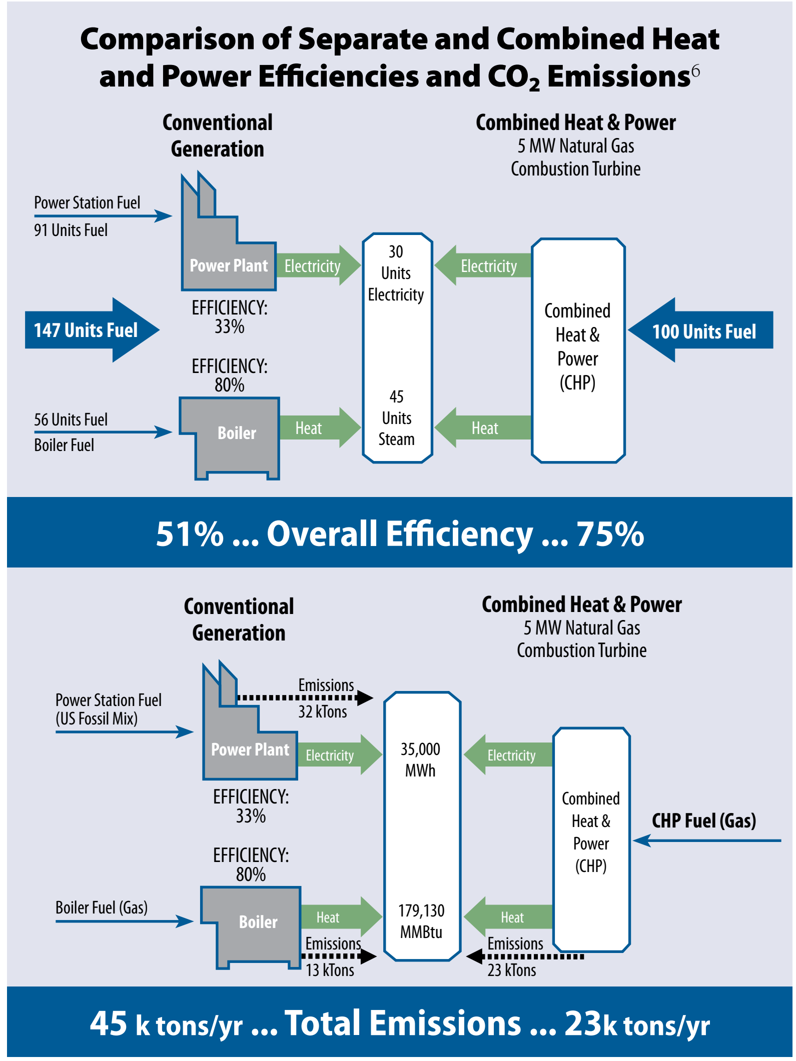
2 Note that because the heat needs to be extracted at a higher temperature and pressure than the large thermal loss in the condensers, recovering this heat from a power plant typically results in losses in power capacity. This is discussed in greater detail below.

3 Total US CHP capacity was 83 gigawatts in 2014. ICF International for the US DOE and Oak Ridge National Laboratory. (2014, March). *CHP Installation Database.* Available at: http://www.eea-inc.com/chpdata/

4 CHP can be said to be underutilized in the US market in comparison to high penetration rates in Europe. For example, CHP accounts for over 45 percent of electricity in Denmark and over 30 percent in the Netherlands (2009). CHP can also be regarded as underutilized on the basis that cost-effective investment opportunities are widely available. Assessments of economic feasibility are discussed below, but estimates typically range between 40 and 50 gigawatts of potential. See: European Environment Agency. (2012, April). *Combined Heat and Power Assessment: ENER 020.* Available at: http://www.eea.europa.eu/data-and-maps/indicators/combined-heat-and-power-chp-1/combined-heat-and-power-chp-2; McKinsey & Company. (2009). *Unlocking Energy Efficiency in the US Economy.* Available at: http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy; US DOE. (2008, December 1). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf

5 US DOE, at supra footnote 4.

Figure 2-1



accounting for them poses challenges. Modifying a generating unit to optimize for electric and thermal output, for example, improves overall energy utilization, but could result in an increase in the facility's direct emissions and an increase in emissions per unit of electric output. Therefore, although the technology is mature and although the emissions reduction potential is large, tapping that potential requires specialized accounting conventions and other carefully constructed regulatory, legal, and financial approaches that look at the total useful energy output of CHP (electric and thermal) and that look at impacts beyond the source of emissions.

Proposed federal regulations for greenhouse gas (GHG) emissions under sections 111(b) and 111(d) of the Clean Air Act are structured to create broad exemptions for CHP facilities. They affect only a portion of the existing CHP units in the power sector, larger units designed to deliver electricity to the grid (criteria provided in Section 2). For those units that are affected, the rules stipulate an accounting method that grants credit for a facility's useful thermal output and avoided line losses as a means of rewarding the environmental benefits of CHP (see Section 4). For other affected EGUs, the viability of retrofitting for CHP would be contingent on site-specific factors, such as plant equipment, local demand for thermal energy, fuel costs, market conditions, and so on, but retrofitting would also allow an EGU to claim the thermal and avoided line loss credits to improve its CO_2 emissions rate toward compliance. Alternatively, retrofitting could provide an opportunity for a unit to qualify for exemption. States could also use the energy efficiency or clean energy building blocks of the US Environmental Protection Agency's (EPA) Best System of Emission Reduction framework to incorporate CHP as a GHG abatement strategy, especially those installations that are exempt from EPA rules, both in and outside the power sector.

There are two basic types of CHP: *topping* and *bottoming* systems. In a "bottoming-cycle" configuration, also known as *waste heat to power,* the primary function is to combust fuel to provide thermal input to an industrial process, such as in a steel mill, cement kiln, or refinery. Waste heat is then recovered from the hot process exhaust for power generation, usually through a heat recovery boiler that makes high pressure steam to drive a turbine generator. More common is a "topping-cycle" system, a configuration in which a steam turbine, gas turbine, or reciprocating engine has the primary purpose of generating electricity. Heat is then captured, usually as steam, and directed to nearby facilities, where it can be used to meet co-located demand for central heating or manufacturing processes. This chapter discusses topping-cycle CHP applications at central station EGUs as a means of reducing the carbon intensity of the electric power sector. Alternatively, CHP can be distributed across the electric grid at individual facilities, where energy users such as institutional, commercial, and manufacturing facilities have both power and heating or

6 US EPA. (2014, August). *CHP Partnership.* Available at: http://www.epa.gov/chp/. A power plant efficiency of 33 percent (higher heating value) denotes an average delivered efficiency based on 2009 data from eGRID for all fossil fuel power plants (35.6 percent), plus 7 percent transmission and distribution losses.

Table 2-1

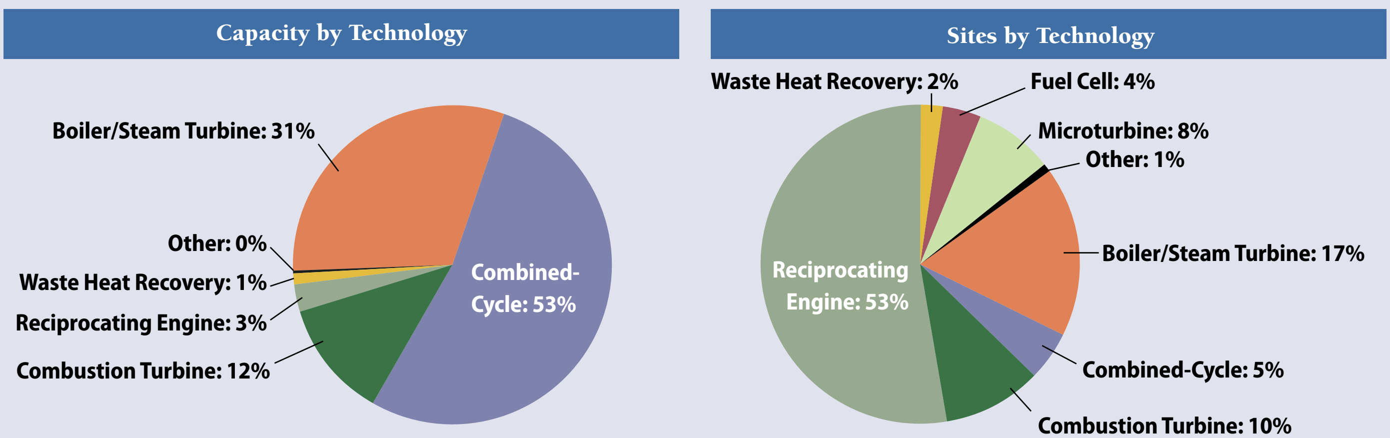
Summary of CHP Technologies for Large-Scale Applications[7]

CHP System Type	Advantages	Disadvantages	Available Sizes	Overall Efficiency (Higher Heating Value)	Installed, 2014 (Capacity/ Sites)[8]
Gas Turbine	High reliability Low emissions High-grade heat available Less cooling required	Requires high pressure gas or in-house gas compressor Poor efficiency at low loading Output falls as ambient temperature rises	500 kW to 300 MW	66% to 71%	64%/16%
Steam Turbine	High overall efficiency Any type of fuel can be used Ability to meet more than one site heat grade requirement Long working life and high reliability Power to heat ratio can be varied within a range	Slow startup Low power-to-heat ratio	50 kW to 300+ MW	Near 80%	32%/17%

kW - kilowatt
MW-megawatt

Figure 2-2

Existing US CHP Technology by Capacity and Site Number[9]



cooling requirements. Potential applications of this kind are more abundant than for large centralized CHP generating units, and are considered a specific type of distributed generation. CHP as a form of distributed generation is the subject of Chapter 3.

CHP can be based on a variety of different technology classes, including gas turbines, steam turbines, reciprocating engines, microturbines, and fuel cells. Of these, steam and gas turbines are the technologies that are most relevant to large capacity applications (25 megawatts [MW] to 300 MW), such as those that are typical in the electric sector. These technologies are summarized in Table 2-1.

As illustrated in Figure 2-2, these technologies comprise

7 US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies.* Tables II & III. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf. Note that CHP efficiency varies with size and power-to-heat ratio. These are illustrative values intended to represent typical CHP systems.

8 The data in the last column indicate each system type's percentage of total installed US CHP capacity (83.3 gigawatts) and total number of installations (4220 sites) as of 2014. Supra footnote 3.

9 ICF International for US DOE at supra footnote 3. Combined-cycle turbines (5 percent of all CHP installations), combustion turbines (10 percent), and steam turbines (17 percent) contribute disproportionately to total installed CHP capacity, collectively accounting for 97 percent of the total 83 gigawatts.

96 percent of all US installed CHP capacity, but account for only 33 percent of CHP sites, reflecting the large capacity of installations in these technology categories.

Whether the boiler is fueled by coal, biomass, solid waste, or other energy source, steam turbine applications are the most well established of utility-scale EGU technologies. CHP can be adapted as a retrofit to steam turbine power plants to capture heat that would otherwise exit the system through the cooling water. The cooling water itself, however, is usually not hot enough for district or process heating purposes. Therefore, depending on the thermal requirements, energy must be extracted farther upstream in the thermodynamic cycle, usually from the turbine, before the pressure and temperature are dropped to condense the steam.[10] This modification to the plant will result in reduced electrical output, although the overall energy utilization (electricity and useful thermal) is greater than would be the case if power and heat were produced separately. Because steam turbines are expensive to operate and generally have long startup times, the economics of a steam generator CHP are often more favorable for medium- to large-scale facilities outside the electric sector, such as chemical plants and primary metal processing plants with high capacity factors. However, the economics of CHP may be favorable at steam generator EGUs that are expected to operate with high capacity factors.[11]

CHP can also be applied to combustion turbine generation, whether burning natural gas, synthetic gas, or another gaseous fuel, in both simple-cycle and combined-cycle natural gas power plants. Natural gas is the most common fuel in CHP applications, accounting for more than 70 percent of capacity in the United States,[12] and although simple-cycle gas turbine CHP is often used in smaller installations (<40 MW), roughly half of the total US capacity is built around large, combined-cycle gas turbines that primarily generate electric output for the grid while also supplying steam to neighboring facilities.

In simple-cycle plants, fuel is combusted to generate electricity by heating and compressing air, the resulting force of which drives the power turbine. The exhaust gas leaving the turbine is very hot, between 800° and 1100° Fahrenheit, depending on the type of unit. In simple-cycle CHP applications, the exhaust gas directly serves as a source of process energy or, more likely, it is run through a heat exchanger, typically a heat recovery steam generator, after which steam serves as the energy carrier for thermal purposes. Although simple-cycle gas turbines have an electric efficiency ranging from 15 to 42 percent, simple-cycle CHP units usually achieve 65 to 70 percent.[13]

A combined-cycle turbine (see Figure 2-3) runs high temperature exhaust through a waste heat recovery unit to produce steam for a second cycle of power generation based on a steam turbine. This configuration has an electric efficiency ranging from 38 to 60 percent. CHP applications to this configuration will usually extract mid- to high-pressure steam before the steam turbine, or low pressure steam after the steam turbine, depending on the required performance specifications of the thermal user. In this way, combined-cycle CHP can achieve system efficiencies of 60 to 70 percent.

Achieving high rates of efficiency depends on having a dedicated thermal load that is compatible in size with the thermal output of the CHP system. A CHP system sited at a commercial or industrial facility will usually be sized and designed to accommodate the thermal demand, but for retrofits to existing power plants, optimizing the CHP system in this way is not an option. Instead, the design objective for EGU retrofits would require balancing the tradeoff between thermal energy sales and reduced power production on steam turbines. In practice, achieving this

10 There are two kinds of steam turbine CHP. In a *non-condensing* or *back-pressure system*, the flow of steam exiting the turbine is fed entirely to the process requirements, usually at low to medium pressure. In an *extraction* turbine, higher pressure steam is extracted through openings in the turbine casing, while the rest of the steam continues its expansion in the turbine to be exhausted into the condenser. An extraction turbine may be designed to allow for regulation of heat-to-power ratio and for extraction of steam at different pressure levels. For more, see: supra footnote 7.

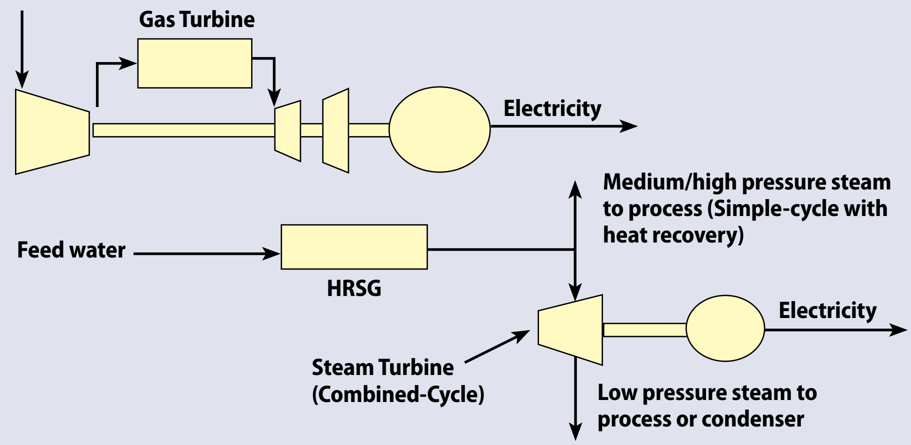
11 In some instances at existing CHP units, the revenue associated with the non-generation (heat supply) aspects of CHP operation can enable particular units to remain economically viable. Steam generator operation may be maintained even when there is no short-term market for the generated electricity. When these types of instances occur, the units tend to be operating very inefficiently.

12 ICF for DOE at supra footnote 3.

13 US EPA. Emission Factors and AP42. *Emission Factors: Stationary Internal Combustion Sources. Chapter 3: Stationary Gas Turbines.* Available at: http://www.epa.gov/ttnchie1/ap42/ch03/final/c03s01.pdf

Figure 2-3

Heat Recovery From a Gas Combustion Turbine Using a Heat Recovery Steam Generator[14]



CHP also faces the challenge of finding concurrent load. In other words, to maximize energy savings, CHP is most advantageous for end-users with high and steady demand for thermal heat. Yet many of the power plants at which the installation of CHP might be technically feasible are gas turbines used as peaking units. Dispatched to meet peak demand for only a few hours or few hundred hours a year, these units would not generate a continuous enough supply of heat to satisfy industrial or district heat users.

Given the complexity of retrofitting existing EGUs, opportunities for developing new, utility-scale CHP using an industrial or energy park model may be more promising. Successful partnerships have created many opportunities in which cogeneration power plants and industrial facilities co-locate to take advantage of low-cost steam. A majority of CHP capacity in the United States today is made up of partnerships between large CHP generators (>100 MW) and industrial facilities. Looking forward, some of the new capacity additions required to offset anticipated coal-fired EGU retirements could be met through this sort of new and efficient utility-scale CHP.

objective will be highly dependent on site-specific factors — for example, plant equipment, geographic constraints, market conditions, steam requirements, pollution control equipment — which may make this category of GHG reduction potential fairly limited, particularly when considering only the electricity sector.

One practical and substantial constraint for CHP is the limited ability to move steam to where it can still be useful. Because steam can only be transported effectively over short distances, a power plant must be situated within close proximity to a district steam network or large industrial user.[15] Alternatively, the guarantee of long-term, low-priced steam energy can attract industrial, institutional, or commercial partners to build facilities or district steam networks adjacent to central station power plants, although the unique financial and partnership circumstances underlying such an investment decision are difficult to generalize.[16]

2. Regulatory Backdrop

In response to the energy crisis of 1973, the United States enacted the Public Utilities Regulatory Policies Act (PURPA) in 1978, which required utilities to purchase electricity from cogeneration facilities as a means of

14 Supra footnote 7. In a combined-cycle gas turbine, high temperature exhaust is used to produce steam for a second cycle of power generation based on a steam turbine. If steam from the heat recovery steam generator is directed instead to meet space or process heating needs, it is considered a simple-cycle CHP unit.

15 In northern Europe, where CHP penetration is highest and much of it serves district heating demands, large transmission pipelines typically have a grid length of between 12 and 50 miles (20 to 80 kilometers). One of the European Union's largest networks, located in Aarhus, Denmark, has 81 miles (130 kilometers) of interconnected bulk heat pipeline fed by more than one source of thermal energy, rivaling the Con Ed Steam System in Manhattan, New York, which on a customer basis is considered the largest district steam system in the world. Cost effectiveness of piping thermal energy depends on demand density and total load, with losses decreasing with scale and pipe diameter. See: European Commission Joint Research Centre. (2012). *Background Report on EU-27 District Heating and Cooling Potentials, Barriers, Best Practices and Measures of Promotion.* Available at: https://setis.ec.europa.eu/system/files/JRCDistrictheatingandcooling.pdf; and International District Energy Association. (2005, August 5). *IDEA Report: The District Energy Industry.* Available at: http://lincoln.ne.gov/city/mayor/arena/assets/idea_district_energy.pdf

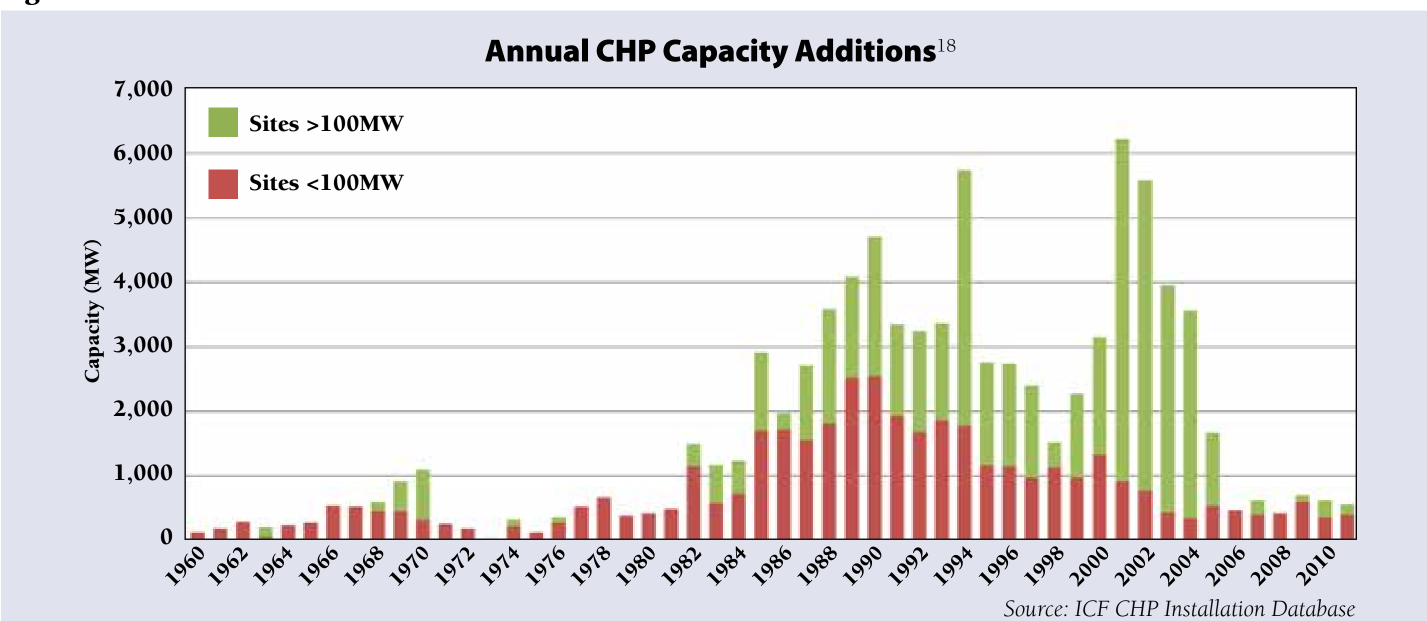
16 Great River Energy's facility in Underwood, North Dakota provides an example, described below.

improving efficiency in the power sector. Under PURPA, utilities were obligated to interconnect all "qualifying facilities," to provide them with reasonable standby rates and backup charges, and to pay prices equivalent to the utilities' avoided cost of generation. These rules, along with subsequent tax incentives, spurred strong market growth from 1980 to 2005. Many of these facilities were owned by independent power producers, third-party CHP developers taking advantage of large-capacity combustion turbine technology that was newly available and capable of achieving high rates of electric output. Today, generating units over 100 MW account for 65 percent of a total US CHP capacity of 83 gigawatts (GW), almost all of which were built in the period following 1980 (Figure 2-4).[17]

The introduction of competitive wholesale markets beginning around the year 2000 affected the mandatory purchase requirement under PURPA. The 2005 Energy Policy Act eliminated the must-buy provision in instances in which larger customer-generators (>20 MW) had nondiscriminatory access to wholesale markets. These changes, coupled with general uncertainty in the face of market deregulation and volatile gas prices, led to a precipitous drop in investment in CHP, as shown in Figure 2-4. From 2005 to 2012, new investment remained largely stagnant and CHP capacity nationwide leveled off at around 80 GW.

Investment in CHP has increased in recent years. After a small upturn in market activity in 2012, 3.3 GW of new capacity are slated for construction between 2014 and 2016. Roughly half of that capacity is in installations greater than 100 MW.[19] There are a number of important drivers that are shaping this growth, including natural gas prices, air pollution regulations, state and federal capacity targets, and concerns about the reliability and resiliency of energy infrastructure. Regulatory drivers relevant to electric-sector CHP applications are described below.

Figure 2-4



17 ICF International for Oak Ridge National Laboratory. (2012). *CHP Installation Database*. Available at http://www.eea-inc.com/chpdata/index.html; and ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States*. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx

18 ICF International for American Gas Association, at supra footnote 17. Trends in capacity additions closely follow a changing regulatory backdrop, with the majority of CHP coming online between 1980 and 2005 and much of that in large-capacity units. Today, 65 percent of total installed capacity in the United States exists in units larger than 100 MW. Note that this figure does not reflect a recent uptick in additions, with nearly 1 GW added in 2012 and an anticipated 3.3 GW under construction and scheduled to come online between 2014 and 2016. Hampson, A. (2014). *CHP Market Status and Opportunities for Growth.* Presentation at the Electric Power Conference and Exhibition. ICF International.

19 Hampson A., at supra footnote 18. ICF International for US DOE, at supra footnote 3. ICF International for American Gas Association, at supra footnote 17.

Air Pollution Regulations

CHP units may be subject to permitting requirements and a variety of existing federal air pollution standards for criteria and hazardous air pollutant emissions, depending on the fuels combusted, the heat input or electrical output of the system, how much electricity is delivered to the grid versus used onsite, and the date of construction, reconstruction, or modification. Criteria pollutant emissions from CHP systems may be subject to New Source Performance Standards (NSPS) under one of the 40 C.F.R. Part 60 regulations, as follows:

- Subpart Da, for electric utility steam generating units;
- Subpart Db, for large industrial, commercial, and institutional steam generating units;
- Subpart Dc, for small industrial, commercial, and institutional steam generating units;
- Subpart IIII, for stationary compression ignition internal combustion engines;
- Subpart JJJJ, for stationary spark ignition internal combustion engines; or
- Subpart KKKK, for stationary combustion turbines.

Hazardous air pollutant emissions from CHP systems may be subject to National Emission Standards for Hazardous Air Pollutants (NESHAP) under one of the 40 C.F.R. Part 63 regulations, as follows:

- Subpart YYYY, for stationary combustion turbines;
- Subpart ZZZZ, for stationary reciprocating internal combustion engines;
- Subpart DDDDD, for large industrial, commercial, and institutional boilers and process heaters;
- Subpart UUUUU, for coal- and oil-fired electric utility steam generating units (often referred to as the Mercury and Air Toxics Standard or MATS rule); or
- Subpart JJJJJJ, for small industrial, commercial, and institutional boilers and process heaters.

As mentioned earlier, the proposed federal regulations for new and existing electric utility GHG emissions under sections 111(b) and 111(d) of the Clean Air Act would also apply to some CHP systems. Under the proposed existing source performance standard (the 111(d) rule), an affected EGU is defined as any steam generating unit, integrated gasification combined-cycle, or stationary combustion turbine that commences construction on or before January 8, 2014 and meets either of the following conditions:

- A steam generating unit or integrated gasification combined-cycle that has a base load rating greater than 73 MW (250 MMBTU[20]/h) heat input of fossil fuel (either alone or in combination with any other fuel) and was constructed for the purpose of supplying one-third or more of its potential electric output and more than 219,000 megawatt-hours (MWh) net-electric output to a utility distribution system on an annual basis; or
- A stationary combustion turbine that has a base load rating greater than 73 MW (250 MMBTU/h), was constructed for the purpose of supplying, and supplies, one-third or more of its potential electric output and more than 219,000 MWh net-electrical output to a utility distribution system on a three-year rolling average basis, combusts fossil fuel for more than 10 percent of the heat input during a three-year rolling average basis, and combusts over 90 percent natural gas on a heat input basis on a three-year rolling average basis.[21]

The EPA proposed a nearly identical definition for new sources in the 111(b) rule. What is noteworthy for the purposes of this chapter is that the definition of affected source in both of the proposed electric sector GHG rules is crafted in a way that would exclude most CHP systems outside of the electric sector (the subject of Chapter 3) from regulation, because those systems are usually designed to deliver more than two-thirds of their electrical output for onsite use. CHP systems within the electric power sector are often larger and designed to deliver electricity to the grid, and thus are more likely to be affected by these proposed GHG regulations.[22] In support documents

20 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

21 US EPA. (2014). *40 C.F.R. Part 60. Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

22 In a similar fashion, the regulatory definition of electric utility steam generating unit in existing NSPS and NESHAP rules is limited to units constructed for the purpose of supplying more than one-third of potential electric output capacity for sale rather than onsite use. This is significant because the existing NSPS and NESHAP rules for electric utility steam generating units are more stringent than for the other combustion technologies noted herein. This is also one of the reasons this document draws a distinction between CHP systems serving the electric power sector (the subject of this chapter) and CHP systems serving other sectors (the subject of Chapter 3).

published with the proposed 111(d) rule, the EPA reviewed data on nearly 3000 US CHP units and identified fewer than 500 that would meet the proposed definition of affected source.[23]

Some of the federal air regulations are designed in a way that acknowledges the emissions benefits of *combined* heat and power systems relative to *separate* heat and power systems. Most notably, the existing NSPS regulations for criteria pollutant emissions from electric utility steam generating units and the proposed NSPS regulations for electric utility GHG emissions allow CHP facilities to convert the useful thermal output of the system into an equivalent amount of electric output when demonstrating compliance with output-based emissions limits expressed in pounds per MWh (lb/MWh). This treatment of useful thermal output is explained in more detail in Section 4. Some air pollution regulations also acknowledge the dual nature of CHP systems in the definitions of affected sources. For example, the NSPS for criteria pollutant emissions from stationary combustion turbines applies to sources with a heat input at peak load equal to or greater than 10 MMBTU per hour, based on the higher heating value of the fuel, but heat input delivered to associated heat recovery steam generators or duct burners are not included when determining peak heat input.

Although most CHP systems in the electric sector are (or will be) subject to various regulations for criteria pollutant, hazardous air pollutant, and GHG emissions, and although compliance with regulations does increase costs, in some ways environmental regulations may be more of a driver for new CHP installations than an impediment. This is because output-based regulations and some of the special regulatory provisions included for CHP make the inherent efficiency of CHP an attractive alternative relative to other options. For example, the MATS rule and the NESHAP for large industrial, institutional, and commercial boilers and process heaters are expected to limit the emissions of roughly 1750 large industrial boilers, fired primarily by coal, oil, and biomass, putting pressure on owners to consider boiler replacement.[24] The latter rule includes special provisions to reward energy efficiency, whereby a firm can opt to use output-based standards to earn compliance credit for energy efficiency improvements at the facility level. This would add to the economic and operational appeal of adopting CHP as a means of complying with regulations.[25] As of August 2014, most compliance decisions had been made in preparation for the January 2016 deadline. The rule and the accompanying technical assistance program undertaken by the DOE[26] offer a model for how environmental regulations and government support can be designed to drive the market for CHP.[27]

The EPA's proposed 111(d) rule could significantly affect dispatch order for existing EGUs, including CHP units in the electric sector.[28] The EPA determined that the Best System of Emission Reduction includes an element of re-dispatch, specifically increasing the utilization rate of existing combined-cycle gas turbines. However, re-dispatch could potentially result in increased capacity factors for simple-cycle gas units as well, which in addition to the thermal credit afforded to CHP plants (discussed later), could make the economics more favorable for CHP. Whether CHP retrofit at an existing EGU is an appropriate option for GHG abatement, perhaps as a result of changes in dispatch, for example, would need to be ascertained on a site-by-site basis. As state planners, utilities, and grid operators face the combined effects of these and other changes in the electric system, and as plant managers consider making modifications to facilities to optimize boiler performance and improve heat rate (Chapter 1), an assessment of CHP feasibility should be included in that review process.

23 Based on data published by the EPA at: http://www2.epa.gov/sites/production/files/2014-06/20140602tsd-egrid-methodology_0.xlsx

24 US DOE. (2013, February). *Summary of EPA Final Rules for Air Toxic Standards for Industrial, Commercial and Institutional Boilers and Process Heaters.* Available at: http://energy.gov/sites/prod/files/2013/11/f4/boiler_mact_article.pdf

25 Federal Register Section 63.7533 outlines the methodology for determining compliance using emissions credits and the EPA provides a hypothetical example online here: http://www.epa.gov/ttn/atw/boiler/imptools/energycreditsmarch2013.pdf

26 US DOE. (2014, May). *Boiler MACT Technical Assistance.* Available at: http://energy.gov/sites/prod/files/2014/05/f15/boiler_MACT_tech_factsheet_1.pdf

27 Chapter 3 discusses the boiler MACT in greater depth.

28 Building Block #2 titled *CO_2 Reduction Potential from Re-Dispatch of Existing Units.* See: US EPA. (2014, June 10). *Technical Support Document for Carbon Pollution Guidelines for Existing Power Plants: GHG Abatement Measures.* Docket ID No. EPA-HQ-OAR-2013-0602 . Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

State and Federal Capacity Targets

State and federal capacity targets have been powerful tools in support of CHP. An Executive Order to Accelerate Investment in Industrial Energy Efficiency issued by the Obama Administration in 2012 set a national target of 40 GW of new, cost-effective CHP to be added by 2020.[29] Many states have also enacted capacity targets or included energy-efficient CHP as a qualifying resource in their energy efficiency or renewable portfolio standards (discussed in Chapters 11 and 16, respectively). As of 2013, 23 states had included CHP in either their energy efficiency or renewable portfolio standards,[30] which typically both puts a procurement obligation on utilities and offers financial incentives. California, New York, North Carolina, New Jersey, and Massachusetts are states that have adopted specific initiatives to support the development of CHP. Because most of the outreach related to these capacity targets has focused on CHP in sectors other than the electric power sector, this topic is covered in more detail in Chapter 3.

Reliability and Resiliency of Energy Infrastructure

CHP systems can serve as low-cost generation additions to the power system that reduce congestion and strain on transmission and distribution networks. Integrated with micro-grid and islanding capabilities, particularly to support hospitals, public security, and other critical infrastructure, CHP can enhance reliability and resiliency during grid disruptions. Recent natural disasters causing widespread and extensive grid failure have demonstrated the resiliency benefits of CHP and called attention to CHP as an important component of building robust energy infrastructure.[31] Following Hurricanes Sandy and Irene, Connecticut, New York, and New Jersey adopted CHP incentives.[32] And earlier, in response to devastating storms in the Gulf region, Texas and Louisiana adopted laws requiring critical government buildings to undertake feasibility studies for implementing CHP.[33]

3. State and Local Implementation Experiences

A review of US Energy Information Administration data for steam turbines at electric utility and independent power producer facilities indicates that in 2012 there were 121 EGUs at 81 facilities that were classified as topping-cycle steam CHPs. The nameplate capacity ratings for these EGUs ranged from 5 to 750 MW.

CHP installations across all sectors are regionally concentrated, as depicted in Figure 2-5, underscoring differences in electricity prices, policy environments, and industrial and manufacturing activities that are chief factors in CHP development. Large-scale petrochemical plants and refineries dominate in the Gulf Coast, where some of the country's largest cogeneration facilities are located. Biomass-fired cogeneration in the pulp and paper industry dominate in the Southeast and in Maine. In contrast, in states like California, New York, Massachusetts, Connecticut, and Rhode Island, CHP has been driven by a combination of high electricity prices and government initiatives. Proximity to buildings that have a high demand for thermal energy can also be a driver for CHP, especially in large northern cities where district heating and cooling is viable. State and local experiences with large-scale CHP facilities similarly demonstrate the local circumstances that create economic and partnership opportunities and lead to successful project development.

29 Executive Order 13624. (2012, August 30). *Accelerating Investment in Industrial Energy Efficiency.* 77 FR 54779. Available at: http://www.gpo.gov/fdsys/pkg/FR-2012-09-05/pdf/2012-22030.pdf

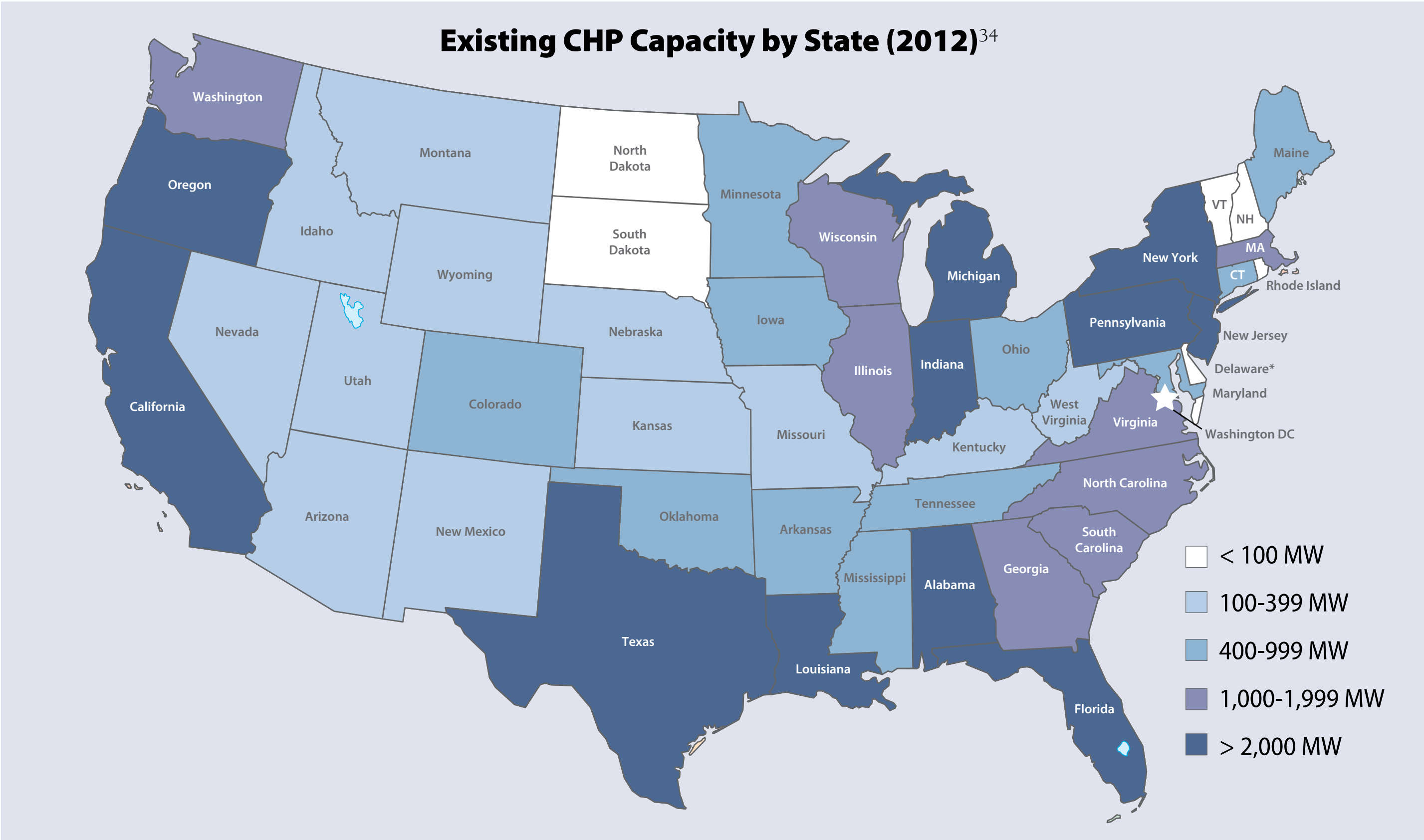
30 US DOE, EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies

31 A. Chittum. (2012, December 6). How CHP Stepped Up When the Power Went Out During Hurricane Sandy. [Web log post]. Available at: http://www.aceee.org/blog/2012/12/how-chp-stepped-when-power-went-out-d

32 CT P.A. 12 148 Section 7. (2012, July). *Microgrid Grant and Loan Pilot Program.* Available at: http://www.cga.ct.gov/2012/act/pa/pdf/2012PA-00148-R00SB-00023-PA.pdf

33 Texas HB 1831. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB01831F.pdf. Texas HB 4409. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB04409F.pdf. Louisiana Senate resolution No. 171. Available at: http://www.legis.la.gov/legis/BillInfo.aspx?s=12RS&b=SR171&sbi=y. For more extensive information on case studies see: ICF International for Oak Ridge National Lab. (2013, March). *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* Available at: http://www.energy.gov/eere/amo/downloads/chp-enabling-resilient-energy-infrastructure-critical-facilities-report-march

Figure 2-5



Although most large CHP plants are owned by third-party independent power producers or industrial facilities themselves, a common lesson from state and local experience is that utility involvement can be critical to project development. Customer-side generation signifies a decline in retail energy sales and has therefore traditionally presented a challenge to the utility business model. Utilities are in a unique position, however, to address many of the barriers facing CHP and take a leadership role in developing partnerships and designing projects to maximize benefits to both the customer and the electric system.

With a strong understanding of the electric delivery system, utilities can help identify where CHP projects would most effectively relieve grid congestion and reliability deficits. Owning and operating an EGU onsite may not be a feasible step for facilities that might benefit from the electrical and thermal output of CHP. However, utilities with the requisite technical expertise could help address those knowledge gaps. If the regulatory environment allows, a utility may own and operate the assets directly, or negotiate a package of services to provide support to the CHP owner. Another role for utilities is in project finance, where utilities typically have a lower cost of capital and are able to tolerate longer investment periods.

That utility ownership accounts for only three percent of CHP capacity may indicate a large untapped opportunity for utilities to capitalize on their unique position in this market.[35] A growing number of policymakers are exploring ways to enable utility participation in the CHP market as a means of addressing persistent administrative and financial barriers, and this may be a focus of regulatory efforts moving forward. Both a 2013 State and Local Energy Efficiency Action Network (SEE Action) study and a 2013 report from the American Council for an Energy-Efficient Economy (ACEEE) highlight possible considerations for utility participation in CHP markets; see these reports for more detail.[36]

34 ICF International for American Gas Association, at supra footnote 17.

35 Ibid.

36 Chittum, A. (2013, July). *How Electric Utilities Can Find Value in CHP.* ACEEE. Available at: http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf

Some specific trends and examples, highlighting utility-owned CHP, are discussed below. Additional case studies can be found online at the Database of State Incentives for Renewables and Efficiency and at the EPA's database of policies and incentives in support of CHP.[37]

The Alabama Power Company

Alabama Power, a subsidiary of Southern Company, exemplifies a model in which a vertically integrated utility both owns CHP units directly and coordinates customer ownership. Costs of utility-owned CHP and of power purchase agreements for customer-generated electricity are part of the company's rate base.

Alabama Power has approximately 2000 MW of CHP on its system, of which roughly 1500 MW is owned by customers. The remaining utility-owned CHP is composed of four large units located at industrial sites, including:

- 97 MW combined-cycle cogeneration plant located at Sabic Plastics in Burkville;
- 102 MW combined-cycle Washington County Cogeneration plant located at Olin Chemicals in McIntosh;
- 130 MW coal-biomass Gadsden Cogeneration plant located at Goodyear Tires and Rubber company; and
- 250 MW combined-cycle cogeneration plant located at the Phenolchemie facility in Theodore.[38]

Many of Alabama Power's CHP units were developed in response to the need to expand generating capacity to meet load obligations during the 1990s. Both utility-owned and customer-owned generation facilities were certified by the Alabama Public Service Commission through a flexible regulatory process, which allows non-steam aspects of the CHP facilities to be included in the utility's rate base. Alabama Power estimates that customer-owned generation has allowed it to avoid building 1.7 GW of central station capacity.[39]

Great River Energy

In the Midwest, Great River Energy (GRE) has taken a joint venture/subsidiary approach to address the financing and partnership challenges associated with integrated thermal-power applications in the biochemical sector. GRE is a member-owned transmission and generation non-profit serving distribution cooperatives in Minnesota and Wisconsin. It has two CHP facilities among its generation assets. The first, at Coal Creek Station in Underwood, North Dakota, was a retrofit to an 1100-MW mine mouth lignite-fired plant originally built in 1979-1980.[40] Although the retrofit itself required minimal modifications, GRE partnered with Headwaters Inc. to build a new ethanol plant at the site. Blue Flint Ethanol came online in 2007 with an annual capacity of 50 million gallons. Access to low-priced steam energy through a long-term contract, in addition to the roughly $5 million in avoided capital expenditure for the boiler and associated compliance requirements, gave the ethanol plant a competitive advantage over other, typically gas-fired, bio-refineries.[41]

GRE's second CHP facility is a new build. Spiritwood Station near Jamestown, North Dakota is the product of a partnership with Cargill Malt. In 2005, GRE was managing growth in electric demand of five percent per year and looking for sites to add new generation. Simultaneously, Cargill Malt was considering options to expand processing capacity and reduce energy costs at its plant in Spiritwood, a facility that dates back to the 1970s. Discussions led to siting a 99-MW lignite-fired power plant adjacent to the Cargill Malt plant. Originally designed to meet the needs of two users of thermal energy, plans stalled in 2008

37 Database of State Incentives for Renewables & Efficiency. Available at: http://www.dsireusa.org/. US EPA. (2014, August). *CHP Policies and Incentives Database.* Available at: http://epa.gov/chp/policies/database.html. Along with other examples discussed peripherally, the policy and implementation experiences of the state of Massachusetts are provided in detail in Chapter 3.

38 ICF International for US DOE and Oak Ridge National Laboratory. (2014). *CHP Installation Database: Alabama.* Available at: http://www.eea-inc.com/chpdata/States/AL.html

39 US DOE, EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies

40 GRE. (2014, August). *About Coal Creek Station.* Available at: http://www.greatriverenergy.com/makingelectricity/coal/coalcreekstation.html

41 This was true despite additional costs associated with transporting corn feedstock to the refinery, which were expected at the time of construction from 2005 to 2007 when Coal Creek was located on the margins of corn growing regions (corn agriculture has expanded in years since). GRE. (2014, August 15). Telephone conversation with Sandra Broekema, Business Development Manager.

when financing for the second user withdrew during the economic recession. GRE invested itself in the second user, Dakota Spirit AgEnergy, a conventional dry mill ethanol refinery, through its majority-owned Midwest AgEnergy Group.[42] The new facility, a 65-million gallon plant, is scheduled to come online in April 2015. The use of CHP steam has allowed the ethanol plant to meet the EPA's Renewable Fuel Standard 2, one of the first ethanol plants in the country to be approved under the lifecycle GHG performance standards added in 2007, which require a 20-percent reduction in emissions below a gasoline baseline.[43] Even with the ethanol plant, Spiritwood Station will have excess steam energy. Fully subscribed, the system is designed to achieve more than 65-percent efficiency.[44]

Other Utility-Ethanol Partnerships

The ethanol industry has many other instances of joint utility-customer CHP ownership. Two examples of municipal utility partnerships come from Missouri and are considered here. The City of Macon shares joint ownership of a gas-turbine CHP system with Northeast Missouri Grain, LLC, which runs an ethanol plant powered by steam from the CHP unit. This experience served as a model for another joint venture in Laddonia, Missouri. There, a partnership between the Missouri Joint Municipal Electric Utility Commission and Missouri Ethanol resulted in a 14.4-MW gas turbine system launched in 2006, which delivers 5 MW of power and 100,000 lb/h of steam to the adjacent 45-million gallon/year ethanol plant. In both examples, the utilities own and manage the gas turbine, while the ethanol companies have responsibility for the waste heat recovery unit and downstream steam system.[45]

4. GHG Emissions Reductions

Thermal recovery at an existing power plant reduces electrical output, but it improves energy utilization system-wide, thereby reducing fuel use and associated GHG emissions. Total GHG emissions from a CHP system can be roughly half the emissions that would occur from separate heat and power operations, as shown in Figure 2-1.

Output-based emissions factors are calculated using the measured emissions (in pounds of CO_2) and the productive output (whether MWh of electricity or MMBTU of steam) of the equipment under consideration. The two outputs of a CHP plant, electricity and thermal energy, are typically measured in different units (MWh and MMBTU). To express a plant's overall emissions factor and properly recognize the emissions benefits of CHP, the two outputs need to be converted into a single unit. A 2013 EPA guidance document on "Accounting for CHP in Output-Based Regulations" provides two approaches for incorporating a secondary output into emissions rate calculations.[46]

Equivalence Method

Under the equivalence approach, thermal output is converted to equivalent electrical units (e.g., 3.412 MMBTU/MWh) and added to the electric output to determine the total system output. The emissions of the CHP system are then divided by the total output to determine an emissions rate in terms of lb/MWh.

The equivalence method is used, for example, by the state of Texas in its Permit by Rule and Standard Permit regulations, and in California in its conventional emissions limits and emissions performance standards for CHP.[47]

42 Midwest Energy News. (2014, May 13). *Prospects Turning Around for Embattled Spiritwood Coal Plant.* Available at: http://www.midwestenergynews.com/2014/05/13/prospects-turning-around-for-embattled-spiritwood-coal-plant/

43 US EPA Office of Air and Radiation. (2013, February 6). *RFS2 Petition From and Letter of Approval to Dakota Spirit AgEnergy.*

44 GRE. (2014, August). *About Spiritwood Station.* Available at: http://www.greatriverenergy.com/makingelectricity/newprojects/spiritwoodstation.html

45 Bronson, T., Crossman, K., & Hedman, B. (2007, 2nd Quarter). *Utility-Ethanol Partnerships: Emerging Trend in District Energy/CHP.* International District Energy Association. Available at: http://www.epa.gov/chp/documents/district_energy_article.pdf

46 US EPA CHP Partnership. (2013, February). *Accounting for CHP in Output-Based Regulations.* Available at: http://www.epa.gov/chp/documents/accounting.pdf

47 Ibid.

In some instances, regulations may specify a certain percentage of credit to be allotted. The NSPS for utility boilers originally issued in 1998 stipulated the equivalence method, but originally applied a 50-percent credit[48] — later amended to 75 percent in 2006 — such that only that portion of the thermal output would be factored into the total system output. Note the value of the conversion factor depends on the underlying regulatory objectives. States like California, Texas, and Massachusetts ascribe a 100-percent credit for thermal output as a way to encourage CHP.

The proposed 111(b) and 111(d) rules for electric power sector GHG emissions use the equivalence method to award CHP systems with a MWh credit equivalent to 75 percent of the useful thermal output. The EPA provides an example of this accounting approach in correspondence with the Office of Management and Budget,[49] based on the following hypothetical plant specifications:

- 100 MW electric output;
- 500 MMBTU/h of useful steam output; and
- 200,000 lb CO_2/h measured emissions rate.

The thermal output rate of 500 MMBTU/h would be converted to an equivalent MW of output (3.412 MMBTU/h = 1 MWh), whereby 500 MMBTU/h = 147 MW. The resultant value would be multiplied by 75 percent to get a value of 110 MW, which would be added to the electric output to calculate the facility's emissions rate. For comparison against the applicable emissions standard — whether the 1000 lb CO_2/MWh or 1100 lb CO_2/MWh standard — the facility emissions rate would be (200,000 lb CO_2/h) / (100 MW + 110 MW) or 950 lb CO_2/MWh.

The EPA's proposed 111(b) and 111(d) rules would further reward CHP by applying an additional five-percent line loss credit to the net electric output to capture the transmission and distribution losses that are avoided through onsite power generation. The line loss credit would apply to CHP facilities where useful thermal output and electric output (or direct mechanical output) both account for at least 20 percent of total gross output.

Data from GRE's Coal Creek Station, the retrofit CHP coal plant mentioned previously, illustrate how CHP can improve carbon intensity calculations at the EGU level. Table 2-2 examines CO_2 emissions rates for 2007, the first year of thermal sales to the co-located Blue Flint Ethanol plant. Factoring in the 75-percent credit for thermal output, the CO_2 emissions rate for total gross energy output (i.e., electric + 75 percent of thermal) was 2119 lb/MWh. An alternative, non-CHP scenario assumes that the steam extracted off the turbine was instead used to generate

Table 2-2

Comparison of CO_2 Emissions Rates With and Without Thermal Energy Exports at Coal Creek Station (2007)[50]

Electric-Only			CHP			Non-CHP Scenario			CO_2 Intensity, % Improvement with CHP
CO_2, tons/yr	Gross Load, MWh/yr	CO_2, lb/MWh	Gross Steam Transfers, MMBTU/yr	Gross Energy Output, MWh/yr	CO_2, lb/MWh Gross Output	Reduced Electrical Output, MWh/yr	Gross Energy Output, MWh/yr	CO_2, lb/MWh Gross Output	
10,141,763	9,262,539	2190	1,400,111	9,570,211	2119	94,973	9,357,512	2167	2.2%

48 Discussion of this point can be found in Section 5.2.5 of: US EPA. (1998, September). *New Source Performance Standards, Subpart Da and Db – Summary of Public Comments and Response.* Available at: http://www.epa.gov/ttn/oarpg/t1/reports/nox-fdoc.pdf

49 US EPA. (2013, August 2). Summary of Interagency Comments on US Environmental Protection Agency's Notice of Proposed Rulemaking "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units" (RIN 2060-AQ91), EPA-HQ-OAR-2013-0495-0045. Available at: http://www.eenews.net/assets/2014/02/04/document_daily_02.pdf

50 "Gross Steam Transfers" incorporates the total mass of steam transferred to Blue Flint Ethanol in 2007 and a weighted average enthalpy of steam of 1306.10 BTU/lb. For the "Non-CHP Scenario," because of the specific CHP configuration at Coal Creek, only roughly 88 percent of the exported steam would have been used to generate additional power; to this portion, the plant's average performance ratio of 10,000 lb of steam per MWh of electrical output is applied to calculate the reduced electrical output. Steam transfers and reduced electrical output data were provided by GRE for the year 2007. Other emissions and operational data were derived from the EPA's online Air Markets Program Database and confirmed by GRE.

additional electricity at a rate of 1 MWh of electrical output per 10,000 lb of steam. Under this scenario, the plant would have had an emissions rate of 2167 lb/MWh. In this way, the export of thermal energy at Coal Creek Station resulted in a 2.2-percent improvement in the facility's CO_2 emissions rate in 2007. Because exported steam at Coal Creek amounted to less than 20 percent of gross energy output in 2007, the five-percent line loss credit would not apply.

The amount of energy output calculated by the equivalence method varies significantly depending on the *power-to-heat ratio* of a CHP unit. The power-to-heat ratio is an important factor with regard to CHP system efficiency. Owing to the low conversion efficiency of electric generation (e.g., an average 33 percent for coal-fired steam turbines), CHP units that produce proportionally more electricity relative to thermal energy (i.e., units with a high power-to-heat ratio) will have a lower total useful output, and therefore a higher emissions factor. As a result, the more thermal output from a system, the lower that system's CO_2 emissions factor would be.

On the one hand, the equivalence method recognizes thermal output, but the effect of this accounting method is largely a function of the relative amounts of thermal and electric energy produced by the CHP system. The method does not reflect the actual environmental benefit provided by CHP in displacing conventional emitting thermal units.

Avoided Emissions Approach

Alternatively, the avoided emissions approach compares the emissions of the CHP system with the emissions that would have been produced had the thermal energy been generated separately in a conventional boiler.[51] Under this approach, the output-based emissions rate for a CHP system is expressed in terms of its electrical output. This approach assumes the CHP system displaces emissions that would have otherwise occurred in the separate production of electricity and useful thermal output. The net emissions are then divided by the unit's electrical output to determine the emissions rate in terms of lb/MWh. The calculation incorporates only the system's electrical output. Regulations would specify default assumptions; avoided thermal emissions, for example, may be based on the performance of a new source, such as a natural gas-fired boiler with 80-percent efficiency and a standard emissions rate of 0.05 lb per MMBTU of heat input. The avoided emissions approach is particularly relevant to CHP systems at industrial, commercial, and institutional facilities and thus is explained in greater detail in Chapter 3.

Delaware and Rhode Island have used the avoided emissions method in conventional emissions limits for CHP; Connecticut and Massachusetts also use this approach in accounting for small distributed generation.[52] There is general consensus that the avoided emissions approach more closely approximates the environmental attributes of a CHP application, although the equivalence approach is often preferred for its simplicity.

5. Co-Benefits

CHP systems within the electric power sector can deliver a wide range of benefits to the utility system and to society. To begin with, although the earlier discussion focused on the GHG emissions reductions that can be achieved through CHP, similar reductions in criteria and hazardous air pollutant emissions are possible. The methods for quantifying those reductions are essentially the same as the methods used to calculate GHG reductions, with the avoided emissions approach offering a more accurate picture of the impacts.

In addition to reduced pollution, CHP provides broader societal benefits. For instance, installations can be configured with micro-grids to support critical infrastructure and enhance resiliency for emergency response and preparedness. By improving competitiveness, CHP can play a role in strengthening the US manufacturing sector. Furthermore, investment in the energy sector can also be expected to stimulate demand for skilled jobs.[53] A DOE study found that achieving the national goal of

51 The Regulatory Assistance Project. (2003). *Output Based Emissions Standards for Distributed Generation.* Available at: http://www.raponline.org/docs/RAP_IssuesLetter-OutputBasedEmissions_2003_07.pdf

52 Supra footnote 47. Other examples can be found in Appendix B of the EPA's 2003 handbook for air regulators on output-based regulations. US EPA. (2004). *Output-Based Regulations: A Handbook for Air Regulators.* CHP Partnership.

53 A 2008 Oak Ridge National Laboratory study found a CHP goal of 20 percent of generation capacity would stimulate $234 billion in capital investment and create nearly one million new jobs by 2030. Shipley, A., Hampson, A., Hedman, B., Garland, P., & Bautista, P. (2008, December 1). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* ORNL for US DOE. Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf

developing 40 GW of additional CHP would save one quadrillion BTUs of energy annually, prevent 150 million metric tons of CO_2 emissions annually, and save $10 billion per year in energy costs, while attracting $40 to $80 billion in new capital investment in manufacturing and other US facilities over the next decade.[54]

From the perspective of utilities, CHP avoids significant line losses, allows deferral of costly investments in new transmission and distribution infrastructure, and represents low-cost capacity additions, all of which can in turn translate into lower bills for rate-payers. The full range of potential co-benefits for society and the utility system are summarized in Table 2-3.

Table 2-3

Types of Co-Benefits Potentially Associated With Combined Heat and Power in the Electric Sector

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Yes
Other	

When a utility customer receives the thermal output from a utility-owned CHP system, the customer may enjoy additional benefits not shown in Table 2-3. From the perspective of these customers, CHP can improve competitiveness by reducing energy costs. Using thermal energy from an adjacent CHP facility can result in avoided capital expenditure and may help mitigate the customer's own environmental compliance costs. Another motivating factor for participants is greater supply reliability, because CHP can reduce risks posed by grid disruptions. Many of these co-benefits have been alluded to earlier and are further discussed in Chapter 3.

6. Costs and Cost-Effectiveness

CHP is generally regarded as one of the most cost-effective ways to reduce CO_2 emissions economy-wide, a finding confirmed by numerous studies in recent years. A 2009 report by McKinsey & Company, for example, found that 50 GW of CHP in industrial and large commercial/institutional applications would yield positive net-present values over the lifetime of the investment.[55] Economic potential of the same order of magnitude was found by a more recent ICF study, which concluded that 42 GW of CHP technical potential[56] (across all sectors, not just the electric power sector) had an investment payback period of less than ten years across the United States.[57]

New CHP installations can be particularly cost-effective, whereas retrofitting existing EGUs to a CHP configuration

54 US DOE & US EPA. (2012, August). *Combined Heat and Power: A Clean Energy Solution.* http://www.epa.gov/chp/documents/clean_energy_solution.pdf

55 Those projects would result in reductions of 100 million metric tons of CO_2 across the country annually through 2020. Updating that analysis to incorporate today's natural gas prices would likely improve those estimates substantially. McKinsey & Company, at supra footnote 4.

56 Technical potential as defined in the ICF analysis accounts for sites that have concurrent thermal and electric demands suitable to CHP, but does not consider economic factors relevant to project investment decisions, nor does it include existing EGUs.

57 Economic viability was screened by incorporating energy prices (excluding other economic incentives). ICF International for American Gas Association, at supra footnote 17.

can be cost-effective in the right circumstances. Capital costs for new boiler/steam and gas turbine CHP units vary significantly based on size, fuel type, fuel accessibility, geographic area, operational specifications, and market conditions, among other factors.[58] Using 2013 dollars, the EPA estimates that for simple installations, new gas turbine CHP costs typically range from $1200/kW to $3300/kW (4 to 50 MW), and new steam turbine CHP units may range anywhere from $670/kW to $1100/kW, with complete plant costs typically greater than $5000/kW. Retrofit costs for boiler/steam and gas turbine CHP units are even more highly dependent on site-specific configuration requirements. This makes it difficult to generalize about costs and cost-effectiveness.

One of the factors that strongly influences the cost-effectiveness of CHP systems is the price of fuel. Increased domestic natural gas production has radically altered the market outlook for gas, reducing prices and volatility.[59] Most forecasts anticipate an increase in electricity prices against continuously low natural gas prices, improving the economic viability of gas-powered demand-side generation. Clean burning gas, already the preferred fuel for CHP applications, will likely enable future growth and greater investment in CHP.

The underlying economics of retrofit opportunities will weigh the capital cost of modifications to the plant against the tradeoffs between reduced power capacity on the one hand and steam energy output on the other. Factors including fuel costs, operating hours, wholesale power prices, the terms of steam contracts, and investment and management arrangements at the facility, would all bear strongly on this financial analysis. Therefore, although retrofitting CHP as a means of improving emissions performance is theoretically an option for EGUs facing compliance with GHG regulations, in practice, whether these factors amount to a favorable investment opportunity would likely be determined by unique circumstances. The EPA has done some evaluation of costs of retrofitting turbines into existing boiler/steam systems, but in the course of research for this chapter no studies were found to have surveyed retrofits at EGUs specifically.

Given the complexity of EGU retrofits, opportunities for developing utility-scale CHP as a source of new generating capacity may have greater relevance. A 2012 report by the DOE and the EPA included an analysis of delivered electricity costs in New Jersey.[60] Figure 2-6 compares costs of power generated from small-, medium-, and large-sized CHP systems, with retail rates and the cost of delivered electricity from central power generators across a mix of resources. The light gray block at the top of the CHP bars denotes the thermal energy cost savings. Net costs of electricity from medium- and large-scale CHP are lower than retail rates in their respective customer classes, and are more competitive than the combined-cycle gas turbine, coal, wind, and photovoltaic when transmission and distribution costs are taken into account. Producing power for the grid, new CHP EGUs would retain associated transmission and distribution costs for offsite electric customers. Adding these costs back in, large CHP would still be roughly on par with the combined-cycle gas plant, and medium-sized CHP would continue to hold an advantage against wind and coal.

Whether through pay-back period, net-present value, levelized costs of energy, or return on investment metrics, there are numerous ways to evaluate cost-effectiveness. And there are various perspectives from which to evaluate it, whether from that of the participants, the gas utility, the electric utility, the ratepayer, or society generally. Additional analyses of the cost-effectiveness of CHP generally are summarized in Chapter 3.

58 See Table 3-4 of Chapter 3 for cost estimates across technology classes. Within the same fuel and configuration class, costs display a clear scale effect, with costs per kW of capacity generally decreasing as size increases. Also, the amount of steam extracted for thermal purposes, and thus not available for electricity generation, significantly affects the costs (in $/kW) of electricity output. US EPA. (2014, September). *Catalog of CHP Technologies*. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

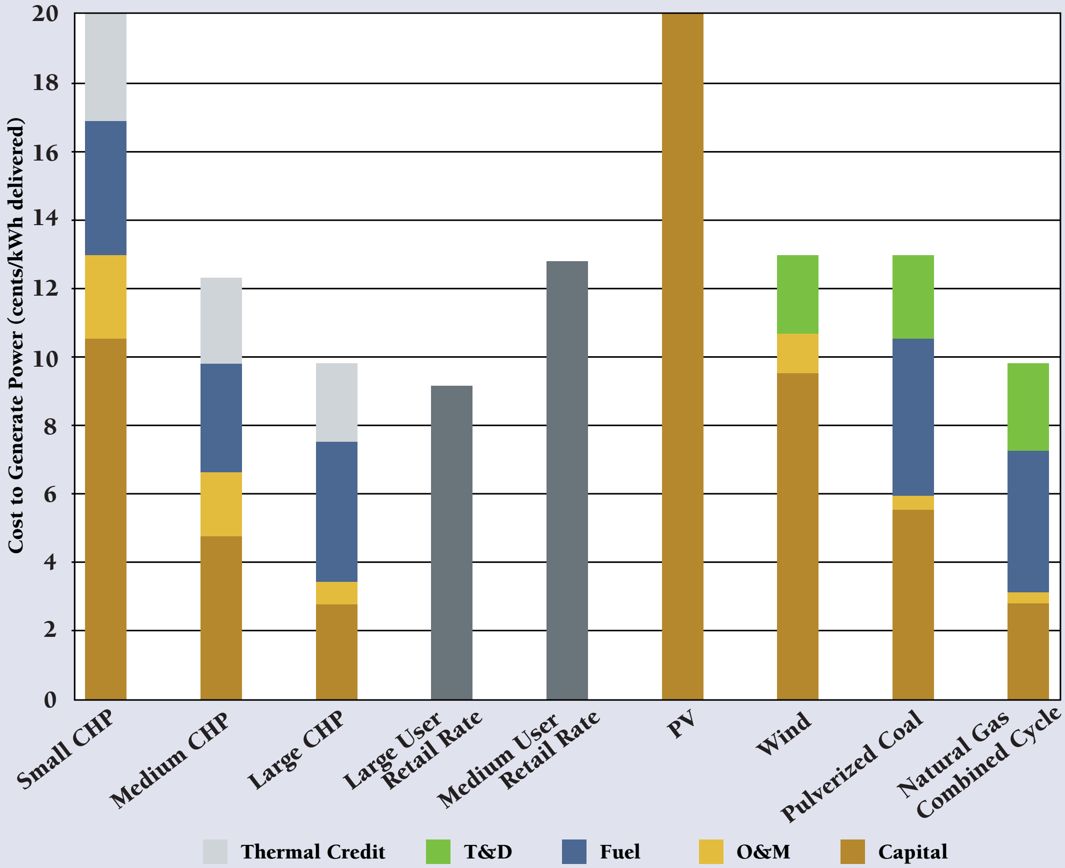
59 Known as a "spark spread," this favorable ratio of gas prices to electricity prices provides increased motivation to CHP producers.

60 Supra footnote 54.

Figure 2-6

CHP Can Be a Cost-Effective Source of New Generation Capacity[61]

Cost of Delivered Electricity — New Jersey



7. Other Considerations

Utility ownership of CHP assets can pose interesting challenges for utility regulators. One issue that often arises is the challenge of deciding how much of the system costs should be paid by electric utility customers in general (and recovered in utility rates) versus how much should be paid by the customer(s) using the CHP system's thermal output. There may also be questions about how to allocate system costs and any revenues from the sale of thermal output to different customer classes. Finally, the risk of stranded assets will also be a significant concern for utility regulators, who must concern themselves with the possibility that a customer who is expected to purchase the thermal output from a long-lived, expensive CHP system, will in the future no longer need the thermal output, or be able to pay for it. Without a customer for the thermal load, the CHP system might someday be uneconomical, but utility customers will still be expected to pay for it. This is what utility regulators call a "stranded asset."

61 Supra footnote 54. Costs of delivered electricity across resource classes and retail rates show that CHP can provide cost-effective generation capacity additions. Note that the light gray block at the top of the CHP bars denotes the thermal energy costs savings. Assumptions: capital and operations and maintenance costs for coal, natural gas combined-cycle, wind, and photovoltaics, and annual capacity factors for wind and photovoltaics based on EIA AEO 2011; annual capacity factors for coal and natural gas combined-cycle based on 2009 national averages (64 and 42 percent, respectively); utility coal and natural gas prices \$4.40/MMBTU and \$5.50/MMBTU, respectively, CHP based on 100-kW engine system and \$7.50/MMBTU natural gas (small CHP), 1-MW engine system and \$6.25 natural gas (medium CHP), 25-MW gas turbine and \$6.25 natural gas (large CHP); cost of capital 12 percent for CHP and 8 percent for central station systems.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CHP in the electric sector.

- ACEEE. *Technical Assistance Toolkit, Policies and Resources for CHP Deployment.* Available at: http://aceee.org/sector/state-policy/toolkit/chp
- ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States.* Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx
- NASEO. (2013). *Combined Heat and Power: A Resource Guide for State Energy Officials.* Available at: http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf
- SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* US DOE and US EPA. Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
- US DOE. CHP Technical Assistance Partnerships website: http://www1.eere.energy.gov/manufacturing/distributedenergy/chptaps.html
- US DOE and Oak Ridge National Laboratory. (2012). *Guidance for Calculating Emission Credits Resulting From Implementation of Energy Conservation Measures.* Available at: http://info.ornl.gov/sites/publications/Files/Pub37258.pdf
- US DOE and Oak Ridge National Laboratory. (2008, December). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf
- US EPA. (2014, July 30). *CHP Emissions Calculator.* Available at: http://www.epa.gov/chp/basic/calculator.html
- US EPA. (2014, July 30). *AVERT.* Available at: http://epa.gov/avert/
- US EPA. (2013, February). *Accounting for CHP in Output-Based Regulations.* Available at: http://www.epa.gov/chp/documents/accounting.pdf
- US EPA. (2012, August). *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems.* Available at: http://www.epa.gov/chp/documents/fuel_and_co2_savings.pdf
- US EPA. (2014). *Output-Based Regulations: A Handbook for Air Regulators.* Available at: http://www.epa.gov/chp/documents/obr_handbook.pdf
- US EPA CHP Partnership website: http://www.epa.gov/chp/
- US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies.* Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

9. Summary

CHP provides a cost-effective, commercially available solution for near-term reductions in GHG emissions, with large technical potential distributed across the country. CHP results in direct energy savings to the user, and offers a host of wider societal benefits, including reductions in air pollution, enhanced grid reliability, low-cost capacity additions, and improved resiliency of critical infrastructure. Retrofit opportunities at existing EGUs will be limited, however, by site-specific factors. Such factors include the geographic proximity to suitable users of thermal energy, and the need to incorporate enough thermal recovery to bring the unit into compliance, while balancing the tradeoff between reduced power production on steam turbines and thermal energy sales. Assessments of CHP feasibility could be undertaken by plant management as they review options for improving heat rate performance, such as those outlined in Chapter 1. As for new construction, larger-scale CHP facilities that integrate the operations of generators with industrial partners offer a cost-competitive alternative to central power production and cost-effective replacement capacity for aging plants poised for retirement. CHP projects are often complex, custom installations with equally complex legal and financial arrangements between partnering entities. Therefore, despite the technology being mature, substantial administrative burdens persist and keep rates of adoption low even in jurisdictions with favorable regulatory environments. Supportive policies and regulations will be required to take full advantage of CHP opportunities, whether as stipulated in the EPA's final 111(b) and 111(d) rules or otherwise in plans and accounting requirements developed by states.

3. Implement Combined Heat and Power in Other Sectors

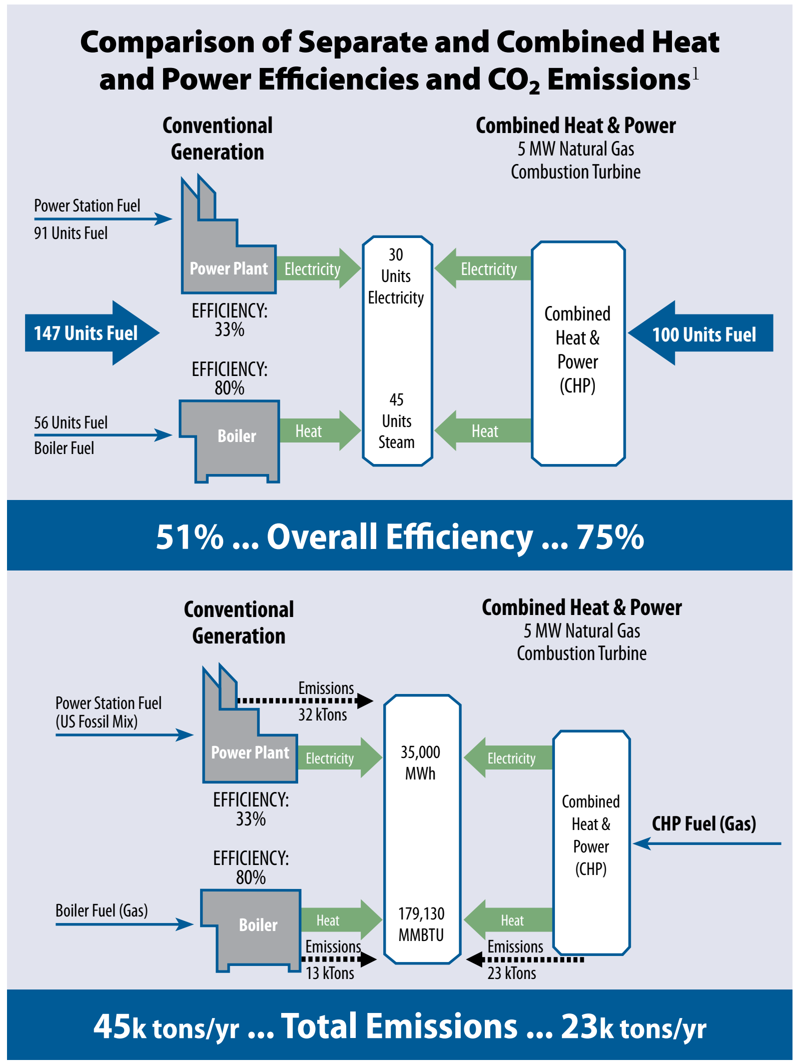
1. Profile

Combined heat and power (CHP) technologies in the commercial, institutional, and manufacturing sectors can reduce carbon dioxide (CO_2) emissions across the economy through system-wide gains in energy efficiency that improve economic competitiveness. Because CHP systems in these sectors indirectly reduce the need for generation within the power sector, they may even play a role in state plans for complying with federal regulations covering power sector greenhouse gas (GHG) emissions, such as the rules proposed by the US Environmental Protection Agency (EPA) in 2014 under sections 111(b) and 111(d) of the Clean Air Act.

CHP, also known as cogeneration, refers to a variety of technology configurations that sequentially generate both electric and useful thermal output from a single fuel source. As discussed in Chapter 2, CHP can take the form of large-capacity power producers that sell bulk electricity to the grid while supplying neighboring industrial facilities or district energy systems with thermal energy for process or space heating purposes. But CHP can also be installed at facilities with onsite or nearby demand for both heating or cooling and electricity, such as manufacturing facilities, universities, hospitals, government buildings, multifamily residential complexes, and so forth, as decentralized generation assets ranging in size and distributed across the electric grid. CHP as a form of distributed generation for these types of facilities is the subject of this chapter.

By displacing onsite boiler use and grid-supplied electricity, CHP systems can ensure supply reliability, save fuel, and reduce operating costs, typically achieving combined efficiencies of 60 to 80 percent as opposed to the 40 to 55 percent that might be expected from separate heat and power operations. These energy savings can amount to a 50-percent reduction in carbon emissions (Figure 3-1). Beyond the facility utilizing CHP, they can deliver a host of societal benefits, including improved environmental

Figure 3-1



1 US EPA. (2014, August). *CHP Partnership*. Available at: http://www.epa.gov/chp/. A power plant efficiency of 33 percent (higher heating value [HHV]) denotes an average delivered efficiency based on 2009 data from eGRID for all fossil fuel power plants of 35.6 percent, plus 7 percent transmission and distribution losses.

performance, high quality jobs, reduced congestion on the electric grid, reduced line losses, and embedded resiliency for emergency response and preparedness.

There are two basic types of CHP, what are referred to as bottoming and topping systems. A "topping-cycle" system is the most common configuration, in which fuel is used to power a steam turbine or combusted in a prime mover, such as a gas turbine or reciprocating engine, with the purpose of generating electricity. Rejected heat is then captured and used for process or space heating needs. In a "bottoming-cycle" system, also called "waste heat to power" (WHP), the fuel is first used to deliver a thermal input to an industrial process, and waste heat is recovered for power generation (see text box on page 3-3).

As a form of distributed generation, CHP can be based on a variety of generation technologies, summarized in Table 3-1, such as combustion turbines, steam turbines, reciprocating engines, microturbines, and fuel cells. These

Table 3-1

Summary of CHP Technologies[2]

CHP System Type	Advantages	Disadvantages	Available Sizes	Overall Efficiency (HHV)	Installed, 2014 (Capacity/ Sites)[3]
Gas Turbine	High reliability. Low emissions. High-grade heat available. Less cooling required.	Requires high-pressure gas or in-house gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.	500 kW to 300 MW	66% to 71%	64%/16%
Steam Turbine	High overall efficiency. Any type of fuel can be used. Ability to meet more than one site's heat grade requirement. Long working life and high reliability. Power to heat ratio can be varied within a range.	Slow start-up. Low power-to-heat ratio.	50 kW to 300+ MW	Near 80%	32%/17%
Reciprocating Engine	High power efficiency with part-load operational flexibility. Fast start-up. Has good load following capability. Can be overhauled onsite with normal operators. Operates on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions.[4] Must be cooled even if recovered heat is not used. High levels of low frequency noise.	1 kW to 10 MW in distributed generation applications	77% to 80%	3%/52%
Fuel Cell	Low emissions and low noise. High efficiency over load range. Modular design.	High costs. Low power density. Slow startup. Fuels requiring processing unless pure hydrogen is used.	5 kW to 2 MW	55% to 80%	0.1%/4%
Microturbine	Small number of moving parts. Compact size, light weight. Low emissions. No cooling required.	High costs. Relatively low electrical efficiency. Limited to lower temperature cogeneration applications.	30 kW to 250 kW	63% to 70%	0.1%/8%

kW: kilowatt
MW: megawatt

2 US EPA. (2015, March). *Catalog of CHP Technologies*. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf. Note that these are illustrative values intended to represent typical CHP systems. CHP efficiency varies with size and power-to-heat ratio.

3 The data in the last column indicate each system type's percentage of total installed US CHP capacity (83.3 gigawatt) and total number of installations (4220 sites) as of 2014. Ibid.

4 Note that reciprocating engines can be configured to produce lower levels of emissions through engine design and add-on controls.

various technology configurations can consume a range of fuels, including oil, biomass, landfill gas, biogas, and hydrogen, but natural gas is the most common, accounting for 70 percent of existing CHP capacity.[5] The revolution in shale gas production has boosted domestic natural gas supplies, reducing both prices and volatility, which,

WHP describes any number of applications by which waste heat is captured from an industrial process through heat exchange to generate electricity. Since the 1970s, steam turbines have been used to generate power from high temperature exhaust. More recent advances allow heat recovery at lower temperatures and smaller scales – using the Organic Rankine Cycle, Kalina Cycle, and the Stirling Engine, for example – permitting power generation from a broader range of industrial applications. Technology is continuing to evolve, expanding the viability of WHP applications to low quality heat, where the majority of industrial heat losses occur.[6]

The Organic Rankine Cycle accomplishes heat transfer at low temperatures using an organic working fluid instead of water. Carbon-based refrigerants with high molecular weight can improve the heat transfer efficiency because they possess a lower boiling point than that of water.[7] The Kalina Cycle is a type of Rankine Cycle that achieves greater efficiencies by using a mixture of two fluids with different boiling points, typically ammonia and water, to extract energy across a wider range of temperature inputs. The Organic Rankine Cycle and Kalina Cycle are the same technologies used to generate power from renewable resources, such as geothermal and solar. In the industrial sector, primary metals, minerals manufacturing, chemical industry, petroleum refining, natural gas compressor stations, and landfill gas systems represent some of the industries that involve numerous processes with potential for WHP.[8,9]

As a technology category, WHP includes ***bottoming-cycle cogeneration*** as it is defined in this chapter, that is, instances in which waste heat is recovered from a thermal process, like a cement kiln or glass furnace, to generate electricity. However, WHP also includes applications in which waste heat is recovered from industrial processes that are not thermal, for example, from natural gas compressor stations. The term combined heat and power is often defined narrowly so as to exclude applications that are delivering useful services other than heating and cooling. Furthermore, Congress, federal agencies, and states have conflicting definitions, such that bottoming-cycle cogeneration and other WHP applications may be excluded from incentive programs – if not in spirit, then only by letter of the law. An example with large repercussions for the WHP market is Section 48 of the Tax Code, which provides a ten-percent investment tax credit for topping-cycle CHP only.[10] One approach taken by states seeking to support industrial efficiency through their portfolio standards has been to define CHP and WHR separately. Eighteen states specifically identify WHP as a qualifying resource in their Renewable, Clean Energy, or Energy Efficiency Portfolio Standards.[11]

5 The second most dominant fuel in CHP installations is coal, at 15 percent of US CHP capacity as of March 2014. ICF International for US Department of Energy and Oak Ridge National Laboratory. (2014, March). *CHP Installation Database*. Available at: http://www.eea-inc.com/chpdata/

6 The US Department of Energy estimates that 60 percent of industrial waste heat is below 450°F, whereas 90 percent is below 600°F. US Department of Energy. (2008). *Waste Heat Recovery: Technology and Opportunities in US Industry.* Available at: http://www1.eere.energy.gov/manufacturing/intensiveprocesses/pdfs/waste_heat_recovery.pdf

7 In the past, choice working fluids for Organic Rankine Cycle were ozone-depleting substances phased out under the Montreal Protocol and replaced by hydrofluorocarbons and perfluorocarbon compounds with high global warming potential, now also in the process of being phased out. Low global warming potential, zero ozone-depleting substance refrigerants like hydrocarbons and other compounds are now being brought into use as substitutes.

8 US EPA. (2012, May 30). *Waste Heat to Power Systems.* (Case studies.) Available at: http://www.epa.gov/chp/documents/waste_heat_power.pdf. Case studies.

9 For detailed project profiles, see: Heat Is Power. (2014). *Case Studies.* Available at: http://www.heatispower.org/waste-heat-to-power/case-studies/

10 26 US Code § 48 - Energy credit. Available at: http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA-partIV-subpartE-sec48.pdf

11 Heat Is Power. (2014). *Waste Heat to Power Fact Sheet.* Available at: http://www.heatispower.org/wp-content/uploads/2014/10/HiP-WHP-Fact-Sheet-10-23-2014.pdf

combined with the fuel's low-emissions profile, positions it as a driving force in CHP growth.

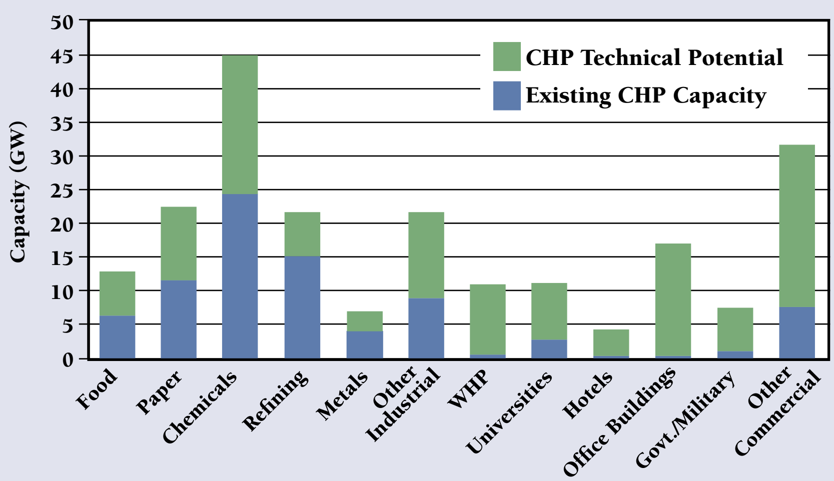
CHP technology is largely mature, which makes it deployable over the near-term at existing facilities and gives it the potential to play an important role at various scales in replacing industrial and commercial coal-fired boilers as they move toward retirement.[12] Accounting for 8 percent of current US generating capacity and 12 percent of electricity, CHP is regarded as an underutilized opportunity for emissions reductions.[13] ICF International estimates there to be a total of 125 gigawatts (GW) of remaining technical potential for CHP at existing industrial and commercial/institutional facilities across the United States (Figure 3-2).[14] A separate research effort in 2008 by Oak Ridge National Laboratory (ORNL) analyzed a goal of increasing CHP to 20 percent of generation capacity by 2030. It found that achieving 20-percent CHP would substantially reduce national energy consumption, saving 5.3 quadrillion BTU of fuel annually, the equivalent of nearly half the total energy consumed currently at the residential level.[15]

2. Regulatory Backdrop

A map of CHP facilities in the United States prepared by the US Energy Information Administration, shown in Figure 3-3, illustrates that US CHP capacity is geographically concentrated and that there are two kinds of conditions in which CHP has taken hold. One condition is where the economics strongly support mid- to larger-scale applications, such as in the petrochemical and refineries of the Gulf Coast (where Texas and Louisiana alone account for 30 percent of national CHP capacity), as well as in timber-rich states in the Southeast, Northwest, and in Maine, where the residual wood waste stream provides cheap boiler fuel in the pulp and paper industry (paper production accounts for 14 percent of national capacity). Large cities in the north are another example where geographic circumstances facilitate the economics of district heating and cooling. The other parts of the country where CHP shows high levels of penetration are in states, such as California (8.8 GW) and New York (5.5 GW), that have high electricity prices and have fostered favorable regulatory environments for CHP.[17] This highlights the extent to which policy is integral to creating or removing barriers to CHP.

Figure 3-2

CHP Technical Potential and Existing Capacity by Sector[16]



Source: ICF Internal Projections

12 Chittum, A. (2012, September). *Coal Retirements and the CHP Investment Opportunity.* Available at: http://www.aceee.org/research-report/ie123

13 ICF International for US Department of Energy and ORNL, at supra footnote 5.

14 Note that technical potential is not the same as economic potential. Technical potential accounts for sites that have electric and thermal demands suitable to CHP, while ignoring economic considerations. ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States.* Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx

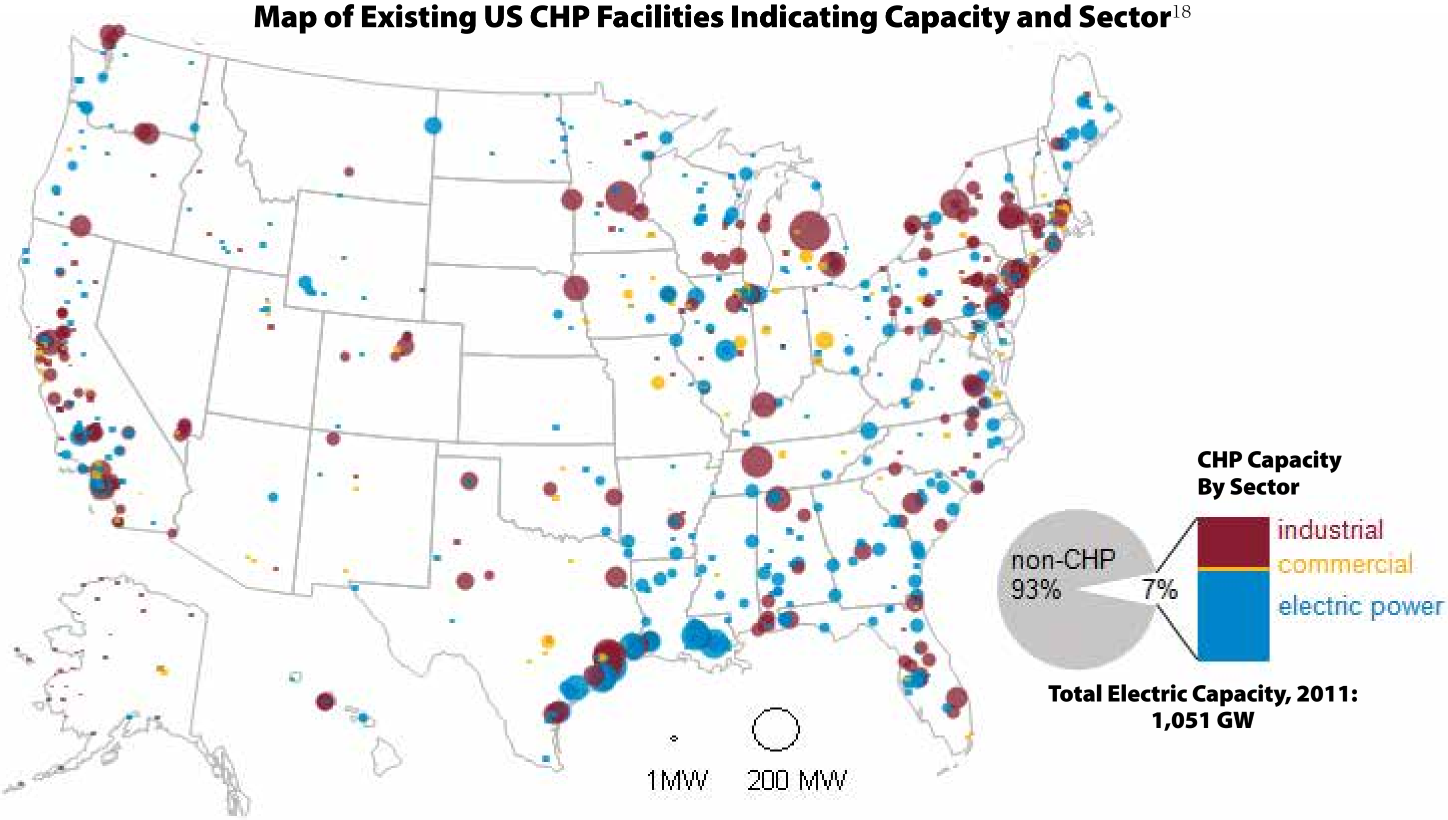
15 Shipley, A., Hampson, A., Hedman, B., Garland, P., & Bautista, P. (2008, December 1). *Combined Heat and Power: Effective Energy Solutions for a Sustainable Future.* ORNL for US Department of Energy. Available at: http://www.energy.gov/sites/prod/files/2013/11/f4/chp_report_12-08.pdf

16 ICF International. (2014, July 23). *From Threat to Asset: How Combined Heat and Power Can Benefit Utilities.* Available at: http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities?_cldee=amVubmlmZXJAZGdhcmRpbmVyLmNvbQ%253d%253d&utm_source=ClickDimensions&utm_medium=email&utm_campaign=Com%253A%20Energy_Webinar_07.08.14

17 ICF International for US Department of Energy and ORNL, at supra footnote 5.

Figure 3-3

Map of Existing US CHP Facilities Indicating Capacity and Sector[18]



Given the diversity of technologies, fuels, sizes, and sectors, the regulatory context surrounding CHP is multifaceted. The following discussion focuses on a number of regulatory drivers currently affecting CHP, namely:

- Issues in utility regulation;
- Air pollution regulations;
- National and state CHP capacity targets; and
- Grid reliability and resilience.

Utility Regulation

Federal and state utility regulation has played a major part in promoting CHP in the industrial, commercial, and institutional sectors. Many of the barriers facing CHP pertain to economies of scale and the technical and administrative burdens facing small power producers who are usually not in the energy business. The Federal Public Utilities Regulatory Policies Act (PURPA) of 1978 had the effect of encouraging CHP by obligating utilities to buy power from independent CHP generators meeting certain eligibility standards. PURPA also requires utilities to pay prices equivalent to the utilities' avoided cost, and to offer reasonable standby rates and backup fees.[19] These rules, in conjunction with federal tax credits initiated in 1980, had the effect of stimulating investment in CHP, which increased five-fold from 1980 through 2000 (refer to Figure 2-4 in Chapter 2).

Following the development of competitive wholesale power markets in parts of the country, the Federal Energy Regulatory Commission (FERC) issued rulings pursuant to the Energy Policy Act of 2005, which exempts utilities from the PURPA must-buy provisions for larger facilities (>20 MW) in cases in which the facility has non-discriminatory access to wholesale markets.[20] This amendment, along

18 US Energy Information Administration. (2012, October). *Today in Energy: Combined Heat and Power Technology Fills an Important Energy Niche.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=8250

19 Avoided cost is defined as the cost of energy that would have been supplied from the utility's own system if the energy had not been supplied by the qualifying facility.

20 US FERC. (2006, October 20). Ruling No. 688. New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities. Available at: https://www.ferc.gov/whats-new/comm-meet/101906/E-2.pdf. All related orders by FERC pertaining to Qualifying Facilities can be found at: https://www.ferc.gov/industries/electric/gen-info/qual-fac/orders.asp

with volatile natural gas prices and general regulatory uncertainty surrounding the establishment of competitive markets, spawned a period starting in 2006 of steep decline in new CHP capacity additions.[21]

Today, PURPA is implemented variably across the country. Interconnection standards, standby rates, and tariffs are still considered regulatory obstacles to greater deployment of CHP. Although financial incentives are part of the problem, low rates of technology adoption are also attributed to administrative burdens surrounding grid interconnection. A 2013 report by the State and Local Energy Efficiency Action Network (SEE Action) provides a thorough survey of the regulatory architecture needed to support CHP deployment, including detailed recommendations on the following issues:[22]

- **Interconnection Standards.** CHP and other distributed generation resources can be facilitated through standardized interconnection rules and streamlined application procedures. Standard guidelines of some kind are in place in 43 states and the District of Columbia.[23]
- **Rates for Standby Services.** Utilities charge CHP customers standby tariffs in exchange for providing a bundle of services that includes back-up power for unplanned outages and scheduled maintenance, supplemental power for customers for whom onsite generation is insufficient, and the associated transmission and distribution delivery services, among other offerings. Originally designed in a vertically integrated electricity market with few interties, standby rates were averaged over customer classes. Today rates may be structured to more closely match actual costs incurred based on individual customer profiles.[24] They can also be accompanied by requirements and incentives that encourage customer-generators to use electric services efficiently and minimize costs on the grid.[25]
- **Prices Paid for Excess Electricity.** Avoided cost rates implemented through PURPA, Feed-In Tariffs (FITs), and competitive procurement have all been demonstrated to be effective methods for setting prices for electricity delivered to the grid from CHP systems. FERC recently ruled that the value of a resource in helping to meet state procurement obligations (i.e., renewable portfolio standards) can be incorporated into avoided cost calculations.[26] This ruling dealt specifically with California's "multi-tiered" avoided cost rate structure for a FIT to acquire smaller CHP systems (<20 MW), which FERC found to be consistent with PURPA. Usually FITs set a fixed price per unit delivered from a specific energy technology type (e.g., wind, solar, CHP) over a set period of years. Such pricing is based on the estimated cost of eligible generation plus a reasonable return to investors, but FIT prices can also be based on the value the generator provides to the electric system. Alternatively, in a restructured environment, CHP projects may bid into energy, capacity, and ancillary service markets if they meet established protocols, and a FIT may take the form of a premium payment on top of the energy market price. In jurisdictions with CHP targets, competitive procurement processes are also used to reveal costs and acquire larger projects.[27]

21 US Department of Energy and US EPA. (2012, August). *Combined Heat and Power: A Clean Energy Solution.* Available at: http://www.epa.gov/chp/documents/clean_energy_solution.pdf

22 US Department of Energy, US EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies

23 For more on best practices in design of interconnection standards, see: Sheaffer, P. (2011, September). *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4572

24 The Regulatory Assistance Project. (2014, February). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States.* Available at http://www.raponline.org/press-release/standby-rates-for-combined-heat-and-power-need-a-fresh. Johnston, L., Takahashi, K., Weston, F., & Murray, C. (2005, December). *Rate Structures for Customers With Onsite Generation: Practice and Innovation.* NREL/SR-560-39142. Available at: http://www.michigan.gov/documents/energy/NREL_419830_7.pdf

25 For more detail and specific case studies, consult The Regulatory Assistance Project's policy brief outlining standby rate design features to support CHP systems, at supra footnote 24. Also see: ACEEE. *Policies and Resources for CHP Deployment: CHP-Friendly Standby Rates.* Available at: http://aceee.org/policies-and-resources-chp-deployment-chp-friendly-standby-rates

26 US FERC. (2010). 133 FERC ¶ 61,059. Available at: https://www.ferc.gov/whats-new/comm-meet/2010/102110/E-2.pdf

27 Supra footnote 22.

Air Pollution Regulations

In Chapter 2, a list of existing and proposed federal New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants (NESHAP) that might impact CHP installations was provided. The applicability of each regulation depends on the fuels combusted, the heat input or electrical output of the system, how much electricity is delivered to the grid versus used onsite, and the date of construction, reconstruction, or modification.

As noted in Table 3-1, most of the installed CHP capacity in the United States uses either steam turbine or gas combustion turbine technology. Furthermore, most of the CHP units described in this chapter do not meet the definition of electric utility steam generating unit because they are designed to generate electricity for onsite consumption, and therefore are not directly affected by regulations for electric generating units such as the proposed GHG regulations under sections 111(b) and 111(d) of the Clean Air Act. Thus, the regulations most relevant to the CHP units described in this chapter are the NESHAP regulations for industrial, commercial, and institutional boilers and process heaters (40 CFR Part 63 Subparts DDDDD and JJJJJ) and for stationary combustion turbines (Subpart YYYY), as well as the New Source Performance Standards regulations for industrial, commercial, and institutional steam generating units (40 CFR Part 60 Subparts Db and Dc) and for stationary combustion turbines (Subpart KKKK). New Source Review (NSR) permitting requirements are also significant.

Finalized in January 2013, the NESHAP for new and existing boilers and process heaters covers major sources in industrial, institutional, and commercial facilities.[28] These Maximum Achievable Control Technology (MACT) standards, commonly called the "Boiler MACT," affect roughly 14,000 boilers across the country, burning a wide range of fuels and providing heat for various mechanical, heating, and cooling processes and uses.[29] Relatively few of these boilers already use CHP technology, but the impact of the regulations on CHP deployment may be much more significant. Notably, the Boiler MACT rule includes provisions that reward energy efficiency upgrades, such as investments in waste heat recovery and CHP. All existing major sources in this source category are required to do routine tune-ups and to conduct a one-time energy assessment to identify cost-effective conservation measures.

The Boiler MACT rules also set specific emissions limits for some 1750 of the largest industrial boilers, fired primarily by coal, oil, and biomass.[30] Facilities can opt to use output-based emissions limits instead of heat input-based limits. These standards are set in terms of pounds of pollution per million BTU of steam output (lb/MMBTU) and pounds of pollution per megawatt-hour of electricity output (lb/megawatt-hour [MWh]), rather than pounds of pollution per million BTU of heat input. Using the output-based standards allows firms to earn credit toward compliance because their implementation of boiler efficiency measures has the effect of reducing energy input relative to a constant level of useful output.[31] But with many of these boilers more than 40 years old,[32] owners have also evaluated options for boiler replacement, creating a timely window for new CHP installations. Subject to a January 21, 2016 deadline, compliance decisions — whether to upgrade coal boilers, convert or replace natural

28 40 CFR Part 63. (2013, January 31). *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.* Available at: http://www.gpo.gov/fdsys/pkg/FR-2013-01-31/pdf/2012-31646.pdf. A major source facility emits or has the potential to emit 10 or more tons per year of any single air toxic or 25 or more tons per year of any combination of air toxics. Sources that emit less than this threshold are classified as area sources.

29 US EPA. (2012, December). *EPA's Air Toxics Standard Major and Area Source Boilers and Certain Incinerators: Technical Overview.* Available at: http://www.epa.gov/airquality/combustion/docs/20121221_tech_overview_boiler_ciswi_fs.pdf

30 US EPA. *Emissions Standards for Boilers and Process Heaters and Commercial/Industrial Solid Waste Incinerators.* Available at: http://www.epa.gov/airquality/combustion/actions.html

31 Federal Register Section 63.7533 outlines the methodology for determining compliance using emissions credits and the EPA provides a hypothetical example online here: http://www.epa.gov/ttn/atw/boiler/imptools/energycreditsmarch2013.pdf

32 Nearly half of the US boiler population with a capacity greater than 10 MMBTU/h is at least 40 years old. Energy and Environmental Analysis for ORNL. (2005). *Characterization of the US Industrial/Commercial Boiler Population.* Available at: http://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/characterization_industrial_commerical_boiler_population.pdf

gas boilers, or switch to natural gas CHP — have largely been made and are being implemented now. This rule demonstrates how environmental regulations can drive markets for energy-efficient technologies like CHP, even while regulating emissions from CHP systems.

The rule also offers a model for how government can assist in promoting the benefits of CHP. Through the seven regional offices of its CHP Technical Assistance Partnerships,[33] the US Department of Energy (DOE) takes advantage of this Boiler MACT compliance opportunity by providing general outreach and market research, as well as site analysis to support CHP project development from feasibility to installation.[34] Outreach to nearly 700 facilities returned interest from 50, representing a potential of 752 MW of CHP capacity additions.[35] Focused on strategic markets, including hospitals, critical infrastructure, biomass, district microgrids, and federal agencies, the DOE's program has sought to develop examples with broader implications for adopting CHP in conjunction with environmental compliance activities. As part of the program, the DOE has produced a number of reports and resources, including a 2012 report prepared by ICF International enumerating financial incentives state by state[36] and a guidance document prepared by ORNL for calculating emissions credits from conservation measures.[37]

CHP applications reduce the total amount of pollution emitted onsite and offsite, yet by generating heat and power onsite they may have the effect of increasing a facility's direct onsite emissions. In this way, accounting for the benefits of CHP requires an outside-the-fence approach, which has posed a challenge to energy and environmental regulations conventionally focused on fuel-use and pollution at individual facilities within individual source categories. The NSR program illustrates this problem.[38]

The NSR permitting process, which may be triggered if modifications to an industrial plant are expected to increase onsite pollution, often requires expensive investments in end-of-pipe pollution controls for facilities seeking to make capital upgrades for CHP. Further challenging conventional regulation is the fact that a CHP facility produces multiple value streams: thermal energy, electric energy, and electricity demand reductions through energy efficiency. Especially given the diverse range of applications, sizes, and fuel types, the issue of how to quantify these values and how to regulate CHP more generally has long been problematic.

The shift in state and federal regulatory strategies over recent years from input-based to output-based regulations (OBR) helps remedy this problem.[39] OBRs, framed as pollution per unit of productive output, encourage clean energy deployment and help incorporate energy efficiency and renewable energy investments directly as compliance options, while granting businesses the opportunity to flexibly achieve the emissions limits through various means, including heat rate improvements, cleaner fuel substitutes, or end-of-pipe technologies. Output-based emissions standards can be applied to any process to promote efficiency. The recently finalized New Source Performance

33 The DOE's CHP Technical Assistance Partnerships (CHP TAPs) were formerly called the Clean Energy Application Centers (CEACs). Available at: http://www1.eere.energy.gov/manufacturing/distributedenergy/chptaps.html

34 US DOE. *Boiler MACT Technical Assistance Program.* Available at: http://energy.gov/eere/amo/boiler-mact-technical-assistance-program. Starting in February of 2012, an initial pilot effort between the DOE and the Ohio Public Utility Commission was subsequently scaled to the national level. Public Utilities Commission of Ohio. *Combined Heat and Power in Ohio.* Available at: http://www.puco.ohio.gov/puco/index.cfm/industry-information/industry-topics/combined-heat-and-power-in-ohio/

35 US DOE. (2014, May). *Boiler MACT Technical Assistance.* Available at: http://energy.gov/sites/prod/files/2014/05/f15/boiler_MACT_tech_factsheet_1.pdf. Hampson, A. (2014). Presentation at the Electric Power Conference and Exhibition. *CHP Market Status and Opportunities for Growth*. ICF International.

36 ICF International for US DOE. *Financial Incentives Available for Facilities That are Affected by the US EPA NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters: Proposed Rule.* Available at: http://www1.eere.energy.gov/manufacturing/states/pdfs/incentives_boiler_mact.pdf

37 ORNL. (2012). *National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers, Guidance for Calculating Emission Credits Resulting from Implementation of Energy Conservation Measures.* Available at: http://info.ornl.gov/sites/publications/Files/Pub37258.pdf

38 US EPA. (2013, July 30). *New Source Review.* Available at: http://www.epa.gov/NSR/

39 US EPA CHP. (2014). *Output-Based Regulations: A Handbook for Air Regulators.* Available at: http://www.epa.gov/chp/documents/obr_handbook.pdf

Standards for Electric Utility Steam Generating Units, for example, include output-based emissions standards for particulate matter, nitrogen oxides (NO_X), and sulfur dioxide (SO_2).[40]

OBRs are especially useful in addressing sources that have more than one productive output. A 2013 EPA guidance document on "Accounting for CHP in Output-Based Regulations" recommends two approaches for incorporating a secondary output into emissions rate calculations.[41] The first is an *equivalence approach,* whereby the secondary output — be it electricity or thermal energy, depending on the configuration — is converted into the units of the primary output by way of a conversion factor. The conversion factor may be a direct unit conversion (e.g., 3.412 MMBTU/MWh) or may reflect a certain valuation of the secondary energy output by discounting as per regulatory objectives. This method has been used by the state of Texas in its permit by rule and standard permit regulations, and in California in its conventional emissions limits and emissions performance standards for CHP.[42]

Alternatively, the EPA outlines an *avoided emissions approach,* which involves developing assumptions about the pollution that would have been emitted if the same outputs had been generated separately.[43] Offset emissions are subtracted from the CHP system's actual emissions to capture its offsite benefits. OBRs thus could specify the default assumptions, for example, *Avoided Thermal Efficiency* would typically be based on the performance of a new natural gas-fired boiler (80 percent) and the Avoided Central Station Emission Factor would be based on fleet data from the EPA's Emissions & Generation Resource Integrated Database (eGRID) database. Connecticut and Massachusetts are using avoided emissions methods in accounting for small distributed generation; Delaware and Rhode Island have also used this approach in conventional emissions limits for CHP.[44]

These two approaches for incorporating a secondary output into emissions rate calculations are described in greater detail in Chapter 2. There is some controversy about which method is most appropriate for regulatory purposes. Although both methods reward efficiency, there is general consensus that quantifying avoided emissions produces a more accurate emissions signature of a CHP system, yet the equivalence method has been preferred historically for its simplicity. Within the equivalence method there is additional debate over the conversion factor. Historically, the EPA has discounted thermal energy 50 percent in OBRs, whereas California and Texas are states that ascribe 100 percent credit for thermal output in their OBRs. In its recent proposal to regulate GHG emissions from existing EGUs [under section 111(d)], the EPA assigned a value of 75 percent credit and requested comment on a range of two-thirds to 100-percent credit for useful thermal output.[45] The same regulatory proposal further rewards CHP by applying an additional five percent line loss credit to the net electric output to capture the transmission and distribution losses that are avoided through onsite power generation.

Capacity Targets

In 2012, the Obama Administration set a national goal of 40 GW of new, cost-effective CHP by 2020 through an Executive Order to Accelerate Investment in Industrial Energy Efficiency.[46] This has helped to motivate greater coordination of existing federal activities on the issue, predominantly between the EPA and the DOE. The SEE

40 40 CFR Part 60, Subpart Da. *Standards of Performance for Electric Utility Steam Generating Units.* Available at: http://www.ecfr.gov/cgi-bin/text-idx?SID=324a6cdb45a7b9a1f8c055dc6e64982d&node=sp40.7.60.d_0a&rgn=div6

41 US EPA CHP Partnership. (2013, February). *Accounting for CHP in Output-Based Regulations.* Available at: http://www.epa.gov/chp/documents/accounting.pdf.

42 Ibid.

43 The Regulatory Assistance Project. (2003). *Output Based Emissions Standards for Distributed Generation.* Available at: http://www.raponline.org/docs/RAP_IssuesLetter-OutputBasedEmissions_2003_07.pdf

44 Supra footnote 41. Other examples can be found in Appendix B of the EPA's 2003 handbook for air regulators on output-based regulations, at supra footnote 39.

45 79 FR 34829. Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

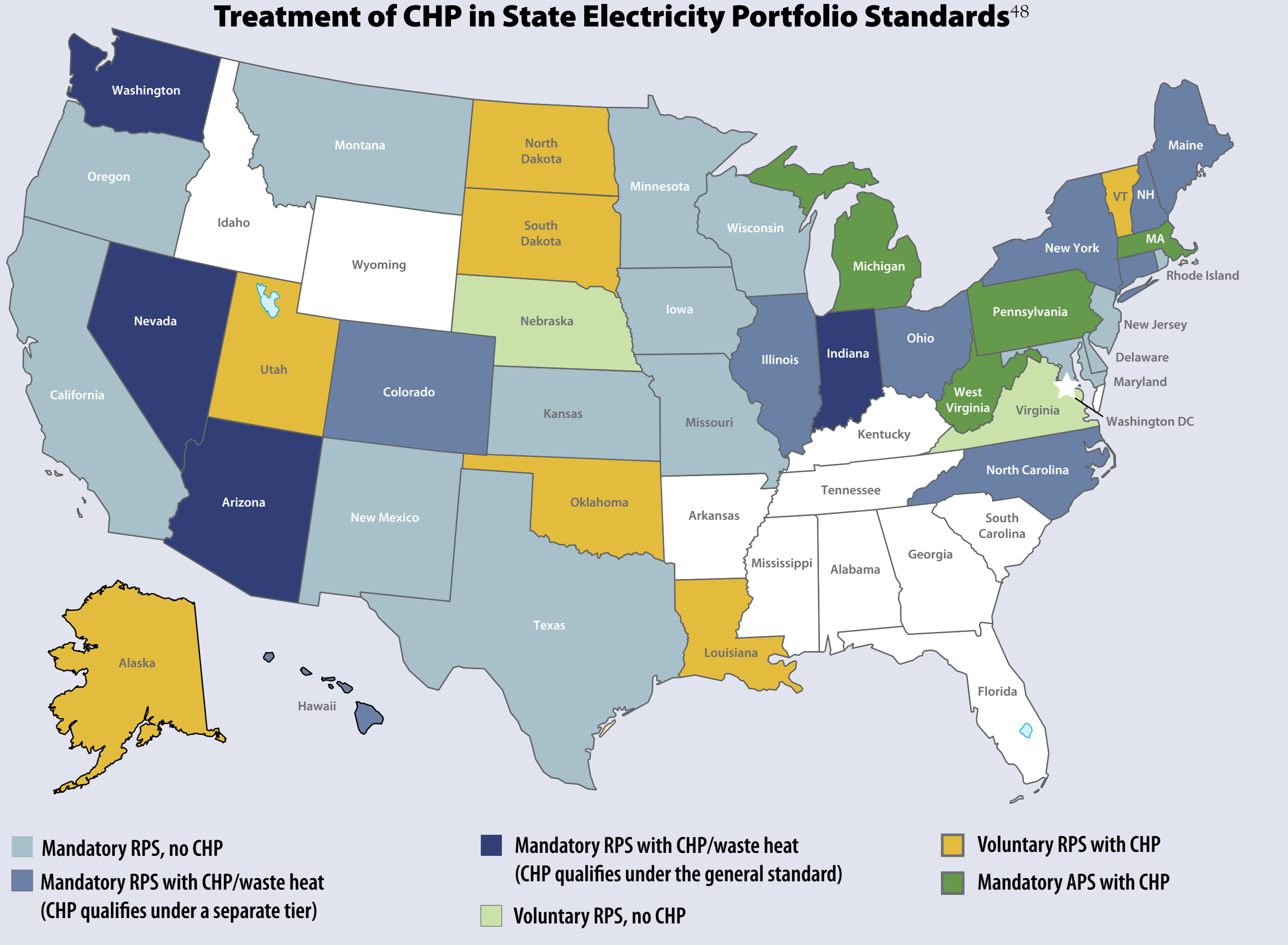
46 Executive Order 13624. (2012, August 30). *Accelerating Investment in Industrial Energy Efficiency.* 77 FR 54779. Available at: http://www.gpo.gov/fdsys/pkg/FR-2012-09-05/pdf/2012-22030.pdf

Action Network has taken the lead, convening stakeholders and providing technical assistance to states. Many resources related to these efforts can be found on SEE Action's website, the EPA's website for its Combined Heat and Power Partnership program, and the DOE's website for CHP Deployment and Technical Assistance Partnerships.[47]

A number of states have supported CHP through portfolio standards. Portfolio standards require electric utilities and retail providers, often through legislation, to meet a certain portion of load with specified clean energy resources. As of 2013, 23 states include CHP in either energy efficiency or renewable energy portfolio standards (Figure 3-4). Energy efficiency portfolio standards are discussed in detail in Chapter 11, and renewable portfolio standards are the focus of Chapter 16. These programs are typically designed to allow eligible projects to generate credits, the sale of which adds a stream of revenue for project finance. However, the terms of eligibility vary across states, often reflecting narrow definitions of CHP that, for example, capture only bottoming-cycle (WHP) or renewable fuel-powered configurations. Where portfolio standards have been more effective at incentivizing investment, they have clearly defined CHP, defined it broadly enough to include fossil fuels, established minimal efficiency requirements (i.e., minimum 60 percent annual combined electric and thermal efficiency with fuel input

Figure 3-4

Treatment of CHP in State Electricity Portfolio Standards[48]



Source: Map based on ICF International research. December 2012.

47 US DOE, US EPA, & SEE Action Network. Available at https://www4.eere.energy.gov/seeaction/. US EPA CHP Partnership. Available at: http://www.epa.gov/chp/. US DOE CHP Deployment. Available at: http://energy.gov/eere/amo/chp-deployment

48 Supra footnote 22.

expressed on a higher heating value basis), and set dedicated CHP targets as a distinct class of resources.

Specific CHP targets have also been enacted through broader legislation and/or issued executive orders in some states. California, for example, established a goal of 6500 MW of new CHP through executive order. New Jersey set a target of 1500 MW of new CHP capacity through its Energy Master Plan.[49]

Grid Reliability and Resiliency

CHP has also been noted for its ability to strengthen grid reliability and improve the resiliency of critical infrastructure. The events of September 11, 2001, the Northeast blackout in 2003, Hurricane Katrina in 2005, and Superstorm Sandy in 2012, among other disasters, have underscored the importance of having independent and reliable power supply for critical infrastructure, such as hospitals, public safety facilities, emergency response communications, and care centers for elderly and other vulnerable populations. CHP has been demonstrated to provide reliability over both instantaneous outages as well as prolonged outages,[50] and systems can be designed to meet power needs more adequately —that is, more seamlessly, at lower cost, and with lower environmental impacts — than traditional backup generators. In the wake of the storms of 2011 and 2012, New York, New Jersey, and Connecticut adopted CHP incentive programs designed to enhance resiliency for disaster response and preparedness.[51] Texas and Louisiana have laws requiring critical government buildings to undertake feasibility studies for implementing CHP.[52,53]

3. State and Local Implementation Experiences

Examples can be found across the country of CHP units that are designed primarily to meet onsite or nearby energy needs, rather than to supply electricity to the grid. These examples include CHP systems owned by state or municipal governments, universities, hospitals, manufacturers, and others. Case studies featuring certain aspects of the policy and regulatory context are enumerated in many of the reports cited earlier, especially The Regulatory Assistance Project (2014), SEE Action (2013), and ICF (2013). The Database of State Incentives for Renewables and Efficiency, which is currently run out of North Carolina State University, provides an online database of CHP policies searchable by type and state; the EPA maintains a similar database.[54] Additional examples are provided in Chapter 2.

CHP projects can be built with the help of public policies and incentives, yet fail to achieve the high efficiency goals anticipated from the technology. Proper sizing for the project demand, engineering, construction, and operation are all critical to a project attaining its goals, and relatively minor variations can have significant impact. Studies that included efficiency evaluations for a number of completed CHP projects in California and New York indicated that the operating efficiencies of some projects were far below expectations and similar to non-CHP EGUs. To ensure accountability for public funds and emissions reductions, incentives programs should be linked to project performance. An example comes from New

49 The Industrial Energy Efficiency and Combined Heat and Power Working Group of the SEE Action Network released a “Guide to the Successful Implementation of State Combined Heat and Power Policies” in 2013, which details options and case studies for effective support of CHP through portfolio standards-like tools. Supra footnote 22.

50 ACEEE. (2012, December 6). *How CHP Stepped Up When the Power Went Out During Hurricane Sandy.* Available at: http://www.aceee.org/blog/2012/12/how-chp-stepped-when-power-went-out-d

51 CT P.A. 12 148 Section 7. (2012, July). *Microgrid Grant and Loan Pilot Program.* Available at: http://www.cga.ct.gov/2012/act/pa/pdf/2012PA-00148-R00SB-00023-PA.pdf

52 Texas HB 1831. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB01831F.pdf. Texas HB 4409. Available at: http://www.capitol.state.tx.us/tlodocs/81R/billtext/pdf/HB04409F.pdf. Louisiana Senate resolution No. 171. (2012). Available at: http://www.legis.la.gov/legis/BillInfo.aspx?s=12RS&b=SR171&sbi=y

53 For more extensive information on case studies, see: ICF International for ORNL. (2013, March). *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* Available at: http://energy.gov/eere/amo/downloads/chp-enabling-resilient-energy-infrastructure-critical-facilities-report-march

54 Database of State Incentives for Renewables & Efficiency. Available at: http://www.dsireusa.org/; US EPA. (2014, August). *CHP Policies and Incentives Database.* Available at: http://epa.gov/chp/policies/database.html

York State Energy Research and Development Authority's CHP performance program, in which projects are subject to measurement and verification procedures and the incentive payment schedule is contingent on monitored performance.[55]

For the purposes of this document, the implementation experiences of the state of Massachusetts are presented in greater detail to illustrate the components of a cohesive state policy in support of CHP.

In 2008, Massachusetts started what has become a concerted push to develop CHP using two main policy vehicles. The first is the utility energy efficiency program called "Mass Save," mandated by the Green Communities Act of 2008 (S.B. 2768), and launched in 2011.[56] The program is funded through: (1) a system benefit charge on electricity use; (2) an energy efficiency reconciliation factor on electricity distribution rates; (3) proceeds from the Regional Greenhouse Gas Initiative; and (4) the New England Independent System Operator's (ISO) Forward Capacity Market.[57] Mass Save provides incentive rebates to residential, commercial, and industrial customer classes for energy efficiency investments, including CHP.

Eligible CHP must pass a benefit-cost ratio (BCR) test, whereby the lifetime benefits are greater than or equal to lifetime costs (i.e., BCR ≥1). The BCR model captures societal value by incorporating:

- Annual power output (net kW);
- Electricity output (net kilowatt-hour [kWh]);
- Installed cost of equipment;
- Annual maintenance costs;
- Quantity and type of fuel consumed and displaced; and
- The timing of power production (i.e., peak/off-peak, summer/winter).

The model uses marginal values for fuel and electricity and the value of deferred transmission and distribution, according to the peak period terms of the ISO of New England.[58]

Qualifying retrofit projects earn rebates based on where the project fits within three tiers of efficiency performance. At the low end of the scale, Tier 1 can earn up to $750/kW. At the high end, Tier 3 can earn up to $1100/kW ($1200/kW for projects <150 kW). The grant of a rebate is contingent on:

- Achieving a system efficiency of greater than 65 percent;
- Undertaking an ASHRAE Level 2 Audit;[59] and
- Implementing efficiency measures to reduce overall energy use at the facility by ten percent within three years.

New construction projects are eligible for a rebate of $750/kW that can be increased on a case-by-case basis, contingent on a project achieving the 65-percent efficiency threshold and implementing additional energy efficiency measures.[60]

A November 2013 review of Mass Save's CHP program found that it had been successful, with high realization rates, accounting for 30 percent of commercial and institutional energy efficiency target savings in 2011. CHP was also found to deliver the lowest cost per kWh of all Mass Save measures.[61] Because proper sizing of a CHP system is essential to its cost-effectiveness, one key lesson learned in Massachusetts has been that reducing load through energy efficiency needs to be the first step in determining the appropriate size and design of a CHP system.[62] This is partly why providing incentives for CHP based on efficiency performance has proved to be so successful.

55 New York State Energy Research and Development Authority. (2015, January). *Combined Heat and Power Performance Program.* Available at: http://www.nyserda.ny.gov/All-Programs/Programs/Combined-Heat-and-Power-Performance-Program

56 Mass Save public website. Available at: http://www.masssave.com/

57 Mass Save. (2012, November). *2013-2015 Massachusetts Joint Statewide Three Year Electric and Gas Energy Efficiency Plan.* Available at: http://www.mass.gov/eea/docs/doer/energy-efficiency/statewide-electric-and-gas-three-year-plan.pdf

58 Mass Save. (2014, May 27). *Combined Heat and Power: A Guide to Submitting CHP Applications for Incentives in Massachusetts.* Available at: http://www.masssave.com/~/media/Files/Business/Applications-and-Rebate-Forms/A-Guide-to-Submitting-CHP-Applications-for-Incentives-in-Massachusetts.pdf

59 See Chapter 15 for a discussion of ASHRAE building energy codes.

60 Supra footnote 58.

61 US DOE/IIP Webinar. (2013, November 20). *Massachusetts Incentives for Combined Heat and Power: Mass Save Energy Efficiency and the Alternative Portfolio Standard.* Dwayne Breger, Director, Renewable Energy Division, Massachusetts Department of Energy Resources. Available at: https://cleanenergysolutions.org/webfm_send/964

62 Supra footnote 57.

The second major policy vehicle supporting CHP in Massachusetts is the state's Alternative Energy Portfolio Standard (APS), which puts an obligation on retail electricity suppliers to acquire Alternative Energy Certificates (AECs) equal to a set percentage of served load. Established pursuant to the 2008 Green Communities Act[63] and administered under the Alternative Energy Portfolio Standard Regulation,[64] compliance obligations began in 2009, requiring one percent of retail sales to come from qualifying energy sources, a level that increases to five percent by 2020. The APS covers a range of nonrenewable technologies, including flywheel energy storage, CHP, and renewable thermal technologies, but as of 2013, nearly all AECs were generated from CHP projects.[65]

The APS complements the Mass Save rebate program. While the latter defrays upfront capital costs, the APS rewards metered performance. CHP units are responsible for metering both thermal and electricity output, as outlined in the APS metering guidelines,[66] where credits are earned based on fuel savings compared to grid power and a separate thermal conversion unit. AECs are calculated as follows:

> The number of Credits = (electricity generated/0.33) + (useful thermal energy output/0.8) – (total fuel consumed by the CHP unit), where all quantities are expressed in MWh.

Massachusetts uses an Alternative Compliance Payment (ACP) mechanism as a price ceiling. The ACP was set at $21.72 per MWh for the 2014 compliance year.[67] In 2013, for example, earned credits fell short of the 1448 gigawatt-hours required to meet the three-percent obligation on utilities for that year. As a result, some 64 percent of the obligation was met through ACPs, totaling nearly $19.8 million[68] — revenues that were recycled back into clean energy initiatives through the Commonwealth's Department of Energy Resources.[69] The supply of credits follows the pace of project approval through the Mass Save rebate program, such that as the number of certified projects grow and with several large projects in the pipeline, the supply of AECs is expected to increase. As of 2014, 329 MW of CHP capacity was either approved or was under review through the APS program.[70]

One example of a successfully supported project highlighted by the Department of Energy Resources was installed on the campus of the University of Massachusetts Medical School. There, a 7.5-MW expansion to the existing 9-MW cogeneration facility boosted overall efficiency from 71 percent to 86 percent, resulting in an annual reduction in GHG emissions of 19 percent. The project was awarded $5.6 million through Mass Save, the equivalent of 20 percent of capital expenditure,[71] and is projected to earn 135,488 credits through the Alternative Portfolio Standard,

63 Part 1, Title II, Chapter 25A, Section 11F1/2. Alternative Energy Portfolio Standard. Available at: http://www.malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter25A/Section11F1~2

64 Code of Massachusetts Regulation. 225 CMR 16.00. Alternative Energy Portfolio Standard. Available at: http://www.mass.gov/eea/docs/doer/rps/225cmr1600-052909.pdf

65 Massachusetts Department of Energy Resources. (2014, December 17). *Massachusetts RPS & APS Annual Compliance Report for 2013.* Available at: http://www.mass.gov/eea/docs/doer/rps-aps/rps-aps-2013-annual-compliance-report.pdf

66 Massachusetts Department of Energy Resources. (2011, June 14). *APS Guideline on the Eligibility and Metering of Combined Heat and Power Projects.* Available at: http://www.mass.gov/eea/docs/doer/rps-aps/aps-chp-guidelines-jun14-2011.pdf

67 Massachusetts, Executive Office of Energy and Environmental Affairs. (2014, August). *Alternative Compliance Payment Rates.* Available at: http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/retail-electric-supplier-compliance/alternative-compliance-payment-rates.html

68 Subject to increases with the consumer price index. Supra footnote 65.

69 Massachusetts Department of Energy Resources. (2014, December 17). *CY 2013 Alternative Compliance Payments – Spending Plan.* Available at http://www.mass.gov/eea/docs/doer/rps-aps/cy-2013-acp-spending-plan.pdf

70 Massachusetts Department of Energy Resources. *APS Qualified Generation Units – Updated May 1, 2014.* Available at: http://www.mass.gov/eea/docs/doer/rps-aps/aps-qualified-units.xls

71 Sylvia, M. (2013, June 26). *Clean Energy Opportunities in Massachusetts.* Presentation before the Juniper Networks Energy Summit. Massachusetts Department of Energy Resources. Available at: http://competitive-energy.com/CES_JuniperNetworksSummit_MADOER_Presentation_062613.pdf

equivalent to more than $2.9 million of annual revenue.[72]

Massachusetts further enables CHP development by providing standardized application procedures and contracts for grid interconnection overseen by the Massachusetts Department of Public Utilities. These procedures apply uniformly across the state's four investor-owned utilities. They offer generator customers transparent rules for expeditious interconnection, while ensuring the safety and reliability of the grid. The model interconnection tariff provides three different review paths based on the complexity of the project, that is, generation type, size, customer load, and the characteristics of the grid where the system is to be located. The "Simplified and Expedited" review paths are designed to streamline projects that pass pre-specified screening tests, whereas the "Standard" path is reserved for all other projects in which system modifications may be required to accommodate the project. These procedures were most recently amended in July 2014 with Order 11-75-F to assign an enforceable timeline for interconnections.[73] Interconnection activity is reported monthly and made available online to give customers a clearer understanding of expectations for the interconnection process.[74]

4. GHG Emissions Reductions

A CHP system can reduce CO_2 emissions roughly 50 percent compared to separate heat and power systems, as shown in Figure 3-1, by reducing fuel consumption. Emissions of other GHGs may also be reduced, including methane, nitrous oxide, precursors to ground-level ozone, and particulate pollution, which can also interact with the climate. The 2008 report by ORNL cited previously in this chapter analyzed a goal of increasing CHP to 20 percent of generation capacity by 2030. It found that achieving 20-percent CHP would reduce CO_2 emissions by more than 800 million metric tons per year, equivalent to 60 percent of projected growth in emissions over that time period.[75] These results echo those of numerous other studies that have shown that CHP is one of the most cost-effective strategies for reducing CO_2 emissions economy-wide.

It is important to note that CHP may not always be an appropriate strategy for reducing carbon emissions. In parts of the country with low GHG electricity, like the gas-dominated grid in California, CHP emissions could conceivably exceed those of separate heat and power. To account for this, eligibility for incentives typically includes threshold efficiency rates, but could also be structured to reward only net-GHG-reducing facilities.

Estimates of CO_2 emissions reductions associated with CHP systems are derived from fuel savings. Calculating fuel savings associated with a CHP system uses a similar methodology to the avoided emissions approach described previously. The fuel used onsite is deducted from the displaced fuel that would have been used for separate production of thermal and electric energy, including transmission and distribution losses, according to the basic series of equations included below.[76]

The first step is to calculate emissions displaced from onsite thermal production.

Equation 1: Avoided Emissions From Displaced Thermal Energy Production

$$C_T = (CHP_T/\eta_T) * EF_F * (1 \times 10\text{-}^6)$$

where:

C_T = CO_2 Emissions From Displaced Onsite Thermal Production (lb CO_2)

CHP_T / η_T = CHP System Thermal Output (BTU) ÷ Estimated Efficiency of the Thermal Equipment = Thermal Fuel Savings (BTU)

EF_F = Fuel-Specific CO_2 Emissions Factor (lb CO_2 / MMBTU)

$1 \times 10\text{-}^6$ = Conversion Factor From BTU to MMBTU

72 Breger, D. (2013, March 5). *Alternative Portfolio Standard and the Energy Efficiency Rebates.* Presentation at the NGA Policy Academy, Philadelphia, PA. Massachusetts Department of Energy Resources. Available at: http://www.nga.org/files/live/sites/NGA/files/pdf/2013/1303PolicyAcademyBREGER.pdf

73 Massachusetts Department of Energy Resources. (2014, August). *Interconnection Project Review Paths (With Recent Changes to Resulting From DPU Order 1-75-E).* Available at: https://sites.google.com/site/massdgic/home/interconnection/interconnection-project-review-paths. See also: DSIRE. (2014, August). *Massachusetts Interconnection Standards.* Available at: http://programs.dsireusa.org/system/program/detail/2774

74 Massachusetts Department of Energy Resources. (2014, August). *Distributed Generation and Interconnection in Massachusetts.* Available at: https://sites.google.com/site/massdgic/home/interconnection

75 Supra footnote 15.

76 US EPA CHP Partnership. (2012, August). *Fuel and Carbon Dioxide Emissions Savings Calculation Methodology for Combined Heat and Power Systems.* Available at: http://www.epa.gov/chp/documents/fuel_and_co2_savings.pdf

The second step is to calculate emissions of displaced grid electricity.

Equation 2: Avoided Emissions From Displaced Grid Electricity

$$C_G = [CHP_E / (1 - L_{T\&D})] * EF_G$$

where:

C_G = CO_2 Emissions From Displaced Grid Electricity (lb CO_2)

CHP_E = CHP System Electricity Output (kWh)

$L_{T\&D}$ = Transmission and Distribution Losses (Percentage in Decimal Form)

$CHP_E / (1 - L_{T\&D})$ = Displaced Grid Electricity From CHP (kWh)

EF_G = Grid Electricity Emissions Factor (lb CO_2 / kWh)

In the final step, CO_2 emissions from the CHP plant are deducted from the sum of Equations 1 and 2.

Fuel-specific CO_2 emissions factors — that is, EF_F in Equation 1 — are typically derived from the inherent energy density of a particular fuel. Table 3-2 lists default emissions factors for select fuels typically used in separate thermal production.

Table 3-2

Default CO_2 Emissions Factors for Fuels Typically Displaced by CHP (HHV)[77]

Fuel Type	CO_2 Emissions Factor (lb/MMBTU)
Natural Gas	116.9
Distillate Fuel Oil #2	163.1
Residual Fuel Oil #6	165.6
Coal Anthracite	228.3
Coal Bituminous	205.9
Coal Sub-bituminous	213.9
Coal Lignite	212.5
Coal (Mixed Industrial)	207.1

As for displaced grid emissions factors — that is, EF_G in Equation 2 — there are several methods used to estimate this value. Most accurate among them is to use a dispatch model. Dispatch modeling demonstrates how generation dispatch for a given region and resource mix would respond to a reduction in demand resulting from the addition of specific CHP resources. The change in emissions is then calculated for that change in dispatch. However, dispatch models are complicated and costly to run. Consequently, the EPA offers a very simple alternative derived from historic performance characteristics of regional electric systems, as reported in the eGRID.[78]

The EPA's eGRID provides two aggregation measures: one based on the average emissions of non-baseload generators and a second based on the average emissions of all fossil fuel generators. Both measures recognize that certain clean energy technologies like CHP are more likely to substitute for existing and/or new fossil generation and not generation from existing "must run" resources, such as nuclear, hydro, and renewables. For baseload CHP systems with high annual capacity factors (i.e., >6500 operating hours), EPA analysis suggests that the average emissions factor of fossil fuel plants provides a reasonable estimate. For CHP operating less than 6500 hours per year, the system can be assumed to displace marginal generating units. In this case, the EPA has recommended using the average emissions factor for non-baseload generation. Average CO_2 emissions rates of fossil fuel generation are generally greater than those of non-baseload generation,[79] but vary from being 35 percent greater (for the Western Electricity Coordinating Council) to 10 percent less (in the case of Nonprofit Coordinating Committee NYC/Westchester) than non-baseload rates across subregions. The EPA has developed an online tool, the CHP Emissions Calculator, which uses the series of equations shown previously with eGRID subregional emissions rates to estimate reductions in CO_2, NO_X, SO_2, methane, and nitrous oxide.[80]

Because the eGRID geographic averages do compromise accuracy for simplicity, this approach (like the thermal credit discussed earlier) has been a point of contention.

77 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Table C-1 of Subpart C. Available at: http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=f483e9df938aea70b74776fc6a440d02&ty=HTML&h=L&r=PART&n=pt40.21.98#ap40.21.98_138.1

78 US EPA, eGRID. (2012). *Summary Tables for Subregions.* Available at: http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2012V1_0_year09_SummaryTables.pdf

79 Supra footnote 76.

80 US EPA. (2014, July 30). *CHP Emissions Calculator.* Available at: http://www.epa.gov/chp/basic/calculator.html

To help address concerns and facilitate state air quality and energy planners in developing clean power plans, the EPA recently released a new online tool, AVoided Emission and geneRation Tool (AVERT). AVERT quantifies the CO_2, NO_X, and SO_2 emissions benefits of energy efficiency and renewable energy policies and programs based on temporal energy savings and hourly generation profiles using a marginal emissions rate method.[81] AVERT generally falls between dispatch models and eGRID emissions factors in terms of both simplicity and accuracy.

5. Co-Benefits

CHP systems outside of the electric power sector can deliver an unusually wide range of benefits, not just for the host facilities but also for society and the utility system.

For industrial and commercial enterprises, a primary motivation for investing in CHP systems is to meet electricity and thermal energy demands at lower cost. In this way, CHP is set apart from other GHG compliance options in that it directly improves a business' competitiveness. CHP upgrades can improve operations and energy supply reliability, mitigating the risk of grid outages to the firm. By saving energy, CHP reduces all air and solid pollution associated with the substituted fuel consumption, including criteria pollutant and toxic emissions — and therefore can lead to lower compliance costs for other environmental regulations. The methods for quantifying those reductions are essentially the same as the methods used to calculate GHG reductions, with the avoided emissions approach offering a more accurate picture of the impacts.

As to system benefits, CHP installations represent low-cost generation capacity additions, which can be dispatched as firm capacity. If appropriately scaled and strategically targeted within certain locations, CHP can relieve congestion on the grid, effectively delaying costly expansions and upgrades, which can translate into lower utility rates. By consuming energy onsite, CHP avoids transmission and distribution line losses. CHP can also conserve water resources when compared to the 0.2 to 0.6 gallons of water consumed per kWh in a typical coal-fired power plant.[82] With opportunities at manufacturing, commercial, and institutional facilities in every state, CHP development can stimulate the creation of technically demanding and highly skilled jobs[83]

The full range of potential co-benefits for society and the utility system are summarized in Table 3-3. Benefits that

Table 3-3

Types of Co-Benefits Potentially Associated With CHP in the Commercial, Institutional, and Manufacturing Sectors

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Yes
Other	

81 US EPA. (2014, July 30). *AVERT*. Available at: http://epa.gov/avert/

82 EPRI. (2002). *Water & Sustainability: US Water Consumption for Power Production*. Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001006786

83 The aforementioned 2008 ORNL study found a CHP goal of 20 percent of generation capacity would stimulate $234 billion in capital investment and create nearly one million new jobs by 2030.

accrue to the utility customer who owns a CHP system are additional to those listed.

6. Costs and Cost-Effectiveness

CHP is one of the most cost-effective ways to reduce CO_2 emissions. That CHP is an underutilized opportunity for GHG emissions reductions is a conclusion reinforced by the findings of various studies in recent years.

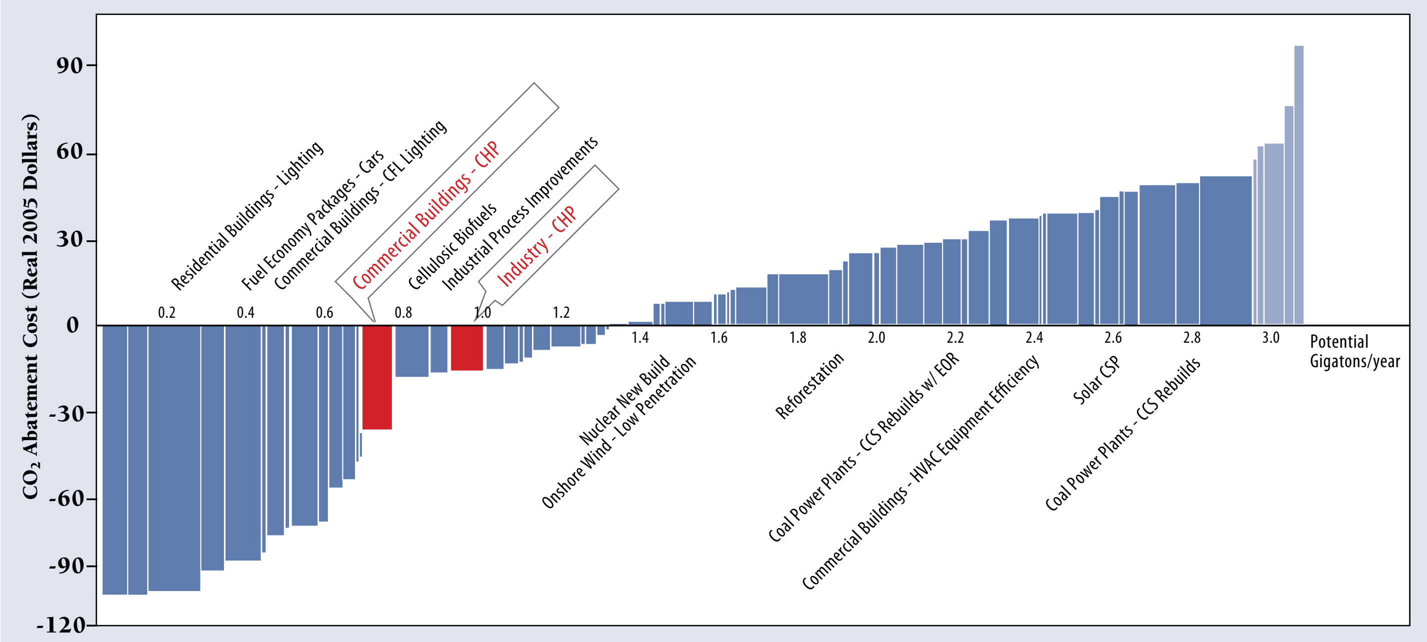
A 2009 report by McKinsey & Company estimated there to be 50 GW of cost-effective CHP in industrial and large commercial/institutional applications through 2020, in which "cost-effective" denotes only investments that had positive net-present values over the lifetime of the measure.[84] These projects were estimated to reduce 100 million metric tons of CO_2 annually (Figure 3-5). Substituting today's natural gas prices and market outlook in the analysis would presumably boost this estimate of economic feasibility.

Mentioned earlier, a 2013 analysis by ICF International found a total of 125 GW of technical potential for CHP at existing industrial (56 GW) and commercial (69 GW) facilities, corresponding to a capacity roughly five times the capacity of the coal-fired generation poised to retire between 2012 and 2016.[86] Technical potential here accounts for sites that have high thermal and electric demands suitable to CHP, but does not consider economic factors relevant to project investment decisions.[87] The states with the greatest technical potential (>5 GW) were California, Florida, Illinois, Michigan, New York, Ohio, Pennsylvania, and Texas.[88] When ICF screened for economic viability by incorporating energy prices (excluding other economic incentives), it found that 42 GW of technical potential had an investment payback period of less than ten years, 6 GW of which would pay for itself through energy savings within five years.[89]

Another more recent study evaluated the impacts of the EPA's proposed GHG regulations on CHP deployment. Using ICF International's CHPower and IPM models, the Center for Clean Air Policy analyzed rates of technology adoption at existing and new facilities across the country in light of the EPA's proposed 111(d) GHG regulations for

Figure 3-5

Comparative Costs of CO_2 Reduction Technologies[85]



84 McKinsey & Company. (2009). *Unlocking Energy Efficiency in the US Economy.* Available at: http://www.mckinsey.com/client_service/electric_power_and_natural_gas/latest_thinking/unlocking_energy_efficiency_in_the_us_economy

85 Supra footnote 15.

86 Supra footnote 14.

87 Also note that the ICF analysis of technical potential does not include EGUs.

88 For summary tables broken down by state, size, and sector, see: supra footnote 14.

89 Ibid.

existing EGUs.[90] Reflecting technical limitations, economic factors, as well as rates of market acceptance, the study determined that a future scenario with 111(d) rules in effect would result in 10 GW of new CHP by 2030, where these 10 GW represent projects that are both economically feasible and "accepted" by firms. The study concludes that 111(d)

Table 3-4

Summary Table of Typical Costs and Performance Characteristics by CHP Technology[91]

Technology	Recip. Engine	Steam Turbine	Gas Turbine	Microturbine	Fuel Cell
Electric efficiency (HHV)	27-41%	5-40+%*	24-36%	22-28%	30-63%
Overall CHP efficiency (HHV)	77-80%	near 80%	66-71%	63-70%	55-80%
Effective electrical efficiency	75-80%	75-77%	50-62%	49-57%	55-80%
Typical capacity (MW)	.005-10	0.5-several hundred MW	0.5-300	0.03-1.0	200-2.8 commercial CHP
Typical power to heat ratio	0.5-1.2	0.07-0.1	0.6-1.1	0.5-0.7	1-2
Part-load	ok	ok	poor	ok	good
CHP Installed costs ($/kW)	1,500-2,900	$670-1,100	1,200-3,300 (5-40 MW)	2,500-4,300	5,000-6,500
Non-fuel O&M costs ($/kWh)	0.009-0.025	0.006 to 0.01	0.009-0.013	0.009-.013	0.032-0.038
Availability	96-98%	near 100%	93-96%	98-99%	>95%
Hours to overhauls	30,000-60,000	>50,000	25,000-50,000	40,000-80,000	32,000-64,000
Start-up time	10 sec	1 hr -1 day	10 min -1 hr	60 sec	3 hrs -2 days
Fuel pressure (psig)	1-75	n/a	100-500 (compressor)	50-140 (compressor)	0.5-45
Fuels	natural gas, biogas, LPG, sour gas, industrial waste gas, manufactured gas	all	natural gas, synthetic gas, landfill gas, and fuel oils	natural gas, sour gas, liquid fuels	hydrogen, natural gas, propane, methanol
Uses for thermal output	space heating, hot water, cooling, LP steam	process steam, district heating, hot water, chilled water	heat, hot water, LP-HP steam	hot water, chiller, heating	hot water, LP-HP steam
Power Density (kW/m^2)	35-50	>100	20-500	5-70	5-20
NO_X (lb/MMBTU) (not including SCR)	0.013 rich burn 3-way cat. 0.17 lean burn	Gas 0.1-.2 Wood 0.2-.5 Coal 0.3-1.2	0.036-0.05	0.015-0.036	0.0025-.0040
NO_X (lb/MWh$_{Total\ Output}$) (not including SCR)	0.06 rich burn 3-way cat. 0.8 lean burn	Gas 0.4-0.8 Wood 0.9-1.4 Coal 1.2-5.0.	0.17 - 0.25	0.08 - 0.20	0.011-0.016

** Power efficiencies at the low end are for small backpressure turbines with boiler and for large supercritical condensing steam turbines for power generation at the high end.*

90 Davis, S., & Simchak, T. (2014, May). *Expanding the Solution Set: How Combined Heat and Power Can Support Compliance With 111(D) Standards for Existing Power Plants.* Center for Clean Air Policy. Available at: http://ccap.org/assets/CCAP-Expanding-the-Solution-Set-How-Combined-Heat-and-Power-Can-Support-Compliance-with-111d-Standards-for-Existing-Power-Plants-May-2014.pdf

91 US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies.* Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf. Note that values are illustrative for commercially available technologies. Installed cost for most CHP technologies consists of costs related to equipment, installation labor and materials, engineering, project management, and financial carrying costs during the construction period. All costs are in 2014$.

rules will not be sufficient to drive development of CHP resources toward the full technical potential, and that the emissions limits must be accompanied by complementary policies to support CHP uptake as a compliance option.

Generalizing about costs on the project level is problematic, given the extent to which site-specific factors determine the configuration requirements and the extent to which the local regulatory environment can add considerably to administrative overhead. According to the National Regulatory Research Institute, whether using payback period, net-present value, upfront capital costs, technical and economic potentials, or other indicators of economic value, each have advantages and disadvantages in communicating the underlying issues influencing technology adoption.[92] There are furthermore multiple points of view from which to evaluate the cost-effectiveness of CHP, whether from that of the participants, the gas utility, the electric utility, the ratepayer, or society generally. Below, three different analyses of cost-effectiveness are summarized on a project basis. For additional analyses, refer to Chapter 2.

Isolating installed costs for new projects, Table 3-4 compares typical applications by technology class (in 2013$). Gas turbines ranging in size from 5 to 40 MW may have costs from $1200/kW to $3300/kW. Steam turbines may range anywhere from $670/kW to $1100/kW. Reciprocating engines have installed costs ranging from $1500/kW to $2900/kW, whereas microturbines in grid-tied CHP installations can cost from $2500/kW to $4300/kW. Lastly, fuel cells are the most costly, with total installed costs ranging from $5000/kW to $6500/kW.

Cost-effectiveness can also be illustrated by comparing cash outlays over the course of the investment lifetime. In

Table 3-5

Financial Comparison of Two Typical Options for Boiler Replacement[93]

	Natural Gas Boilers	Natural Gas CHP	Impact of CHP Increase / (Decrease)
Peak Boiler Capacity, MMBTU/hr input	120	NA	
Peak Steam Capacity, MMBTU/hr	96	96	
Average Steam Production, MMBTU/hr	76.8	76.8	
Boiler Efficiency	80%	NA	
Electric Generating Capacity, MW	NA	14	
CHP Electric Efficiency	NA	31%	
CHP Total Efficiency	NA	74%	
Steam Production, MMBTU/year	614,400	614,400	0
Steam Production, MMlbs/year	558.6	558.6	0
Power Generation, kWh/year	NA	106,400,000	106,400,000
Fuel Use, MMBTU/year	768,000	1,317,786	549,786
Annual Fuel Cost	$4,608,000	$7,906,716	$3,298,719
Annual O&M Cost	$729,600	$1,687,200	$957,600
Annual Electric Savings	0	($6,703,200)	($6,703,200)
Net Annual Operating Costs	$5,337,600	$2,890,719	($2,447,331)
Net Steam Costs, $/1000lbs	$9.56	$5.18	($4.38)
Capital Costs	$4,200,000	$21,000,000	$16,800,000
10 Year Net Cash Outlays	$65,389,602	$54,138,850	($11,250,752)
Payback – CHP vs. Gas Boilers			6.9 years
10 Year IRR - CHP vs. Gas Boilers			10%
10 Year NPV – CHP vs. Gas Boilers			$2,580,588

Source: ICF International

Notes: Based on 8,000 hours facility operation, 7 cents per kWh electricity price, and $6/MMBTU natural gas price. Natural gas boiler estimated capital cost of $35/MBTU/hour input and O&M cost of $0.95/MMBTU input were provided by Worley Parsons. CHP capital cost of $1,500/kW, turbine/generator and heat recovery steam generator O&M costs of $0.009/kWh and 31 percent electrical efficiency are taken from a California Energy Commission Report, "Combined Heat and Power: Policy Analysis and 2011 – 2030 Market Assessment," 2012. Annual CHP O&M cost includes an amount to maintain the steam system, which is approximated by the O&M cost of the boilers, which produce the same steam output. CHP availability of 95 percent and portion of electric price avoided by on-site generation of 90 percent are values based on typical CHP feasibility analyses. 10 year net cash outlays are the sum of 10 year's operating costs escalated at 3 percent annually. NPV determined using a 7% discount rate. All efficiency values and natural gas prices are expressed as higher heating values.

92 Costello, K. (2014, June). *Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do?* Report No. 14-06. National Regulatory Research Institute. Available at: http://www.nrri.org/documents/317330/16dd1f89-c8ec-44db-af73-7c6473a3ef09

93 US EPA CHP Partnership. (2013, March 11). *Fact Sheet: CHP as a Boiler Replacement Opportunity.* Available at: http://www.epa.gov/chp/documents/boiler_opportunity.pdf

the context of Boiler MACT compliance, a common choice for facilities seeking to replace a coal-fired or other boiler system is a natural gas boiler. The financial analysis shown in Table 3-5 was developed by ICF International for the EPA's CHP Partnership program. It juxtaposes two options for meeting the average steam demand of a small industrial or medium-sized institutional facility.[94] The first consists of two natural gas boilers, and the second is a CHP system based on a natural gas combustion turbine and a heat recovery steam generator. As the financial comparison details, the CHP system requires an upfront capital expenditure of $16.8 million more than the gas boilers, but produces net annual operating savings of $2.4 million, which yields a payback period of less than seven years, and over ten years generates an internal rate of return of ten percent and a net present value of approximately $2.6 million.

Yet another way to characterize the cost-effectiveness of a CHP project is to compare performance across other generation classes of similar capacity size. Table 3-6 does this, listing annual electric output, thermal output, and avoided emissions from a typical 10-MW gas turbine CHP system, alongside a 10-MW apportionment of utility-scale wind, photovoltaic, and natural gas combined-cycle generators. On a capacity basis, the 10 MW of CHP displaces more CO_2 emissions than any of the other options. Homing in on a comparison with wind power, the CHP project achieves 60 percent more CO_2 savings than the wind project, while generating 2.5 times the electric output, at 83 percent of the capital cost.

In utility regulation, standard tests for cost-effectiveness are used to evaluate energy efficiency programs,[96] and can also be useful for determining the relative value of CHP programs. Cost-effectiveness can be assessed from many different perspectives, whether from that of the gas utility,

Table 3-6

CHP Energy and CO_2 Emissions Savings Potential Compared to Other Generation Options[95]

Category	10 MW CHP	10 MW PV	10 MW Wind	10 MW Natural Gas Combined-Cycle
Annual Capacity Factor	85%	25%	34%	70%
Annual Electricity	74,446 MWh	21,900 MWh	29,784 MWh	61,320 MWh
Annual Useful Heat Provided	103,417 MWh	None	None	None
Footprint Required	6,000 sq ft	1,740,000 sq ft	76,000 sq ft	N/A
Capital Cost	$20 million	$48 million	$24 million	$9.8 million
Annual National Energy Savings	343,787 MMBTU	225,640 MMBTU	306,871 MMBTU	163,724 MMBTU
Annual National CO_2 Savings	44,114 Tons	20,254 Tons	27,546 Tons	28,233 Tons
Annual National NO_X Savings	86.9 Tons	26.8 Tons	36.4 Tons	76.9 Tons

The values in Table 3-6 are based on:

- 10 MW Gas Turbine CHP - 28% electric efficiency, 68% total CHP efficiency, 15 ppm NOx emissions
- Capacity factors and capital costs for PV and Wind based on utility systems in DOE's Advanced Energy Outlook 2011 Capacity factor, capital cost and efficiency for natural gas combined-cycle system based on Advanced Energy Outlook 2011 (540 MW system proportioned to 10 MW of output), NGCC NO_X emissions 9 ppm
- CHP, PV, Wind and NGCC electricity displaces National All Fossil Average Generation resources (eGRID 2010) - 9,720 BTU/kWh, 1,745 lbs CO_2/MWh, 2.3078 lbs NO_X/MWh, 6% T&D losses; CHP thermal output displaces 80% efficient on-site natural gas boiler with 0.1 lb/MMBTU NO_X emissions
- CHP, PV, Wind and NGCC electricity displaces EPA eGRID 2010 California All Fossil Average Generation resources - 8.050 BTU/kWh, 1,076 lbs CO_2/MWh, 0.8724 lbs NO_X/MWh, 6% T&D losses; CHP thermal output displaces 80% efficient on-site natural gas boiler with 0.1 lb/MMBTU NO_X emissions

94 Supra footnote 93.

95 Supra footnote 14.

96 National Action Plan for Energy Efficiency. (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs: Best Practices, Technical Methods, and Emerging Issues for Policymakers.* Energy and Environmental Economics, Inc. and The Regulatory Assistance Project. Available at: www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf

the electric utility, ratepayers, or the participating entities. Tests like the Program Administrator Cost test, the Total Resource Cost test, and the Rate Impact Measure tests can help account for how costs and benefits affect all parties involved. Appendix A of the 2013 SEE Action report describes how these tests can be used to evaluate benefits and costs as they accrue across parties and energy types.[97]

7. Other Considerations

Increased deployment of CHP outside of the electric sector will have impacts both on natural gas utilities and electric utilities. Each is discussed briefly below.

Natural Gas Distribution Utilities

CHP in commercial and institutional sectors, where ICF International estimates that more than half of untapped technical potential is located (69 of 125 GW), may offer a substantial new market opportunity for natural gas local distribution companies.[98] Gas utilities can bring their technological expertise to bear, working with customers to develop energy efficiency solutions that ensure customer retention. A gas utility can also potentially provide financial support for capital upgrades over longer-term investment horizons, consistent with its business model.

A case study from Philadelphia Gas Works (PGW) exemplifies a partnership of this nature. PGW collaborated with the Four Seasons hotel in downtown Philadelphia to develop a technology configuration that would deliver reasonable savings, including introducing the customer to the microturbine technology it would ultimately select. The project was based around three 65-kW gas microturbines to provide 100 percent of the hotel's domestic hot water, 25 percent of its electric, and 15 percent of its heating needs. To address upfront costs, PGW developed an arrangement whereby it provided $1.2 million in upfront capital, to be paid back through a surcharge on the hotel's energy bills. Recovery of PGW's cost was estimated to take three years, after which the customer would financially benefit from the energy savings over the lifetime of the investment.[99]

Oregon is one state adopting specific provisions to enable natural gas utility ownership and investment in CHP. Oregon Senate Bill 844 of 2013 created an inventive program for gas utilities that would allow recovery of investments in GHG reduction projects.[100] As of August 1, 2014, the rules were still being finalized by the Public Utility Commission, but gas utilities had identified CHP as a primary area of interest.[101] Baltimore Gas and Electric and New Jersey Natural Gas also provide financial support and incentives to industrial and commercial customers who install CHP. Baltimore Gas and Electric funds this through a ratepayer-funded energy efficiency program, and New Jersey Natural Gas through loan repayment schemes negotiated between the utility and the participant. A 2013 report from the American Council for an Energy-Efficient Economy (ACEEE) provides an extensive discussion of the role for natural gas utilities in developing CHP more fully.[102]

Electric Utilities

Distributed generation, including CHP, is causing a transformation in the way electricity is generated, delivered, and paid for in the United States, and how it fits within existing regulatory frameworks. The shift away from centralized production toward dispersed, demand-side resource solutions signifies a reduction in utility revenue and has been perceived as chief among threats to the traditional utility business model. This stance is beginning to evolve, however, as utilities engage stakeholders and look for ways to position themselves in this new order.[103,104] Perhaps especially with regard to CHP, where energy falls outside the

97 Supra footnote 22.

98 Larger industrial facilities, in contrast, are usually connected to interstate gas pipelines or consume other fuels. CHP applications smaller than 100 MW would usually be connected to a distribution network.

99 Supra footnote 22.

100 Oregon State Legislature, Senate Bill 844. Available at: https://olis.leg.state.or.us/liz/2013R1/Measures/Text/SB844/Enrolled

101 Oregon Public Utility Commission, Docket No. AR 580. Available at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=18862

102 Chittum, A., & Farley, K. (2013, July). *How Natural Gas Utilities Can Find Value in CHP.* ACEEE. Available at: http://www.aceee.org/files/pdf/white-paper/chp-and-gas-utilities.pdf

103 Kind, P. (2013, January). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.* Edison Electric Institute. Available at: http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

104 ICF International. (2014). *From Threat to Asset: How CHP Can Benefit Utilities.* Available at: http://www.icfi.com/insights/white-papers/2014/how-chp-can-benefit-utilities

core business of most participating enterprises, utilities are uniquely positioned to shoulder risk and responsibility and provide assistance in design, installation, and operations to maximize benefits to the electrical system. Examples of how electric utilities can profit from distributed CHP development are discussed in Chapter 2. Creating avenues for utility participation in CHP development is expected to be a growing focus for regulators seeking to address the administrative, financial, and technical barriers that have led to persistently low rates of adoption. Both the 2013 SEE Action study and a 2013 ACEEE report highlight possible considerations for utility participation in CHP markets.[105]

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CHP in the commercial, institutional, and manufacturing sectors.

- ACEEE. *Technical Assistance Toolkit, Policies and Resources for CHP Deployment*. Available at: http://energytaxincentives.orgwww.energytaxincentives.org/policies-and-resources-chp-deployment
- ICF International for the American Gas Association. (2013, May). *The Opportunity for CHP in the United States*. Available at: http://www.aga.org/Kc/analyses-and-statistics/studies/efficiency_and_environment/Pages/TheOpportunityforCHPintheUnitedStates.aspx
- NASEO. (2013). *Combined Heat and Power: A Resource Guide for State Energy Officials*. Available at: http://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf
- The Regulatory Assistance Project. (2014, February). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States*. Available at: http://www.raponline.org/press-release/standby-rates-for-combined-heat-and-power-need-a-fresh
- The Regulatory Assistance Project. (2003). *Output Based Emissions Standards for Distributed Generation*. Available at: http://www.raponline.org/docs/RAP_IssuesLetter-OutputBasedEmissions_2003_07.pdf
- US DOE, US EPA, & SEE Action Network. (2013, March). *The Guide to Successful Implementation of State Combined Heat and Power Policies*. Available at: https://www4.eere.energy.gov/seeaction/publication/guide-successful-implementation-state-combined-heat-and-power-policies
- US DOE. *Boiler MACT Technical Assistance Program* website. Available at: http://energy.gov/eere/amo/boiler-mact-technical-assistance-program
- US DOE. *CHP Technical Assistance Partnerships* website. Available at: http://www1.eere.energy.gov/manufacturing/distributedenergy/chptaps.html
- US DOE & ORNL. (2012). *Guidance for Calculating Emission Credits Resulting From Implementation of Energy Conservation Measures*. Available at: http://info.ornl.gov/sites/publications/Files/Pub37258.pdf
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- US EPA CHP Partnership website. Available at: http://www.epa.gov/chp/
- US EPA CHP Partnership. (2015, March). *Catalog of CHP Technologies*. Available at: http://www.epa.gov/chp/documents/catalog_chptech_full.pdf

9. Summary

CHP offers a technologically mature, cost-effective, and near-term strategy for reducing GHG emissions, with technical potential distributed across the industrial, commercial, and institutional sectors. Grid-tied CHP facilities, however, can be complex, site-specific installations that carry significant technical and administrative burdens that have led to low rates of adoption, even in jurisdictions where financial incentives improve economic feasibility. Designing CHP to maximize co-benefits to the system, such as grid reliability, critical infrastructure resilience, and reduced congestion, further requires careful consideration and expertise that is typically beyond the field of participating enterprises. Concerted effort through supporting policy and regulation, as well as utility cooperation, will be required to take full advantage of CHP as a GHG reduction compliance option.

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105 US DOE, US EPA, & SEE Action Network. Available at https://www4.eere.energy.gov/seeaction/; US EPA, CHP Partnership. Available at: http://www.epa.gov/chp/; Chittum, A. (2013, July). *How Electric Utilities Can Find Value in CHP.* ACEEE. Available at: http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf

4. Improve Coal Quality[1]

1. Profile

Power plant boilers are designed to accommodate a range of types of coal but, within this range, variations in coal properties can affect performance and efficiency. A boiler designed to burn a high rank bituminous coal is going to perform quite differently if lower rank sub-bituminous coal is introduced, and properties such as high ash or sulfur content can impair not only the thermal performance of the boiler, but also associated duct work and virtually all boiler auxiliary systems, including sootblowing, forced and induced draft systems, steam temperature control, bottom and fly ash removal, pulverizers, and primary air, secondary air, burners, and combustion controls.[2] Air permit conditions for new or modified boilers specify fuel type and quality, and require fuel sampling in order to bind the range of potential emissions that are associated with variations in these parameters. Off-design fuels can affect boiler performance and efficiency.

Higher ash content in coal affects every piece of plant equipment that handles and processes coal, such as conveyors, pulverizers, crushers, storage, and so forth. The increased load on this equipment also increases auxiliary power consumption; that is, the quantity of plant-site energy needed simply to operate the plant, which reduces the quantity of electricity that can be transmitted for sale, thus increasing the plant's operating costs and decreasing its profit potential.

Plant operators understand that there are benefits from specifying coal quality in purchasing contracts, even if higher quality coal is more expensive. Even before the establishment of environmental requirements for coal quality, operators of coal-fired power plants voluntarily established standards and specifications for the fuel they purchased so they would be able to effectively operate their boilers and minimize the amount of time the boilers had to be taken off-line for maintenance. Boilers are typically designed and constructed based on a specification coal or range of specification coals that the purchaser intends to use as its fuel, such as that secured for a long-term purchase agreement with a given mine or group of mines. Once a boiler is constructed and in operation, owner/operators will typically continue to specify fuel coals to be compatible with the design characteristics of their boiler and boiler auxiliaries and any associated regulatory requirements. Alternatively, the owners/operators may make the decision to purchase off-spec fuels that they can live with to provide an economic advantage, assuming there are no regulatory requirements that influence those decisions.

Some coal processing may be required for an as-mined coal to meet the specifications of purchasers.[3] To maintain coal quality within specified ranges and meet boiler performance objectives, coals with different properties can be blended, either by the coal producer or at a power plant. Another option for meeting coal quality specifications is through "beneficiation." Coal beneficiation is the industry's term for any of several processes and treatments that improve coal quality. The most common of these beneficiation processes is "coal washing."

1 Adapted from James, C., & Gerhard, J. (2013, February). *International Best Practices Regarding Coal Quality.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6438

2 The trend toward increased use of Powder River Basin coals, even in the Eastern United States, has led to newer boilers being designed to operate within broader ranges of fuel types and quality. Tangentially fired boilers can also accommodate a broader range of fuel types and quality. See, for example, the Alstom boiler specification sheet available at: http://www.alstom.com/Global/Power/Resources/Documents/Brochures/pulverised-coal-boiler-tower-type-boilers.pdf.

3 The Virginia Center for Coal and Energy Research. (2009). *Meeting Projected Coal Production Demands in the USA: Upstream Issues, Challenges, and Strategies.* Prepared for the National Commission on Energy Policy. Chapter 4 (Coal Preparation). Available at: http://www.energy.vt.edu/ncepstudy/outline/Coal_Production_Demands_Chapter4.pdf.

Beneficiation results in a variety of improvements to power plant operations that directly affect the profitability of a coal plant, its emissions and ability to meet environmental requirements, and its ability to avoid future economic risks. In particular, coal washing can dramatically reduce the sulfur and ash content of coal, resulting in a significant reduction in air emissions, a reduction in auxiliary power demand, and a number of other co-benefits.

2. Regulatory Backdrop

Coal quality standards are typically implemented through state or local construction and operating permits and via language in procurement contracts.

There are several ways in which quality control requirements can be specified in a permit. For example, the source's operating permit may specify a maximum ash content and a maximum sulfur content for coal burned in a boiler. These conditions are typically enforced through sampling, recordkeeping, and reporting requirements.

Although air permit limitations are important for regulatory purposes, contractual arrangements between the seller of the coal and the purchaser are the primary means by which commercial quality control is established. One example of contractual standards for coal quality comes from the New York Mercantile Exchange. Under standard New York Mercantile Exchange rules, there are a number of coal quality specifications; for example, the following are specifications for Central Appalachian Coal:

Coal delivered under this contract shall meet the following quality specifications on an as-received basis [as-received does not refer to subsections (6) and (7)]:

1. **BTU**[4]: Minimum 12,000 BTU/lb, gross calorific value, with an analysis tolerance of 250 btu/lb below (A.S.T.M. D1989)
2. **Ash**: Maximum 13.50%, with no analysis tolerance (A.S.T.M. D3174 or D5142) (3) Sulfur: Maximum 1.00%, with an analysis tolerance of 0.050% above (A.S.T.M. D4239)
3. **Moisture**: Maximum 10.00%, with no analysis tolerance (A.S.T.M. D3302 or D5142)
4. **Volatile Matter**: Minimum 30.00%, with no analysis tolerance (A.S.T.M. D5142 or D3175)
5. **Grindability**: Minimum 41 Hardgrove Index (HGI) with three-point analysis tolerance below (A.S.T.M. D409)
6. **Sizing**: "Three inches topsize, nominal, with maximum fifty five per cent passing one quarter inch square wire cloth sieve to be determined basis the primary cutter of the mechanical sampling system (A.S.T.M. D4749)[5]" [*sic*]

Under these kinds of contractual arrangements, quality standards are enforced by the parties to the contract, with recourse to the appropriate judicial body in cases of disputes over performance.[6]

3. State and Local Implementation Experiences

Coal specifications were utilized for the design of water tube boilers in the mid to late 1800s and were in place for some of the early steam electric stations that were in operation prior to 1900. More than a hundred years ago, the United States government adopted coal quality specifications for the coal it purchases.[7] In the years since, quality specifications have become an industry norm and essentially all purchasers of coal, including those who use it to generate electricity, have experience with such specifications.

Coal beneficiation has been a common practice for meeting coal quality specifications across the United States. However, coal beneficiation is most economical and beneficial today when applied to fuel that will be burned in a pulverized boiler. Less coal washing occurs in the United States today than in the 1980s and 1990s owing to:

- increased use of fluidized bed boilers;
- increased availability of coal from the Powder River Basin; Powder River Basin coal has a relatively low ash content of five to six percent, is also lower in sulfur than Appalachian coal, and is mined almost exclusively through longwall or opentop extraction,

4 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit.

5 CME Group. (2012). NYMEX Rulebook: Chapter 260 – *Central Appalachian Coal Futures.* Available at: http://www.cmegroup.com/rulebook/NYMEX/2/260.pdf.

6 Contracts generally specify the method of resolving conflicts, as well as the adjudicatory body and jurisdiction.

7 Pope, G. (1910). *Purchase of Coal by the Government under Specifications: with Analyses for Coal Delivered in the Fiscal Year 1908-09.* Government Printing Office. Available at: http://pubs.usgs.gov/bul/0428/report.pdf.

which optimizes the amount of coal that can be removed per unit of labor;

- increased coal prices – boilers (including pulverized coal boilers) were designed and/or modified with more flexibility to operate acceptably with the lower quality, less expensive coals; and
- utilization of new or improved emissions controls that allowed the use of lower quality/lower cost coals while still meeting air emissions requirements.

Thus, it is often possible for coal quality specifications to be met without requiring any coal beneficiation techniques.

Air pollution regulators in virtually all states will be familiar with the practice of limiting the sulfur and ash content of coal in power plant operating permits. This, too, has become an industry norm. But because they generally don't specify *how* sources will meet those limitations, air regulators in some cases may not be familiar with the costs or benefits of coal beneficiation.

4. Greenhouse Gas Emissions Reductions

Historically, the primary reasons for improving coal quality have been to increase the thermal efficiency of coal-fired power plants and to improve overall profit margins. Although air pollution concerns have not been the primary driver, a significant body of research indicates that beneficiation can result in substantial direct and indirect emissions reductions.

By improving thermal efficiency (heat rate), coal washing can directly reduce the carbon dioxide (CO_2) emissions rate of coal-fired boilers. Waymel and Hatt assessed the costs and benefits of improving coal quality for a hypothetical 500-megawatt (MW) coal plant, with a heat rate of 10,000 BTU per kilowatt hour (kWh), burning bituminous coal. Their results indicate that a heat rate improvement to 9890 BTU/kWh, that is, a one-percent increase in boiler efficiency, can be achieved through coal washing.[8] Each one-percent increase in boiler thermal efficiency can in turn decrease CO_2 emissions by two to three percent.[9] These results will vary depending on the specific fuel combusted; plants burning lower quality coals are likely to have more potential to improve thermal efficiency.[10] The Asian Development Bank (ADB) conducted an extensive survey of the Indian coal industry in the 1990s and found that for each 10-percent reduction in ash content, thermal efficiency can be improved by up to six percent, with an average of one to two percent; CO_2 emissions were found to decrease by 2.5 to 2.7 percent on average.[11] The ADB study included coals with high ash content, more representative of US lignite coals, and higher than the typical bituminous and sub-bituminous coals more commonly used in the United States.

In addition to boiler heat rate improvements, coal washing can also reduce auxiliary power demand (i.e., the electricity consumed onsite to power auxiliary equipment such as coal and ash handling equipment, fans, pollution control equipment, and the like). Reducing auxiliary power demand reduces the net emissions rate (pounds of emissions per net megawatt hour (MWh) delivered to the grid) of a power plant. The previously cited ADB survey noted a range of 8 to 12 percent of the gross power output at coal-fired power plants was used for plant auxiliary power requirements and found that auxiliary power demand declined by 10 percent on average with coal washing.[12]

Finally, as coal beneficiation can reduce the weight of raw coal by up to 25 percent, a net reduction in transportation energy demand of about 20 percent is

8 Waymel, E., & Hatt, R. (1987). *Improving Coal Quality: An Impact on Plant Performance.* Lexington, KY: Island Creek Corporation. (Estimated publication date based on references in the paper.) Available at: http://www.coalcombustion.com/PDF%20Files/Improving%20Coal%20Quality.pdf.

9 Supra footnote 3.

10 The U.S Environmental Protection Agency's (EPA) Technical Support Document (TSD) for 111(d): *GHG Abatement Measures,* describes several techniques to improve boiler efficiency. These techniques are also covered in Chapter 1 of this document (Optimize Plant Operations). The EPA's technical analysis does not quantify the CO_2 emissions impact of each specific technique for improving heat rates, as boiler types and fuels combusted in them vary. Rather, the IPM modeling conducted for the EPA and described in Section 2.6.4 of the EPA's TSD analyzed the combined influence from all heat rate improvement technologies on CO_2 emissions. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

11 ADB. (1998). *India: Implementation of Clean Technology through Coal Beneficiation.* Project number 26095, prepared for the ADB by Montan-Consulting GMBH in association with International Economic and Energy Consultants and CMPDI International Consultants, India. Available at: http://www2.adb.org/documents/reports/Consultant/IND/26095/26095-ind-tacr.pdf.

12 Ibid.

possible, requiring less fuel to transport the coal from a mine to a power plant, and yielding additional reductions in greenhouse gas (GHG) emissions.

5. Co-Benefits

Several qualitative and authoritative studies discuss factors that affect the performance of coal boilers, and the direction of the particular effect (i.e., increasing or decreasing). The Electric Power Research Institute (EPRI) and many utilities have developed proprietary models that can assess how a variable, or variables, will influence a particular plant.[13] These models require interested users to purchase them to determine specifics. However, agencies have conducted more general and broader studies that can be used to assess why coal quality matters, and what variables are the most important to consider. Evaluating the benefits of improving coal quality also required a search of the early literature, as later studies have been both narrower and more in-depth (looking at a particular variable like ash on a particular type of boiler, like a fluidized bed), and often refer back to the 1980s (and earlier) work as references.

The International Energy Agency (IEA) surveyed coal boiler operators in the early 1990s to assess what variables affect boiler performance and efficiency, and the direction of each variable (beneficial or harmful).[14] Sixty power plants in 12 countries were included in the survey. Based on the survey responses, the IEA concluded that coal quality factors account for up to 60 percent of forced outages at power plants. Applying mineral additives containing aluminum can reduce ash fouling and slagging in pulverized coal boilers by up to 78 percent.[15] Wet pretreatment can reduce the amount of ash that adheres to boiler tubes, thus reducing fouling. Dry additives, such as alumina, can make the ash less sticky and thus reduce the amount of ash that forms on boiler surfaces. Reducing the ash content of coal also makes the coal less abrasive and operators can reduce the amount of scheduled and unscheduled maintenance required to remove the ash accumulation. Reducing the abrasiveness of the ash and sulfur deposits on plant duct work can reduce corrosion that shortens the plant's expected life. The greatest improvements in boiler efficiency and coal quality occurred when the base coal itself was of poor quality, such as lignite coals combusted in the United States and Eastern Europe, and high ash content coals combusted in China and India.

In the United States, higher quality bituminous and sub-bituminous coals are more commonly used. And consistent with the Chapter 1 discussion on heat rate improvements, the actual benefits from improved coal quality will vary according to the power plant and its specific operating conditions.

Beneficiation also has benefits for the operation of emissions control devices. About 80 percent of the ash in coal eventually travels through the combustion process and, along with the flue gas, is captured by the emissions control equipment. Coal washing reduces the amount of ash produced and collected by particulate control devices, thereby extending the life of the particulate control devices. Washing or processing coal before it is combusted can also permit the power plant to design and purchase smaller emissions control devices, thus reducing capital costs.

Studies of US coals show that washing reduces sulfur content by 10 to 20 percent (on a lb/MMBTU[16] basis). Ash reductions of 30 to 50 percent were reported for Mexican coals, with a 20- to 30-percent reduction in sulfur content. A National Academy of Sciences study reports sulfur reductions for China's coals of up to 20 percent.[17] A minimum ten-percent reduction in sulfur dioxide (SO_2) is considered to be a conservative assumption of the emissions-savings potential from coal washing. This minimum ten-percent reduction in SO_2 for a 600-MW plant, operating at an 80-percent capacity factor (or 7000 hours per year), would result in a minimum SO_2 annual reduction of 1682 metric tons.

13 Examples include EPRI's Coal Quality Impact Model, EBASCO performance models, heat rate models, or least-cost fuel models.

14 Skorupska, N. (1992). Coal Specifications - *Impact on Plant Performance: An International Perspective.* Presented at Effects of Coal Quality on Power Plants, Third International Conference, EPRI.

15 Vutharulu, H. (1999). Remediation of Ash Problems in Pulverized Coal-fired Boilers. *Fuel.* 78 (15), 1789–1803.

16 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

17 National Research Council. (2004). *Urbanization, Energy and Air Pollution in China: The Challenges Ahead - Proceedings of a Symposium.* Washington, D.C.: National Academies Press.

As noted above, the Waymel and Hatt study assessed the co-benefits of improving coal quality for a hypothetical 500-MW coal plant, with a heat rate of 10,000 BTU per kWh, burning bituminous coal. In addition to the heat rate improvements noted above, they noted a 45-percent decrease in ash and more than a 50-percent decrease in sulfur. The sulfur emissions rate was estimated to decrease from 4.2 lb/MMBTU to 1.9 lb/MMBTU.[18]

The ADB survey cited above mentions several other environmental co-benefits of coal washing. To begin with, the efficiency of electrostatic precipitators improves from 98 to 99 percent.[19] Land requirements for ash disposal are also reduced. For a 1000-MW coal plant, assuming a plant life of 20 years, the amount of land required for ash disposal is reduced from 400 hectares to 229 hectares. Finally, the amount of water required to move ash from the plant to a land disposal site is reduced by 30 percent. For a typical 1000-MW plant, this translates to 11.99 million m^3 per year consumption, compared to 17.05 million m^3 per year for a plant using unbeneficiated coal.

It is also worth repeating that as coal beneficiation can reduce the weight of raw coal by up to 25 percent, less energy is needed for transportation of the fuel, and additional reductions in fine particulates, nitrogen oxides, and other pollutants can result.[20] In a 2003 study of Chinese coals, Glomrod and Taoyuan calculated that coal cleaning removes 25 percent of the coal weight, resulting in a 20-percent net reduction in transportation demand for each unit of thermal energy.[21]

The full range of co-benefits that can be realized through coal beneficiation are summarized in Table 4-1.

18 Waymel & Hatt, supra footnote 8.

19 In effect, this is a 50-percent improvement in the particulate collection efficiency. A 98-percent efficiency means that, for each 100 tons of particulate mass in the flue gas, two tons would not be captured and would be emitted to the atmosphere. A 99-percent efficiency means that for each 100 tons of particulate mass in the flue gas, one ton would not be captured.

20 Supra footnote 11. Data on transport savings were calculated for India at Table 4-2 on page 69 of this document.

21 Glomrod, S., & Taoyuan, W. (2003). *Coal Cleaning: A Viable Strategy for Reduced Carbon Emissions and Improved Environment in China?* Norway and China. Available at: http://www.ssb.no/a/publikasjoner/pdf/DP/dp356.pdf.

Table 4-1

Types of Co-Benefits Potentially Associated With Coal Beneficiation

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_x[22]	Yes
SO_2	Yes
PM[23]	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes[24]
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	No
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Maybe
Other	

22 Nitrogen oxides.

23 Particulate matter.

24 Depending on the coal beneficiation techniques used, water consumption can be a potential concern. Improved thermal efficiency reduces water consumption per MWh of generating output, which must be weighed against any water impacts of the techniques that are used to improve coal quality.

6. Costs and Cost-Effectiveness

Power plant owners benefit directly from burning better quality coal. Coal-fired boilers represent significant economic assets for their owners and operators. Construction materials used are high value, such as stainless steel for certain ductwork and equipment, and boilers are designed to last for 20 to 30 years or more. Improving coal quality preserves the value of this long-term investment.[25] However, the environmental and private benefits associated with improving coal quality must be compared with the costs, including the environmental costs of washing and processing coal. Actual costs and cost-effectiveness of improved coal quality will vary according to the power plant and its specific operating conditions.

As noted above, the Waymel and Hatt study assessed the costs and benefits of improving coal quality for a hypothetical 500-MW coal plant, with a heat rate of 10,000 BTU per kWh, burning bituminous coal. In addition to the results noted above, they reported that delivered coal costs would increase from $41.50 per ton (for coal with a heating value of 11,900 BTU/lb) to $46.50 per ton for the washed coal (with a heating value of 13,300 BTU/lb), leading to an increase in annual fuel costs of $200,000. However, the plant operator would realize a net annual savings of $710,000 per year, attributable to $450,000 in savings from increased boiler efficiency, $230,000 in savings from reduced ash disposal, and $230,000 from improved coal handling. On a net output basis, fuel costs were forecast to decline slightly, from 17.44 mil/kilowatt (kW) to 17.25 mil/kW.[26] Savings were also expected (but not quantified) from extended boiler and equipment life.

The ADB survey, also cited above, found that by reducing ash content from 41 percent to 34 percent, operation and maintenance costs declined by 20 percent and overall capital investment in the power plant could be reduced 5 percent.[27]

The IEA also published detailed results in conjunction with the above-mentioned survey.[28] Changes in coal quality were evaluated in general, and several case-specific examples were provided. The general trends in coal quality were evaluated for a 1000-MW plant, with a 65-percent capacity factor, a 10,000 BTU/kWh heat rate, a coal heating value of 12,000 BTU/lb, an ash content of 10 percent, and a fuel cost of $35/ton. Changing the quality of the coal burned by increasing the ash content 10 percent, increasing moisture content by 5 percent, and decreasing heating value by 15 percent resulted in a higher heat rate, and a negative cost impact of $4.46 million/year (1986$).

Results of other case studies also reflect significant cost effects from poor quality coal. The Tennessee Valley Authority (TVA) improved coal quality at its Cumberland power plant (two units, each at 1300 MW) over the period from 1977 to 1986. TVA found that its operating and maintenance costs decreased on average by $15 million per year. The largest change in coal quality was decreasing the ash content from 15.2 percent to 9.2 percent.[29] Sulfur content also decreased from 3.5 percent to 2.8 percent, and heating value increased from 10,712 BTU/lb (24.9 MJ/kg) to 11,635 BTU/lb (27.1 MJ/kg).

The Southern Company, which operates several coal-fired plants in the Southeastern United States, also analyzed its operating and maintenance costs. Southern found that increasing the ash content from 15 percent to 20 percent increased waste disposal costs, maintenance costs, and

25 It must be acknowledged, however, that even with higher quality coal, boiler design is still critical to the efficient operation of a power plant. Boiler design life is predicated on adherence to good fluid dynamics and heat transfer principles. Layout of the plant's ductwork and piping aims to minimize turns and bends and have large diameter ducts to minimize pressure drops, to maximize the thermal efficiency of the plant, and to avoid extra energy demand just to move flue gases from one point to another. Critical to this are well-mixed flue gases, which depend on adequate retention time in the combustion chamber to complete chemical reactions, achieve maximum heat transfer, and minimize the formation of air pollutants. Well-mixed flue gases also ensure that duct velocities are uniform from top to bottom and side to side. Doing so helps to assure that flue gas temperatures are as uniform as possible. Flue gas hot spots can cause duct deformation and flue gas cold spots can cause corrosion if the temperatures drop below the acid dew point.

26 Waymel & Hatt, supra footnote 8.

27 Supra footnote 11.

28 Skorupska, N. (1993). *Coal Specifications - Impact on Power Station Performance*. London: IEA. IEACR/52.

29 Ibid, page 75.

Figure 4-1

Coal Characteristics by Coal Type

	Higher Heating Value (kJ/kg)	Moisture Content (%wt)	Carbon Content (%wt)	Ash Content (%wt)	Sulfur Content (%wt)	Minemouth Coal Cost (2005 $/ton)
Anthracite	30,000[a]-31,500[b]	2.1[b]-12[a]	72[a]-87[b]	6.9[b]-11[a]	0.5[b]-0.7[a]	44-87[e]
Pittsburgh #8	30,800[c]-31,000[d]	1.1[d]-5.13[c]	73[d]-74[c]	7.2[c]-13[d]	2.1[c]-2.3[d]	45-55[e]
Illinois #6	25,400[c]-25,600[d]	8.0[d]-13[c]	60[d]-61[c]	11[c]-14[d]	3.3[c]-4.4[d]	32-39[e]
Chinese Coal	19,300-25,300[f]	3.3-23[f]	48-61[f]	28-33[f]	0.4-3.7[f]	N/A
Indian Coal	13,000-21,000[g]	4[g]-15[f]	30-50[h]	30-50[g]	0.2-0.7[g]	14-19[g]
WY Powder River Basin	19,400[c]-19,600[d]	28[d]-30[c]	48[c]-49[d]	5.3[c]-6.3[d]	0.37[c]-0.45[d]	6-17[e]
Texas Lignite	14,500[i]-18,300[j]	30[j]-34[i]	38[i]-44[j]	9[j]-14[i]	0.6[j]-1.5[i]	14[k]-15[l]
ND Lignite	14,000[c]-17,300[d]	32[d]-33[c]	35[c]-45[d]	6.6[d]-16[c]	0.54[d]-1.6[c]	9[l]

a Eberle, J.S., Garcia-Mallol, A.J., Simmerman, AM, "Advanced FW Arch Firing: NOXReduction in Central Power Station," WPS Power Development, Inc. & Foster Wheeler Power Group, Inc., Presented at Pittsburgh Coal Conference, Pittsburgh, PA, Sept. 2002.

b Edward Aul & Associates, lnc., & E.H. Pechan & Associates, Inc., "Emission Factor Documentation for AP-42 Section 1.2 Anthracite Coal Combustion," US EPA, Research Triangle Park, NC, 1993.

c Integrated Environmental Control Model, Carbon Sequestration Edition, IECM-cs 5.02, Carnegie-Mellon University, 2005.

d US Department of Energy, OFE/NETL "Carbon Capture and Sequestration Systems Analysis Guidelines," Washington, D.C, April 2005.

e US Department of Energy, Energy Information Administration, "Coal News and Markets," webpage, downloaded 11/30/05 from http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html

f Oskarsson, Karin, et al., "A planner's guide for selecting clean-coal technologies for power plants," Washington, DC: The World Bank, 1997.

g International Energy Agency, "Coal in Energy Supply of India," OECD/IEA, Paris, France, 2002.

h Ohio Supercomputer Center, "Anthropogenic Emissions from Energy Activities in India: Generation and Source Characterization" website, downloaded 11/30/05 from http://www.osc.edu/research/pcrm/emissions/coal.shtml.

i San Filipo, John R., "US Geological Survey Open-File Report 99-301," US Geological Survey, Reston, VA, 1999.

j Gray, D., et al., "Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite," NETL, Falls Church, VA, 2004.

k US Department of Energy, Energy Information Administration, "Coal Industry Annual, 2000," Washington, D.C. 2000.

l US Department of Energy, Energy Information Administration, "Average Open Market Sales Price of Coal by State and Coal Rank," 2004, webpage, downloaded 11/30/05 from http://www.eia.doe.gov/cneaf/coal/page/acr/table31.html.

forced outages due to ash.[30]

A review of publicly available information on coal washing often finds an emphasis on the benefits to coal *producers* from washed coal (i.e., they can fetch a higher price for their product). Coal with lower sulfur and ash content is indeed more expensive than coal with higher sulfur and ash content.[31] The Massachusetts Institute of Technology study, "The Future of Coal," includes Figure 4-1, which illustrates the influence of these and other variables on the price of coal.[32]

Table 4-2 below is an example of the coal commodity spot price data available from the EIA. This table illustrates the price differences based on both heating value and sulfur content. Low-sulfur Central Appalachian coal represents the highest price, whereas low-BTU Powder River Basin coal is lowest.

The EIA also summarizes the prices fetched by various coal ranks. Table 4-3 on the following page presents data for 2012. Regardless of the mine location, bituminous coals sold for much higher prices than sub-bituminous coals and lignite. Anthracite is mined in Pennsylvania; its high heating value makes it attractive as a coking or metallurgical coal.

7. Other Considerations

As is the case for many other pollution control options, beneficiation has the potential to increase the utilization of a given power plant. The ADB survey found that for each 10-percent reduction in ash content, the plant use factor (or capacity factor) can increase up to six percent as forced outages and maintenance issues related to tube leaks, the economizer, and associated components are reduced. Thus, the potential exists for the gross annual emissions of a given power plant to increase as a result of beneficiation, despite decreases in the emissions *rates*. Any increases in plant

Table 4-2

Average Weekly Coal Commodity Spot Prices (Per Short Ton)[33]

Week Ended	Central Appalachia 12,500 Btu, 1.2 SO_2	Northern Appalachia 13,000 Btu, <3.0 SO_2	Illinois Basin 11,800 Btu, 5.0 SO_2	Powder River Basin 8,800 Btu, 0.8 SO_2	Uinta Basin 11,700 Btu, 0.8 SO_2
18 January 2013	$68.05	$62.10	$47.90	$10.15	$35.85
25 January 2013	$68.05	$62.10	$47.90	$10.15	$35.85
01 February 2013	$66.50	$62.10	$47.90	$10.15	$35.85
08 February 2013	$66.50	$62.10	$47.90	$10.15	$35.85
15 February 2013	$66.50	$62.10	$47.90	$10.25	$35.85

30 Supra footnote 29 at page 75.

31 Coal is priced both on a dollars per ton and a dollars per MMBtu basis. The price itself is based on several factors, including its rank, how it is mined, and its quality. Coal mined through subsurface means is more expensive than coal mined at the surface (e.g., mountain top removal).

32 Massachusetts Institute of Technology. (2007). *The Future of Coal - Options for a Carbon Constrained World.* Available at: http://web.mit.edu/coal/.

33 The historical data file of spot prices is proprietary and cannot be released by EIA. This sample table is printed with permission from SNL Energy (http://www.snl.com/Sectors/Energy/Default.aspx). Note: Coal prices shown are for a relatively high-Btu coal selected in each region, for delivery in the "prompt quarter." The prompt quarter is the quarter following the current quarter. For example, from January through March, the second quarter is the prompt quarter. Starting on April 1, July through September define the prompt quarter.

Table 4-3

Average Sales Price of Coal by State and Coal Rank, 2012 (Dollars Per Short Ton)[34]

Coal-Producing State	Bituminous	Sub-bituminous	Lignite	Anthracite	Total
Alabama	106.57	-	-	-	106.57
Alaska	-	w	-	-	w
Arizona	w	-	-	-	w
Arkansas	w	-	-	-	w
Colorado	w	w	-	-	37.54
Illinois	53.08	-	-	-	53.08
Indiana	52.01	-	-	-	52.01
Kentucky Total	**63.12**	**-**	**-**	**-**	**63.12**
Kentucky (East)	75.62	-	-	-	75.62
Kentucky (West)	48.67	-	-	-	48.67
Louisiana	-	-	w	-	w
Maryland	55.67	-	-	-	55.67
Mississippi	-	-	w	-	w
Missouri	w	-	-	-	w
Montana	w	17.6	w	-	18.11
New Mexico	w	w	-	-	36.74
North Dakota	-	-	17.4	-	17.4
Ohio	47.8	-	-	-	47.8
Oklahoma	59.63	-	-	-	59.63
Pennsylvania Total	**72.57**	**-**	**-**	**80.21**	**72.92**
Pennsylvania (Anthracite)	-	-	-	80.21	80.21
Pennsylvania (Bituminous)	72.57	-	-	-	72.57
Tennessee	73.51	-	-	-	73.51
Texas	-	-	19.09	-	19.09
Utah	34.92	-	-	-	34.92
Virginia	109.4	-	-	-	109.4
West Virginia Total	**81.8**	**-**	**-**	**-**	**81.8**
West Virginia (Northern)	63.34	-	-	-	63.34
West Virginia (Southern)	91.4	-	-	-	91.4
Wyoming	-	14.24	-	-	14.24
US **Total**	**66.04**	**15.34**	**19.6**	**80.21**	**39.95**

- = No data reported.

w = Data withheld to avoid disclosure.

Note: An average sales price is calculated by dividing the total free onboard rail/barge value of the coal sold by the total coal sold. Excludes mines producing less than 25,000 short tons, which are not required to provide data. Excludes silt, culm, refuse bank, slurry dam, and dredge operations. Totals may not equal sum of components because of independent rounding.

34 US EIA. (2013). Annual Coal Report 2012. Available at: http://www.eia.gov/coal/annual/pdf/acr.pdf.

use factor could of course allow for decreased generation and emissions from some other power plant. These factors will need to be evaluated in the context of the EPA's Clean Power Plan proposal, where heat rate improvements are the cornerstone of Building Block 1.

Using scarce water resources to improve coal quality may not be justified in some geographic areas, and it may be better to improve coal quality at the power plant or at some intermediate site between the mine mouth and the plant, where water resources are more plentiful and can be reused. Also, washing coal creates a need to impound the residual slurry from the washing process itself. Slurry storage ponds give rise to the risk for contamination of local waterways and ground water if the containment ponds leak. This is a serious environmental consideration and requires careful oversight by regulators.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on coal beneficiation:

- ADB. (1998). *India: Implementation of Clean Technology through Coal Beneficiation.* Project number 26095, prepared for the ADB by Montan-Consulting GMBH in association with International Economic and Energy Consultants and CMPDI International Consultants, India. Available at: http://www2.adb.org/documents/reports/Consultant/IND/26095/26095-ind-tacr.pdf.
- Pacyna, J.,Sundseth, K., Pacyna, E. G., Jozewicz, W., Munthe, J., Belhaj, M. & Aström, S. (2010). An Assessment of Costs and Benefits Associated with Mercury Emission Reductions from Major Anthropogenic Sources. *Journal of the Air & Waste Management Association.* 60:3, 302-315, doi: 10.3155/1047-3289.60.3.302. Available at: http://dx.doi.org/10.3155/1047-3289.60.3.302.
- Rubin, E., Chen, C., & Rao, A. B. (2007). Cost and Performance of Fossil Fuel Power Plants with CO_2 Capture and Storage. *Energy Policy.* 35, 4444–4454. Available at: http://www.cmu.edu/epp/iecm/rubin/PDF%20files/2007/2007b%20Rubin%20et%20al,%20Energy%20Policy%20%28Mar%29.pdf
- Skorupska, N. (1993). *Coal Specifications - Impact on Power Station Performance.* London: IEA. IEACR/52.
- Waymel, E., & Hatt, R. (1987). *Improving Coal Quality: An Impact on Plant Performance.* Lexington, KY: Island Creek Corporation. (Estimated publication date based on references in the paper.) Available at: http://www.coalcombustion.com/PDF%20Files/Improving%20Coal%20Quality.pdf.

9. Summary

Coal beneficiation has the potential to provide economic, energy, and environmental benefits for some units depending on unit-specific design. Even small reductions in coal consumption on the order of one to two percent, for the same generating output, improve the profit margin of the power plant, extend the life of pollution controls, reduce the quantity of water and solid waste discharged, and reduce GHG, criteria pollutant, and mercury emissions. Water constraints in certain regions will favor dry beneficiation processes over wet.

5. Optimize Grid Operations

1. Profile

Electricity networks are changing today in ways that fundamentally challenge traditional grid reliability and planning tools. New technologies and approaches are creating opportunities – but also challenges – that will require innovative approaches by electricity grid operators to meet system needs reliably and at least cost. These issues are of greatest interest to utilities, grid operators, and public utility commissions, but many also have greenhouse gas (GHG) emissions ramifications. This chapter focuses on approaches that have the most influence on GHG emissions, and summarizes emerging opportunities that can simultaneously improve electric reliability and reduce air pollution.

"Optimizing grid operations" refers to activities undertaken to improve the performance and efficiency of electricity transmission and distribution systems by grid operators (i.e., independent system operators [ISOs], regional transmission organizations [RTOs], and distribution utilities). Performance improvements include better and lower-cost levels of grid reliability, more efficient delivery of electricity, reduced system losses, and increased capacity utilization for more efficient use of assets (and thus requiring, over time, less capital investment). This chapter describes innovative approaches for the active management of the bulk electricity transmission and distribution systems to accomplish these improvements. It also covers enhancements to load management and rate design that can foster better management of the distribution system.

Optimizing the operation of transmission and distribution systems has not been a typical control measure considered by air quality agencies for GHGs or for other regulated air pollutants.[1] However, improved grid operations can help to reduce GHG emissions and improve air quality, and states that implement these options may be able to develop more cost-effective plans for reducing GHG emissions. Improved grid operations may also be a suitable option for regional (multistate) collaboration on emissions reductions because electricity grids are characteristically multistate in nature.

Efforts to optimize the grid system center on the many strategies that can be used to get the same or greater capability out of a utility's wires, saving energy and thereby reducing the need for upstream generation. Examples include optimizing voltage regulation and power factor management, adjusting load levels, and enhancing levels of grid intelligence to meet energy demands (e.g., "smart grid" solutions). Efforts to optimize grid operations can also include market mechanisms to encourage the participation of new service providers and innovators. Finally, optimizing grid operations can involve a myriad of ways (including pricing and rebates) that utilities, system operators, and regulators can encourage customers to modify their electrical loads in exchange for some form of compensation.[2]

New challenges to grid operation also include the integration of more distributed and variable energy

1 For example, the US Environmental Protection Agency did not explicitly include grid optimization measures in its determination of the "best system of emission reduction" for the proposed Clean Power Plan regulations under section 111(d) of the Clean Air Act.

2 Some of the technologies and policies used to optimize grid operations are relevant in the context of other GHG reduction strategies, or can be adopted as standalone strategies. In other words, there is intentional overlap between this chapter and other chapters in this document. In particular, readers will find overlapping references between this chapter and Chapter 10 (which focuses exclusively on losses in the transmission and distribution system), Chapter 23 (which focuses exclusively on demand response), and Chapter 26 (which discusses electricity storage, smart grid, electric vehicles, rate design, and other topics).

resources,[3] plus the inherently more diffuse nature of system operations associated with diverse customer ownership of distributed resources. Fortunately, intelligent grid capabilities, along with advanced communications and new grid technologies, are providing solutions to these new challenges.[4]

Many of the approaches considered in this chapter rely on or can be enhanced by some degree of "smart grid" technology. The "smart grid" – a suite of enabling technologies that are increasingly prevalent, but the potential of which has hardly been tapped in practice – is discussed in greater detail in Chapter 26. It is worth noting here, however, that the US Department of Energy[5] and many states[6,7] have launched smart grid or other grid modernization initiatives in pursuit of such opportunity. Several similar efforts are also underway in the private sector (e.g., by the Electric Power Research Institute [EPRI][8]).

Along with these new approaches, there are also several existing, mature technologies and technical solutions that can be applied in many areas of the electrical system. Many of these ways to improve operation of the grid fall into one of the following categories: conservation voltage regulation, volt-ampere reactive (VAR) control/power factor management, dynamic pricing and demand response (DR) programs, and well-placed storage to optimize the grid. These options are discussed in greater detail below.

a. Conservation Voltage Regulation (or Conservation Voltage Reduction)

Utilities typically maintain distribution grid voltages at the higher end of the 114- to 126-voltage range permitted by American National Standards Institute in order to provide a greater margin of safety in avoiding reliability issues (e.g., against changing loads on remote circuits). Conservation voltage regulation (CVR) can be exercised by both transmission system and distribution system operators, and is usually implemented by reducing voltages at the substation level to achieve power savings over short time periods.[9] Transmission and distribution systems are designed to operate within certain voltage tolerance limits. Utilities can save energy by operating the distribution system at the lower end of the acceptable voltage range. Reducing voltage also reduces the energy consumption of some consumer equipment without materially affecting service quality.[10] The grid system typically loses three to seven percent of the electricity that it carries while

3 "Distributed energy resources" refers to small electricity generating sources (usually less than 1 megawatt capacity) typically installed at a customer's location. Such sources can be fossil-fueled (e.g., diesel generators installed for backup or emergency power), but increasingly they are renewable, such as photovoltaic (PV) solar systems installed on homes, businesses, and commercial locations or small-scale wind power installations. "Variable energy resources" generally refers to renewable generation sources. Passing clouds and nighttime reduce or eliminate PV solar output, and wind generation can vary over the day, from day to day, or during different weather patterns.

4 "Intelligent grid" includes technologies popularly referred to as the "smart grid." These are an array of technologies enabling unprecedented utility control over the system and devices through the use of computers, sensors, two-way communications, micro-grids, and automation to seamlessly integrate and manage both the supply and demand for electricity. The concept of the intelligent grid also encompasses new aggregation services by a number of new third-party providers that deliver services to both system operators and utilities.

5 More information on the US Department of Energy's grid modernization efforts is available at: http://energy.gov/oe/services/technology-development/smart-grid

6 More information on the Massachusetts Department of Public Utility's grid modernization efforts is available at: http://www.mass.gov/eea/docs/dpu/electric/12-76-a-order.pdf

7 More information on the New York State Department of Public Service's grid reform and modernization efforts is available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument

8 EPRI. (2015, February). *The Integrated Grid: A Benefit-Cost Framework.* Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878

9 Utilities routinely operate at the high end of the 114- to 126-voltage range permitted by American National Standards Institute Standard C-84.1. Willoughby, R., & Warner, K. (2013, June 4). *Time to Take a Second Look at Conservation Voltage Regulation?* Intelligent Utility. Available at: http://www.intelligentutility.com/article/13/06/time-take-second-look-conservation-voltage-regulation

10 Net benefits depend on the design of the distribution system, the types of loads on the system, and the generating resource mix. Motors and other constant power loads, for example, tend to draw more current to compensate for reduced service voltage levels. Voltage levels must be kept within American National Standards Institute specifications

continued on next page

delivering electricity to homes and businesses. But as discussed in Chapter 10, losses can rise to around 20 percent during periods of peak electricity demand, such as on hot summer days with elevated residential and commercial air conditioning load.[11] These losses have to be made up through additional generation. Additional generation, in turn, emits additional GHGs and criteria pollutants, contributing to the unhealthy air quality conditions that often coincide with system peak periods.

Utilities control line voltage by changing settings on equipment at the substation serving the line or on equipment connected to the line. Voltage drops gradually as electricity flows further from the substation, so utilities need to ensure that the voltage level at the "end of the line" is above the minimum standard. This can be challenging because changing factors such as weather, load, electric generating unit (EGU) operations, and design (and changes in design to meet changes in load with growth, for example) must be taken into account to ensure that the voltage levels are acceptable at all points at all times. Using advanced metering systems, utilities can now remotely monitor and control voltage levels more accurately on individual circuits, allowing voltage margins to be smaller without affecting service to customers. In doing so, utilities reduce energy consumption, peak loads, and reactive power needs, reducing upstream generation and its corresponding costs and emissions. Pilot projects matching such technologies and real-time operating systems show that energy savings and demand reductions of three percent are possible.[12]

b. Power Factor Management

The flow of electrical current through a wire induces a magnetic field. Called "induction," "reactive power," or just "VARs,"[13] this magnetizing effect is most pronounced in electric motors, transformers, lighting ballasts, and so on, and least pronounced in such applications as resistance heating. Unfortunately this effect consumes energy, thereby reducing the amount of energy actually left to perform useful work.

Power factor is a measure of this effect, the ratio of "real power" (the amount available for useful work) to "total power" or "apparent power" (the amount originally provided). Ideally this ratio would be 1:1, making power factor equal to 1.0. Unfortunately in the real world, highly inductive loads reduce power factor, often to 0.70 or less. At this level, 30 percent of the original power is consumed by inductive loads and is unavailable to do useful work. Depending on requirements, it may be possible to adjust the output of existing online generators to increase the reactive power, or VAR output, to help meet grid requirements.[14] Otherwise costly steps, like bringing on additional generation and ensuring adequate transmission capacity, then have to be taken by grid operators in order to meet demand.[15] It is not surprising, then, that utilities

to avoid the possibility of heating or damage to motors when operated at reduced voltage levels. Some loads may use the same amount of power over time, even if they consume less when voltage is lowered. In such cases, the redistribution of power consumption over a longer period may still reduce peak demand and the operation of less efficient generating units. See: Pratt, R., Kintner-Meyer, M. C. W., Balducci, P. J., Sanquist, T. F., Gerkensmeyer, C., Schneider, K. P., Katipamula, S., & Secrest, T. J. (2010, January). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Pacific Northwest National Laboratory. Publication no. PNNL-19112. Prepared for the US Department of Energy. Available at: http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf

11 Lazar, J., & Baldwin, X. (2011, August). *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4537. Also, see: EPRI. (2008, March). *Green Circuit Field Demonstrations.*

12 Supra footnote 9.

13 Reactive power is often referred to simply as VAR or "VARs" for "volt-ampere reactive," its unit of measure.

14 For example, combustion turbines can be used as synchronous condensers for reactive control. This operation includes the start and stop of the combustion turbine in order to bring the generator to synchronous speed. The combustion turbine is then de-clutched from the generator and the generator operates as a "motor" providing reactive services to the grid. Areas that have markets for reactive power provide payment for operation in this manner.

15 In areas where there is a market for reactive power, such as PJM, generator owners/operators may receive compensation for their reactive output. Otherwise, generator owners/operators may be hesitant because megawatt output (and hence electrical sales) may have to be reduced (depending on the total load of the generator) to ensure that the generator is not loaded beyond acceptable limits. Also, some small generating units may be (or may have been) modified to act as synchronous condensers to help control system reactive power (primarily in areas where there is a viable reactive market).

often charge extra costs to commercial customers who have a power factor below some limit (e.g., 0.90 to 0.95).

Power factor management or "VAR control" refers to practices that maintain voltage levels at all points of the distribution systems for all load conditions.[16] Power factor can be "corrected" through technologies like capacitors or inductors that act to cancel the inductive or capacitive effects of the load, respectively. Automatic power factor correction units monitor power and switch blocks of capacitors in or out of service as required.[17] Additional benefits of power factor management include lower losses, better voltage regulation, and additional available system capacity.

Power factor correction is increasingly being built into consumer electronics as well. Energy Star's® Program Requirements for Computers Version 5.0, for example, calls for a power factor of ≥0.9 for computers. Energy Star® does not impose a minimum power factor on new residential refrigerators,[18] however, and even some highly rated models have relatively poor power factors.[19]

In summary, power factor management can both improve the working energy available from the system and reduce line losses made more severe by high current levels resulting from poor power factors. A more thorough discussion of this topic can be found in Chapter 10.

c. Demand Response

Demand response reflects a variety of approaches – typically financial in nature, such as rate designs, price signals, or rebates – that can motivate electricity end-users to curtail their load or shift it from peak to off-peak periods. DR is typically considered a tactic to address shortfalls in generation when peak electricity demand approaches or exceeds available supply. However, it is equally effective in addressing peak constraints imposed by the transmission and distribution grid as well. Shifting or curtailing loads reduces stress on the grid, lessens line losses, and can avoid or delay the need for upgrades to the grid system. In doing so, DR implicitly reduces reliability risks associated with stressed grid systems.

Increasingly sophisticated DR services can also extend to the delivery of ancillary services to grid operators. Since November of 2011, for instance, ENBALA Power Networks has aggregated loads to provide balancing services in PJM.[20] Aggregators of DR services are capable of facilitating the delivery of a wide range of services at both the distribution and bulk transmission level.

In addition to other benefits, DR may also provide a cost-effective way to maintain or improve grid system performance in the face of increasing levels of variable energy resources and distributed generation (e.g., renewables). As such, DR and the tools by which it is implemented (like time-of-use pricing and advanced dynamic pricing) will gain in importance with increasing penetration of distributed generation and electrification of the passenger vehicle fleet.[21]

Curtailment or shifting of loads from peak to off-peak periods can provide significant energy savings because losses increase with the square of demand, causing losses at critical peak period to be much larger than average losses. It is important to recognize, however, that DR may not always be beneficial in reducing GHG emissions. When grid users curtail their load under a DR program but shift to higher-emitting backup or standby generation, GHG

16 Uluski, B. (2011). *Volt/VAR Control and Optimization Concepts and Issues.* EPRI. Available at: http://cialab.ee.washington.edu/nwess/2012/talks/uluski.pdf

17 Power factor correction technologies are advancing rapidly. Distribution system capacitor banks can now be operated using real-time voltage data from advanced metering infrastructure to optimize voltage and VAR control. Power factor correction of high-voltage power systems may require specialized devices to automatically provide shunt capacitance or shunt reactance as required to maintain acceptable transmission line voltage. These systems compensate for sudden changes of power factor much more rapidly than contactor-switched capacitor banks or shunt reactors, and require less maintenance.

18 See: http://www.energystar.gov/ia/products/appliances/refrig/NAECA_calculation.xls?f1ac-7464

19 Regulatory Assistance Project Senior Advisor Jim Lazar measured power factor on two Energy Star® refrigerators in 2013 at 0.39 and 0.41. This suggests that the Energy Star® criteria, which address only kilowatt-hour usage per cubic foot, need to be revised.

20 Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6597

21 For a discussion of time-varying pricing, see: Faruqui, A., Hledik, R., & Palmer, J. (2012, July). *Time-Varying and Dynamic Rate Design.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://raponline.org/document/download/id/5131

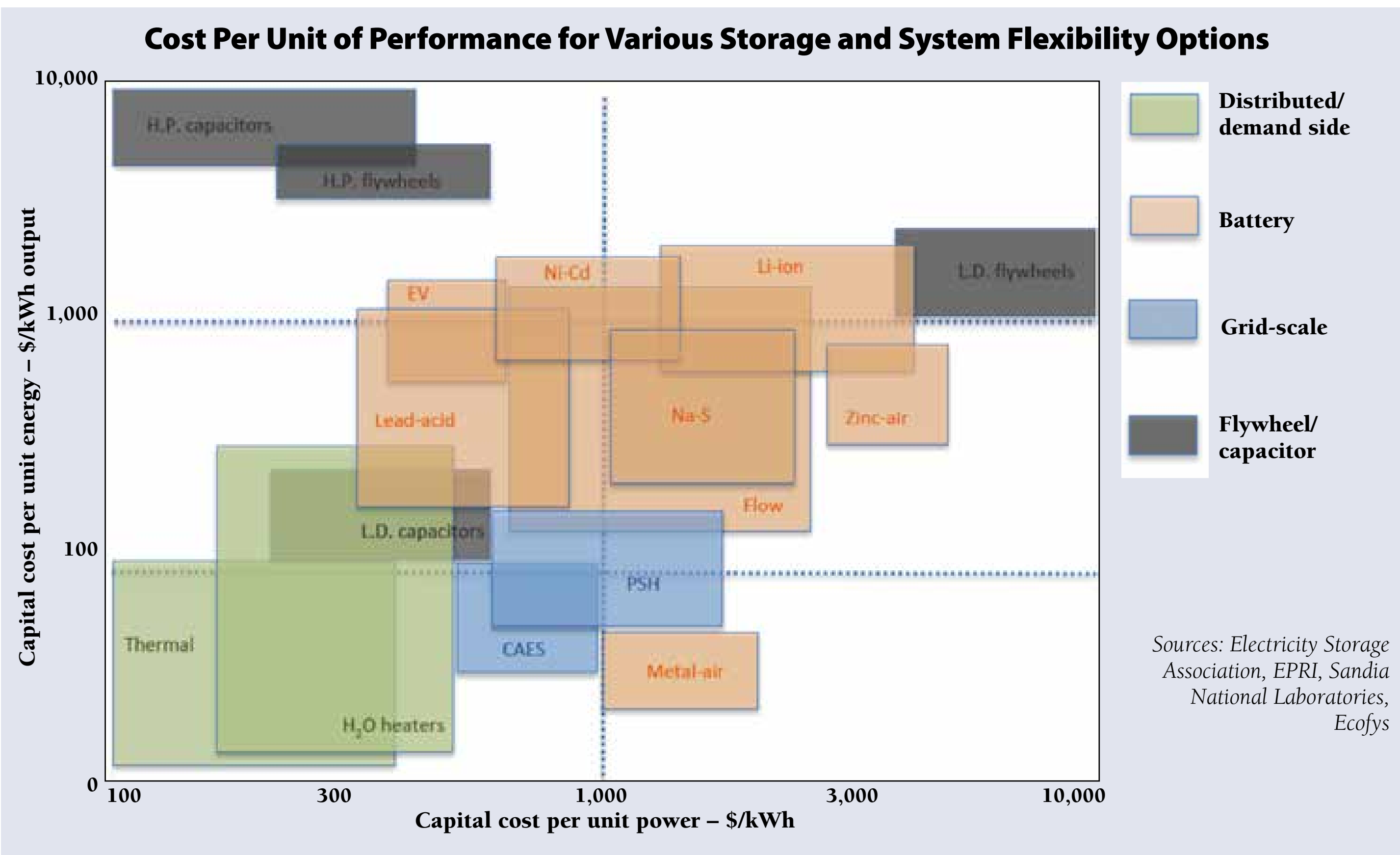
emissions could actually increase. Chapter 23 provides a comprehensive discussion of DR as a GHG emissions reduction strategy.

d. Storage of Electrical and Thermal Energy

Storage of electrical energy can be expensive, but it can also be an important part of a comprehensive approach to system optimization. Although there are multiple technologies currently available, including batteries, pumped hydro storage, compressed air energy storage, flywheel technology, and others, all are expensive. This is partly attributable to the nascent state of most electricity storage options, and partly to the inherent losses incurred as electricity is converted into another form of energy (e.g., mechanical or chemical) for storage and then re-converted later back to electricity. By contrast, thermal energy can be stored in the form it is eventually used (e.g., solar thermal hot water, ice, or chilled water), so it does not suffer conversion losses. Both electrical and thermal energy storage can provide targeted options to help optimize the grid.

Storage can serve multiple roles. One is bulk energy storage; pumped hydro has been used extensively for this purpose.[22] During the storage phase, when water is pumped up to an elevated impoundment, slightly more energy is used than is generated in the production phase, when stored water is released to drive turbines. Pumping usually occurs during low load levels (e.g., at night); subsequent water releases enable generators to better respond to peak demands. The economics work because peak power is much more valuable, and using pumped storage can avoid incremental fossil generation at peak times. Pumped hydro generators typically lie in remote locations and require additional transmission investment to provide pumping power and to bring their capacity to load centers. Another role for storage is to provide fast response to assist with ramping and system reliability; here batteries and flywheel systems seem to be the preferred technologies. Compressed air storage could also be an option. There are two working, utility-scale compressed air storage systems in the world, one in the United States and the other in Germany. Other large-scale technolo-

Figure 5-1



22 For more information on pumped hydro, see: *Pumped Hydro.* The National Hydropower Association. Available at: http://www.hydro.org/tech-and-policy/technology/pumped-storage/

gies are emerging as well. Figure 5-1 shows the relative cost characteristics of different types of storage that can provide additional flexibility for grid operations.

There are already situations in which electricity storage can be cost-effective and should be pursued. These include placement at strategic points where storage can provide supplemental capacity to meet peak loads, or a place to "park" surplus generation created by high renewable or nuclear generation at times when it isn't needed for current demand (e.g., because of high winds occurring at night). Strategically placed storage like battery banks can also help smooth wind generator output to enable more gradual ramping of other generation sources, including fossil-fueled electricity generating units, reduce localized peak loads (and associated losses) and thereby postpone or avoid more expensive transmission and distribution system upgrades, and even provide ancillary services to the grid, such as frequency control and voltage support.

Advances in two-way communications between the grid and devices – an element of what is commonly called the "smart grid" and increasingly referred to as part of "the internet of things" – may offer special promise regarding electricity storage. This prospective opportunity concerns use of new and existing batteries, such as those in electric vehicles (EVs) and uninterruptible power supplies, selectively charging them when power is available (e.g., during low night loads) and drawing upon these collective resources to help supply the grid during peak load periods.

An early application of this approach is likely to be grid control of EV chargers,[23] turning them from "charge" to "draw" as power supply market conditions warrant or to meet ancillary service needs on the grid. Sophisticated selective discharge systems – called "vehicle to grid" (V2G) systems – are being tested today and may emerge as a valuable grid resource within this decade. Even before such "bidirectional" charging infrastructure becomes widely available, however, plug-in EVs can deliver value to the grid in the form of ancillary services. Furthermore, EVs may be able to assist in the integration of renewable energy resources into the grid, by providing storage for renewable energy output when renewables might otherwise be curtailed.[24,25] The economics of such approaches must be compared to the full value of the benefits they provide (i.e., generation, transmission, distribution, capacity, environmental, and other), not just the distribution capacity upgrades they may help defer.[26]

There are several different types of thermal energy storage technologies as well; many are well proven historically, and several reflect new technological advancements. Residential hot water heating is a good example of the former. Home hot water heating is concentrated in the morning and evening hours, when residential consumers get up in the morning and again when they return home at the end of the day. By shifting water heating load from morning and evening to mid-day (when PV is most active) and overnight (when load is lowest), and "storing" the heated water until used, water heating's electricity requirements can help level overall demand on the grid rather than contributing to its peaks. A related strategy "supercharges" water heaters to higher temperatures, and uses a blending valve to deliver normal hot water temperatures to residents. In this manner, the grid operator can use "storage capacity" within existing water heaters to reduce electricity demand during peak periods.[27]

Air conditioning, both residential and commercial, represents a dominant summer electrical load in most of the United States, contributing greatly to afternoon and early evening peaks. Requiring new central air conditioners and large-building cooling systems to have two hours of thermal storage in the form of ice or chilled water would allow air conditioning loads to be time-shifted, much like the supercharging of hot water heaters noted previously. These types of devices are commercially available today, and they actually provide both capacity (peak) and energy savings, because they make ice or chilled water at night, when temperatures are lower and chilling units operate more efficiently.[28]

23 Permission for grid control would likely be at the vehicle owner's option, and in return for financial consideration.

24 Keay-Bright, S., & Allen, R. (2013, June 24). *Policy Brief: EU Power Policies for PEVs: Accelerating from here to en masse.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6620

25 M. J. Bradley & Associates for The Regulatory Assistance Project and International Council on Clean Transportation. (2013, July). *Electric Vehicle Grid Integration in the US, Europe, and China: Challenges and Choices for Electricity and Transportation Policy.* Available at: www.raponline.org/document/download/id/6645

26 Lazar, J. (2014, January). *Teaching the "Duck" to Fly.* Montpelier, VT: The Regulatory Assistance Project. p. 16. http://www.raponline.org/document/download/id/6977

27 Supra footnote 26 at p. 10.

28 Ibid at p. 12.

Finally, solar thermal generation can time-shift generation itself by using solar energy to heat a fluid that is then stored to generate electricity during later hours. Operating at a slightly higher cost than PV generation, this form of storage technology has been deployed in Arizona with fully six hours of successful storage.[29,30]

e. Other Opportunities for Optimization

There are other avenues for improving the performance of the grid, including numerous hardware improvements to reduce system losses that are the focus of Chapter 10. Other opportunities to achieve small but significant improvements are also possible based on the physical character of the grid system.

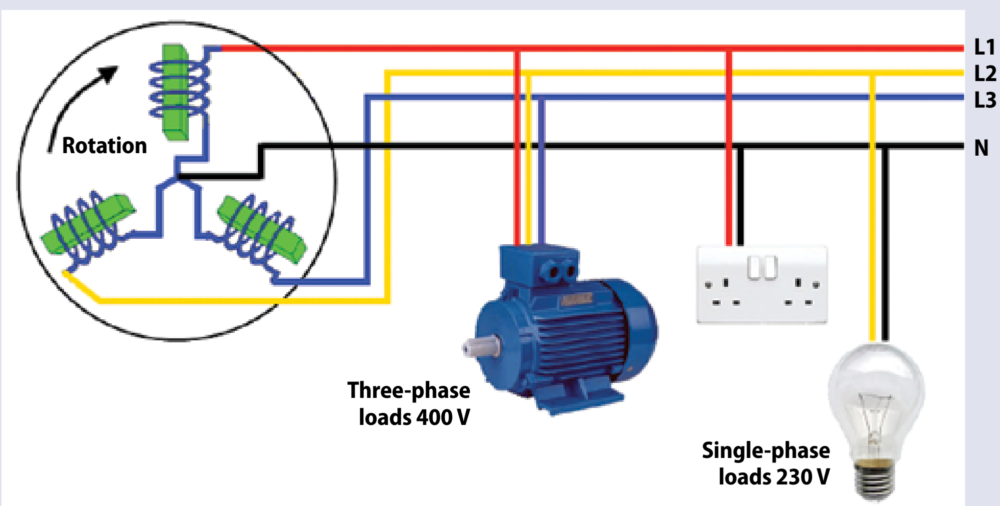
Most bulk transmission and distribution systems are based on three-phase alternating current power systems. Each phase is represented by a generator coil passing through a magnetic field on the motor. The three phases of the system can be delivered at a high voltage to large three-phase loads, or can be delivered as individual phases at lower voltages, as is commonly found in homes. Figure 5-2 illustrates this relationship.

High-voltage transmission systems are typically balanced, but electricity delivered on single-phase circuits is more susceptible to imbalances owing to variations in the loads served. As a result, distribution systems are often highly unbalanced, increasing system losses. Furthermore, the energy consumption of electrical loads changes continuously, which makes the balancing process challenging. Balancing three-phase loads periodically throughout a network can reduce losses significantly. Balancing can be done relatively easily and offers considerable scope for cost effective reduction in system losses. Use of smart grid assets to monitor individual phases, and to shift single-phase loads from one phase to another can also help correct and reduce unwarranted losses.

Joints and connections between two conductors or other components in the construction of the physical transmission system can also be a source of electricity losses attributable to aging and corrosion. Minimizing the number of joints, ensuring proper joining techniques, and conducting regular inspection and maintenance through thermal imaging and other techniques can help reduce losses from loose or corroded connections.[32,33]

Figure 5-2

Three-Phase and Single-Phase Electricity Distribution[31]



29 Supra footnote 26 at p. 9.

30 Owano, N. (2013, October 11). *Arizona solar plant achieves six hours after sun goes down.* Phys.org. Available at: http://phys.org/news/2013-10-arizona-solar-hours-sun.html

31 McFadyen, S. (2012, April 17. *Three Phase Power Simplified.* Available at: http://myelectrical.com/notes/entryid/172/three-phase-power-simplified.

32 Electrical Engineering Portal. (2013, August). *Total Losses in Power Distribution and Transmission Lines.* Available at: http://electrical-engineering-portal.com/total-losses-in-power-distribution-and-transmission-lines-1

33 Supra footnote 31 and, Black, J. W., Tinnium, K. N., Larson, R. R., Wang, X., & Johal, H. (2012, March 29). Patent Application Title: *System and Method for Phase Balancing in a Power Distribution System.* Available at: http://www.faqs.org/patents/app/20120074779

2. Regulatory Backdrop

The technologies discussed in this chapter are either regulated by federal requirements, state regulations, or voluntary utility industry standards. In general, the federal government generally has jurisdiction over bulk transmission lines via the Federal Energy Regulatory Commission (FERC). State public service commissions have jurisdiction over distribution lines, usually defined as the power lines that feed into homes or businesses. There are many inconsistencies in this paradigm, however, a number of which reflect the evolving nature of the electric grid.

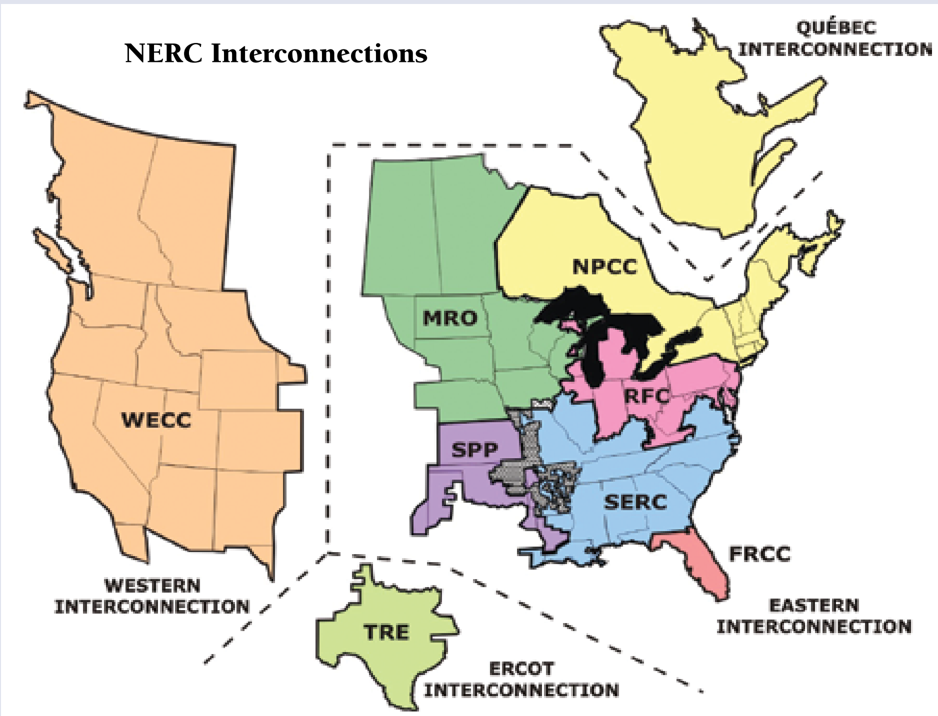
Power is distributed across the United States over high-voltage transmission networks linked by three major interconnections: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).[34] The North American Electric Reliability Corporation (NERC) oversees these three broad interconnections for reliability purposes. The three major interconnections are further subdivided into eight reliability planning areas, also under the oversight of NERC. NERC has adopted specific reliability standards that are legal requirements under FERC's authority. These regions are shown in Figure 5-3.

Because 47 states (excluding ERCOT, Hawaii, and Alaska) have transmission systems that are interconnected with other states' transmission networks, FERC regulates most bulk transmission, setting its rates and standards of service.[36]

Within the NERC regions, the minute-to-minute coordination of electricity supply with demand is managed by RTOs, ISOs, or individual utilities for their specific control areas. Both RTOs and ISOs are voluntary organizations established to meet FERC reliability and other requirements. As such, they plan, construct, operate, dispatch, and provide open access to transmission services.[37]

Figure 5-3

Major North American Electricity Interconnections[35]



34 When completed, the Tres Amigas project will significantly enhance the linkage between these three existing interconnection "islands," improving reliability in all three interconnection areas and providing a pathway for the transfer of substantial generation from renewable resources between the interconnections. Additional information is available at: http://www.tresamigasllc.com/

35 See NERC website: http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Interconnections_Color_072512.jpg

36 Not all transmission is subject to FERC jurisdiction. Public power entities such as the New York Power Authority, Arizona's Salt River Project, North Carolina's Santee Cooper, or the Los Angeles Department of Water and Power are not under FERC jurisdiction. Federal agencies also self-govern, so the Bonneville Power Administration, the Western Area Power Administration, and the Tennessee Valley Authority all fall outside of FERC's authority. Finally, most of Texas and all of Hawaii and Alaska are outside FERC jurisdiction because they are not connected, or not tightly connected, to the interstate transmission grid. See: Brown, M., & Sedano, R. (2004). *Electricity Transmission: A Primer.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/812

37 Lazar, J. (2011). *Electricity Regulation in the US: A Guide.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/645

Most grid optimization technologies must comply with federal, state, market, or utility rules, or some combination thereof. For instance, the rules that enable customer-side resources (such as DR) to participate in the delivery of grid services are defined in ISO/RTO market rules and by the utilities that operate the electricity distribution grid in areas outside of (or in addition to) formal wholesale markets regulated by FERC. FERC also regulates DR in the context of bulk transmission and wholesale markets. State regulators may also require certain levels of DR as a matter of state policy.

Regulatory oversight for conservation voltage reduction is split between federal and state regulators. Regulatory oversight at the level of the distribution and sub-transmission level comes from state regulatory commissions, whereas oversight at the transmission level comes from FERC and NERC.

To date, most options like power factor management, storage, and DR have been subject to market forces with little direct oversight by regulators. However, utilities typically have an obligation, enforced by utility regulators, to pursue low operations and maintenance costs on behalf of ratepayers as part of requirements for "just and reasonable" rates. So indirectly, utilities must consider these options if they can help reduce costs. California also took an initial step toward regulating electricity storage in late 2013, when the California Public Utilities Commission adopted requirements for its three largest utilities to procure 1325 megawatt-hours (MWh) of storage by 2020.[38]

3. State and Local Implementation Experiences

Most of the capabilities discussed in this chapter – including conservation voltage reduction, power factor optimization, phase balancing, and certain storage and DR capabilities – have existed in the past, but are being materially enhanced by the grid's evolution to two-way communications and automation (i.e., the "smart grid"). The enhanced versions of these approaches are relatively recent or just now emerging, so implementation experiences are limited. Accordingly, the discussion below focuses on pilot initiatives and reasons to expect greater benefit from these approaches in the future.

a. Conservation Voltage Reduction, Phase Balancing, and Power Factor Management

Utilities and system operators have used voltage reduction during capacity shortages for many years. In fact, ISO New England's operating procedures include it among the actions that the system operator may take to avoid involuntary load curtailments (i.e., "brownouts" or "blackouts"). The ISO estimates that a five-percent voltage reduction saves about 421 megawatts (MW) in its 28,000-MW system, approximately 1.5 percent of required capacity.[39] Emissions saved or avoided by this technique are discussed below.

The Northwest Energy Efficiency Alliance sponsored an extensive load research and field study of CVR with 11 utilities in the Pacific Northwest involving 31 transmission lines and ten substations from 2004 to 2007.[40] According to the project report, "operating a utility distribution system in the lower half of the acceptable voltage range (i.e., 114–120 volts) saves energy, reduces demand, and reduces reactive power requirements without negatively impacting the customer." The study estimated CVR could save one to three percent of total energy, two to four percent of kilowatt (kW) demand, and four to ten percent of kVAR demand.[41]

Little is known about how CVR may interact with smart grid technologies. As part of its Smart Grid City project in Boulder, Colorado, Xcel Energy is testing dynamic voltage/VAR optimization based on monitored real-time conditions. A recent review by Pacific Northwest National Laboratory

38 California Public Utilities Commission. (2013, October 21). Decision 12-10-040, Adopting Energy Storage Procurement Framework and Design Program. Available at: http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm

39 See: ISO-NE. *OP-4 - Action During a Capacity Deficiency.* Appendix A. Available at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4a_rto_final.pdf

40 Global Energy Partners, LLC for Northwest Energy Efficiency Alliance. (2008, June 27). *Utility Distribution System Efficiency (DEI): Phase 1. Final Market Progress Evaluation Report.* Available at: http://neea.org/docs/reports/utility-distribution-system-efficiency-initiative-dei-phase-1-final-report-no-3.pdf

41 Ibid at p. E-1. kVAR Volt-Ampere Reactive defined: In alternating current power transmission and distribution, volt-ampere reactive (var) is a unit used to measure reactive power in an AC electric power system. Reactive power exists in an ac circuit when the current and voltage are not changing at the same time.

concluded that, although additional research is needed, combining VAR control with smart grid technologies could potentially reduce total electricity consumption by two percent incrementally beyond the savings provided by CVR as practiced today.[42]

The EPRI launched a "Green Circuits" project in 2008 to build on the Northwest Distribution Efficiency Initiative by expanding field deployments of technologies and strategies and testing smart grid measurement, communication, and control.[43] Its goals were to improve modeling and loss analysis methods, analyze the economics of various strategies to improve distribution efficiency, and develop general guidelines for improving efficiency as a function of circuit and customer load characteristics.

The project involves 24 utilities and related organizations in 33 states and four countries. Roughly 90 circuits in rural and urban areas are included. Initial studies have been completed for 50 circuits. Distribution efficiency options were modeled as modifications to the base case, including:

- *Voltage optimization/CVR* – keeping transmission feeder line voltage in the lower band of the allowed range;[44]
- *Phase balancing* – rearranging loads on each phase of the circuit to lower the current on the most heavily loaded phase(s); and
- *Power factor correction/reactive power optimization* – adding capacitor banks or modifying switching schemes.

Hardware solutions modeled include:

- *Re-conductoring* – replacing selected conductors (wires) in the transmission and distribution systems; and
- *High-efficiency transformers* – replacing lower-efficiency line transformers with higher-efficiency units.

The average CVR savings factor – the change in load resulting from a one-percent reduction in voltage – was 0.79 percent, with a range of 0.66 to 0.92 percent. That's higher than determined in the Northwest Energy Efficiency Alliance study described previously, likely owing to the higher levels of resistive electric space and water heating loads where the Alliance conducted its study. The next phase of the EPRI project will validate these preliminary findings, assess costs and benefits, test the reaction of specific customer end-use devices to voltage optimization using advanced metering infrastructure data, and evaluate additional efficiency measures, such as coordination with distributed resources for loss reduction and load management through distribution automation.[45]

To optimize system voltage requires data on real-time voltage levels, which can be provided by smart meters and associated smart grid telecommunications equipment, along with voltage regulators at substations and on longer distribution feeder lines from the transmission system.

Utilities now have access to advanced modeling tools for the power system from the extra high voltage transmission system right down to the customer meter. Advanced metering infrastructure and GIS data now make it possible to optimize every line and distribution feeder for voltage control options, using equipment such as capacitors and static VAR compensators. The effects of CVR can be verified and even predicted.

b. Demand Response

Demand Response is now widely used to deliver a variety of grid services, as Chapter 23 discusses in detail. All organized markets in the United States now use or plan to use DR for ancillary services, and hundreds of local distribution utilities operate some form of DR program. DR is also used in energy markets and to deliver capacity-related services. Third-party aggregators (e.g., EnerNOC) play an important part in the delivery of DR in organized markets.

Price-based DR has long been available at the level of the

42 Based on research sponsored by the Northwest Energy Efficiency Alliance and engineering estimates for dynamic optimization of voltage and reactive power. Assumes 100-percent penetration of the required smart grid technologies in 2030. Pratt, R., Kintner-Meyer, M. C. W., Balducci, P. J., Sanquist, T. F., Gerkensmeyer, C., Schneider, K. P., Katipamula, S., & Secrest, T. J. (2010, January). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Publication no. PNNL-19112. Pacific Northwest National Laboratory for the US Department of Energy. Available at: http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf

43 Material in this section is based on information from Karen Forsten, EPRI, March 2010.

44 Voltage set point = 118.5 Volts (V); bandwidth = 2 V (+/– 1 V).

45 Coordination with distributed resources for loss reduction refers to the dispatching of distributed generation to supply power to a transmission feeder line, and thus reduce line losses during peak loads. Load management through distribution automation means controlling customer loads by remote means to limit peak load.

vertically integrated distribution utility in the form of time-of-use pricing or some form of interruptible rates. Almost all utilities in the United States offer some form of time-of-use and interruptible tariffed rates and have for decades. Advanced metering infrastructure is enabling much more dynamic pricing arrangements in the form of critical peak pricing, real-time pricing, and peak-time rebates. There is available a growing body of experience with these frameworks in the various pilot program initiatives.

c. Energy Storage

As noted earlier, the storage of electricity can be relatively expensive. But if one expands the idea of storage to include thermal storage capabilities on the customer side of the meter (e.g., storing hot water in water heaters rather than electricity in batteries), the potential is quite large. Recall that electricity demand met through either the storage of electricity or its end products (e.g., heated water) can be a resource equivalent to acquiring additional generation. Against this measure, some forms of storage (see Figure 5-1) are already more cost-effective than new fossil plants, plus they provide the grid operator with more operating flexibility and avoid new criteria pollutant and GHG emissions that would also accompany additional fossil-fueled generation. Furthermore, electricity storage capabilities promise to improve significantly over time with the electrification of vehicles and other technological developments. And as noted earlier, California has recently established electricity storage procurement requirements for its major utilities.

Although there are many storage technologies available, some of the least expensive are those involving distributed thermal heat. The United States has about 45 million electric water heaters in service, and residential hot water use is concentrated in the morning and evening hours, when residential consumers are getting up in the morning and again when they return home at the end of the day. Residential water heaters are thus excellent targets for load control, and more than 100 rural electric cooperatives already operate simple load control programs using members' electric water heaters. By shifting water heating load from morning and evening to mid-day (when solar PV is greatest) and overnight (when wind and thermal capacity may be underutilized), water heating energy requirements can be served far more economically than at peak periods. One favored strategy involves "supercharging" water heaters to higher temperatures during off-peak electrical demand periods (coupled with a blending valve to deliver normal hot water temperatures to homeowners). In this manner, the grid operator can use the ability to store electricity as hot water within existing water heaters.

Using these water heaters to help balance the loads and resources of an urban utility may require new institutional arrangements (e.g., voluntary agreements, contracts, compensation, and so forth), but the necessary technologies are readily available and can be installed quickly and managed easily. To date, most water heater load control programs have used radio signaling systems, but with the communication systems that have been installed by many electric utilities to support advanced metering infrastructure, it will also be possible to control electric water heaters remotely from utility control centers.

Electric water heating is dominant in the Pacific Northwest and in the south, whereas natural gas water heating is dominant in California. But even the investor-owned electric utilities in California have approximately ten-percent electric water heat saturation – about one million installed units – primarily in mobile homes and multifamily housing. One million electric water heaters could enable up to 4000 MW of capacity and up to 10,000 MWh per day to be shifted as needed. Projects are being advanced in Canada and Hawaii to use electric water heating controls to add system flexibility.[46]

Thermal storage systems can shift cooling requirements just as effectively as they can shift heating requirements. Systems that make ice during off-peak hours and then use that ice for cooling during on-peak periods – instead of relying on an electric air conditioning compressor – are already commercially available. They provide an excellent alternative for storing off-peak energy, such as nighttime generation from wind turbines. Using direct control of these cooling systems and other air conditioning systems with cold storage could greatly increase DR capabilities. The use of ground source heat pumps for residential heating and cooling systems could be similarly useful in various locations and under certain conditions.

As noted earlier, electricity can be directly stored in compressed air storage systems, mechanical flywheel systems, some chemical phase-change systems, utility-scale battery banks, and even existing batteries, such as those in EVs and uninterruptible power supplies. These systems can be used to supply power to the grid, but they can also be managed to help meet ancillary service needs on the

46 Supra footnote 26.

grid (e.g., by turning them off and on, drawing on them as power "sources," or charging them as power "sinks") as power supply market conditions change.

The electrification of the transportation system would use off-peak electricity (i.e., nights and weekends) from the grid to charge the vehicles. This would enhance the efficiency of the grid by shifting electricity use to off-peak nighttime hours, reducing the difference between off-peak and peak demand levels and allowing EGUs to operate more steadily and efficiently. EVs also are capable of providing electric services to the grid – a concept called "vehicle-to-grid" (V2G). A large number of EVs, plugged in and aggregated together as a single resource, could serve as a large "battery on the grid." One service that these vehicles can provide is regulation, used to balance variations in load by correcting for short-term changes in electricity use that might affect the stability of the power system. Regulation helps match generation and load and adjusts generation output to maintain the desired frequency.[47]

In an initiative with the University of Delaware and NRG Energy, a group of EVs is providing regulation services through the PJM Regulation Market. This project aggregates power from multiple EVs to create one larger power resource, rather than individual, smaller ones, and it has demonstrated for the first time that V2G technology can sell electricity from EVs to the power grid. Like large-scale batteries, this kind of energy storage can also store wind power generated at night for use during the day when demand is higher.[48]

A study on EVs in Texas found that if vehicle charging is optimized, an EV fleet of up to 15 percent of light duty vehicles could actually decrease electric generator nitrogen oxide emissions, even while increasing load. This is because selectively increasing system load allows generating units to run more efficiently, and allows system operators to deploy more efficient units. The same study found that using the batteries in the vehicles to provide V2G services could also reduce the sulfur dioxide and carbon dioxide (CO_2) emissions impacts of increased load from EVs. V2G services include using batteries for spinning reserves, frequency regulation, and energy storage to address peak load.[49] The study did not compare EVs to conventional vehicles, however.[50,51]

One recent study suggested that the value EVs could bring to the grid would compensate for a significant proportion of their annual electricity "refueling" cost. The study modeled three unidirectional grid-to-vehicle services: one-way frequency response/primary reserve (i.e., for short durations), one-way secondary reserve (i.e., for longer durations), and energy storage to reduce curtailment of renewable energy output. The total value of the three services was estimated to be $192 per year in 2020, split fairly evenly between the three services. This value is predicted to decline over time to $120 per year by 2050, as the value of frequency response per participant reduces significantly with market saturation. By contrast, the value of reduced renewable energy curtailment and reserves stays fairly constant to 2050 such that EV refueling costs in 2050 may be offset by 50 percent.[52]

Beyond issues associated with EVs' potential impact on grid optimization lies a broader set of questions related to the US Environmental Protection Agency's proposed Clean Power Plan (CPP). States choosing a mass-based pathway for complying with the CPP, for instance, could be discouraged from pursuing large-scale EV penetration because emissions from EGUs (which are covered by the CPP) could increase owing to additional charging load, even though overall GHGs from motor vehicles (which the CPP does not cover) could decline.[53]

47 PJM Fact Sheet. (2014, February 2). *Electric Vehicles and the Grid.* Available at: http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/electric-vehicles-and-the-grid-fact-sheet.ashx

48 Supra footnote 47.

49 "Spinning reserves" are generation resources that are kept on standby and are able to provide capacity to the grid when called by the system operator. "Frequency regulation" is a service, typically provided by a power plant, which system operators use to maintain a target frequency on a power grid. Signaled, a frequency-regulating unit will either increase or decrease its output or load to re-balance system frequency.

50 Supra footnote 25.

51 Sioshansi, R., & Denholm, P. (2009). Emissions Impacts and Benefits of Plug-In Hybrid Electric Vehicles and Vehicle-to-Grid Services. *Environ. Sci. Technol.*, *43*(4):1199–1204. Available at: http://pubs.acs.org/doi/abs/10.1021/es802324j

52 European Climate Foundation. (2013). *Fuelling Europe's Future: How Auto Innovation Leads to EU Jobs.* Available at: http://www.camecon.com/EnergyEnvironment/EnergyEnvironmentEurope/FuellingEuropesFuture.aspx

53 Toor, W., & Nutting, M. (2014, November 30). *Southwest Energy Efficiency Project (SWEEP) and the Electric Vehicle Industry Coalition (EVIC), Comments on the Treatment of Electricity Used by Electric Vehicles in the EPA's Proposed Clean Power Plan Rule.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www.seealliance.org/wp-content/uploads/SWEEP-EVs.pdf

4. GHG Emissions Reductions

As currently applied during periods of capacity shortfalls at the level of bulk transmission, the potential GHG reductions from CVR are limited. If the practice becomes more widespread at the transmission and especially the distribution levels, the impacts could increase significantly. As noted earlier, distribution system savings from a one-percent reduction in voltage corresponds to a 0.4- to 0.8-percent reduction in total generation requirements. Taking the midpoint, a 0.6-percent reduction in generation requirements nationally, at system-average emissions rates for fossil generators, would be approximately 22.8 million MWh, or the equivalent of 16 million metric tons of CO_2 emissions reduction.

The Northwest Energy Efficiency Alliance study estimated that CVR could save one to three percent of total energy, two to four percent of kW demand, and four to ten percent of kVAR demand. Every kWh saved is equivalent to an annual reduction in CO_2 emissions of 0.0007 metric tons. To put this in perspective, a small- to medium-sized utility serving 1 billion kilowatt-hour in load annually could reduce CO_2 emissions by 6896 metric tons for each one-percent reduction in energy losses, the equivalent in terms of CO_2 emissions of taking 1452 passenger cars off the road.[54] The report points out that major distribution efficiency improvements beyond CVR can achieve even higher levels of energy savings and emissions reductions.

Demand response and well-placed distributed storage can reduce losses in the transmission and distribution of electricity by reducing loads during periods at which power lines and other equipment are most stressed and losses can be as high as 20 percent. Recall that losses increase by the square of the current traveling through the system, so reducing current during peak periods can yield substantial benefits. By reducing losses during peak periods, these technologies also help avoid periods in which some of the least efficient fossil generation is called up to operate in order to meet peak electricity demands. The geographic impacts of the resulting emissions reductions, however, are likely to be highly variable. Also, to ensure that the environmental benefits of DR are realized, air regulators will need to ensure that inefficient backup diesel generation is used only sparingly (i.e., in emergencies) rather than regularly by those curtailing grid electricity use under DR programs. Chapter 23 provides a more comprehensive discussion of the GHG reduction potential of DR.

The impacts of power factor management or VAR control and phase balancing will be comparable to those that are associated with emissions reductions from energy efficiency program initiatives, because the practical effect of VAR control is to improve the ability of the system to deliver real power available to do work.

Among many implementation questions associated with the US Environmental Protection Agency's proposed CPP are the issues of how grid-related GHG reductions would be allocated to or claimed by the states covered by a grid control area, and how such reductions would be accounted for in state compliance plans. Given the interstate nature of the electricity grid, it may be challenging to attribute GHG savings from these measures to individual states.

5. Co-Benefits

Strategies to optimize the grid will produce co-benefits within the utility system and for utility customers by reducing both the capacity and the energy requirements of the system. In addition, by reducing the amount of electricity generated to meet demand, emissions of criteria and hazardous air pollutants will be reduced in rough proportion to the reductions in GHG emissions. The full range of co-benefits that can be realized through grid optimization is summarized in Table 5-1.

The array of existing and anticipated "smart grid" technologies described in this chapter can reasonably be expected to enable a variety of control actions that in the aggregate can provide or contribute to the co-benefits listed in Table 5-1, including improved grid reliability. It is important to note, however, that "smart" technologies can introduce additional system vulnerabilities as well (e.g., cyber attacks, hacking, and the like). Policymakers and system planners must be mindful of and account for such vulnerabilities in order to not adversely impact grid reliability and incur its associated costs.

54 US Environmental Protection Agency. *Greenhouse Gas Equivalencies Calculator.* Available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html

Table 5-1

Types of Co-Benefits Potentially Associated With Optimizing Grid Operations

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Typically yes
Employment Impacts	Yes – largely a function of increasing disposable income created by the net savings resulting from displacing higher cost generation that is avoided at the margin
Economic Development	Yes
Other Economic Considerations	No
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Maybe
Avoidance of Uncollectible Bills for Utilities	Maybe
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	Maybe
Demand Response-Induced Price Effect	Yes
Other	No in most cases

6. Costs and Cost-Effectiveness

The costs and cost-effectiveness of approaches to grid optimization vary considerably. The strategies emphasized previously are generally cost-effective or emerging; they can lower overall costs by reducing losses on the system, avoiding the operation of less efficient generation, or operating the system at lower voltage levels to reduce the power delivered to loads. The technologies and rate designs that have enabled these capabilities in the past (e.g., pumped storage, interruptible rates) are being complemented by a new generation of operational enhancements to improve system performance that are enabled by advancing smart grid technology capabilities (e.g., grid-integrated water heaters allow operators to provide ancillary services as well as "store" energy by superheating their contents and time-shifting their load).

One estimate for CVR's cost-effectiveness derives from the Northwest Energy Efficiency Alliance study cited earlier. Voltage reductions ranged from 1 to 3.5 percent. The study found that a one-percent reduction in distribution line voltage provided a 0.25- to 1.3-percent reduction in energy consumption, with most substations seeing results between 0.4 and 0.8 percent.[55] The results further indicate that when voltage reduction is coupled with major system improvements, 10 to 40 percent of the energy savings are from reduced losses on the utility distribution system. That means the majority of savings are from reduced consumption in homes and businesses owing to equipment operating at lower voltage.

Extrapolating these results to the four Northwest states, the Northwest Power and Conservation Council estimates the regional savings potential of CVR combined with distribution system upgrades to be more than 400 average MW by 2029.[56] The Council also estimates that the cost of acquiring those savings is low, with two-thirds of the potential savings achievable at

55 Supra footnote 54.

56 One average MW equals the energy produced by 1 MW of capacity operating every hour of the year.

a levelized cost of less than $30 per MWh,[57] compared to average wholesale power costs averaging $37.53 in 2013.[58]

7. Other Considerations

The approaches discussed previously generally offer a combination of benefits that include enhanced system reliability and reduced or deferred need for additional system investment – and associated risks of overcapitalizing such investments (i.e., creating “stranded” assets) in the rapidly changing power sector.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on optimizing grid operations.

- Cappers, P., MacDonald, J., & Goldman, C. (2013, March). *Market and Policy Barriers for Demand Response Providing Ancillary Services in US Markets.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6155e.pdf
- Cappers, P., Todd, A., & Goldman, C. (2013). *Summary of Utility Studies: Smart Grid Investment Grant Consumer Behavior Study Analysis.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6248e.pdf
- Faruqui, A., Hledik, R., & Palmer, J. (2012, July). *Time-Varying and Dynamic Rate Design.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://raponline.org/document/download/id/5131
- Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Wholesale Market Resource.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://raponline.org/document/download/id/6597
- Lazar, J. (2014, January). *Teaching the “Duck” to Fly.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6977
- Schneider, K. P., Tuffner F. K., Fuller, J. C., & Singh, R. (2010, June). *Evaluation of Conservation Voltage Reduction (CVR) on a National Level.* Pacific Northwest Labs. Available at: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19596.pdf
- Schwartz, L. (2010, May). *Is It Smart If It Is Not Clean? Strategies for Utility Distribution Systems.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Schwartz_SmartGrid_IsItSmart_PartOne_2010_05.pdf
- Porter, K., Mudd, C., Fink, S., Rogers, J., Bird, L., Schwartz, L., Hogan, M., Lamont, D., & Kirby, B. (2012, June 10). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge.* Western Governors’ Association. Available at: http://www.westgov.org/images/dmdocuments/RenewableEnergyTargets2012-13.pdf
- Keay-Bright, S., & Allen, R. (2013, June 24). *Policy Brief: EU Power Policies for PEVs: Accelerating From Here to en Masse.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6620
- M. J. Bradley & Associates for The Regulatory Assistance Project and the International Council on Clean Transportation. (2013, July). *Electric Vehicle Grid Integration in the United States, Europe, and China: Challenges and Choices for Electricity and Transportation Policy.* Available at: www.raponline.org/document/download/id/6645

9. Summary

There is a long and growing list of system capabilities that can improve grid reliability, increase efficiency, reduce cost, and enhance operating performance. Each of these opportunities to enhance or optimize the grid also typically reduces CO_2 emissions as a result of less – or lower-emitting – generation being needed. This is true at both the level of the transmission grid and the distribution system. With the expansion of the grid to accommodate new types of loads and resources, efforts to identify avenues to manage the cost and performance of the grid will also be required. Advanced communications and automation, including those generally associated with the smart grid, are enabling grid managers to use new, cost-effective strategies for managing the wires. The list of emerging strategies is long, but includes innovative applications of CVR, power factor optimization, phase balancing, the strategic use of electrical and thermal storage capabilities, and focused use of DR capabilities.

57 Northwest Power and Conservation Council. (2010, February). *Sixth Northwest Conservation and Electric Power Plan*, pp. 4–13. Available at: http://www.nwcouncil.org/energy/powerplan/6/default.htm

58 US Energy Information Administration. (2014, January 8). *New England and Pacific Northwest had largest power price increases in 2013.* Today in Energy. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=14511

6. Increase Generation from Low-Emissions Resources

1. Profile

More than two-thirds of the electricity generated in the United States is produced from fossil-fueled generators that emit substantial amounts of carbon dioxide (CO_2) and other greenhouse gases (GHGs), as well as many criteria and hazardous air pollutants. However, nearly all of the non-fossil fuel technologies used to generate electricity produce far fewer emissions[1] of most pollutants, or produce no emissions at all. Hydroelectric (a.k.a. hydro) and nuclear power technologies are the most mature and widely deployed of the zero-emissions technologies. Wind turbines and utility-scale and distributed solar photovoltaics (PV) currently produce considerably less electricity than hydro and nuclear, but are experiencing rapid, sustained growth in the United States and worldwide. Other relevant technologies include geothermal and concentrating solar power generators. Biomass, landfill gas, and biogas[2] technologies clearly result in emissions of some air pollutants, but are considered by many to be net-zero GHG emissions technologies on a lifecycle basis.[3] Table 6-1 exhibits the major zero- and low-emissions technologies that are covered in this chapter and their proportionate contribution to total US generation in 2012.

Table 6-1

Contribution of Zero- and Low-Emissions Technologies to Total US Generation (2012)[4]

Technology	kWh	Percentage of Total US Generation (2012)
Nuclear	769,331,249	19.0%
Hydroelectric	276,240,223	6.8%
Biomass[5]	57,622,166	1.4%
Wind	140,821,703	3.5%
Geothermal	15,562,426	0.4%
Solar	4,326,675	0.1%
Total	**4,047,765,259**	**31.4%**

Increasing the proportion of these zero- and low-emissions technologies in the electricity supply portfolio can be a cost-effective way to reduce carbon emissions from the levels currently produced by a fossil fuel-heavy portfolio. This chapter therefore focuses on the inherent potential of these technologies to reduce GHG and other air pollutant emissions, and the costs and cost-effectiveness of the technologies themselves. Public policy measures that may be used to accelerate deployment of these technologies are covered separately in Chapters 16 and 17, and complementary policies that are necessary or helpful to integrate higher levels of renewable resources into the power system are addressed in Chapter 20.

Although the net energy contribution from wind, solar, and other renewable technologies today is relatively low, these technologies may offer the most promising sources of

1 Throughout this chapter, references to “emissions” or “pollution” generally refer to GHG emissions, unless the context for the specific discussion is tailored to criteria or hazardous air pollutants or pollution in other media.

2 Biogas systems use anaerobic digestion to turn organic waste into a gas (primarily methane) and useable liquid and solid products. Sources of organic waste include manure from dairy and livestock operations, sludge filtered from wastewater, municipal solid waste, food waste, yard clippings, crop residues, and so on. For additional information, see: www.americanbiogascouncil.org or www.biogas-renewable-energy.info

3 The regulatory treatment of emissions from these technologies is explored in greater detail later in this chapter.

4 Based on US Energy Information Administration data available at: http://www.eia.gov/electricity/

5 Includes wood, wood-derived fuels, landfill methane, biogas, municipal waste, and other biomass waste.

carbon emissions reduction in coming years. There are at least three key reasons for this.

First, the main alternative to the introduction of zero- and low-emissions technologies is the application of carbon capture and sequestration to support the continued use of higher-emitting, predominantly fossil-fueled generation. However, to achieve GHG emissions reductions from fossil-fueled generators comparable to those that could be achieved with zero- and low-emissions alternatives would likely require carbon capture and sequestration to be used on a massive scale. But sequestration is very expensive today; major breakthroughs are required to match the economics that wind and solar already exhibit.[6]

Second, the economics of many of these zero- and low-emissions technologies are improving. Their life-cycle costs are declining, making them increasingly cost-competitive with the fossil fuel alternatives. Depending on available weather-related resources and grid connections, wind now competes favorably with fossil-fueled generation in most regions of the United States and internationally. Solar compares favorably with utility service at retail price levels in some regions of the United States, and it is increasingly competitive[7] with fossil-fueled generation and market resources.[8]

Third, the potential scale of renewable resources is large. This is fortunate, as a large amount of generation will be needed to replace the energy produced by an aging fleet of fossil-fueled generators, many of which are scheduled for retirement even in the absence of GHG regulations. Wind resources are now widespread, and utility-scale and distributed solar resources represent the fastest-growing category of generation (in terms of percentage growth rate) across all categories of generation, including fossil fuels. Between 2011 and 2012, solar energy grew by 138 percent in the United States. Its economics continue to show significant improvement.

Figures for the United States suggest that the technical resource potential for wind in the United States at 80 meters (wind turbine hub height) is between 10,000 and 12,000 gigawatts (GW), more than enough to match all energy requirements of US retail consumers.[9,10] Although geothermal only provides a material contribution to the current resource mix in a few states (and 0.4 percent of total generation nationally), the National Renewable Energy Laboratory estimates that existing and emergent geothermal technologies (especially deep enhanced geothermal) may offer a resource potential comparable to onshore wind potential (i.e., a multiple of total US retail requirements).[11] However, the potential based on existing geothermal technologies is much more limited, and according to Bloomberg New Energy Finance, the United States has already realized a 34-percent share of its 9-GW potential

6 The topic of carbon capture and sequestration is covered separately in Chapter 7.

7 As used here and throughout this chapter, "competitive" means that the resource can compete favorably (i.e., the levelized costs are near or below the reference market basis – or, in context, the retail rate) with comparable market-based resources free of either tax incentives, ratepayer-based incentives, or other policy-based encouragements unless specified.

8 See, for example: Rocky Mountain Institute. (2014, February). *The Economics of Grid Defection.* Available at: http://www.rmi.org/electricity_grid_defection

9 Refer to: http://www.windpoweringamerica.gov/windmaps/resource_potential.asp. Even at a low 30-percent capacity factor, this suggests that the resource potential of wind alone is many times the retail load in the United States of roughly 4,000,000 megawatt-hours.

10 There are multiple ways to assess the potential deployment of renewable resources. Technical potential represents "the achievable energy generation of a particular technology given system performance, topographic limitations, environmental, and land-use constraints. The primary benefit of assessing technical potential is that it establishes an upper-boundary estimate of development potential." Lopez, A., Roberts, B., Heimiller, D., Blair, N., & Porro, G. (2013, July). U.S. *Renewable Energy Technical Potentials: A GIS-Based Analysis.* National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy12osti/51946.pdf

11 Traditional geothermal technologies pipe pockets of steam from modest depths below the surface to generate electricity in turbines. Deep enhanced geothermal systems extract energy from deep within the Earth's crust. This is achieved by fracturing hot dry rock between three and ten kilometers below the earth's surface using a hydroshearing method similar to the hydrofracturing methods now commonly used for gas and oil extraction. Fluid is pumped through the rock and absorbs the earth's heat before it is pumped back to the surface to generate electricity. Lopez, et al, at supra footnote 10. Enhanced geothermal systems technology is new and uncertain. The first US project to rely on this technology was connected to the grid in early 2013.

from identified geothermal systems.[12] The potential for emerging geothermal technologies may take considerable time to realize.[13] Finally, the potential for solar generation is many times that of either wind, biomass, or geothermal in the United States. Table 6-2 summarizes the technical potential of various renewable energy technologies as reviewed by the National Renewable Energy Laboratory in 2012. Nuclear energy is not considered to be a renewable resource and is not shown in this table, although it is a zero-emissions technology covered elsewhere in this chapter.

Table 6-2

Total Estimated US Technical Potential by Technology[14]

Technology	Generation Potential (TWh)[a]	Capacity Potential (GW)[a]
Urban utility-scale PV	2,200	1,200
Rural utility-scale PV	280,600	153,000
Rooftop PV	800	664
Concentrating solar power	116,100	38,000
Onshore wind power	32,700	11,000
Offshore wind power	17,000	4,200
Biopower[b]	500	62
Hydrothermal power systems	300	38
Enhanced geothermal systems	31,300	4,000
Hydropower	300	60

a Non-excluded land was assumed to be available to support development of more than one technology.

b All biomass feedstock resources considered were assumed to be available for biopower use; competing uses, such as biofuels production, were not considered.

TWh - terawatt-hours

In contrast to most of the emerging renewable energy technologies, nuclear and hydro are mature technologies and are expected to continue to provide a material contribution to the generation mix for years to come, reducing the carbon footprint of the power sector. Even under current baseline projections, the International Energy Agency and the US Energy Information Administration both recognize a 24-percent expected contribution from nuclear and hydro in the United States in 2035, roughly comparable to their 26-percent share in 2011.[15,16] Nuclear and hydro resources typically have high construction costs, but once built operate at high capacity factors because they have relatively low operating costs. All nuclear generators and some of the larger hydro plants typically operate as base load, that is, they operate at higher capacity factors not just on average but across all or most hours of the day, on all or most days of the year.[17]

After a period of nearly two decades when no new nuclear power plants were built in the United States, some new nuclear generation is currently under construction in three states: South Carolina, Georgia, and Tennessee. However, the relatively high capital costs, longer planning and construction periods, and additional investor protections that are necessary (federal loan guarantees, regulatory assurances of cost recovery, and protections from

12 Bloomberg New Energy Finance. (2013, February). *Geothermal – Research Note,* Appendix A; Williams, C. F., Reed, M. J., & Mariner, R. H. (2008). *A Review of Methods Applied by the US Geological Survey in the Assessment of Identified Geothermal Resources.* US Geological Survey Open-File Report 2008-1296. Available at: http://pubs.usgs.gov/of/2008/1296/pdf/of2008-1296.pdf

13 One government-sponsored MIT report concluded that a "cumulative capacity of more than 100,000 MWe (megawatts of energy) from enhanced geothermal systems can be achieved in the United States within 50 years with a modest, multiyear federal investment for RD&D in several field projects in the United States." Massachusetts Institute of Technology. (2006). *The Future of Geothermal Energy: Impact of Enhanced Geothermal Systems (EGS) on the United States in the 21st Century.* pp. 1-6.MIT-led Interdisciplinary Panel for US Department of Energy. Available at: http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf

14 Supra footnote 10.

15 International Energy Agency. (2013, November). *World Energy Outlook.* Available at: http://www.worldenergyoutlook.org/publications/weo-2013/

16 US Energy Information Administration. (2014, May). *Annual Energy Outlook 2014, with Wind Projections to 2040.* Available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

17 The need for baseload generation and the economics of operating in that fashion have changed considerably in recent years in ways that have contributed to the early retirement of a few nuclear units. This is especially true in areas where wholesale electricity markets exist. Low natural gas prices have reduced wholesale energy costs, which translates into less revenue for nuclear units. The widespread deployment of wind turbines (which have near-zero operating costs) has similarly reduced wholesale prices and nuclear revenues.

liability) remain a deterrent to widespread development of new nuclear capacity in much of the United States.[18] Given the risks and capital requirements, it seems unlikely that the private sector can manage these investments without significant state-sponsored support. The federal government role therefore seems essential to maintaining an ongoing viable role for nuclear generation.

The promise of increased hydro capacity appears to be similarly constrained, but for different reasons. In the United States, most of the potential for large-scale hydro generation was tapped decades ago. Looking ahead, most of the potential for increased hydro capacity consists of imports from new, large projects in Canada, uprates of existing US hydro projects, and new, small community-scale projects. Major new hydro projects are underway in at least two Canadian provinces, and at least one regional transmission organization (ISO New England) is reviewing the ability of the current system to accommodate more imports from northern neighbors.[19]

Some forms of biomass power generation, principally those involving combustion of biomass in a steam generating unit, are also quite mature. Many states also classify generation from municipal waste combustors (i.e., waste-to-energy facilities), another mature technology, as renewable for regulatory purposes.[20] Waste-to-energy generation can provide additional benefits by reducing the volume of waste sent to landfills and the associated methane emissions. Although the technical potential to increase biomass generating capacity is promising, the availability and costs of this resource can be extremely location-dependent. Also, the regulatory treatment of emissions from some forms of biomass combustion is currently a subject of considerable debate (discussed below).

Although the technical potential for deploying zero- and low-emissions technologies is vast, far in excess of actual US electricity needs, the economic potential is of course more limited. Assessments of technical potential do not take into consideration the costs or cost-effectiveness of building and operating the resources. Zero- and low-emissions technologies are frequently more capital-intensive than fossil fuel technologies. But even though they may be more expensive to construct, once built they tend to have lower operating costs relative to thermal and fossil fuel resources. For that reason, where they are available, these resources tend to be the first resources used to serve load.[21]

2. Regulatory Backdrop

This section explains some of the air pollution regulations applicable to low-emissions resources, summarizes other types of regulations unique to nuclear and hydro generators, and then turns to some of the

18 Nuclear energy in the United States has also confronted ongoing challenges associated with project delays, higher than planned costs of construction, high decommissioning costs, and uncertain and high costs of spent fuel handling and disposal. For more details, refer to Chapter 4 of: Sovacool, B. (2011, May). *Contesting the Future of Nuclear Power: A Critical Global Assessment of Atomic Energy.* Singapore: World Scientific Publishing. An abbreviated discussion of these issues can be found at: Union of Concerned Scientists. (2009, May). *Fact Sheet: A Resurgence of Nuclear Power Poses Significant Challenges.* Available at: http://www.ucsusa.org/assets/documents/nuclear_power/nuclear-resurgence.pdf

19 See, for example: ISO New England. (2013). *Regional System Plan.* p. 126. Available at: http://www.iso-ne.com/trans/rsp/index.html. See also: http://www.hydroquebec.com/about-hydro-quebec/who-are-we/hydro-quebec-glance.html and http://www.gov.nl.ca/lowerchurchillproject/backgrounder_7.htm.

20 *DSIRE Quantitative RPS Data Project.* (2011, April 15). Available at: http://www.dsireusa.org

21 As a general rule, electricity resources are dispatched (signaled to deliver energy) based on merit order. *Merit order* reflects the dispatch or operation of available generators based on economic merit that is dictated by the short-run operating costs of each generator relative to others available to the system. Resources with zero or low operating costs are dispatched before higher operating cost resources. The practical effect of building low-carbon resources is that they displace operation of higher-carbon emission sources. An additional megawatt of wind, solar, or nuclear capacity will typically operate first in merit order and displace generation from a higher operating-cost resource, typically a fossil-fueled generator. However, it is also worth noting that some renewable generation technologies, wind and solar PV in particular, are generally considered to be "non-dispatchable," because these technologies either do or do not generate electricity based on factors (weather, time of day) that are beyond the control of the system operator. Instead of dispatching these resources, the system operator anticipates the amount of generation from them and then dispatches other resources in merit order to meet the "net demand" (i.e., the total demand minus the amount served by non-dispatchable resources).

financial incentives that have been used to reduce the effective costs of zero- and low-emissions resources.

Air Pollution Regulations

From an air pollution regulator's perspective, zero-emissions generation resources are unregulated.[22] This is the case for nuclear and hydro generators, as well as wind and solar and most other renewable resources. There are some low-emissions resources, however, that are subject to a variety of air pollution regulatory requirements. The low-emissions resources considered in this chapter include generators fueled by solid biomass, landfill gas, and biogas.[23] Although they are not zero-emissions resources, they are included in this chapter because they are often considered to be net-zero GHG emissions sources on a lifecycle basis.

The combustion of *solid biomass* fuels (typically derived from trees, wood wastes, certain types of woody plants, or municipal waste) can produce stack emissions that are greater than or less than those from fossil fuel combustion. To begin with, the emissions from solid biomass combustion can be highly variable depending on details about the biomass fuel and the combustion unit. In general, on a comparable input basis (i.e., pounds of pollutant per million British Thermal Units [MMBTU] of heat input), biomass fuels will produce higher emissions of almost all pollutants than natural gas does. Compared to coal or oil combustion, the results tend to vary by pollutant. For these reasons, solid biomass combustion is covered under a wide range of air pollution regulations, and larger sources are subject to permit requirements. Case-by-case assessments of potential emissions and control requirements are often necessary.

Landfill gas is produced in landfills when waste is anaerobically digested by microorganisms. The produced gas consists primarily of methane, an extremely potent GHG. Over the course of time, landfill gas is slowly emitted to the atmosphere as a fugitive emission unless the gas is captured. To address this problem, the US Environmental Protection Agency (EPA) promulgated an existing source performance standard for municipal solid waste landfills under its Clean Air Act Section 111(d) authority in 1996. That standard requires large landfills to install systems for capturing, and then flaring or controlling, landfill gas. One of the options available for compliance is to use the captured landfill gas to generate electricity. Landfill gas is similar in composition to natural gas and produces similar air pollutants when combusted. Thus, when landfill gas is used to produce electricity, it is regulated in a manner similar to a generator combusting natural gas.

Biogas is a broad term referring to gases produced from biological sources, most commonly from the anaerobic digestion of animal waste, wastewater, or food waste. Methane comprises the largest portion of biogas, just as it comprises the largest portion of natural gas or landfill gas. When biogas is combusted to produce electricity, it is used in the same manner that natural gas or landfill gas is used and produces similar air pollutants. With respect to most air pollutants, biogas combustion is therefore regulated in a manner similar to natural gas combustion.

Combustion of biomass, landfill gas, or biogas will produce CO_2 at the stack. However, the regulatory treatment of CO_2 emissions (or more generically, GHG emissions) from biomass, landfill gas, and biogas generators is a topic of considerable ongoing debate and controversy. At issue is the question of whether and to what extent to treat such fuels as "carbon neutral" (i.e., attribute no net CO_2 emissions to these fuels). In particular, details about solid biomass resources, including harvest management practices, accounting frameworks, and regulatory oversight, can be complex and influential in determining the actual carbon reduction potential and the appropriate calculation of that potential.[24] Although the scientific arguments in this debate are generally beyond the scope of this document, the salient point is that the regulatory treatment of GHG emissions from combustion of these fuels – particularly

22 Many zero-emissions generators are located at facilities that have other regulated sources of air emissions, such as fossil-fueled backup generators, but the zero-emissions generator itself is not regulated.

23 It should be noted that many publications, data sources, and regulations use the term "biomass" to encompass all solid or gaseous fuels derived from biological sources. A distinction is drawn in this chapter between solid biomass and biogas, because these two types of resources can have significantly different emissions profiles and different applicable regulations.

24 For an extensive discussion of the challenges associated with carbon accounting for solid biomass combustion, see: Fisher, J., Jackson, S., & Biewald, B. (2012, June). *The Carbon Footprint of Electricity from Biomass: A Review of the Current State of Science and Policy.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/sites/default/files/SynapseReport.2012-06.0.Biomass-CO2-Report.11-056.pdf

biomass – remains uncertain at this time and could strongly influence the demand for generation from these sources.[25] Furthermore, state regulations may differ from federal regulations with respect to this topic.[26]

In the emissions guidelines for GHG emissions from existing power plants that the EPA proposed on June 2, 2014 (a.k.a. the Clean Power Plan), the EPA determined that increasing generation from renewable resources is an adequately demonstrated and cost-effective measure for reducing power sector CO_2 emissions. With respect to nuclear power, the EPA concluded that constructing new generators is generally not cost-effective, but completing construction of units that are already underway and preserving the availability of existing units that might otherwise be retired is a cost-effective way to reduce GHG emissions. Although the proposed Clean Power Plan regulation would not require states to include increased renewables and nuclear power in their compliance plans, the emissions targets that the EPA proposed for each state are based on assumed levels of zero-emissions resource deployment.

Regulations Unique to Nuclear and Hydro Generators

The nuclear energy industry is subject to a broad and unique regime of federal licensing, safety, and waste disposal regulations. These federal requirements, which are enforced by the Nuclear Regulatory Commission (NRC), add to the inherent cost and complexity of nuclear power, and make it very expensive and time-consuming to build new reactors.

To begin with, new sources must obtain a combined construction and operating license from the NRC prior to construction. The NRC must approve reactor design (or the project developer can choose among previously approved designs) prior to construction to ensure that necessary and appropriate safety and security features are included. The current licensing and construction process, shown in Figure 6-1, can take nine years to complete. Once obtained, an initial nuclear license spans a period of 40 years.

Most of the regulatory issues associated with nuclear power plant safety are beyond the scope of this chapter. What is relevant here is the fact that the NRC has sole authority and responsibility to monitor plant performance on an ongoing basis, with an eye toward reactor safety, radiation safety, and security. In doing so, the NRC serves as the implementing and enforcement authority for radiological emissions regulations, specifically the Environmental Radiation Protection Standards for Nuclear Power Operations promulgated by the EPA under 40 C.F.R. Part 190.

Spent nuclear fuel is an extremely dangerous material requiring special handling and disposal. Spent fuel is usually stored onsite at the power plant in steel-lined concrete pools filled with water, or in airtight steel or concrete-and-steel containers. According to federal law, the US Department of Energy (DOE) has responsibility for developing a permanent nuclear waste storage facility and transferring spent fuel from reactor sites to that facility. Since 1983, nuclear power plant owners have been required to pay into a nuclear waste fund for building such a facility. More than $20 billion has been paid into the fund, but a permanent storage site still does not exist.[27] In addition, every nuclear power plant in the United States is required by the NRC to set aside sufficient funds to decommission the entire plant when it reaches the end of its useful life.

Against this backdrop of regulations, most of the activity

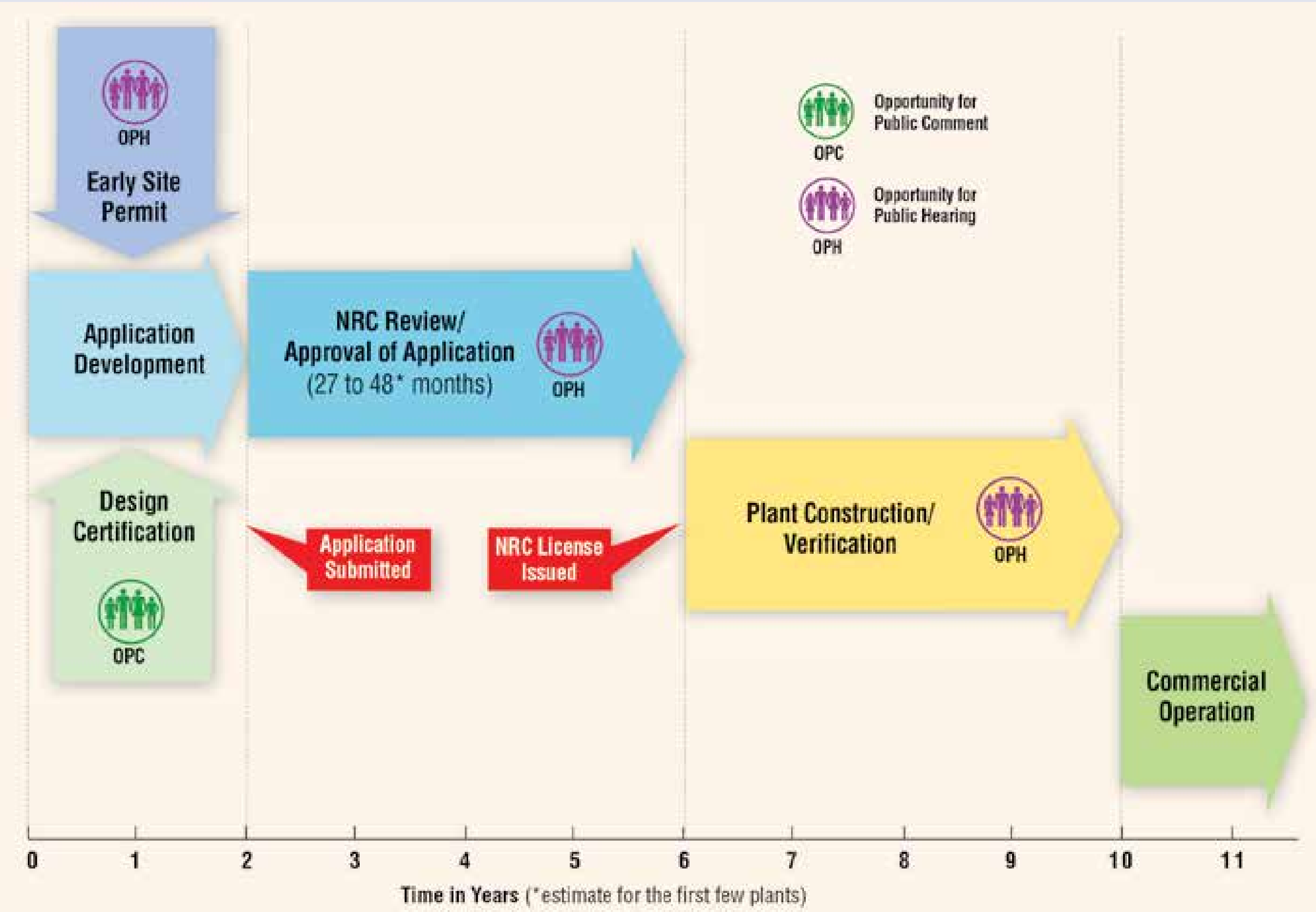
25 In July 2011, the EPA decided to temporarily defer the application of Prevention of Significant Deterioration and Title V permitting requirements to CO_2 emissions from biogenically fueled stationary sources while it studied whether and how to regulate such emissions. However, that decision was vacated by the US Court of Appeals for the District of Columbia Circuit in July 2013, *Center for Biological Diversity v. EPA,* 722 F.3d 421 (D.C. Cir. 2013), and the temporary deferral expired by its own terms in July 2014. In November 2014, the EPA released a revised *Framework for Assessing Biogenic Carbon Dioxide Emissions* from Stationary Sources (available at: http://www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html); that document continues to undergo technical review. From a regulatory standpoint, the GHG reductions that may be achievable by switching to these fuels are thus uncertain.

26 Vermont, for example, has adopted regulatory requirements for sustainable biomass harvesting and forest management practices that reduce the lifecycle GHG emissions associated with biomass fuels. For further information, refer to Vermont Public Service Board, Docket 7380, 2/28/2008 and certification proceedings and orders. Available at: http://www.state.vt.us/psb/orders/2008/files/7380amendedcpg.pdf

27 In 2013, a federal court ordered the DOE to stop collecting payments for the nuclear waste fund until the department makes provisions for actually collecting and storing nuclear waste.

Figure 6-1

Nuclear Power Plant Licensing and Construction Process [28]



in the nuclear power industry in recent decades has been associated with existing units rather than new units. This is largely a result of federal initiatives to enable both the relicensing of existing units and increases in the generating capacity of those units (i.e., "uprates"), which can generally be accomplished at a lower cost, with less lead time, and with lower financial risk than construction of an entirely new reactor. NRC approval is required for both relicensing and power uprates; license extensions typically add 20 years to the life of a unit. Since the 1970s, the NRC has granted 134 uprates, adding capacity roughly equal to that of six new nuclear facilities.[29] But by way of comparison, the last entirely new nuclear reactor built in the United States began operation in 1996, and there are just five new nuclear power stations under construction today.

Finally, it is worth noting that several states have adopted laws concerning the construction of new nuclear reactors. Minnesota has banned new nuclear facilities, while 12 other states have imposed preconditions on any new construction. Three states (Maine, Massachusetts, and Oregon) require voter approval of any new reactors, and five states require approval by the state legislature (Hawaii, Illinois, Massachusetts, Rhode Island, and Vermont). California, Connecticut, Illinois, Kentucky, Maine, Oregon, West Virginia, and Wisconsin require the identification of a demonstrable technology or a means for high-level waste disposal or reprocessing. Two states, West Virginia and

28 Nuclear Energy Institute. Available at: http://www.nei.org/corporatesite/media/filefolder/Key_Licensing_Steps.pdf

29 For more information on uprates, refer to: http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/power-uprates.html

Wisconsin, further require a finding that the construction of a nuclear facility will be economically feasible for ratepayers.[30]

With few exceptions, licensing requirements for hydroelectric generating facilities are similarly vested in federal rather than state hands. The Federal Energy Regulatory Commission (FERC) is responsible for licensing and relicensing almost all hydro projects and overseeing ongoing project operations, including dam safety inspections and environmental monitoring. Licenses are issued to new projects for a 30- to 50-year term. The traditional licensing process is a lengthy one, requiring up to seven years to license or relicense a large project. The FERC is currently testing a new two-year licensing process for certain types of hydro projects. Other matters concerning FERC regulation of hydro projects are beyond the scope of this chapter.

Financial Incentives

The remainder of this section presents a summary of public policies that have been used to advance and accelerate deployment of zero- or low-emissions technologies specifically by *lowering the effective cost of these technologies*. These types of public policies represent only one of several ways to increase deployment of cleaner technologies; some of the other ways are addressed separately in different chapters of this document.[31]

Financial incentives supporting nuclear and hydro generation have largely come from the federal government rather than state governments. This is because all nuclear and most hydro projects are very large and require huge investments to complete. The scale of economic support needed to make a difference has generally been beyond what states are able or willing to support. In addition, nuclear and hydro generators have benefitted in most cases from cost recovery guarantees that have traditionally been granted to large capital investments by rate-regulated utilities and public power entities.

Beginning nearly a century ago, early efforts by the federal government focused on creating large hydro projects through government-owned entities such as the Tennessee Valley Authority and the Bonneville Power Administration. These federal entities were large enough to raise the capital necessary to take advantage of scale economics, and they were able to justify projects not merely based on the economics of electricity generation but also based on co-benefits for agricultural water needs.

Early barriers to the development of nuclear energy in the United States were associated in large part with catastrophic failure liability. These barriers were addressed through the passage in 1957 of the federal Price-Anderson Act, which largely socialized those risks by pooling the liability across the entire industry. That Act also capped the amount of liability that could be due from the industry. Because private liability insurance was not available for new nuclear investments, federal liability insurance was necessary to make nuclear investments possible. The federal government thus provided an essential economic service (at taxpayer expense) that the private sector was unable or unwilling to provide.

In contrast to the large investments in nuclear and hydro power that have mostly been made by rate-regulated utilities and public power entities with an assurance of cost recovery from utility customers, renewable power projects tend to be smaller, owned by independent power producers or by utility customers, and financed by private capital with no assurance of cost recovery. Recognizing those differences, the federal government and many state governments have adopted financial incentives specifically for some types of renewable resources that lower the effective cost or price of these technologies. These economic policies come in the form of tax credits, incentives, and exemptions; rebates and grants; favorable loan terms; and support for renewable manufacturing industries. The states' experiences with financial incentives are summarized in the following section of this chapter.

30 Based on information compiled by the National Conference of State Legislatures. Available at: http://www.ncsl.org/research/environment-and-natural-resources/states-restrictions-on-new-nuclear-power-facility.aspx

31 Chapter 16 addresses legislative and regulatory frameworks (e.g., renewable portfolio standards) that have been used to require utilities to procure power from renewable resources, thus increasing the market share of these resources regardless of their effective costs. Chapter 19 addresses another set of public policies specifically related to the promotion of distributed generation resources (i.e., generally speaking, resources that are owned by a customer of a utility rather than the utility itself). And finally, a number of other chapters describe complementary policies that are necessary or helpful to integrate higher levels of zero- or low-emissions resources into the power system while ensuring system reliability and controlling costs. Several policies are mentioned briefly in this chapter and then addressed more expansively in those other chapters.

Table 6-3

Generation Mix by State for the Year 2012[32]

State	Coal	Natural Gas	Oil	Nuclear	Hydro	Biomass	Geothermal	Wind	Solar	Other
AK	10%	52%	15%	0%	23%	0%	0%	1%	0%	0%
AL	30%	36%	0%	27%	5%	2%	0%	0%	0%	0%
AR	44%	26%	0%	24%	3%	3%	0%	0%	0%	0%
AZ	36%	27%	0%	29%	6%	0%	0%	0%	1%	0%
CA	1%	60%	0%	9%	14%	3%	6%	5%	1%	1%
CO	66%	20%	0%	0%	2%	0%	0%	11%	0%	0%
CT	2%	46%	0%	47%	1%	2%	0%	0%	0%	2%
DC	0%	87%	13%	0%	0%	0%	0%	0%	0%	0%
DE	16%	79%	0%	0%	0%	1%	0%	0%	0%	3%
FL	20%	68%	1%	8%	0%	2%	0%	0%	0%	1%
GA	33%	35%	0%	28%	1%	3%	0%	0%	0%	0%
HI	15%	0%	71%	0%	1%	3%	2%	4%	0%	4%
IA	62%	3%	0%	8%	1%	0%	0%	25%	0%	0%
ID	0%	12%	0%	0%	71%	4%	0%	12%	0%	0%
IL	41%	6%	0%	49%	0%	0%	0%	4%	0%	0%
IN	81%	13%	1%	0%	0%	0%	0%	3%	0%	2%
KS	63%	6%	0%	19%	0%	0%	0%	12%	0%	0%
KY	92%	3%	2%	0%	3%	0%	0%	0%	0%	0%
LA	21%	57%	3%	15%	1%	2%	0%	0%	0%	2%
MA	6%	68%	0%	16%	2%	5%	0%	0%	0%	3%
MD	43%	13%	0%	36%	4%	1%	0%	1%	0%	1%
ME	0%	42%	1%	0%	26%	22%	0%	6%	0%	3%
MI	49%	20%	0%	26%	0%	2%	0%	1%	0%	1%
MN	44%	14%	0%	23%	1%	4%	0%	15%	0%	1%
MO	79%	7%	0%	12%	1%	0%	0%	1%	0%	0%
MS	13%	71%	0%	13%	0%	3%	0%	0%	0%	0%
MT	50%	2%	2%	0%	41%	0%	0%	5%	0%	1%
NC	44%	17%	0%	34%	3%	2%	0%	0%	0%	0%
ND	78%	0%	0%	0%	7%	0%	0%	15%	0%	0%
NE	73%	2%	0%	17%	4%	0%	0%	4%	0%	0%
NH	7%	37%	0%	43%	7%	6%	0%	1%	0%	0%
NJ	3%	43%	0%	51%	0%	1%	0%	0%	0%	1%
NM	68%	24%	0%	0%	1%	0%	0%	6%	1%	0%
NV	12%	73%	0%	0%	7%	0%	7%	0%	1%	0%
NY	3%	44%	0%	30%	18%	2%	0%	2%	0%	1%
OH	66%	17%	1%	13%	0%	1%	0%	1%	0%	1%
OK	38%	50%	0%	0%	1%	0%	0%	10%	0%	0%
OR	4%	19%	0%	0%	65%	1%	0%	10%	0%	0%
PA	39%	24%	0%	34%	1%	1%	0%	1%	0%	1%
RI	0%	99%	0%	0%	0%	1%	0%	0%	0%	0%
SC	29%	15%	0%	53%	1%	2%	0%	0%	0%	0%
SD	24%	2%	0%	0%	50%	0%	0%	24%	0%	0%
TN	46%	10%	0%	32%	10%	1%	0%	0%	0%	0%
TX	32%	50%	0%	9%	0%	0%	0%	7%	0%	1%
UT	78%	17%	0%	0%	2%	0%	1%	2%	0%	0%
VA	20%	35%	1%	41%	0%	3%	0%	0%	0%	1%
VT	0%	0%	0%	76%	17%	5%	0%	2%	0%	0%
WA	3%	5%	0%	8%	77%	1%	0%	6%	0%	0%
WI	51%	18%	0%	22%	2%	3%	0%	2%	0%	0%
WV	96%	0%	0%	0%	2%	0%	0%	2%	0%	0%
WY	88%	1%	0%	0%	2%	0%	0%	9%	0%	1%
US Overall	**37%**	**30%**	**1%**	**19%**	**7%**	**1%**	**0%**	**3%**	**0%**	**1%**

3. State and Local Implementation Experiences

Current deployment levels for zero- and low-emissions technologies vary geographically based on a number of factors, including the local availability of renewable resources, state financial incentives, state procurement requirements such as those explained in Chapter 16, and underlying regional energy market fundamentals.[33] Table 6-3 details the approximate contribution of each resource to the generation mix of each state in 2012 based on data collected by the US Energy Information Administration.[34]

Throughout the twentieth century, the federal government took actions that spurred the development and deployment of large-scale nuclear and hydro generators. State policies played only a small role in this deployment. As noted in Tables 6-1 and 6-3, those technologies currently provide about 26 percent of total US generation. That number has changed very little over the past two decades. No new nuclear plants have been built since 1996 and, after allowing for variable weather conditions, the amount of electricity generated by hydroelectric facilities has remained fairly constant since 1969.[35]

In contrast, emerging technologies like wind and utility-scale and distributed solar are seeing rapid growth spurred by a combination of federal, state, and local policies as well as global economic forces. At the national level, in 2010 wind and solar represented just 2.3 percent and 0.03 percent of total generation, respectively. By 2012, their contributions had increased more than 50 percent, to 3.5 percent and 0.1 percent of total generation, respectively. Recent data on the installed capacity of wind and solar generators are summarized in Table 6-4.

Table 6-4

Installed Capacity of Wind and Solar Power, 2014[36]

Technology	Installed Capacity
Utility-scale wind	Greater than 65 GW
Residential solar PV	3.47 GW_{dc}
Non-residential solar PV	5.09 GW_{dc}
Utility-scale solar PV	9.74 GW_{dc}
Concentrating solar power	1.69 GW_{ac}

These values currently represent a small portion of the overall generation mix. However, wind power represented 2012's second-largest category of growth in generation, after natural gas, and the largest in terms of capacity additions. And in some states, wind is already providing sizable portions of total generation (25 percent or more in two states, and between 12 percent and 24 percent in seven states).[37] Wind remains the largest source of investment in the US electricity sector.[38] Solar PV is seeing the highest growth trajectory in the United States of any resource

32 Specifically, this is based on US Energy Information Administration summaries of Form 923 data. Facilities with generators having a nameplate capacity of 1 MW or greater and that are connected to the grid are required to submit Form 923. Because smaller facilities are not required to report, these data are only an approximation of total generation. Most PV sites, for example, have a rated capacity of less than 1 MW and thus are omitted from the totals. Source data are available at: http://www.eia.gov/electricity/data/state/annual_generation_state.xls

33 It should be noted that utilities facing state procurement requirements will in many cases procure renewable energy from facilities in other states. For this reason, the geographic deployment of renewable generators does not always align closely with state procurement requirements. For example, according to a legislative committee report, approximately 62 percent of the wind power generated in Montana is used to meet renewable energy procurement requirements of California utilities. Report available at: http://leg.mt.gov/content/Committees/Interim/2013-2014/Energy-and-Telecommunications/Meetings/September-2013/other-state-rps.pdf

34 Supra footnote 32.

35 Refer to: http://www.eia.gov/beta/MER/index.cfm?tbl=T10.01#/?f=A&start=1949&end=2013&charted=15-6

36 American Wind Energy Association. (2015, January 28). *US Wind Industry Fourth Quarter 2014 Market Report.* Available at: http://awea.files.cms-plus.com/4Q2014%20AWEA%20Market%20Report%20Public%20Version.pdf; Solar Energy Industries Association. (2015, March). Solar Market Insight Report 2014 Q4. Available at: http://www.seia.org/research-resources/solar-market-insight-report-2014-q4; Solar Energy Industries Association. (2015, March). Personal communication.

37 American Wind Energy Association. (2013). *State Capacity and Generation.* From *US Wind Industry Annual Market Report: Year Ending 2013.* Available at: http://www.awea.org/AnnualMarketReport.aspx?ItemNumber=6308&RDtoken=61755&userID

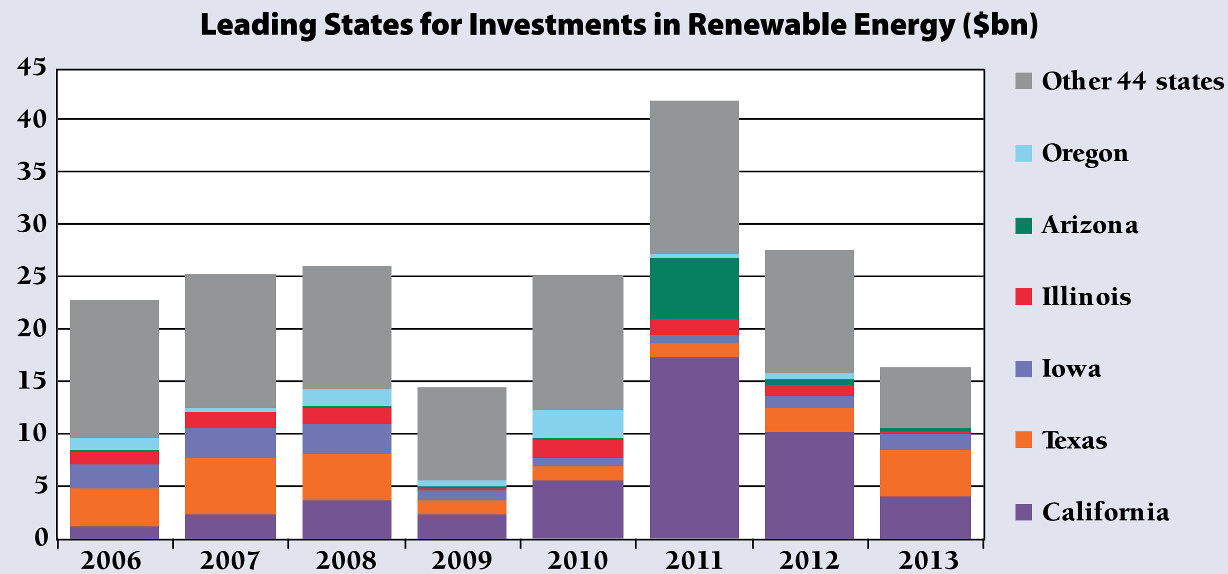
38 Wiser, R., & Bolinger, M. (2013, August). *2012 Wind Technologies Market Report.* Lawrence Berkeley National Laboratory for the US Department of Energy. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf

(138 percent growth in energy generation from 2011 to 2012). Between 2010 and 2013, solar PV installations grew by roughly 940 megawatts $(MW)_{dc}$ to 1470 MW_{dc} per year.[39] This is consistent with larger global trends: solar generating capacity increased globally by 26 percent in 2013, from 31 GW in 2012 to 39 GW in 2013.[40] In the United States currently, distributed PV provides roughly 40 percent of installed solar capacity, whereas utility-scale PV provides most of the rest of the capacity and concentrating solar power provides a small percentage.[41] Utilities are already relying on solar and wind to meet an increasing portion of their electric load.

As shown in Figure 6-2, the states that have seen the greatest investment in renewable energy include six states that represented 54 percent of total US investment from 2008 through 2013. California alone accounted for 23 percent of US investment. California's contribution is rooted in a combination of factors that include a large economy, progressive clean energy policies, high-quality resources, and relatively high electricity prices. The next three states that are large investors in renewables simply exist in a region that is rich in renewable energy. Illinois, Iowa, and Texas are part of an American "wind corridor" where the wind resource is abundant, land is relatively cheap, and population density is low (making siting of wind turbines easier).

State policies are certainly one of the drivers for deployment of renewables. A summary of financial incentives adopted by state governments is presented in Table 6-5, with each type of incentive explained in more detail following the table. Information cited below and additional details about each state policy can be obtained

Figure 6-2



Source: Bloomberg New Energy Finance Note: This captures new build asset finance (ie, project investment) and VC/PE transactions for renewable energy deals. Asset finance excludes small distributed capacity. VC/PE excludes PE buy-outs as these are not new investment. In cases where a particular deal had more than one applicable state, the investment amount was allocated equally across each of the recipient states. For asset finance, the recipient state(s) are determined according to the location of the project(s) being financed. For VC/PE, the recipient state is determined according to the location of the organization raising the funds. The values shown here do not correspond to investment numbers shown in Figure 12 as this chart only includes two of the asset classes (AF and VC/PE), only includes renewable energy (and not other forms of clean energy), and only includes transactions with specified location.

39 Compiled from Solar Energy Industries Association and GTM Research. (2012 and 2013). *US Solar Market Insight;* Interstate Renewable Energy Council. (2012 and 2013). *US Solar Market Trends.*

40 United Nations Environment Programme. (2014, April). *Global Trends in Renewable Energy Investment.* Available at: http://www.unep.org/energy/Publications/Publication/tabid/131188/language/en-US/Default.aspx?p=843151a8-8975-41d2-be27-07554800b702

41 Solar Energy Industries Association and GTM Research. (2014, Quarter 2). *US Solar Market Insight.* Available at: http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

Table 6-5

Financial Incentives for Lowering Effective Cost of Zero- and Low-Emissions Technologies[42]

Mechanism	Incentive	Number of States Implementing	Examples[43]
Personal Tax	Investment Tax Credit	22	Kentucky Federal Government Montana
Corporate Tax	Investment Tax Credit Production Tax Credit Accelerated Depreciation	24	Federal Government Arizona Hawaii
Sales Tax	Sales Exemption Exemption From Generation Tax	28	Indiana Connecticut
Property Tax	Discounted Basis on Renewables Qualifying Renewables Exclusion	40	Arizona Florida
Rebates	Investment Rebate Incentive Purchase Payment	47	Idaho Arizona
Grants	Community Grants Low-Income Support Competitive Grants	21	Connecticut Colorado Vermont
Loans	Revolving Loan for Renewables Loan Loss Reserve Fund	49	Alabama Hawaii
Industry Support	Manufacturer Tax Credit	24	South Carolina Utah Oklahoma

through the Database of State Incentives for Renewables & Efficiency website at: http://www.dsireusa.org/.

Personal Investment Tax Credit

The federal government and many states have established some form of personal investment tax credit for eligible renewable energy projects. At the federal level, the tax credit extends through 2016 and can be applied to 30 percent of the cost of the initial investment. In addition to the federal tax credit, 22 states have implemented their own personal tax credits against state income tax obligations. States like North Carolina have applied the tax credit to a long list of eligible technologies. The credit available in North Carolina is equal to 35 percent of the eligible investment and applies through 2015.

Corporate Tax Incentives

In 1992, the federal government initiated a renewable energy production tax credit program. This program currently offers a tax credit equal to 2.3 cents per kilowatt-hour (kWh) of generation for a short list of qualifying technologies, including wind. Other technologies are eligible for a tax credit equal to 1.1 cents per kWh. The production tax credits generally apply only to the first ten years of operation for each eligible generator. This tax credit expired at the end of 2013, but projects that began construction prior to 2014 remain eligible and eligible

42 Database of State Incentives for Renewables & Efficiency. Available at: http://www.dsireusa.org/

43 A complete list of the types of incentives adopted by each state is available from the Database of State Incentives for Renewables & Efficiency website at: http://www.dsireusa.org/summarytables/finee.cfm

projects will continue to receive the tax credits.

The federal government also offers a business investment tax credit equal to 30 percent of expenditures for solar, fuel cells, and small wind, and a credit of ten percent for other technologies, including geothermal. The federal government also offers accelerated depreciation (often five years) on qualifying investments. Similarly, 24 states offer an investment tax credit for qualifying technologies. For example, in the case of Arizona the focus is on various solar technology investments and the investment tax credit is equal to ten percent. Arizona also offers production tax credits for qualifying wind and solar investments.

Sales Tax Exemptions

Twenty-eight states offer some form of sales tax exemption on qualifying renewable equipment. New Jersey, as an example, offers a sales tax exemption on qualifying solar investments that applies to residential and commercial customers. The amount of the exemption in New Jersey is 100 percent.

Property Tax Exemption

Forty states offer some form of exemption on property taxes associated with qualifying renewables technology. Connecticut, for example, offers a 100-percent exemption on what it deems "Class I" renewables (including wind and solar), which applies to both the commercial and residential sectors.

Rebate Programs

Forty-seven states offer some form of rebate program for qualifying clean energy investments. An advantage of rebates is that they offer value to both for-profit and non-profit (tax exempt) entities. States like Illinois offer rebates for solar and wind technologies. In the case of Illinois, the solar rebate offered to for-profit entities is equal to 25 percent of the project cost, or $1.50/watt for residential projects and $1.25/watt for commercial projects. Nonprofits and the public sector are eligible for rebates equal to 40 percent of solar project costs or $2.50/watt. A similar framework is applied for wind.

Grants

Twenty-one states offer some form of grant program. States like Wisconsin offer grants for qualifying energy projects. Wisconsin had a program budget equal to $9 million in 2013. Grants are awarded for 10 percent to 40 percent of project costs, with a minimum award of $5000. Maximum incentives of $100,000 apply to wind and PV projects.

Loans

Forty-nine states and the District of Columbia have some form of loan program for renewable generation investments. Iowa, for example has established a revolving loan fund for a variety of qualifying technologies. The loans are offered at zero percent interest for a period of up to 20 years. The maximum incentive offered is up to 50 percent of project cost and $1 million. Iowa also has the Iowa Energy Bank, offering low-interest loans to non-profits, schools, hospitals, and municipalities, as well as state government. Loan programs also exist at the municipal level, as in Florida, where they are widespread.

Manufacturing Industry Support

Twenty-four states offer some form of industry support through mechanisms like manufacturing tax credits. States such as South Carolina offer manufacturing tax credits to renewable energy operations. In the case of South Carolina, the credits are offered for the manufacture of a number of qualifying renewables, including wind and solar. The credits are available up to $500,000 for any year and $5 million total for operations that begin during the period between 2010 and 2015.

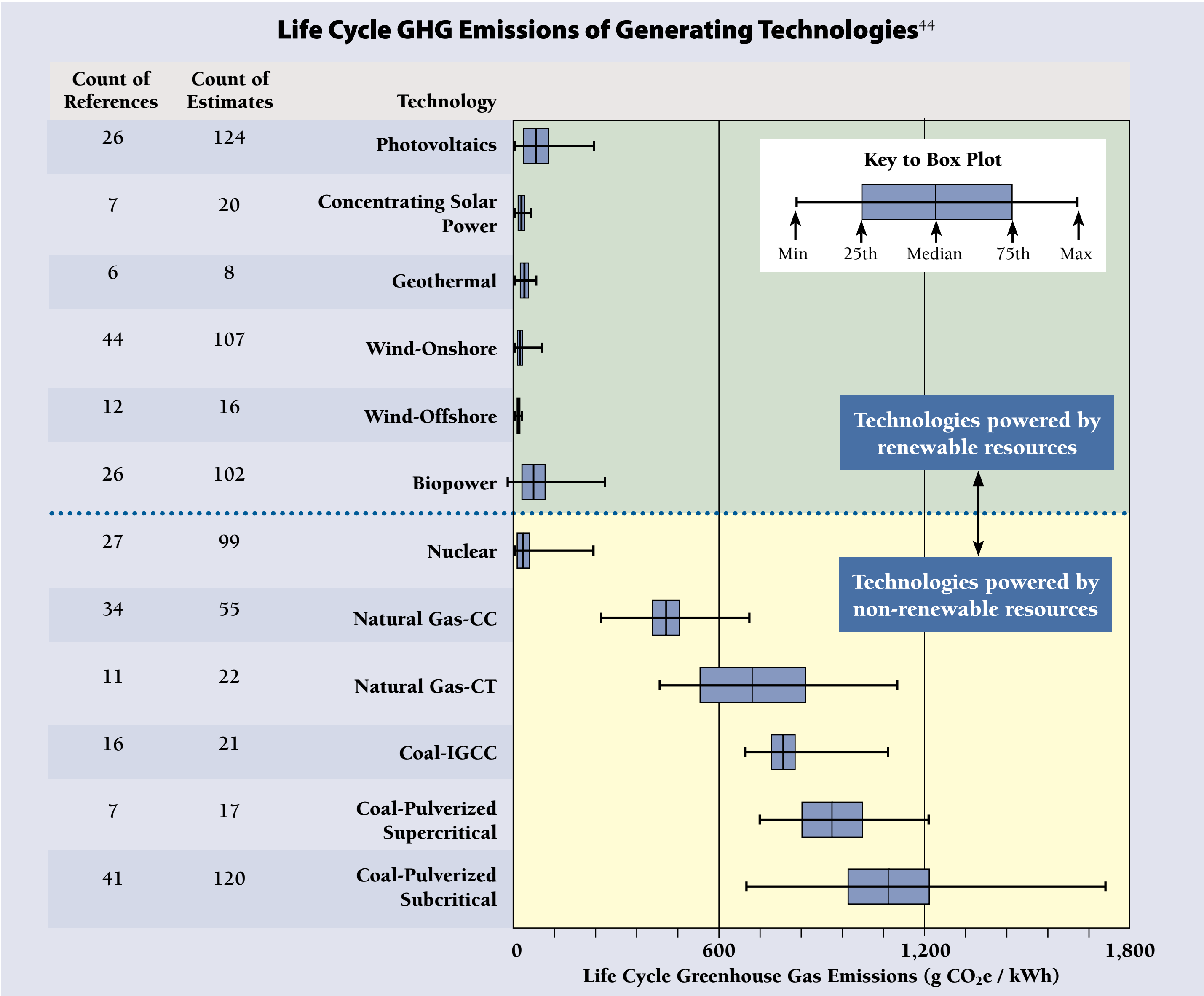
In summary, there is a wide variety of strategies used by both the federal government and by individual states that have the effect of lowering the effective cost observed in the market and typically borne by ratepayers. The federal tax credits that apply to solar and wind, among other categories of clean energy technologies, are substantial. State initiatives have further driven down the costs of manufacturing, owning, and purchasing electricity from qualifying renewable generation technologies.

4. Greenhouse Gas Emissions Reductions

The GHG emissions reduction potential of zero- and low-emissions technologies is potentially substantial. Several variables and viewpoints factor into the quantification of that potential.

One of the viewpoints that factors into quantification is whether to consider the "lifecycle" GHG emissions of different resources or only the stack emissions. This question is particularly important with respect to solid biomass, landfill gas, and biogas generators, because they are the only resources discussed in this chapter that have

Figure 6-3



stack emissions. A lifecycle perspective on emissions requires that consideration be given to GHG emissions that occur in every stage of the production and operation of both a generating technology and any fuels that it uses. Biogenic fuels come from plants and trees that absorb CO_2 as they grow, and release CO_2 when they are combusted. Thus, the lifecycle emissions of such fuels tend to be lower than the stack emissions. In contrast, the lifecycle emissions of most other resources are somewhat higher than their stack emissions, because some amount of GHG emissions occurs in the process of building the generator or producing and delivering its fuel. Figure 6-3 summarizes the results of numerous assessments of the lifecycle GHG emissions profile of different generation technologies, based on a review of literature and surveys conducted.

Regardless of whether one accounts for lifecycle emissions or only stack emissions, another viewpoint that factors into quantification is the time scale under consideration. When viewed over an immediate or short-term time scale, the way that renewable energy deployment decreases emissions is by reducing the need for generation

44 Hand, M. M., Reilly, J. M., Porro, G., Baldwin, S., Mai, T., Meshek, M., DeMeo, E., Arent, D., & Sandor, D., eds. (2012). *Renewable Electricity Futures Study.* Volume 1 of 4, at A-51. NREL/TP-6A20-52409. National Renewable Energy Laboratory. Available at: http://www.nrel.gov/analysis/re_futures/

from existing fossil-fueled generating units. For example, each MWh generated by a geothermal power plant means one less MWh needs to be generated by some other unit that already exists and is connected to the grid. Over a longer time frame, however, the deployment of new zero- and low-emissions resources reduces the need for future deployment of other higher-emitting resources.

As previously noted, zero-emissions resources may in some cases have high construction costs, but once built tend to have low operating costs and for that reason tend to be the first resources used to serve load. So in the immediate and near-term time scale, deployment of these resources tends to displace generation from resources with higher operating costs, most commonly the fuel costs associated with fossil-fueled generators. However, coal-fired generators typically emit about twice as much CO_2 per unit of net generation as gas-fired generators. Therefore, the amount of GHG emissions reduction attributable in the short-term to the deployment of zero-emissions resources depends on which generators serving the same grid operator operate "on the margin," that is, which generators would have been dispatched but for the availability of zero-emissions resources. The answer to that question varies by location, time of day, and season.[45] Detailed discussions of the topic of avoided emissions are available from several sources.[46]

The EPA has created a tool called AVERT (AVoided Emissions and geneRation Tool) to help air pollution regulators assess the short-term avoided emissions that result from renewable generation or energy efficiency programs.[47] The American Wind Energy Association used AVERT to make its own assessment of the emissions avoided in each state in 2013 owing to the deployment of wind energy. The assessment estimated that wind energy reduced power sector emissions by more than five percent in 2013.[48] The American Wind Energy Association's results for CO_2 emissions are presented in Figure 6-4 for illustrative purposes, to demonstrate the approximate magnitude of the impact from just this one zero-emissions technology.[49]

Historically, electricity demand has grown over time and new generating capacity has been built to meet demand. Although growth rates are projected to be lower over the next few decades than they were over the past few decades, there is still an expectation that additional generating capacity (incremental to what exists today) will be needed to meet future demand. Also, the capacity lost when power plants retire needs to be replaced. So, from this longer-term perspective, the addition of zero- and low-emissions capacity displaces not just the need to dispatch existing fossil-fueled generators but also the need to add new fossil fuel capacity in the future. The GHG reduction potential of zero- and low-emissions resources over this longer time scale thus depends on the type of new capacity that is displaced, and virtually all recent assessments assume that the type of capacity displaced will be natural gas generators.

Putting all of this together, the immediate and short-term GHG emissions reduction of zero- and low-emissions resources depends on which existing units (usually fossil-fueled generators) operate on the margin, and the answer depends on local conditions, time of day, and season. If an average coal-fired unit is displaced, the emissions reductions could be on the order of 2250 pounds of CO_2

45 For example, CO_2 emissions of the marginal generators in the Northeast region (principally gas- and oil-fired units) were calculated to be roughly 900 pounds per MWh. ISO New England. (2013, December). *2012 ISO New England Electric Generator Air Emissions Report.* Available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/eag/mtrls/2013/dec202013/draft_2012_emissions.pdf

46 See, for example: Shenot, J. (2013, August). *Quantifying the Air Quality Impacts of Energy Efficiency Policies and Programs.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6680. The methodologies are virtually the same for any MWh of generation from a zero-emissions resource or MWh of energy savings from an energy efficiency measure.

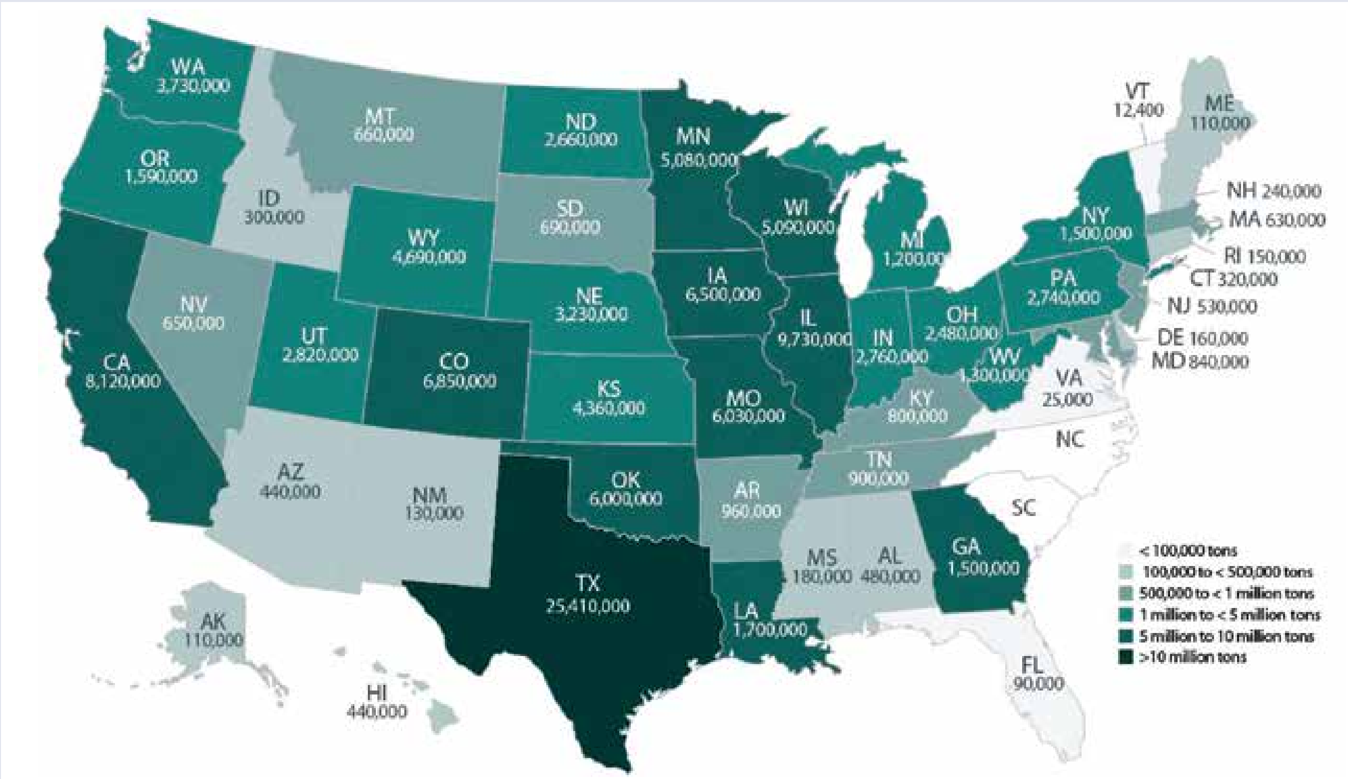
47 The EPA's AVERT is available at: http://www.epa.gov/avert/

48 Personal communication from Tom Vinson, Vice President of Federal Regulatory Affairs, American Wind Energy Association, February 9, 2015.

49 AVERT is designed to provide more accurate estimates in most cases than would be expected from using the regional average emissions factors included in the EPA's Emissions & Generation Resource Integrated Database (eGRID), with only a little extra effort. However, AVERT is also designed to be simple to use, and it cannot be expected to produce extremely precise or accurate results. Dispatch models and other sophisticated methods of assessing avoided emissions (which require much greater effort to use) offer more precision and accuracy and may be more appropriate for regulatory purposes.

Figure 6-4

Avoided CO_2 Emissions From Wind Energy in 2013[50]



per MWh or more. If an average gas-fired unit is displaced, the value could be about half that amount.[51] But over a longer time scale, the GHG emissions reduction potential of zero-emissions resources will probably trend toward the emissions rates for new gas-fired power plants, on the order of 800 to 1000 pounds of CO_2 per MWh.

Before moving on to other topics, it is worth noting that the regulatory treatment of GHG emissions reductions might differ from a scientific or analytical assessment of emissions reductions. For example, in the proposed Clean Power Plan emissions guidelines, the EPA has proposed that states using a rate-based approach to compliance develop plans whereby the adjusted emissions rate of covered fossil-fueled generators must meet specified (pounds per MWh) targets. In calculating an adjusted emissions rate, the EPA has proposed that states would be allowed to add MWh of generation from "preserved" nuclear and renewable resources to the MWh of generation from covered fossil-fueled generators. This would have the effect of treating those resources as zero-emissions resources for regulatory purposes, rather than forcing states to make the kinds of "avoided emissions" calculations discussed previously.[52]

5. Co-Benefits

Zero- and low-emissions technologies can provide a wide range of co-benefits in addition to GHG emissions reductions. Benefits relating to other air pollutants, water consumption, and electric system operations are briefly discussed here before presenting a summary of all co-benefits.

The air emissions co-benefits for zero-emissions technologies depend on the same factors that were

50 American Wind Energy Association. (2014, May). *The Clean Air Benefits of Wind Energy.* Available at: http://awea.files.cms-plus.com/FileDownloads/pdfs/AWEA_Clean_Air_Benefits_WhitePaper%20Final.pdf

51 Based on data from the EPA clean energy website at: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

52 The EPA requested public comments on this approach, and it is of course possible that a different approach will be taken in the final rule. The treatment of renewable resources that emit GHG (e.g., biomass-fueled generators) as net zero-emissions resources is one area of considerable debate, as previously noted.

discussed with respect to GHG emissions reductions. It is important to understand the differences between immediate or short-term impacts caused by displacing generation from existing fossil-fueled units operating on the economic margin, and longer-term impacts caused by displacing the need for new fossil generation capacity.

Generators using solid biomass, landfill gas, or biogas are not zero-emissions resources; they will emit criteria and hazardous air pollutants. Regulators may need to carefully assess whether those emissions are less than or greater than what would be emitted from the displaced generation sources. In general, for these types of generators, uncontrolled emissions of most pollutants are equal to or higher than uncontrolled emissions from natural gas-fired units. Compared to coal- or oil-fired generators, some pollutants are emitted at higher levels and other pollutants (principally sulfur dioxide) are emitted at lower levels. An assessment by state and local agencies in the state of Washington, summarized in Table 6-6, offers one such comparison of uncontrolled emissions factors.[53] Controlled emissions factors would of course depend on the control devices used on each type of generator.

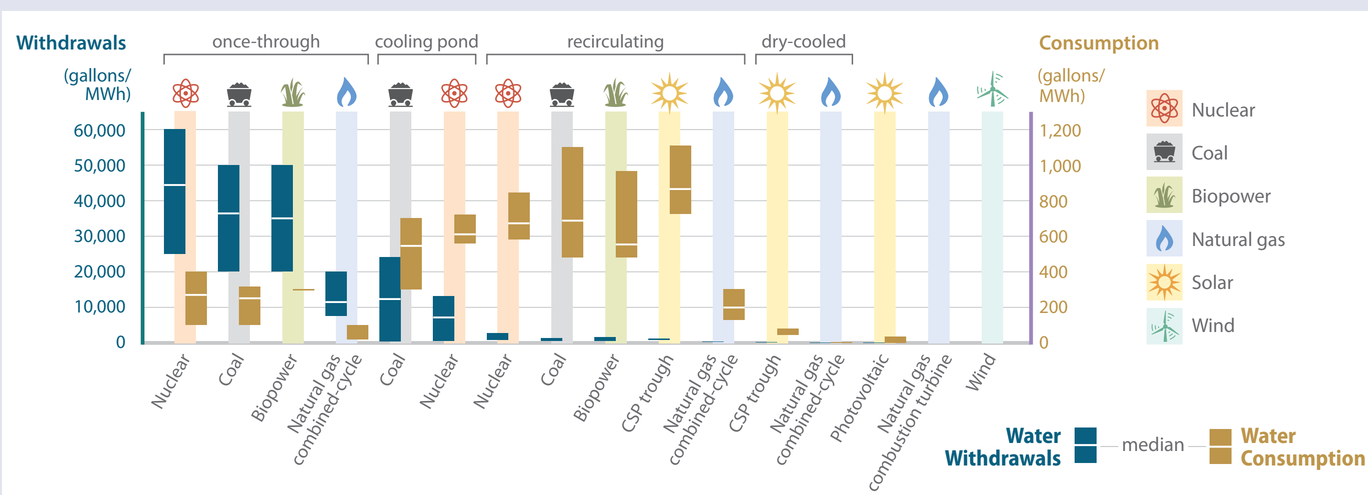
Table 6-6

Typical Uncontrolled Emissions From Biomass, Coal, and Natural Gas Generators[54]

Pollutant	Emissions (Pounds per MMBTU of Heat Input) Forest Biomass	Coal	Natural Gas (Combined-Cycle)
Nitrogen Oxides	0.220	0.510	0.0371
Carbon Monoxide	0.600	0.025	0.0075
Sulfur Dioxide	0.025	0.890	0.0028
Volatile Organic Compounds	0.017	0.003	0.0043
Particulate Matter	0.570	0.460	0.0083
Hydrogen Chloride	1.9E-02	6.1E-02	0
Mercury	3.5E-06	1.6E-05	0
Manganese	1.6E-03	1.2E-03	0

Figure 6-5

Water Use by Fuel and Cooling Technology [55]



53 Washington State Department of Natural Resources. (Undated brochure citing 2010 reports). *Forest Biomass and Air Emissions*. Available at: http://www.dnr.wa.gov/Publications/em_forest_biomass_and_air_emissions_factsheet_8.pdf

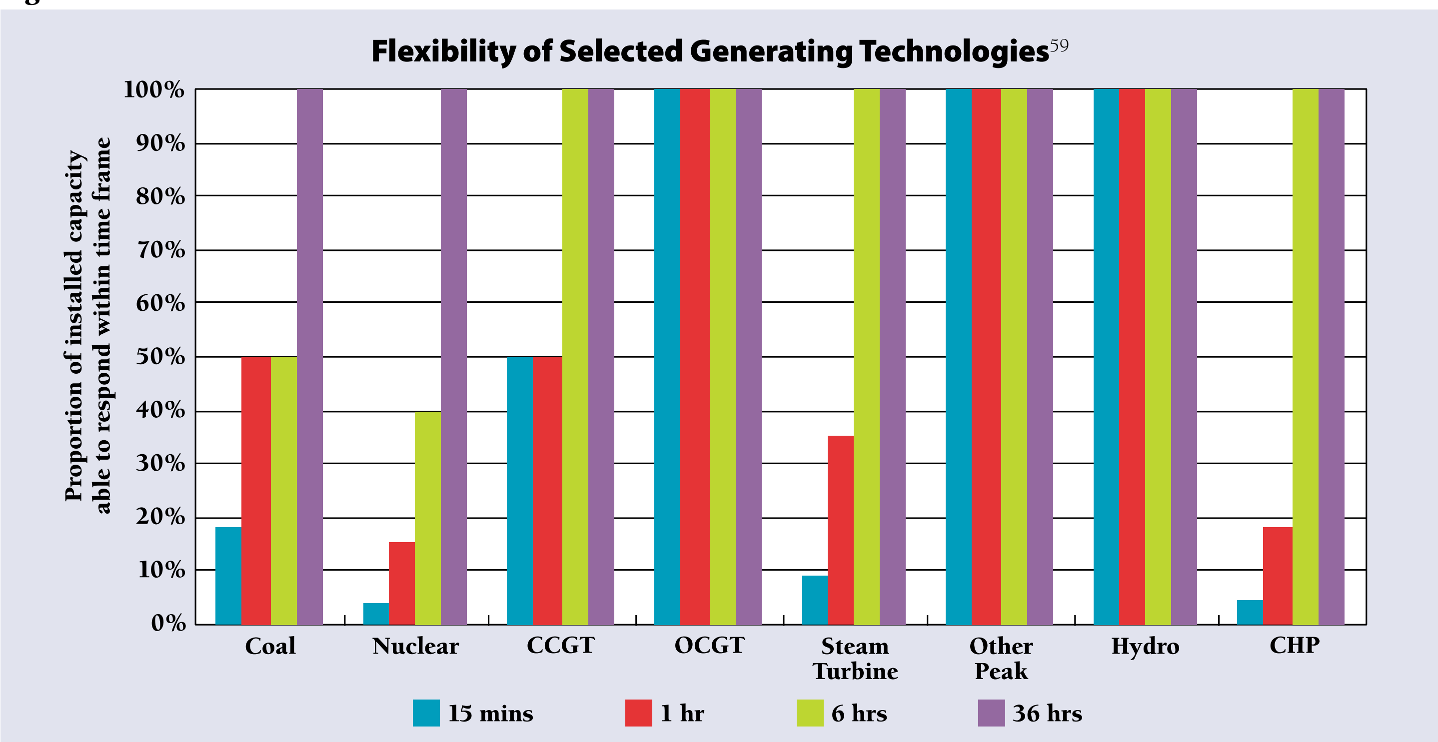
54 Ibid.

55 Averyt, K., Fisher, J., Huber-Lee, A., Lewis, A., Macknick, J., Madden, N., Rogers, J., & Tellinghuisen, S. (2011, November). *Freshwater Use by US Power Plants: Electricity's Thirst for a Precious Resource*. A report of the Energy and Water in a Warming World Initiative. Union of Concerned Scientists. Available at: http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf

For most generation technologies, there is a strong symbiotic relationship between electricity generation and water use. Water extraction and distribution practices place demands on the electric system, and conversely the generation of electricity places demands on water systems. Electricity generation in the United States accounts for 41 percent of overall US water requirements, mostly withdrawals associated with once-through cooling of thermal generation. The sector accounts for roughly three percent of US freshwater consumption. Categories of zero- and low-emissions technologies that do not require significant cooling (e.g., wind and solar) require little water. Figure 6-5 provides a summary graphic showing the different water requirements of various generating technologies.

Non-dispatchable generation will be an increasingly large and important component of the overall electricity mix going forward, but will also place new requirements on the broader system. A few zero- and low-emissions technologies enjoy the advantage of being both flexible and dispatchable technologies. Included among them are those combusted in traditional steam boilers or gasified for use in combined-cycle turbines.[56] As such, there is a solid understanding of how best to operate these resources and integrate them into the existing electricity grid. Use in traditional boilers and turbines renders biomass one of the few dispatchable renewable energy technologies. Unlike traditional wind and solar technologies, these boilers and turbines can be ramped as required for load, increasing their value for both capacity and energy purposes.[57] Hydro is another technology that can be extremely flexible. Nuclear generation units are comparatively inflexible.[58] Figure 6-6 provides a summary of

Figure 6-6



56 However, the flexibility of the generating technology may be limited in some cases by an inflexible fuel delivery system and lack of fuel storage capacity, meaning the generator must use all fuel as it is delivered. Generators firing landfill gas often fall into this category.

57 Supra footnote 24.

58 The currently operating nuclear units in the US fleet, all of which were built more than two decades ago, were designed specifically for baseload operation rather than flexible, load-following operation. This is not a purely physical limitation. Modern nuclear plants with light water reactors are designed to operate more flexibly. Some nuclear reactors in other countries (e.g., France and Germany) vary their output as customer demand increases or decreases. Refer to: Nuclear Energy Agency. (2011). *Technical and Economic Aspects of Load Following with Nuclear Power Plants.* Organisation for Economic Co-Operation and Development. Available at: http://www.oecd-nea.org/ndd/reports/2011/load-following-npp.pdf

59 International Energy Agency. (2011). *Harnessing Variable Renewables: A Guide to the Balancing Challenge.* Available at: https://www.iea.org/publications/freepublications/publication/Harnessing_Variable_Renewables2011.pdf

the typical response rate capabilities of different technologies over varying time frames as observed in the Nordic power area to highlight the opportunities and challenges.

Safe, reliable electric service is an essential service. This of course means that all types of generation bring public benefits. Zero- and low-emissions generators bring the same electricity system benefits for each MWh of net generation delivered to end-users that other generating

Table 6-7

Types of Co-Benefits Potentially Associated With Zero- and Low-Emissions Technologies

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes – biomass can vary depending on the category of pollutant and displaced alternative
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes – varies by technology
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes – varies at the local level
Economic Development	Yes – the economic development impacts will vary at the local and regional level and can be positive or negative[60]
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Only for some customer-owned distributed generation
Avoidance of Uncollectible Bills for Utilities	Likely limited
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	Yes – the primary technologies relied on (wind and solar) are typically capital intensive, with no energy and small operating costs
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Not generally – additional transmission capacity may be needed to reach resource-rich regions and to increase system flexibility to accommodate certain categories of variable energy resources
Avoided Distribution Capacity Costs	Generally applies for low to moderate levels of distributed generation and varies by technology
Avoided Line Losses	Generally applies for low to moderate levels of distributed generation and varies by technology
Avoided Reserves	No – the details matter, but the addition of variable energy resources, in isolation of other changes could increase the need for more system flexibility and capacity during periods of system stress
Avoided Risk	Yes, but specific risks are particular to the circumstances
Increased Reliability	Maybe
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	The addition of variable energy renewables is typically associated with wholesale price reduction and stabilization effects[61]
Other	

60 One survey suggested an economic development benefit range of between $22 and $30 per MWh. Refer to: Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K., & Wiser, R. (2014, May). *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards.* National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6589e.pdf

61 One survey estimated the impacts at about $1 per MWh of total wholesale generation in specific markets. Refer to: Supra footnote 60.

resources do. In other words, nuclear, hydro, and other renewable generating resources shouldn't be considered simply as a pollution control cost, because they bring with them the value of an essential service: electricity. Besides the traditional energy and reliability benefits that extend to all categories of utility resources, whether directly owned or purchased through third parties, the addition of zero- and low-emissions resources – many of which do not burn any fuel – can bring diversity to the generation portfolio that potentially reduces the risk of fossil fuel price volatility. Many categories of zero- and low-emissions technologies (especially solar) are also well suited for placement close to loads, and can therefore provide transmission and distribution capacity benefits, reductions in operating reserve requirements, and reduced line losses. Those topics are covered in other chapters of this document.

The full range of co-benefits that can be realized through deployment of zero- and low-emissions technologies are summarized in Table 6-7.

Having mentioned all of the co-benefits of zero- and low-emissions resources, it bears mentioning that these resources, like all electric resources, can potentially have negative impacts as well. Nuclear power plants require vast quantities of water for cooling, and large hydro projects alter aquatic habitats on a vast scale. Wind turbines are sometimes opposed based on concerns about noise, ridgeline views, or avian impacts. Large-scale solar and wind projects may alter natural habitats across large tracts of land. The siting and permitting of zero- and low-emissions resources will sometimes generate significant public and political opposition, more so in some locations than others.

6. Costs and Cost-Effectiveness

The costs and cost-effectiveness of state efforts to rely on zero- and low-emissions resources vary by category of technology, geographic regions of the United States, and pre-existing state and federal support for these initiatives. They can also be quite variable and may depend in part on the perspective applied by any given economic screening tool.

Figure 6-7 shows the relative economics of different technologies based on estimates of the forward-looking levelized costs of energy (LCOE), a term explained in the following text box. The analysis in Figure 6-7 was prepared by Bloomberg New Energy Finance and has largely adopted the convention of excluding subsidies and incentives.[62]

Levelized costs provide a convenient reference point for the relative economics of different technologies on a roughly "apples-to-apples" basis. Nevertheless, there are also some important differences that are not captured in this type of cost comparison.[63]

As Figure 6-7 shows, there is overlap in the range of

Levelized Costs or LCOE

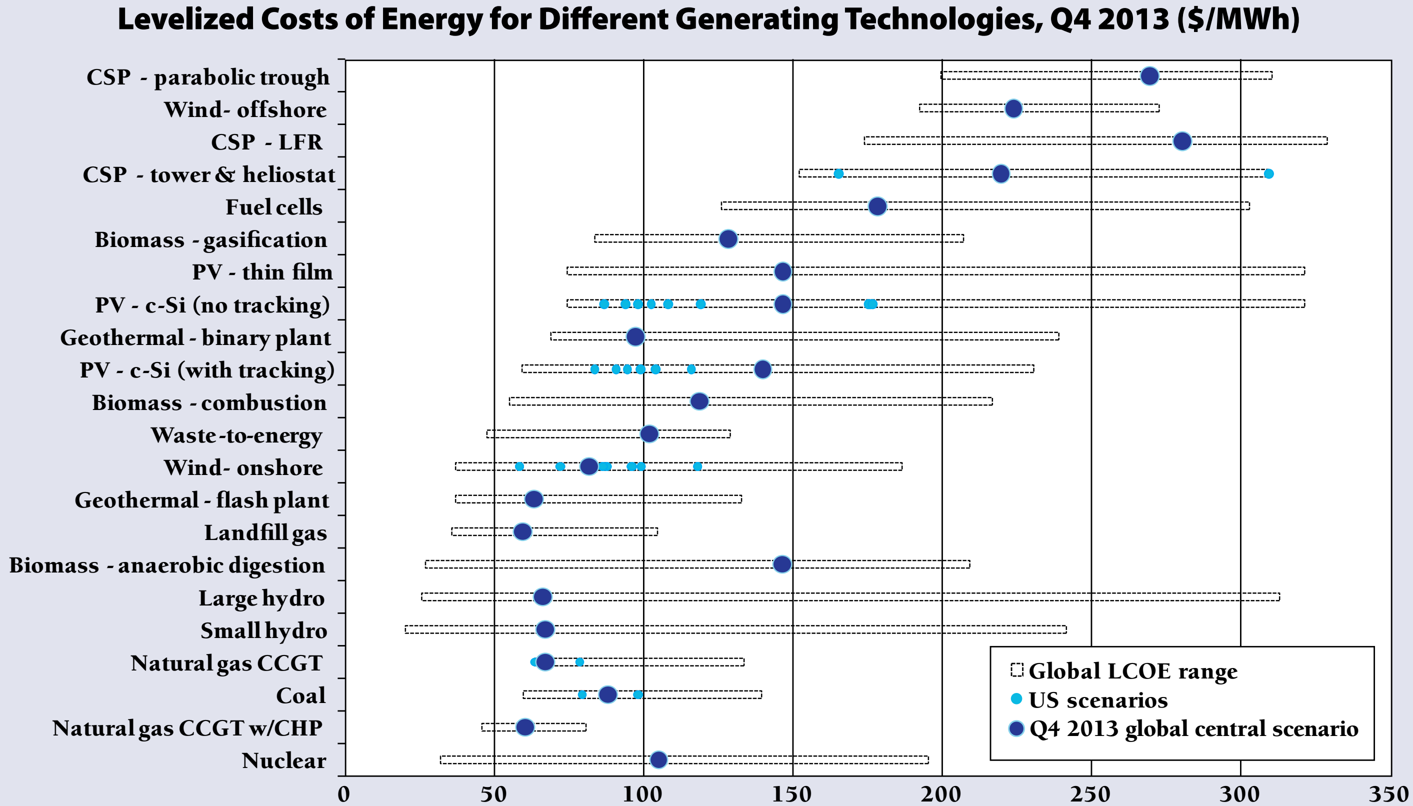
The LCOE reflect the average cost of producing the unit electricity over the life of its source. The LCOE estimates include consideration of all costs (including capital and fuel costs) and the amount of electricity produced from a particular type of generation.

Levelized cost calculations also include the costs of financing a project.

62 Earlier estimates prepared by the DOE and presented in January 2013 found similar values. The Bloomberg New Energy Finance values are presented here because they reflect more recent cost data.

63 Levelized costs comparisons do not effectively account for significant changes in capital costs associated with technologies like wind and solar that have few operating costs. Capital costs, especially for solar PV, have declined significantly over the last several years. Levelized costs comparisons that are presented as a single value typically do not account for important regional differences associated with weather that may improve the value of some resources in regions that have supportive weather conditions. Levelized costs comparisons of this sort typically do not incorporate tax advantages that are associated with different technologies. In addition, the duration of the lifecycle of different technologies varies, and this can affect LCOE calculations. LCOE estimates are also calculated using an "overnight cost" for purposes of the cost comparison. This ignores important advantages of technologies like solar, wind, and even gas, that can be introduced over relatively short periods as compared with, for example, the addition of a large nuclear generator that may require eight to ten years. Also, LCOE estimates of this sort do not account for regional differences in the avoided costs or wholesale market differences between regions. Costs that are the same in two regions for a given technology may be cost-effective in one region but uneconomic in another, solely based on the comparative economics of the alternatives in that region.

Figure 6-7



Source: *Bloomberg New Energy Finance, EIA Notes: LCOE is the per-MWh inflation-adjusted lifecycle cost of producing electricity from a technology assuming a certain hurdle rate (ie, after-tax, equity internal rate of return, or IRR). The target IRR used for this analysis is 10% across all technologies. All figures are derived from Bloomberg New Energy Finance analysis. Analysis is based on numbers derived from actual deals (for inputs pertaining to performance). Capital costs are based on evidence from actual deals, which may or may not have yielded a margin to the sellers of the equipment; the only 'margin' that is assumed for this analysis is 10% after-tax equity IRR for project sponsor. The dark-colored circles correspond to a global central scenario, with the exception of nuclear, gas, and coal – where the light blue circles correspond to US-specific scenarios; there are multiple light blue circles per technology, corresponding to different projects, with varying economics, that have been installed in the US across different regions. 'CHP' stands for combined heat and power; 'CCGT' stands for combined cycle gas turbine; 'c-Si' stands for crystalline silicon; 'CSP' stands for concentrated solar power; 'LFR' stands for linear Fresnel reflector.*

LCOE values observed for each resource. Considering the central scenarios for global LCOE, we see a cluster of technologies that are all roughly equal in cost. Those technologies include natural gas units, but also include hydro, geothermal, and landfill gas. Onshore wind projects cost somewhat more, but are competitive with coal-fired units. But it is also important to recognize that the costs of some of the less-mature renewable technologies have changed significantly in recent years and continue to decline. Wind generation, a prime example, is improving its performance with time as the industry's size and scale grows. Prices for new wind energy projects in the United States have fallen more than 40 percent in the past five years; in 2014, more than 3300 MW of new wind power purchase agreements were announced, building on the roughly 8000 MW of power purchase agreements signed during 2013.[64] Wind could be competitive with natural gas (even without tax and renewable energy incentives) if the delivered gas price rose above approximately $6 per MMBTU.[65] Solar PV module prices have dropped 80

64 Supra footnote 36.

65 Channell, J., Savvantidou, S., Jansen, H. R., Morse, E. L., Syme, A. R., & Yuen, A. (2013, October). *Energy Darwinism: The Evolution of the Energy Industry,* p. 53.Citi GPS: Global Perspectives and Solutions. Available at: https://ir.citi.com/Jb89SJMmf%2BsAVK2AKa3QE5EJwb4fvI5UUplD0ICiGOOk0NV2CqNI%2FPDLJqxidz2VAXXAXFB6fOY%3D

The Apples-to-Oranges of Levelized Costs Comparisons

LCOE provides a framework for apples-to-apples comparisons of different generating technologies, but it can also obscure important differences that may bias the results. Nuclear energy provides a good example. Not accounted for in these cost comparisons are costs that either go unaccounted for in commercial transactions or are undervalued. In the case of nuclear energy, this can be a relatively long list and includes both the undervalued cost of spent fuel disposal and the full insurance value of liability (or costs) in the face of a potential catastrophic accident. The high cost of decommissioning facilities at the end of their life provides yet a third category of undervalued costs.

Other areas that can differ between technologies include their flexibility in terms of planning, construction, and then operation. Wind and solar resources that are in close proximity to existing grid infrastructure can be planned and constructed over a relatively short period, and to a certain extent sized to meet specified needs. In contrast, nuclear reactors must be planned eight to ten years in advance of operation and currently are built only in very large-capacity increments. So hypothetically, if a jurisdiction needs 100 MW of capacity and nuclear reactors are only economical in a 500-MW size, the LCOE value of nuclear might be skewed. Also, if planning assumptions like needed capacity fail to materialize, there can be a sizeable liability for committed (but ultimately underutilized) investments. These investments are often shifted from prospective investors to ratepayers or taxpayers through regulatory pre-approvals or loan guarantees.

Another shortcoming of LCOE methodologies is that they fail to distinguish between the cost of resources and the *value* of what those resources can do, beyond simply generating MWh. Wholesale electricity prices are always higher during times of peak demand and lower off peak. Any resource that produces a disproportionate amount of its total generation on peak will be producing MWhs that have more value than a resource that disproportionately produces off peak. Also, nuclear generators and some types of renewables are inflexible and/or non-dispatchable. As the mix of resources available to system operators grows to include more and more inflexible and non-dispatchable resources, the *value* of flexible, dispatchable resources will increase. Value does not equal cost, and LCOE does not capture value.

Levelized costs comparisons can assume away one other critical feature of costs. Although not true for the levelized costs reflected previously by Bloomberg, levelized costs sometimes assume that the capital costs of investment can be made "overnight." Yet the differential costs of long construction periods and associated costs of financing are effectively ignored, even though those costs can be substantial and are typically borne by ratepayers in the form of capitalized financing costs.

percent since 2008.[66] The DOE recently announced that solar PV is 60 percent of the way toward the Department's goal of lowering costs to $0.06 per kWh by decade's end.[67] By the end of 2013, utility-scale solar averaged $0.11 per kWh; currently utilities in some areas are signing solar power purchase agreements for $50 to $60 per MWh over 20 to 25 years.[68] The learning curve (the rate of cost decline in relation to a doubling of capacity) is estimated to be between 20 and 40 percent.[69] Increasingly, zero- and low-emissions technologies are simply priced at or below

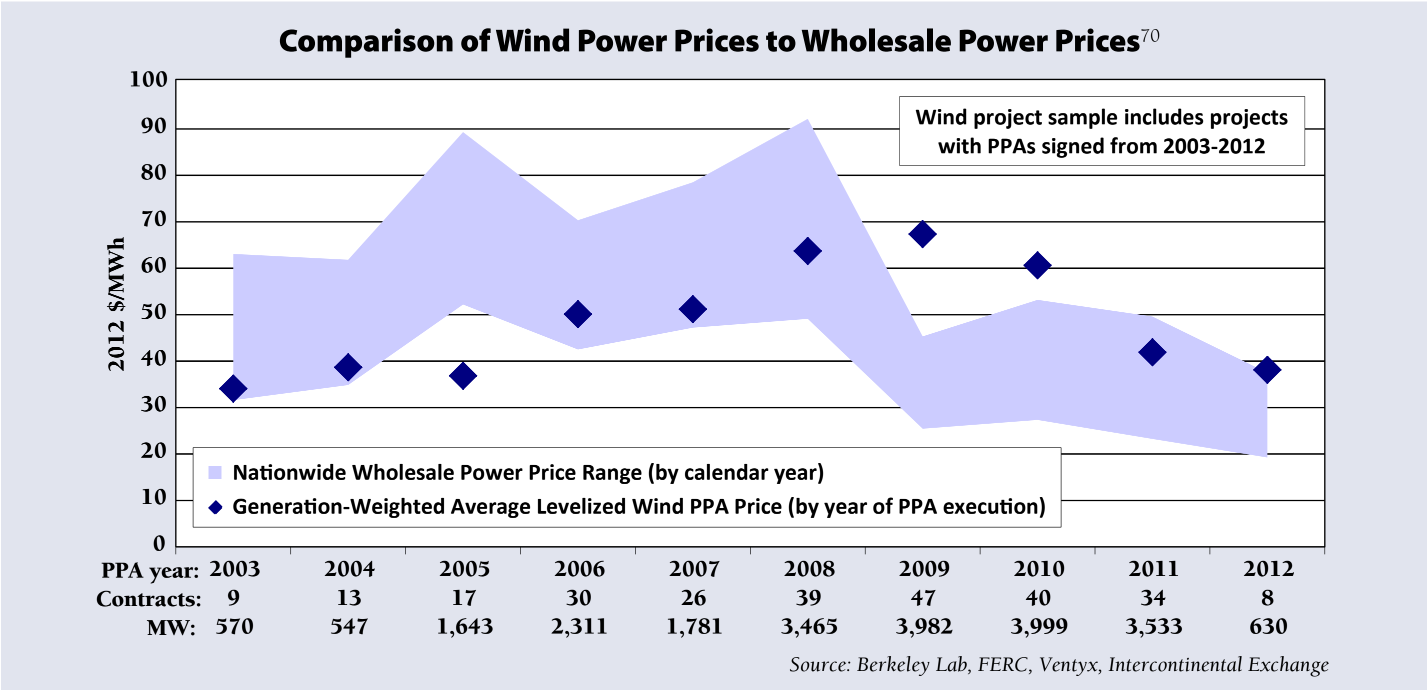
66 Bloomberg New Energy Finance. (2014, February). *2014 Sustainable Energy in America: Factbook.* Available at: http://about.bnef.com/white-papers/sustainable-energy-in-america-2014-factbook/

67 Available at: http://energy.gov/articles/us-utility-scale-solar-60-percent-towards-cost-competition-goal

68 See, for example: Case No. 12-0038-UT before the New Mexico Public Regulation Commission. Available at: http://www.epelectric.com/files/html/Macho_Springs/Macho_Springs_Notice_of_Proceeding_and_Hearing_12-00386-UT__2_.pdf. Also, in 2014 Austin Energy signed a 20-year power purchase agreement with Recurrent Energy for 150 MW of solar power. The terms of that agreement were not publicly reported but the cost was widely reported to be "less than $50 per MWh."

69 Supra footnote 65 at p. 48.

Figure 6-8



the fossil fuel alternatives. In Texas, for example, wind projects are coming in at $37 per MWh. At such levels they are competitive with any fossil fuel alternative.

LCOE values compare the long-term costs of different types of new resources. This provides useful information for assessing the cost-effectiveness of different options for building new resources to meet growing electricity demand or replace retiring generators. However, in the more immediate term, where existing generating capacity is sufficient to meet demand, the short-term *cost-effectiveness* of generation investments will depend critically on the relative price of wholesale electricity, which is highly dependent on the costs of operating *existing* generators. If it costs more to build a new generator than the unit can expect to recover in wholesale energy prices, it will not be cost-effective. Wholesale prices have declined in all regions of the United States over the last seven years, owing to low natural gas prices, surplus generating capacity, and a sluggish economy. Figure 6-8 shows how the economics of wind power have changed in the United States with the relative prices of wholesale electric energy. In some years, wind power prices were at the low end of the range of wholesale power prices and this type of generating resource was very cost-effective. In other years, wind prices have been higher than average wholesale prices, making it less cost-effective. Whether any resource is cost-effective over the lifetime of the investment will depend on how wholesale market prices change over the long-term.

7. Other Considerations

Many of the zero- and low-emissions technologies can pose challenges for system operators. On the one hand, large nuclear units are designed to run more or less at full capacity at all times. System operators have to essentially manage the system around the inflexibility of nuclear units. On the other hand, non-dispatchable resources like wind and solar PV vary their output based on weather conditions, and the system operator has to manage the system around the variability of their output. Both of these situations create challenges for the system operator, who must balance generation to meet end-user demand in real time, at all times.[71]

70 Wiser, R., & Bolinger, M. (2013, August). *2012 Wind Technologies Market Report.* Lawrence Berkeley National Laboratory for the US Department of Energy. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf

71 Advancing technologies and markets, however, increasingly enable system operators to achieve this balance by adjusting electricity demand (through demand response and other programs), as well as through traditional generation supply resources. Chapter 23 provides additional information on this capability.

At low levels of deployment, the challenge of integrating inflexible and variable resources is not terribly difficult. But at higher levels of penetration, grid integration can be enormously challenging. Solutions, discussed in Chapter 20 of this document, are available and include an expanding array of options. But as a practical matter, the costs, cost-effectiveness, and emissions savings associated with zero- and low-emissions sources should account for the costs of those solutions and any incremental costs necessary to facilitate grid integration.[72] Most integration studies performed to date on renewable energy have focused on wind, as wind has been the predominant variable energy renewable technology to date. Many global studies suggest that the costs are between $1 and $7 per MWh for 10- to 20-percent penetration of variable energy renewable technologies.[73] Higher penetrations see higher costs, but actual experience with higher penetrations is limited, and time and experience with integration are likely to bring down integration costs.[74] State- and utility-specific studies in the United States show considerable variability in these integration costs, again based on the increasing wind penetration.

Additional issues could arise with the widespread adoption of customer-owned distributed generation, particularly distributed PV systems. Utilities may find it particularly challenging to maintain the electric grid if they can't control or reliably predict the output of customer-owned distributed generation. Reductions in retail sales could also make it difficult for utilities to maintain grid services unless significant changes are made to retail rates or rate designs. The unique opportunities and challenges associated with distributed generation are addressed in much greater detail in Chapter 17.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on zero- and low-emissions technologies.

- American Wind Energy Association. (2014, May). *The Clean Air Benefits of Wind Energy.* Available at: http://awea.files.cms-plus.com/FileDownloads/pdfs/AWEA_Clean_Air_Benefits_WhitePaper%20Final.pdf
- Barbose, G., Darghouth, N., Weaver, S., & Wiser, R. (2013, July). *Tracking the Sun VI.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf
- Bolinger, M. (2014, May). *An Analysis of the Costs, Benefits, and Implications of Different Approaches to Capturing the Value of Renewable Energy Tax Incentives.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/publications/analysis-costs-benefits-and-implications-different-approaches-capturing-value-renewable
- Bolinger, M., & Weaver, S. (2013, September). *Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/publications/utility-scale-solar-2012-empirical-analysis-project-cost-performance-and-pricing-trends
- Hand, M. M., Reilly, J. M., Porro, G., Baldwin, S., Mai, T., Meshek, M., DeMeo, E., Arent, D., & Sandor, D., eds. (2012). *Renewable Electricity Futures Study.* Volume 1 of 4, at A-51. NREL/TP-6A20-52409. National Renewable Energy Laboratory. Available at: http://www.nrel.gov/analysis/re_futures/

72 Integration costs are not unique to zero- and low-emissions resources; they are also an issue with more traditional forms of generation, which, because of size and inflexibility, may impose additional costs on the system.

73 Supra footnote 59.

74 Although actual experiences with high penetrations are limited, the National Renewable Energy Laboratory has extensively studied and modeled the potential implications of high penetrations. Refer to Chapter 20, and: Supra footnote 44.

- International Energy Agency. (2013, November). *World Energy Outlook.* Available at: http://www.worldenergyoutlook.org/publications/weo-2013/
- Lopez, A., Roberts, B., Heimiller, D., Blair, N. & Porro, G. (2013, July). *US Renewable Energy Technical Potentials: A GIS-Based Analysis.* National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy12osti/51946.pdf
- National Renewable Energy Laboratory. (2013, November). *2012 Renewable Energy Data Book.* Available at: http://www.nrel.gov/docs/fy14osti/60197.pdf
- Rocky Mountain Institute. (2014, February). *The Economics of Grid Defection.* Available at: http://www.rmi.org/electricity_grid_defection
- Solar Energy Industries Association. (2014, September). *Solar Market Insight Report 2014 Q2.* Available at: http://www.seia.org/research-resources/solar-market-insight-report-2014-q2
- Union of Concerned Scientists. (2014, May). *Fact Sheet: Renewable Energy on Regional Power Grids Can Help States Meet Federal Carbon Standards.* Available at: www.ucsusa.org/renewablesandregionalgrids
- US Energy Information Administration. (2014, April). *Annual Energy Outlook 2014, with Projections to 2040.* Available at: http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf
- Wiser, R., & Bolinger, M. (2013, August). *2012 Wind Technologies Market Report.* Lawrence Berkeley National Laboratory for the US Department of Energy. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf

9. Summary

A wide range of zero- and low-emissions technologies are available to help displace higher-emitting sources of generation. Mature technologies like hydro and nuclear generation have limited room for expansion, largely owing to the best hydro locations having already been exploited, and the economics of nuclear technology in the United States being particularly disadvantaged. However, the potential for increased deployment of less-mature renewable technologies is extremely large. Policies adopted at the federal, state, and local levels have successfully led to cost reductions in certain categories of zero- and low-emissions technologies, especially wind and solar.

The GHG reduction benefits of zero-emissions generating resources is obvious and substantial, but will vary in the short-term depending on which higher-emitting resources are displaced (i.e., dispatched less often) owing to the availability of a zero-emissions alternative. Generating technologies that are low- but not zero-emissions at the stack require additional analysis to assess the GHG and other air pollutant benefits. Over time, ever-increasing deployment of zero- and low-emissions resources will reduce emissions by reducing not just the dispatch of existing fossil-fueled units but also the need to add new capacity from higher-emitting generators, most likely natural gas-fired units. It will also facilitate the retirement of fossil units of all types while maintaining adequate resources for system reliability.

The principal challenge associated with increased generation from zero- and low-emissions resources, aside from cost considerations, is likely to be the challenge of integrating inflexible or non-dispatchable resources into the grid and balancing generation with demand on a real-time basis. Solutions to address this challenge are presented in Chapter 20.

7. Pursue Carbon Capture and Utilization or Sequestration

Carbon capture and utilization and/or storage refers to a two-pronged approach to reducing carbon dioxide (CO_2) emissions from fossil-fired electric generating units (EGUs) and other CO_2-emitting facilities. At EGUs, CO_2 can be collected prior to or after combustion of fuel using one of three types of capture: pre-combustion, oxy-combustion, or post-combustion. Following *capture*, the CO_2 can be compressed and transported to an injection site for underground *storage,* or it can be *utilized* for productive purposes.

CO_2 is primarily considered a waste product, but there are a limited number of exceptions in which it can be used for productive purposes. These exceptions include using CO_2 for enhanced oil recovery (EOR); producing consumer products like carbonated beverages; and growing algae that can be used for biofuels, animal feed, or chemical production.[1] Of these options, EOR is the most technologically mature and has the most working examples demonstrating its feasibility for widespread use. The demand for CO_2 in consumer products, on the other hand, is currently very limited and in most cases the gas would eventually be emitted as the product is used or consumed. Using CO_2 to grow algae is a promising option that is the subject of numerous demonstration projects but is not yet commercially deployed at full scale. Therefore, this chapter focuses primarily on the combination of carbon capture with underground storage or with EOR.

Pre-combustion capture is a technology applicable to Brayton cycle[2] facilities including integrated gasification combined-cycle (IGCC) plants. IGCC plants gasify solid fuels such as coal and petroleum coke[3] to produce "synthesis" gas or "syngas," a combustible fuel whose main constituents are hydrogen, carbon monoxide (CO), and CO_2. Carbon capture removes the latter two components of syngas, leaving primarily hydrogen to be burned for electricity production.

As shown in Figure 7-1, following gasification and gas cleanup in the particle remover, syngas is sent to a shift reactor that "shifts" CO to CO_2, hence the need for steam at this step to add the additional oxygen atom and create CO_2 out of CO. Next, the sulfur content in syngas, in particular hydrogen sulfide or acid gas, must be removed.[4] Finally, the CO_2 can be separated from the syngas and then compressed for transport and storage.

Oxy-combustion capture creates a highly concentrated stream of CO_2 by firing fuel in an oxygen-rich environment.

1 For more information regarding the use of CO_2 to grow algae, refer generally to the Algae Biomass Organization website at: http://www.algaebiomass.org/. A summary of demonstration projects is available at: http://www.algaebiomass.org/wp-content/uploads/2010/06/ABO_project_book_lo-res_July2013.pdf.

2 The Brayton cycle (or Joule cycle) represents the operation of a gas turbine engine. The cycle consists of four processes: compression of an inlet stream (air); constant pressure fuel combustion; expansion and exhaust through a turbine and/or exhaust nozzle, turning a generator (and also driving the compressor); and cooling the air back to its initial condition. See: http://web.mit.edu/16.unified/www/SPRING/propulsion/notes/node27.html

3 Petroleum coke is a byproduct of oil refining.

4 Figure 7-1 shows gypsum as the byproduct of sulfur removal, but in order to recover gypsum from an IGCC plant a hydrogen sulfide furnace and limestone-gypsum absorber are necessary. Onishi, H. (2004, September). *250 MW Air-Blown IGCC Demonstration Plant in Japan and its Future Prospect.* 19th World Energy Congress.

Figure 7-1

Pre-Combustion Capture at an IGCC Plant[5]

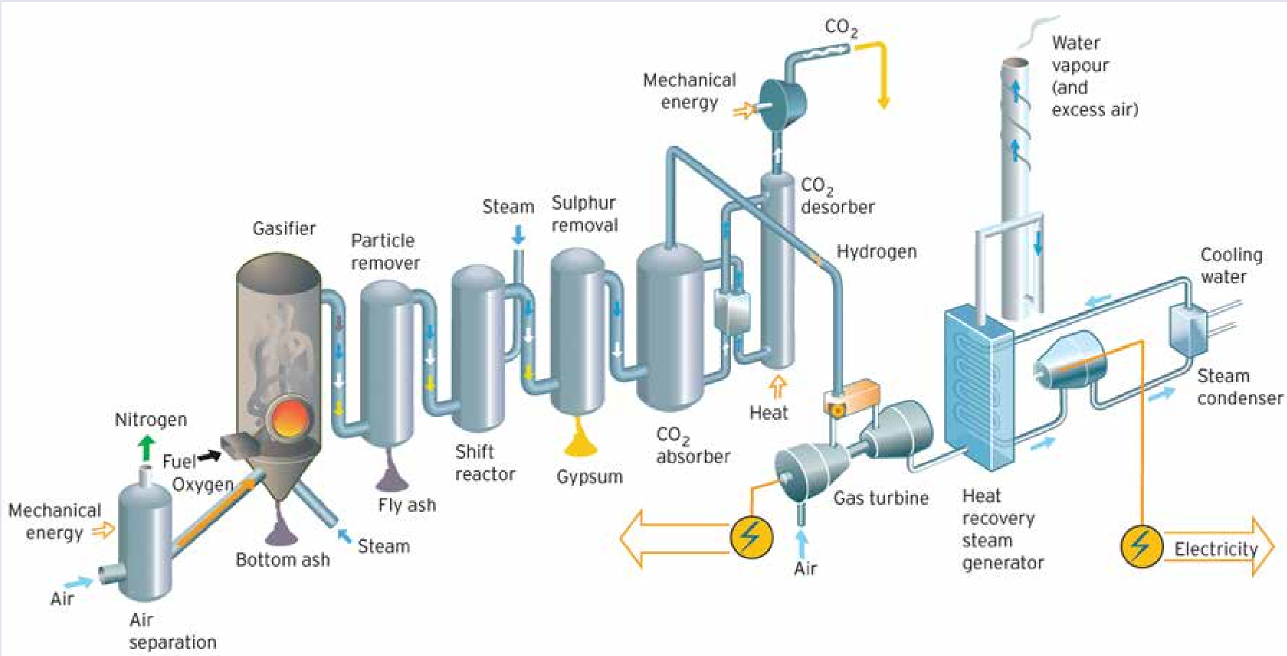
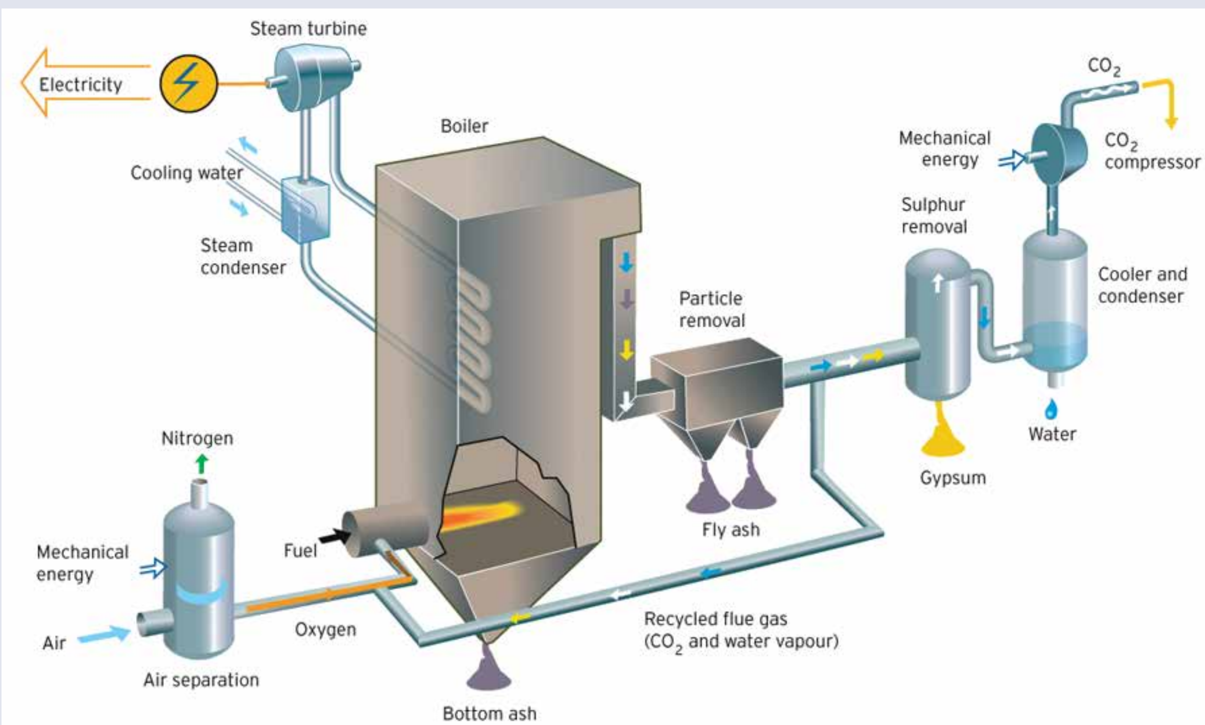


Figure 7-2

Oxy-Combustion Capture at a Pulverized Coal Plant[6]

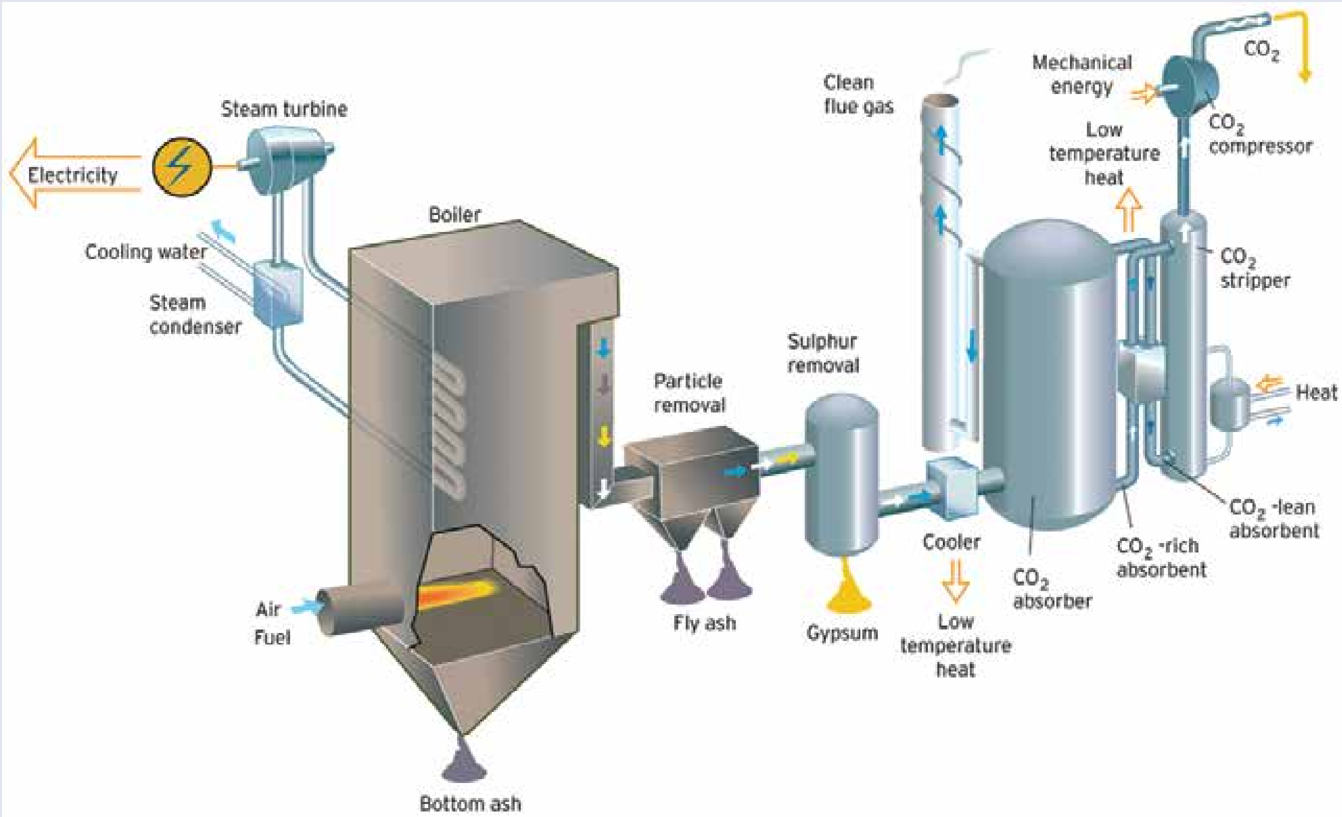


5 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Pre-combustion%20Capture%20Process_Vattenfall.jpg

6 Vattenfall. (2012, December). *Illustrations*. Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Oxyfuel%20Combustion%20Capture%20Process_Vattenfall.jpg

Figure 7-3

Post-Combustion Capture at a Pulverized Coal Plant[7]



The resulting flue gas is approximately 70 percent CO_2.

As shown in Figure 7-2, ash and sulfur emissions must be removed, as in typical pulverized coal plant operations. In addition, the water content of the flue gas must be reduced before the CO_2 is ultimately compressed for transport.

Because of the expense associated with oxy-combustion (discussed in Section 6) and because there are only three operating IGCC plants in the United States,[8] the focus of most of this chapter is on carbon storage coupled with post-combustion capture. Post-combustion capture is typically envisioned on pulverized coal plants, as shown in Figure 7-3, but could also occur on the back end of natural gas-fired power plants.

Post-combustion capture strips the flue gas of its CO_2 using ammonia or an amine as the absorbent and then compresses the CO_2 for transport and storage. The maximum percentage of CO_2 that can be captured by any of these technologies is 90 percent. But regardless of how the CO_2 is captured, it must be compressed to its supercritical phase for transport. In its supercritical state, the CO_2 has properties of both a gas and a liquid.

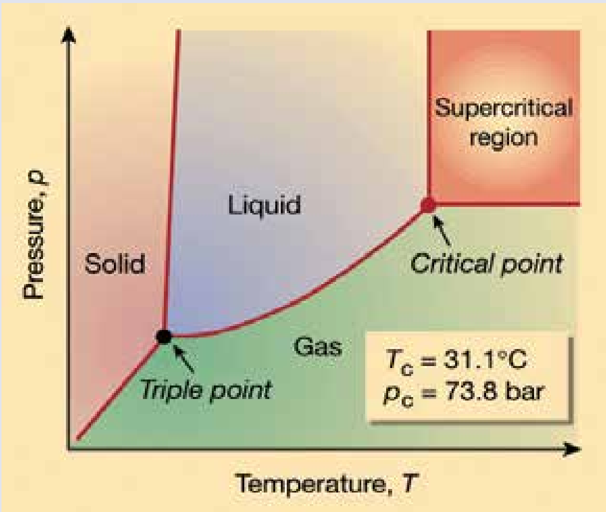
To reach its supercritical phase, the CO_2 is compressed in multiple stages. The minimum temperature and pressure at which CO_2 reaches its supercritical state are 31.1 degrees Celsius and 73.8 bar as shown in Figure 7-4. Compression to this phase is necessary to transport large volumes of CO_2, and also to inject the CO_2. Much more underground

7 Vattenfall. (2012, December). *Illustrations.* Available at: http://www.captureready.com/userfiles/image/Carbon%20Capture/Post-combustion%20Capture%20Process_Vattenfall.jpg

8 The operating IGCC plants are Wabash River and Edwardsport in Indiana and Polk Power in Florida. The Kemper County IGCC plant is under construction in Mississippi. The Texas Clean Energy Project, a coal-fired IGCC plant, and the Hydrogen Energy California Project, a petroleum coke-fired IGCC plant, are also in the planning stages but not yet under construction.

Figure 7-4

CO_2 Phase Diagram[9]



volume is needed to store CO_2 in the gas phase than in the supercritical phase.[10]

There are three main types of geologic formations thought to provide sufficient capacity to store large volumes of CO_2: saline aquifers, oil and gas reservoirs, and unmineable coal seams. Saline aquifers consist of layers of sedimentary porous and permeable rocks saturated with salty water, called brine.[11] Saline aquifers are thought to have the largest potential for carbon storage because they are so widespread.

Oil and gas reservoirs are less plentiful than saline aquifers, but they are generally better understood owing to years of oil and gas production. These reservoirs may be used purely for sequestration, but often they are used for EOR as well. In EOR, CO_2 is injected into a reservoir to stimulate oil production. Because CO_2 is miscible[12] with oil, it makes the oil more fluid and pushes it toward the producing well.[13] CO_2-EOR can produce approximately 35 percent of the residual oil in a reservoir.[14]

Coal seams may be considered unmineable for geologic, economic, or other reasons. Coal seams have less potential storage capacity than saline aquifers or oil and gas reservoirs, but they do have the possible co-benefit of enhancing methane production while trapping CO_2. Methane is the primary consituent of natural gas. Coal and methane are often found together; methane resides on the surface of the coal, a phenomenon known as adsorption.[15] However, because coal preferentially adsorbs CO_2 over methane, the coal releases the methane for production from the seam when CO_2 is present.

Whether storage in a saline aquifer, hydrocarbon reservoir, or coal seam is contemplated, characterization of the formation is extremely important. Among the characteristics that must be determined are *porosity* and *permeability.* Porosity is the "percentage of pore volume or void space… that can contain fluids."[16] Permeability is "the ability, or measurement of a rock's ability, to transmit fluids [measured in darcys[17]]."[18] A permeable formation typically has many large pores that are well connected.[19] Porosity and permeability help determine another very important aspect of any storage formation, *injectivity.* Injectivity is "the rate and pressure at which fluids can be pumped into the treatment target without fracturing the formation."[20] Although fractures

9 Leitner, W. (2000, May 11). Green Chemistry: Designed to Dissolve. *Nature 405,* 129–130. Available at: http://www.nature.com/nature/journal/v405/n6783/fig_tab/405129a0_F1.html

10 US Department of Energy National Energy Technology Laboratory. (2010, September). *Geologic Storage Formation Classifications: Understanding Its Importance and Impacts on CCS Opportunities in the United States,* p. 11. Available at: www.netl.doe.gov/File%20Library/Research/Carbon-Storage/Project-Portfolio/BPM_GeologicStorageClassification.pdf

11 US Department of Energy National Energy Technology Laboratory. (2012). *Carbon Utilization and Storage Atlas.* Available at: http://www.netl.doe.gov/research/coal/carbon-storage/atlasiv

12 A "miscible" fluid can be mixed with other fluids to form a homogenous solution.

13 Hyne, N. (2001). *Nontechnical Guide to Petroleum Geology, Exploration, Drilling, and Production.* Tulsa, OK: PennWell.

14 Supra footnote 13

15 Nazaroff, W., & Alvarez-Cohen, L. (2001). *Environmental Engineering Science.* New York: Wiley.

16 Schlumberger. (2011). *Porosity.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/en/Terms/p/porosity.aspx

17 A rock formation with a permeability of 1 darcy permits a flow of 1 cm^3/second of a fluid with viscosity of 1 under a pressure gradient of 1 atmosphere/cm acting across an area of 1 cm^2.

18 Schlumberger. (2011). *Permeability.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/en/Terms/p/permeability.aspx

19 Ibid.

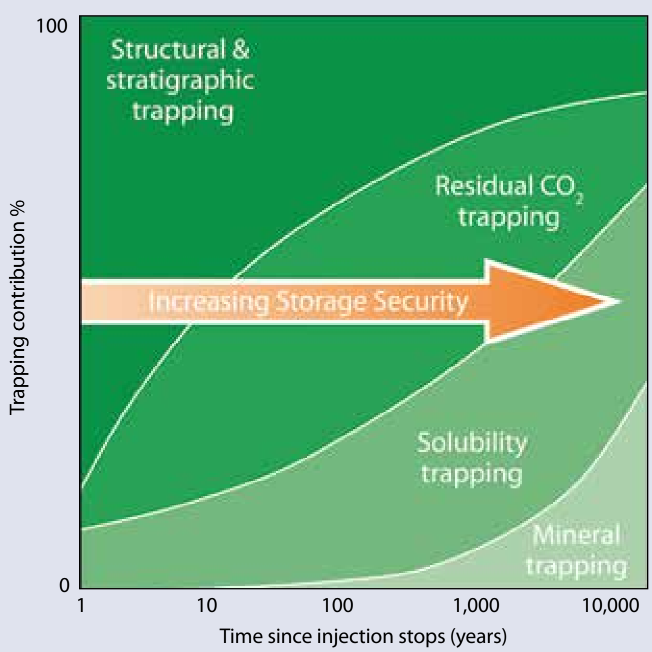
20 Schlumberger. (2011). *Injectivity Test.* Entry in oilfield glossary available at: http://www.glossary.oilfield.slb.com/Display.cfm?Term=injectivity%20test

in a storage formation would seem to offer additional pathways for the CO_2 to move, they can also provide pathways for the CO_2 to escape to the surface and thereby compromise the integrity of the storage formation.

When CO_2 is injected underground, several mechanisms may work to keep it underground. First, because the other fluids in saline aquifers and oil and gas reservoirs are less buoyant than CO_2, a low permeability seal or caprock is necessary to prevent CO_2 from migrating upward.[21] This is known as "primary" or "buoyant" trapping.[22] "Secondary" trapping mechanisms include: dissolving CO_2 in water (solubility trapping); trapping CO_2 by capillary forces between pore spaces (residual trapping); precipitation of CO_2 in a carbonate compound (mineral trapping); and trapping CO_2 in coal seams (adsorption trapping, discussed previously).

Figure 7-5

Trapping Mechanisms Occur on Different Time Frames[23]



Each trapping mechanism happens on a different time scale (Figure 7-5).

Primary trapping (also known as "structural" or "stratigraphic" trapping) occurs immediately, but residual trapping is thought to happen after injection stops.[24] Mineral trapping, in particular, is believed to occur on much longer time frames.

In 2012, the United States Geological Survey (USGS) published its estimate of the technical CO_2 geologic storage potential in the United States. USGS's assessment of the CO_2 storage resource was conducted using "present-day geological and engineering knowledge and technology for CO_2 injection into geologic formations."[25] It did not incorporate economic or engineering constraints.

The areas analyzed by the USGS are shown in the map in Figure 7-6. The lighter grey areas were evaluated by the USGS but were not assessed. The resulting storage estimates predicted that the most storage capacity lies in the Coastal Plains (1900 gigaton [Gt]), followed by the Rocky Mountains and Northern Great Plains and Alaska (270 Gt each), and the Eastern Mid-Continent (230 Gt). All other regions were estimated to have 150 Gt or less of storage potential, for a total mean storage potential of 3000 Gt. The USGS's assessment included saline aquifers and oil and gas reservoirs, but not unmineable coal seams because the USGS could find no definition to determine which coals seams are unmineable.[26]

The USGS's methodology accounted for two trapping mechanisms: buoyant and residual. The residual trapping resource was divided into three classes based on reservoir permeability: class 1 (formations with permeability greater than 1 darcy [D]); class 2 (formations with permeability between 1 millidarcy [mD] and 1 D); and class 3 (formations with permeability of less than 1 mD).

21 Benson, S. M., & Cole, D. R. (2008). CO_2 Sequestration in Deep Sedimentary Formations. *Elements 4(5),* 325–331. doi: 10.2113/gselements.4.5.325 Available at: http://elements.geoscienceworld.org/content/4/5/325.short

22 Supra footnote 11.

23 Metz, B., Davidson, O., de Coninck, H., Loos, M., & Meyer, L., eds. (2005). *Carbon Dioxide Capture and Storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambrige, United Kingdom: Cambridge University Press, pp. 195–276. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf

24 Supra footnote 21.

25 Brennan, S. T., Burruss, R. C., Merrill, M., D.; Freeman, P. A., & Ruppert, L. F. (2010). *A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage.* USGS Open-File Report 2010–1127. Available at: http://pubs.usgs.gov/of/2010/1127

26 US Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Results.* US Geological Survey Circular 1386. Available at: http://pubs.usgs.gov/circ/1386/

Figure 7-6

Eight Regions Used in USGS's Geologic Storage Resource Assessment[27]

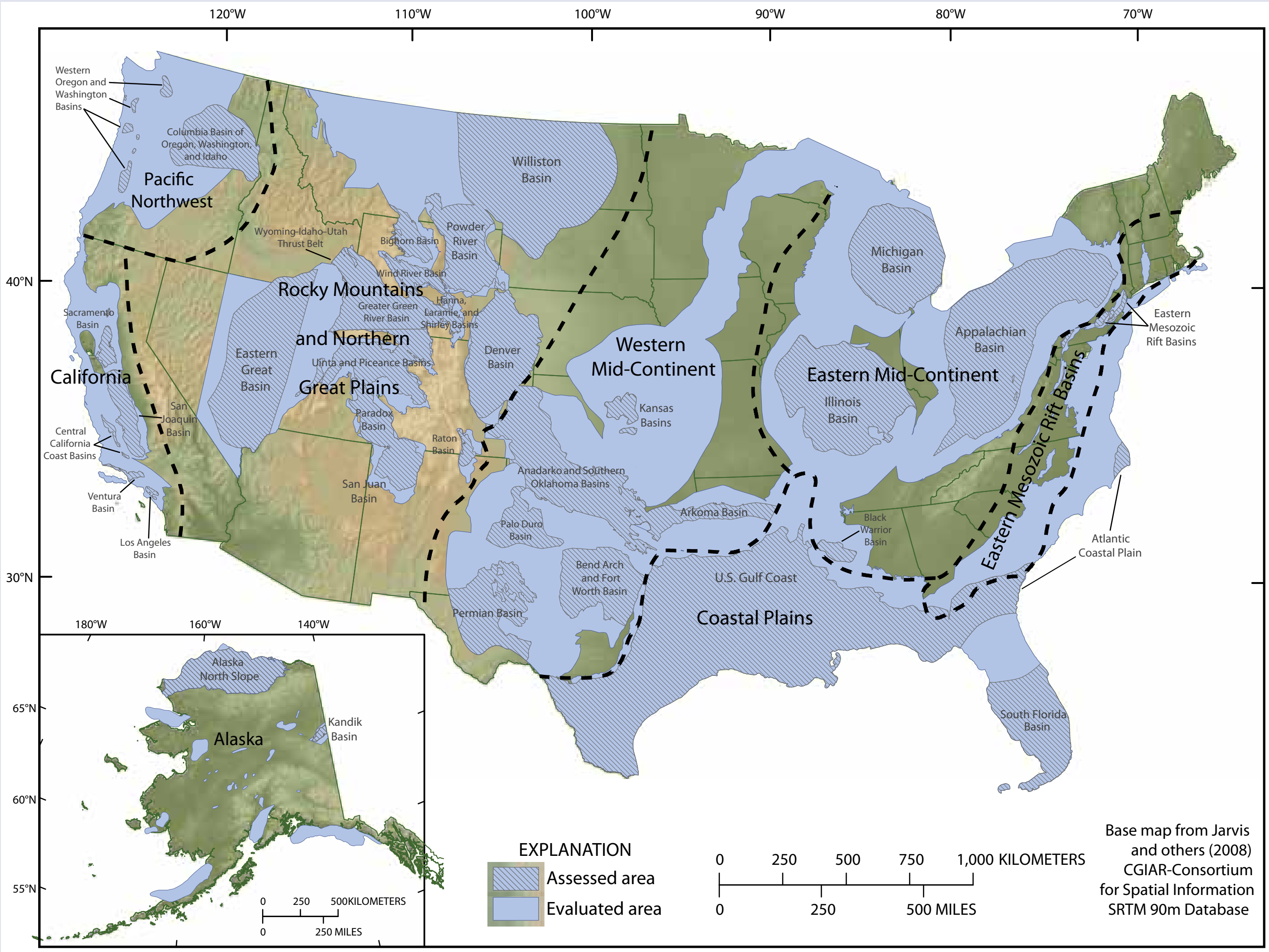
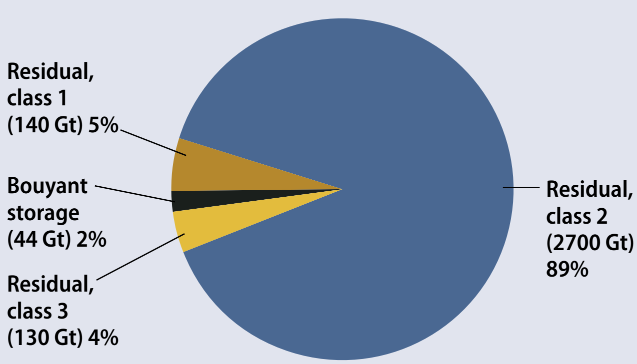


Figure 7-7

Geologic Storage Resource by Trapping Mechanism and Permeability Class[28]



The USGS found residual trapping in class 2 formations to be the overwhelming driver of total nationwide storage capacity, accounting for 89 percent of the resource (Figure 7-7).

Figure 7-8 depicts a sample cross-section of a storage formation such as those the USGS analyzed in this assessment.

The blue areas show the parts of the formation where buoyant trapping occurs. The green depicts the areas where residual trapping would have to be relied upon. Simply from a visual perspective, it's clear that residual trapping dramatically increases the volume available for CO_2 storage.

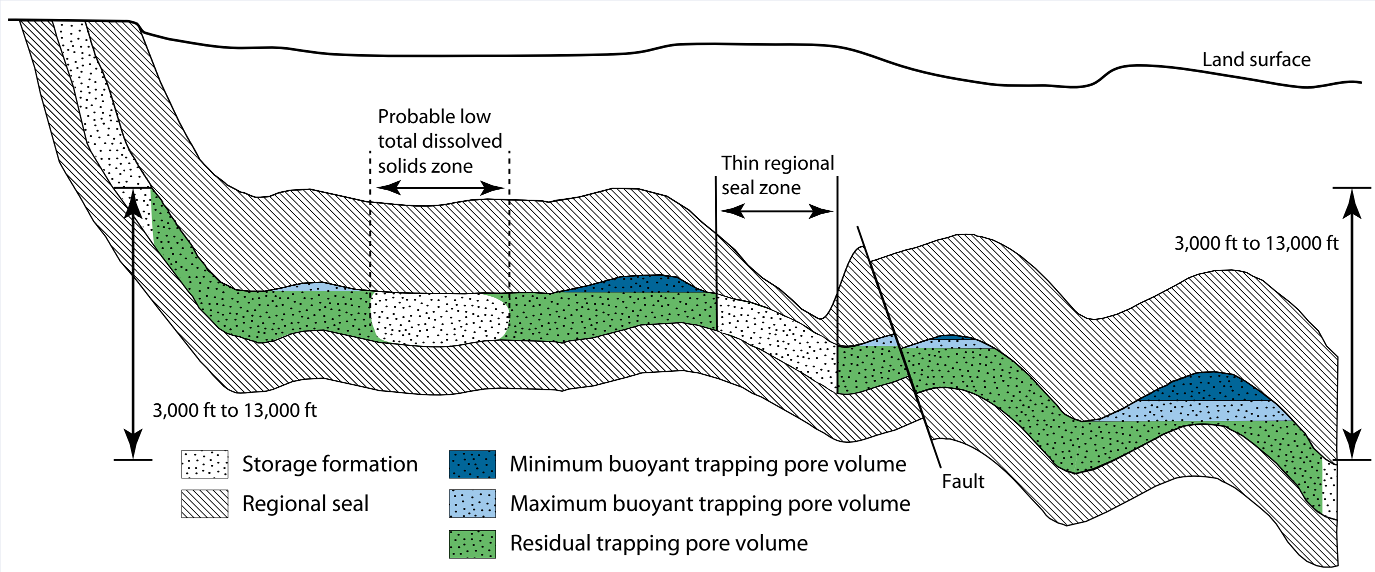
It is important to note, therefore, that "storage efficiencies

27 Supra footnote 26.

28 Ibid.

Figure 7-8

Cross-Section of a Sample Storage Formation Showing the Distribution of Pore Volume Between Buoyant and Residual Trapping[29]



associated with residual trapping are poorly understood," because no commercial-scale injection projects using this trapping mechanism have been undertaken.[30] In 2013, the United States emitted approximately 5.4 Gt of energy-related CO_2.[31] If carbon storage is to play a major role in addressing climate change, then secondary trapping mechanisms must be dependable. Relying on buoyant trapping alone would only provide enough capacity to store eight years' worth of the nation's CO_2 emissions.

2. Regulatory Backdrop

In the United States, no state or federal law has mandated the application of carbon capture and sequestration (CCS) to any power plant. However, partial CCS was proposed by the US Environmental Protection Agency (EPA) to be the Best System of Emission Reduction for new utility boilers and IGCC units under the agency's proposed carbon pollution standards for these sources (a.k.a. the proposed "111(b) rule," because it is based on the EPA's authority under section 111(b) of the Clean Air Act). The EPA defined partial CCS as achieving a CO_2 emissions rate of 1100 pounds per gross megawatt-hour (MWh). A new source would likely use a continuous emissions monitoring system to measure the plant's mass CO_2 emissions and demonstrate compliance. With respect to *existing* power plants and the Clean Power Plan that the EPA proposed in June 2014, the EPA determined that CCS is *not* an adequately demonstrated and cost-effective measure for reducing CO_2 emissions on a national scale:

> While the EPA found that partial CCS is technically feasible for new fossil fuel-fired boilers and IGCC units, it is much more difficult to make that determination for the entire fleet of existing fossil fuel-fired EGUs. Developers of new generating facilities can select a physical location that is more amenable to CCS – such as a site that is near an existing CO_2 pipeline or an existing oil field. Existing sources do not have the advantage of pre-selecting an appropriate location. Some existing facilities are located in areas where CO_2 storage is not geologically favorable and are not near an existing CO_2 pipeline. Developers of new facilities also have the advantage of integrating the partial

29 Blondes, M., Brennan, S., Merrill, M., Buursink, M., Warwick, P., Cahan, S., Cook, T., Corum, M., Craddock, W., DeVera, C., Drake II, R., Drew, L., Freeman, P., Lohr, C., Olea, R., Roberts-Ashby, T., Slucher, E., & Varela, B. (2013). *National Assessment of Geologic Carbon Dioxide Storage Resources—Methodology Implementation.* US Geological Survey Open-File Report 2013–1055. Available at: http://pubs.usgs.gov/of/2013/1055/

30 Supra footnote 25.

31 US Energy Information Administration. (2014, June). *Monthly Energy Review.* Available at: http://www.eia.gov/totalenergy/data/monthly/archive/00351406.pdf

CCS system into the original design of the new facility. Integrating a retrofit CCS system into an existing facility is much more challenging. Some existing sources have a limited footprint and may not have the land available to add partial CCS system. Integration of the existing steam system with a retrofit CCS system can be particularly challenging.[32]

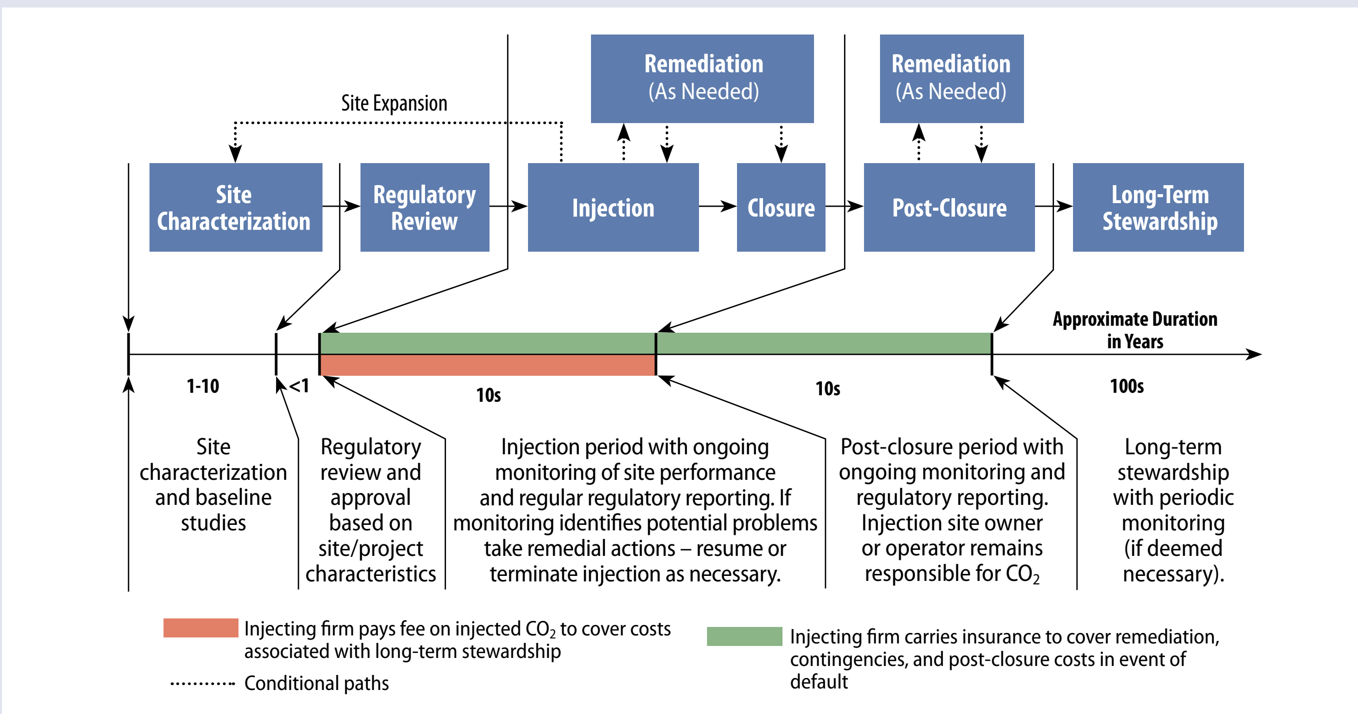
Although the EPA decided not to include CCS as part of the Best System of Emission Reduction for existing power plants, the agency notes that "at some existing facilities, the implementation of partial CCS may be a viable greenhouse gas (GHG) mitigation option and some utilities may choose to pursue that option" for complying with the 111(d) rule.[33] No specific mechanism for measuring the impact of CCS at existing facilities was included in the EPA's proposal, but all affected EGUs would be equipped with CO_2 continuous emissions monitoring systems. With respect to both the 111(b) and 111(d) proposals, the EPA appears to have based its findings about the viability of CCS on a review of geologic storage and EOR technical potential, without consideration of other potential utilization options, such as growing algae for biofuels.

It is worth noting that geologic storage of CO_2 is a fairly new field for regulation. Among the steps in carbon storage that need to be addressed through regulation are site characterization, site operations, closure, and long-term stewardship.[34]

As Figure 7-9 shows, each of these steps is likely to be

Figure 7-9

Phases of a Geologic Storage Project[35]



32 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures

33 Ibid.

34 Wilson, E., & Pollak, M. (2008). *Policy Brief: Regulation of Carbon Capture and Storage.* International Risk Governance Council. Available at: http://www.hhh.umn.edu/people/ewilson/pdf/regulation_carbon_capture_storage.pdf

35 Rubin, E. S., Morgan, M. G., McCoy, S. T., & Apt., J. (2007, May). *Regulatory and Policy Needs for Geological Sequestration of Carbon Dioxide.* Proceedings of US Department of Energy 6th Annual Conference on Carbon Capture and Sequestration. Available at: http://www.epp.cmu.edu/people/faculty/rubin/index.php?p=2007

multiyear. Site characterization is the process of identifying a potential site and confirming that it is suitable for carbon storage. The steps involved have been defined more conceptually than in terms of specific characteristics or analytical methodologies, owing to the lack of experience with carbon storage.[36] Regulation of injection would address such contingencies as release to the atmosphere, surface damage, and CO_2 migration beyond the intended storage formation.[37] The transition from post-closure to long-term stewardship is largely defined by who holds the responsibility to ensure that the injected CO_2 is retained in the storage formation. The authors of Figure 7-9 assume that long-term stewardship, which could last hundreds of years, will ultimately be taken over by the federal government because they "do not believe that there is any feasible way to assign long-term stewardship responsibility in perpetuity to any private entity, nor would private actors accept such responsibility."[38]

Missing from Figure 7-9 is the need for rules governing the ownership of pore space in the subsurface. Although surface property rights and subsurface mineral rights have been separable for many years in several areas of the United States, there is no clear precedent as to whether pore space rights belong to the surface owner, subsurface mineral rights owner, or neither.[39] Because CO_2 storage may interact with other subsurface activities such as produced water disposal, water recovery, hydrocarbon production, or natural gas storage,[40] resolving the question of who has access to pore space is important to the success of CCS projects.

To date, there are federal regulations governing injection, to a degree, but not other aspects of storage.

On July 25, 2011, the EPA finalized a rule establishing a permitting system for wells used in the geologic storage of CO_2.[41] The Federal Underground Injection Control (UIC) Class VI Program for Carbon Dioxide Geologic Sequestration will allow states and potential owners/operators of wells used in geologic storage to receive a permit from the appropriate EPA regional office. The federal government has primacy over this program until a state applicant submits and has its application approved by the EPA.[42] Thus far only North Dakota has submitted an application for primacy.[43]

The UIC program, however, was established under the Safe Drinking Water Act and, as such, it is aimed at preventing drinking water contamination, not at ensuring long-term storage of CO_2.[44] In addition, the UIC program does not cover injection in offshore formations.[45]

The CCSReg Project, a group of academics and lawyers exploring how to "best…implement an appropriate regulatory environment in the US for the commercialization of carbon capture and deep geological sequestration," has called for federal legislation to accomplish the following:

- Declare that sequestering CO_2 in geologic formations to mitigate the detrimental effects of climate change is in the public interest;
- Address the issue of access to and use of geologic pore space;
- Amend the Safe Drinking Water Act to direct UIC regulators to promulgate rules for geologic sequestration (GS) that:

36 Rodosta, T. D., Litynski, J. T., Plasynski, S. I., Hickman, S., Frailey, S., & Myer, L. (2011). US Department of Energy's Site Screening, Site Selection, and Initial Characterization for Storage of CO_2 in Deep Geological Formations. *Energy Procedia 4,* pp. 4664–4671. Available at: http://www.sciencedirect.com/science/article/pii/S1876610211007065

37 Supra footnote 35.

38 Ibid.

39 Wilson, E., & Klass, A. (2009, April). *Climate Change, Carbon Sequestration, and Property Rights.* University of Illinois Law Review, Vol. 2010, 2010 and Minnesota Legal Studies Research Paper No. 09-15. Available at: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=1371755

40 Ibid.

41 Refer to the Federal Register at: http://www.gpo.gov/fdsys/pkg/FR-2011-09-15/pdf/2011-23662.pdf

42 Ibid.

43 Refer to the Vinson & Elkins law firm website at: http://climatechange.velaw.com/EPAIssuesGuidanceSDWAClassVIPrimacyApplicants.aspx

44 Pollak, M., & Wilson, E. (2009). Regulating Geologic Sequestration in the United States: Early Rules Take Divergent Approaches. *Environmental Science & Technology, 43(9)*, pp. 3035–3041. Available at: http://pubs.acs.org/doi/abs/10.1021/es803094f

45 Supra footnote 35.

  - Address all environmental, health, and safety issues associated with GS;
  - Are principally based on adaptive, performance-based standards, as opposed to design standards; and,
  - Include mechanisms to balance and resolve conflicts between multiple environmental objectives;
- Direct UIC regulators to coordinate with regulators in charge of GHG inventory accounting for the United States;
- Obligate GS project operators to contribute on the basis of their operating performance to a revolving fund to cover long-term stewardship; and
- Create an independent public entity (the Federal Geologic Sequestration Board) to approve and accept responsibility for appropriately closed GS sites.[46]

The CCSReg Project has also issued model legislation to cover these issues, but to date, Congress has taken no action. Meanwhile, several states have stepped in with legislation to address certain aspects of storage and transportation of CO_2.[47]

3. State and Local Implementation Experiences

In support of the proposed 111(b) GHG standards for new power plants, the EPA cited several examples of "currently operating or planned CO_2 capture or storage systems, including, in some cases, components necessary for coal-fired power plant CCS applications."[48] At the time the proposed rule was issued, there were no power plants in the United States or in the rest of the world that integrated commercial-scale CCS, but two carbon capture and EOR projects were under construction. One of them, the Boundary Dam Project in Saskatchewan, came online in October 2014 with an output of 110 MW. The project rebuilt an existing pulverized coal plant and retrofit it with a 90-percent post-combustion capture system at a cost of $1.35 billion.[49] The CO_2 captured at this facility is used in EOR at the Weyburn oil field.[50] The Kemper County IGCC project in Mississippi remains under construction, with commercial operation projected in mid 2016. It would capture approximately 65 percent of total CO_2 emissions and have a nominal output of 583 MW.[51] Kemper County has experienced schedule delays and cost increases that have pushed its in-service date into 2016 and raised the cost of the project to $5.5 billion. Kemper's captured CO_2 will be used for EOR in a Mississippi oil field.[52]

There are several other CO_2-emitting industrial facilities that capture and sequester CO_2 or use it in EOR. The Great Plains Synfuels Plant in North Dakota provides approximately 8700 tons per day of CO_2 for use in EOR at the Weyburn and Midale oil fields in Saskatchewan.[53] Great Plains Synfuels receives $20 per ton for its CO_2 and the project is expected to ultimately result in the storage of 20 million tons of CO_2.[54] The Sleipner gas processing facility in Norway had sequestered more than ten million tons of

46 Carnegie Mellon, Van Ness Feldman Attorneys at Law, Vermont Law School, & University of Minnesota. (2009, July). *Policy Brief: Comprehensive Regulation of Geologic Sequestration.* CCSReg Project. Available at: http://www.ccsreg.org/pdf/ComprehensiveReg_07202009.pdf

47 Refer to the CCSReg Project website at: http://www.ccsreg.org/billtable.php?component=Sequestration and http://www.ccsreg.org/billtable.php?component=Transportation.

48 US EPA. (2014, January 8). *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule,* pp. 1474–1475. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

49 Refer to the SaskPower website at: http://www.saskpowerccs.com/ccs-projects/boundary-dam-carbon-capture-project/carbon-capture-project/.

50 Massachusetts Institute of Technology. (2014, March). *Boundary Dam Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/boundary_dam.html

51 Folger, P. (2014, February). *Carbon Capture and Sequestration: Research, Development, and Demonstration at the US Department of Energy.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R42496.pdf

52 Massachusetts Institute of Technology. (2014, May). *Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/kemper.html

53 Massachusetts Institute of Technology. (2013, December). *Weyburn-Midale Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/weyburn.html

54 Supra footnote 53.

CO_2 as of 2008.[55] Sleipner was designed specifically as a sequestration project in order to avoid paying Norway's carbon tax on CO_2 emissions. A second gas processing facility, In Salah in Algeria, injected about 3.8 million tons of CO_2 into a depleted gas reservoir for seven years before ceasing operations because of concerns about the integrity of the caprock.[56] More recently, an Archer Daniels Midland ethanol plant in Decatur, Illinois captured and sequestered 317,000 tons of CO_2 in its first year of operations.[57] The project is scheduled to continue through September 2015.[58]

In general, efforts in the United States to deploy carbon capture and/or storage are funded, at least in part, by the US Department of Energy (DOE). On the storage side, the DOE's Regional Carbon Sequestration Partnership supported seven regional partnerships pursuing a number of projects intended to ultimately sequester one million tons of CO_2 or more.[59] The Decatur, Illinois project discussed previously is one of these. And the Cranfield project in Mississippi had stored 4.7 million tons of mostly natural,[60] as opposed to anthropogenic, CO_2 by August 2013.[61]

A prominent piece of the DOE's investment in CCS research was the FutureGen project. Originally announced in 2003 and first conceived as an IGCC plant that would capture and sequester at least one million metric tons of CO_2 per year,[62] FutureGen was restructured in 2008 and then postponed because of rising costs.[63] In 2010, former Secretary of Energy Steven Chu announced a new version of the project, FutureGen 2.0, which would use $1 billion of American Recovery and Reinvestment Act money to retrofit an existing pulverized coal plant in Meredosia, Illinois with oxy-combustion capture and sequestration.[64] In February 2015, however, the DOE directed the suspension of FutureGen 2.0 project development activities because the project could not be completed prior to the expiration of American Recovery and Reinvestment Act funding in September 2015.[65]

4. GHG Emissions Reductions

There were more than 550 coal-fired power plants in the United States in 2012.[66] Some of those plants will retire before the proposed initial 111(d) compliance period begins in 2020. However, the majority are likely to still be operating and could be candidates for CCS.

55 Massachusetts Institute of Technology. (2014, January). *Sleipner Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/sleipner.html

56 Massachusetts Institute of Technology. (2014, January). *In Salah Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/in_salah.html

57 Massachusetts Institute of Technology. (2014, May). *Decatur Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/decatur.html

58 Ibid.

59 Supra footnote 11.

60 Southeast Regional Carbon Sequestration Partnership. (2007). *Factsheet for Partnership Field Validation Test: SECARB Phase III Tuscaloosa Formation CO_2 Storage Project.* Available at: http://www.netl.doe.gov/publications/proceedings/07/rcsp/factsheets/3-SECARB_Large%20Scale%20Saline%20Formation%20Demo.pdf

61 Massachusetts Institute of Technology. (2013, December). *Cranfield Fact Sheet: Carbon Dioxide Capture and Storage Project.* Carbon Capture and Sequestration Technologies at MIT, CCS Project Database. Available at: http://sequestration.mit.edu/tools/projects/cranfield.html

62 Government Accountability Office. (2009, February). *Clean Coal: DOE's Decision to Restructure FutureGen Should Be Based on a Comprehensive Analysis of Costs, Benefits, and Risks.* GAO-09-248. Available at: http://www.gao.gov/new.items/d09248.pdf

63 Folger, P. (2014, February). *The FutureGen Carbon Capture and Sequestration Project: A Brief History and Issues for Congress.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R43028.pdf

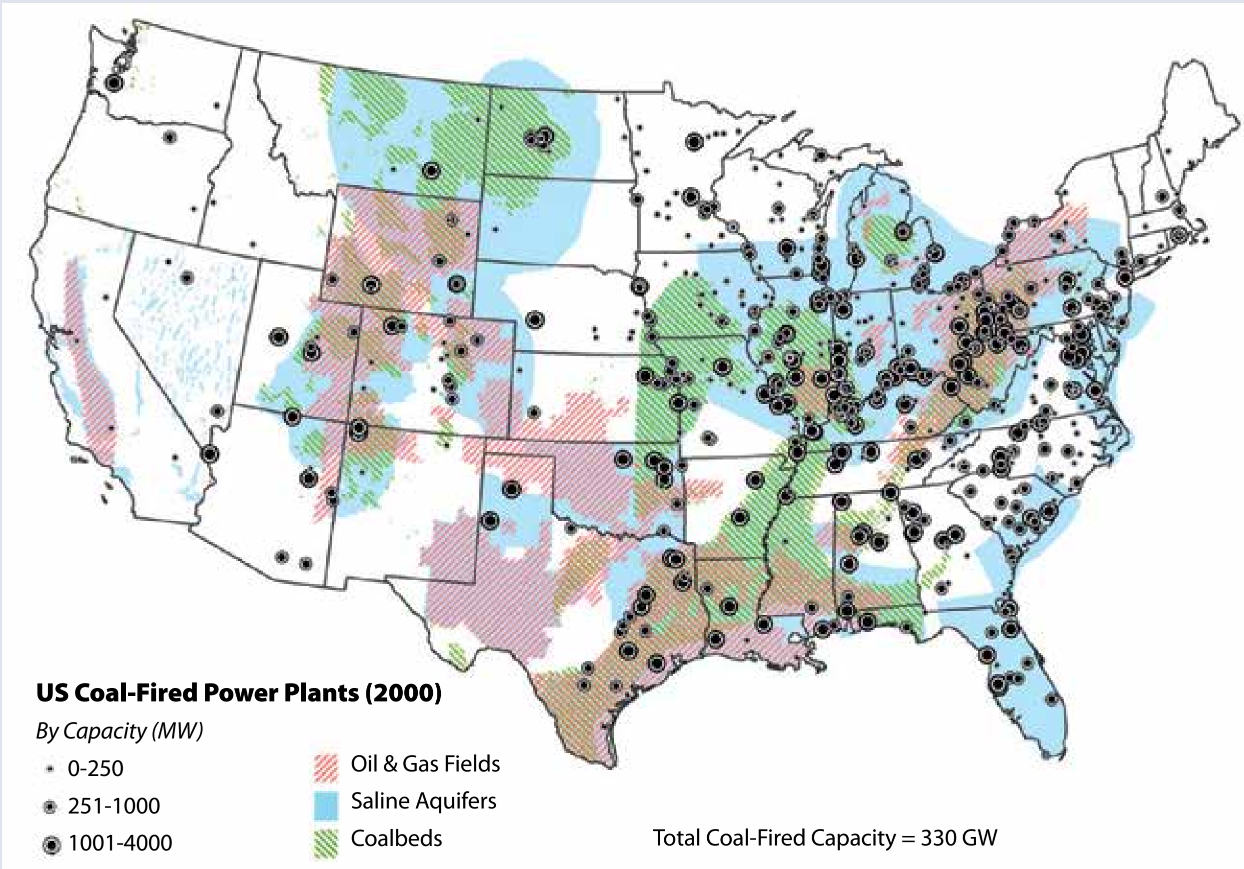
64 Ibid.

65 Daniels, S. (2015, February 3). *FutureGen 'Clean-Coal' Plant is Dead.* Crain's Chicago Business. Available at: http://www.chicagobusiness.com/article/20150203/NEWS11/150209921/futuregen-clean-coal-plant-is-dead

66 Refer to the US Energy Information Administration website at: http://www.eia.gov/electricity/annual/html/epa_04_01.html.

Figure 7-10

Many Coal-Fired Power Plants Overlie Potential Storage Formations[67]



Should large-scale deployment of CCS occur, not all those facilities would be retrofitted, but on the basis of location alone, few can be ruled out as candidates. Figure 7-10 shows the extent to which coal-fired power plants overlie saline aquifers, hydrocarbon reservoirs, and coal seams. This synergy is part of the reason that CCS may have large potential. Note, however, that no pipeline network connecting power plants to potential CO_2 storage formations currently exists. That infrastructure would need to be built in conjunction with any CCS retrofits.

Table 7-1

Potential CO_2 Emissions Reductions per Year From CCS

CO_2 Emissions From Coal-Fired Power Plants in 2012[68] (million metric tons)	Potential Emissions Sequestered With 30% Capture (million metric tons)	Potential Emissions Sequestered With 60% Capture (million metric tons)	Potential Emissions Sequestered With 90% Capture (million metric tons)
1514	454	908	1363

Assuming all existing coal-fired power plants are retrofitted with CCS, the potential scale of sequestered emissions is estimated in Table 7-1.

Using the most recent emissions data from the year 2012, with 30 to 90 percent capture at all coal-fired power plants, a total of 454 to 1363 million metric tons of CO_2 could potentially be sequestered each year. Table 7-1 is akin to a simple technical potential estimate. It does not take into account the cost of sequestering this quantity of CO_2, nor the feasibility of doing so. And some subset of existing

67 Orr, F. (2009). CO_2 Capture and Storage: Are We Ready? *Energy & Environmental Science, 2,* pp. 449–458. Available at: http://pubs.rsc.org/en/Content/ArticleLanding/2009/EE/b822107n#!divAbstract

68 Refer to the US Energy Information Administration website at: http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=11.

coal-fired power plants may simply be unable to retrofit because their sites cannot accommodate the footprint of a CCS system.

5. Co-Benefits

The primary co-benefit of CCS is that it would allow the United States to continue using a fuel (i.e., coal) that provides a large, although declining, share of the country's electricity even as we enter a carbon-constrained world.

There is relatively little information about CCS's other possible co-benefits such as employment and economic impacts. With regard to air emissions, applications of CCS at *new* pulverized coal plants would lower sulfur dioxide emissions as the proportion of carbon captured increases. However, nitrogen oxides, particulate matter, and mercury emissions would increase.[69] We would expect the same to be true of retrofit applications.

The full range of possible co-benefits associated with CCS is summarized in Table 7-2.

6. Costs and Cost-Effectiveness

The US Energy Information Administration (EIA) periodically produces estimates of the overnight capital costs of constructing new power plants with CCS as part of the modeling assumptions that are used in the *Annual Energy Outlook*. In the most recent data set, the EIA estimates that adding CCS to a typical, new, advanced pulverized-coal generating unit would increase the capital costs from $3246/kilowatt (kW) to $5227/kW. For an IGCC unit, the cost increases from $4400/kW to $6599/kW. And for an advanced natural-gas fired combined-cycle unit, the cost doubles from $1023/kW to $2095/kW.[70] The EIA also produces estimates of the levelized cost of energy for those plants. For an IGCC unit, the EIA estimates that CCS adds $31.5/MWh to the levelized cost of energy; for advanced natural-gas fired combined-cycle units, CCS increases costs by $26.9/MWh.[71]

Because of limited implementation experience, there is little information estimating the costs of retrofitting existing power plants with carbon capture. A 2014 presentation by the National Energy Technology Laboratory (NETL) predicted that retrofitting a pulverized coal plant with post-combustion capture would raise its cost of energy from $45 to $124 per MWh (2011$) and

Table 7-2

Types of Co-Benefits Potentially Associated With CCS

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	No
Sulfur Dioxide	Yes
Particulate Matter	No
Mercury	No
Other	No
Water Quantity and Quality Impacts	No
Coal Ash Ponds and Coal Combustion Residuals	No
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	No
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	No
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other:	

69 NETL. (2013, September). *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.* DOE/NETL-2011/1498. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

70 Refer to the EIA website at: http://www.eia.gov/forecasts/capitalcost/.

71 Refer to the EIA website at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm.

cost $72 per ton of CO_2 captured.[72] No further supporting documentation or details for these estimates appears to have been published.

A 2011 analysis published in *Energy Procedia* estimated that the revenue requirement of power plants retrofitted with post-combustion capture and using ammonia as the absorbent would vary between $117 and $148 per MWh.[73] The authors noted that there were limited data from which to develop their estimates and identified 11 key uncertainties that would influence the cost of capture, including the auxiliary steam loads, cooling equipment costs, and CO_2 compression.

In 2007, the Massachusetts Institute of Technology estimated that retrofitting an existing coal plant would cost $1600 per kW and reduce net plant output by at least 40 percent.[74] The authors of this report suggested that it may be more economical to simply rebuild coal plants with more efficient supercritical or ultra-supercritical boilers (the majority of existing plants are subcritical) so as to raise the efficiency of the plant.

Although it did not present any CCS cost estimates in its 111(d) proposed rule, the EPA concluded that "the costs of integrating a retrofit CCS system into an existing facility would be substantial. For example, some existing sources have a limited footprint and may not have the land available to add a CCS system. Moreover, there are a large number of existing fossil-fired EGUs. Accordingly, the overall costs of requiring CCS would be substantial and would affect the nationwide cost and supply of electricity on a national basis."[75]

There is also little information on the cost of oxy-combustion. NETL simply states that oxy-combustion systems are not "affordable at their current level of development" owing to problems with capital cost, parasitic energy demand, and operational challenges.[76] The only power plant proposed to use this technology, FutureGen 2.0, would have had a projected gross output of 168 MW and was originally estimated to cost $1.3 billion, but this estimate rose to $1.65 billion.[77] That project was effectively ended in February 2015 when the DOE suspended its federal funding.

NETL estimated the cost of transporting and storing CO_2 to be anywhere from approximately $10 to $22 per ton of CO_2, depending on factors like capture rate, plant capacity factor, and the total quantity of CO_2 sequestered.[78] However, the Intergovernmental Panel on Climate Change puts the cost of storage alone as high as $30 per ton of CO_2.[79]

7. Other Considerations

Any power plant, new or retrofitted, that captures CO_2 will consume significantly more water than it would otherwise. In water-constrained regions, this additional water consumption may pose a material obstacle to permitting a CCS project. Figure 7-11 shows NETL's theoretical estimates of water consumption at new power plants with and without carbon capture.

At pulverized coal plants, water consumption would likely double. Cooling water duties increase as a result of both

72 Gerdes, K. (2014, January). *NETL Studies on the Economic Feasibility of CO_2 Capture Retrofits for the US Power Plant Fleet.* US Department of Energy. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/NETL-Retrofits-Overview-2014-01-09-rev2.pdf

73 Versteeg, P., & Rubin, E. (2011). Technical and Economic Assessment of Ammonia-Based Post-Combustion CO_2 Capture. *Energy Procedia 4,* pp 1957–1964. Available at: http://www.sciencedirect.com/science/article/pii/S1876610211002736

74 Massachusetts Institute of Technology. (2007). *The Future of Coal: Options for a Carbon-Constrained World.* Available at: http://web.mit.edu/coal/The_Future_of_Coal.pdf

75 US EPA. (2014, June 18). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule,* p. 34876. Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating

76 Refer to the NETL website at: http://www.netl.doe.gov/research/coal/energy-systems/advanced-combustion.

77 Folger, P. (2013, April). *FutureGen: A Brief History and Issues for Congress.* Congressional Research Service Reports. Available at: http://op.bna.com/env.nsf/id/avio-96nmz2/$File/CRS%20report%20FutureGen.pdf

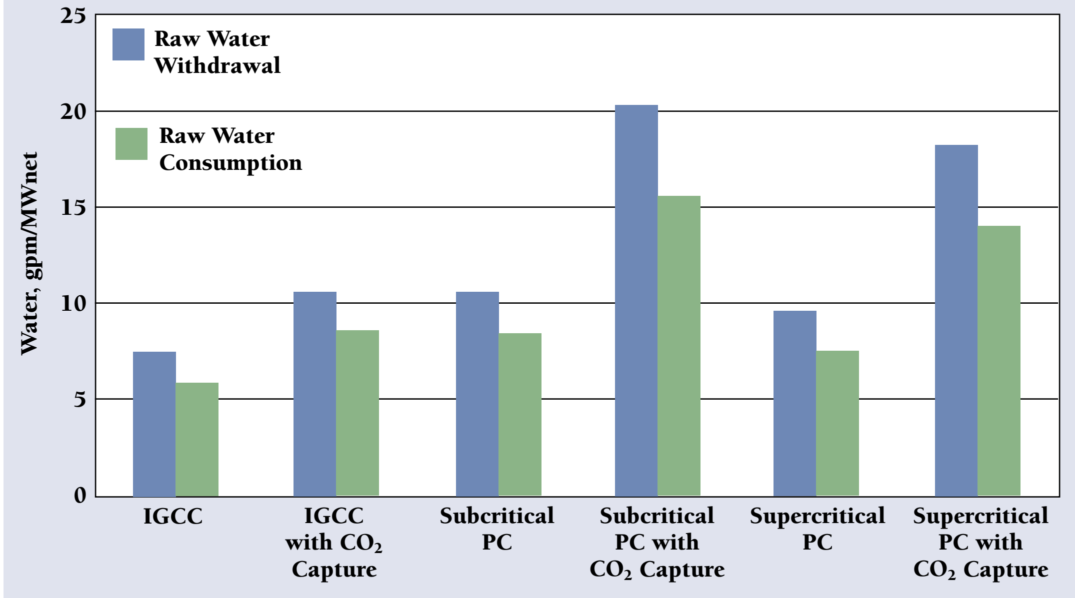
78 Grant, T., Morgan, D., & Gerdes, K. (2013, March). *Carbon Dioxide Transport and Storage Costs in NETL Studies.* NETL. DOE/NETL-2013/1614. Available at: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/QGESS_CO2T-S_Rev2_20130408.pdf

79 Supra footnote 23.

capture and compression. For example, in amine-based post-combustion capture systems, the capture reaction is exothermic, which necessitates cooling to allow the reaction to proceed as efficiently as possible. The process of compressing CO_2 nearly two orders of magnitude from 23 PSI to 2200 PSI creates enough heat to require additional cooling water as well.[81]

Figure 7-11

Estimated Water Consumption at New Power Plants With and Without Carbon Capture[80]

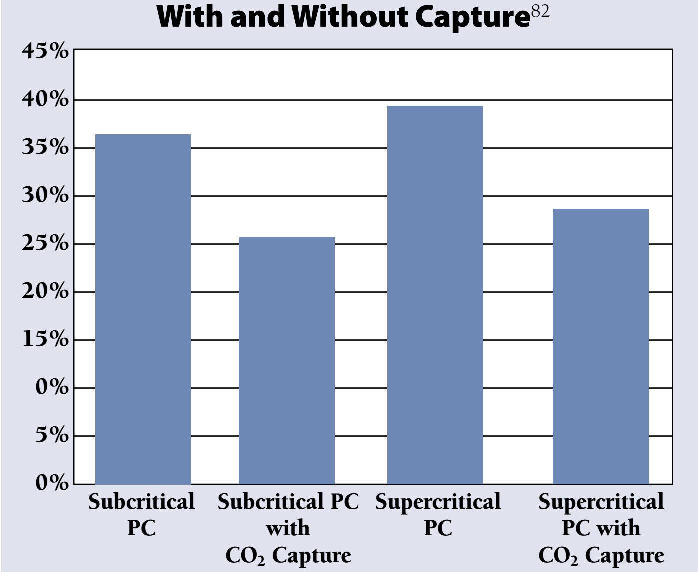


The increase in water consumption is just one of several factors contributing to an increase in auxiliary (a.k.a. "parasitic") power demand. Regenerating the solvent used to capture the CO_2 normally requires part of the plant's steam output and thereby reduces the net power output. Figure 7-12 shows the difference in plant efficiency at new pulverized coal plants with and without capture. Similar data for retrofits of existing power plants are not available owing to the lack of full-scale retrofit projects.

The decline in net plant efficiency can be thought of as a proxy for the decline in plant output, because a decrease in efficiency means that the electric output per unit of energy input has decreased. Retrofits of existing plants would be expected to result in at least the degree of change in efficiency shown for new plants in Figure 7-12 (i.e., approximately a ten-percentage-point decrease in efficiency). The *Future of Coal* study published by the Massachusetts Institute of Technology, citing data from Alstom Power, concluded that retrofitting a subcritical pulverized coal plant would reduce efficiency by about 14 percentage points, which translates to a 41-percent relative reduction in net output.[83] The Global CCS Institute

Figure 7-12

Net Plant Efficiency (High Heating Value) With and Without Capture[82]



80 Based on data from: NETL. (2013, September). *Cost and Performance Baseline for Fossil Energy Plants - Volume 1: Bituminous Coal and Natural Gas to Electricity.* US Department of Energy. DOE/NETL-2010/1397. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf

81 NETL. (2013, September). *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture.* US Department of Energy. DOE/NETL-2011/1498. Available at: http://netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf

82 Supra footnote 80.

83 Supra footnote 74.

offers a somewhat more optimistic assessment, estimating a parasitic load of 20 to 30 percent for post-combustion CO_2 capture and compression technologies, with net plant efficiency dropping from 38 to 27 percent.[84] The practical implication for existing plant retrofits is that this reduction in power output may have to be made up by other sources of power. This indirect cost and the possible CO_2 emissions from these other sources of power are rarely accounted for in estimates of CCS costs and benefits.

If CCS is to be used as an essential strategy for complying with mandatory CO_2 emissions regulations, some issues surrounding the coordination of ordinary power plant operations with CO_2 compression, transportation, and storage operations are likely to arise and will need to be resolved. If, for instance, the pipeline is unavailable for some reason, the plant operator would have to decide whether to vent the CO_2, shut down the plant, or find some way to store the CO_2. Some research has been done into storing CO_2-rich solvent in such situations.[85] These strategies could also be used during times of peak demand when it would be preferable to have the plant's full output.

Although many reports, including this one, may seem to blur the line, it should be emphasized that there is a difference between CO_2-EOR and carbon storage – one seeks to improve oil production and the other to sequester CO_2. A CO_2-EOR project can eventually transition to a carbon storage project,[86] but in the interim, some but not all of the CO_2 injected for EOR will be sequestered. Therefore, tons of carbon captured for the purpose of CO_2-EOR do not yield the same tons of CO_2 sequestered.

Because CO_2-EOR increases the production of oil, there may also be implications for the carbon benefit attributed to EOR-focused CCS projects. The ultimate fate of that recovered oil is combustion in some form, which in turn creates its own CO_2 emissions. Therefore, from a lifecycle perspective, the total sequestration benefit of CO_2-EOR is certainly less than the total mass of CO_2 sequestered. Indeed, a 2009 analysis of five CO_2-EOR sites found that all were net *positive* emitters of CO_2 after accounting for the combustion of the recovered oil.[87] Regulation of GHG emissions either across the entire economy or from a lifecycle perspective would account for this impact.

Economy-wide regulation of GHG could also have negative implications for the economics of CO_2-EOR projects. Although operators of EOR projects currently pay for CO_2, in a world with a price on each ton of CO_2 emitted regardless of its source, it is not clear that the EOR market would continue to *pay* for CO_2. It could be that CO_2-emitting facilities would have to compensate EOR operators for taking their CO_2 instead of receiving revenue for it. Such a shift in the EOR market could dramatically change the economics of capture projects relying on an EOR revenue stream.

Public acceptance of CCS may also play a role in its success or failure. For example, to the extent that the public perceives hydraulic fracturing (or "fracking") for oil and natural gas as the same or similar to CCS because it involves underground fluid injection, there could be a strong, negative reaction to CCS projects.[88]

84 Global CCS Institute. (2012, January). *CO_2 Capture Technologies: Post Combustion Capture (PCC)*. Available at: http://www.globalccsinstitute.com/publications/co2-capture-technologies-post-combustion-capture-pcc

85 Chalmers, H., Lucquiaud, M., Gibbins, J., & Leach, M. (2009). Flexible Operation of Coal Fired Power Plants With Postcombustion Capture of Carbon Dioxide. *Journal of Environmental Engineering, 135,* Special Issue: Recent Developments in CO_2 Emission Control Technology, 449–458. Available at: http://ascelibrary.org/doi/abs/10.1061/%28ASCE%29EE.1943-7870.0000007

86 Whittaker, S. (2010, October). *IEA GHG Weyburn-Midale CO_2 Storage & Monitoring Project*. Regional Carbon Sequestration Partnerships Annual Review. Available at: http://www.netl.doe.gov/publications/proceedings/10/rcsp/presentations/Tues%20am/Karen%20Cohen/Whittaker.%20WMP_Regional%20Partnership.pdf

87 Jaramillo, P., Griffin, W., & McCoy, S. (2009). Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System. *Environmental Science & Technology, 43,* pp. 8027–8032. Available at: http://www.ncbi.nlm.nih.gov/pubmed/19924918

88 Supra footnote 51.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on CCS.

- Metz, B., Davidson, O., de Coninck, H., Loos, M., & Meyer, L., eds. (2005). *Carbon Dioxide Capture and Storage*. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge, United Kingdom: Cambridge University Press. Available at: http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf
- Folger, P. (2013, November). *Carbon Capture: A Technology Assessment.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/R41325.pdf
- Parfomak, P. (2008, July). *Community Acceptance of Carbon Capture and Sequestration Infrastructure: Siting Challenges.* Congressional Research Service Reports. Available at: http://fas.org/sgp/crs/misc/RL34601.pdf

9. Summary

CCS offers the potential to prevent the emissions of millions of tons of CO_2 from fossil-fuel fired power plants into the atmosphere. The extent to which that potential is leveraged will be determined by our ability to overcome the technical and economic hurdles that confront this technology. Carbon capture is costly and has significant auxiliary power demands. Carbon storage may be hindered by the absence of a robust legal framework under which it can be implemented and requires further research into its functionality. It remains to be seen whether federal action – including the New Source Performance Standards for GHG emissions from utility boilers and IGCC plants and the DOE's research and development efforts in CCS – will spur sufficient interest and investment to make it a commercial technology.

Chapter 8. Retire Aging Power Plants

1. Profile

Retiring aging fossil-fired electric generating units (EGUs) can produce significant reductions in greenhouse gas (GHG) emissions. This is particularly true when the EGUs in question are existing coal-fired units, because their carbon dioxide (CO_2) emissions are typically double those of natural gas combined-cycle EGUs. Most of the EGUs currently slated for retirement are coal-fired units, resulting from greater fuel price competition with natural gas, higher operating costs, and new environmental regulations such as the US Environmental Protection Agency's (EPA) recent Mercury and Air Toxics Standards (MATS). The EPA has identified 233 coal-fired, non-cogeneration EGUs which, based on recent announcements, have retired or are expected to do so before 2016.[1]

Although retiring aging coal-fired EGUs is becoming more and more prevalent, these decisions remain a sensitive topic. Despite the likely environmental benefits, retiring an aging EGU has the potential to produce profound economic consequences for utility ratepayers, companies, and the community where the unit is located. Paying for a unit to retire can be expensive and disruptive. However, when weighed against various policy alternatives, retiring an aging EGU may be a lower-cost solution to the challenge of emissions reductions and worthy of inclusion in a state's Clean Air Act compliance plans.

There are numerous factors that can affect a plant owner's or regulator's decision to continue operating an aging EGU or to retire it. These include forward-looking market factors and environmental regulatory requirements. The ability to recover past plant-related investments will also heavily influence the decision. States that consider EGU retirement as a compliance option will have to consider these issues, and the varying degrees to which these factors support such a decision. Consideration of these same issues has led many plant owners and regulators to require aging EGUs to be repowered (to utilize a lower-emitting fuel) instead of retired – a policy option reviewed in detail in Chapter 9. Along these lines, some observers have recommended (but not yet implemented) the idea that retirement deliberations be institutionalized through the adoption of a "birthday provision" whereby EGUs would automatically become subject to new source emissions standards upon expiration of their originally defined useful lifetime.

Although the EPA's Clean Power Plan proposal of June 2014 nowhere mandates EGU retirements, given the flexibility that the proposal would provide states, this option — with its related benefits and challenges — constitutes a potential compliance pathway worthy of state consideration.

2. Regulatory Backdrop

Most EGU retirement decisions begin with a decision by the owner of the EGU that it makes sense to retire the unit. There are also limited examples of decisions that are initiated by other decision-makers and imposed on EGU owners.

The market and regulatory context in which an EGU operates provides an additional backdrop and regulatory context for retirement decisions. In most cases, the owner of the EGU will need additional approvals before it can actually retire the unit. To understand these approvals it is helpful to review some of the terminology used to describe

1 The EPA reports that its "research found 233 coal-fired, non-cogeneration EGUs that have announced they will retire before 2016." US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. p. 235, note 29 citing to Integrated Planning Model documentation includes a list of the announced retirements. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf. See Table 4-36 of Integrated Planning Model Documentation: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_4.pdf

EGU ownership and energy markets.

EGUs can be owned by "vertically integrated" utilities that own electric generation assets and an electric distribution system, and sell energy to retail customers within their retail monopoly jurisdiction. Large EGUs may be jointly owned by more than one party. Vertically integrated utilities can be investor-owned, publicly owned, or member-owned cooperatives. States vary in terms of whether and how each type of utility is regulated by the state public utility commission (PUC), with the common thread being that investor-owned utilities are regulated by PUCs everywhere. EGUs can also be owned by non-utility "independent power producers," also known as "merchant generators."

In some parts of the country, the electric power sector has been "restructured." Utilities in those areas were required to divest their ownership of EGUs. Although distribution utilities continue to exist in those areas, they only have a monopoly with respect to the distribution system. All EGUs in those areas are owned by merchants and the wholesale sale of electricity is a competitive market.

Today there are a variety of energy market structures in place around the United States. "Traditionally regulated" markets persist in many jurisdictions (principally in the West and the South). In those areas, most EGUs are owned and controlled by vertically integrated utilities, but some merchant generators own EGUs and sell energy to utilities through bilateral contracts. EGU dispatch decisions are made in those areas by the utility based on the needs of its customers. In other areas, competitive wholesale electricity markets have been created, in most cases spanning across state lines. Within those competitive wholesale markets, EGUs may be owned by vertically integrated utilities or by merchant generators, but decisions about which EGUs operate (and at what level of output) are made by an independent system operator (ISO) or regional transmission organization (RTO) based on system-wide customer needs and competitive bids made by EGU owners.

Returning to the issue of EGU retirements, in different jurisdictions retirements occur as a result of unit owner decisions, decisions from ISOs with organized wholesale markets that permit units to be "de-listed," and rulings from state regulatory commissions in "abandonment" proposals, planning dockets, or special accounting or rate-treatment processes.

Unit Owner Decisions

EGU owners make decisions to retire plants for various economic and other reasons explained in greater detail later in this chapter. In restructured jurisdictions, EGUs are owned by merchants, and retirement and cost considerations are not likely to be subject to PUC review. However, in jurisdictions with organized wholesale markets, those EGU owners' retirement decisions must be reviewed by the ISO or RTO as explained below. In traditionally regulated jurisdictions, EGU owners' retirement decisions must be reviewed and approved by state regulatory commissions except in cases in which the PUC has no regulatory authority (as is sometimes the case for publicly owned utilities and cooperatives and normally the case for merchant generators). These processes are described in more detail below.

ISO/RTO Decisions

In organized wholesale markets like the PJM Interconnection (PJM) or Midcontinent Independent System Operator RTOs, electric generation is made available through resource auctions and the establishment of a dispatch order for EGUs based on economic merit (see Chapter 21 for a more comprehensive discussion of dispatch order). For example, in the New England ISO's energy markets,[2] in order to participate an EGU owner needs to submit a bid reflecting the amount of energy that the generator can provide and the price, and that bid must clear through the auction. If the bid is successful (i.e., the unit owner has a position and a price), that EGU must deliver generation for the specific time and

2 Power plants that participate in organized markets are paid for both the energy they produce and for the generation capacity that they agree to provide. Electric energy is produced and sold daily at wholesale and then resold to end-use consumers. Capacity is typically sold over longer time periods in an attempt to ensure that generation resources will be available in the future and that there is enough time to build them. In PJM, for example, there is an annual auction for power delivery three years in the future. There are also other smaller capacity markets where, within that three-year time frame, power can be sold to ensure that precisely the right amount will be available when it is needed. For further discussion of capacity markets, see Chapter 19. For a more complete discussion of this topic, also see, e.g.: James, A. (2013, June 17). *Explainer: How Capacity Markets Work.* MidWest Energy News. Available at: http://www.midwestenergynews.com/2013/06/17/explainer-how-capacity-markets-work/

in the amount of capacity it bid. If it fails to do so, it could face a penalty, and would certainly forego any revenue for the electricity it failed to deliver. Additional details regarding capacity markets and dispatch are also provided in Chapters 19 and 21.

In this context, retirement involves removing an EGU from current or future auctions, a process called "de-listing." In the New England ISO's forward capacity market, existing resources are able to leave the market by submitting a "de-list" bid.[3] All de-list bids are subject to a reliability review by the ISO. If the ISO concludes that the unit submitting the de-list bid is needed for reliability purposes, the bid is rejected and the resource is retained.[4] Other RTOs and ISOs possess similar ability to deny EGU retirements that would jeopardize system reliability.[5]

Decisions in Traditionally Regulated Markets

Retirement of EGUs works differently in traditionally regulated or vertically integrated markets; there, EGU owners are relatively free to retire a unit if they wish. Owners make such decisions subject to reliability demands and to any additional constraints that might be included in a generator's permission to operate, that is, a "certificate of public convenience and necessity" or "certificate of public good" granted by a state commission where the generator is located.

For example, Public Service Company of Colorado, as part of its decision-making under Colorado's "Clean Air – Clean Jobs Act,"[6] relied on its own dispatch models and reviewed options across its system to "take action" (i.e., to retire, control, or fuel-switch a unit to natural gas). Companies in traditionally regulated markets have responsibility for capacity and are required to demonstrate that they can meet this responsibility, but generally speaking there is no affirmative obligation to offer any particular EGU for service.

Decisions by State Regulatory Commissions

When an EGU retirement proposal comes before state regulatory commissions, it is likely to do so in one of the following contexts: "abandonment" proposals or relinquishment of certificates of public convenience and necessity; planning dockets; or special accounting or rate-treatment processes. The value of being able to review retirement proposals is that it provides an opportunity to require a utility to produce a thorough analysis of the potential costs of the proposal and reasonable alternatives, and to subject that analysis to public scrutiny through an administrative proceeding. These processes are briefly described below.

Relinquishment of Certificate of Public Convenience and Necessity

EGUs need regulatory permission to go into service, and they are typically issued a certificate to do so by state utility commissions. These certifications are granted after a commission's public review of the suitability of a proposal, including financial, legal, engineering, and other relevant considerations.

Companies need permission to take EGUs out of service as well, as illustrated below in Vermont's statutory requirements:

> *A company subject to the general supervision of the public service board … may not abandon or curtail any service subject to the jurisdiction of the board or abandon all or any part of its facilities if it would in doing so effect the abandonment, curtailment or impairment of the service, without first obtaining approval of the public service board, after notice and opportunity for hearing, and upon finding by the board that the abandonment or curtailment is consistent with the public interest….*[7]

As the statute indicates, this regulatory review is intended to examine whether or not abandoning an EGU will affect the company's service, specifically calling out

3 ISO New England, Inc. (2012, May 15). *Overview of New England's Wholesale Electricity Markets and Market Oversight*. Internal Market Monitor, pp. 7–8. Available at: http://iso-ne.com/pubs/spcl_rpts/2012/markets_overview_final_051512.pdf

4 See ISO New England Inc. 5th Rev. Sheet No. 7308, FERC Electric Tariff No. 3, Section III – Market Rule 1 – Standard Market Design Tariff at Section III.13.2.5.2.5: "The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules."

5 In each ISO market, there are also rules (tariffs) that specify how an EGU owner whose de-listing request has been denied will be "made whole" through wholesale market compensation for costs that exceed revenues.

6 A process that was ultimately reviewed and approved by the state utility commission and environmental agency.

7 30 V.S.A. § 231(b). *Certificate of Public Good; Abandonment of Service; Hearing.*

"impairment of service" (i.e., reliability) as a criterion. In an abandonment proceeding, a utility has to demonstrate why its proposal to retire an EGU is in the public interest. It is also an opportunity for the utility commission to provide the public its reasons for granting or denying its approval.

Planning

Utility planning, also referred to as integrated resource planning (IRP), is another context in which a state might review a proposal to retire an EGU.[8] An IRP docket is a public process designed to look broadly at a utility's needs over a certain time period, and to identify the least-cost means of meeting those needs. More specifically, an IRP investigation is a review of various supply- and demand-side options, potential utility plans, and a schedule to monitor and revisit plans as necessary. PacifiCorp, for example, describes its IRP as a:

> *Comprehensive decision support tool and road map for meeting the company's objective of providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business.*[9]

The value in having this structured and comprehensive look forward lies in being able to identify a resource mix before capital is committed to expenditures. This is the case in a traditionally regulated environment in which a utility will seek approval of expenditures. It is also the case in restructured states, where some decisions – transmission expansions, for example – can be shaped or targeted to reflect least-cost, least-risk options.

In the context of EGU retirements, it is also valuable to identify alternatives that avoid raising electric system reliability problems.[10] An IRP's typical "least-cost" criterion implies "the lowest total cost over the planning horizon, given the risks faced" – including reliability. The best resource mix is one that "remains cost-effective across a wide range of futures and sensitivity cases that also minimize the adverse environmental consequences associated with its execution."[11] Planning for EGU retirement is thus an extensive examination of related costs, and costs associated with alternatives. Additional details regarding IRP are provided in Chapter 22.

Tariff Riders and Preapproval

Some state laws provide for the recovery of costs associated with environmental compliance. Given the flexibility granted states by the EPA's proposed Clean Power Plan, an argument could be made that costs related to EGU retirement fit in the category of recoverable costs.

An adjustment clause (also sometimes referred to as a "cost tracker" or "tariff rider") is a separate surcharge (or sur-credit) to incorporate specific costs in rates, independent of overall utility costs and rates established in a general rate case.[12] Utilities in some jurisdictions also enjoy preapproval of expenditures related to environmental compliance.[13] In these cases, utility regulators generally review the proposed plan and the associated budget, and allow cost recovery (barring imprudence in implementing an approved plan[14]). Preapproval is not an uncommon practice and, once obtained, makes cost recovery by the

8 See Chapter 22 for a comprehensive discussion of IRP.

9 PacifiCorp. Integrated Resource Plan website, Overview. Available at: http://www.pacificorp.com/es/irp.html. See also: Lazar, J. (2011, March). *Electricity Regulation in the US: A Guide,* p. 73. Available at: http://www.raponline.org/document/download/id/645, and Farnsworth, D. (2011). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance,* pp. 20–38, for a more detailed discussion of integrated planning. Available at: www.raponline.org/document/download/id/919

10 US EPA. (2014, June). *Technical Support Document (TSD): Resource Adequacy and Reliability Analysis.* Office of Air and Radiation. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf. The EPA defines the term "resource adequacy" to mean "the provision of adequate generating resources to meet projected load and generating reserve requirements." It defines "reliability" as ensuring the "ability to deliver the resources to the loads, such that the overall power grid remains stable." Reliability Standards for the Bulk Electric Systems of North America, updated December 16, 2014. Available at: http://www.nerc.com/pa/Stand/Reliability%20Standards%20Complete%20Set/RSCompleteSet.pdf

11 Lazar, at supra footnote 9.

12 For a general discussion of adjustment mechanisms, see: Ibid.

13 See discussion of Alabama Power below at footnotes 87–88 and accompanying text.

14 An inquiry into the "prudence" of a decision might focus on such things as failure to consider factors known to management in the original proposal, failure to effectively manage a retrofit process, or failure to reconsider the project as additional cost information becomes available.

utility highly likely.[15] Under Ohio law, for example, an automatic recovery rider allows for utilities to recover the costs of environmental compliance, including "the cost of emission allowances; and the cost of federally mandated carbon or energy taxes…" and a "reasonable allowance for construction work in progress … for an environmental expenditure for any electric generating facility of the electric distribution utility."[16] Regulators need to assess the circumstances and financial impacts of EGU retirements claimed as recoverable costs, especially where preapproval provisions exist.

State 111(d) Compliance Plans

The EPA's Clean Power Plan, proposed in June 2014, would impose a requirement on states to develop a plan for reducing the average CO_2 emissions rate of affected EGUs to specified levels (or "goals") by 2030. The EPA would not require states to include EGU retirements in their plans, but states would have the option to do so. If an EGU has a higher-than-average emissions rate, and the output of the EGU can be replaced with the output from an EGU not affected by the rule or by an affected EGU that has a lower CO_2 emissions rate, the average emissions rate of affected EGUs will decline and the state will be closer to compliance with its emissions goal. This fact, combined with the fact that it is relatively easy to administer and enforce a retirement decision (compared, for example, to other emissions reduction options), may make EGU retirements an option of interest to state air pollution regulators even in the face of the economic complexities that factor into these decisions.

3. State and Local Implementation Experiences

As noted previously, various administrative approaches provide utility regulators with frameworks to analyze potential costs and other relevant factors (such as reliability implications) associated with retirement proposals. The examples below – reflecting both restructured and traditionally regulated states – show that the exact process states use to analyze proposals may be less important than the willingness to take an integrated approach and thoroughly consider alternatives.

In 2011 the state of Colorado, a traditionally regulated state, used a process similar to IRP in implementing 2010 legislation that proposed, among other things, EGU retirements. The "Clean Air – Clean Jobs Act" (the Act) passed in April 2010 anticipated new EPA regulations for criteria air pollutants (nitrogen oxide [NO_X], sulfur dioxide [SO_2], and particulates), mercury, and CO_2.[17] It required:

> *[b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/ Colorado Electric Utility Company LP … to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units.*[18]

The two Colorado utilities developed these required plans and gained the approval of the PUC and state air regulators on an extraordinarily rapid schedule. Their approved plans were then included in a state implementation plan (SIP) submitted by the state to the EPA. As a result, two coal-fired power units totaling more than 210 megawatts (MW) have been retired and repowered, and three additional units are expected to be retired and repowered by 2017. Formal IRP implementation is typically an ongoing, multiyear process; this effort, from signed legislation to EPA approval of

15 Although some states allow for preapproval as a matter of law or administrative practice, others insist that decision-making is a management responsibility and will only review the actions of management when an investment is completed and goes into service. Utility regulators reach their own conclusion on this issue, guided by state law and regulatory precedent.

16 Ohio Revised Code, Section 4928.143(B) (2) (a) and (b).

17 In addition to anticipating new EPA regulations for criteria air pollutants including CO_2, it requires a utility to (1) consult with the Colorado Department of Public Health and Environment on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (2) submit a coordinated multipollutant plan to the state PUC.

18 Memorandum from the Office of Legislative Legal Services to Legislative Counsel, March 16, 2011, re: H.B. 10-1365 and Regional Haze State Implementation Plan. Available at: http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf

Colorado's SIP changes, took approximately 30 months.[19]

It is often the case that a proposal to retire a power plant can itself change over the course of the proposal's review, as was the case with Nevada's Mohave Generating Station and Oregon's Boardman Plant. In some cases, the proposal to close can be amended and become a proposal to repower.

In 1999, the owners[20] of the Mohave Generating Station – a two-unit, 1580-MW coal-fired power plant built between 1967 and 1971 – executed a consent decree to either install SO_2 controls or close the plant by 2005.[21] In 2003, Southern California Edison approached the California PUC for approval of preliminary engineering costs for a retrofit.[22] After an extended hearing, the California PUC ordered a comprehensive review of the future of the Mohave project.[23] The Mohave Alternatives and Complements Study was completed in 2005. It examined alternatives to a retrofit of Mohave, found a wide variety of cost-effective options, and at the conclusion of the study, the Mohave plant was closed permanently on December 31, 2005.[24]

Oregon's 550-MW coal-fired Boardman plant was originally expected to operate until 2040. However, to comply with state and federal environmental regulations, in 2010 Boardman was required to install approximately $500 million of pollution control equipment by 2017. In early 2010, owner Portland General Electric (PGE) announced that it was considering an alternative plan for Boardman that would retire the plant in 2020. PGE asked regulators to allow it to make a $45 million investment by 2011 to partially clean up Boardman's emissions of mercury and NO_X, and then operate the plant until 2020.[25] In June 2010, Oregon's Environmental Quality Commission rejected PGE's proposal to close Boardman by 2020, stating that Oregon's Environmental Quality Commission did not oppose early shutdown of the plant, but only wanted to do so using the best options possible.[26] PGE proceeded to look at other ways to close the plant by 2020, including alternative levels of investment in controls and different closure dates. The company concluded that earlier closure than 2020 was not an option because that time was needed to develop alternatives for the power produced. Later in 2010, PGE filed its Integrated Resource Plan with the Oregon PUC, stating that the 2020 shutdown was its preferred option.[27] On the basis of its IRP analysis, PGE ultimately proposed termination of coal use at Boardman at the earliest date that the utility felt resulted in adequate reliability for its customers: 2020. After reviewing various alternatives, the Oregon PUC acknowledged this approach in its order on

19 The Act was signed into law in April 2010, a Commission docket was opened in May, and a final order was issued in December. In January 2011 the Colorado Department of Public Health and Environment adopted changes and the EPA approved the new Colorado SIP in September the following year. NARUC Climate Policy Webinar 3: State Case Studies. (2010, December 17). *Dispatches from the Front: The Colorado Clean Air-Clean Jobs Act.* Ron Binz, Chairman, Colorado Public Utilities Commission. Available at: http://www.naruc.org/Publications/Binz%20TFCP%20Presentation%20121710.pdf; NARUC Task Force on Climate Policy Webinar. (2011, March 11). *Coal Fleet Resource Planning: How States Can Analyze their Generation Fleet.* Colorado Case Study. Karen T. Hyde, Vice President, Rates & Regulatory Affairs, & Jim Hill, Director, Resource Planning and Bidding; Xcel Energy. Available at: http://www.naruc.org/domestic/epa-rulemaking/default.cfm?more=3

20 Southern California Edison was the majority owner (56 percent) of the plant. The Los Angeles Department of Water and Power (10 percent), Nevada Power Company (14 percent), and Salt River Project (20 percent) were the other owners.

21 Grand Canyon Trust, the Sierra Club, and National Parks Conservation Association sued the owners of Mohave because of haze over the Grand Canyon and other air pollution that was caused by the plant.

22 Study of Potential Mohave Alternative/Complementary Generation Resources Pursuant to CPUC Decision 04-12016 Report Prepared for Southern California Edison SL-008587. (2006, February).

23 The California Public Utilities Commission ordered Southern California Edison to perform for them a study of alternatives for replacement or complement of its share of the Mohave Generating Station under Decision 04-12-016, issued on December 4, 2004.

24 Edwards, J. (2009, June 6). Laughlin Coal-Fired Power Plant Going Away. *Las Vegas Review-Journal*. Available at: http://www.reviewjournal.com/business/laughlin-coal-fired-power-plant-going-away

25 PGE was also considering using biomass to continue operating the plant after ending its use of coal.

26 Sickinger, T. (2010, June 28). DEQ Proposes New Options for Shutdown of PGE Coal Plant. *The Oregonian.*

27 During the pendency of the IRP process, the plant owners made additional investments that the Oregon PUC considered in its final decision.

PGE's IRP.

In jurisdictions that have restructured their utility sector, generation is considered a competitive service that is no longer subject to regulatory review or treatment. When Ohio restructured, for example, generators were given a choice to continue to be traditionally regulated by the PUC or to participate in a largely deregulated wholesale market. In 2010, Ohio Power sought approval for a rate adder in order to recover an unamortized plant balance of $58.7 million on its retiring 450-MW Sporn Unit 5, under the same statute that provided an automatic recovery rider for traditionally regulated facilities.[28] The Sporn Plant, however, had chosen to operate in the deregulated market, so the PUC denied its request for cost recovery for closure-related costs.

In many cases, EGU retirements are tied to approval of proposals to convert and repower them with another fuel.[29] Indianapolis Power & Light Company (IPL), for example, conducted an integrated analysis ahead of its proposal to the Indiana Utility Regulatory Commission to repower Harding Street Generation Station Unit 7 from coal to natural gas as part of the company's "overall wastewater compliance plan for its power plants."[30] The Commission had already approved IPL's proposal to convert Harding Street Units 5 and 6 from coal to natural gas. Unit 7's conversion would conclude the closing of all of IPL's coal units at Harding Street by 2016, a move that the company says, "would reduce IPL's dependence on coal from 79 percent in 2007 to 44 percent in 2017…."[31] This plan was motivated not only by IPL's need to comply with Clean Water Act requirements; these closures will enable IPL to close Harding Street Generation Station's coal pile and ash ponds, which are subject to Resource Conservation and Recovery Act (RCRA) solid waste rules.

4. GHG Emissions Reductions

EGU retirements that occur in response to GHG regulations have the potential to avoid significant amounts of GHG emissions. The retirement of coal, oil, or inefficient natural gas capacity will not only reduce GHG emissions, but also emissions of other regulated air pollutants, depending on the fuels burned at a retiring EGU.

CO_2, methane, and nitrous oxide emissions are all produced during coal combustion; nearly all of the fuel carbon (99 percent) in coal is converted to CO_2 during the combustion process.[32] This conversion is relatively independent of firing configuration.[33] Consequently, the level of avoided emissions available from a coal plant retirement will vary only slightly, depending on the operating characteristics of each unit, but more so based on the type of coal normally used at the plant. CO_2 emissions for coal are linked to carbon content, which varies between the classes of bituminous and subbituminous coals. As a consequence, there is a significant range in emissions factors within and between ranks of coal (Table 8-1).

Table 8-1

Average Input Emissions Factors of Coal[34]

Coal Type	Input Emissions Factor (lb CO_2/MMBTU)
Coal – Anthracite	227
Petroleum Coke	225
Coal – Lignite	212 to 221
Coal – Subbituminous	207 to 214
Coal – Bituminous	201 to 212

28 In the Matter of the Application of Ohio Power Company for Approval of the Shutdown of Unit 5 of the Philip Sporn Generating Station and to Establish a Plant Shutdown Rider, Case No. 10-1454-EL-RDR, Finding and Order at 19. (2012, January 11). Ohio Revised Code, Section 4928.143(B) (2) (a) and (b).

29 Repowering of existing EGUs is examined in Chapter 9.

30 IPL Power. (2014, August 15) IPL plans to stop burning coal at Harding Street Generation Station in 2016; Utility to seek approval to switch power generation from coal to natural gas. [Press release]. Available at: http://www.indianadg.net/ipl-announces-plans-at-harding-street-plant-to-switch-from-coal-to-natural-gas-in-2016/

31 Ibid.

32 AP 42, Fifth Edition, Volume I, Chapter 1: External Combustion Sources, 1.1 Bituminous And Subbituminous Coal Combustion. Available at: http://www.epa.gov/ttn/chief/ap42/ch01/index.html

33 Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced.

34 Based on: US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf

The majority of the fuel carbon not converted to CO_2 is entrained in bottom ash. Furthermore, carbon content also varies within each class of coal based on the geographical location of the mine. Methane emissions also vary with the type of coal being fired and the firing configuration, but are highest during periods of incomplete combustion, such as the start-up or shut-down cycle for coal-fired boilers.

Several utilities and operators of coal-fired power plants have already announced retirements. In late 2013, the Tennessee Valley Authority announced the retirement of eight coal-fired units totaling 3000 MW of capacity at three different plant sites.[35] These eight units include:

- All five coal-fired units in its Colbert, Alabama plant location, representing CO_2 emissions of 6.5 million tons in 2010;
- Unit 8 at Widow's Creek, Alabama, with 2010 CO_2 emissions of 3.3 million tons; and
- The smaller two of three units at Paradise, Kentucky with combined 2010 CO_2 emissions of 8.9 million tons.[36]

South Carolina Electric and Gas announced the closure of its 295-MW unit at Canadys station in November 2013,[37] completing the retirements of all units at this plant. The other two units at Canadys were closed by South Carolina Electric and Gas in 2012. In 2010, combined CO_2 emissions from these three units totaled 14 million tons.

Coal plant retirements have also been announced in restructured electricity markets. Energy Capital Partners, operators of the Brayton Point plant in Massachusetts, announced plans to close Units 1–3 of this plant when its supply agreements with ISO New England expire in May 2016.[38] In 2010, CO_2 emissions from Units 1–3 were 6.3 million tons.

SourceWatch, a project of the Center for Media and Democracy, has prepared an assessment of expected coal EGU retirements by size and year, starting with 2009 as the first year.[39] The list of planned retirements is constantly changing, which means that any assessment of the total capacity of expected retirements soon becomes outdated. For example, the Government Accountability Office (GAO) estimated in August 2014 that more than 42 gigawatts (GW) of coal capacity had either been retired since 2012 or was planned for retirement by 2025. This estimate in 2014 exceeded the high end of the range of expected retirements cited by GAO in a similar 2012 report.[40]

As for the aggregated impact of EGU retirements on CO_2 emissions, it must first be understood that EGUs vary in their output and their emissions from year to year. It is easy to assess the historical CO_2 emissions of a retiring unit in a particular baseline year, as the previous examples demonstrate. However, such estimates tend to vary in their selection of baseline year and in any event become quickly out of date. Although the number of units and the aggregated capacity of expected retirements is large, the units that have thus far retired or announced plans to retire tend to mostly be smaller EGUs or EGUs that operate less frequently. The largest, most frequently operated coal EGUs produce the lion's share of coal-fired generation, and few of these units are slated for retirement. Because of these factors, assessments of the reduction in coal-fired EGU emissions that will result from retirements generally represent less than ten percent of total EGU emissions.[41] Furthermore, it must also be understood that retiring units can be replaced by a variety of types of resources, or not replaced at all, and the net emissions reductions attributable to EGU retirement decisions are rarely assessed in a consistent or rigorous way.

35 Tennessee Valley Authority. (2013, November). TVA Board Takes Action to Improve TVA's Operations and Financial Health. [Press release]. Available at: http://www.tva.com/news/releases/octdec13/board_111413.html

36 All emissions data are obtained from the EPA's eGRID database, which can be accessed or downloaded at http://www.epa.gov/cleanenergy/energy-resources/egrid/

37 South Carolina Electric and Gas. (2013, November). SCE&G Retires Canadys Station Power Plant as Part of Strategy to Meet More Stringent Environmental Regulations. [Press release]. Available at: https://www.sceg.com/about-us/newsroom/2013/11/13/sce-g-retires-canadys-station-power-plant-as-part-of-strategy-to-meet-more-stringent-environmental-regulations

38 US Energy Information Administration. (2014, March 20). *Today in Energy*. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15491

39 SourceWatch.org. *Coal Plant Retirements*. Available at: http://www.sourcewatch.org/index.php/Coal_plant_retirements#Projected_retirements_range_from_25.2C000_-_60.2C000_megawawatts

40 GAO. (2014, September). *EPA Regulations and Electricity: Update on Agencies' Monitoring Efforts and Coal-Fueled Generating Unit Retirements*. Available at: http://www.gao.gov/assets/670/665325.pdf

41 See, for example, an assessment reported by *USA Today* at: http://www.usatoday.com/story/money/business/2014/06/08/coal-plant-retirements-barely-cut-carbon-emissions/10008553/

5. Co-Benefits

In addition to the GHG emissions reductions noted previously, EGU retirements will likely result in reductions in emissions of other regulated air pollutants, depending on the fuels burned prior to retirement and the resources used to replace the power generated by the retired EGUs.

The full range of co-benefits that can be realized through EGU retirement are summarized in Table 8-2. The non-GHG air quality benefits are based on an assumption that any plant that is closed will be replaced by either a more efficient fossil-fueled plant, renewable energy, energy efficiency, or a combination of these resources, but the magnitude of the benefits can be expected to vary widely depending on the new resource.

Table 8-2

Types of Co-Benefits Potentially Associated With Retiring Aging Power Plants

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes – for coal-fired EGUs
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	Maybe
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	Maybe
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other: Alternative Land Use	Yes

6. Costs and Cost-Effectiveness

It is common business practice to make decisions based on forward-looking costs, the costs one reasonably expects to confront in the future. A decision to close an EGU is no different, except the costs are measured in millions or billions of dollars, not thousands.[42] As one commentator noted:

> *In general, the owner of a coal-fired power plant (or of any generating facility, for that matter) may decide to retire the plant when the revenues produced by selling power and capacity are no longer covering the cost of its operations. While sometimes these decisions are complex, they essentially can resemble the basic choices that households face, for example, when they have to decide whether making one more repair on an old car is worth it: often, making the repair is more expensive and risky than the decision to trade in that car and buy a new one with better mileage and other features that the old car lacks.*[43]

The costs and cost-effectiveness of an EGU retirement proposal will depend on a number of unique factors related to the physical plant in question, the costs that it is reasonably likely to incur in the future, and regulatory treatment of incurred costs.

Environmental Regulatory Factors

In addition to being subject to standards for GHG emissions under section 111(d) of the Clean Air Act, existing fossil generation sources will be subject to additional environmental regulatory requirements in coming years. The EPA has recently developed regulations under its Clean Water Act and RCRA authority that would

42 Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance With Public Health and Environmental Regulations.* Available at: www.raponline.org/document/download/id/4670

43 Tierney, S. F. (2012, February 16). *Why Coal Plants Retire: Power Market Fundamentals as of 2012.* Analysis Group, Inc. p 2. Available at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf

apply to fossil generators subject to the EPA's Clean Power Plan. Clean Water Act regulations focus on cooling water structures at EGUs, and EGU toxic effluent discharges. RCRA regulations apply generally to solid waste production and containment, in this case, to coal combustion residuals. In addition to promulgating water and solid waste regulations, the EPA has or can be expected to develop a number of standards and regulations under its Clean Air Act authority, including updated National Ambient Air Quality Standards, the Cross-State Air Pollution Rule, and the MATS.[44] For example, the EPA is expected to finalize a revised, more stringent National Ambient Air Quality Standards for ground-level ozone in 2015.

A review of specific compliance costs associated with these environmental programs is beyond the scope of this discussion. However, an integrated review of potential environmental compliance costs would be an appropriate part of the analysis a state might conduct in response to an EGU retirement proposal, inasmuch as the EGU's economic viability and suitability as a utility asset could be affected.

Market Factors

A brief review of market factors may also be instructive for regulators in understanding the role that markets play as they analyze Clean Power Plan compliance options and prepare to make informed decisions on potential EGU retirement proposals. It is important to note, however, that fuel prices and quantities are volatile and are likely to change in the future. After a low in 2012, for instance, natural gas prices have rebounded, as shown in Figure 8-1. Increased domestic natural gas supplies are expected to result in relative price stability and continue to allow gas to compete effectively with other fuels. US coal exports also declined recently owing to a slowing of the Chinese economy and caps placed on the consumption of coal by many Chinese cities and provinces as a way to improve air quality.

The owners of EGUs will consider market factors, including current and projected fuel prices, as part of any retirement or investment decision. A decision to retire a coal-fired EGU that seems cost-effective when coal prices are high and gas prices are low, for example, might not be cost-effective if market conditions change.

Decreasing Cost of Natural Gas

Declining natural gas prices over the past several years owing to the availability of shale gas made available through more effective drilling techniques have made natural gas-fired EGUs more competitive, and this has been a factor in decisions of EGU owners to retire or idle coal plants.[45] Although a number of factors coalesced to cause recent low gas prices,[46] however, other factors suggest that current prices may not necessarily be sustainable.[47]

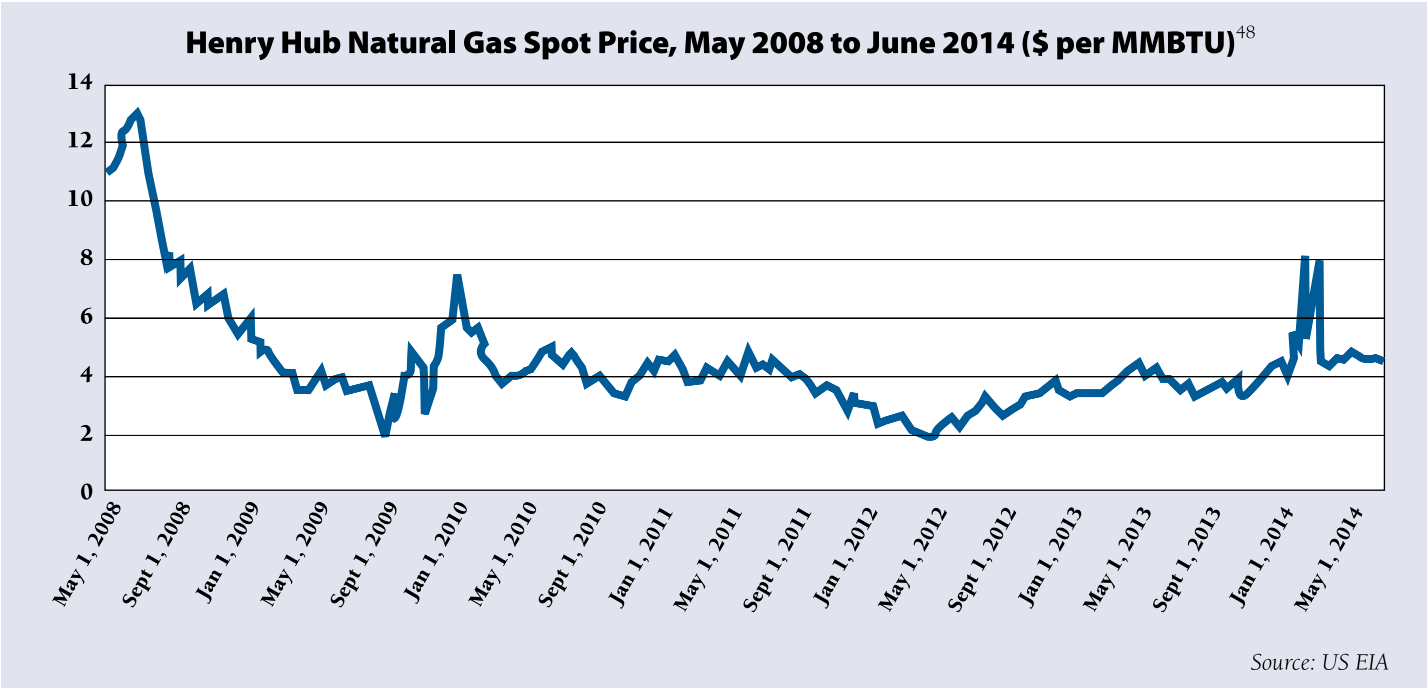
44 The US Energy Information Agency reports that, between 2012 and 2020, approximately 60 GW of coal-fired capacity is projected to retire in the AEO2014 Reference case, which assumes implementation of the MATS standards, as well as other existing laws and regulations. Supra footnote 38.

45 Gerhard, J. (2013). *Coal Plant Closures and US Wholesale Electricity Markets.* In Regulatory Assistance Project Knowledge Management Series (2013). *Complying With Environmental Regulations.* Available at: http://www.raponline.org/featured-work/complying-with-environmental-regulations-a-knowledge-management

46 Including reduced demand owing to economic recession; shale gas production from early high-production sites and gas dumping; price subsidization of dry gas from high "wet gas" and "liquids" prices; the "non-winter" of 2011/2012 (the first four months of 2012 were the warmest January to April in US recorded history); residential and commercial natural gas consumption down more than 18 percent; and gas storage at record levels, and nearing capacity. See: Kushler, M. (2013, October 23). *Natural Gas Prices and Natural Gas Energy Efficiency: Where Have We Been and Where Are We Headed.* Presentation to the Energy Foundation Advocates Meeting, ACEEE. Kushler, M., York, D., & Witte, P. (2005, January). *Examining the Potential for Energy Efficiency to Help Address the Natural Gas Crisis in the Midwest.* ACEEE, p 5. Available at: http://www.aceee.org/research-report/u051

47 Including increased exports of domestic gas, and gas/electricity interdependence, that is, the greater share of gas-fired electricity production and the risk associated with seasonal demand spikes and storage miscalculation. See, e.g.: Farnsworth, D. (2014). *Further Preparing for EPA Regulations.* Appendix 1 and discussion of natural gas cost risk at pp. 48–52. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6989

Figure 8-1



Excess Natural Gas Generation Capacity

Another factor weighing on the closure of coal plants is the significant amount of underused natural gas generating capacity in the United States. According to a 2011 Massachusetts Institute of Technology study, the existing US natural gas generation fleet has an average capacity factor of approximately 41 percent, whereas its design capacity allows such plants to operate at 85 percent.[49] The EPA, in its analysis supporting the Clean Power Plan proposal, concluded that existing combined-cycle gas plants could reliably operate at an average capacity factor of 70 percent.[50] This unused capacity is sufficient surplus to displace roughly one-third of US coal generation.[51] Thus, as the cost of natural gas comes down, underutilized gas plants have available capacity with which to compete with coal plants and possibly displace them in the dispatch order.[52]

Inherent Efficiency of Natural Gas Plants

Modern natural gas-fueled combined-cycle units are generally more efficient than existing coal plants. Coal and combined-cycle gas plants typically have heat rates of 10,000 BTU/kilowatt-hour (kWh) and 7000 BTU/kWh, respectively. To the degree that coal and gas costs converge, the more efficient natural gas plants will become more economically competitive than their coal counterparts.[53]

Increasing Cost of Coal

Increasing coal costs put additional pressure on the ability of US coal plants to participate in US electricity markets.[54] In many cases, mining and mining-related regulatory requirements have increased, contributing to higher mining costs that are passed along to coal consumers and the closure of some mines. Most notably, however, coal prices have increased every year since 2002, and have done

48 NGA Issue Brief: Natural Gas Price Trends. (2014, August). *Henry Hub Natural Gas Spot Price, May 2008 to June 2014 ($ per MMBtu)*. Available at: http://www.northeastgas.org/nat_gas_price_trends.php

49 Supra footnote 45.

50 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

51 Ibid.

52 Supra footnote 45.

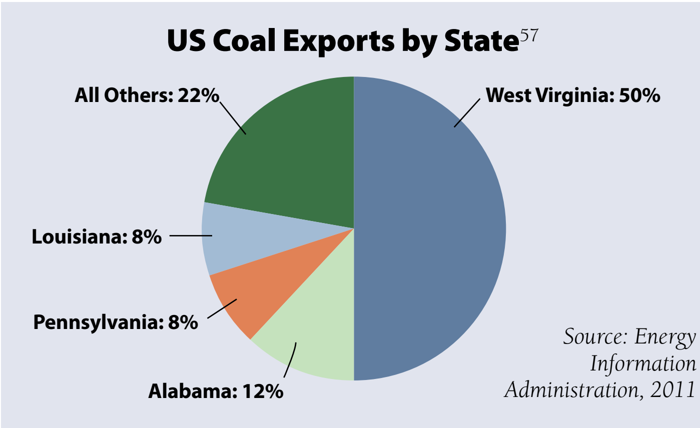
53 Ibid.

54 Ibid.

so in part because of increased exports,[55] particularly to European and Asian markets, and in part because of recent reductions in production in other parts of the world, such as Australia and Indonesia.[56]

According to the National Mining Association, US coal exports increased 31 percent from 2010 to 2011.[58] The average price per ton of coal in 2011 was up 24 percent over 2010, and coal exports represented 9.8 percent of all US coal production in 2011.[59] According to *The Wall Street Journal*, "US coal shipments outside the country in 2014 are expected to surpass 100 million tons for the third year, a record string"[60] (Figure 8-3).

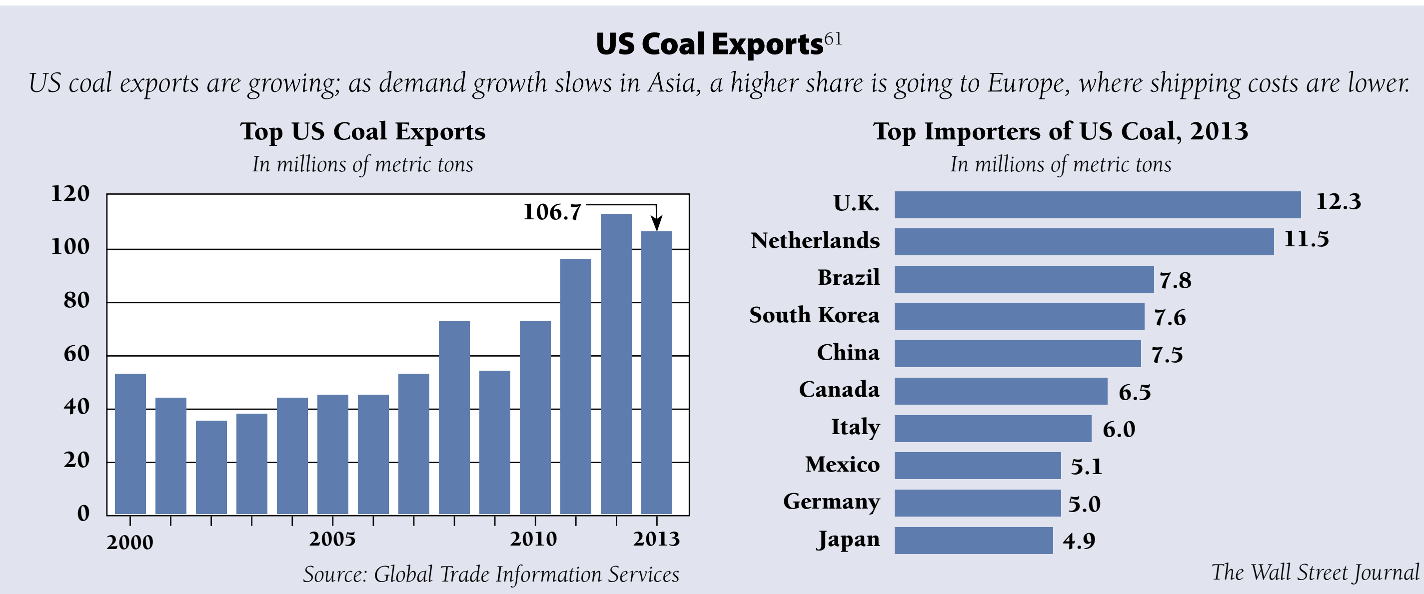
Figure 8-2



Increasing Cost to Transport Coal

The cost of transporting coal to coal-fired generators raises generator costs and can make them less economical to run.[62] Coal plants receive approximately 72 percent of their coal by rail.[63] Costs can range anywhere from 10 percent to almost 70 percent of the delivered price of coal, depending on the type of coal purchased and location of the power plant.[64] The US Energy Information Administration (EIA) reports that rail transportation costs increased from \$13.04 to \$15.54 per ton (19 percent) from 2001 to 2010.[65] Competition for rail capacity from tight oil producers has exacerbated shipping costs for coal generators.

Figure 8-3



55 Miller, J. W. (2014, March). The New Future for American Coal: Export It. *Wall Street Journal*. Available at: http://online.wsj.com/news/articles/SB10001424052702303563304579447582374789164.

56 Supra footnote 45.

57 Department of Transportation, Federal Highway Administration. (2013). *National Gateway and Corridor Concepts*. Available at: http://www.fhwa.dot.gov/planning/border_planning/gateways_and_corridors/gateway_ops/sec03.cfm (DOT FHWA 2013).

58 Coleman, L. (2012, May). *2011 Coal Producer Survey.* National Mining Association. Available at: http://nma.dev2.networkats.com/pdf/members/coal_producer_survey2011.pdf; Supra footnote 45.

59 Supra footnote 45.

60 Supra footnote 55.

61 Ibid.

62 Supra footnote 45.

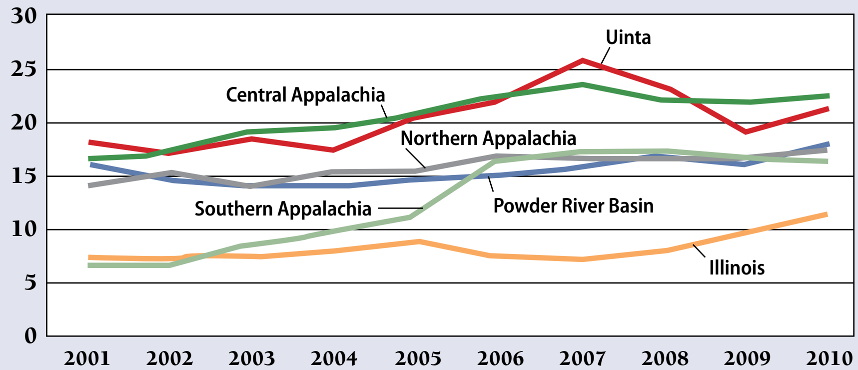
63 Ibid.

64 Ibid.

65 Ibid.

Figure 8-4

Average Rail Transport Cost of Coal to the Power Sector by Major Coal Basin[66]



Source: EIA

Age of Coal Plant Fleet

Another factor that weighs into the decision to retire coal plants is that many of the coal plants under consideration are at or near the end of their economically useful lives.[67] These units tend to have higher fixed and variable operation and maintenance (O&M) costs per megawatt-hour of electricity generated, to be less efficient in generating electricity, and to be more expensive to retrofit than newer units.[68]

Flat or Decreasing Electricity Demand

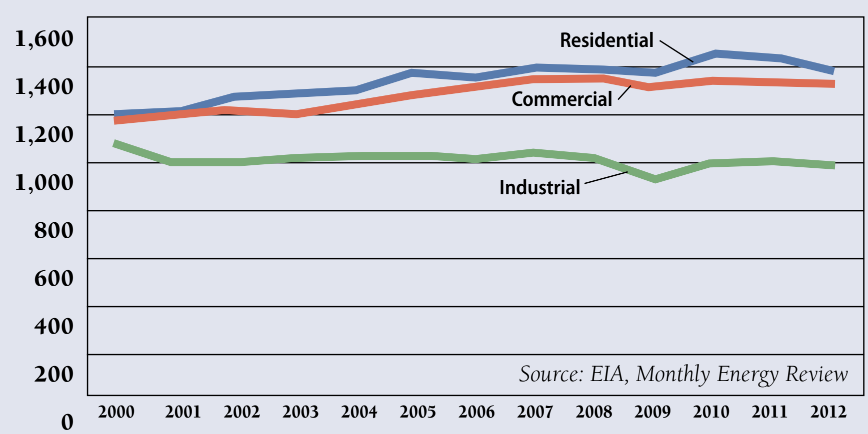
The recent economic downturn and ongoing investments in end-use energy efficiency are combining to flatten load growth and moderate demand for electricity. This in turn lowers potential revenues to generators.[69] In December 2013, the EIA found that "US electricity sales … declined in four of the past five years," driven by declining industrial sales and flat sales in the residential and commercial sectors.[70] This occurred "despite growth in the number of households and commercial building space." And, "The only year-over-year rise in electricity use since 2007 occurred in 2010, as the country exited the 2008-09 recession"[71] (Figure 8-5).

Increasing Competitiveness of Renewable Energy

Several observers have noted that downward trends in the costs of renewable energy are now reaching the point at which they are placing pressure on coal plants at certain times in the year and replacing some coal plants in the dispatch stack.[72] For example, the Analysis Group has

Figure 8-5

Annual Retail Electric Sales by Sector (2000–12)[73]



Note: Direct electricity usage and sales to the transportation sector are not graphed as both account for less than 4% of electricity usage.

66 Association of American Railroads. (2013, August). DOT FHWA 2013. The nation's rail system is a key part in US coal-fired electricity production. According to the Association of American Railroads, coal accounted for nearly 20 percent of rail gross revenue in 2013. https://www.aar.org/ See also: Association of American Railroads. (2014, July). *Railroads and Coal*. Available at: https://www.aar.org/BackgroundPapers/Railroads and Coal.pdf#

67 Supra footnote 45; *Air Emissions and Electricity Generation at US Power Plants*. (2012, April 18). Available at: http://www.gao.gov/assets/600/590188.pdf

68 Depending on the regulatory treatment of coal plant costs, plants may or may not be fully depreciated. See discussion below of "Other Regulatory Factors."

69 Supra footnote 45.

70 US EIA. *Annual Retail Electric Sales by Sector (2000–12)*. Today in Energy. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=14291

71 Supra footnote 70.

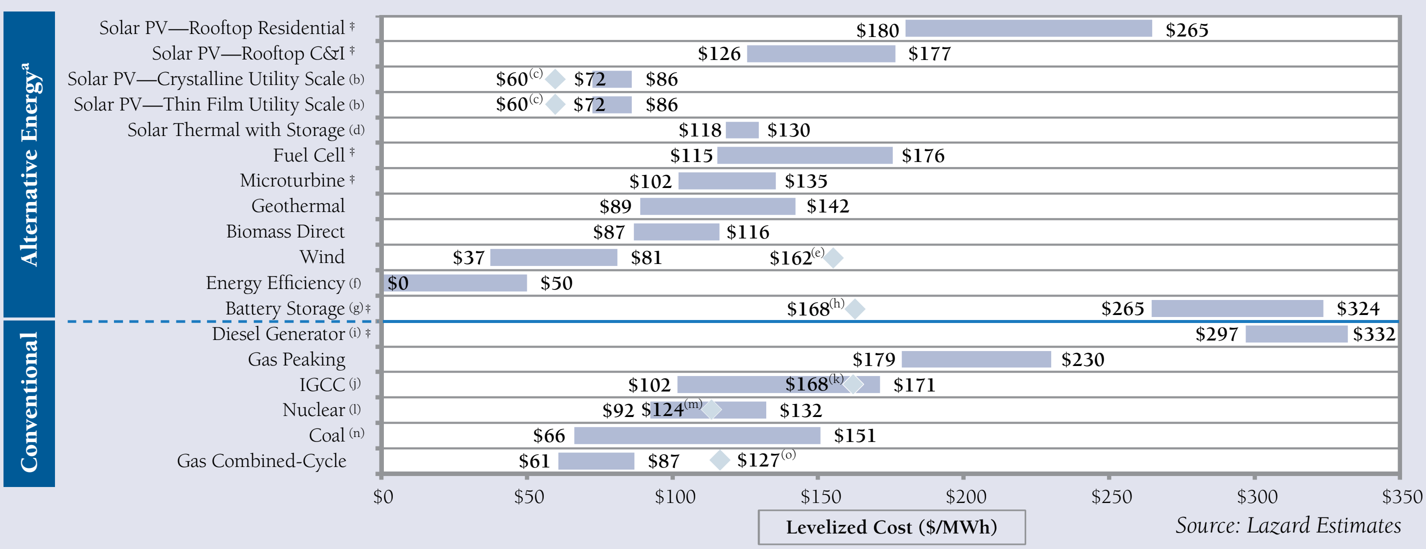
72 Supra footnote 45.

73 Supra footnote 70.

noted that renewables and other distributed resources made up approximately ten percent of PJM's 2014–2015 capacity auction, displacing other generation resources and contributing to "the economic pressure on existing generating resources."[74] In particular, the levelized cost of electricity produced by wind and solar resources dropped by more than 50 percent from 2008 to 2013.[75] Lazard's most recent Levelized Cost of Energy Analysis reveals continuing and significant competitive price improvements of certain renewables against other more traditional resources, as summarized in Figure 8-6. A Deutsche Bank analyst has forecast that by 2016, solar prices will be

Figure 8-6

Lazard's Estimates of Unsubsidized Levelized Cost of Energy (Dollars per MWh)[76]



Source: Lazard Estimates

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Assumes Powder River Basin coal price of $1.99 per MMBtu and natural gas price of $4.50 per MMBtu. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

a. Analysis excludes integration costs for intermittent technologies. A variety of studies suggest integration costs ranging from $2.00 to $10.00 per MWh.

b. Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest US). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

c. Diamond represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

d. Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

e. Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.

f. Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely. Estimates involving demand response may fail to account for opportunity cost of foregone consumption.

g. Indicative range based on current stationary storage technologies; assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

h. Diamond represents estimated implied levelized cost for "next generation" storage in 2017; assumes capital costs of $300/KWh for six hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% and fixed O&M costs of $5.00 per KWh installed per year.

i. Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

j. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

k. Represents estimate of current US new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.

l. Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

m. Represents estimate of current US new nuclear construction.

n. Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

o. Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

74 Supra footnote 43.

75 Silvio Marcacci. (2013, September 20). Analysis: 50 Percent Reduction In Renewable Energy Cost Since 2008. Commentary on "Lazard's Levelized Cost of Energy Analysis—Version 7.0." The Energy Collective. [Web log post]. Available at: http://theenergycollective.com/silviomarcacci/276841/analysis-50-reduction-cost-renewable-energy-2008

76 Lazard, J. (2014, September). *Lazard's Levelized Cost of Energy Analysis – Version 8.0.* Available at: http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

competitive with or lower than those of average power prices in 36 states; solar is already competitive today in ten states.[77]

Poor Load Forecasting

One source cited poor load forecasting as a reason some plants may be retired, saying, "As changes in demand and the economy evolved, some utilities acknowledged weaknesses in the forecast models used by the industry to project future electricity use. When overstated load forecasts were identified, the new plant was no longer viable."[78]

The previous discussion illustrates that numerous forward-looking market factors affect plant closure decisions by plant owners and regulators. Understanding the role of these factors can help in weighing the relative merits of plant closure proposals, because the central question facing regulators is whether plant closures are cheaper and less risky than alternative compliance options.

7. Other Considerations

As the prior discussion illustrates, the cost-effectiveness of a plant closure proposal needs to be determined on a case-by-case basis, but there are some useful general observations that can be made. Older power plants in many ways are at a disadvantage when compared to newer generation resources. In a market context, retirement is considered when the potential income for the unit is no longer sufficient to justify the unit's continued O&M. This may be attributable to such factors as fuel costs, regulatory pressure, or costs of required controls that combine, making it no longer economically justifiable to continue to maintain the unit in operable condition.

Comparative fuel costs and underutilized and more efficient capacity all contribute to the inability of older generating resources to compete economically. This is why conventional wisdom holds that old power plants are more suitable for retirement. For example, a plant's age was a major factor in a 2013 M.J. Bradley and Associates analysis of pending coal retirements in which it found that most of the 52 GW of coal units slated for retirement by 2025 are "small in size, lack environmental controls, and are over 50 years old"[79] (Table 8-3). In 2012, the US GAO reached similar conclusions in "Air Emissions and Electricity Generation at US Power Plants," a study that examines older EGUs.[80]

Although utility decisions related to plant closure are largely driven by the age of a power plant, they are also heavily influenced by whether or not a company will be able to recover a plant's undepreciated costs – despite the

Table 8-3

Coal Retirements as of March 2013 [81]

Characteristic	Announced for Retirement (since January 2006) by 2025	Overall US Fleet
Capacity	52 GW	322 GW
Units	340	1264
Unit Age (avg)	54 years	43 years
Unit Size (avg)	153 MW	254 MW
Utilization (avg in 2011)	49%	71%
Regulated (% of capacity owned by vertically integrated utilities)	70%	75%

77 Walton, R. (2014, October 30). *Study: At Least 36 States Will See Solar Hit Grid Parity by 2016.* Utility Dive. Available at: http://www.utilitydive.com/news/study-at-least-36-states-will-see-solar-hit-grid-parity-in-2016/327286/

78 Supra footnote 45.

79 Saha, A. (2013, April 12). *Review of Coal Retirements.* M.J. Bradley & Associates, LLC. Available at: http://www.mjbradley.com/reports/coal-plant-retirement-review

80 US GAO. (2012, April 18). *Air Emissions and Electricity Generation at US Power Plants.* Available at: http://www.gao.gov/assets/600/590188.pdf. In this study the US GAO defines "older plants" as having been in operation "in or before 1978."

81 Based on *Coal Retirements,* in: supra footnote 79.

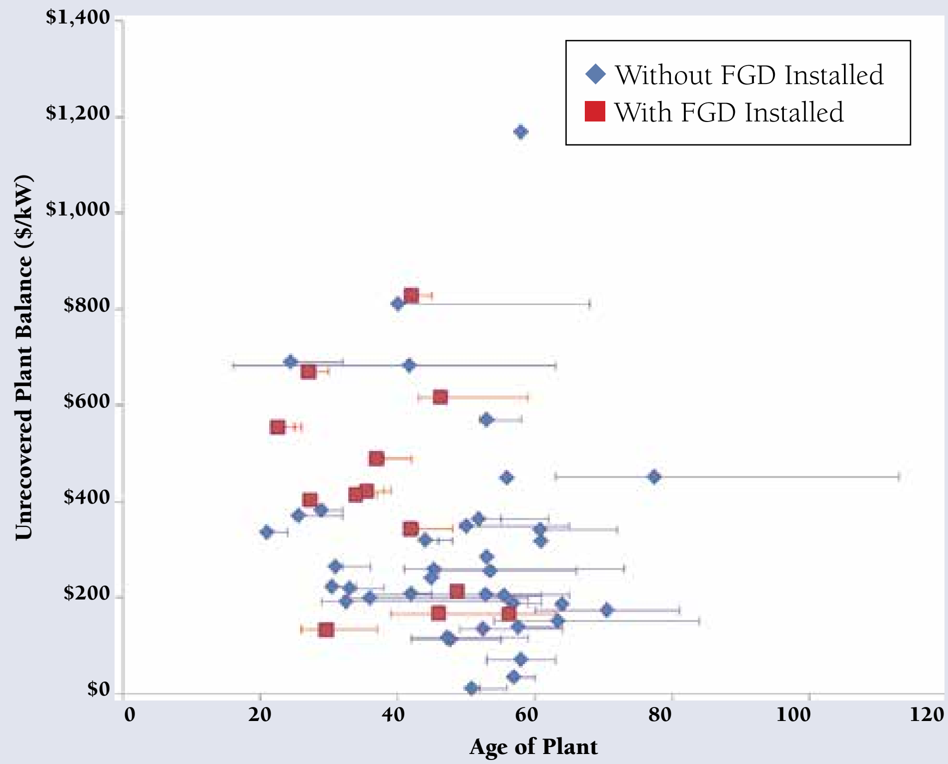
plant's age.[82] Plant owners are understandably reluctant to face such "stranded costs" where they lack certainty of recovery from ratepayers.

Nationwide information on plant depreciation is not readily available because depreciation studies are typically confidential. But based on one sample derived from non-confidential studies, plants may have hundreds of dollars per kilowatt of unrecovered value on the books, as illustrated in Figure 8-7.[83]

In this sample, comprising 52 coal plants owned by 11 utilities, the average plant age (weighted by capacity) is approximately 47 years. Average plant capacity is approximately 675 MW. Average unrecovered plant balance is approximately $336/kilowatt. And the unrecovered balance is over 50 percent of total plant balance.

Figure 8-7

Utility Incentives: Old Coal Plants Have Significant Investment in Rate Base [84]



As noted earlier, older plants are less likely to be dispatched, and if they are not running, then they are at risk of not recovering their fixed operations and maintenance costs and undepreciated plant costs, an untenable outcome from both an economic and regulatory perspective. Not only are older plants more likely to be producing less revenue, typical regulatory practice for utility-owned generating units requires those investments to be "used-and-useful" in order to be recovered in utility rates.[85] Although a used-and-useful determination is complex and fact-specific, there are some general observations relevant to power plant closures that can be made with regard to this doctrine.[86]

82 See, e.g.: Wishart, S. (2011, September 27). *Coal Retirement vs. Refurbishment – The Role of Energy Efficiency.* Delivered at ACEEE National Conference on Energy as a Resource. Available at: http://aceee.org/ Important economic drivers for coal retrofit versus retirement include: costs of environmental controls (capital and O&M), replacement capacity; replacement energy; CO_2 assumptions; current rate base; and accelerated depreciation.

83 Synapse Energy Economics collected information from 52 coal plants owned by 11 companies.

84 Biewald, B. (2014, January 21). *The Future of Coal: Economics and Planning.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/Downloads/SynapsePresentation.2014-01.0.Future-of-Coal.S0091.pdf

85 Lazar 101 at 39. Electricity prices are set by utility commissions in rate cases. In these investigations, commissions review company costs, including those associated with power plant investment, and determine which are appropriate and suitable for recovery in rates. In rate cases, companies justify their costs, which can include expenses associated with fuel, O&M, purchased power, and other administrative-related activities. These considerations only apply to utility-owned generating units. Generating units that are owned by independent power producers and operating in a wholesale market will make retirement decisions based on whether potential income for the unit is sufficient to justify the unit's continued O&M, as previously noted.

86 When a new power plant enters service and its costs are considered for inclusion in rates, regulators often perform a "prudence review" to determine if the plant was built in an economic manner. If regulators determine that the planning or construction was imprudent, they can disallow a portion of the investment, and refuse to include it in the company's rate base. Lazar at 39.

For a facility to be considered "used" means that the facility is actually providing service. Being "useful" means that without the facility, either costs would be higher or the quality of service would be lower.[87] In rate investigations, the utility has the burden of proving that an investment meets this test, but utilities often enjoy the presumption of used-and-usefulness in the absence of evidence to refute it.[88] In circumstances in which plant investment is found to not be used-and-useful, its costs are not allowed in utility rates. This is one reason plant closure is such a sensitive topic. Companies with generating units that are marginal and barely operational are at risk of being determined to not be used-and-useful. And companies do not want to see this happen, because it will directly compromise their ability to receive the full recovery of their investment.[89]

Not surprisingly, finding a plant to not be used-and-useful also poses political and economic ramifications for utility commissions and public advocates. This is why commissions may only respond obliquely to utilities in this regard. Commissions might observe, for example, that the economics of a plant are questionable. They might provide "signals" to utilities about the propriety of making further investments in a plant, perhaps suggesting that if an investment is undertaken the commission will take a "hard look" at that utility decision, or if there are related cost overruns, the company's shareholders and not the ratepayers can be expected to shoulder these costs.

An additional observation: the previous discussion has described "typical" regulatory practice. A plant closure undertaken for purposes of compliance with a Clean Air Act requirement may not be typical. This is a significant distinction that companies may make and that utility commissions could take into consideration. For example, although granting recovery of costs that would otherwise not be deemed used-and-useful is not recommended, an investigation might conclude that granting recovery of undepreciated costs associated with the retirement of older power plants is a more cost-effective approach compared with other Clean Power Plan compliance alternatives, and is thus worthy of inclusion in a state plan.

An example from the state of Alabama of regulatory accounting treatment of a utility plant may be instructive. In August 2011, Alabama Power petitioned the Alabama Public Service Commission for an authorization "related to cost impacts that could result from the implementation of new [EPA] regulations."[90] More specifically, Alabama Power sought:

> *Authorization to establish a regulatory asset on its balance sheet in which it would record the unrecovered investment cost associated with full or partial unit retirements caused by such regulations, including the unrecovered plant asset balance and the unrecovered cost associated with site removal and closure.*[91]

The Commission granted the company's request, allowing it to put in place an accounting approach designed "to benefit customers by addressing certain potential cost pressures they would otherwise face."[92] The Commission went on to explain:

> *Should environmental mandates from EPA result in the Company prematurely retiring a generating unit or partially retiring certain unit equipment in order to effectuate the transition of that unit's operational capability to a different fuel type, the Company will be able, through these authorizations, to recover the remaining investment costs, as well as expenses associated with unused fuel, materials and supplies, over the time period that would have been utilized for that unit, but for the [EPA's] mandates.*[93]

87 Lazar at 39.

88 Ibid.

89 Utilities and utility regulators cannot predict with perfect accuracy whether an EGU will be used and useful at some future data. The possibility of stranded costs is a factor in nearly every decision about whether to retrofit or retire a utility-owned EGU. The Regulatory Assistance Project has cited best practices on this topic and offered recommendations to utility regulators in two publications on environmental regulations: (1) Lazar, J. & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/4670; and (2) Farnsworth, D. (2014, January). *Further Preparing for EPA Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6989

90 Alabama PSC Docket U-5033, Order: September 7, 2011. Available at: https://www.pscpublicaccess.alabama.gov/pscpublicaccess/ViewFile.aspx?Id=132f89da-98f5-4c6d-b218-c7a116224e1e at p. 1-2.

91 Supra footnote 90 at p. 2.

92 Ibid at p. 7.

93 Supra footnote 92.

On one hand, it is perhaps surprising that the utility was given preapproval for such a potentially large amount of costs, with no specific plan identifying specific regulations at issue and the actual or likely costs that the utility may face in order to comply. Information related to reasonably anticipated costs, the specific environmental regulations requiring these investments, and justification by the company for the compliance approaches it chose would normally be a condition for such preapproval. It would seem that regulators should have an opportunity to review the company's comprehensive analysis evaluating the value of the preapproved project under a range of possible outcomes. On the other hand, a policy like this allows a company to come forward and propose plant closures as an option that a state commission might reasonably consider for its cost-effectiveness and overall effectiveness. In this case, making a regulatory determination about cost recovery for unamortized rate-base balances for retiring coal plants could be an important and appropriate part of a plant's retirement plan and the state's compliance plans.

As with many regulatory matters in practice, there are balances to be struck. Rate trajectory over the transitional period is an important aspect, along with such issues as incremental carrying costs and key debt ratios. Given the regulatory status quo, in which companies are unlikely to draw attention to an uneconomic resource owing to concerns over disallowance, a policy like Alabama's could encourage utilities to consider plant retirements as an option for compliance with the EPA's Clean Power Plan requirements.

8. For More Information

Interested readers may wish to consult the following documents for more information on retiring aging power plants:

- Farnsworth, D. (2011). *Preparing for EPA Regulations: Working to Ensure Reliable and Affordable Environmental Compliance*, pp. 20–38 for a more detailed discussion of integrated planning. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/919
- Farnsworth, D. (2014). *Further Preparing for EPA Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6989
- Lazar, J., & Farnsworth, D. (2011, October). *Incorporating Environmental Costs in Electric Rates, Working to Ensure Affordable Compliance with Public Health and Environmental Regulations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4670
- US EPA. (2014, June). *Technical Support Document (TSD): Resource Adequacy and Reliability Analysis.* Office of Air and Radiation. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf
- Tierney, S. F. (2012, February 16). *Why Coal Plants Retire: Power Market Fundamentals as of 2012.* Analysis Group, Inc. p 2. Available at: http://www.analysisgroup.com/uploadedFiles/News_and_Events/News/2012_Tierney_WhyCoalPlantsRetire.pdf
- US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units — GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents

9. Summary

Although closing an aging EGU can be a disruptive and challenging process, when weighed against various alternatives, it may provide a lower-cost solution and be worthy of inclusion in a state's plans for Clean Air Act compliance, including compliance with Clean Power Plan requirements.

There are various regulatory contexts in which states can review proposals to close power plants. There are also numerous factors that can affect decisions to keep a plant running or to retire it, including forward-looking market considerations, environmental regulatory requirements, and the ability to recover past plant-related investments.

States that consider plant closure as a compliance option will have to consider these issues, and the varying degree to which these factors support such a decision. However, states that do engage in this effort will be better prepared to evaluate a wider array of potential compliance options, and better able to strike their preferred balance between cost and other policy goals, including the most affordable and reliable compliance scenarios allowable under the EPA's Clean Power Plan.

9. Switch Fuels at Existing Power Plants

1. Profile

One option for reducing the carbon dioxide (CO_2) emissions from an existing electric generating unit (EGU) is to switch to a lower-emitting fuel. Fuel switching is perhaps the most familiar and most proven method for reducing greenhouse gas (GHG) emissions from existing EGUs. The technological challenges are familiar and manageable, the co-benefits can be substantial, and the costs are generally lower than for other technology options.[1]

Fuel switching can involve at least three distinct strategies. First, if an EGU is already designed and permitted to use multiple fuels, the owner or operator can reduce annual emissions by increasing the use of a lower-emitting backup fuel and decreasing the use of a higher-emitting primary fuel. For example, the EGU could reduce annual combustion of coal and increase annual combustion of natural gas. With this strategy, the hourly emissions rate of the EGU when it is burning coal would not change, and the hourly emissions rate of the EGU when it is burning gas would not change, but its annual emissions would decrease.

The second strategy is to blend or cofire a lower-emitting fuel with a higher-emitting fuel. For example, the owner or operator of the EGU could blend two different ranks of coal, or cofire a biomass fuel with coal, to reduce the emissions rate of the unit.

The third fuel-switching strategy is to repower the EGU, that is, to modify the unit or the fuel delivery system to accommodate the use of a lower-emitting fuel not previously used. For example, a coal-fired EGU might be reconstructed to burn natural gas, thus reducing the unit's emissions rate.

Switching fuels is one of the most straightforward and technologically feasible strategies for reducing emissions, but it is not a trivial undertaking. For any existing EGU, there are reasons the current fuels are used and other fuels are not used. Similarly, there are reasons the primary fuel is primary and the backup fuels are backups. These decisions are influenced by many different factors, such as delivered fuel costs, fuel handling system design, boiler design, permit conditions, emissions of criteria or toxic air pollutants, availability of natural gas pipeline capacity, and so forth.

Switching fuels will be most feasible from a technological perspective where an EGU is already designed and permitted to combust more than one type of fuel, but the current primary fuel has a higher input emissions factor than the secondary fuel. Even so, economic considerations will determine whether fuel switching is a practical option. Blending or cofiring strategies can introduce additional difficulties, as the use of blended fuel or cofiring of two fuels may affect the performance of the fuel delivery system, boiler, pollution control devices, ash handling system, and the like. Repowering projects tend to be major undertakings requiring considerable capital investment.

2. Regulatory Backdrop

With few exceptions, fuel switching has not been imposed on regulated entities as a statutory or regulatory requirement, nor has it been mandated through air pollution permitting processes. It is normally adopted by regulated entities as either an economic choice or as an optional strategy for complying with environmental requirements.

The US Environmental Protection Agency (EPA) evaluated fuel switching as a potential GHG abatement measure in conjunction with the June 2014 proposed Emission Guidelines for Greenhouse Gas Emissions from Existing Electric

1 This chapter focuses exclusively on switching the fuels used (or the proportions in which they are used) at existing power plants to reduce onsite emissions without necessarily reducing electrical output. Note that Chapter 21 addresses a different strategy that is often explained in other publications using the same term "fuel switching." Chapter 21 examines the potential to reduce CO_2 emissions by less frequently dispatching (i.e., operating) higher-emitting power plants (e.g., coal units) while increasing the dispatch frequency of other, lower-emitting power plants (e.g., gas units).

Utility Generating Units. Chapter 6 of the GHG Abatement Measures Technical Support Document (TSD) is dedicated to fuel switching.[2] In the TSD, the EPA analyzed the GHG reduction potential, co-benefits, and cost-effectiveness of cofiring natural gas or biomass with coal, and of repowering a coal unit to 100 percent gas or biomass. Based on its analysis, the EPA concluded that fuel switching should not be included as part of the "best system of emissions reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities." Details of the EPA's analysis and conclusions are provided later in this chapter.

Most federal and state air pollution regulations have been implemented in a "fuel-specific" way that results in separate emissions limits, control requirements, and compliance demonstration methods for each fuel that a source is permitted to burn. The emissions limits and other applicable requirements for each fuel tend to be based on what is realistically achievable when burning that fuel.[3] Part of the explanation for this approach comes from a precedent-setting 1988 permit decision in which the EPA Administrator held on appeal that "...permit conditions that define these [control] systems are imposed on the source *as the applicant has defined it.* Although imposition of the conditions may, among other things, have a profound effect on the viability of the proposed facility as conceived by the applicant, the conditions themselves are not intended to redefine the source."[4]

In the context of the federal Prevention of Significant Deterioration (PSD) regulations, the EPA has held since that 1988 decision that control options that "fundamentally redefine the source" may be excluded from a best available control technology (BACT) analysis, but state and local permitting authorities have the discretion to engage in a broader analysis if they so desire. A number of past EPA statements in guidance documents and precedents in the case of actual permit applications indicate that requiring (for example) a coal-fired EGU to switch to natural gas as the BACT would be to "fundamentally redefine the source."[5] In summary, state and local permitting authorities have the discretion to consider fuel switching as a possible BACT option but, under current EPA policy, they are not required to do so. In practice, fuel switching has historically rarely been considered in BACT analyses.

Nearly all of the exceptions to the traditionally "fuel-specific" approach to regulation come from federal or state regulations that in some way cap annual emissions of a specified pollutant from a category of sources. Examples of such "fuel neutral" regulations include the federal Acid Rain Program, the federal Clean Air Interstate Rule (CAIR), the Cross-State Air Pollution Rule, and the Regional Greenhouse Gas Initiative (RGGI). Regulations like these that include a mass-based annual emissions cap do not force sources to switch fuels but allow for fuel switching as one of many possible compliance strategies.

Colorado's *Clean Air – Clean Jobs Act* provides a different kind of exception to the fuel-specific generalization.[6] This state statute, enacted in 2010, did not create annual mass-based emissions limits, but required the state's largest public utility to develop a coordinated plan for reducing emissions from coal-fired power plants in sufficient amounts to satisfy current *and anticipated future* Clean Air Act requirements. Here again, fuel switching was not mandated by the legislation but the reductions were targeted toward coal-fired plants, and fuel switching was specifically listed as one of the options available to the utility for inclusion in the plan.

Along a similar vein, in 2011 the State of Washington enacted a law that imposes a GHG emissions performance standard for the two boilers at an existing coal-fired power plant. The law does not require fuel switching per se, but the standards are sufficiently stringent that the source is

2 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

3 During the permitting process, regulators occasionally find that a source will be unable to meet all applicable requirements while burning a particular fuel. In such cases, the owner of the source might opt to switch to a different fuel in order to obtain the permit, or accept limitations on the quantity of the problematic fuel that will be combusted, but the regulator will not unilaterally mandate fuel switching.

4 In re Pennsauken County, N.J., Resource Recovery Facility, 2 E.A.D. 667 (Adm'r 1988) (emphasis added).

5 *See, e.g.,* In re Old Dominion Elec. Coop., 3 E.A.D. 779 (Adm'r 1992), in which the EPA found no error in a state's determination that it could not require a proposed new coal-fired EGU to instead fire natural gas.

6 Colo. Rev. Stat. §§ 40-3.2-201 to 40-3.2-210.

Table 9-1

Compliance Methods Used in Phase 1 of the Acid Rain Program

Compliance Method	Number of Generators	Average Age[a] (years)	Affected Nameplate Capacity (megawatts)	Allowances[b] (per year)	1985 SO_2 Emissions (tons)	1995 Emissions (tons)	Percentage of Total Nameplate Capacity Affected by Phase I	Percentage of SO_2 Emission Reductions in 1995[c]
Fuel Switching and/or Blending	136	32	47,280	2,892,422	4,768,480	1,923,691	53	59
Obtaining Additional Allowances	83	35	24,395	1,567,747	2,640,565	2,223,879	27	9
Installing Flue Gas Desulfurization Equipment (Scrubbers)	27	28	14,101	923,467	1,637,783	278,284	16	28
Retired Facilities	7	32	1,342	56,781	121,040	0	2	2
Other	8	33	1,871	110,404	134,117	18,578	2	2
Total	**261**	**32**	**88,989**	**5,550,821**	**9,301,985**	**4,444,432**	**100**	**100**

widely expected to either shut down or repower by 2025. The installation of carbon capture and storage technology might provide a third compliance option that allows for continued use of coal.[7]

Fuel switching strategies may have permitting implications for existing sources. In cases in which an EGU is already permitted to burn more than one fuel, it will often be the case that the source can increase its use of a lower-emitting fuel without requesting any changes to its operating permit because the emissions rates will not change. There may be exceptional cases in which a source that has a limit on annual or monthly mass emissions or hours of operation will need to request a permit revision in order to increase its use of a fuel for which it is already permitted. If the owner of an EGU wishes to switch to a fuel that the source was already capable of burning but was not permitted to burn (i.e., a switch that does not require a physical change to the source), it will be necessary to obtain a revised operating permit. Finally, if the source will be repowered, it may require a new source construction permit and a revised operating permit.

3. State and Local Implementation Experiences

As noted earlier in this chapter, there are virtually no examples of state or local governments that have instituted fuel switching through a mandatory statute or regulation. However, there are abundant examples from virtually all states in which fuel switching has been implemented by sources as a Clean Air Act compliance strategy or for economic reasons (with emissions reductions as a co-benefit). One such example can be found in a 1997 US Energy Information Administration (EIA) review of the compliance strategies adopted by regulated units during the first phase of the Acid Rain Program.[8] As shown in Table 9-1, fuel switching and fuel blending were the chosen strategies for more than half the affected sources, and those strategies accounted for nearly 60 percent of the sulfur dioxide (SO_2) emissions reductions.

An EIA 2012 survey of generators identified over 3600 EGUs that were operable at that time and had the regulatory permits needed to burn multiple fuels.[9] Multi-fuel facilities were operating in every state. With so many EGUs already designed and permitted to burn multiple fuels, the strategy of switching between primary and backup fuels to reduce emissions will be familiar to many power plant owners and state regulators. This is especially true in ozone non-attainment areas that have been subject to seasonal nitrogen oxides (NO_x) emissions limits. It is quite common in such cases for regulated entities to switch to burning natural gas, normally a backup fuel, to meet seasonal limits. Similar strategies have also been used by owners of Acid

7 The possibilities for reducing CO_2 emissions from existing power plants through carbon capture and storage technologies are addressed in Chapter 7.

8 US EIA. (1997, March). *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*. Washington, DC.

9 US EIA. (2013, December 4). Form EIA-860 detailed data for 2012 retrieved from the EIA website: http://www.eia.gov/electricity/data/eia860/index.html.

Rain units (as already noted) and EGUs subject to CAIR in order to comply with annual SO_2 emissions limits. In fact, more than half of the coal-fired EGUs in the Acid Rain and CAIR programs have not installed SO_2 emissions controls, but have complied using fuel switching or other strategies such as allowance trading.[10]

In 2012, electric power industry analysts at the firm SNL Energy reported the results of their review of recent fuel switching at multi-fuel facilities.[11] SNL Energy looked at reported fuel use data to identify power plants capable of burning both coal and natural gas. Overall, 197 facilities (many with multiple EGUs) with a total generating capacity of 78,544 megawatts (MW) were identified as burning both coal and natural gas for electricity generation during at least one month between 2008 and 2012. SNL Energy reported that the volume of gas burned at those plants increased 11 percent in 2011 compared to 2008, whereas the volume of coal burned fell nine percent. These data offer a clear indication that substantial levels of fuel switching can occur at multi-fuel facilities over a relatively short period of time (years rather than decades). What is not quite as clear is how much *additional* fuel switching, beyond what already happened in 2012, is still possible for existing multi-fuel facilities.

Fuel blending has also been a common Acid Rain and CAIR compliance strategy. Many boiler owners in the United States have routinely blended lower-sulfur sub-bituminous coal with higher-sulfur bituminous coal to reduce annual SO_2 emissions while meeting other performance and cost objectives. Unfortunately, most of the analyses of Acid Rain and CAIR compliance strategies have conflated fuel blending with other forms of fuel switching, so it is difficult to quantify how much fuel blending has occurred.

Cofiring is yet another variation on fuel switching. The Electric Power Research Institute (EPRI) published a technical report in 2000 that assessed five proven technologies and one experimental technology for cofiring natural gas with coal at EGUs.[12] EPRI closely examined over 30 full-scale installations of these technologies that had been installed across the entire range of coal-fired boiler types in use in the United States: tangentially fired boilers, wall-fired boilers, cyclone boilers, and turbo-fired boilers. The technologies and installations reviewed are summarized in Table 9-2; for complete descriptions refer to the EPRI report.

The 2012 EIA survey data cited above offers a more recent and comprehensive look at cofiring capabilities in the United States across all technologies and fuels. The EIA data indicate that 1980 of the multi-fuel generating EGUs in the United States have cofiring capability and the necessary regulatory approvals. Although the earlier EPRI report focused only on cofiring coal and gas, the EIA data show that the most common configuration among these units is the ability to cofire oil with gas, as shown in Figure 9-1.

Repowering of existing EGUs is the last type of fuel switching examined in this chapter. In recent years, dozens of repowering projects have been undertaken, announced, or proposed for United States power plants. Most of these projects involve repowering existing coal units to burn natural gas, but there are also several examples involving a switch from coal to biomass. An example of a coal plant that has already been converted to natural gas can be found at Dominion Virginia Power's 227-MW Bremo Power Station in Bremo Bluff, Virginia. Examples of completed coal to biomass repowering projects include

Table 9-2

Cofiring Technologies Reviewed in EPRI Study
(Circa 2000)

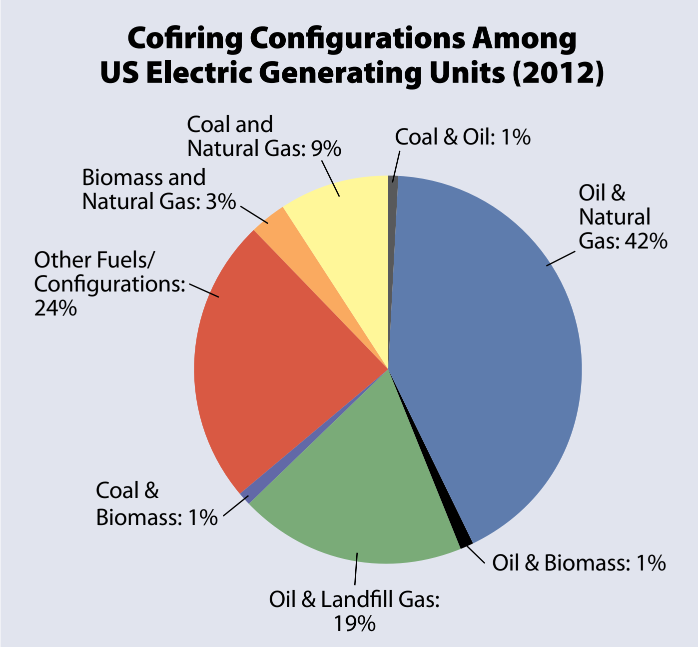
Technology	Number of Installations
Supplemental Gas Cofiring (simultaneous firing of both fuels through separate burners in boiler's primary combustion zone)	10
Gas Reburning (in secondary combustion zone)	11
Fuel Lean Gas Reburning	6
Advanced Gas Reburning	2
Amine-Enhanced Fuel Lean Gas Reburning	2
Coal/Gas Cofiring Burners	0

10 US EPA. (2013). *Clean Air Interstate Rule, Acid Rain Program, and Former NOx Budget Trading Program: 2012 Progress Report.* Available at: http://www.epa.gov/airmarkets/progress/ARP-CAIR_12_downloads/ARPCAIR12_01.pdf.

11 SNL Energy reports are available only to subscribers but are frequently cited in trade media accounts. For example, the data reported here appeared in *Coal Age News* (http://www.coalage.com/features/2386-us-power-plants-capable-of-burning-coal-and-natural-gas.html) in October 2012.

12 EPRI. (2000). *Gas Cofiring Assessment for Coal-Fired Utility Boilers.* Palo Alto, CA.

Figure 9-1



DTE Energy Services' 45-MW power plant at the Port of Stockton in California and a 50-MW unit at Public Service of New Hampshire's Schiller Station in Portsmouth, New Hampshire.

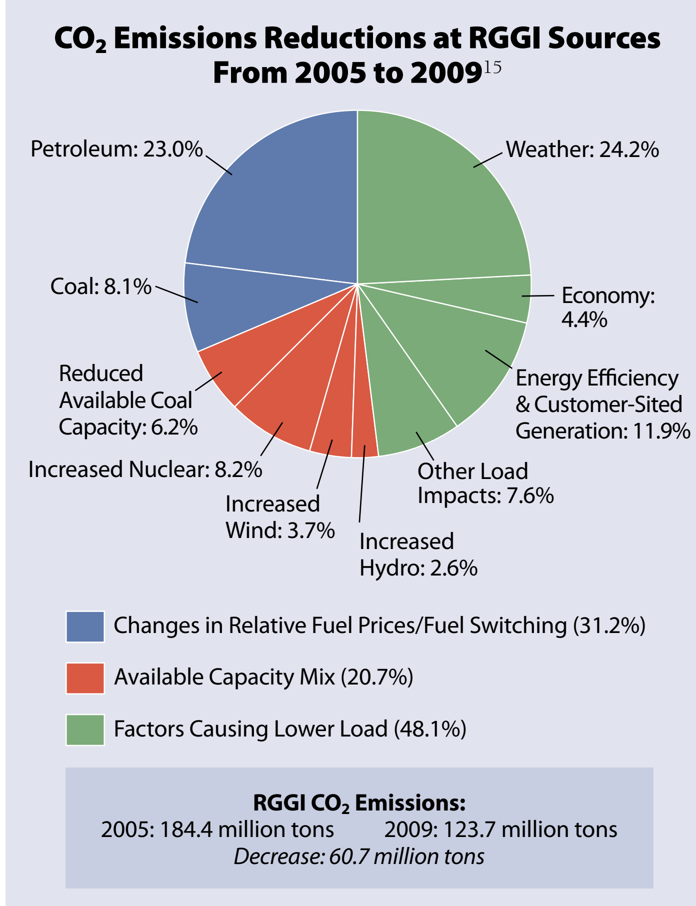
Looking ahead, an April 2014 review by SNL Energy found that utilities and merchant power plant owners have announced plans to repower 7600 MW of current coal-fired generating capacity with other fuels, and an additional 3600 MW of coal capacity is slated for either repowering or retirement, with those decisions to come at a later date.[13]

4. GHG Emissions Reductions

To date, switching fuels at existing facilities has occurred primarily in response to criteria pollutant and air toxics regulations and as an economic choice driven by low natural gas prices. However, in nearly all parts of the country, federal GHG regulations for existing sources could conceivably provide the impetus for additional fuel switching beyond what has already happened and what is already planned.

Most of the state experience to date with mandatory CO_2 emissions limits for existing sources comes from the states participating in RGGI.[14] One analysis by the New York State Energy Research and Development Authority (NYSERDA), summarized in Figure 9-2, found that sources regulated under RGGI reduced their CO_2 emissions by 60.7 million tons (33 percent) between 2005 and 2009, and 31 percent of the reductions could be attributed to fuel switching. This underscores two facts: that significant CO_2 emissions reductions are achievable over a short time period, and that fuel switching can be a preferred option for reducing CO_2 emissions.

Figure 9-2



13 As reported in *Coal Age News* at http://www.coalage.com/61-uncategorised/3572-coal-unit-conversions.html.

14 The nine states currently participating in RGGI are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. New Jersey was previously a participant. California, like the RGGI states, has enacted a mandatory CO_2 cap-and-trade program for existing sources including but not limited to power plants. But in the case of California, similar data on emissions reductions and the factors causing them are not yet available because 2013 was the first year for enforceable compliance obligations. California regulators expect fuel switching to play a relatively smaller role than it has in the RGGI states because most of that state's generating fleet is already gas-fired.

15 NYSERDA. (2010, November 2). *Relative Effects of Various Factors on RGGI Electricity Sector CO_2 Emissions: 2009 Compared to 2005.* Available at: http://www.rggi.org/docs/Retrospective_Analysis_Draft_White_Paper.pdf.

At a theoretical or hypothetical level, the output emissions rate of any combustion unit can be determined as follows:

E = EF * HR where
E = output emissions rate (lbs CO2/MWh[16]gross);
EF = input emissions factor (lbs CO2/MMBTU[17]); and
HR = heat rate (MMBTU/MWhgross).

The input emissions factor is a function of the carbon and heat content inherent in the chemical and physical composition of any given fuel; it varies across fuel types and even within fuel types, as shown in Table 9-3. One option for reducing the CO_2 emissions from an existing EGU is to switch to a fuel that has a lower input emissions factor. (Another but very different option, discussed in Chapter 1, is to improve the heat rate of the unit.)

The data in Table 9-3 suggest the levels of emission reductions that are at least hypothetically possible from fuel switching. To begin with, it should be noted that there is a range of emissions factors within most coal ranks. This suggests the possibility that some sources may be able to reduce their output emissions rate by a small amount, but probably no more than five percent, simply by obtaining coal of the same rank that has a lower input emissions factor. Significantly greater reductions are possible if a source switches to an entirely different fuel. For example, switching from lignite coal to natural gas could cut an EGU's output emissions rate nearly in half.

One fuel switching option that has received considerable attention is the option of blending or cofiring biomass or waste-derived fuels with coal, or completely repowering a coal-fired unit to burn only biomass. Table 9-3 does not show input emissions factors for biomass, biogas, or municipal solid waste fuels. This is because there is significant ongoing debate and controversy about whether or to what extent to treat such fuels as "carbon neutral" (i.e., attribute no net CO_2 emissions to these fuels). The scientific arguments in that debate are beyond the scope of this document, but the salient point is that the regulatory treatment of GHG emissions from biomass and waste-derived fuels remains uncertain at this time and is likely to strongly influence the demand for biomass fuels.[19]

Table 9-3

Average Input Emissions Factors of Various US Fuels[18]

Fuel Type	Input Emissions Factor (lbs CO_2/MMBTU)
Coal – Anthracite	227
Petroleum Coke	225
Coal – Lignite	212 to 221
Coal – Sub-bituminous	207 to 214
Coal – Bituminous	201 to 212
Residual Oil	174
Distillate Oil	161
Natural Gas	117

If biomass fuels are ultimately treated by regulators as fully or partially carbon neutral, biomass utilization at existing coal-fired power plants could potentially play a role in reducing CO_2 emissions. At least two published papers have concluded that a five-percent reduction in CO_2 emissions from the North American electric power sector (roughly 100 Mt[20]/year) could be achieved solely by cofiring biomass with coal at existing EGUs.[21,22] Analysts

16 Megawatt hour.

17 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

18 US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.

19 In July 2011, the EPA decided to temporarily defer the application of PSD and Title V permitting requirements to CO2 emissions from biogenic stationary sources while it studied whether and how to regulate such emissions. However, that decision was vacated by the US Court of Appeals for the District of Columbia Circuit (DC Circuit) in July 2013. From a regulatory standpoint, the GHG reductions that may be achievable by switching to these fuels are thus uncertain.

20 Mt is defined as millions of tons.

21 Robinson, A., Rhodes, J. S., & Keith, D. W. (2003). Assessment of Potential Carbon Dioxide Reductions Due to Biomass-Coal Cofiring in the United States. *Environ Sci Technol.* 37 (22), 5081-5089. Available at: http://pubs.acs.org/doi/pdf/10.1021/es034367q.

22 Zhang, Y., McKechnie, J., Cormier, D., Lyng, R., Mabee, W., Ogino, A., & Maclean, H. L. (2010). Life Cycle Emissions and Cost of Producing Electricity from Coal, Natural Gas, and Wood Pellets in Ontario, Canada. *Environ Sci Technol.* 44 (1), 538–544.

at McKinsey & Company offer a different estimate of the potential for reducing CO_2 emissions in the United States through biomass cofiring, putting the number at 50 Mt in the year 2030.[23] The biggest difference between these two assessments appears to be that McKinsey assumes that other, less costly CO_2 abatement measures would be implemented prior to 2030 that would lead to the retirement of large amounts of coal capacity and thus a reduced potential to cofire biomass with coal.

In the previously cited GHG Abatement Measures TSD, the EPA separately assesses the emissions reduction potential of fuel switching from coal to gas and from coal to biomass.[24] With respect to gas, the EPA concludes that emissions are reduced in direct proportion to the amount of gas cofired. Cofiring 10 percent gas with 90 percent coal will reduce GHG emissions four percent relative to firing 100 percent coal. Switching to 100 percent gas reduces GHG emissions 40 percent. WIth respect to biomass, the EPA found that stack CO_2 emissions can increase or decrease relative to firing 100 percent coal, depending on the amount and type of biomass fired, and the extent to which biomass-related GHG emissions are treated by regulators as "carbon neutral."

5. Co-Benefits

Most of the future fuel switching that will occur as a response to GHG regulations will likely involve a switch from coal (or possibly oil) to natural gas or biomass. In addition to the CO_2 emissions reductions noted above, fuel switching is likely to result in reduced emissions of other regulated air pollutants. The extent of the reductions will depend on the fuels burned before and after the fuel switch.

According to the EPA, the average natural gas-fired EGU emits just 28 percent as much NO_X as the average coal-fired EGU on an output (lb/MWh) basis, or 43 percent as much NO_x as the average oil-fired EGU, whereas emissions of particulate matter (PM), SO_2, and mercury are orders of magnitude lower for gas than for coal or oil. For repowering projects, the effects on NO_x emissions may be greater than these averages would suggest because new gas-fired EGUs are likely to be more efficient and have lower emissions than the average of gas-fired units already in place. In the GHG Abatement Measures TSD, the EPA presents information on avoided emissions of SO_2, NO_X, and $PM_{2.5}$ for a hypothetical coal plant switching to natural gas at either a ten-percent cofiring rate or at 100 percent gas.[25] For ten-percent cofiring, SO_2 emissions are reduced by 0.3 lbs/net MWh, NOx by 0.2 lbs/net MWh, and $PM_{2.5}$ by 0.02 lbs/net MWh. If 100-percent gas is fired, the reductions are 3.1 lbs/net MWh for SO_2, 2.04 lbs/net MWh for NO_x, and 0.2 lbs/net MWh for $PM_{2.5}$.

The previously cited EPRI report on cofiring natural gas with coal summarized the expected impacts of each cofiring technology on emissions of NO_x, SO_2, and CO_2. With respect to SO_2 and CO_2, EPRI reports that emissions are reduced roughly in proportion to the differences in emissions factors between natural gas and coal, and the extent to which gas is burned in lieu of coal. The effect on NO_x emissions depends on the cofiring technology used. Supplemental gas cofiring (i.e., simultaneously firing both fuels through separate burners in the boiler's primary combustion zone) can reduce NO_x emissions 10 to 15 percent, whereas the various reburn technologies, which were developed specifically for the purpose of reducing NO_X emissions, can reduce NO_X emissions by 30 to 70 percent across a range of boiler types.

In the GHG Abatement Measures TSD, the EPA does not provide avoided criteria pollutant emissions data for cofiring of biomass as it does for cofiring natural gas. Biomass fuels come in so many varieties that it is much harder and less meaningful to discuss average emissions, but the EPA notes elsewhere that in general the emissions of SO_2, NO_X, and mercury will be lower for biomass fuels than for coal, because biomass contains much less sulfur, nitrogen, and mercury than coal does. For example, Peltier reports that the repowered biomass EGU at Public Service of New Hampshire's Schiller Station emits about 75 percent less NO_X, 98 percent less SO_2, and 90 percent less mercury than before the repowering project, when the unit burned coal.[26]

When biomass and coal are cofired there is some evidence of interactive effects between the products of combustion that makes it harder to predict the resulting

23 McKinsey & Company. (2007, December). Reducing US Greenhouse Gas Emissions: How Much at What Cost? Available at: http://www.mckinsey.com/client_service/sustainability/latest_thinking/reducing_us_greenhouse_gas_emissions.

24 Supra footnote 2.

25 Ibid.

26 Peltier, R. (2007). PSNH's Northern Wood Power project repowers coal-fired plant with new fluidized-bed combustor. POWER. Available at: http://www.powermag.com/psnhs-northern-wood-power-project-repowers-coal-fired-plant-with-new-fluidized-bed-combustor/

impact on non-GHG emissions. The literature on this subject, as summarized by Robinson et al, consistently reports SO_2 emissions reductions, but there are some indications that a 10-percent/90-percent cofiring of biomass/coal (for example) can produce a greater than ten-percent reduction in SO_2 emissions. The majority of studies also report modest NO_X reductions, but some studies report no NO_X benefit and one study found that biomass reburning in a secondary combustion zone can reduce NO_X emissions by 60 percent.[27] Aerts & Ragland, on the other hand, reported the results of one test in which cofiring 10 percent switchgrass with 90 percent coal reduced NO_x emissions by 17 to 31 percent.[28]

The full range of co-benefits that can be realized through fuel switching is summarized in Table 9-4. In this table, "utility system" benefits are those that are shared between the owners of power plants and their customers.

6. Costs and Cost-Effectiveness

In virtually all cases, fuel switching will increase operations and maintenance (O&M) costs above the status quo, or require a capital investment, or both. Where neither type of cost increase is necessary, fuel switching will usually have already occurred for economic reasons. In the context of mandatory GHG regulations for existing sources, the relevant question will not be whether fuel switching increases capital or operating costs but whether it costs less than other compliance options. This question can only be answered on a case-by-case basis for each EGU, but some useful general observations can be gleaned from the literature.

The previously cited NYSERDA report on CO_2 emissions reductions in the RGGI states does not delineate the costs of fuel switching as an emissions reduction strategy, but it does offer a few insights into the economic drivers for fuel switching. NYSERDA found that switching from petroleum and coal generation to natural gas "was caused in large part by the decrease in natural gas prices relative to petroleum and coal prices... Natural gas prices decreased by 42 percent from 2005 to 2009, while both petroleum and coal prices increased. Through 2005, natural gas prices were generally higher than No. 6 oil prices (dollars per MMBTU); beginning in 2006, natural gas prices have been lower than No. 6 oil prices... The price gap between US natural gas and coal decreased by 61 percent, from $6.72 per MMBTU in 2005 to $2.62 per MMBTU in 2009... The changing fuel price landscape has resulted in dual fuel units

Table 9-4

Types of Co-Benefits Potentially Associated With Fuel Switching

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_x	Yes
SO_2	Yes
PM	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	Yes; could be positive or negative
Other	

27 Robinson et al., at supra footnote 21.

28 Aerts, D. & Ragland, K. (1997). *Switchgrass production for biomass.* Research Brief No. 51: University of Wisconsin, Madison, WI. Available at: http://www.cias.wisc.edu/switch-grass-production-for-biomass/.

burning natural gas rather than oil."[29]

The observations in the NYSERDA report are likely to hold true for multi-fuel facilities everywhere, although the fuel price differentials may vary geographically. In some cases, other operational cost impacts of fuel switching, such as reduced ash handling costs when gas use displaces coal, may factor into compliance decisions. Over the longer term, maintenance costs may vary somewhat based on how much of each type of fuel is used, and those costs could affect compliance decisions as well.

It is more difficult to assess costs and cost-effectiveness when cofiring or repowering strategies are used, but this question has been tackled head-on in some of the relevant literature. With respect to cofiring coal and natural gas, the previously cited EPRI report examined case studies of actual cofired EGUs.[30] In several of these cases, supplemental gas cofiring was used either to allow use of an alternate coal or to reduce fly ash carbon levels. EPRI found that in these applications, "gas cofiring improved the combustion characteristics of an alternate coal or reduced the existing carbon levels in the fly ash, but was not sufficient to produce a payback. Either carbon in the fly ash remained above three percent, making it unsalable as a high-priced cement additive, or alternate coal combustion characteristics were not improved sufficiently to provide added boiler flexibility." However, EPRI also found examples where cofiring with gas corrected problems that had led to a derate of the EGU. Eliminating the derate made cofiring a cost-effective choice. Finally, EPRI found that gas re-burn technologies were cost-effective means of reducing NO_x emissions, relative to installing pollution control devices, and supplemental gas cofiring was similarly cost-effective for reducing NO_x in some but not all cases. More recent studies from the engineering firm Black & Veatch indicate that capital costs for cofiring gas with coal can range from $10 to $100 per kilowatt (kW).[31]

Robinson et al offer a number of insights into the economics of cofiring biomass with coal.[32] Their analysis assigns a 5- to 15-percent premium on the nonfuel O&M costs for biomass fuels relative to coal, depending on the cofire rate. Biomass fuel costs are much more variable. Fuel costs can be zero or even negative in cases where onsite or local biomass sources exist, especially if the biomass fuel is a waste-derived fuel that would otherwise have to be landfilled. But in general, they found that the fuel costs of biomass on a BTU basis can be up to four times the cost of coal. Finally, in terms of the capital costs necessary to enable cofiring, their model assumes that biomass can be cofired at up to two percent of total energy input without any modifications to the coal handling and combustion systems. Higher rates of biomass cofiring require a capital investment on the order of $50/kW to $300/kW, depending on the cofire rate. Compiling all of these data along with the potential for cofiring at existing US coal EGUs, the authors found that cofiring with biomass could reduce CO_2 emissions from the coal-fired electricity generation sector by ten percent at a carbon price of about $50 per metric ton. The previously cited analysis by McKinsey & Company cited a lower CO_2 abatement cost, on the order of about $30 per metric ton.[33]

The last fuel switching option to consider is repowering. In a recent study of options for repowering existing steam plants with combined-cycle technology, EPRI found that repowering could cost about 20 percent less than building a completely new combined-cycle plant on a capacity ($/kW) basis, and 5 percent less on a cost-of-electricity ($/MWh) basis.[34] Other analysts have placed the cost of converting an existing coal-fired boiler to natural gas at just 15 to 30 percent of the cost of a new gas boiler.[35] Black & Veatch analysts estimate that the capital costs of repowering from coal to gas range between $100/kW and $250/kW, or higher if a new combined-cycle gas turbine is installed.[36] These costs compare quite favorably to the EIA's estimated cost for a new conventional natural gas combustion turbine of $973/kW or a new conventional natural gas combined-

29 Supra footnote 15.

30 Supra footnote 12.

31 Nowling, U. (2013, October 1). Utility Options for Leveraging Natural Gas. *POWER.* Available at: http://www.powermag.com/utility-options-for-leveraging-natural-gas/?pagenum=1.

32 Robinson et al., at supra footnote 21.

33 Supra footnote 23.

34 EPRI. (2012, August 8). *Repowering Fossil Steam Plants with Gas Turbines and Heat Recovery Steam Generators: Design Considerations, Economics, and Lessons Learned.*

35 Ingraham, J., Marshall, J., Flanagan, R. (2014, March 1). Practical Considerations for Converting Industrial Coal Boilers to Natural Gas. *POWER.* Available at: http://www.powermag.com/practical-considerations-for-converting-industrial-coal-boilers-to-natural-gas/.

36 Supra footnote 31.

cycle unit of $917/kW.[37]

A 2012 case study analysis by Reinhart et al considered the relative costs of five different strategies for reducing emissions from a hypothetical coal-fired power plant.[38] The options considered included full repowering of the existing boiler and turbine to natural gas; modifications of the existing equipment to allow cofiring of natural gas with coal; installation of emissions control equipment without other changes; repowering the existing steam turbine to operate in combined-cycle mode; and full replacement of the existing unit with a combined-cycle natural gas unit. The authors concluded that the least-cost option varied depending on assumptions about future fuel prices, the service life of the unit, and future capacity factors of the unit. Modifying the unit to allow cofiring was not the least-cost option in any of the examined scenarios, but each of the other options was least-cost in at least one scenario. The conclusion one can draw from this paper is that the relative merits of different fuel-switching options depend in part on variables that are generally location- and case-specific.

In the GHG Abatement Measures TSD, the EPA published its own review of the costs and cost-effectiveness of repowering an existing coal boiler to be able to fire gas or biomass.[39] For a typical 500-MW pulverized coal boiler, total capital costs for repowering to gas were estimated to be $237/kW, which would add about $5/MWh to levelized costs of generation. The EPA further estimated that fixed O&M costs would decline by 33 percent, whereas variable O&M costs would drop 25 percent owing to reduced waste disposal, reduced auxiliary power requirement, and miscellaneous other costs. Fuel costs, on the other hand, were expected to double – adding $30/MWh to levelized costs. Putting these factors together, the EPA estimated that the average cost of repowering to gas would be $83/metric ton of CO_2 reduction for 100-percent gas firing, or $150/metric ton for ten-percent gas cofiring.

The EPA estimated that the capital cost associated with adding ten-percent biomass cofiring capability to a 500-MW coal unit would be $20/kW. Fixed O&M costs in this case were estimated to increase by ten percent, while variable O&M costs remained constant. The EPA found that the fuel cost of biomass is highly site-specific. Putting these factors together, the EPA estimated that the cost per metric ton of CO_2 reduction would likely fall between $30 and $80 for biomass cofiring, if the biomass-related emissions were treated as carbon-neutral.

Although the EPA acknowledged in the GHG Abatement Measures TSD that some coal plant owners are engaging in repowering projects, the agency concluded that this kind of fuel switching will be on average more expensive than other available options, such as constructing a new natural gas combined-cycle unit. Because gas and biomass cofiring options were found to be relatively expensive when national average cost data were used, the EPA declined to include fuel switching as part of the "best system of emissions reduction" in its proposed emissions guidelines.

7. Other Considerations

Where physical modifications of a power plant are necessary to facilitate fuel switching, the owner of the power plant will generally not want to make such modifications unless he or she has a reasonable expectation that the capital costs of the project can be recovered from the sale of energy to wholesale markets, a purchasing utility, or retail ratepayers. (Exceptions to this general rule may exist where the owner has a compliance obligation and less costly options are not feasible.) In the case of a power plant owned by an investor-owned utility, the utility will further expect to realize a profit for shareholders. This concern with cost recovery (and profit) is likely to be even more pronounced in regions of the country that have adopted competitive wholesale markets. In those regions, the owners of power plants have no guarantee that their assets will clear the energy market over any given operating period, be dispatched, and earn revenue. Thus, they have no guarantee that the considerable costs associated with repowering an EGU, or even the lesser costs of modifying an EGU to allow cofiring of different fuels, will be recovered. Still, where the owner sees a reasonable expectation of reward to accompany this risk, fuel switching may be an attractive option.

One potential regulatory issue that is often cited by regulated entities as a concern is the possibility that a repowering project could trigger federal New Source Review, PSD, or New Source Performance Standard (NSPS)

37 US EIA. (2013, April). *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants.* Available at: http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf.

38 Reinhart, B., Shah, A., Dittus, M., Nowling, L., & Slettehaugh, B. (2012). *A Case Study on Coal to Natural Gas Fuel Switch.* Retrieved from the Black & Veatch website: http://bv.com/Home/news/solutions/energy/paper-of-the-year-a-case-study-on-coal-to-natural-gas-fuel-switch.

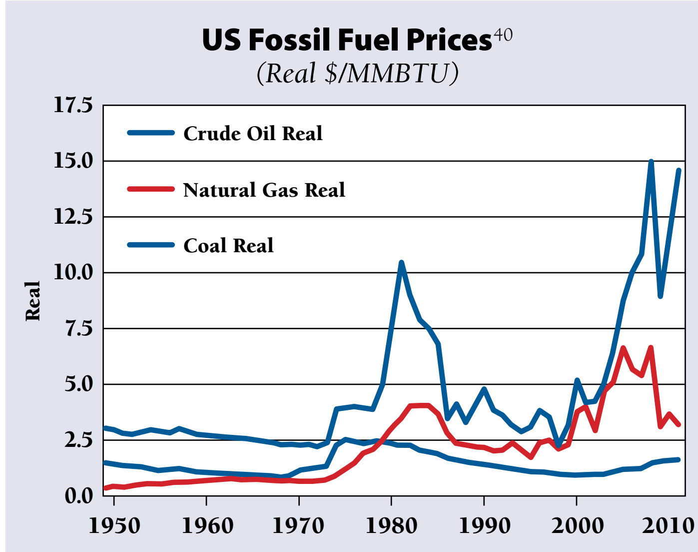
39 Supra footnote 2.

requirements. Satisfying New Source Review, PSD, or NSPS requirements could require the installation of new pollution control devices and add considerably to the cost of such a project, perhaps to the point at which it is no longer economically justifiable to the source owner. But in general, repowering projects will reduce not just CO_2 emissions rates (per MWh), but also the emissions rates of other regulated air pollutants, and this potential problem for source owners is unlikely to materialize. Exceptions may arise in which a repowering project opens the door to greater utilization of the EGU. This could happen, for example, if the repowered unit will have significantly lower operating costs than the existing EGU. If the unit then increases its annual hours of operation, its annual emissions of one or more pollutants could conceivably increase by an amount large enough to trigger other regulations. There may also be cases in which the capital cost of a repowering project exceeds 50 percent of the capital cost that would be required to construct a comparable new facility, thus meeting the Clean Air Act definition of "reconstruction" and triggering NSPS requirements.

The most obvious opportunities to reduce emissions through fuel switching are found at power plants that burn coal or oil as a primary fuel. However, the availability of firm natural gas pipeline capacity may in some cases create limitations on the potential for fuel switching. The most obvious limitation arises where a power plant is not connected to a natural gas pipeline. Extending a pipeline to reach such a power plant requires a significant capital investment, over and above any costs of modifying the power plant itself, as well as a lengthy permitting and construction process. But even where the power plant is already connected to a gas pipeline, there may be limitations. The capacity of gas pipelines relative to peak customer demand varies regionally. During a prolonged cold spell in the winter months of 2014, many power plants in the Northeastern United States found that they could not obtain gas because they did not have firm delivery contracts, and those that did have firm contracts were using nearly all of the existing pipeline capacity. This is not an insurmountable problem; it can be alleviated by adding gas pipeline capacity or by changing contract terms. But it does potentially limit the ability of some sources to reduce CO_2 emissions through fuel switching.

Historically, oil and natural gas prices have been more volatile than coal prices, as shown in Figure 9-3. Owners of coal-fired generation may be reluctant to depend on fuel switching as the means to meet mandatory CO_2 emissions

Figure 9-3



limitations because of the perception, backed by history, that using other fossil fuels increases uncertainty about future fuel costs. Recent advances in production techniques (hydraulic fracturing, principally) have reduced short-term domestic gas prices considerably, but it remains to be seen if these techniques will have an impact on the long-term volatility of prices.

The potential for emissions reductions described earlier in this chapter assumes that the operating capabilities of an EGU will not be affected by fuel switching. In practice, this may not always be the case. The capacity of an EGU can be uprated or derated depending on the heat content of the fuels used, if the rate at which the fuels are consumed remains constant. So, for example, consider the case in which a boiler burns a coal with a high input emissions factor at some maximum rate based on the design of the fuel delivery system and burners. If this coal is then blended with a different rank of coal that has a lower heating value, but the maximum rate that the blended fuel is consumed remains unchanged, then the capacity of the EGU will decrease. Any owner of an EGU will be concerned about a derate of its capacity.

Any fuel switching project that requires an EGU to go offline for an extended period of time may raise concerns about reliability impacts. The likelihood of such impacts will vary with the size (i.e., capacity) of the EGU, the duration of the scheduled downtime, and the amount of

40 US EIA. (2012, September). *Annual Energy Review 2011*. Available at: http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

excess capacity available to meet load during the scheduled downtime.

Power plants that have not previously utilized biomass or biogas fuels may encounter significant challenges in securing reliable fuel supplies and a supply chain that can reliably deliver the fuel. This can present a classic chicken-and-egg dilemma, wherein generators will not switch fuels until they are certain a reliable fuel supply and supply chain exists, but a supply chain will not materialize until there is sufficient demand for the fuel. Onsite storage of solid biomass fuels can also pose problems in terms of storage space, fire risks, or fugitive dust concerns. These same concerns are present at coal-fired power plants, so they are not novel issues when it comes to fuel switching to biomass. Just as there are techniques to deal with these issues at coal plants, there are similar techniques to deal with them at biomass plants.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on fuel switching:

- Black, S., & Bielunis, D. (2013, August). *Challenges when Converting Coal-Fired Boilers to Natural Gas.* Babcock Power Inc. Available at: http://www.babcockpower.com/pdf/RPI-TP-0232.pdf.
- EPRI. (2000, August). *Gas Cofiring Assessment for Coal Fired Utility Boilers.* Palo Alto, CA.
- EPRI. (2012, August 8). *Repowering Fossil Steam Plants with Gas Turbines and Heat Recovery Steam Generators: Design Considerations, Economics, and Lessons Learned.*
- Nicholls, D., & Zerbe, J. (2012, August). *Cofiring Biomass and Coal for Fossil Fuel Reduction and Other Benefits—Status of North American Facilities in 2010.* General Technical Report PNW-GTR-867. US Department of Agriculture, Forest Service, Pacific Northwest Research Station.
- US EPA. (2010, October). *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Coal-fired Electric Generating Units.* Office of Air and Radiation. Available at: http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf.
- US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units—GHG Abatement Measures.* Office of Air and Radiation. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-technical-documents.

9. Summary

Fuel switching in its various forms offers a proven emissions reduction strategy that will be feasible to a lesser or greater extent for many covered sources. Literally thousands of EGUs in the United States already have the capability to fire multiple fuels, and many more could be candidates for a repowering project. The primary limitation on this strategy is not technical but economic. Most EGUs that are not already using low-emitting fuels as a primary energy source are using higher-emitting fuels for economic reasons. Fuel switching could increase the operating costs, and possibly add capital costs, for these sources. However, the underlying economics will change when new mandatory CO_2 emissions limits are in place. Generation owners will then want to reconsider the relative costs of different fuels and determine if fuel switching is their best compliance option.

10. Reduce Losses in the Transmission and Distribution System

1. Profile

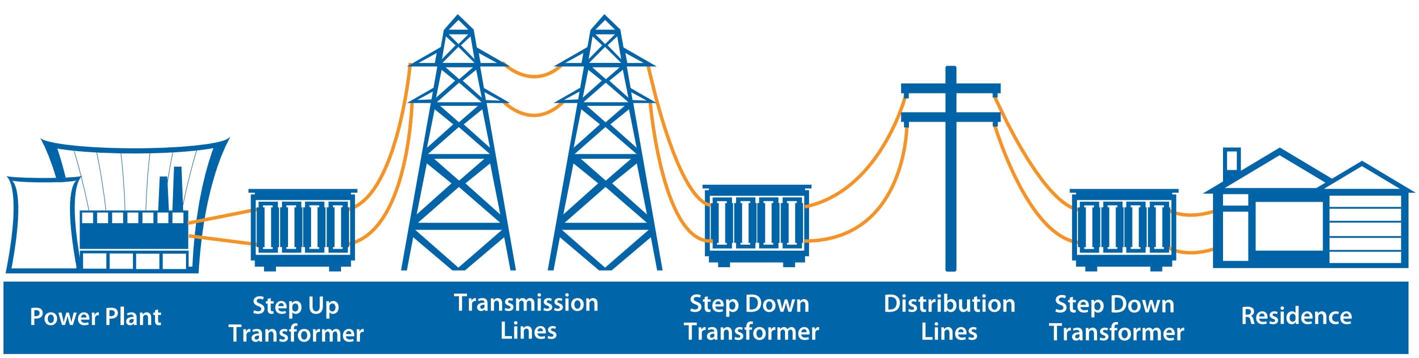
Electricity losses occur at each stage of the power distribution process,[1] beginning with the step-up transformers[2] that connect power plants to the transmission system, and ending with the customer wiring beyond the retail meter. The system consists of several key components: step-up transformers, transmission lines, substations, primary voltage distribution lines, line or step-down transformers, and secondary lines that connect to individual homes and businesses. Figure 10-1 shows a diagram of these system components. These electricity losses are often referred to generically as "line losses," even though the losses associated with the conductor lines themselves represent only one type of electricity loss that occurs during the process of transmitting and distributing electricity. System average line losses are in the range of six to ten percent on most US utility grids, but they increase exponentially as power lines become heavily loaded. Avoiding a small amount of electricity demand in the highest peak hours can reduce line losses by as much as 20 percent. At such levels of losses, disproportionately more generation resources need to be operated to deliver the same amount of electricity to end-users.

Each of the stages identified in Figure 10-1 is subject to losses, and therefore provides opportunity for efficiency improvements. The cumulative benefits can be very significant. This is because a one-kilowatt (kW) load reduction at the customer's end translates into more than a one-kW load reduction – sometimes very much more – moving "upstream" to the distribution, transmission, and generation levels because of losses compounding along the way.

Each component of the distribution system can be optimized to reduce line losses. This chapter discusses each component, and how equipment choices can affect efficiency

Figure 10-1

Simple Diagram of an Electric Transmission and Distribution System[3]



1 "Distribution" is, regrettably, an ambiguous term when discussing electric power. As used in this sentence, it reflects the overall process of delivering electricity from power plants (where it is generated) to end-users (where it is consumed by homes, businesses, and institutions). Distribution is also a technical term of art, however, which refers to the lower-voltage, later stages in the electricity delivery process, as illustrated in Figure 10-1. The reader should remain cognizant of the potential for the confusion this ambiguity creates.

2 Transformers are used to increase voltage for more effective transportation of electricity and to decrease voltage back to levels suitable for industrial, commercial, and residential use.

3 Adapted from: Cowlitz County (WA) Public Utility District. (Undated). *Electricity-Transmission (How Electricity Moves)*. Available at: http://www.cowlitzpud.org/pdf/electricity101/6%20Electricity%20-%20Transmission.pdf.

and, by extension, greenhouse gas (GHG) emissions.

In addition, line losses can be significantly affected by end-use energy efficiency policies (detailed in Chapters 11 through 15) and demand response programs (Chapter 23).

Engineering Fundamentals

Losses occur in both transmission and distribution lines and in transformers, the fundamental components of the electricity distribution system or "the grid." Some losses, called "core" or "no-load" losses, are incurred to energize transformers in substations and on the distribution system. A larger share is labeled "resistive" or "copper" losses; these losses reflect the resistance of the materials themselves to the flow of electricity.

Core losses are typically 25 to 30 percent of total distribution losses, and do not increase (or decrease) with changes in load. They are largely influenced by the characteristics of the steel laminations used to manufacture the core of transformers.

Resistive losses are analogous to friction losses in the lines and transformers. As loads increase, the wires (including those in the transformers) get hotter, the material becomes more resistive, and line losses increase. For this reason, resistive losses increase exponentially with the current on a line.[4]

At low-load periods, system losses are almost entirely core losses, and may be as low as three percent.[5] During peak electrical demand periods, however, resistive losses become dominant. At the highest load hours, average line losses increase into the 10- to 15-percent range, but marginal line losses (those that are avoided if load is reduced) may increase to 20 percent or more. This concept is analogous to a freeway at rush hour – even a small reduction in traffic volumes can produce very large reductions in "friction" and improve traffic flow. At peak extremes, it can take five power plants operating to provide the end-use electricity normally provided by four.

Therefore, line loss reduction is partly a function of system design and construction, but is also heavily affected by operation of the underlying electrical loads and by how well peak loads are managed. Chapters 11 through 15 and 23 address energy efficiency and peak load management, both of which are very important in reducing line losses.

Key Units for Measuring Electricity

This chapter necessarily involves technologies and terminology that may be foreign to air quality regulators, but are quite well understood by the utilities that they regulate. Several terms reflecting common units of electrical measurement – and their abbreviations – are defined below.

- **Amperes (A):** A measure of the current flow through lines and transformers. It is analogous to the flow of water through a pipe.
- **Kilovolts (kV):** Thousand volts, the unit of measure for generation, transmission, and distribution lines.
- **Kilowatt-hour (kWh):** A measure of energy or power consumed in one hour.
- **Volts (V):** Voltage is what drives current through lines and transformers to end-use appliances in homes and businesses. It is analogous to pressure in a water pipe. Voltage must be delivered within a narrow range of between 110 and 124 volts at all times for residential appliances and equipment to operate properly.
- **Watts (W):** A measure of the quantity of power or work (horsepower) that electricity can do at any moment. Watts is the product of amperes multiplied by volts. For example, 220 volts at 20 amps equals 4400 watts, about the amount that a typical residential electric water heater uses. A one-horsepower (1 hp) swimming pool pump motor uses 746 watts.

A later section will discuss additional terms, including power factor and reactive power, which slightly modify these units of measurements to reflect the character of electricity usage. Reactive power is measured by volt-amperes (VA) and by volt-ampere reactive (VAR).

4 This is reflected mathematically as I^2R, meaning the losses increase with the square of the current ("I" or amperage) multiplied by the resistance (R) of the transformer winding or line conductor.

5 Because the current is low, the square of the current is also small.

Components of the System That Contribute to Losses

Each component of the utility transmission and distribution system contributes to losses, so a loss avoided at the customer's end-use or meter compounds, moving back up the system to the generation level. Table 10-1 below illustrates typical line losses at each stage below the transmission receipt point. Transmission system line losses generally involve two (or more) additional transformation stages and one (or more) additional set of lines. Depending on voltage and distance, transmission line losses range from two to five percent.

Table 10-1

Losses at Each Stage of Electricity Distribution[6]

Component	Estimated Loss as a Percentage of Energy Sold: Typical Urban	Typical Rural
Subtransmission Lines	0.1	0.7
Power Transformers	0.1	0.7
Distribution Lines	0.9	2.5
Distribution Transformers No Load	1.2	1.7
Distribution Transformers Load	0.8	0.8
Secondary Lines	0.5	0.9
Total	**3.6**	**7.3**

The following section describes each segment of the transmission and distribution system, with an indication of how losses occur and how they can be mitigated.

Step-Up Transformers. These are the transformers located at generating facilities, which convert the power produced at generating plants to voltages suitable for transmission lines. Typical large generators produce power at 6600 volts, 13,800 volts, 18,000 volts, or even 22,000 volts, whereas typical transmission voltages in the United States are 115 kV, 138 kV, 230 kV, 345 kV, 500 kV, and 765 kV. Step-up transformers are typically sized to the generating units, with modest losses at normal operating levels. If, however, they carry more power than their original intended capacity, losses increase sharply. This can be a problem when generating units have been "uprated" to provide higher output without similar uprating of the step-up transformers. Also, if the generators are operating at a non-optimal power factor (explained below), the resulting increased reactive power output (also explained below) can increase system losses at every level.

Transmission System Conductors. Long-distance transmission lines bring power from generators to the service territory of the distribution utility. In the western United States, these distances can exceed 1000 miles (for example, power from the Canadian border to Los Angeles). Although the conductors themselves have low resistance, the length of the lines and the sizing of the conductors affect losses. Losses along the line may be greatly reduced in direct current (DC) long-distance transmission systems, making DC transmission desirable for very long-distance transmission lines. However, additional losses of up to 1.5 percent occur in the converter stations at each end of a DC transmission line.

Distributing Stations. Many utilities have an intermediate step on their systems, with power taken from "distributing stations," which receive power at high voltage (230 kV and higher) and deliver that power to multiple distribution substations at 69 kV or 115 kV. Transformer losses that occur in substations are incurred twice – first in transforming power from high-voltage transmission to an intermediate voltage, then again at the substations transforming it down to primary voltage. The principal losses in distributing stations are transformer losses. The reason utilities use separate voltage levels is to isolate bulk power transfers from power that is serving load. This approach increases system reliability.

Substation Transformers. These take power from the transmission system, typically at 115 kV or higher, and convert it to the distribution voltage levels of 4 kV to 34 kV. Sized specifically for their maximum expected loads, they very seldom carry power near that limit in order to allow for load transfer between circuits, but there are two issues of concern. The first is core losses that may be too high when they are lightly loaded. The second is resistive losses that may be too high when they are heavily loaded.

Voltage Regulators. These are transformers with multiple taps installed along distribution circuits to enable increasing or decreasing voltage at various points. Historically these were installed along long rural distribution lines to enable a step-up of voltage at distant points, offsetting reduced voltage caused by resistance

6 Hydro One. *Distribution Line Loss Study.* Ontario Energy Board Docket. No. RP-2005-0020. Available at: http://www.ontarioenergyboard.ca/documents/edr-2006-rates/hydro_one_networks/eb-2005-0378/Exhibit%20A%20-%20Tab%2015%20-%20Schedule%202.pdf.

of the lines. Today there are additional functions for these devices. They enable acceptance of higher levels of distributed resources, such as residential solar, onto a circuit, by allowing the grid operator to ensure that "hot spots" do not result from the injection of power at mid-circuit. In addition, they enable more rigorous conservation voltage regulation along a distribution line, which can reduce total power consumption (see Chapter 5). Because they are transformers, they involve both core losses and resistive losses, and attention to both the materials and the sizing of these affects the level of line losses.

Primary Distribution Lines. Primary lines connect substations to circuits that bring power into business districts and neighborhoods. These typically run at 4 kV to 34 kV. The higher the voltage, the lower the current, and thus the lower the resistive losses on these lines. However, higher voltages require taller poles (or more expensive undergrounding technology), so there is a cost/efficiency tradeoff.

Line Transformers. These are the garbage-can-sized cylinders you see mounted on neighborhood power poles or in metal boxes mounted on concrete pads. They convert primary voltage distribution power to the voltages we use in our homes and businesses, typically 120 V, 208 V, 240 V, 277 V, and 480 V.

Secondary Distribution Lines. These connect line transformers to individual homes and businesses. They are typically very short, in part because at these lower voltages, the amperage needed to move power is significant, which requires larger (and thus more expensive) conductors. Losses can be quite high owing to the high current. This is especially true if the secondary load has grown beyond or faster than original projections.

Reducing Transformer Losses

Recall that transformer losses are caused in two different ways, core (no-load) losses and resistive (copper) losses.

Core losses are the losses incurred to energize the transformer. These vary with the size of the transformer and the materials used to construct the transformer. It is essential to "right-size" transformers to minimize core losses. In a situation in which, for example, a large industrial customer with heavy machinery and high power demand moves out of a large building and is replaced by a warehouse operation with only lights and a few office machines, and no accompanying modification is made to the transformers, core losses could exceed the annual power consumption of the new business.

Resistive losses are primarily a function of the current flowing through a transformer, heating it up. These losses are exponential with the current. For this reason it is important to not have too small a transformer, or it will "run hot" with high losses. One option is for utilities to install banks of three or more transformers at substations, de-energizing one or more during low-load periods (to avoid excessive core losses), but then switching them on during high-demand periods (to avoid excessive resistive losses). Again, there may be trade-offs resulting from increased circuit breaker maintenance costs and risk for decreased reliability.

Reducing Line (Conductor) Losses

All utility-grade conductors are made of very pure aluminum or copper, both of which have inherently low resistance to electrical current. There are three factors that contribute most significantly to conductor losses. The first is the quality of the connections at each end of the conductors (and any splices that may exist mid-line). The second is the size of the conductor relative to the amperage it carries. The third is the voltage at which the conductors operate.

Connection quality is generally very good in the United States, but is a source of very significant line losses in less developed countries. Corroded connectors, or simple twisted wires, result in significant arcing of the electrical current, which wastes power in the form of heat.

Conductor size affects the resistance of the line to current passing through it.[7] Where high amperage is anticipated, larger conductors are required, just as a larger-gauge extension cord is needed to handle power tools and other high-usage appliances. Utilities sometimes change out the wires or "re-conductor" an existing distribution circuit (without changing its voltage) in order to increase the capacity and reduce losses on that circuit. This is expensive, but not as expensive as the full reconstruction necessary to increase voltage. And sometimes there is no other alternative, as when a single-family residential area gradually converts to multifamily or commercial development.

Voltage affects losses by reducing the amperage needed to deliver any given number of watts to customers. By increasing voltage on a line – which usually means that new transformers must also be installed – a utility can reduce the amperage in the line.[8] Higher-voltage lines

7 The radius of the conductor reflects the "R" portion of the I^2R formula noted previously.

8 Thus reducing the "I" portion of the I^2R formula.

also generally require taller poles, however, and the costs involved in setting new poles may be prohibitive. The use of underground cable for higher-voltage lines is several times more expensive than overhead construction and is generally limited to relatively short distances and relatively flat terrain.

Encouraging the use of distributed generation such as solar photovoltaics and wind can also greatly reduce system losses if planned wisely. Distributed generation assists by providing a source of power closer to the receiving loads of the utility, thereby avoiding the need for power to be delivered from distant central power stations, suffering losses en route.

Power Factor and Reactive Power

These topics delve fairly deeply into electrical engineering, but they also represent very promising sources of increased electric grid capacity and reduced line losses. "Power factor" is a quantity that basically indicates how effectively a device utilizes electricity. It is measured as the ratio of "real power in kW" to "apparent power in kilovolt-ampere (kVA)" on a distribution circuit or end-use. The difference between the two reflects how efficiently real power is used. "Real power" is the portion of electricity that does useful work. "Reactive power" establishes the magnetic field required by motors and transformers to operate, but does not contribute to useful work.

Real power is produced only from generators – and distributed generation such as solar photovoltaics. Reactive power can be produced from both generators and capacitors. For maximum efficiency, a generator should operate at its rated power factor or higher. The same is true for motors and other end-use equipment.

Resistive loads (such as incandescent light bulbs) have a power factor of 1.00, meaning that they use only real power; so real power and apparent power are the same for such loads. However, motors, transformers, electronic equipment, and distribution lines consume both real and reactive power. So their power factor is less than 1.00 unless power factor correction technology is applied. In fact, some motors (such as those in refrigerators and especially older air conditioners) and electronic power supplies (such as those in personal computers, office equipment, and televisions) impose loads on the electric system that exceed the amount of power they actually use productively.[9]

While kilowatt hours (kWh) measure the amount of power used by an end-user, kilovolt-ampere hours measure the total amount of power that must be supplied by the utility. Modern metering can identify this difference, and can help enable consumers or utilities to take corrective action. This usually involves installing capacitors to supply reactive power at the customer's equipment instead of requiring the grid to supply all the reactive power needed.

Although utilities typically bill large customers in part for their peak demand level, including additional losses owing to poor power factor, most small business and residential consumers are not charged for peak demand. The primary reason for this is that the necessary metering equipment was historically fairly expensive, and residential consumers had few loads that created significant power factor issues. Today both of these factors have changed. Modern, inexpensive, smart meters can measure kilovolt-ampere hours as easily as they measure kWh, so utilities can bill customers for the actual power they require (kVA), not just the power they consume (kW). This in turn provides a real incentive for consumers to invest in power factor correction.

This is not a trivial matter. One of the most efficient home refrigerators sold, a Whirlpool 22-cubic-foot bottom-freezer model, has been measured to have a power factor below 40 percent, meaning that the kVA capacity required to serve it is 2.5 times the kW the unit actually consumes.[10] This drives up the current on the home circuit, the secondary distribution line, the line transformer, and so on up the distribution circuit if capacitors are not installed somewhere on the circuit to address and correct this power factor problem. Because conductors, transformers, and power generators are actually rated in kVA not kW, if this power factor is not corrected, it increases the cost of the entire electrical system. And, if left uncorrected, the resulting higher amperage imposed on lines and transformers also drives up resistive losses. Utilities – and their ratepayers – must then spend more money sooner to replace grid equipment that becomes unnecessarily overloaded. Circuit and station upgrades and even generation additions can be reduced or even postponed if power factor is corrected.

As residential loads have moved from resistive loads (e.g., incandescent light bulbs, electric ranges, electric dryers, and electric water heaters) to more electronic and

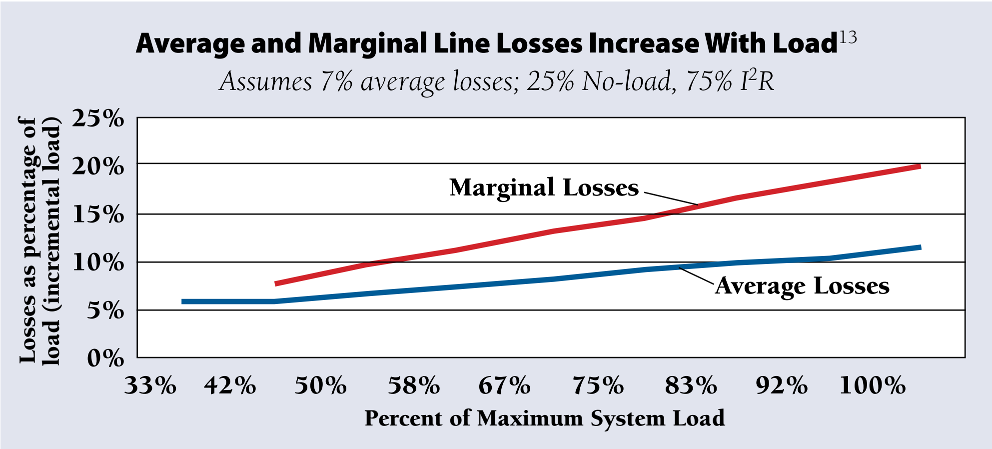
9 The increased current on the distribution system therefore affects the "I" component of the I^2R formula. This means that losses will increase by the square of the current.

10 Measured by RAP Senior Advisor Jim Lazar, using a Kill-A-Watt meter, on August 10, 2014.

motor loads (e.g., air conditioning compressors), residential power factor has become a promising source of significant capacity reduction, making power factor correction increasingly important in improving system efficiency.

Power factor correction is most effective when done close to the loads involved, so that the higher current does not affect wiring upstream from the end-use. Federal appliance standards could require high power factor along with high measured kWh energy efficiency, but until this is in place and the existing appliance stock has been upgraded, utilities may be able to achieve significant capacity benefits and reductions in line losses by addressing commercial and residential power factor issues with carefully placed capacitor installations on distribution circuits.

Figure 10-2



Benefits of Demand Response Programs on Line Losses

Demand response (DR) programs reduce loads during the highest demand hours on a system. These are the hours when line losses are highest, because the amperage on conductors is highest.

Because line losses are exponential, reducing load a little bit at peak hours results in an exponential reduction in line losses.[11] Figure 10-2 shows how marginal losses increase with load twice as rapidly as average losses on a utility distribution system.[12] As the figure shows, peak hour line losses on a distribution circuit may exceed 20 percent.

Conversely, off-peak marginal losses may be as little as five percent. Thus, shifting an electric water heater load from on-peak to off-peak may save 15 percent of the power shifted, a savings that would dwarf the standby loss that would occur from holding that hot water in a well-insulated tank.

Ice storage or chilled-water storage for air conditioning can provide similar benefits, reducing on-peak losses dramatically, while increasing off-peak losses only moderately. And there is another benefit of making ice at night: the outside air is cooler, allowing the chiller equipment to work more efficiently because heat is more readily released (i.e., the "heat rejection" of the equipment is improved).

The capacity value of DR needs to be measured in a manner that includes the avoided line losses, because the amount of generation avoided is a function not only of the end-use load that is reduced, but also the losses incurred between the generation system and the load. As noted earlier, this can range from 5 to 20 percent more than the load.

Other forms of DR (addressed more comprehensively in Chapter 23) not only provide peak load relief, but also reduce line losses by shrinking on-peak losses, thereby avoiding not only the fuel used to generate wasted electricity (and the associated emissions), but also over time at least some of the capital investment in generation, transmission, and distribution facilities necessary to supply that wasted electricity.

2. Regulatory Backdrop

The technical standards of the electric distribution system are defined and largely self-regulated by the industry in the United States, notably by the Institute of Electrical and Electronics Engineers, the American National Standards Institute, and the National Electrical Manufacturers Association.

11 In mathematical terms, the first derivative of the I^2R function is 2IR, meaning that the marginal resistive losses at every hour are two times the average resistive losses.

12 Assumes an illustrative hypothetical system with 25-percent core (no-load) losses and 75-percent resistive (copper) losses.

13 Lazar, J., & Baldwin, X. (2011, August). *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/4537.

The US Department of Energy (DOE) has regulated the efficiency of distribution line transformers since 2007, but because of their 40-plus-year lifespan, millions of older, less-efficient transformers remain in service. States that have adopted energy efficiency resources standards may allow utilities to meet a portion of their obligation through distribution system efficiency improvements such as transformer replacement, conductor replacement, or voltage upgrades.[14] The DOE's standards for distribution transformers adopted in 2013 are expected to save 350 billion kWh over the next 30 years, compared with the typical transformers being built. This equates to a savings of about 30 percent in losses.[15] Further refinements to these standards could increase these savings by an additional one-third, although there is also a cost trade-off involved owing to the more costly materials used.

It is important to note that capital projects to install new, or to improve existing, transmission and distribution systems or components are typically regulated by public utility commissions and require commission approval above certain expenditure levels. Public utility commissions strive to ensure that such capital expenditures are "prudent" and "used and useful" to avoid undue burden to ratepayers. As such, improvements in these systems may also be required to demonstrate reliability gains and/or cost reductions to ratepayers before they are approved.

3. State and Local Implementation Experiences

Aside from initial siting issues, improvements to electricity transmission and distribution systems rarely come before air quality regulators. They do often appear in public utility regulatory dockets, typically for prudency review and cost recovery purposes.

Almost every electric utility has undertaken specific programs for distribution system improvement, and they generally consider line loss reduction as one of the resulting benefit streams. Comparatively few utilities, however, have undertaken specific programs directed solely toward line loss reduction.

Burbank Water and Power, a small municipal utility in Burbank, California, is an exception. It has given specific attention to line loss reduction in the following ways. It has:

- Increased some distribution circuits from 4 kV to 13 kV and 34 kV;
- Installed gas-cooled substations with high-efficiency station transformers;
- Re-conductored some residential circuits with larger conductors to reduce resistive losses;
- Installed smart meters that enable the system controllers to measure voltage at thousands of points in order to facilitate a conservation voltage regulation program;
- Identified substations where one of three station transformers can be de-energized during the winter period to reduce core losses;
- Extended power factor (kVA) rates to medium-sized commercial customers to create an incentive for these customers to install power factor correction;
- Installed capacitor banks at strategic points on the distribution system to improve power factor; and
- Identified customers occupying premises with oversized (or undersized) line transformers to optimize or "right-size" the transformers and thereby reduce losses.

The multiple-transformer approach described in an earlier section is used by many utilities at the substation level, but there are also opportunities to do it at the customer level where loads vary seasonally. For example, a program to de-energize transformers serving only irrigation pumping loads during the non-irrigation season has been examined by the Northwest Power and Conservation Council's Regional Technical Forum.[16] Installing the necessary switching would, of course, require additional capital investment in the distribution system.

4. Greenhouse Gas Emissions Reductions

Distribution system efficiency improvements can readily avoid two to four percent of total energy required at the generation level. Air quality regulators could nominally anticipate a corresponding reduction in GHG emissions from reduced generation. However, depending on which

14 Energy efficiency resources standards policies are discussed in Chapter 11.

15 American Council for an Energy-Efficient Economy. (2013, April). *New Department of Energy Transformer Standards Are a Mixed Bag.* Available at: http://aceee.org/press/2013/04/new-department-energy-transformer-st.

16 Refer to: Podell-Eberhardt, Z.,Travis, R., Phillips, C., & Koski, S. (2012). *Draft Presentation of Five Standard Protocols.* Cascade Energy, Inc. Available at: http://rtf.nwcouncil.org/meetings/2012/10/Draft%20Protocol%20Presentation%20for%20Oct%2023.pptx.

generation sources are dispatched to serve the reduced load, the impact on GHG emissions can be greater or less than the percentage of energy savings. If older steam generating units are curtailed or retired, GHG savings are likely to significantly exceed the percentage of energy savings; if newer gas turbines are curtailed instead, the GHG savings are likely to be less than the energy savings percentage.

5. Co-Benefits

Addressing line losses reduces both capacity and energy requirements on the electricity system. In addition, by reducing electricity generated, the societal benefits of reduced emissions – of all emitted GHG, criteria, and toxic pollutants – are realized. Numerous co-benefits, including energy-related and non-energy benefits, also occur with reduced generation, as noted in Table 10-2.

Where losses are reduced by improving power factor at the customer's end-use, the amount of heat released within the customer premises can also be reduced, avoiding some air conditioning load in air conditioned buildings. Refrigerator motors that run cooler after power factor correction also reduce the amount of cooling that is required for the refrigerator to keep food cool. These can provide additional participant benefits, which are not mentioned in the table at right, in comfort and operations and maintenance costs.

Figure 10-3 illustrates that the benefits of line loss reduction spread across the spectrum of direct and indirect economic benefits associated with energy efficiency.

Table 10-2

Types of Co-Benefits Potentially Associated With Reducing Line Losses

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Criteria and toxic pollutants emitted by generating units are also reduced
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	No
Economic Development	No
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	Maybe
Avoided Distribution Capacity Costs	Maybe
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	No
Other	

6. Costs and Cost-Effectiveness

Line loss reduction investments at the time of system upgrades are almost always highly cost-effective. That is, when a transformer, conductor, or electric motor is being replaced, it is essential that the replacement be a high-efficiency and high power-factor unit. Retrofit costs associated with replacing an in-service, operational unit are dramatically higher than the incremental capital costs of selecting a more efficient component at the time of installation.

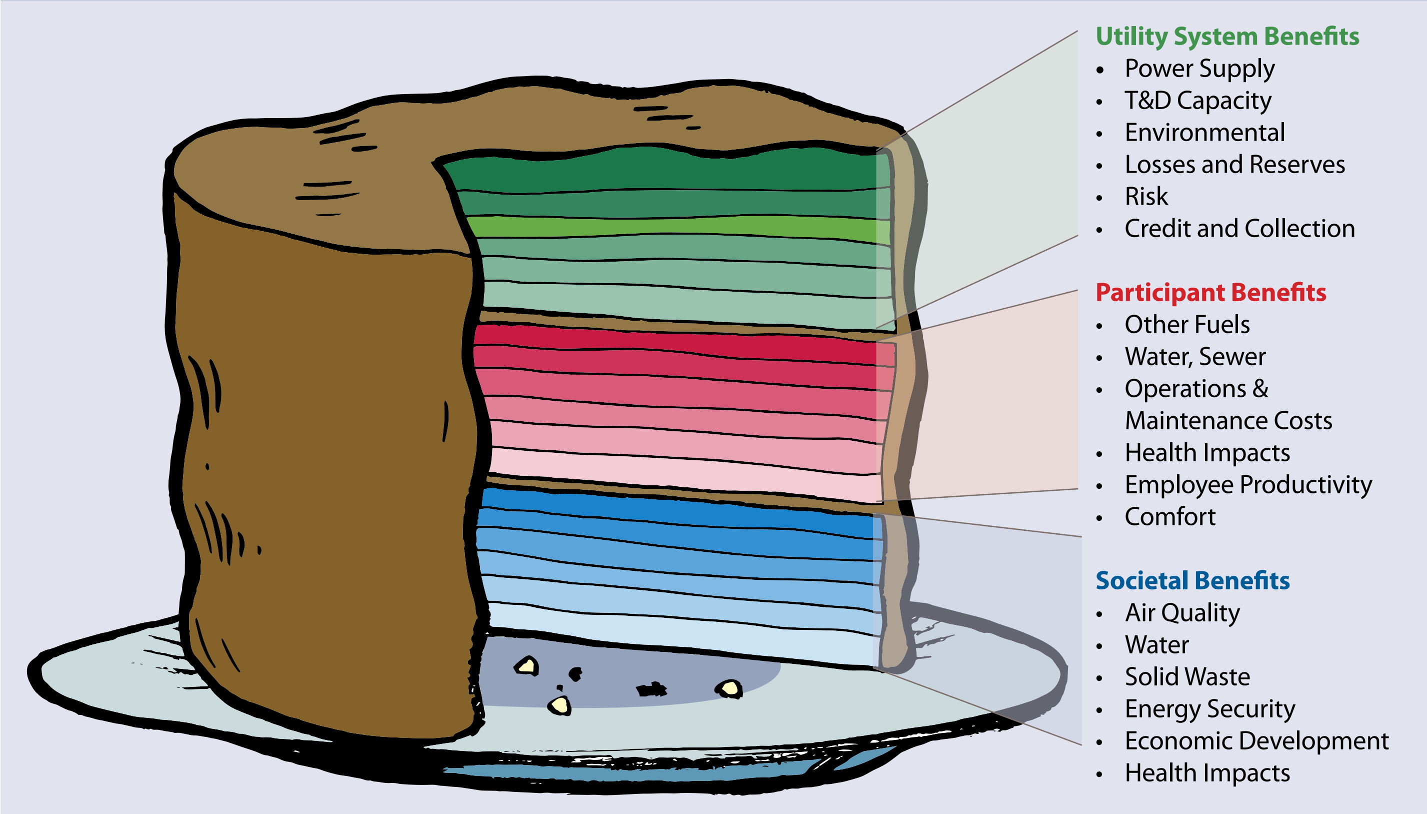
For example, the economic analysis associated with the DOE transformer standards referenced previously estimated a payback period of as little as 2.4 years for some sizes. For all sizes of transformers, however, the payback period was well within the useful life of a utility-grade distribution system transformer.[17]

Power factor correction is one of the most cost-effective measures both utilities and customers can take to improve efficiency and reduce losses. Making their customers aware of potential power factor savings should be an important

17 US DOE. (2007, October). Federal Register, Vol. 72, No. 197, Page 58219.

Figure 10-3

"Layer Cake" of Benefits Associated With Line Loss Reduction[18]



part of every utility's conservation program. Utility rules and regulations should specify a minimum power factor requirement as a condition of service. Overall power factor of 95 to 98 percent should be the norm.[19]

7. Other Considerations

Reducing line losses makes it less likely that system loads will exceed system capacity, thus enhancing reliability by avoiding brownouts and blackouts that can occur under such circumstances.

In addition, improving the power factor of end-use motors extends the lifetime of those motors owing to reduced heating, thereby providing end-use reliability improvements for businesses and consumers.

More fundamentally, the electric power industry is undergoing unprecedented change at this time. The associated uncertainty should foster enhancements to the transmission and distribution system as a way to secure greater yield from existing generation resources (which compares favorably to the risks involved in constructing new supply resources). At the same time, however, declining electrical growth in many areas, coupled with increasingly competitive distributed generation alternatives, may make the financing of new, more efficient grid infrastructure challenging.

18 Adapted from: Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)*. Montpelier, VT: The Regulatory Assistance Project. Available at www.raponline.org/document/download/id/6739.

19 Power factor for individual induction motors may be limited (e.g., to 93 percent) to avoid harmonic issues, depending on the motor's design.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on line losses in electricity transmission and distribution systems.

- Lazar, J., & Baldwin, X. (2011, August). *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/4537.
- Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)*. Montpelier, VT: The Regulatory Assistance Project. Available at http://www.raponline.org/document/download/id/6739.
- Rozenblat, L. (2013). *What is Power Factor?* Available at: http://powerfactor.us/whatis.html.
- Schneider Electric. (2008). *Electrical Installation Guide, Chapter K: Energy Efficiency in Electrical Distribution.* Available at: http://www.schneider-electric.com.au/documents/electrical-distribution/en/local/electrical-installation-guide/EIG-K-energy-efficiency.pdf.

9. Summary

Reducing line losses in the electrical transmission and distribution system is a readily available option to enhance electrical efficiency and reduce generation-related emissions. Advances in technology and understanding have made possible significant efficiency gains through investments in improved grid components and, on the demand side, in load management at peak levels. As with several other options, the primary limitation on this strategy is economic, not technical. It is essential that new system builds take advantage of more efficient components. Upgrade and/or replacement of the broad electrical distribution infrastructure now in place, however, will remain a significant obstacle. Changes in the electric power industry, declining electrical demand in many areas, and increasingly competitive distributed generation alternatives, may make the financing of new, more efficient grid infrastructure challenging. The advent of mandatory CO_2 emissions reduction requirements will improve the payback of such improvements, but it will simultaneously motivate more efficient end-use equipment and clean distributed generation as well.

Chapter 11. Establish Energy Savings Targets for Utilities

1. Profile

Energy efficiency refers to technologies, equipment, operational changes, and in some cases behavioral changes that enable our society to enjoy equal or better levels of energy services while reducing energy consumption.[1] Efforts to improve efficiency in the generation, transmission, or distribution of electricity are covered in Chapters 1 through 5 and in Chapter 10. In contrast, Chapters 11 through 15 address different policy options for making the end-user's consumption of electricity more efficient. This chapter focuses on policies that establish mandatory energy savings targets for electric utilities, the achievement of which is generally funded through revenues collected from customers themselves. Chapter 12 focuses on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency as an alternative or supplement to government-mandated programs or regulatory requirements. Chapter 13 focuses on an emerging type of energy efficiency program, behavioral energy efficiency, that is worthy of separate treatment because it is sometimes included within the mandated programs described in this chapter (Chapter 11) and sometimes implemented as a voluntary effort outside of those programs. Chapter 14 covers mandatory appliance efficiency standards that are imposed on manufacturers, and Chapter 15 covers mandatory building energy codes that are imposed on builders and developers.

The efficient consumption of energy is already a critical driver of our economy. Although the US economy has tripled in size since 1970, three-quarters of the energy needed to fuel that growth has come from efficiency improvements rather than new electric generation resources.[2] Yet much more can be done. A 2009 study concluded that 86 percent of energy consumed in the United States is wasted.[3] Adopting a broad base of energy efficiency programs is a critical step in rectifying this problem. Recently, energy efficiency programs have grown in scope and quantity in many states, but significant savings can still be found in every state. For instance, McKinsey & Company concluded that non-transportation energy use across the country could be reduced by 23 percent from a business-as-usual scenario by 2020. As McKinsey put it, "Energy efficiency offers a vast, low-cost energy resource for the US economy – but only if the nation can craft a comprehensive and innovative approach to unlock it."[4]

Energy efficiency also holds a unique place among all the policies and technologies discussed in this report in that it provides the largest source of greenhouse gas (GHG) abatement at negative cost. That is, energy efficiency simultaneously reduces GHG emissions and cost. McKinsey attempted to quantify both the cost and GHG abatement potential of a host of technologies including energy efficiency in a 2007 report. As indicated in Figure 11-1, many electric efficiency measures from residential and commercial electronics to shell improvements in commercial buildings constituted the majority of the negative cost abatement opportunities.

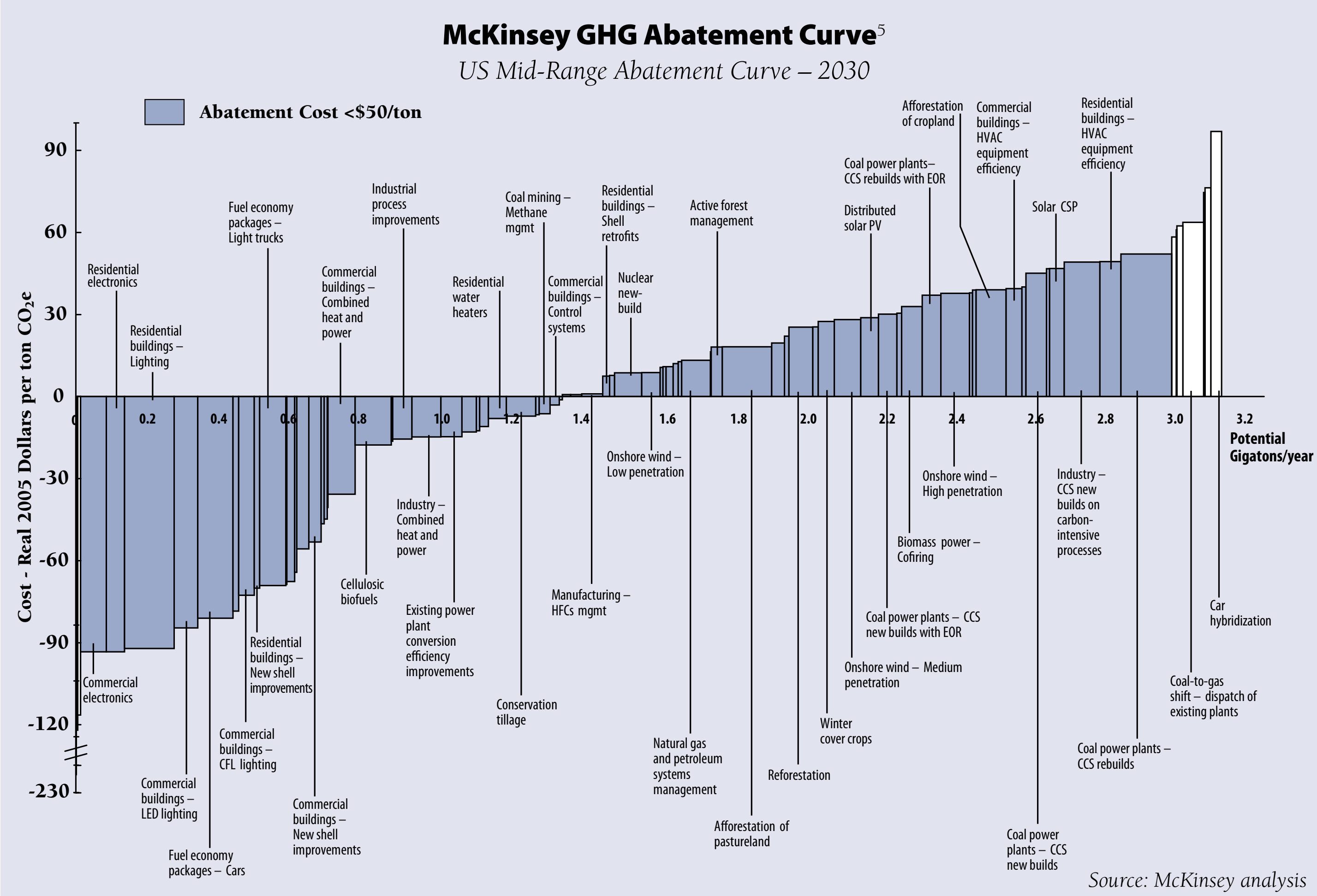
1 In contrast, some people use the term "energy conservation" to refer to actions that reduce energy consumption but at some loss of service. Neither term has a universally accepted definition and they are sometimes used interchangeably.

2 Laitner, J. A. S., Nadel, S., Elliott, R. N., Sachs, H., & Khan, A. S. (2012, January). *The Long-Term Efficiency Potential: What the Evidence Suggests.* ACEEE. Available at: http://www.aceee.org/sites/default/files/publications/researchreports/e121.pdf

3 Ibid.

4 Choi Granade, H., Creyts, J., Derkach, A., Farese, P., Nyquist, S., & Ostrowski, K. (2009, July). *Unlocking Energy Efficiency in the US Economy.* McKinsey & Company. Available at: http://www.greenbuildinglawblog.com/uploads/file/mckinseyUS_energy_efficiency_full_report.pdf

Figure 11-1



Ratepayer-Funded Energy Efficiency Programs and Mandatory Savings Targets

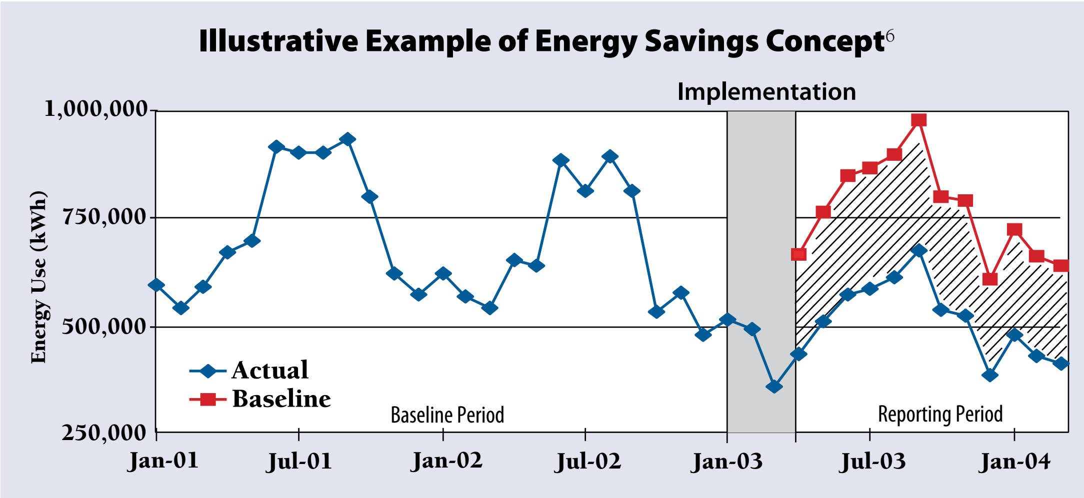
For decades, in jurisdictions across the United States, electric utilities have offered programs to help their customers use energy more efficiently. These programs are generally funded by the customers (a.k.a., "ratepayers") themselves; utilities set aside a portion of the revenues collected from customers and reinvest that money in energy efficiency programs. Although ratepayer-funded energy efficiency programs are generally administered by utilities, there are several examples from the United States where the programs are administered by a third party instead of the utility. For this reason, throughout this chapter we refer generically to energy efficiency "program administrators."

In most cases, ratepayer-funded energy efficiency programs were created in response to a state government policy that directly or indirectly obligated utilities to offer energy efficiency programs. Some of these jurisdictions also require utilities to achieve specified targets for energy savings. The reason these policies exist is that energy efficiency is a low-cost, low-risk resource. Evidence from energy efficiency policies implemented across the United States has consistently demonstrated that a suite of enabling policies, complemented with an effective implementation strategy and support mechanisms, leads to significant energy savings and emissions reductions while reducing total electric system costs.

"Energy savings" is an important but confusing concept that brings with it all of the difficulties of "measuring" something that did not happen – in this case, the consumption of energy that did not happen because a customer became more efficient. The process of quantifying

5 McKinsey & Company. (2007, December). *Reducing US Greenhouse Gas Emissions: How Much at What Cost?* US Greenhouse Gas Abatement Mapping Initiative. Executive Report. Available at: http://www.mckinsey.com/~/media/McKinsey/dotcom/client_service/Sustainability/cost%20curve%20PDFs/US_ghg_final_report.ashx.

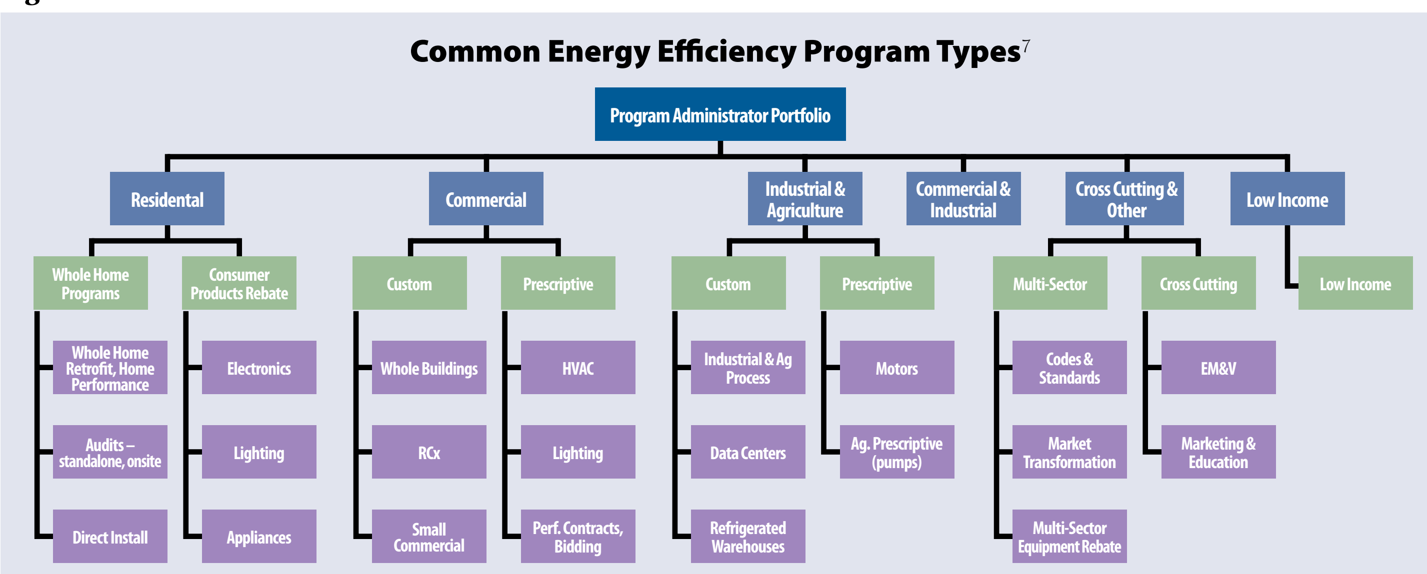
Figure 11-2



energy savings necessarily requires a comparison between an actual outcome and an assumed "baseline" or business-as-usual outcome (i.e., one in which the customer did not take an action to become more efficient). This concept is illustrated in Figure 11-2, in which the hatched area represents the energy savings from implementing an energy efficiency measure.

Energy efficiency programs encompass a wide variety of activities. Although this chapter focuses only on electric energy efficiency, programs can apply to all manner of fuels, from electricity to natural gas to heating oil. Energy efficiency programs can also target all end-uses of energy. There are programs to make commercial lighting more efficient, to reoptimize or replace an office building's heating, ventilation, cooling and lighting systems, to weatherize homes, to customize industrial processes to make them as efficient as possible, to replace or repair inefficient gas heating systems, among many, many others. In most jurisdictions, the energy efficiency program administrator offers a portfolio of energy efficiency programs targeting different energy end-uses by different classes of customers (e.g., residential, commercial, industrial). Figure 11-3 depicts the variety of energy efficiency program types that are often included within such a portfolio. Although the portfolio of any

Figure 11-3



6 National Action Plan for Energy Efficiency. (2007, November). *Model Energy Efficiency Program Impact Evaluation Guide.* Available at: http://www.epa.gov/cleanenergy/documents/suca/evaluation_guide.pdf

7 Hoffman, I., Billingsley, M. A., Schiller, S. R., Goldman, C. A., & Stuart, E. (2013, August 28). *Energy Efficiency Program Typology and Data Metrics: Enabling Multi-State Analyses Through the Use of Common Terminology.* LBNL. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6370e.pdf. In the figure, "HVAC" refers to heating, ventilation, and air conditioning; "RCx" refers to retro-commissioning of buildings; and "EM&V" refers to evaluation, measurement, and verification, a topic covered in more detail later in this chapter.

given program administrator may not include all of the program types shown in Figure 11-3, the key to unlocking significant savings is to offer a broad array of energy efficiency programs addressing multiple end-uses and targeting all classes of customers.

Figure 11-3 indicates that "Codes & Standards" are one type of energy efficiency program that may be included in a program administrator's portfolio. Although this is true, it is much more common for appliance efficiency standards and building energy codes to be addressed through separate policies, outside the context of ratepayer-funded energy efficiency programs. For that reason, this document describes appliance efficiency standards separately in Chapter 14 and building energy codes separately in Chapter 15. Behavioral efficiency programs, not shown in Figure 11-3, are another type of energy efficiency program that might appear in a program administrator's portfolio or might be offered as a separate, stand-alone program by another party. Because behavioral efficiency programs are a relatively new development, presenting some unique opportunities and issues, they are treated separately in Chapter 13.

The design of each energy efficiency program in the portfolio will vary across administrators but often includes actions such as auditing buildings to determine which systems are inefficient; providing rebates, discounts, or other financial incentives to influence consumer purchasing, design, and remodeling decisions;[8] installing or subsidizing the installation of more efficient equipment; and rating buildings for their energy performance. Examples of good energy efficiency program design have been featured in publications of the American Council for an Energy-Efficient Economy (ACEEE).[9] Typically these efficiency programs are funded through a charge to electric or gas customers per unit of energy consumption. The funds collected pay for everything from administrative costs to equipment incentives to the costs of marketing the program to potential participants.

Critics of mandatory energy efficiency programs often argue, based on economic principles, that people (and profit-making businesses, especially) will choose energy-saving options if they are truly cost-effective, without any incentives or subsidies or government-mandated energy efficiency programs. However, this common critique overlooks the fact that ratepayer-funded energy efficiency programs seek to address market failures that create barriers to more efficient consumption of electricity. These barriers could be as simple as the difference in up-front purchase cost between the most efficient and least efficient air conditioner. Or the barriers could be as complex as addressing a tenant-landlord situation in which the tenant pays all energy-related bills but would reap no other benefits from structural improvements to the leased property. Properly designed energy efficiency programs will find ways to correct these and other market failures for a wide range of participants.

2. Regulatory Backdrop

The enabling legislative and regulatory framework for establishing energy savings targets can take multiple and sometimes overlapping forms, including (1) as an obligation on energy service providers such as gas and electric utilities to achieve mandated levels of energy savings (known in the United States as an energy efficiency resource standard or EERS); (2) as part of an integrated resource planning framework that seeks to identify the least-cost means of meeting electric demand;[10] and (3) as part of a demand-side management (DSM) plan.[11]

In the past decade, there has been a noticeable trend in state policies toward establishing EERS policies. The most

8 In the past, rebates and other incentives have usually been offered to consumers to directly influence their decisions. For example, many energy efficiency programs will provide a rebate to customers who purchase an Energy Star appliance. An alternative approach that is increasingly included in energy efficiency portfolios and that may be prevalent in the future is to offer "mid-stream" financial incentives to retailers for stocking, promoting, and selling more efficient products than they would have otherwise. The theory behind this approach is that retailers can be motivated by even small changes in their profit margin, whereas many consumers will only change their purchasing decisions if they perceive a rebate to be "large" and worth the trouble of mailing it in.

9 Nowak, S., Kushler, M., White, P., & York, D. (2013, June). *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs.* ACEEE. Available at: http://www.aceee.org/sites/default/files/publications/researchreports/u132.pdf

10 Integrated resource planning encompasses much more than just energy efficiency; because of the breadth of the subject and its potential role in reducing power sector emissions, it is covered separately in Chapter 22.

11 DSM is often intended to mean the combination of end-use energy efficiency and demand response. Demand response programs are described in Chapter 23.

common formulation for an EERS obligation is one that requires a utility to achieve an amount of energy savings (in megawatt-hours [MWh]) in each year that equals a specified percentage (e.g., one percent) of the provider's retail sales in a previous year. Some EERS policies include two savings levels: a "first year" savings level, referring to the energy savings achieved by new energy efficiency measures in the compliance year, and a "cumulative" savings level that sums the "first year" savings and the persistent savings from energy efficiency measures installed in previous years that are still saving energy compared to what would have occurred if those measures had not been implemented.

An EERS is most likely to originate from state legislation or a public utility commission (PUC) order.[12] In addition to a target savings level, a good EERS policy will address the following:[13]

1. **Policy Objective.** Policymakers are likely to support an EERS because energy efficiency reduces consumer costs, but efficiency may also have many ancillary benefits, such as providing bill relief to low-income families or creating jobs. Achieving those benefits can also be an objective of an EERS and will help shape the ways in which the policy is implemented.
2. **Coverage.** Policymakers will need to determine if the EERS covers one or multiple fuels (e.g., electricity only or electricity, natural gas, and heating oil) or if certain sectors of the economy are excluded, for example, large industrial customers. The scope of coverage will impact how broadly energy efficiency's benefits are distributed. State policies also vary in terms of whether they apply to all utilities and service providers, or only a subset (e.g., only investor-owned electric utilities).
3. **Implementing Parties.** Service providers such as electric and natural gas utilities are frequently targeted to comply with an EERS because they have an existing relationship with customers as well as knowledge of their customers' energy consumption patterns. However, certain states have chosen a third-party administrator to handle energy efficiency program implementation. The reasons for establishing a separate third-party entity may vary, but include concern that utilities may lack effective financial motivation to design and implement energy efficiency programs (discussed further in Section 7). Another reason to select a third-party entity is that it can offer a comprehensive program across fuels and utility service territories.[14]
4. **Compliance Verification.** An EERS is unlikely to be supported by stakeholders if there is no structure to ensure that savings are measured and verifiable. There is no "one size fits all" approach to verifying compliance. Evaluation, measurement, and verification (EM&V) of energy savings is discussed further in the text box on page 11-6.

Neme and Wasserman concluded that an EERS is a critical policy in achieving aggressive energy efficiency savings.[15] A study of nine, mostly Midwestern states bears that out – it found that clear legislative or regulatory direction such as setting a specific savings goal through an EERS-type mechanism resulted in greater efficiency savings.[16]

The second framework for establishing energy savings targets, incorporating energy efficiency into resource planning, is discussed in detail in Chapter 22, but is briefly summarized here as it relates to energy savings targets. The purpose of utility resource planning is to look far into the future, estimate the future demand for energy, and devise a least-cost plan for meeting that demand while satisfying all other legal and public policy objectives. A resource plan is said to be an "integrated resource plan" (IRP) if the options for meeting demand include both supply-side options (e.g.,

12 Almost all aspects of the regulation of retail energy sales, including energy efficiency programs, fall within the jurisdiction of state rather than federal authorities.

13 The Regulatory Assistance Project. (2012, June). *Best Practices in Designing and Implementing Energy Efficiency Obligation Schemes.* Available at: http://www.raponline.org/document/download/id/5003

14 Nichols, D., Sommer, A., & Steinhurst, W. (2007, May). *Independent Administration of Energy Efficiency Programs: A Model for North Carolina.* Available at: http://ncsavesenergy.org/wp-content/uploads/IndependentAdminEfficiencyProgramsModelforNC.pdf.

15 Wasserman, N., & Neme, C. (2012, October). *Policies to Achieve Greater Energy Efficiency.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6161.

16 Gunn, R., Neumann, R., & Lysyuk, M. (2012). *Regulatory Regimes (Across Nine States) and Potential Improvement for Energy Efficiency Programs.* 2012 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.aceee.org/files/proceedings/2012/start.htm

EM&V of Energy Savings

EM&V refers to a retrospective analysis of the impacts of energy efficiency programs that have already been implemented. The analysis typically estimates energy savings and peak demand reductions, as well as economic costs and benefits. Some evaluations also estimate avoided emissions. Energy efficiency program evaluations are most often done by a third-party contractor working for a utility, PUC, or state energy office.

Estimates of energy savings can be made based on actual onsite measurements, by formulas, or by statistical methods. Where formulas are used, results may be verified through onsite visits or audits. Technical reference manuals (TRMs) are a common tool used to promote high-quality EM&V. A TRM provides documentation of the standard values or formulas that are used to estimate energy savings attributable to specific energy efficiency measures and programs. For example, the TRM might provide a value or formula for estimating the energy savings from a program that promotes efficient clothes washers. Many (but not all) states with energy efficiency policies have formally adopted a TRM to bring consistency and predictability to the EM&V process. Air quality regulators might think of these manuals as analogous to the US Environmental Protection Agency's (EPA) AP-42 Emission Factor manuals. They provide a way to make consistent, credible estimates of energy savings without having to measure every single efficiency action taken by every individual. There is also a continual improvement aspect to these methods. As part of the larger EM&V process, data are adjusted in the TRM after audits are completed and methods become more accurate over time. However, one key distinction between TRMs and AP-42 must be noted. AP-42 is national in scope, whereas TRMs can vary significantly from one state to the next. Thus, the consistency promoted by a TRM is *intra*-state consistency, not *inter*-state consistency.

In most states, energy efficiency program administrators are required to aggregate the evaluation results from all of the energy efficiency programs they offer into annual energy savings reports. Many states require that these reports be scrutinized and verified by an independent evaluator and even, in some cases, by other parties in a docketed proceeding. These energy savings reports will normally be far more useful to the air regulator than individual program evaluations.

Energy efficiency program evaluation can be extremely complex, and it is generally undertaken by one of a relatively small number of companies and experts that specialize in this subject. Many states require evaluations to be done by a third-party EM&V contractor who answers directly to a state agency, not a utility, in order to ensure that the results are viewed as unbiased and legitimate. Any oversight of the process will normally fall to the PUC or state energy office, not the air regulator.

Although air regulators may not consider EM&V data to be as accurate or reliable as continuous emissions monitoring data, the estimates presented in evaluation reports and energy savings reports are not mere guesswork or wishful thinking. Program evaluations have been conducted for several decades and in nearly every state and municipality that has made a significant public investment in energy efficiency. In its 2011 survey of energy efficiency program administrators, the Consortium for Energy Efficiency found that 3.6 percent of total energy efficiency budgets (on average) were allocated to EM&V activities. This amounted to over $180 million budgeted for EM&V among the program administrators that responded to the survey.[17]

In general, air regulators may wish to become familiar with EM&V methods, but should not expect — and don't need — to become experts on this subject. What is more important is that the air regulator knows in a general way how evaluation is conducted and where to find the energy savings reports.[18] A variety of helpful resources and reference documents on this topic are listed in Section 8.

17 Forster, H. J., Wallace, P., & Dahlberg, N. (2013, March 28). *State of the Efficiency Program Industry: Budgets, Expenditures, and Impacts.* p 27. Consortium for Energy Efficiency. Available at: http://library.cee1.org/sites/default/files/library/10533/CEE_Annual_Industry_Report.pdf

18 For details on evaluation methods, including a 17-page chapter on methods for estimating avoided emissions, refer to: State and Local Energy Efficiency Action Network. (2012). *Energy Efficiency Program Impact Evaluation Guide.* Available at: https://www4.eere.energy.gov/seeaction/system/files/documents/emv_ee_program_impact_guide_0.pdf

building new power plants) and demand-side options, such as reducing the need for energy through energy efficiency programs. How those options are considered varies from one jurisdiction to the next. An IRP could include energy efficiency in a head-to-head comparison against supply-side resources, in which the least-cost means of meeting every MWh of demand is evaluated. More often, a single trajectory of “achievable” energy savings is simply assumed and incorporated as a decrement (reduction) to the forecast of future energy demand.

Good resource planning can convey important information about the need for and role of energy efficiency in a portfolio of resources. For instance, IRPs generally extend for 20 years or more, but energy efficiency program plans may only cover three to five years at a time, so incorporating energy efficiency into the IRP can signal the extent to which a utility plans to offer energy efficiency programs beyond the current energy efficiency program planning cycle. The IRP process can also be used to evaluate how long-term costs of supply-side resources are avoided or deferred by energy efficiency. And even in states that have an EERS policy, resource planning can still impact the level of savings a utility strives to achieve; IRPs can be used to assess the cost-effectiveness of going above and beyond the state’s EERS requirements. However, simply having an IRP requirement does not ensure that energy efficiency will be properly evaluated. The details of each utility’s IRP methodology matter, and a specific approach to considering energy efficiency is often not specified in the IRP requirements dictated by regulators.[19]

It is frequently through a third framework – DSM planning – that a utility’s specific energy efficiency program offerings are determined. Some states require utilities to conduct short-term DSM plans, either as a step in complying with an EERS requirement or in the absence of such a requirement. In a DSM plan, energy efficiency is judged through a series of cost-effectiveness tests (discussed in Section 6) that include what is known as a utility’s “avoided cost.” The avoided cost is a projection of the costs of energy services that can be avoided by implementing an energy efficiency program.[20] The level of energy savings that is established through a DSM plan ultimately depends on the level of achievable, cost-effective savings that is identified through the planning process. Like an IRP, DSM planning normally comes within the regulatory purview of a PUC, because energy efficiency programs will necessarily affect customers’ rates and bills. The PUC will typically choose the metrics used to judge the cost-effectiveness of energy efficiency as well as the level of savings to be achieved. As with an EERS policy, EM&V protocols are generally established by the PUC in order to ensure that targeted level of energy savings are actually achieved.

A fourth framework for implementation of energy efficiency requires no enabling legislation or commission order. Utilities can simply volunteer to provide energy efficiency programs. Certainly some investor-owned utilities do so, for example, in exchange for concessions by other parties in PUC-adjudicated cases. Principally, it is municipal utilities and cooperatives that take this route because they are frequently exempt from state regulation and requirements. Even so, public power utilities will take many of the same steps discussed previously, such as determining their policy objective and the program coverage, evaluating possible programs using cost-effectiveness metrics and then verifying their savings.

In addition to the regulatory frameworks summarized previously, the federal government and some state governments have adopted mandatory appliance efficiency standards. Those policies are described in Chapter 14. Most state governments have also adopted mandatory building energy codes, which are described in Chapter 15. In some jurisdictions, state regulators have allowed utilities to count some of the energy savings attributable to state appliance efficiency standards and state building energy codes toward their energy savings targets, if the utility supports and facilitates the adoption of such codes and standards. But to date that has been the exception rather than the norm, and codes and standards are usually excluded from mandated energy savings targets.

Although the federal government does not establish

19 For more information on IRPs, see Chapter 22 of this document, and see: State and Local Energy Efficiency Action Network. (2011, September). *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* Available at: https://www4.eere.energy.gov/seeaction/publication/using-integrated-resource-planning-encourage-investment-cost-effective-energy-efficiency.

20 Utility planners don’t always distinguish between DSM and integrated resource planning, perhaps because the avoided cost may be determined using IRP methodologies or because DSM planning is a step in developing a plan combining supply- and demand-side resources.

energy savings targets for utilities, energy efficiency programs play a prominent role in the emissions guidelines for carbon dioxide (CO_2) emissions from existing power plants that the EPA proposed in June 2014, citing its authority under section 111(d) of the Clean Air Act, as part of its "Clean Power Plan."[21] The EPA determined that the "best system of emission reduction" for existing power plants consists of four "building blocks," one of which is end-use energy efficiency. Although states will not be required to include energy efficiency in their 111(d) compliance plans, the emissions rate goals for each state are based on an assumption that a certain level of energy savings (and thus, emissions reduction) is achievable. The level of savings that the EPA used to set each state's emissions rate goals is based on the demonstrated performance of leading states with respect to ratepayer-funded energy efficiency programs and a meta-analysis of energy efficiency potential studies. Based on those factors, the EPA concluded that all states could ramp up their energy efficiency program efforts and achieve incremental "first year" energy savings equal to 1.5 percent of retail sales per year.[22] The EPA requested comments on whether this was an achievable level of energy savings for all states, and also requested comments on EM&V issues. The agency has indicated that additional guidance on EM&V issues and the use of energy savings in state compliance plans is forthcoming.

The Clean Power Plan is not the EPA's first venture into encouraging states to use energy efficiency to reduce power sector emissions. In 2004, the EPA offered guidance to states on how to incorporate electric-sector energy efficiency and renewable energy measures in state implementation plans (SIPs) for criteria pollutants.[23] Then in July 2012, the EPA followed up on the 2004 guidance with a new document called the Roadmap for Incorporating Energy Efficiency/Renewable Energy (EE/RE) Policies and Programs into State and Tribal Implementation Plans (SIPs/TIPs). The purpose of this Roadmap document, according to the EPA, is "to reduce the barriers for state, tribal and local agencies to incorporate energy efficiency/ renewable energy policies and programs in SIPs/TIPs by clarifying existing EPA guidance and providing new and detailed information."[24] The Roadmap provides states with more options, better explanations, and fewer restrictions than previously existed in guidance documents. Of particular interest here is that the Roadmap offers greater clarity to states on the methods that can be used to quantify the emissions reductions that are associated with energy efficiency energy savings and renewable energy generation. States are not obligated to include energy efficiency or renewable energy in their SIPs, but they have the option of doing so.

3. State and Local Implementation Experiences

There are 24 states that have an active EERS or similar energy efficiency policy. Although 25 are shown in Figure 11-4, in June 2014 the Ohio legislature suspended that state's EERS for two years.

Two states, Nevada and North Carolina, combine their renewable energy and energy efficiency requirements into one standard. Texas was the first state to enact an EERS in 1999.[25]

In nearly all cases, EERS targets have been developed by the state legislature or by the PUC in response to a legislative mandate. Among early adopters, the target levels were set based on a combination of factors, including an assessment of the levels that had historically been achieved through ratepayer-funded energy efficiency programs,

21 Refer to: US EPA. (2014, June). *40 CFR Part 60 – Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule.* Federal Register Vol. 79, No. 117. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

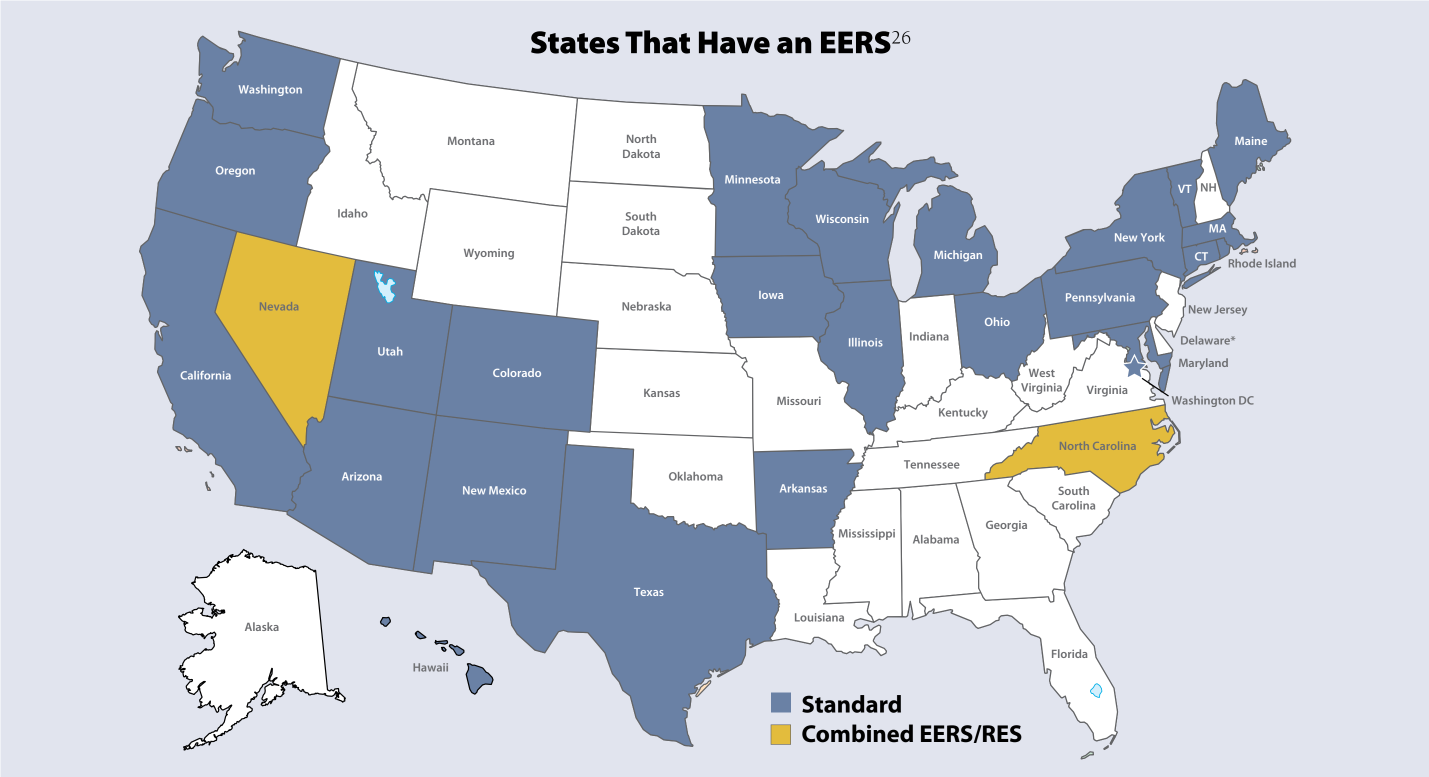
22 Refer to: US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures

23 US EPA. (2004.) *Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures.* Available at: http://www.epa.gov/ttn/caaa/t1/memoranda/ereseerem_gd.pdf

24 US EPA. (2012.) *Roadmap for Incorporating Energy Efficiency/ Renewable Energy Policies and Programs into State and Tribal Implementation Plans.* EPA-456/D-12-001a. Available at: http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf

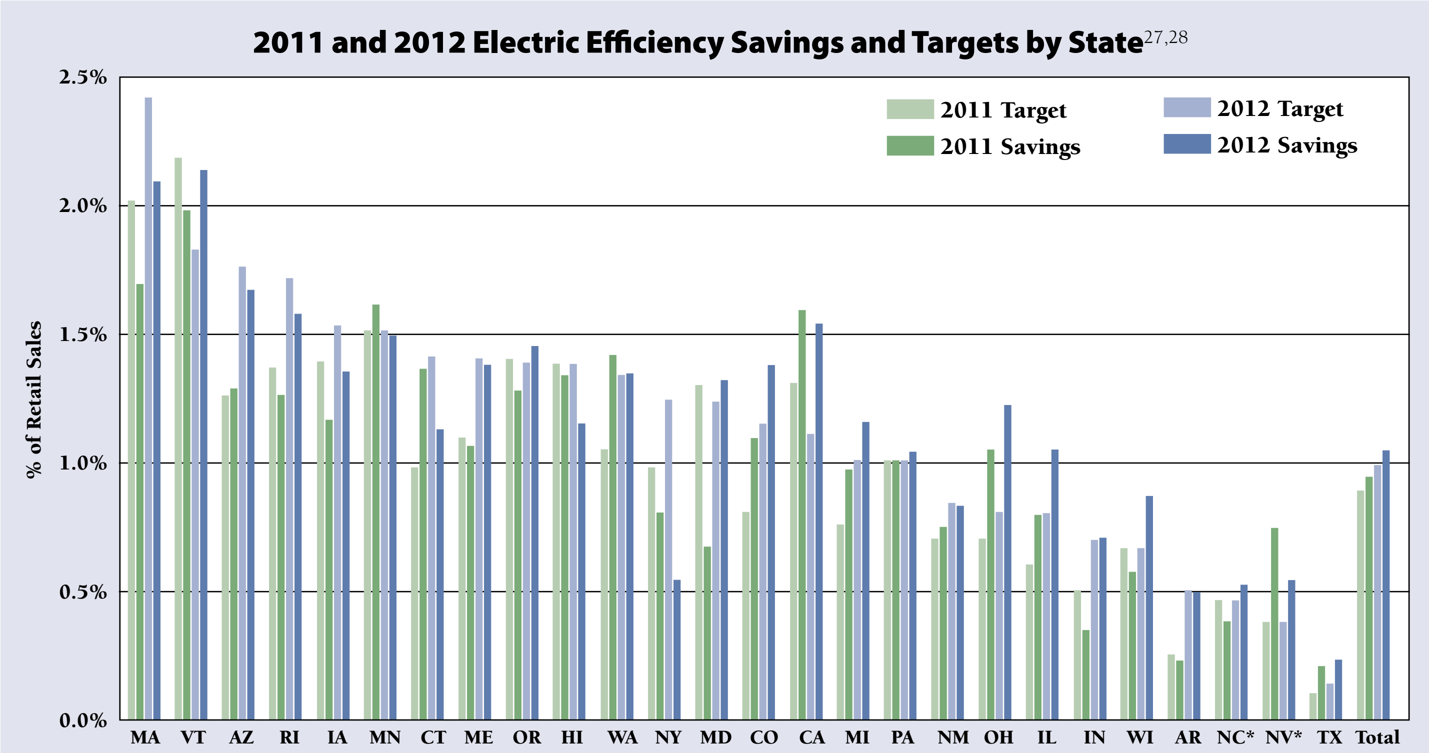
25 ACEEE Policy Brief. (2014, April). *State Energy Efficiency Resource Standard (EERS) Activity.* Available at: http://www.aceee.org/policy-brief/state-energy-efficiency-resource-standard-activity

Figure 11-4



States That Have an EERS[26]

Figure 11-5



2011 and 2012 Electric Efficiency Savings and Targets by State[27,28]

26 Downs, A., & Cui, C. (2014, April). *Energy Efficiency Resource Standards: A New Progress Report on State Experience.* ACEEE. Available at: http://aceee.org/sites/default/files/publications/researchreports/u1403.pdf

27 Ibid.

28 Indiana is shown here because it had an EERS until the legislature eliminated it in March 2014.

economic potential studies, political considerations, and so on. As more and more states adopted EERS policies, the results achieved by early adopters have also influenced target-setting and the targets have generally become more ambitious.

Utilities and other program administrators have largely been able to meet their state's EERS targets to date, as shown in Figure 11-5. The figure shows "first year" energy savings.

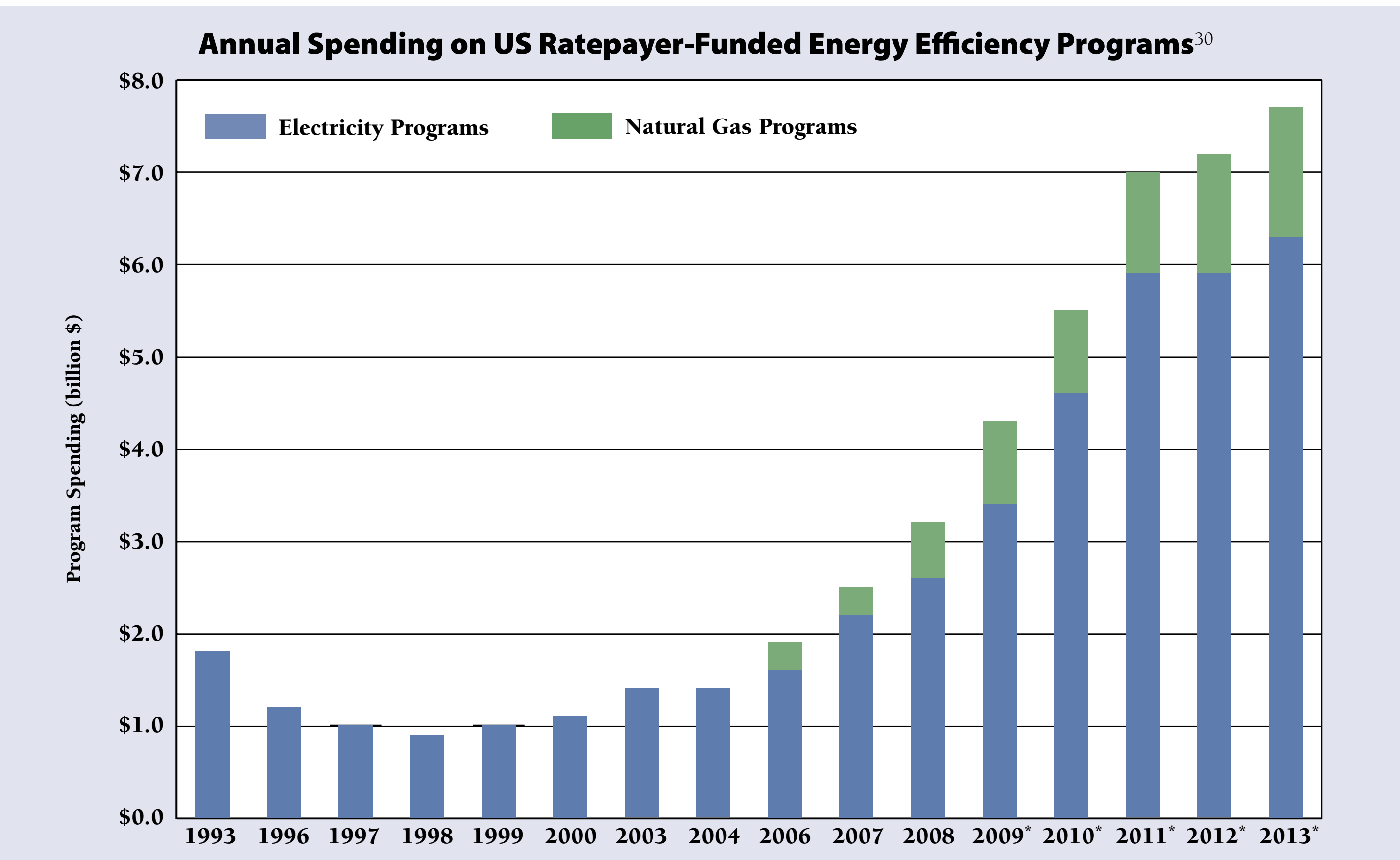
In 2012, 16 states met or exceeded their targets and another 6 came within 90 percent of meeting their targets. In 2012, states that had an EERS saved over 20 terawatt-hours, approximately 85 percent of the total energy savings realized in the United States.[29] Several of these states have already achieved a level of "first year" energy savings greater than the 1.5 percent of retail sales that the EPA included in its analysis of the "best system of emission reduction" for power sector CO_2 emissions as part of the proposed Clean Power Plan.

Not surprisingly, the trend toward an increase in achieved energy savings is consistent with a trend in increased spending on electric efficiency programs. Figure 11-6, developed by ACEEE, shows that trend.

Research and analysis by the Lawrence Berkeley National Laboratory (LBNL) predicts yet further increases in state energy efficiency program expenditures in the future, primarily owing to growth in electric energy efficiency programs. Upwards of $12 billion could be spent in 2025 on electric efficiency programs alone, as shown in Figure 11-7.

Nationwide, the additional expenditures forecasted by LBNL would be expected to translate into significant additional savings beyond what was actually achieved in 2010, as indicated in Figure 11-8. Twelve billion dollars of spending would save over 1.1 percent of US retail electric sales in 2025, with savings from most energy efficiency

Figure 11-6



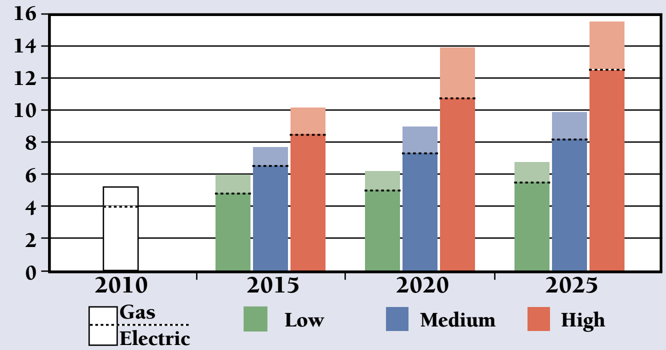
29 Supra footnote 26.

30 Values shown for 2009 and later years reflect program budgets rather than actual program expenditures. Source: Gilleo, A., Chittum, A., Farley, K., Neubauer, M., Nowak, S., Ribeiro, D. & Vaidyanathan, S. (2014, October). *The 2014 State Energy Efficiency Scorecard.* ACEEE. Available at: http://www.aceee.org/sites/default/files/publications/researchreports/u1408.pdf

Figure 11-7

Projected Spending on Energy Efficiency Programs

($billion, nominal)[31]

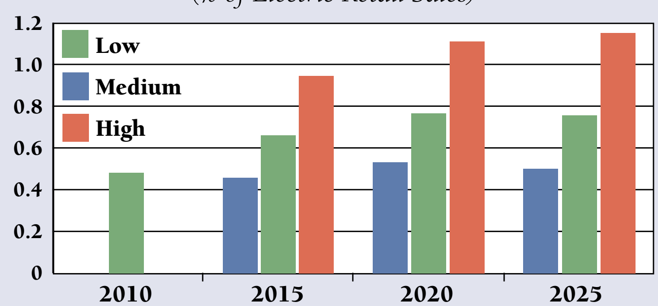


measures persisting for years and adding to cumulative energy savings. The differences between the low, medium, and high scenarios are described in LBNL's report, but it is not assumed that each state will achieve similar "first year" savings (e.g., 1.5 percent of retail sales). States that have little experience implementing energy efficiency programs are projected by LBNL to achieve fewer savings than states that have more robust programs. This is why the nationwide level of projected energy savings in Figure 11-8 is lower than the level achieved by many states in 2011 and 2012 (see Figure 11-5), despite increased nationwide spending. If every state achieved the levels of energy savings that the EPA asserts are achievable in the proposed 111(d) rule, the national level of expenditures and energy savings would exceed what LBNL has forecast.

Figure 11-8

Projected Incremental Savings

(% of Electric Retail Sales)[32]



In many states, utilities were required to offer ratepayer-funded energy efficiency programs before an EERS policy with defined energy savings targets was adopted. Adopting an EERS policy simply strengthened the state's commitment to energy efficiency. Minnesota is one such state. Its EERS was established in 2007 by an act of the legislature and covers investor-owned, municipal, and cooperative gas and electric utilities. Up until passage of the Next Generation Energy Act, the state's utilities were required to commit a portion of their annual revenues toward energy efficiency measures, but there was no explicit energy savings goal. The spending requirement had ensured that energy efficiency programs were offered for several years prior to 2007. However, since the EERS was enacted, total energy savings by Minnesota utilities have increased significantly and, as shown in Figure 11-5, the state's utilities collectively exceeded their electric savings goal in 2011 and came close to meeting the goal in 2012. Every three years, the utilities file their plans for providing energy efficiency programs with the Minnesota Department of Commerce (DOC) Division of Energy Resources, the equivalent of the state energy office. There is no financial penalty for failure to achieve the EERS goal or failure to file a plan that complies with the goal. But there is a financial incentive available to rate-regulated utilities that achieve or exceed the 1.5-percent goal.[33] And although the DOC's role with regard to public power utilities is largely an advisory one,[34] the combination of the DOC, ratepayer advocates, and utility staff working together has helped to create quality program offerings by those utilities.[35]

31 Barbose, G., Goldman, C. A., Hoffman, I. M., & Billingsley, M. (2013, January). *The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Project Spending and Savings to 2025.* Available at: http://emp.lbl.gov/sites/all/files/lbnl-5803e.pdf

32 Ibid.

33 Minnesota Public Utilities Commissioner order in Docket No. E,G-999/CI-08-133 on December 20, 2012. Available at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={7B916D08-09C1-4084-8C13-852C2F8CC8E9}&documentTitle=201212-82007-01

34 Minnesota Department of Commerce, Office of Energy Security. (2009, January 15). *2006–2007 Minnesota Conservation Improvement Program Energy and CO_2 Savings Report.* Available at: http://archive.leg.state.mn.us/docs/2009/mandated/090117.pdf

35 Personal communication with Will Nissen, Fresh Energy. August 28, 2014.

Based on experience to date, some of the components of an EERS policy that appear to be conducive to high levels of energy savings and compliance include:[36]

- Clear statement of energy efficiency goal(s);
- Clear direction to the entity responsible for implementation and oversight;
- Complementary and supportive regulatory policies, such as revenue decoupling or another method to address lost contributions to utility fixed costs (a.k.a., "lost revenues");[37]
- "Collaborate vs. litigate" approach that engages stakeholder groups; and
- Rigorous, independent EM&V.

Minnesota exemplifies many of these components, although it has a limited form of revenue decoupling. This likely contributes to a tendency to view the EERS targets as a ceiling for energy savings rather than a floor that is lower than the level that could be achieved by implementing all cost-effective energy efficiency measures.

Just as there are critical elements in an EERS policy that are conducive to high levels of energy savings, there are also provisions that can limit or deter end-user savings. These provisions can include:

- Stop and start (i.e., unpredictable) funding for energy efficiency programs;
- Provisions allowing industrial customers to opt out of ratepayer-funded energy efficiency programs;
- Allowing the program administrator to count savings that result from activities upon which it had no influence toward its savings targets;
- Allowing the program administrator to count savings that result from infrastructure improvements such as those described in Chapters 5 and 10 toward its savings targets;[38] and
- Overcompensating the utility either through excessive shared savings incentives or lost revenue adjustments that are not based on realistic assessments of sales and fixed costs.

Many of the states that have an EERS policy also have IRP requirements, and again the IRP requirements tend to pre-date the EERS policy. An IRP requirement by itself has generally not been sufficient in most jurisdictions to stimulate large-scale investment in energy efficiency.[39] One exception to this general rule is found in the IRPs of the Northwest Power and Conservation Council. The Council conducts resource planning on behalf of the Bonneville Power Administration and its customer utilities. Its most recent plan recommended that energy efficiency be used to meet 85 percent of new demand over the 20-year period from 2010 to 2030.[40] IRP requirements are treated in more detail in Chapter 22.

There are many examples of states that have DSM planning requirements, at least 28 on the electrical side.[41] As an example, Connecticut's electric and gas utilities jointly file periodic plans to achieve "all cost-effective" energy efficiency. The 2013–2015 plan was filed after the Connecticut Department of Energy and Environmental Protection created a statewide IRP and concluded that annual "first year" electric savings could be cost-effectively achieved at a level equal to two percent of retail sales.[42]

Mandatory energy efficiency policies like an EERS are not the only way to save energy. Austin Energy, the municipal utility serving the city of Austin, Texas, is an example of one utility that voluntarily chooses to administer efficiency programs. Although it is exempt from its state's EERS, in 2011 Austin Energy saved energy at a level equal to 0.92 percent of retail sales and devoted 1.28 percent of its revenues to energy efficiency programs.[43] In

36 See, for example, a study produced for the New Hampshire Energy Efficiency & Sustainable Energy Board at: http://www.puc.nh.gov/EESE%20Board/Meetings/2013/20131108Mtg/NH%20EESE%20Board%2011-8-13%20Final.pdf

37 See Section 7 of this chapter for a discussion of lost contributions to fixed costs.

38 As noted in Chapters 5 and 10, these kinds of improvements can reduce electric system costs and reduce GHG emissions. The point is not that those improvements are undesirable (the opposite is true), rather that allowing utilities to use those energy savings to meet mandatory EERS targets reduces the savings that will be achieved through end-user energy efficiency.

39 Supra footnote 26.

40 6th Power Plan Energy Efficiency Two-Pager. Available at: https://www.nwcouncil.org/energy/powerplan/6/2010-08/

41 Supra footnote 31.

42 *2013–2015 Electric and Natural Gas Conservation and Load Management Plan.* (2012, November). Available at: http://energizect.com/sites/default/files/2013_2015_CLM%20PLAN_11_01_12_FINAL.pdf

43 Mackres, E., Johnson, K., Downs, A., Cluett, R., Vaidyanathan, S., & Schultz, K. (2013, September). *The 2013 City Energy Efficiency Scorecard.* ACEEE. Available at: http://www.aceee.org/sites/default/files/publications/researchreports/e13g.pdf

contrast, Texas as a whole saved 0.20 percent of retail sales and spent 0.46 percent of revenue.[44]

Finally, returning to the topic of air pollution regulation, it should be noted that the guidance the EPA issued in 2004 for including energy efficiency in SIPs had only a very limited impact. Based on that guidance, energy efficiency measures were subsequently included in ozone SIPs prepared by Texas, Louisiana, Connecticut, and the District of Columbia region.[45] The EPA's publication of the Roadmap in 2012 appears to be sparking renewed interest among air pollution regulators in the possibility of using energy efficiency to improve air quality. For example, the Northeast States for Coordinated Air Use Management (NESCAUM) worked with the EPA, the Massachusetts Department of Environmental Protection, the New York State Department of Environmental Conservation, and the Maryland Department of the Environment to test the usability of the new "pathways" for including energy efficiency in SIPs that are described in the Roadmap. Massachusetts tested the new "baseline pathway," New York tested the "control strategy" pathway, and Maryland tested the "weight of evidence" pathway. NESCAUM and the three states then provided the EPA with a summary of their perspectives and suggestions on key policy issues, including some of the potential implications for using energy efficiency to comply with 111(d) requirements.[46]

4. GHG Emissions Reductions

Most of the generation that serves load in the United States burns fossil fuels and emits CO_2 and other GHGs. When consumers reduce their electricity use, somewhere on the grid one or more electric generating units (EGUs) will produce less electricity than they otherwise would. If those EGUs are fossil-fueled, less fuel is burned and less CO_2 is emitted. Thus, the immediate impact of energy efficiency programs is that they indirectly result in GHG emissions reductions from existing EGUs.[47] Over the longer term, energy efficiency programs can also defer or avoid the deployment of new EGUs. The longer-term avoided emissions will depend not so much on the characteristics of existing EGUs, but on the costs and development potential for new EGUs.[48]

The magnitude of emissions reductions attributable to energy efficiency programs will depend first and foremost on the amount of energy saved. EM&V protocols, discussed previously, provide the means of retrospectively assessing the amount of energy saved by any energy efficiency program or portfolio of programs. Similar methods can be applied prospectively to forecast the expected energy savings from energy efficiency programs yet to be implemented. However, we would note that the magnitude of emissions reductions that result from those energy savings also depends on when energy was (or will be) saved, and which marginal EGUs reduced (or will reduce) their output at those times.

In general, when customers reduce electricity use, the grid operator will reduce the output of the most expensive generating unit(s) currently operating with manual or automatic load control capability (i.e., the "marginal" unit[s]) to match customer load. One caveat is that the grid operator also must consider transmission constraints that

44 Downs, A., Chittum, A., Hayes, S., Neubauer, M., Nowak, S., Vaidyanathan, S., Farley, K., & Cui, C. (2013, November). *The 2013 State Energy Efficiency Scorecard*. ACEEE. Available at: http://www.aceee.org/sites/default/files/publications/researchreports/e13k.pdf

45 Refer to Appendix K of the *Roadmap* document. Supra footnote 24.

46 Guerette, A., & Weiss, L. (2014, May). *States' Perspectives on EPA's Roadmap to Incorporate Energy Efficiency/Renewable Energy in NAAQS State Implementation Plans: Three Case Studies*. NESCAUM. Available at: http://www.nescaum.org/initiatives/ee-re-in-sips/states2019-perspectives-on-epa2019s-roadmap-to-incorporate-energy-efficiency-renewable-energy-in-state-implementation-plans-three-case-studies

47 Some energy efficiency programs reduce onsite natural gas combustion (e.g., for space heating purposes), and thus directly reduce emissions. Such programs are noteworthy but beyond the power sector focus of this document.

48 The fact that energy efficiency programs can defer the need for new generating capacity means that they can also potentially extend the life of existing EGUs. New EGUs will tend to be lower-emitting than the existing EGUs most prone to retirement, and the developers of new EGUs often size the units not only to meet load growth but also to replace an existing EGU. For example, they might develop a 200-MW EGU in anticipation of 150 MW of load growth, and thus some of the existing EGUs would run less or might choose to retire. Air regulators should be cognizant of this possibility, but not view it as a certainty or as an argument against using energy efficiency to reduce emissions. Older, less-efficient, higher-emitting EGUs will generally be dispatched less often (not more often) as a result of demand reductions, and the economic pressures that lead to a retirement decision will generally arise sooner (rather than later) as a result of energy efficiency programs.

affect the deliverability of electric power from generators to customers. So the true reduction in system emissions associated with a given unit of energy savings depends on which of the generators capable of delivering power to that location is operating on the economic margin at the specific time that the customer reduces energy consumption. The GHG emissions rates of marginal generating units can vary substantially in different parts of the country and at different times of year. In one region of the country, coal plants might be on the margin in one hour and natural gas the next, whereas in a different region of the country, gas plants might be on the margin in both hours. Thus, an energy efficiency program that reduces annual energy consumption by one percent, for example, could conceivably reduce GHG emissions by more than or less than one percent, depending on whether the marginal EGUs have higher-than-average or lower-than-average emissions rates.

Historically, the specific timing and locations of energy savings have typically not been assessed by standard EM&V protocols, and this has posed a considerable challenge for accurately estimating avoided emissions. EM&V practices are evolving, however, with more specificity about the timing of energy savings and much greater consideration for quantifying avoided emissions. Guidance and technical assistance for energy efficiency program evaluators and air pollution regulators are increasingly available on this topic. For example, the State and Local Energy Efficiency Action Network included a 17-page chapter on methods for estimating avoided emissions in its Energy Efficiency Program Impact Evaluation Guide and the Regulatory Assistance Project published a paper dedicated entirely to this topic.[49,50] In some states, energy efficiency program evaluations now routinely include estimates of avoided emissions. A brief explanation of the common methods for estimating avoided emissions follows.

Methods and Tools for Estimating Avoided Emissions from Energy Efficiency Programs

To quantify the air quality impacts of an energy efficiency program or portfolio, one begins with an assessment of energy savings. Standard EM&V protocols can be used for this step. Where possible, it is also helpful to estimate the timing of energy savings in each hour of the year and estimate the location of energy savings with respect to electricity markets or balancing areas. Any one of three common methods can then be used to estimate the avoided emissions associated with those energy savings.

Average Emissions Method

The first method for estimating avoided emissions is to use an emissions factor approach based on the average emissions resulting from one unit of energy consumption. For this simple method, the annual emissions of all of the generators operating within a defined geographic area are divided by the aggregated annual net generation within the same area to get "system average" emissions rates. For example, one could use the average emissions rate of non-baseload generating units operating in a given area. This approach would be equivalent to assuming that all baseload generators are unaffected by energy efficiency, but all non-baseload generators will reduce their output by an equal percentage when system load is reduced. This simple approach is informative but may not be suitable for regulatory purposes.

The EPA's Emissions & Generation Resource Integrated Database, available at www.epa.gov/egrid/, compiles emissions rate data (in pounds per MWh) for nitrogen oxides (NO_X), sulfur dioxide (SO_2), mercury, and GHGs for every power plant in the United States. Power-plant level data are aggregated to develop average emissions rates for 26 subregions of the country.

Marginal Emissions Method

With marginal emissions methods, one attempts to apportion energy savings only to those generating units that are likely to be operating on the margin when the energy savings occur. Some system operators now routinely provide information about the fuel type of the marginal generating units through their websites and smart phone applications. The actual marginal units are not identified, but merely knowing the fuel type of the marginal units can lead to much more accurate emissions analyses than using system averages. In addition, the EPA has published an Avoided Generation and Emissions Tool (dubbed AVERT, and available at http://epa.gov/avert/) that is based on a marginal emissions methodology. Users can enter the amount of energy saved in each hour of the year in a specified location, and AVERT will produce estimates of avoided emissions at the unit, county, state, and regional

49 Supra footnote 18.

50 Shenot, J. (2013, August). *Quantifying the Air Quality Impacts of Energy Efficiency Policies and Programs.* Montpelier, VT: The Regulatory Assistance Program. Available at: http://www.raponline.org/document/download/id/6680%20

levels. This enables analysts to estimate not just the amount but also the expected locations of avoided emissions, which can be difficult or impossible to do with average emissions rate methods.

The marginal emissions rate method will generally produce more accurate results than an average emissions rate method, and it may be appropriate in some circumstances to use the results of this method for regulatory and planning purposes. However, like the average emissions rate method, the marginal emissions rate method assumes that future system operation will mirror past system operation. As the system changes and as fuel prices and other variables change with time, that assumption becomes increasingly suspect. Consequently, it may be inappropriate to use this method to estimate avoided emissions many years into the future. In fact, on the AVERT website, the EPA says that the tool "should not be used to examine the emission impacts of major fleet adjustments or changes extending further than five years from the baseline year."

Dispatch Modeling Method

Analysts in the electric power sector use sophisticated economic dispatch models, and somewhat less sophisticated capacity expansion models, to predict how the system will react to different scenarios — that is, which generating units will be dispatched by the system operator to meet any given future load. Instead of assuming that future behavior will match past behavior, these models are driven by the input data, in particular price and operating cost assumptions. Because these models can forecast the output of each generator on the system, and each generator's emissions rates are known, they can also be used to project emissions. By modeling two scenarios — one including the impacts of energy efficiency policies and programs, and one without those impacts — the analyst can develop values for avoided emissions.

Most of the dispatch models that might be useful for estimating avoided emissions are proprietary software products that must be purchased from a private sector vendor. Some notable examples of chronologic dispatch models include PROSYM, PROMOD, and PLEXOS. Other models that approximate dispatch decisions but also evaluate the energy system more broadly include the National Energy Modeling System (used by the US Energy Information Administration), the Integrated Planning Model (used by the EPA for various regulatory purposes), ENERGY 2020 (used by California Air Resources Board for modeling impacts of GHG regulations), and MARKAL (used by several Northeast states for assessing avoided emissions). Most air quality regulators at the state level will not have licenses for dispatch model software or the training on how to use the models. However, they may be able to work in partnership with utilities, consultants, or PUC staff to use these models.

Estimates of the GHG Reduction Potential of Energy Efficiency

Whichever methodology is used to make estimates, the potential to reduce CO_2 emissions by establishing energy savings targets for utilities is very real. ACEEE estimated that a national EERS policy that was proposed in 2009 would have saved 15 percent of forecasted electricity sales by 2020, had it been enacted.[51] That percentage, which reflects cumulative energy savings, is comparable to the cumulative effect of the existing EERS requirements in Illinois and Iowa, but falls short of the more stringent existing EERS policies in states like Vermont, Massachusetts, and Hawaii.[52] The proposed national EERS was projected to result in 260 million tons of cumulative CO_2 reductions by 2020, an amount equal to five percent of the 5.4 Gt of CO_2 that was emitted in the United States in 2013.

Northeast Energy Efficiency Partnerships (NEEP) compiles energy efficiency program impact data from nine Northeastern and Mid-Atlantic states and the District of Columbia in its Regional Energy Efficiency Database (REED). In the most recent REED annual report, NEEP estimates (using average emissions factors provided by the region's system operators) that the first-year energy savings from energy efficiency programs in those ten jurisdictions avoided over 3.5 billion pounds (1.75 million tons) of CO_2 emissions in the year 2012.[53]

51 ACEEE. (2009, March 17). *Energy Efficiency Resource Standard (EERS) Retail Electricity and Natural Gas Distributors: Fact Sheet.* Available at: http://www.aceee.org/files/pdf/fact-sheet/FederalEERSfactsheet_Mar09.pdf

52 US Energy Information Administration. (2014, June 25). *Monthly Energy Review.* Available at: http://www.eia.gov/totalenergy/data/monthly/previous.cfm

53 Northeast Energy Efficiency Partnerships. (2014, August). *Regional Energy Efficiency Database: Program Year 2012 Annual Report.* Available at: http://www.neep.org/sites/default/files/resources/2012%20REED%20Annual%20Report.pdf

According to an EPA analysis of states that currently have mandatory GHG reduction targets, energy efficiency programs are expected to be a major contributor to total emissions reductions:

> "Demand-side energy efficiency is considered a central part of climate change mitigation in states that currently have mandatory GHG targets, accounting for roughly 35 percent to 70 percent of expected reductions of state's power sector emissions. For example, California expects to achieve reductions of 21.9 $MMTCO_2e$ in 2020 from energy efficiency programs targeting electricity reductions... [E]nergy efficiency makes up 48 percent of power sector reductions based on California's Climate Change Scoping Plan. Another state, Washington, expects to reduce 9.7 $MMTCO_2e$ from energy efficiency measures in 2020… [E]nergy efficiency makes up 70 percent of expected emission reductions from stationary energy within the state."[54]

Treatment of Energy Efficiency and Avoided CO_2 Emissions in the Proposed 111(d) Rule

In the proposed 111(d) rule, the EPA recognized the significant potential to reduce CO_2 emissions through energy efficiency programs by including energy efficiency as one of the four "building blocks" that comprise the best system of emissions reduction for the power sector. As noted previously, the EPA established target emissions rates for each state based in part on an assumption that each state could achieve annual first-year energy savings equal to 1.5 percent of retail sales, although states are not obligated to use energy efficiency as a means of achieving their assigned emissions rate goals.

However, it should also be noted that in the proposed 111(d) rule, the EPA took a simple and direct approach to the treatment of avoided emissions. Rather than using one of the three methods described previously for quantifying the avoided emissions resulting from energy savings, the EPA proposed to give states the option of merely adding the quantity of energy savings (in MWh) to the denominator of the emissions rate formula when determining compliance. The "adjusted" emissions rate is thus the actual pounds of CO_2 emissions from regulated sources, divided by the sum of the actual MWh of generation from those regulated sources plus the MWh of energy savings from energy efficiency programs.[55] The EPA does not, in the proposed 111(d) rule, require states to convert MWh of energy savings into pounds of CO_2 emissions reductions, as is the case for SIPs.[56] This proposed methodology should lessen the analytical burden on state air regulators who choose to include energy efficiency programs in their state compliance plans.

5. Co-Benefits

Energy efficiency programs can provide the broadest number of co-benefits of any policy or technology discussed in this document. Because of the diversity of types of programs that can be included in an energy efficiency portfolio, essentially every type of co-benefit imaginable is possible. However, quantifying those benefits is not always straightforward and is not consistently done across jurisdictions.

Virtually all energy efficiency program evaluations will attempt to quantify the economic benefits associated with avoided or deferred utility system costs. Those costs will include energy costs, capacity costs (including generating capacity, and in some cases transmission and distribution capacity), and operation and maintenance (O&M) costs.[57] These avoided utility system costs, rather than environmental benefits, are the primary justification for most ratepayer-funded energy efficiency investments.

54 US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Pages 112-113. Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations

55 The EPA also proposes that states could make similar adjustments for MWh of generation from nuclear and renewable EGUs.

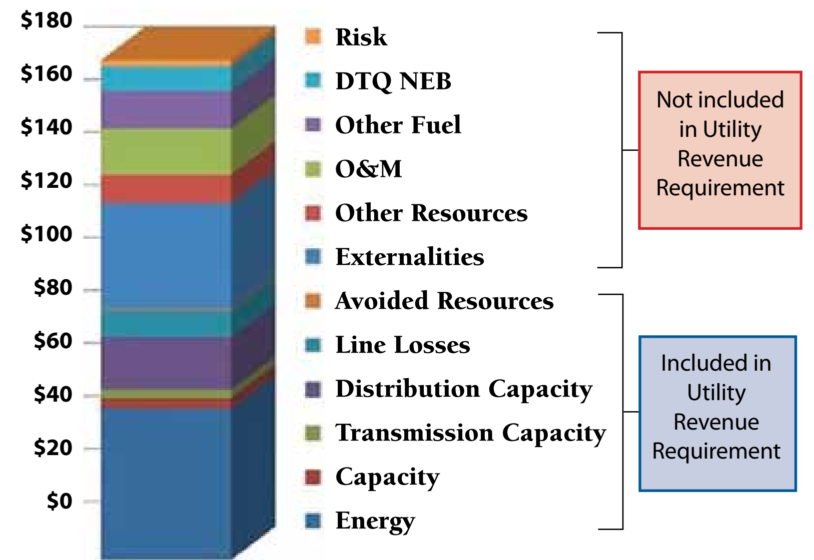
56 The 111(d) rule is not a final rule. The EPA has requested comments on whether an approach similar to the SIP approach should be required, in which the emissions reductions must be quantified in pounds and subtracted from the numerator of the compliance formula.

57 The potential to avoid transmission and distribution capacity costs generally receives less attention than other avoided utility system costs, and frequently is unappreciated and undervalued. For more information on this topic, refer to: Neme, C., & Sedano, R. (2012, February). *US Experience with Efficiency As a Transmission and Distribution System Resource.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/4765

Figure 11-9

The Benefits of Implementing Energy Efficiency in Vermont[58]

Updated Externality and NEB Values, $/MWh



Created with assistance from Efficiency Vermont, based upon data from their annual reports and personal communications.

However, even though other categories of economic benefits are frequently excluded from energy efficiency program evaluations, those co-benefits can also be substantial. An example demonstrating this fact is provided in Figure 11-9, based on evaluation data from the state of Vermont.

In Vermont's estimation, energy efficiency avoids significant externality costs, primarily those associated with the damage from climate change. It also reduces O&M expenses incurred by program participants, in addition to the utility's avoided O&M costs. And an adder is included for "difficult-to-quantify" benefits, which include such things as the assumed value of increased participant comfort and productivity. Nearly half of the total benefit of the energy efficiency programs comes from categories of benefits that are typically excluded from program evaluations in other jurisdictions.

The magnitude of the benefits illustrated in Figure 11-9 will vary across jurisdictions, but the Vermont example is reinforced by evidence from other states. Program evaluations in Wisconsin, for example, indicate that the economic benefit of avoided emissions can form a large portion of the total societal benefits of energy efficiency programs. A recent evaluation report for Wisconsin's Focus on Energy program found that over 20 percent of the total economic benefits of this statewide energy efficiency program were attributable to avoided emissions.[59] What is clear from both the Vermont and Wisconsin examples is that a failure to assess all of the benefit categories for energy efficiency programs will likely lead to a lower estimate of the net benefits, and thus in turn a lower level of efficiency investment than is optimal for customers and society as a whole.

The environmental benefits of energy efficiency, in particular the air quality benefits, can be substantial. In nearly all regions of the country, energy efficiency will displace fossil-fueled generation. As a result, criteria and hazardous air pollutant emissions, notably including emissions of NO_X, SO_2, and mercury, will be reduced when energy efficiency is implemented. As was explained for GHG emissions, the magnitude of that co-benefit will depend on the amount of energy savings, as well as the timing and location of those savings. The same tools and methods described previously for estimating avoided CO_2 emissions are applicable to other air pollutants.

As an example of the potential scale of air quality co-benefits, ACEEE found that if all 12 Southeastern states adopted an annual energy efficiency savings goal equal to one percent of retail sales, they would avoid 52,000 tons of NO_X emissions, 160,000 tons of SO_2, and 4500 pounds of mercury through 2025.[60] ACEEE further asserts that it would cost over $12 billion to achieve the same

58 Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6739.

59 Cadmus Group. (2013). *Focus on Energy Calendar Year 2012 Evaluation Report: Volume I.* Madison, WI: Public Service Commission of Wisconsin. Pages 49-52. Available at: https://focusonenergy.com/sites/default/files/FOC_XC_CY%2012%20Report%20Volume%20I%20Final_05-3-2013.pdf

60 Hayes, S. (2013, September 23). *Energy Efficiency: A Resource for Meeting Air Quality Goals While Keeping the Lights On.* ACEEE. Available at: http://aceee.org/files/pdf/conferences/eer/2013/1B-Hayes.pdf

results using traditional air pollution control devices. In fact, this is what sets energy efficiency apart from most other GHG reduction options: energy efficiency is a power sector investment that simultaneously reduces emissions of multiple air pollutants while lowering system costs, rather than a "control measure" that achieves emissions reductions at some incremental system cost.

Another example of the magnitude of air pollution co-benefits can be found in the previously cited REED annual report for program year 2012. NEEP estimates (using average emissions factors provided by the region's system operators) that the first-year energy savings from energy efficiency programs in those ten jurisdictions avoided over 2.7 million pounds (1350 tons) of NO_X emissions and 7 million pounds (3500 tons) of SO_2 emissions in the year 2012.[61]

Energy efficiency programs can also lead to economic co-benefits outside of the power sector. To give another example of how far-reaching energy efficiency's benefits can be, the authors of a study examining higher investment in energy efficiency in New England found that gross state product would increase multiple times above the efficiency program cost and induce significant job growth. For example, raising New England region-wide electric program spending to $16.8 billion over 15 years (to capture all cost-effective electricity energy efficiency investments) would increase total gross state product in the region by $99 billion and raise employment equivalent to 767,000 job years.[62]

Although quantifying all these benefits may seem daunting, this is not uncharted territory. For instance, the Regulatory Assistance Project offers some best practices in calculating the benefits of energy efficiency, including:

- Count all the benefits you can quantify except when measures pass easily with readily quantifiable benefits;
- Use partners such as equipment vendors and advocates to obtain data; and
- Use a discount rate appropriate to the source of funding.[63]

The full range of societal and utility system co-benefits that can be realized through energy efficiency is summarized in Table 11-1. Although not shown in the table, energy efficiency programs can also produce substantial benefits for the participants (i.e., the customers that improve their efficiency), including reduced future energy bills, other resource savings (e.g., septic, well pumping), reduced O&M costs, positive health impacts, increased employee productivity, higher property values, and more comfortable indoor environments. Low-income consumers may see additional benefits unique to their circumstances.

Table 11-1

Types of Co-Benefits Potentially Associated with Energy Efficiency

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Demand Response-Induced Price Effect	Yes
Other	Yes

61 Supra footnote 53.

62 Howland, J., Murrow, D., Petraglia, L., & Comings, T. (2009, October). *Energy Efficiency: Engine of Economic Growth.* Environment Northeast. Available at: http://www.ctenergy.org/pdf/DSMESERPT.pdf

63 Supra footnote 58.

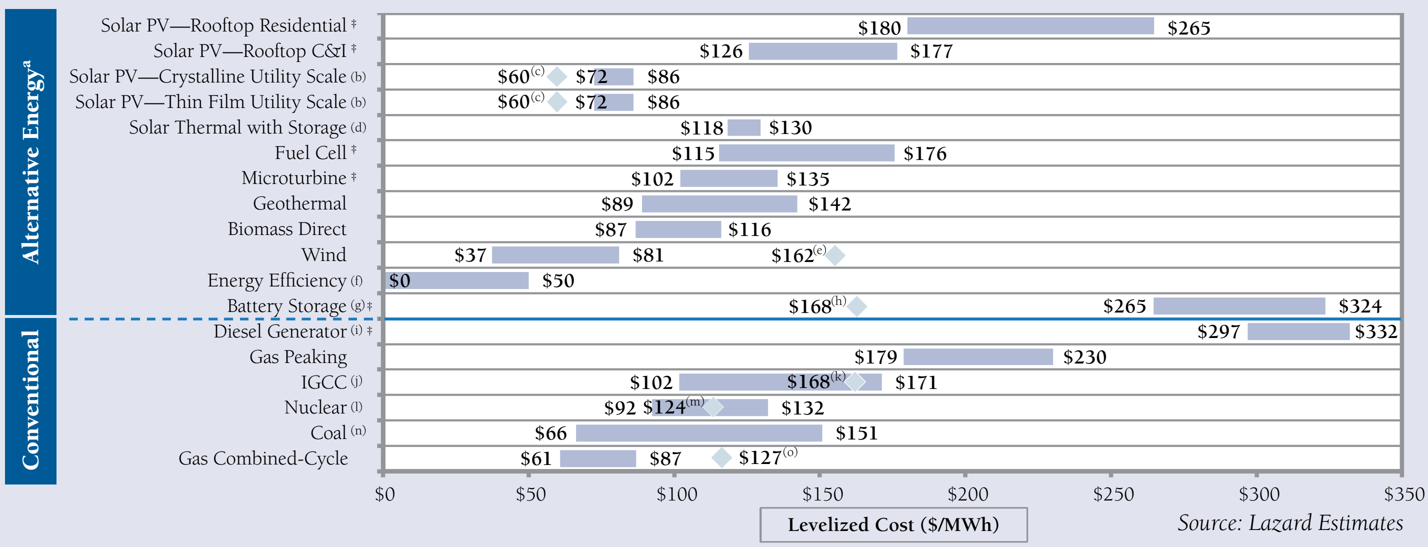
6. Costs and Cost-Effectiveness

Well-designed and implemented energy efficiency programs routinely deliver MWh savings at costs to the utility that are below the cost of producing the same number of MWh with supply-side resources. On an "all-in" basis, energy efficiency is estimated by the management firm Lazard to cost in the range of $0 to $50 per MWh. As summarized in Figure 11-10, energy efficiency is cheaper on a levelized cost of energy basis than all resources except some wind projects. In many cases, it is significantly cheaper than other resources.

Analyses by LBNL and ACEEE support Lazard's estimate. LBNL collected data from over 100 program administrators in 31 states from 2009 to 2011. Collectively these programs cost utilities an average of $21 per MWh saved.[65] ACEEE

Figure 11-10

Lazard's Estimates of Unsubsidized Levelized Cost of Energy (Dollars per MWh)[64]



Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Assumes Powder River Basin coal price of $1.99 per MMBtu and natural gas price of $4.50 per MMBtu. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

a. Analysis excludes integration costs for intermittent technologies. A variety of studies suggest integration costs ranging from 2.00 to $10.00 per MWh.

b. Low end represents single-axis tracking. High end represents fixed-tilt installation. Assumes 10 MW system in high insolation jurisdiction (e.g., Southwest US). Not directly comparable for baseload. Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

c. Diamond represents estimated implied levelized cost of energy in 2017, assuming $1.25 per watt for a single-axis tracking system.

d. Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

e. Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $3.10 – $5.50 per watt.

f. Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely. Estimates involving demand response may fail to account for opportunity cost of foregone consumption.

g. Indicative range based on current stationary storage technologies; assumes capital costs of $500 – $750/KWh for 6 hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% – 85% and fixed O&M costs of $22.00 to $27.50 per KWh installed per year.

h. Diamond represents estimated implied levelized cost for "next generation" storage in 2017; assumes capital costs of $300/KWh for six hours of storage capacity, $60/MWh cost to charge, one full cycle per day (full charge and discharge), efficiency of 75% and fixed O&M costs of $5.00 per KWh installed per year.

i. Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of $4.00 per gallon.

j. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

k. Represents estimate of current US new IGCC construction with carbon capture and compression. Does not include cost of transportation and storage.

l. Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

m. Represents estimate of current US new nuclear construction.

n. Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

o. Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

64 Lazard Ltd. (2014, September). *Lazard's Levelized Cost of Energy Analysis – Version 8.0.* Available at: http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

65 Billingsley, M. A., Hoffman, I. M., Stuart, E., Schiller, S. R., Goldman, C. A., & LaCommare, K. (2014, March). *The Program Administrator Cost of Energy Saved for Utility Customer-Funded Energy Efficiency Programs.* LBNL. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6595e.pdf

estimated an average cost of $28 per MWh saved over the period 2009 to 2012 for a total of 20 states.[66]

The numbers cited previously reflect the cost that utilities and ratepayers pay per MWh of saved energy. This is the appropriate metric for comparing energy efficiency program investments to other investments the utility might make to meet customer demand. However, those numbers do not reflect additional costs paid by energy efficiency program participants. Because energy efficiency program participants gain the most from implementing energy efficiency, they are willing to invest their own money to save energy, in addition to any money invested by the utility and its ratepayers. Air regulators may see estimates of the cost of saved energy that are significantly higher than those cited previously, if the estimates include the total societal costs including the utility's costs and the participant's costs. For example, in the regulatory impact analysis it conducted for the proposed 111(d) rule, the EPA cites a levelized cost of saved energy approaching $85 per MWh saved in the year 2020 and $90 per MWh in the year 2030.[67] But even at those costs,

Cost-Effectiveness Tests for Energy Efficiency Programs

In 1983, the California PUC adopted a Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs. This "Standard Practice Manual" described five different "tests" that could be used to determine whether an energy efficiency program was (or will be) cost-effective.[68] Each test considers the question from a different perspective (i.e., a different definition of what it means for a program to be "cost-effective"):

- **Participant Test.** Accounts for the benefits and costs of energy efficiency programs from the perspective of the customer implementing the measure;
- **Rate Impact Measure (RIM) Test.** Includes the benefits and costs affecting utility rates;
- **Utility Cost Test.** Includes the benefits and costs accruing to the program administrator, excluding revenues lost because of reduced sales;
- **Total Resource Cost (TRC) Test.** Includes the benefits and costs from both the utility and participant perspectives as well as those of non-participating customers; and
- **Societal Cost Test.** Includes the benefits and costs affecting all members of society.

Because each test considers different categories of costs and benefits, each test will yield a different calculation of cost-effectiveness for the same energy efficiency program. This is critically important to understand because the results of these tests will often dictate whether a particular energy efficiency program will be offered. Air pollution regulators need to understand that regulatory compliance costs are considered a utility cost that should be included in all of the tests except the participant test. Externality costs, such as public health costs associated with air pollution, are not a utility cost and are only included in the societal cost test.

In the years since the Standard Practice Manual was first published, it has been revised and adapted for use by PUCs across the country. In most cases, PUCs have ordered utilities and energy efficiency program evaluators to consider more than one of the five tests, but often with one test designated as the primary test for determining cost-effectiveness. States have differed in substantial ways in which tests they favor, and in whether and how they consider environmental compliance costs and externalities. Best practices with regard to those factors continue to evolve.[69]

66 Molina, M. (2014, March). *The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs.* Available at: http://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf

67 US EPA. (2014, June). *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants.* pp. 3-17 to 3-18. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf

68 The manual was revised and updated in 1987-1988, and again in 2001, and corrections were made in 2007. The current version is available at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

69 See, for example: Woolf, T., Steinhurst, W., Malone, E., & Takahashi, K. (2013, November). *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6149

energy efficiency is cheaper to society than most supply-side resources, and much of that cost is borne by participants rather than utilities or ratepayers.

Some might argue that even if energy efficiency currently costs $50 per MWh or less, states with a history of administering programs will see their costs rise as the stock of available, low-cost energy efficiency is used up. However, evidence points to the opposite being true, that is, as savings increase the cost of obtaining those savings goes down.[70] The reasons for this are not clear but could include economies of scale and scope as programs grow and greater experience is gained, leading to greater efficiency in program administration.[71] In any event, despite its low cost, there are many states that have left a large amount of potential efficiency savings on the table. Two of the most significant reasons for this are described in Section 7.

Cost-effectiveness, as distinguished from the cost of saved energy, requires consideration of the benefits of energy efficiency programs, primarily in the form of avoided utility system costs. The cost-effectiveness of energy efficiency programs is generally expressed as a ratio of benefits to costs, or in terms of net benefits (i.e., benefits minus costs). Energy regulators, utilities, and energy efficiency program evaluators have developed very robust methods for gauging the cost-effectiveness of energy efficiency programs, and all parties work together to ensure that the portfolio of ratepayer-funded energy efficiency programs is cost-effective. Although this topic of cost-effectiveness is generally beyond the scope of this chapter, a brief summary of methods is provided in the text box on page 11-20.

Finally, from the perspective of a participant in a ratepayer-funded program, energy efficiency represents a potentially valuable investment opportunity. As noted in testimony made by ACEEE's Executive Director to the US House of Representatives, energy efficiency investments typically provide a 25-percent return on investment, well above the returns of any other category of investment, and are associated with job creation and economic development.[72]

7. Other Considerations

One objection often raised against energy efficiency focuses on its impact on rates, because energy efficiency is largely funded through ratepayer charges. Related to this is a concern about equity — although a customer who participates in an energy efficiency program will see his or her bill *decrease,* often dramatically, there is likely to be a small bill *increase* for those who do not participate in any program offering. The underlying assumption within this criticism is that participation rates in these programs will be low and therefore only a subset or even a small minority of customers will directly benefit. Certainly PUCs have to be concerned about consumers' rates, bills, and the equity of charging all customers for energy efficiency programs. However, these concerns can be largely remedied so as to not overshadow the substantial benefits of pursuing a robust efficiency program.

It is the rare utility that has no foreseeable need for additional energy resources. In the case of electric utilities, energy efficiency is nearly always cheaper than supply-side investments as demonstrated in Section 6. However, this fact can be obscured by the methodology used to evaluate new resources. When energy efficiency and supply-side investments are evaluated differently, a utility may conclude that it is advantageous to pursue the supply-side investment. This situation arises frequently whenever energy efficiency is judged by its impact on rates, whereas supply-side investments are judged on the basis of *total system cost.* Total system cost can be thought of as the sum of payments by ratepayers to meet future needs. Because customers ultimately judge cost based on their bills, total system cost (rather than the impact on rates) is a better measure by which to select between energy efficiency and supply-side investments.

For example, in its Sixth Power Plan, the Northwest Power & Conservation Council looked at the average rates and bills for a variety of different planning scenarios. Removing energy efficiency as a possible future resource lowered the average system rate from $69.49 per MWh to $66.52 per MWh, but raised average residential bills from $77.91 per month to $82.24 per month.[73] If lower rates

70 Takahashi, K., & Nichols, D. A. (2008, August 20). *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date.* The 2008 ACEEE Summer Study. Available at: http://www.synapse-energy.com/Downloads/SynapsePresentation.2008-08.0.Sustainability-and-Costs-of-Efficiency-Impacts.S0051.pdf

71 Ibid.

72 Nadel, S. (2014, July 24). *Economic Impacts of State Energy Policy.* ACEEE. Available at: http://www.aceee.org/files/pdf/testimony/nadel-house-072414.pdf

73 Sixth Northwest Conservation and Electric Power Plan. Appendix O: Calculation of Revenue Requirements and Customer Bills. Available at: https://www.nwcouncil.org/media/6335/SixthPowerPlan_Appendix_O.pdf

had guided the Council's plan, consumers would ultimately pay more for electric service.

With regard to equity and returning to the Northwest Power & Conservation Council example, the appropriate question becomes, "How does one ensure that as many ratepayers as possible see their bills go down?" The answer lies in offering a broad portfolio of programs that addresses all end-uses and customer types, and is sufficiently funded so that any customer who desires to do so can participate.[74] Often programs that have a higher level of savings will have higher participation rates and therefore fewer equity issues.[75]

Another barrier to energy efficiency is utilities' financial disincentive to offer energy efficiency programs. Energy efficiency reduces the utility's sales of electricity below what would otherwise occur. When a utility's sales are reduced, the utility experiences: (1) "lost revenues" or a "lost contribution to fixed costs," meaning that the utility has less revenue than it expected to have when it incurred debt to make capital investments in the electric system; and (2) a reduction in its shareholders' return on equity, because money that would have gone to shareholders under business as usual instead is used to replace the lost revenues. These are serious issues for shareholders but fortunately they can be addressed to varying degrees through two mechanisms: lost revenue recovery or decoupling. As Moskovitz et al explains:

> At first blush, the lost-base revenue approach appears simple and straightforward. One simply calculates how many dollars a utility has lost due to its DSM programs and increases revenues by that amount. For example, suppose a utility has a program to replace existing electric motors with more efficient ones, and that it estimates that, as a result, its electricity sales are 100 million kilowatts lower as a result. If each kilowatt-hour produced, say two cents in revenue net of fuel and any other variable costs, then the utility would lose $2 million in net revenue to this program, which would be recovered under a lost-base revenue adjustment.
>
> A decoupling approach operates differently. Here, one determines during a normal rate case how much revenue a utility requires to cover its expenses and sets an electric rate which is expected to produce that level. Later, perhaps at the end of a year, we return to see whether, in fact, that revenue has been generated or whether, due to fluctuations in sales from the expected level, some greater or lesser amount has been realized. To the extent that the utility has, in fact, received too little (too much) the error is corrected through a surcharge (rebate).[76]

Energy efficiency does offer several ancillary benefits that may be attractive to utilities. Energy efficiency measures can be targeted toward reducing system peak load or reducing congestion.[77] Energy efficiency is also relatively quick to deploy. The planning cycles for new supply resources can vary from two years to ten years, whereas new energy efficiency programs and initiatives can be implemented in a matter of months. And because energy efficiency programs typically target a portfolio of measures and projects, the impacts on the system are predictable and can be shaped to match the load characteristics of a baseload generator.[78]

8. For More Information

Interested readers may wish to consult the following reference documents for more information on end-use energy efficiency:

- Crossley, D. (2013, January). *Effective Mechanisms to Increase the Use of Demand-Side Resources*. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6135

74 Woolf, T. (2013, September 24). *Energy Efficiency: Rate, Bill and Participation Impacts*. A presentation at the ACEEE Energy Efficiency as a Resource Conference. Available at: http://www.aceee.org/files/pdf/conferences/eer/2013/5C-Woolf.pdf

75 Ibid.

76 Moskovitz, D., Harrington, C., & Austin, T. (1992, May). *Decoupling vs. Lost Revenues: Regulatory Considerations*. Available at: http://www.epa.gov/statelocalclimate/documents/pdf/5_19decoupling_lost_revs_compariso_RAP.pdf. The authors further note: "The phrase lost-base revenues is used to distinguish fuel revenues from base revenues. Fuel revenues comprise nearly all of a utility's variable costs. In most states, fuel revenues are fully recovered on a reconciled basis in fuel adjustment factors. Fuel revenues are not lost as a result of energy efficiency investments."

77 See: https://www.efficiencyvermont.com/About-Us/Energy-Efficiency-Initiatives/Geographic-Targeting

78 Crossley, D. (2012, September). *The Efficiency Power Plant Model*. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6135

- Downs, A., & Cui, C. (2014, April). *Energy Efficiency Resource Standards: A New Progress Report on State Experience.* Available at: http://aceee.org/sites/default/files/publications/researchreports/u1403.pdf
- Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Montpelier, VT: The Regulatory Assistance Project. Available at: Available at: www.raponline.org/document/download/id/6739
- NEEP. *Regional Energy Efficiency Database.* Database and supporting documentation available at: http://neep-reed.org/
- Nowak, S., Kushler, M., White, P., & York, D. (2013, June). *Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs.* Available at: http://www.aceee.org/sites/default/files/publications/researchreports/u132.pdf
- Regional Technical Forum. (2014, June). *Roadmap for the Assessment of Energy Efficiency Measures.* Available at: http://rtf.nwcouncil.org/subcommittees/Guidelines/RTF%20Guidelines%20(revised%206-17-2014).pdf
- Sciortino, M., Young, R., & Nadel, S. (2012, May). *Opportunity Knocks: Examining Low-Ranking States in the State Energy Efficiency Scorecard.* Available at: http://www.aceee.org/sites/default/files/publications/researchreports/e126.pdf
- Shenot, J. (2013, August). *Quantifying the Air Quality Impacts of Energy Efficiency Policies and Programs.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6680%20
- Slote, S., Sherman, M., & Crossley, D. (2014, March). *Energy Efficiency Evaluation, Measurement, and Verification.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7064
- State and Local Energy Efficiency Action Network. (2012). *Energy Efficiency Program Impact Evaluation Guide.* Available at: http://www1.eere.energy.gov/seeaction/pdfs/emv_ee_program_impact_guide.pdf
- State and Local Energy Efficiency Action Network. Numerous other publications and resources are available at: http://seeaction.energy.gov/
- US Department of Energy. (2013, April). *The Uniform Methods Project: Methods for Determining Energy Efficiency Savings for Specific Measures.* Available at: http://energy.gov/eere/downloads/uniform-methods-project-methods-determining-energy-efficiency-savings-specific
- US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources:* Electric Utility Generating Units. Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures
- US EPA. 2012. *Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans.* EPA-456/D-12-001a. Available at: http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf
- Wasserman, N., & Neme, C. (2012, October). *Policies to Achieve Greater Energy Efficiency.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6161

9. Summary

Ratepayer-funded energy efficiency programs have expanded significantly over the past decade or so, yielding significant economic and environmental benefits. Nevertheless, the potential to achieve even greater energy savings exists across the country, perhaps even more so in states that have a shorter history with energy efficiency programs or have historically invested less money in energy efficiency.

Recent evidence suggests that states that have established mandatory energy savings targets for utilities see the highest levels of achieved energy savings. This revelation has led to a proliferation of EERS policies, which now exist in half of all states.

Energy efficiency is a low-cost, low-risk resource that compares favorably to all supply-side alternatives. It is also a proven and effective means of reducing air emissions, increasingly recognized and encouraged by the EPA and state air regulators. By leveraging several policy mechanisms, chiefly an EERS, states can make significant reductions in CO_2 emissions while stimulating job growth and their economies.

12. Foster New Markets for Energy Efficiency

1. Profile

"Energy efficiency" refers to technologies, equipment, operational changes, and in some cases behavioral changes that enable our society to enjoy equal or better levels of energy services while reducing energy consumption.[1] Efforts to improve efficiency in the generation, transmission, or distribution of electricity were covered in Chapters 1 through 5 and in Chapter 10. In contrast, Chapters 11 through 15 address different policy options for making the end-user's consumption of electricity more efficient. Chapter 11 focuses on policies that establish mandatory energy savings targets for electric utilities, the achievement of which is generally funded through revenues collected from customers themselves. This chapter, Chapter 12, focuses on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency as an alternative or supplement to government-mandated programs or regulatory requirements. Chapter 13 focuses on an emerging type of energy efficiency program, behavioral energy efficiency, that is worthy of separate treatment because it is sometimes included within the mandated programs described in Chapter 11 and sometimes implemented as a voluntary effort outside of those programs. Chapter 14 covers mandatory appliance efficiency standards that are imposed on manufacturers, and Chapter 15 covers mandatory building energy codes that are imposed on builders and developers.

As explained in Chapter 11, investments in end-use energy efficiency have proven to be a low-cost option for states to achieve carbon reduction, and this option provides the longest and most robust list of co-benefits of all the options described in this document.[2] But despite the fact that energy efficiency provides numerous benefits to utilities, their customers, and society,[3] this option is frequently undervalued and underused. Indeed, the level of investment in the energy efficiency of the buildings in which we live and work is well below economically optimal levels, given current energy prices.

One reason for the persistent underinvestment in efficiency is that the markets in which families and businesses make efficiency investments are separate and fundamentally different from the markets in which power suppliers make investment decisions for power plants, transmission lines, and distribution substations. For building owners and occupants, energy needs are just one — and usually not the most important — of the many concerns in their daily lives. Moreover, efficiency is just one — and often not the most important — of the many attributes of the energy-consuming products that they buy. This complicated comingling of features, with

1 In contrast, some people use the term "energy conservation" to refer to actions that reduce energy consumption but at some loss of service. Neither term has a universally accepted definition, and the two are sometimes used interchangeably.

2 McKinsey & Company prepared a series of reports and carbon abatement cost curves for various nations around the world, including the United States. Energy efficiency initiatives have consistently been revealed to be the lowest cost path toward carbon abatement, and are generally associated with creating a net benefit. See: http://www.mckinsey.com/client_service/sustainability/latest_thinking/greenhouse_gas_abatement_cost_curves. As noted in the House of Representatives testimony of the American Council for an Energy-Efficient Economy's (ACEEE) Steve Nadel, energy efficiency investments typically provide a 25-percent return on investments, well above the returns of any other category of investment, and are associated with job creation and economic development. Nadel, S. (2014, July 24). *Economic Impacts of State Energy Policy.* Available at: http://www.aceee.org/files/pdf/testimony/nadel-house-072414.pdf

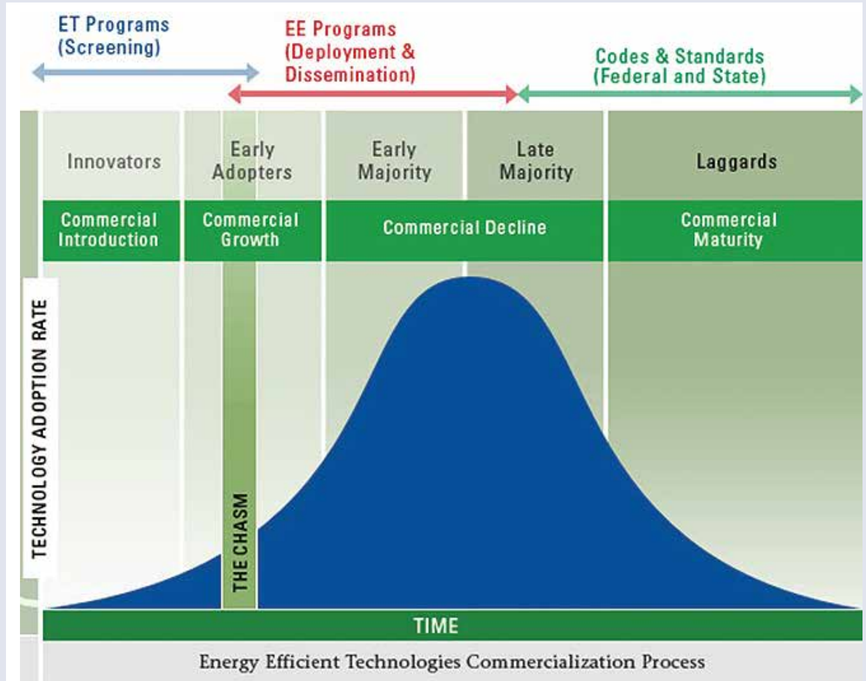
3 For more information on the full benefits of energy efficiency, see: Lazar, J., & Colburn, K. (2013). *Recognizing the Full Value of Energy Efficiency.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6739

efficiency usually being the least "visible" feature, also leads lenders, appraisers, and prospective buyers and renters of buildings to undervalue efficiency. As a result, building owners and consumers typically have much less information about, and much less focus on, the energy implications of their investment decisions than do those who make investments in the energy supply infrastructure.[4]

Government mandates, such as those described in Chapters 11, 14, and 15, offer one option for overcoming informational, motivational, and financial barriers and for increasing investment in energy efficiency toward more economically optimal levels. However, these kinds of mandates typically represent only part of a broader "market transformation" strategy.[5] As indicated in Figure 12-1, market transformation initiatives often begin with research and development focused on emerging technologies and early adopters. As a technology begins to mature, additional adoption can be motivated through formal energy efficiency programs like those described in Chapter 11, complete with incentives. Then, as the technology becomes more mainstream, incentives may be reduced or eliminated and efforts may focus more on growing its market share. Finally, once acceptance of the technology becomes more widespread, this evolution usually ends with some sort of mandatory building energy code or appliance efficiency standard, as described in Chapters 14 and 15, respectively

Figure 12-1

Market Transformation Process for Efficient Technologies[6]



Regardless of the stage of commercialization, the very fact that investments in efficiency are suboptimal means by definition that there is untapped potential for customers to save money through energy efficiency, and for companies to *make* money by providing energy efficiency products and services, with or without government mandates. Indeed, there is a wide range of policies and activities that states can initiate to help foster new voluntary markets and expand existing voluntary markets for energy efficiency services and investments. Each of the following options will be described in more detail in this chapter:

- Encouraging or facilitating the use of energy auditing and energy savings contracts between consumers and third-party energy service companies (ESCOs);
- Improving consumer access to affordable private financing or providing tax incentives for energy efficiency improvements;
- Creating voluntary energy consumption labeling and benchmarking programs for appliances and buildings; and
- Allowing energy efficiency to compete for compensation in wholesale electricity markets.

4 Neme, C., & Cowart, R. (2012). *Energy Efficiency Feed-in-Tariffs: Key Policy and Design Considerations.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/4908

5 ACEEE defines market transformation as "… the strategic process of intervening in a market to create lasting change in market behavior by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency as a matter of standard practice." See: ACEEE. (2013). *Market Transformation.* Available at: http://www.aceee.org/portal/market-transformation

6 Supra footnote 5.

ESCOs and Third-Party Energy Efficiency Delivery Models

Third-party businesses — whether they are retailers, community action agencies, ESCOs, or engineering firms — typically play an integral role in the delivery of energy efficiency programs. This is true even for the mandated energy efficiency programs described in Chapter 11. But in this chapter we focus instead on a type of third-party business called an ESCO, which exists for the purpose of capturing value from energy efficiency.

As used in this chapter, ESCOs refer to organizations that engage in some form of performance-based contracting for energy efficiency services. The ESCO business model is a framework in which specialized construction companies deliver services through performance-based contracts, usually guaranteed savings projects. The delivery of services generally begins with an energy audit to identify energy efficiency opportunities, followed by two contracts: the first is with a financial institution supporting the capital investments; the second is a performance contract between the client and the ESCO that typically guarantees the energy savings.[7] The ESCO then installs the energy-saving equipment and both parties share in the long-term savings from reduced energy bills. The ESCO model typically involves the installation of comprehensive solutions across many categories of end-use devices (including lighting, HVAC, and the building envelope).

Historically, the ESCO industry has focused on customers who have longer investment horizons, including institutional customers and government agencies. The average ESCO contract with a public sector client has exceeded ten years. ESCOs are currently most active in the "MUSH" sectors: municipal governments, universities, schools, and hospitals. The military services are also significant customers. Roughly 85 percent of ESCO contracts are with these kinds of public and institutional customers.

More recently, the opportunities for ESCOs and energy efficiency performance contracts have expanded greatly to include more privately owned buildings.[8] Private buildings are significantly more numerous than public buildings, and offer a potentially large market for ESCOs. However, the challenges for ESCOs in penetrating this market segment include: (1) the short payback horizon required by most private building owners; (2) high costs of capital for energy efficiency investments; and (3) a lack of motivation on the part of building owners to address energy inefficiency. Whereas the ESCO may be satisfied with making investments that earn money over a long time period, most private building owners require an investment payback of three years or less. Thus, the contracts between ESCOs and private building owners tend to be much shorter than for public and institutional customers, averaging only 3.5 years.[9]

Private Financing and Tax Incentives for Energy Efficiency

Another avenue for fostering or encouraging new markets for energy efficiency services is through mechanisms designed to increase consumer access to inexpensive private sector financing.[10] Most energy efficiency measures require an upfront investment of capital that slowly pays off over a long period of reduced energy bills. For example, a residential customer might pay $2000 for an attic insulation project that reduces their energy bill by $50 per month and pays for itself over the course of several years. However, customers who, for whatever reason, cannot afford or obtain financing for the upfront investment cannot capture the potential bill savings. Thus, policies that create opportunities for more customers to obtain affordable financing, although never a sufficient solution alone, can increase markets for voluntary energy efficiency and lead to greenhouse gas (GHG) emissions reductions.[11]

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7 Performance contracts are critically important to the success of ESCOs because they serve to reassure the customer, who may know little or nothing about their own energy use or about efficient alternatives, that the benefits of efficiency are real and attainable. Rather than taking the assertions of the ESCO on faith, the customer has a contractual guarantee of a certain level of savings. Accreditation programs, such as those offered by the National Association of Energy Service Companies, may offer further reassurances to customers that accredited ESCOs are capable of delivering promised savings.

8 For more information, see: ACEEE. (2013). *Energy Efficiency Financing.* Available at: http://www.aceee.org/topics/energy-efficiency-financing.

9 Performance contracts become even more necessary and important as ESCOs expand their focus to include more and more privately owned, smaller buildings.

10 Supra footnote 8.

11 Borgeson, M., Zimring, M., & Goldman, C. (2012, August). *The Limits of Financing for Energy Efficiency.* LBNL. Available at: http://emp.lbl.gov/publications/limits-financing-energy-efficiency

One way to facilitate affordable financing that is beginning to gain some traction is on-bill financing. On-bill financing allows utility customers to invest in energy efficiency and repay the upfront costs through additional charges on their utility bills. Financing is provided by the utility or through a third-party lender such as a Community Development Financial Institution, and can sometimes be provided at a lower interest rate because credit losses on utility bills tend to be far lower than for other financial obligations. If structured properly, on-bill financing can reduce the customer's bills and allow the lender to earn a return.

Another relatively new financing option comes in the form of Property-Assessed Clean Energy (PACE) financing. PACE financing programs enable property owners to pay back energy efficiency financing costs (or renewable energy investment costs) via long-term property tax payments. The improvements and the loan attach to the property itself, rather than the initial borrower, and would pass on to a future purchaser of the property. Here again, lenders have a greater level of certainty that future property tax bills will be paid than for normal loans, and thus it is possible to offer better financing terms through a PACE program.

An Energy Efficient Mortgage (EEM) can also be used to finance energy efficiency improvements or increase the borrowing ability of consumers. With an EEM, a person buying or refinancing a home can include the cost of energy efficiency improvements in their mortgage or (as is more often the case) qualify for a larger loan amount when purchasing an efficient building, on the premise that reduced future energy bill payments will allow for increased mortgage payments without adding risk for default.

State government funding of energy efficiency through revolving loan funds is a third financing option. Revolving loan funds can be managed either by state institutions or existing financial institutions. As described in Chapter 24, a big source of financing in the Eastern states participating in the Regional Greenhouse Gas Initiative (RGGI) is through carbon market allowance auction revenues. Other sources of finance at the state level include tax-exempt bonds, typically backed by the state, potentially in conjunction with some form of financial backing (e.g., a letter of credit) from larger commercial banks. Government-backed loans can usually be offered at lower interest rates to consumers than purely private financing.

The federal government, as well as state and local governments, can also expand opportunities for voluntary investment in energy efficiency by providing tax incentives.

Voluntary Energy Efficiency Labeling and Benchmarking

Other avenues for fostering or encouraging new markets for energy efficiency services are through mechanisms that are designed to elevate consumer and public awareness of opportunities for energy efficiency. Important here are efforts to promote customer and public awareness of energy use through energy audits, appliance labeling programs (e.g., Energy Star®), building certification and labeling programs (e.g., Energy Star® or Leadership in Energy and Environmental Design [LEED]), building benchmarking programs (comparisons of the energy use between similar buildings), and time-of-sale disclosures for homes and commercial buildings. Some of these mechanisms can be implemented either as a voluntary measure, which is the focus of this chapter, or as a mandatory measure.[12] When implemented as voluntary measures, labeling, benchmarking, and disclosure of efficient products and buildings can help buyers overcome information barriers while providing product differentiation for sellers. Both parties can benefit from the purchase of voluntarily labeled products, and a market for efficient alternatives can thus be fostered.

Compensation for Energy Efficiency in Wholesale Electricity Markets

There are a variety of ways to treat energy efficiency as an electricity system resource and enable it to compete in wholesale electricity markets. Laws, regulations, and tariffs may be established to support market-based mechanisms to allow energy efficiency (and other demand-side resources) to compete with generators, transmission providers, and other traditional supply-side resources. Whenever energy efficiency resources bid lower prices than supply alternatives, they are selected. For example, energy efficiency and demand-side resources are allowed to participate in the forward capacity markets organized by two regional transmission organizations, ISO-New England (ISO-NE) and PJM. Doing so fosters new avenues for utilities to lower the costs of complying with energy efficiency mandates, but also offers ESCOs and other parties a greater opportunity to make money by offering voluntary energy efficiency services to paying customers.

12 Mandatory appliance efficiency standards are described in Chapter 14, and mandatory building energy codes are described in Chapter 15.

This chapter provides a cursory treatment of the potential to foster new energy efficiency markets through wholesale electricity market rules, because the opportunity this creates to increase energy efficiency without government mandates is significant. However, because there are several aspects of forward capacity markets that can help or hinder efforts to reduce GHG emissions, that topic is treated more broadly and deeply in Chapter 19.

2. Regulatory Backdrop

This chapter focuses primarily on voluntary, market-based approaches to increasing energy efficiency investment and thereby reducing GHG emissions. Because the emphasis is on voluntary programs, laws and regulations are generally only significant to the extent that they facilitate or impede opportunities to expand market-based energy efficiency.

Energy efficiency plays a prominent role in the emissions guidelines for carbon dioxide (CO_2) emissions from existing power plants that the US Environmental Protection Agency (EPA) proposed in June 2014, citing its authority under section 111(d) of the Clean Air Act, as part of its "Clean Power Plan."[13] The EPA determined that the "best system of emission reduction" for existing power plants under the Clean Air Act consists of four "building blocks," one of which is end-use energy efficiency. Although states will not be required to include energy efficiency in their 111(d) compliance plans, the emissions rate goals for each state are based on an assumption that a certain level of energy savings (and thus, emissions reduction) is achievable. The level of savings that the EPA used to set each state's emissions rate goals is based on the demonstrated performance of leading states with respect to the kinds of ratepayer-funded energy efficiency programs described in Chapter 11 and a meta-analysis of energy efficiency potential studies. The EPA did not separately consider market-based energy efficiency potential as a component of the "best system of emission reduction," and the goals proposed for each state do not presume that states will implement any market-driven programs in addition to mandated programs. It appears likely that the final rules will allow market-driven efficiency programs to be included in state compliance plans. However, as with other types of efficiency programs, states would need to have a solid plan for tracking and evaluating energy savings and avoided emissions if complying with a rate-based approach. This issue could be mitigated if a state chooses a mass-based approach to demonstrate CO_2 emissions reductions.

The following discussion provides further description of the regulatory backdrop for the various approaches to fostering and expanding market-driven energy efficiency.

ESCOs and Third-Party Energy Efficiency Delivery Models

The federal Energy Policy Act of 1992 provided an early stimulus for third-party energy efficiency delivery models by authorizing federal agencies to enter into Energy Savings Performance Contracts (ESPCs) for periods of up to 25 years, provided that annual payments by an agency to both utilities and energy savings performance contractors will not exceed the amount that the agency would have paid for utilities in the absence of the ESPC. The US Department of Energy promulgated the original implementing regulations in 1995. The use of ESPCs by federal agencies was permanently reauthorized in the Energy Independence and Security Act of 2007.

Energy Performance Contracts (EPCs) are also used extensively in the US Department of Housing & Urban Development's Public Housing Program as a means of reducing utility costs. Unlike federal ESPCs, Public Housing EPCs are projects approved by the Department of Housing & Urban Development and implemented by state-chartered Public Housing Authorities with or without the assistance of an ESCO. Because Public Housing Authorities are legally authorized to carry debt, ESCOs involved in the Public Housing sector typically do not need to provide financing to the project, but rather are simply providers of architectural/engineering services.

Some state and local governments have adopted equivalent laws and regulations regarding the ability of state agencies to enter into long-term performance contracts with ESCOs.

Some of the energy efficiency programs that utilities or third-party energy efficiency program administrators implement to comply with state-mandated energy efficiency savings targets (described in Chapter 11) may be implemented by ESCOs. The services provided by an ESCO, for example energy auditing services, may be exactly the same regardless of whether the customer is responding

13 Refer to: US EPA. (2014, June). *40 CFR Part 60 – Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule*. Federal Register Vol. 79, No. 117. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

to a mandated utility program or hoping to get a rebate. However, if a mandated program is the impetus, the ESCO may be subject to rules that are imposed by a public utility commission (PUC) to ensure that ratepayer-funded energy efficiency programs are prudently administered. Similar rules may not apply when the ESCO is working for a customer acting outside of the mandated utility programs.

Private Financing and Tax Incentives for Energy Efficiency

All of the financing and tax incentive options described previously require legislation, administrative rules, or a PUC order to implement. PUCs in some jurisdictions may already have authority to adopt on-bill financing programs for the utilities they regulate; in other jurisdictions, current law prevents such programs. Even if they have the authority to take this step, PUCs have generally been hesitant to add all of the complexity of loans and loan payments for individual properties to the already complex realm of rate design and billing systems. They may be especially reluctant if they perceive on-bill financing programs as increasing the risk that a utility will accumulate unpaid debt.

PACE programs face similar challenges. In most states, property taxes are implemented by local jurisdictions based on authority granted by the state. Many state laws are very specific about the scope of costs that local jurisdictions may include on property tax bills. Thus, to adopt a PACE program, it may be necessary to change property tax policy first at the state level to authorize it, and then one local jurisdiction at a time to implement it. Further complicating matters is the fact that in the summer of 2010 the Federal Housing Finance Agency advised Fannie Mae and Freddie Mac to avoid buying or holding mortgages with PACE assessments, and hinted that a property's participation in a PACE program could default the mortgage. This was a very consequential decision, as more than 90 percent of mortgages written in recent years have been backed by Fannie Mae or Freddie Mac. As a result, most of the nascent PACE programs in the United States quickly subsided.[14] Some states, for example Vermont, have taken steps to address these concerns by passing legislation that creates a PACE mechanism, but in a form that subordinates the recovery of invested funds to the mortgage itself.[15]

EEMs are viewed less skeptically by federal authorities than PACE programs. The Federal Housing Administration and the Veterans Administration both offer EEMs to eligible buyers. Fannie Mae and Freddie Mac do not offer EEMs, but allow underwriters to consider future energy costs when approving mortgages.

The creation of a state-backed revolving loan fund for energy efficiency, or tax incentives for energy efficiency investments, obviously requires government actions through legislation or regulations.

Voluntary Energy Efficiency Labeling and Benchmarking

Voluntary labeling and benchmarking programs generally do not require authorizing legislation or regulations. Mandatory programs are addressed in other chapters.

Compensation for Energy Efficiency in Wholesale Electricity Markets

Wholesale electricity markets are regulated by the Federal Energy Regulatory Commission (FERC) based on a variety of federal energy laws. The creation of a forward capacity market, and the rules that determine whether energy efficiency can or cannot compete in the market, are subject to FERC approval. FERC does not initiate this process and thus does not prescribe the creation of such markets. However, FERC could condition the approval of a forward capacity market on rules that allow fair market competition between energy efficiency, other demand-side resources, and traditional supply-side resources.

Changes in state law or regulations, as well as a PUC order, may be necessary in order for utilities and third-party energy efficiency providers to participate in these wholesale

14 On November 7, 2014, Asset-Backed Alert, a trade publication for the securities industry, reported that the Federal Housing Finance Agency "reached an agreement with several mid-size lenders that will allow Fannie and Freddie to buy mortgages on homes encumbered by liens booked under the property-assessed clean energy (PACE) program, so long as the mortgage lenders agree to repurchase any of the home loans that default. The FHFA, which declined to comment, has yet to officially adopt the policy." Refer to: www.ABAlert.com

15 Vermont Legislation passed in May 2011 made some key changes to earlier PACE legislation. The more recent legislation establishes that PACE liens are subordinate to existing liens and first mortgages but superior to any other liens on the property recorded after the PACE lien is recorded (except for municipal liens, which also take precedence over the PACE lien). See: Database of State Incentives for Renewables and Efficiency. DSIRE. (May 20, 2013). Vermont. Available at: http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=VT38F&re=0&ee=1

energy market programs. If a state-regulated utility receives revenues from those markets, it will also be necessary to establish rules for the use of those revenues and their treatment in ratemaking processes. Utilities that deliver energy efficiency programs as part of organized markets for capacity may in some cases treat such revenues as another source of revenue to cover costs of service, or in other cases they may dedicate some portion of those revenues for special purposes, including further investments in clean energy initiatives and energy efficiency.

Details concerning forward capacity market regulation are provided in Chapter 19.

3. State and Local Implementation Experiences

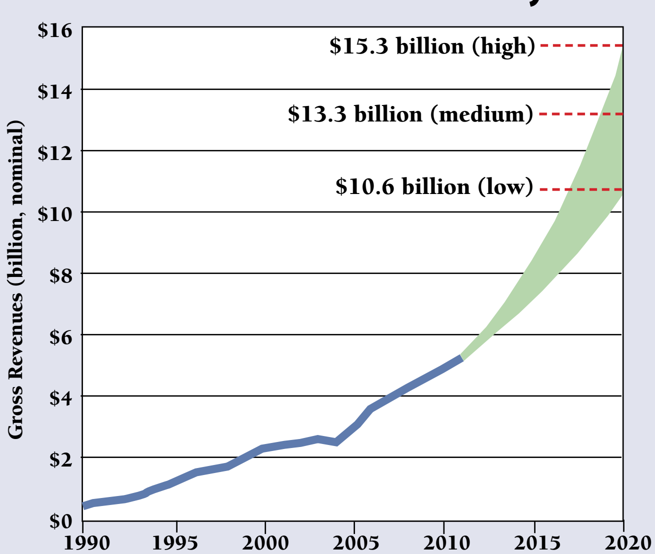
All of the states, and in addition many local governments, have had experience with one or more of the market-based energy efficiency policies and programs described in this chapter. An overview of those experiences is presented below.

ESCOs and Third-Party Energy Efficiency Delivery Models

In the United States, the ESCO industry reported revenues exceeding $5 billion in 2011, and the Lawrence Berkeley National Laboratory (LBNL) projects that the industry will grow to over $13 billion in revenues by the year 2020, as shown in Figure 12-2.

Figure 12-2

Growth of the US ESCO Industry[16]



As noted previously, most ESCO activity in the United States is focused on government and institutional customers, including public sector clients, schools, universities, and hospitals. Commercial, residential, and industrial clients account for only about 11 percent of revenues. Within the residential sector, ESCO activities center on condominiums and apartment buildings. Opportunities may exist for expanding the reach of ESCOs to other customer segments, especially commercial buildings and large residential complexes. There is a wide gap between the requirements of public and private building owners with respect to payback requirements.[17] Yet there is also tremendous potential. LBNL estimates that the remaining investment potential for all of these market segments ranges from $71 billion to $133 billion.[18]

Historically, the industrial sector has not been a focus of ESCO activities in the United States. ESCOs prefer standard and replicable measures and arrangements that can be recovered, typically over long-term contract arrangements. Industrial facilities typically require nonstandard and fairly complex improvements that may be sector-specific. Also, industrial customers typically are reluctant to enter into long-term contracts with ESCOs for energy efficiency improvements because they tend to have short payback requirements for capital investments. However, there are some states where mandatory energy efficiency resource standards like those described in Chapter 11 have fostered a market for ESCO activity in the industrial sector. The most notable example is Texas, where, although the energy efficiency obligation is placed on utilities, utilities are required to contract with energy service providers to implement energy savings measures. All of the state's utilities offer a Commercial and Industrial Standard

16 Stuart, E., Larsen, P. H., & Goldman, C. A. (2013, September). *Current Size and Remaining Market Potential of US ESCO Industry.* LBNL. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6300e-ppt.pdf

17 An indicator of this is the considerable difference in the payback between commercial building projects and public projects found by LBNL. LBNL found that although the payback from publicly owned properties was 10.5 years, it was only 3.5 for private projects. Larsen, P., Goldman, C., & Satchwell, A. (2012). *Evolution of the US Energy Service Company Industry: Market Size and Project Performance from 1990– 2008.* Berkeley: Ernest Orland Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-5447e.pdf

18 Supra footnote 16.

Offer Program, which pays energy service providers for implementing energy and summer peak demand savings.[19] Although these are mandated energy efficiency programs rather than voluntary programs, they demonstrate that there is potential for ESCOs to find cost-effective energy efficiency at industrial sites, if given the opportunity.

Private Financing and Tax Incentives for Energy Efficiency

A wide array of financing initiatives have been implemented across the United States that serve to increase energy efficiency and reduce GHG emissions by lowering financing costs and increasing access to capital.[20]

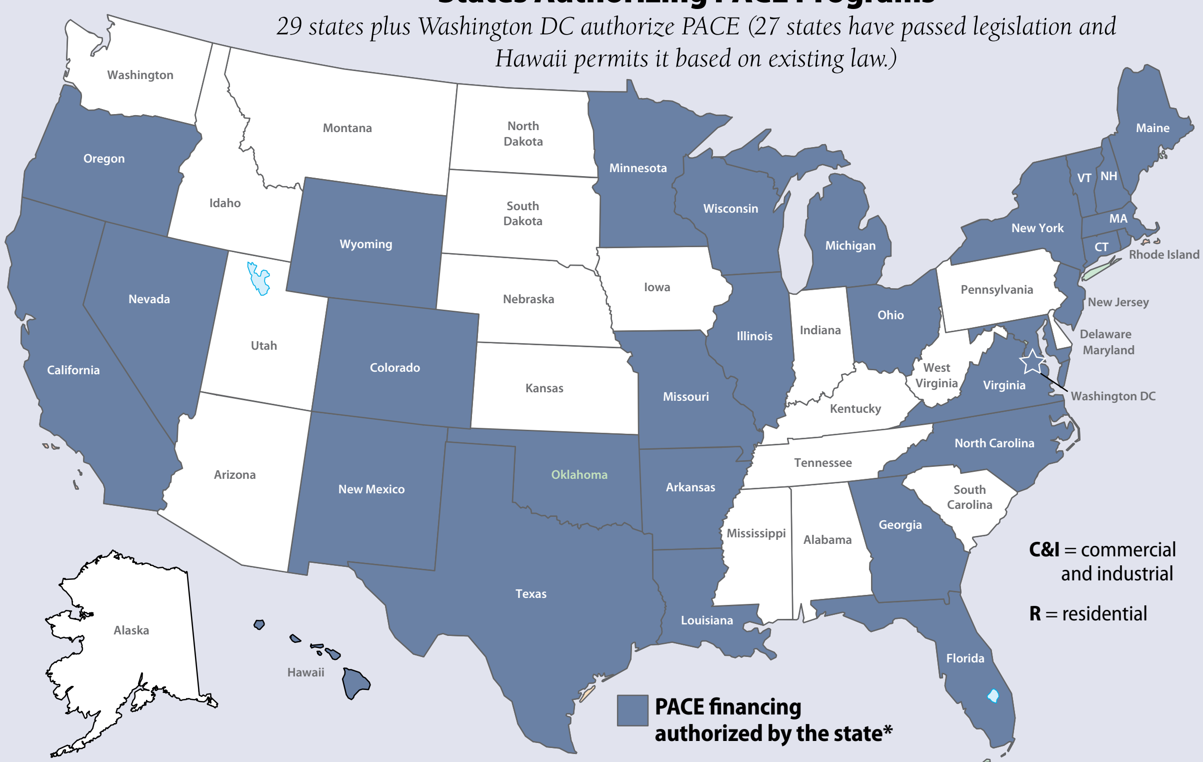
In a 2011 report, the American Council for an Energy-Efficient Economy (ACEEE) found that utilities in at least 20 states were offering or were about to offer on-bill energy efficiency financing programs.[21] With only one exception, the default rate for these programs was just two percent or less. ACEEE featured on-bill finance programs from Connecticut, Oregon, and South Carolina that had supported more than 11,000 loans with more than $30 million of financing.[22]

The PACE financing idea was first tested in 2008 with small pilot programs in California, Colorado, and New York that focused primarily on energy efficiency and renewable energy upgrades to single-family residential homes.[23] The

Figure 12-3

States Authorizing PACE Programs[24]

29 states plus Washington DC authorize PACE (27 states have passed legislation and Hawaii permits it based on existing law.)



AR: 2013
CA: 2008
CO: 2008
CT: 2011
DC: 2010 (C&I only)
FL: 2010
GA: 2010
HI: Existing Authority
IL: 2009
LA: 2009
MA: 2010
MD: 2009
ME: 2010
MI: 2010 (C&I only)
MN: 2010
MO: 2010
NC: 2009
NH: 2010
NM: 2009
NJ: 2012
NV: 2009
NY: 2009
OH: 2009
OK: 2009
OR: 2009
TX: 2009
VA: 2009
VT: 2009 (R only)
WI: 2009
WY: 2011

**The Federal Housing Finance Agency (FHFA) issued a statement in July 2010 concerning the senior lien status associated with most PACE programs. In response to the FHFA statement, most local programs have been suspended until further clarification is provided.*

19 For a brief summary of the Texas program, see: US Department of Energy, Energy Efficiency Programs, Texas.

20 Freehling, J. (2011, August). *Energy Efficiency Finance 101: Understanding the Marketplace.* Washington, DC: ACEEE. Available at: http://aceee.org/white-paper/energy-efficiency-finance-101

21 Bell, C. J., Nadel, S., & Hayes, S. (2011). *On-Bill Financing for Energy Efficiency Improvements: A Review of Current Program Challenges, Opportunities, and Best Practices.* ACEEE report number E118. Washington, DC: ACEEE. Available at: http://www.aceee.org/research-report/e118

22 Supra footnote 21.

23 PACENow Annual Report. (2013, June). Available at: http://pacenow.org/wp-content/uploads/2013/06/Annual-report-6.18.13.pdf

24 See: Database of State Incentives for Renewables and Efficiency. Available at: http://www.dsireusa.org/documents/summarymaps/PACE_Financing_Map.pdf

policy mechanism itself quickly attracted attention, to the point where more than 27 states have now authorized local tax authorities to offer PACE financing programs, as shown in Figure 12-3.

However, as noted earlier, the Federal Housing Finance Agency advised Fannie Mae and Freddie Mac in 2010 not to buy or hold mortgages with a PACE assessment. Because most residential mortgages are bought or held by these institutions, this severely stifled the actual use of PACE financing by tax authorities. In many of the states that authorized PACE, no projects have been financed with PACE to date. Nevertheless, the non-profit organization PACENow reported that as of June 2013, PACE financing had been used to support $33 million worth of projects in seven states and the District of Columbia, and an additional $71 million worth of projects had applied for PACE funding and were "in the pipeline," as shown in Figure 12-4. Some of these projects were energy efficiency projects, but others were renewable energy projects.

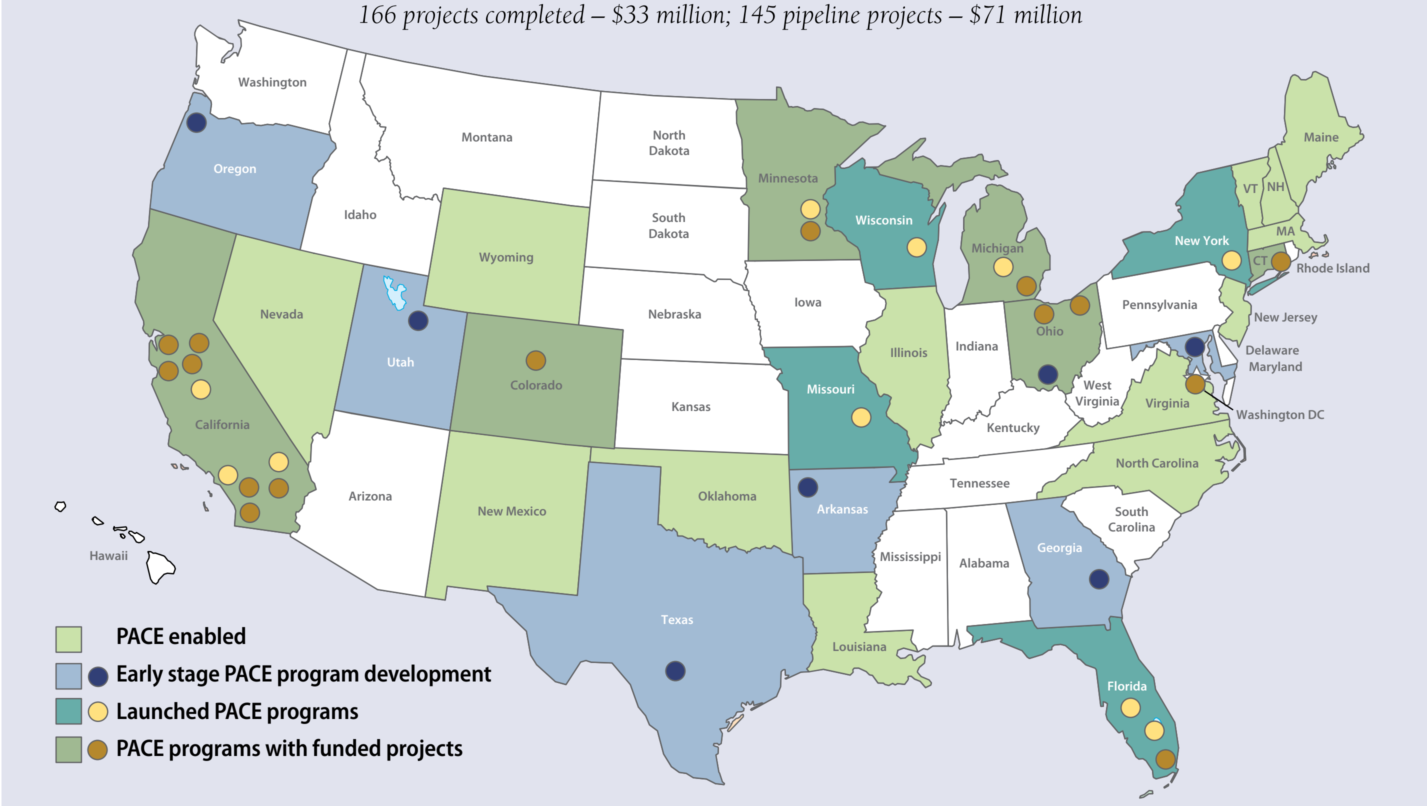
Although the Federal Housing Administration and the Veterans Administration both offer EEMs to eligible buyers, there are few publicly available data on how often those options are used by customers and to what extent it provides financing for energy efficiency. Data on EEMs issued by private lenders are not publicly available.

State government funding of energy efficiency through revolving loan funds has increased precipitously in recent years. This is largely the result of State Energy Program funding provided through the American Recovery and Reinvestment Act of 2009 and RGGI allowance auction revenues. States have allocated $650 million in State Energy Program funds for revolving loan funds.[26] Revolving loan funds can be managed either by state institutions or by existing financial institutions. RGGI allowance auctions, described in more detail in Chapter 24, have provided the participating states with nearly $1 billion in additional revenues, the vast major-

Figure 12-4

PACE-Financed Projects as of June 2013[25]

166 projects completed – $33 million; 145 pipeline projects – $71 million



25 Supra footnote 23.

26 See: Goldman, C. A., Stuart, E., Hoffman, I. M., Fuller, M. C., & Billingsley, M. A. (2011, March). *Interactions between Energy Efficiency Programs funded under the Recovery Act and Utility Customer-Funded Energy Efficiency Programs*. LBNL. Report #4322E. Available at: http://emp.lbl.gov/publications/interactions-between-energy-efficiency-programs-funded-under-recovery-act-and-utility-c

ity of which has been directed toward state energy efficiency programs and other clean energy programs. Other sources of finance at the state level include tax-exempt bonds, typically backed by the state, potentially in conjunction with some form of financial backing (e.g., a letter of credit) from larger commercial banks.

Other instruments for financing energy efficiency at the state and local level include Community Development Financial Institutions, credit unions, and commercial banks. The main connection between commercial banks to energy efficiency is through the financing of energy service performance contracting arrangements from traditional ESCOs.[27]

Other categories of lending bodies providing private financing for energy efficiency include socially responsible investment managers and other institutional money managers. Institutional managers that have financed energy efficiency projects include insurance companies like MetLife, John Hancock, and Prudential. Philanthropy represents another category of financing, primarily through program-related investments. Program-related investment issuers include the Ford Foundation, the MacArthur Foundation, and the F.B. Heron Foundation. Private equity and venture capital firms constitute yet another category of financing. Large firms working in this space include RNG, Goldman Sachs, and Kleiner Perkins.

The federal government offered a residential energy efficiency tax credit for purchases of qualifying equipment between 2006 and 2013, with a cap on the amount of credit that each taxpayer could claim. That program has expired. Comprehensive data on the value of state energy efficiency tax incentives are not readily available.

Voluntary Energy Efficiency Labeling and Benchmarking

There are several programs for voluntarily certifying and labeling new buildings that are more efficient than required under typical mandatory building codes. The two best known are the EPA's Energy Star® program and the LEED program operated by the US Green Building Council.[28]

The Energy Policy Act of 1992 authorized the federal government to develop voluntary testing and consumer information programs for energy efficiency. Since that year, the EPA and the US Department of Energy have managed the federal Energy Star® program, a voluntary endorsement labeling program covering more than 60 product categories, including home and office electronic equipment and household appliances. The Energy Star® program also created an online building efficiency benchmarking tool called Portfolio Manager that is widely used (voluntarily) by owners of residential and commercial buildings.[29]

Energy Star® has separate certification programs for newly constructed residential and commercial buildings. In the past, the EPA estimated that participating buildings would use 15 to 30 percent less energy than standard buildings. The level of incremental energy savings from this voluntary program will of course depend on the stringency of local mandatory building energy codes. In addition, Energy Star® has programs for retrofit and operation of commercial buildings. According to the EPA website, nearly 25,000 US buildings have been certified to the Energy Star® standard as of October 2014. Examples can be found in every state.[30]

The LEED program offers four levels of certification for new commercial buildings, based on a point system. In most states, a building constructed to meet current model building energy codes could qualify for some level of certification, but only a portion of building developers choose to pay the fees required for LEED certification.[31] As of October 2014, more than 50,000 buildings in the United States were LEED-certified, including numerous examples in every state. At least seven states have more than 1000 LEED-certified buildings.[32]

Because LEED allows compliance on a "point" system,

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27 Supra footnote 20 at p. 3.

28 See: https://www.energystar.gov/index.cfm?c=new_homes.hm_index&s=mega and http://www.usgbc.org/leed#overview

29 Individual states generally don't adopt their own voluntary appliance labeling programs, but some have adopted mandatory appliance efficiency standards (see Chapter 14). California, Washington, and some large cities in other states also use Portfolio Manager as the basis for mandatory building benchmarking and disclosure policies (see Chapter 15).

30 Energy Star® Certified Buildings and Plants database. Accessed on October 24, 2014. Available at: http://www.energystar.gov/buildings?s=mega

31 Avsatthi, B. (2014, August 11.) How Energy Efficient are LEED-Certified Buildings? [Web log post]. Retrieved from: http://www.energyblogs.com/buildingenergymodeling/index.cfm/2014/8/11/How-Energy-Efficient-are-LEED-Certified-Buildings

32 LEED Project database. Accessed on October 24, 2014. Available at: http://www.usgbc.org/leed. Many records in the database do not identify the state where the building is located; thus, the numbers cited are conservative estimates.

with provision of bicycle parking and recycling systems (for example) given credit in the same manner as energy efficiency, LEED does not define a specific level of energy efficiency. In some jurisdictions with aggressive mandatory building energy codes, compliance with code will generally result in buildings that meet the LEED Silver standard with respect to energy efficiency. The LEED Platinum standard effectively requires installation of solar photovoltaics or other onsite renewable energy supply options and, in that sense, goes well beyond energy efficiency alone.

In addition to Energy Star® and LEED certification, there are some local residential construction certification programs, such as "Good Cents" and "Super Good Cents," but in most areas these have given way to the Energy Star® program standards.[33]

An analysis by the EPA of 35,000 benchmarked buildings found that those buildings reduced consumption by an average of seven percent over three years.[34] A report commissioned by the California PUC found that benchmarking strongly correlated with building energy improvements and management actions, and was a strong catalyst for customer participation in utility rebate and incentive programs.[35] In addition, work by the Institute for Market Transformation on markets with existing benchmarking laws found that local businesses were experiencing significant new demand for energy efficiency services.

Compensation for Energy Efficiency in Wholesale Electricity Markets

Two organized wholesale electricity markets in the United States — PJM and ISO-NE — conduct forward capacity auctions that permit a wide range of demand-side resources to compete with supply-side resources in meeting the resource adequacy requirements of the region. Energy efficiency and demand response (including distributed generation) can compete on a level playing field with generation to provide capacity in future years. If an energy efficiency provider's bid to provide forward capacity is accepted, it means they will receive payments from the market organizer (ISO-NE or PJM) that will provide additional revenue or profit to support energy efficiency.

Like generating resources, demand-side resources must meet market rules for eligibility and availability, including demonstrating they will be available at the start of the proposed delivery year. Each type of demand-side resource has a specific set of performance hours across which load reductions are required. To be eligible for the auction, service providers must demonstrate in advance their ability to perform during those hours. Like other resources, demand-side resources are subject to penalties if there is a mismatch between their capacity commitment and their performance. These mechanisms are formalized in FERC-approved tariffs and rules.[36]

PJM and ISO-NE currently serve electricity customers in parts or all of 19 states and the District of Columbia. More details on their forward capacity markets are available in Chapter 19.

4. GHG Emissions Reductions

As explained in Chapter 11, the magnitude of emissions reductions attributable to energy efficiency measures depends first and foremost on the amount of energy that was (or will be) saved. However, the emissions reductions that result from those energy savings also depend upon when energy was (or will be) saved, and which marginal electric generating units (EGUs) reduced (or will reduce) their output at those times.[37] Over the longer term, the

33 International Institute for Energy Conservation. Profiles by Program, Bonneville Power Administration, Super Good Cents (residential-new construction), Profile #7. http://www.iiec.org/index.php?option=com_content&view=article&id=379&Itemid=178

34 Institute for Market Transformation (2012, October 11). EPA Analysis Shows Big Benchmarking Savings. [Press release]. Retrieved from: http://www.imt.org/news/the-current/epa-analysis-shows-big-benchmarking-savings

35 NMR Group, Inc. (2012, April). *Statewide Benchmarking Process Evaluation.* Volume 1: Report. Available at: http://www.calmac.org/publications/Statewide_Benchmarking_Process_Evaluation_Report_CPU0055.pdf

36 For example, ISO-NE Market Rule 1 addresses the market rules within ISO-NE. Rule III.13 addresses the capacity markets and III.13.1.4 addresses the rules related to demand-side resources, including energy efficiency's participation in the forward capacity market. Market Rule 1, Section III.13 is available at: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html

37 For example, the average CO_2 emissions rate from natural gas power generation in the United States is about 1100 lb per MWh, whereas the average emissions rate from coal power plants is twice as much as this rate. See: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

more significant impact of energy efficiency programs and policies is that they can defer or avoid the deployment of new EGUs. Over that longer term, the avoided emissions will thus depend not so much on the characteristics of existing EGUs, but on the costs and development potential for new EGUs.[38]

In either the near term or the longer term, GHG emissions reductions are proportional to energy savings, but not necessarily on a one-to-one basis (i.e., a one-percent reduction in energy consumption could reduce emissions by more or less than one percent, depending on how the emissions rates of the marginal or deferred EGUs compare to the system average emissions rates). Chapter 11 describes three methods for quantifying the short-term emissions impacts of energy efficiency programs: the average emissions method, the marginal emissions method, and the dispatch modeling method. Over a longer time period, the emissions rates of new natural gas-fired EGUs may represent a better proxy for avoided emissions.

Data from voluntary and market-driven energy efficiency programs are often proprietary, so less information about the energy savings and emissions avoided through these programs is publicly available. One exception is the EPA's 2010 report on building benchmarking results from over 35,000 buildings enrolled in the Energy Star® Portfolio Manager program, which found that the average participant reduced its energy consumption (normalized for weather and business activity) by 2.4 percent each year and 7.0 percent cumulatively over the three-year analysis period. The EPA projected that if every building in the United States followed such a trend through 2020, more than 18 million metric tons of CO_2 emissions equivalents could be avoided each year.[39]

5. Co-Benefits

In addition to GHG emissions reductions, energy efficiency initiatives can provide a wide range of co-benefits, including cost savings and reductions in other air pollutant emissions. The air emissions co-benefits depend on the same factors that were discussed with respect to GHG emissions reductions.

The full range of co-benefits that can be realized through deployment of energy efficiency technologies is summarized in Chapter 11, and need not be repeated here. The only difference between mandated programs, such as those described in Chapter 11, and voluntary programs, such as those described in this chapter, is in the impetus for change. The co-benefits, as listed in Table 12-1, are the same. Although not shown in the table, voluntary, market-based energy efficiency programs can also produce substantial benefits for the participants (i.e., the customers who improve their efficiency), including reduced future energy bills, other resource savings (e.g., septic, well pumping), reduced operations and maintenance costs, positive health impacts, increased employee productivity, higher property values, and more comfortable indoor environments.

6. Costs and Cost-Effectiveness

The costs and cost-effectiveness of implementing energy efficiency measures are described generally in Chapter 11 with an emphasis on mandatory energy efficiency savings targets imposed on utilities and the costs *to the utilities* of implementing those programs. This chapter focuses instead on voluntary energy efficiency programs.

38 The fact that energy efficiency programs can defer the need for new generating capacity means that they can also potentially extend the life of existing EGUs. New EGUs will tend to be lower emitting than the existing EGUs most prone to retirement, and the developers of new EGUs often size the units not only to meet load growth but also to replace an existing EGU. For example, they might develop a 200-MW EGU in anticipation of 150 MW of load growth, and thus some of the existing EGUs would run less or might choose to retire. Air regulators should be cognizant of this possibility, but not view it as a certainty or as an argument against using energy efficiency to reduce emissions. Older, less efficient, higher emitting EGUs will generally be dispatched less often (not more often) as a result of demand reductions, and the economic pressures that lead to a retirement decision will generally arise sooner (rather than later) as a result of energy efficiency programs.

39 US EPA. (2012, October). *Benchmarking and Energy Savings.* Available at: http://www.energystar.gov/ia/business/downloads/datatrends/DataTrends_Savings_20121002.pdf?3d9b-91a5

Table 12-1

Types of Co-Benefits Potentially Associated with Fostering New Markets for Energy Efficiency

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Demand Response-Induced Price Effect	Yes
Other	Yes

In terms of the costs of implementing voluntary energy efficiency measures, and thus the associated costs of reducing GHG emissions, the emphasis in the present case should be on the cost to the end-user and, where appropriate, the third-party service provider. But although there is clearly a difference in who pays the costs of implementing voluntary energy efficiency measures, it is not at all clear that there is a significant difference in the total costs of mandated energy efficiency and voluntary energy efficiency. However, far fewer data are available for voluntary energy efficiency programs than for mandated programs to verify that assertion, in part because the vehicle used to deliver most of the voluntary energy efficiency covered in this chapter is a contract between an ESCO and its client. Although some of the contractual details may be publicly available in some cases, such as the amount paid by a government client to an ESCO, the ESCOs' cost of saved energy is not known. And for private sector clients, there will normally be no publicly available information on the costs of saving energy and reducing emissions.

In any event, the presumption for voluntary energy efficiency programs should be that participants only volunteer on the expectation that energy efficiency is indeed cost-effective for them, and ESCOs will only offer their services if they expect to be able to profit from the venture. This is a distinctly different cost-effectiveness test than the tests generally applied to the mandatory programs described in Chapter 11.[40]

The costs and cost-effectiveness of allowing energy efficiency to compete in forward capacity markets is covered in more detail in Chapter 19, but it is worth noting here that the response of demand-side resources in the PJM and ISO-NE auctions has been substantial, and their participation is clearly demonstrating that reducing consumer demand for electricity is functionally equivalent to — and cheaper than — procuring capacity commitments from new generating resources. One study suggests that participation of these resources in the first New England auction potentially saved customers as much as $280 million by lowering the price paid to all capacity resources in the market. In a recent PJM auction, demand-side resources were credited with reducing the unit clearing price from $178.78 to $16.46 in unconstrained zones — a savings of $162.32/MW-day.[41]

40 Using standard industry terminology explained in Chapter 11, voluntary programs can succeed if they pass the Participant Test, whereas most ratepayer-funded mandatory programs must pass a Utility Cost Test or Total Resource Cost Test that also considers costs and benefits to nonparticipants.

41 Gottstein, M. & Schwartz, L. (2010, May). *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects.* Montpelier, VT: Regulatory Assistance Project; p 3. Available at: http://www.raponline.org/document/download/id/91

7. Other Considerations

States that are considering their options for reducing GHG emissions will see much to like in voluntary energy efficiency programs, but may also struggle to determine the extent to which they can rely on this strategy. This is a normal limitation for any voluntary emissions reduction strategy.

On the plus side, voluntary energy efficiency policies and programs avoid much of the criticism that is often leveled against mandatory energy efficiency policies and programs. Voluntary efforts are not funded by nonparticipating utility customers, yet nonparticipants enjoy some of the societal and utility system benefits.

One reason ESCOs have been so successful in the government sector is that local government officials can reduce their energy bills and thus their overall operating budget (all else being equal). This can be an effective response to known budget reductions, or a strategy to save taxpayers money in the future.

The participation of energy efficiency in forward capacity markets raises a number of issues, detailed in Chapter 19. One concern frequently cited is whether the energy efficiency that is bidding into forward capacity markets will truly materialize and will result in the expected reduction in the resources needed to meet future electricity demand. Many observers consider this less certain (and thus riskier) than the expectation that an EGU with a known rated capacity can deliver that level of energy in a future year.

8. For More Information

Interested readers may wish to consult the following sources and reference documents for more information on fostering new markets for energy efficiency:

- ACEEE. Available at: http://www.aceee.org
- Institute for Market Transformation. Available at: http://www.imt.org
- McEwen, B., & Miller, J. *Local Governments' Role in Energy Project Financing: A Guide to Financing Tools for the Commercial Real Estate Sector.* IMT. Available at: http://www.imt.org/uploads/resources/files/energy_finance_06.pdf
- Larsen, P. H., Goldman, C. A., & Satchwell, A. (2012). *Evolution of the US Energy Service Company Industry: Market Size and Project Performance from 1990–2008.* Berkeley, CA: Ernest Orland Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-5447e.pdf
- Freehling, J. (2011, August). *Energy Efficiency Finance 101: Understanding the Marketplace.* ACEEE. Available at: http://aceee.org/files/pdf/white-paper/Energy%20Efficiency%20Finance%20Overview.pdf
- Wasserman, N. & Neme, C. *Policies to Achieve Greater Energy Efficiency.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6161
- Gottstein, M., & Schwartz, L. (2010, May). *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/91
- Stoddard, R., & Adamson, S. (2009). *Comparing Capacity Market and Payment Designs for Ensuring Supply Adequacy.* International Proceedings of the 42nd Hawaii International Conference on System Sciences. Available at: http://www.computer.org/csdl/proceedings/hicss/2009/3450/00/04-02-06.pdf

9. Summary

There are a range of activities that states and their utilities can initiate directly or through organized regional markets to promote voluntary investments in energy efficiency. New markets for energy efficiency services can be spurred by encouraging the development of third-party partners, like ESCOs. These markets can be encouraged through enabling mechanisms that motivate end-users to improve their energy performance, while enabling third-party providers to effectively target and monitor and verify performance. State policies can influence whether affordable private financing is available, and can create favorable tax treatment for voluntary energy efficiency measures. States can also foster the expansion of energy efficiency markets by increasing public awareness through voluntary efforts, such as auditing, labeling, and benchmarking programs. Finally, energy efficiency markets can be expanded by allowing energy efficiency to compete with traditional central station generation in organized wholesale energy markets. Efforts to do so will require the approval of grid operator tariffs, and will likely involve some level of state approval for the use of funds and regulatory approvals.

13. Pursue Behavioral Efficiency Programs

1. Profile

"Energy efficiency" refers to technologies, equipment, operational changes, and in some cases behavioral changes that enable our society to enjoy equal or better levels of energy services while reducing energy consumption.[1] Efforts to improve efficiency in the generation, transmission, or distribution of electricity are covered in Chapters 1 through 5 and in Chapter 10. In contrast, Chapters 11 through 15 address different policy options for making the end-user's consumption of electricity more efficient. Chapter 11 focuses on policies that establish mandatory energy savings targets for electric utilities, the achievement of which is generally funded through revenues collected from customers themselves. Chapter 12 focuses on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency as an alternative or supplement to government-mandated programs or regulatory requirements. This chapter, Chapter 13, focuses on an emerging type of energy efficiency program, behavioral energy efficiency, that is worthy of separate treatment because it is sometimes included within the mandated programs described in Chapter 11 and sometimes implemented as a voluntary effort outside of those programs. Chapter 14 covers mandatory appliance efficiency standards that are imposed on manufacturers, and Chapter 15 covers mandatory building energy codes that are imposed on builders and developers.

Some energy efficiency programs use information dissemination, social interaction, competition, and/or potential rewards, rather than direct financial incentives, as the primary mechanisms for changing energy consumption behavior. These programs are known as "behavioral energy efficiency programs."[2] To date, most energy efficiency programs have focused on realizing savings through technical approaches, such as replacements, upgrades, and modifications to equipment and buildings.[3] However, program administrators are increasingly considering behavioral energy efficiency programs for inclusion in their portfolios, and these programs are becoming more mainstream.[4]

Behavioral efficiency programs are sometimes included in a broader portfolio of programs used by a utility to satisfy state energy efficiency mandates, but they can also be offered as standalone or voluntary programs. This is one rationale for devoting a separate chapter to behavioral programs. It is also true that behavioral approaches are newer than the types of mandatory programs described in Chapter 11; they are less familiar to many regulators, and they are a focal point for new research and pilot testing.

Behavioral energy efficiency programs offer significant potential savings: a 2013 study by McKinsey & Company identified 1.8 to 2.2 quadrillion BTUs[5] per year of

1 In contrast, some people use the term "energy conservation" to refer to actions that reduce energy consumption but at some loss of service. Neither term has a universally accepted definition and they are sometimes used interchangeably.

2 As the term is used in this chapter, a behavioral energy efficiency program can include approaches promoting behaviors that result in use of less energy (i.e., energy conservation), as well as approaches that encourage implementation of energy efficient technologies by raising awareness of consumption and efficient alternatives. The distinction between "energy conservation" and "energy efficiency" is thus blurred in the case of behavioral programs.

3 Frankel, D., Heck, S., & Tai, H. (2013). *Sizing the Potential Of Behavioral Energy-Efficiency Initiatives in the US Residential Market.* McKinsey & Company. Available at: http://www.mckinsey.com/~/media/mckinsey/dotcom/client_service/epng/pdfs/savings_from_behavioral_energy_efficiency.ashx

4 Russell, C., Wilson-Wright, L., Krecker, P., & Skumatz, L. (2014). *Behavioral Effects: How Big, How Long, From Whom, How Best?* 2014 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.aceee.org/files/proceedings/2014/data/index.htm

5 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit.

untapped non-transportation residential energy efficiency potential from behavioral adjustments that have no or minimal impact on consumers' lifestyles.[6] That potential is equivalent to 16 percent to 20 percent of current US residential energy use.[7] These programs can be moderately to very cost-effective, with a cost of saved energy[8] ranging from $0.01 per kilowatt-hour (kWh) to $0.08 per kWh according to a 2013 study of ten such programs.[9] They may also be more time efficient: behavioral programs do not require as much time to implement and accumulate savings as some other types of energy efficiency programs, such as those focused on market transformation. However, the body of research on savings, persistence, and customer responses to behavioral energy efficiency programs is somewhat sparse.[10]

Behavioral efficiency programs bypass barriers faced by more traditional energy efficiency programs, because they do not require capital investment or installation of measures.[11] Moreover, they can be designed to address other key barriers, including lack of consumer awareness of the benefits of energy efficiency and lack of information on efficient products.

For some types of behavioral energy efficiency programs, the benefits (including energy savings and associated emissions reductions) are difficult to quantify and may not persist after the stimulus is removed. The vast majority of these programs have not been subject to rigorous evaluation, measurement, and verification (EM&V),[12] although peer comparison feedback programs such as those provided by Opower and others have been rigorously evaluated by independent evaluators for many utility programs over the past five years or so. In addition to encouraging energy conservation efforts (e.g., turning off lights, increasing air cooling temperature set points), another key benefit of behavioral energy efficiency programs is that they help to increase participation and savings in other, more traditional energy efficiency programs, but this complicates how savings and costs are attributed and tracked for each program.[13] States may encounter challenges related to measuring and verifying energy and carbon dioxide (CO_2) emissions savings, given the limited experience in this area. Responding to these issues, efforts are underway to develop standard recommendations for estimating cross-program energy savings impacts resulting from behavioral energy efficiency programs.

This chapter discusses in more detail the types, benefits, and limitations of behavioral energy efficiency programs, as well as program administrators' and states' experiences in addressing barriers to implementing them.

Characterizing Behavioral Energy Efficiency Programs

In a 2013 report, Mazur-Stommen and Farley of the American Council for an Energy-Efficient Economy (ACEEE) developed and presented taxonomic classifications for the universe of behavioral energy efficiency programs, based on a sample of 281 programs in operation from 2008 to 2013. This chapter considers four types of behavioral energy efficiency programs described in the 2013 ACEEE report: (1) communication, social media, and education; (2) social interaction; (3) home energy reports; and (4) games.[14]

6 The behavioral adjustments for which McKinsey & Company estimated energy savings include, for example, increasing air cooling temperature set points, decreasing air and water heating temperature set points, reducing time showering, changing dishwasher and clothes washer/dryer operation settings, and turning off lights and electronics when they are not in use.

7 Supra footnote 3.

8 Cost of Saved Energy equals the program costs divided by program energy savings.

9 Mazur-Stommen, S., & Farley, K. (2013). *ACEEE Field Guide to Utility-Run Behavior Programs.* ACEEE Report No. B132, p. 32. Available at: http://www.aceee.org/research-report/b132

10 Supra footnote 4.

11 Ibid.

12 Supra footnote 9 at p. 11.

13 Goldman, M., & Dougherty, A. (2014). *Integrating Behavior Programs into Portfolio Plans to Encourage Cross-Program Effects.* 2014 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.aceee.org/files/proceedings/2014/data/index.htm

14 Mazur-Stommen and Farley (ACEEE) categorize behavioral energy efficiency programs into three families: cognition (including communication, social media, and education), social interaction, and calculus. According to Mazur-Stommen and Farley, the calculus grouping includes behavior programs that rely on consumers making economically rational decisions, such as real-time and asynchronous feedback, games, incentives, home energy audits, and direct installation of measures. For the calculus category, this chapter describes home energy reports — a

continued on next page

Communication, social media, and education programs are primarily focused on delivering information to customers. These programs use various channels for reaching energy consumers, including mass-market media, targeted communication efforts, social media, classroom-based education, and training.

- Mass-market media campaigns use television, radio, printed media, and billboards to broadcast to a relatively undifferentiated audience. These programs offer no direct means for the consumer to respond to the program administrator, and generally their impacts are not tracked.[15] These campaigns are fairly widespread.
- Social media, such as Facebook, Twitter, and blogs, also broadcast to an undifferentiated audience. Unlike mass-market media, these platforms enable the public to redistribute content, potentially reaching far beyond the program administrator's service area. Generally the impacts and budgets of these programs are not tracked or reported separately.[16]
- Targeted communication efforts include enhanced billing (bill inserts and bill redesign to improve consumers' ability to interpret and use energy consumption information) and direct mail campaigns. These efforts target customers or groups of customers about whom the program administrators have already collected and analyzed data.[17] (Customer-specific home energy reports are discussed in "Peer Comparison Feedback Programs," below.) Targeted communication efforts are common.
- Classroom education uses age-appropriate material for students, from kindergarten through higher education, to encourage changes in energy consumption behavior. Most programs focusing solely on classroom education do not report or track program outcomes. Based on the Alliance to Save Energy's PowerSave Schools Program, ACEEE estimated an average cost of saved energy of approximately $0.06 per kWh, assuming that savings persist for 1.5 years on average.[18] Education programs can be combined with energy efficiency initiatives to improve energy performance in schools; for example, Schools for Energy Efficiency is a comprehensive program that provides K-12 schools with educational awareness materials to engage staff and students, and a plan to save energy and money for the school.[19] Curriculum materials for grades K-12 are readily available, for example from the US Department of Energy's Energy Education & Workforce Development searchable resource library.[20]
- Training often targets the commercial, industrial, and institutional sectors. These programs frequently take place in the workplace, allowing consideration of site-specific issues and processes. Program impacts (e.g., participation and savings) are usually not reported.[21] However, efforts to facilitate tracking and claiming savings by program administrators are underway for the US Department of Energy's Superior Energy Performance program.

Social interaction programs are driven by the human need for sociability. The interaction can be in person or online, for only a few minutes or for longer periods. Group structure ranges from one-on-one interactions, such as with Progress Energy's Neighborhood Saver program, to small groups of people organized as eco-teams, to community-wide efforts such as community-based social marketing (CBSM) campaigns.[22]

- Implemented at the community level, CBSM seeks to influence a targeted behavior (such as energy consumption) through social and behavioral factors. The results of CBSM can be much deeper savings than those achieved by programs that only use economic and attitudinal traits as motivation. CBSM follows five steps: (1) selecting behaviors that will achieve

Footnote 14, continued from previous page

form of asynchronous feedback — and games. Other mechanisms in the calculus category are described elsewhere in this guide: real-time feedback, an enabling technology for demand response, is discussed in Chapter 23, and financial incentives, home energy audits, and installation of measures are discussed in Chapter 11.

15 Supra footnote 9 at pp. 12-15.

16 Ibid, p. 15.

17 Ibid, p. 14.

18 Ibid, p. 16.

19 See: http://www.class5energy.com/schools-for-energy-efficiency-see-program

20 See: http://www1.eere.energy.gov/education/lessonplans/#more_resources

21 Supra footnote 9 at p. 17.

22 Ibid, p. 26.

program outcomes; (2) identifying and addressing historical local barriers and benefits as experienced by a specific, local audience; (3) developing strategies based on social science tools to address identified barriers; (4) piloting the strategies; and (5) implementing the strategies on a broad scale and measuring the outcome.[23] CBSM programs have been implemented by both public power and investor-owned utilities, with a wide range in numbers of participants. (In its sample, ACEEE found a range of just 1000 participants to as many as 200,000.) Participation rates tend to be high: for example, Tucson Power's Community Education program reported 45-percent participation. Project Porchlight, a CBSM campaign that has been implemented in a range of settings, has proved highly cost-effective: the sample of four campaigns analyzed by ACEEE achieved a cost of saved energy of just $0.01 per kWh.[24] (See Section 3 for more information about Project Porchlight.)

- Online forums that allow people to share experiences and information and that focus on peer-to-peer or community-based communication fall into the social interaction family of programs. The success of these forums has been mixed, but the limited, initial experience with this strategy suggests that it can be successful (e.g., the Cape Light Compact reported that users saved nine percent off their monthly bills on average during the first phase of a pilot featuring an online social forum).[25]
- Gifts, such as giveaways of items like compact fluorescent light (CFL) bulbs, can encourage behavior change by triggering the recipient to reciprocate — that is, by saving energy. These programs are typically counted as marketing, and usually the savings from them are not tracked.[26]

Peer comparison feedback programs (or home energy reports) provide one-way feedback on a household's energy use as compared to that of similar households, and offer energy saving tips and information about other programs offered by the program administrator. The feedback is intended to induce behavior changes to bring energy consumption in line with a more efficient baseline, presented as a social norm. Reports can be mailed to participants or be presented online, and they can be delivered regularly (e.g., monthly or quarterly) or irregularly (e.g., when prompted by an action by the customer, such as visiting a website to view energy account data). Participation rates are generally very high for these programs, and they are moderately to very cost-effective.[27] Peer comparison feedback programs are described further in Section 3.

Games, including competitions, challenges, and lotteries, use a combination of social interaction and rewards as their primary mechanism. Competitions seek to motivate individuals or groups of people to change energy use behavior relative to another group, such as another neighborhood or city. Games can also take the form of challenges, which focus on an individual, group, or community reducing energy use relative to its own baseline. Lotteries offer an economic reward to the winner, selected at random. Participation in a lottery can be tied to a behavior change, such as participation in a home energy audit.[28]

Program Administration

Behavioral energy efficiency programs can be implemented and administered by utilities, state and local governments, nonprofit entities, private businesses, and even groups of public citizens. Often the entity that administers traditional, measures-focused energy efficiency programs will also offer behavioral energy efficiency programs, but that need not be the case. In addition to the administrators of traditional energy efficiency, other entities such as school districts, colleges and universities, and state departments of education or energy are very good candidates to undertake classroom education, general communication, online forums, and social media campaigns. As another example, challenges, competitions, and community-based social marketing efforts can be implemented by teams or other groups.[29]

23 Vigen, M., & Mazur-Stommen, S. (2012). *Reaching the "High-Hanging Fruit" Through Behavior Change: How Community-Based Social Marketing Puts Energy Savings within Reach.* ACEEE. Available at: http://www.aceee.org/white-paper/high-hanging-fruit

24 Supra footnote 9 at p. 27.

25 Ibid, p. 29.

26 Ibid, pp. 29-30.

27 Ibid, pp. 20-21.

28 Ibid, pp. 22-23.

29 Supra footnote 23.

2. Regulatory Backdrop

Behavioral energy efficiency programs have not been the subject of specific state legislation or regulations, but have evolved in many jurisdictions as a component of broader efficiency policies and programs such as those summarized in Chapter 11. In still other jurisdictions, behavioral programs have been launched without any regulatory driver whatsoever.

In those jurisdictions where behavioral programs have been included within a portfolio of mandated efficiency programs, energy regulators have often approved the programs on a pilot basis, at least initially. This approach indicates that behavioral approaches are indeed new and unfamiliar to many regulators, and that there is (or has been) a degree of skepticism about the expected results and cost-effectiveness of such programs. Regulators want to be certain that ratepayer money invested in behavioral programs will be cost-effective. Nevertheless, more and more utilities and third-party program administrators have been convinced that the programs can be cost-effective and have decided in recent years to include behavioral programs in their portfolios.

If programs are developed using ratepayer funds, program administrators generally need to submit program plans to regulators for review and approval on a regular basis (usually every one to four years). Program plans generally describe the program, its objectives and goals (e.g., in terms of units of energy saved), the target customer segment, a marketing and program delivery strategy, and budget; other factors may also be considered.

Many administrators must issue annual or periodic reports showing actual program results, which typically include participation rates; electric energy, electric demand, and other fuel savings; and expenditures. In addition, program administrators are often required to submit EM&V plans and study results to regulators for review. Although no standard EM&V methods exist to estimate savings from education and marketing-focused programs and cross-program savings from other types of behavior programs, standard or best practice EM&V methods exist for certain behavioral efficiency programs (e.g., home energy reports and efficiency measures installed as a result of a CBSM campaign).[30]

Energy efficiency plays a prominent role in the emissions guidelines for CO_2 emissions from existing power plants that the Environmental Protection Agency (EPA) proposed in June 2014, citing its authority under Section 111(d) of the Clean Air Act, as part of its "Clean Power Plan." The EPA determined that the "best system of emission reduction" for existing power plants under the Clean Air Act consists of four "building blocks," one of which is end-use energy efficiency. Although states will not be required to include energy efficiency in their 111(d) compliance plans, the emissions rate goals for each state are based on an assumption that a certain level of energy savings (and thus, emissions reduction) is achievable. The level of savings that the EPA used to set each state's emissions rate goals is based on the demonstrated performance of leading states with respect to the kinds of ratepayer-funded energy efficiency programs described in Chapter 11 and a meta-analysis of energy efficiency potential studies. The EPA did not explicitly include or exclude behavioral efficiency programs from consideration when determining the level of achievable energy savings, but behavioral programs can clearly contribute to achieving the assumed level of savings. It appears likely that the final rule will allow behavioral efficiency programs to be included in state compliance plans, regardless of whether the behavioral programs stand alone or are incorporated into a portfolio of mandated programs as described in Chapter 11. However, as with other types of efficiency programs, states would need to have a solid plan for tracking and evaluating energy savings and avoided emissions if complying with a rate-based approach. This issue could be mitigated if a state chooses a mass-based approach to demonstrate CO_2 emissions reductions.

30 For example, traditional EM&V methods (i.e., a combination of engineering estimates of per-unit energy savings and participant counts) can be used to estimate the portion of savings from CBSM programs that involve direct installations of certain low-cost energy efficiency measures (e.g., CFL bulbs). For peer comparison feedback (or home energy reports) programs, a standard EM&V method is to establish both a treatment group and a control group, and estimate statistically significant differences in household consumption between the two groups. Details of this approach are discussed in Section 3 in this chapter and provided in the references in Footnote 37. Methods to estimate cross-program savings are discussed in Section 7.

3. State and Local Implementation Experiences

This section describes experiences with two types of behavior programs: peer comparison feedback programs by Opower and others, and Project Porchlight, a successful CBSM campaign by One Change Foundation.

Peer Comparison Feedback Programs

Utilities are increasingly considering and implementing peer comparison feedback programs. Evaluation studies show that peer comparison feedback programs are cost-effective energy efficiency programs, costing from $0.03 to $0.08 per kWh.[31] Their savings range from 1.5 percent to as much as 12 percent (as discussed in the following section, Greenhouse Gas Emissions Reductions). Among various entities, Opower is the most widely used platform for peer comparison feedback programs. Others include Tendril, Aclara, and C3. In partnership with local utilities and third-party administrators, Opower has offered behavioral programs to over 70 utilities in the country.[32]

Peer comparison feedback programs compare a household's energy use to that of similar households and provide relevant, personalized energy conservation tips. They also provide customers with information about other programs offered by their local utilities or efficiency program administrators.[33] Peer comparison programs using home energy reports take advantage of social norms to enhance the reception of their message. Home energy reports establish social norms and encourage participants to conform as closely as possible to sets of established norms.[34] In fact, a recent survey conducted for a study of Connecticut Light and Power's home energy reports program revealed that the comparison to neighbors was the most important aspect of the program for program participants. Through telephone surveys, almost 90 percent of households mentioned the neighborhood comparison when asked what information they remember from the reports. Furthermore, focus group attendees indicated the reports "sparked a 'competitive spirit,' motivating them to try to maintain a favorable status in comparison to their neighbors."[35]

Participation rates for home energy report programs are generally very high (upwards of 90 percent for a sample of Opower programs) because they are typically opt-out, rather than opt-in like most traditional energy efficiency programs. For example, a 2013 program evaluation on behavioral programs in Massachusetts found that Western Massachusetts Electric Company reached over 100,000 participants in its Opt-Out Home Energy Report programs, but reached only about 8000 customers in its opt-in programs. Together with other program administrators, the state's opt-out behavior programs have reached about 550,000 participants to date.[36]

A peer comparison feedback program often establishes both a treatment group and a control group, and estimates statistically significant savings by examining household consumption between the two groups.[37] Individuals in these groups are randomly selected. This experimental program design (using a randomly selected, large population) is another unique feature of peer comparison feedback programs, and is the feature that makes it possible to develop precise and unbiased savings estimates.[38]

31 Allcott, H. (2011). Social Norms and Energy Conservation. *Journal of Public Economics* 95:9-10: 1082-1095. Available at: http://www.sciencedirect.com/science/article/pii/S0047272711000478; Supra footnote 9 at pp. 21-22.

32 Opower. (2012). *Successful Behavioral EE Programs.* Available at: https://opower.com/uploads/files/BEE_Whitepaper.pdf

33 Supra footnote 9 at pp. 20-21.

34 Ibid.

35 Supra footnote 4 at p. 7-281.

36 Opinion Dynamics Corporation, Navigant Consulting, & Evergreen Economics. (2013, June). *Massachusetts Cross-Cutting Behavioral Program Evaluation Integrated Report.* Available at: http://www.rieermc.ri.gov/documents/2013%20Evaluation%20Studies/ODC_2013_Cross_Cutting_Behavioral_Program_Evaluation.pdf.

37 Supra footnote 36; KEMA (2012, April). *Puget Sound Energy's Home Energy Reports Program – Three-Year Impact, Behavioral and Process Evaluation.* Available at: https://conduitnw.org/_layouts/Conduit/FileHandler.ashx?RID=849; Supra footnote 4 at p. 7-281; Smith, B. A., & and Morris, L. (2014, August). *Neighbor Comparison Reports Produces Savings, but HOW?* 2014 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.aceee.org/files/proceedings/2014/data/index.htm

38 KEMA, at supra footnote 37.

Project Porchlight CBSM Program

Project Porchlight is a very cost-effective, highly successful CBSM program developed by One Change Foundation. The program mobilizes a significant number of volunteers and community networks to encourage members of a community to switch from inefficient incandescent light bulbs to new, energy-efficient CFL bulbs. By providing people with a free CFL bulb and information about energy conservation, the campaign aims to convert awareness into action by making first steps toward more energy-efficient practices (i.e., changing to a CFL bulb) accessible to all people.[39] One Change has run Project Porchlight campaigns in over 900 communities since 2005, and has been sponsored by a number of utilities and agencies in North America, including Puget Sound Energy (PSE), the New Jersey Board of Public Utilities, Ontario Power Authority, and SaskPower.[40]

One of the major benefits of a CBSM campaign is that it can reach out to numerous people with various backgrounds within a community, including those who are not aware of utility energy efficiency programs. CBSM does this first by addressing the specific barriers and benefits to energy efficiency and conservation within a given community. Second, CBSM relies on non-profit community organizations and local volunteers to conduct community outreach and to deliver credible messages, in that they have no commercial gain from participation.[41] Unlike utilities, local non-profit organizations leading a CBSM campaign can also take "a more light-hearted, nimble and fun tone in their communications."[42] Lastly, a successful CBSM campaign motivates a large number of volunteers to participate in the campaign by generating a sense of community, connection, and contribution.[43]

Using these approaches, Project Porchlight/One Change Foundation reached a significant number of households with various demographics in numerous communities, and in some cases reached 100 percent of the households in a community. For example, One Change Foundation's evaluation data on Project Porchlight in New Jersey (shown in Figure 13-1) show that the participation in four counties ranged from 48 percent to 100 percent of households and together reached about 45,000 households in these counties. The diversity of income levels and racial demographics in the figure also implies that people with various backgrounds have participated in the program, given the high participation rates.

Figure 13-1

Participation Rate and Demographics of Project Porchlight in New Jersey[44]

Phase Two (2009)

					Income Levels (K/yr)*			Racial Demographics			
Location	Completed Deliveries	Household Count*	% Households Delivered	Population*	25–35	35–45	50–75	Caucasian	African American	Chinese	Population Density* (pers./sq. mi.)
Bergenfield Bergen County	4,572	7,491	61.0%	26,247	14.9%	21.3%	16.8%	62.9%	6.9%	20.4%	9,065
Newark Essex County	15,490	15,488	100.0%	278,980	12.9%	13.9%	14.3%	26.5%	53.5%	1.2%	11,400
Jersey City Hudson County	5,719	12,158	47.0%	242,389	12.9%	15.5%	17.3%	34.0%	28.3%	16.2%	16,045
Paterson Passiac County	19,020	39,750	48.0%	149,222	14.3%	16.6%	16.8%	30.8%	32.9%	1.9%	17,675

39 See: http://www.projectporchlight.com/content/what-we-do

40 Summit Blue. (2010, April). *Evaluation of Consumer Behavioral Research.* p. 21. Available at: https://www.nwcouncil.org/media/5449/Consumer_Behavioral_Research_Report___Summit_Blue.pdf; OneChange. (2008). *Impact and Evaluation Summary.* Available at: http://www.onechange.org/wp-content/doc_impact_and_evaluation_summary.pdf; Supra footnote 9.

41 Summit Blue, at supra footnote 40 at pp. 21-22.

42 Ibid, p. 21.

43 Ibid, p. 22.

44 OneChange, at supra footnote 40 at p. 3.

Another benefit of a CBSM campaign is that it raises individuals' awareness of the benefits of energy conservation as well as of local energy efficiency programs. For example, a single county in New Jersey in which the Porchlight volunteers brought information about refrigerator recycling to consumers' doors accounted for 25 percent of the state's refrigerator recycling program. In the campaign sponsored by BC Hydro Power, 41 percent of those who received a Project Porchlight bulb rated BC Hydro's Power Smart program "very favorable" in a survey, whereas just 27 percent of those who did not receive a bulb rated the program "very favorable." In the same survey, 17 percent of those who received a bulb rated Energy Star® "very favorable," and 13 percent of those who did not receive a bulb rated Energy Star® "very favorable." This indicates increased awareness of energy conservation among those who received a bulb, but also an increased awareness of and positive attitudes toward BC Hydro's program (given the "very favorable" rating for BC Hydro's program was much higher than the rating for Energy Star®).[45]

Lastly, Project Porchlight campaigns have been proven to be very cost-effective in a number of utility- and state-sponsored programs. Table 13-1 presents costs and estimated savings associated with this campaign sponsored by four entities in North America. The cost of saved energy ranged from 1.2 cents to 1.6 cents per kWh, with an average of 1.4 cents. However, if savings persist beyond the initial year, the cost of saved energy would be lower than these estimates. As explained in the Costs and Cost-Effectiveness section that follows, a 2013 report by ACEEE assumed the savings last 1.5 years on average for various behavior programs. Using this assumption, the average cost of saved energy for Project Porchlight is just about one cent per kWh.

4. Greenhouse Gas Emissions Reductions

As explained in Chapter 11, the magnitude of emissions reductions attributable to energy efficiency measures depends first and foremost on the amount of energy that was (or will be) saved. However, the emissions reductions that result from those energy savings also depend on when energy was (or will be) saved, and which marginal electric generating units (EGUs) reduced (or will reduce) their output at those times.[47] Over the longer term, the more significant impact of energy efficiency programs and policies is that they can defer or avoid the deployment of new EGUs. Over that longer term, the avoided emissions will thus depend not so much on the characteristics of existing EGUs, but on the costs and development potential for new EGUs.

In either the near term or the longer term, greenhouse

Table 13-1

Costs and Savings of Project Porchlight Campaigns[46]

	Year	Duration (y)	Customers Served	Program Costs	Savings (MWh)	Cost of Saved Energy (cents/kWh)	Savings (kWh) per Participant
Ontario Power Authority	2007	0.3	12,851,821	$3,500,000	300,800	1.2	23
Puget Sound Energy	2009	0.5	957,025	$1,700,000	129,700	1.3	136
New Jersey Board of Public Utilities	2008	4	8,864,590	$10,942,383	690,515	1.6	78
SaskPower	2008	0.5	490,000	$1,440,000	94,000	1.5	192
Total			23,163,436	$17,582,383	1,215,015	1.4	52
Average		1.33	5,790,859	$4,395,596	303,754	1.4	52

45 Summit Blue, at supra footnote 40 at p. 22; One Change, at supra footnote 40 at p. 4.

46 Based on: Supra footnote 9. The final column (cost of saved energy) was calculated based on data in the source document, based on an assumption that savings persist for one year.

47 For example, the average CO_2 emissions rate from natural gas power generation in the United States is about 1100 lb per megawatt-hour (MWh), whereas the average emissions rate from coal power plants is twice as much as this rate. See: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

gas (GHG) emissions reductions are proportional to energy savings, but not necessarily on a one-to-one basis (i.e., a one-percent reduction in energy consumption could reduce emissions by more or less than one percent, depending on how the emissions rates of the marginal or deferred EGUs compare to the system average emissions rates). Chapter 11 describes three methods for quantifying the short-term emissions impacts of energy efficiency programs: the average emissions method, the marginal emissions method, and the dispatch modeling method. Over a longer time period, the emissions rates of new natural gas-fired EGUs may represent a better proxy for avoided emissions.

In this section, we will summarize some of the currently available information on how much energy has actually been saved by behavioral programs, and how much could potentially be saved. However, information on GHG emissions reductions achieved through behavioral efficiency programs is unfortunately scarcer than similar information regarding standard energy efficiency programs.[48]

It has been several years since behavior-based utility energy efficiency programs were first developed. Although experience is still limited, the growing number of impact evaluation studies suggests that energy savings and associated GHG emissions reductions from behavioral energy efficiency programs can be significant. For the residential sector, annual energy savings could be about 1.5 to 2 percent of annual electricity consumption from households at a minimum, and possibly last more than a year after the program intervention (such as sending a home energy report) ends.

A 2013 paper by the University of California, Los Angeles presented a comprehensive meta-analysis of information-based energy conservation experiments conducted to date.[49] The study examined in detail 59 unique journal papers, representing 156 field experiments in 13 countries from 1975 to 2012, and estimated energy savings from the information-based strategies such as savings tips, energy audits, peer comparison feedback and pecuniary feedback, and pricing strategies. On average, the study found that individuals in the experiments saved electricity consumption by 7.4 percent. It also reviewed savings by program types. Among others, the study revealed energy savings tips, individual usage feedback, and social comparisons reduced energy use by 9.6 percent to 11.5 percent on average, and audits and consulting reduced energy use by 13.5 percent. However, the study also indicated that these savings effects may be overstated, because average savings effects from high-quality experiments (that include statistical controls such as weather, demographics, and a control group) within the 156 experiments were approximately two percent. Unfortunately it is not clear from the study which types of programs were included in the selected high-quality experiments.

More recent experiments on residential behavioral energy efficiency programs found similar levels of energy savings overall and revealed more details, such as savings for average energy users versus high energy users, and savings persistence in the time period following intervention. A 2014 study of Connecticut Light and Power's home energy reports program found that while receiving home energy reports, households with typical energy consumption levels achieved savings of 1.17 percent on average, whereas high energy use households achieved an even higher rate of 2.31 percent. On average, households achieved savings of 1.82 percent.[50] The study also observed continued energy savings for more than a year after home energy reports were suspended. Other recent reports observed that energy savings persisted for roughly two years at around 1.5 to 2.5 percent per year; in some cases, savings rates grew over time.[51] It is also notable that one of the behavioral programs, offered by Cape Light Compact in Massachusetts, showed a much higher savings rate, at about eight to nine percent over three years with a slight savings decrease in the second and third years.[52]

There are two national energy savings potential studies

48 Although the EPA has not been clear about how it intends to verify emissions reductions, the draft Clean Power Plan states that additional information and reporting may be necessary to accurately quantify the avoided CO_2 emissions associated with demand-side energy efficiency measures, such as information on the location and the hourly, daily, or seasonal basis of the savings. See: US EPA. (2014, June). *40 CFR Part 60 – Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule.* Federal Register Vol. 79, No. 117. p. 34920. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

49 UCLA Institute of the Environment and Sustainability. (2013, February). *Information Strategies and Energy Conservation Behavior: A Meta-Analysis of Experimental Studies from 1965–2011.* Available at: http://www.environment.ucla.edu/media/files/Delmas-Fischlein-Asensio.pdf

50 Supra footnote 4.

51 Supra footnote 38; Supra footnote 36.

52 Supra footnote 36.

focusing on behavioral energy efficiency programs. A 2013 preliminary study by McKinsey & Company examined the energy savings potential associated with behavioral adjustments by residential energy consumers that have little or no impact on their lifestyles. Although the scope of the study is not clear, the study found a total of 1.8 to 2.2 quadrillion BTUs per year of untapped residential energy efficiency potential, equivalent to 16 to 20 percent of current US residential energy use.[53]

Another study conducted in 2014 by Opower, one of the largest providers of residential behavioral programs in the nation, estimated savings potential from Opower-type peer comparison feedback programs for the entire country by state. This study relied on a dataset based on 218 programs in operation at 88 utilities, and estimated both energy and peak load savings.[54] The peak load savings estimates are based on a subset of data points, in which Opower observed that savings are 1.5 times higher during the peak hours. Overall, the study found behavioral programs are cost-effective for 79 million households, or about 60 percent of the US population. More specifically, the study estimated a potential of about 18,700 gigawatt-hours (GWh) of annual energy savings, about 3.2 gigawatt (GW) generation capacity savings, and 10 billion metric tons of CO_2 savings for the entire nation (see Table 13-2). According to the study, this level of energy savings represents about 1.6 percent of current residential electricity use, and is enough energy to take the entire state of Arkansas off the grid for a year, or to take 2.1 million cars off the road. At the state level, the highest relative amounts of energy savings were found in California, Texas, Florida, New York, Pennsylvania, and Ohio, attributable in part to these states' high populations, high avoided costs, and/or high air conditioning loads (see Figure 13-2).

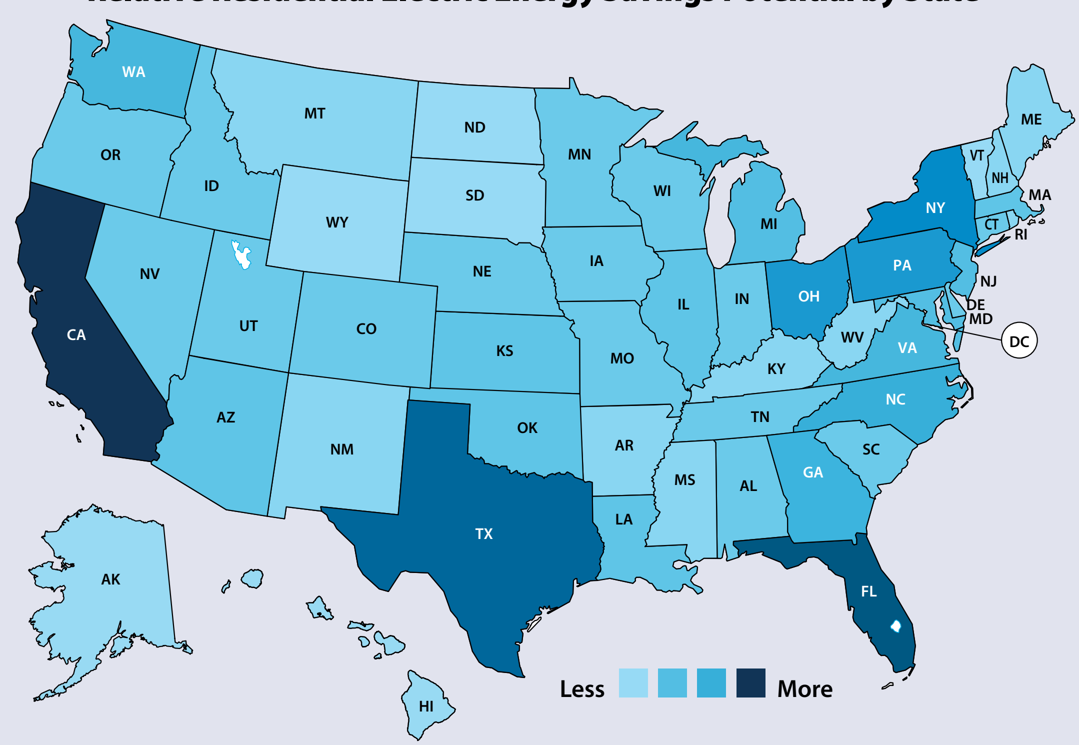
Table 13-2

Overview of Residential Electric Behavioral Potential Results[55]

Total Households	Technical Potential Households	Economic/ Achievable Potential Households	Annual Generation Savings (GWh)	Annual Capacity Savings (MW)	Annual CO_2 Savings (metric ton)	Annual Customer Bill Savings
110 million	96 million	79 million	18,679	3198	10,200,007	$2.2 B

Figure 13-2

Relative Residential Electric Energy Savings Potential by State[56]



54 Kane, R., & Srinivas, N. (2014, August). *Unlocking the Potential of Behavioral Energy Efficiency: Methodology for Calculating Technical, Economic, and Achievable Savings Potential.* Proceedings of the 2014 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.aceee.org/files/proceedings/2014/data/index.htm

55 Ibid.

56 Ibid, figure 5 at p. 5-205.

Few if any studies have analyzed the CO_2 emissions savings from other behavior programs, or all behavior programs combined. The studies that do exist provide only rough estimates. For example, Opower's CO_2 savings estimate (discussed previously) is a rough estimate based on state-level carbon emissions rates.[57] This assumption implies that all types of power plants are ramping generation down in all of the hours that behavioral program savings actually occur. In reality, marginal generation, the type of generation that ramps up or down, differs by region and time of day or year. Detailed studies must use region-specific CO_2 emissions rates from marginal power plants. Fortunately studies and tools are available to estimate CO_2 reduction from marginal generation based on hourly or temporal savings profiles.[58]

Temporal savings profiles of behavioral programs were examined for the first time in 2013, made possible by the availability of new, detailed consumption data from smart meters.[59] One recent Lawrence Berkeley National Laboratory study examined Pacific Gas and Electric's home energy report pilot program for its hourly and peak load savings using smart meter data.[60] This pilot is one of the largest in the nation and includes 500,000 households. The study found energy savings during every hour, but observed higher savings during peak hours. The study results suggest that, to the extent that power plants with lower emissions outputs (e.g., combined-cycle natural gas or hydroelectric units) are used for meeting peak demands, the total CO_2 savings from behavioral programs are likely to be lower than what was estimated by the Opower potential study discussed previously. Conversely, if power plants with higher-than-average emissions (e.g., diesel backup generators or inefficient coal-fired units) are used to meet peak demand, the potential savings could be higher than estimated by Opower. However, in order to draw more definitive conclusions applicable to different regions of the country, more studies need to be conducted to evaluate hourly savings profiles of behavioral programs. States that intend to include behavioral programs as part of their 111(d) compliance plan could include a specific EM&V study plan to evaluate CO_2 emissions from behavior programs.[61]

To the authors' knowledge, the potential savings and emissions reduction benefits of commercial and industrial behavioral energy efficiency programs have not been rigorously studied and quantified.

5. Co-Benefits

As summarized in Table 13-3, behavioral efficiency programs provide a variety of co-benefits for society and the utility system beyond the GHG emissions reduction benefits described previously. The types of co-benefits are likely to be very similar to the types of co-benefits for traditional energy efficiency programs such as those described in Chapter 11; however, benefits from behavioral efficiency programs largely accrue to residential customers, as these programs tend to focus only on the residential sector.

Emissions of non-GHG air pollutants will decrease as a result of behavioral efficiency programs, just as they are reduced by other types of efficiency programs. The air emissions co-benefits depend on the same factors that were discussed with respect to GHG emissions reductions. As indicated in a recent paper on a peer comparison/home energy report program by Pacific Gas and Electric, savings from this program were observed at all hours, with higher savings at peak hours. This implies that savings

57 Supra footnote 54 at p. 5-204.

58 US EPA. AVoided Emissions and geneRation Tool (AVERT). Available at: http://epa.gov/statelocalclimate/resources/avert/index.html; ISO New England. (2014, January). 2012 ISO New England Electric Generator Air Emissions Report. Available at: http://www.iso-ne.com/static-assets/documents/genrtion_resrcs/reports/emission/2012_emissions_report_final_v2.pdf

59 Stewart, J. (2013, November). *Peak-Coincident Demand Savings from Residential Behavior-Based Programs: Evidence from PPL Electric's Behavior and Education Program.* Cadmus. Available at: http://escholarship.org/uc/item/3cc9b30t

60 Lawrence Berkeley National Laboratory. (2014, June). *Insights from Smart Meters: The Potential for Peak-Hour Savings from Behavior-Based Programs.* Available at: http://emp.lbl.gov/publications/insights-smart-meters-potential-peak-hour-savings-behavior-based-programs

61 For more information on impact evaluation methods for behavioral energy efficiency programs, see: State and Local Energy Efficiency Action Network (SEE Action). (2012, May). *Evaluation, Measurement, and Verification (EM&V) of Residential Behavior-Based Energy Efficiency Programs: Issues and Recommendations.* Available at: https://www4.eere.energy.gov/seeaction/system/files/documents/emv_behaviorbased_eeprograms.pdf. In addition, see various references in Footnote 37 under Section 3 in this chapter.

occur because of changes in equipment settings such as heating, air conditioning, water heating, and lighting timers.[62] The emissions rates of marginal generating units can vary substantially in different parts of the country and at different times of year. Thus, a behavioral program that reduces annual energy consumption by one percent, for example, could conceivably reduce emissions of various pollutants by more than or less than one percent.

Although not shown in Table 13-3, behavioral efficiency programs can also produce substantial benefits for the participating customers, including reduced future electricity bills, other energy and resource savings (e.g., heating fuels, water), and reduced operations and maintenance costs. Behavioral programs also provide low-income benefits such as reduced utility collection costs, to the extent that low-income customers reduce their energy bills and avoid or reduce non-payment incidents.

Behavioral efficiency programs could provide additional and different benefits if they increase participation in more traditional energy efficiency programs.

Table 13-3

Co-Benefits of Behavioral Energy Efficiency Programs

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Demand Response-Induced Price Effect	Yes
Other	Yes

6. Costs and Cost-Effectiveness

As noted in Chapter 11, energy efficiency measures vary in their costs and cost-effectiveness at reducing load. Because behavioral efficiency programs are a relatively new innovation, there are fewer data available on their costs than are available for other types of efficiency programs. However, the data that are currently available suggest that behavioral programs fall within the range of typical values for efficiency programs in general. And as is true for all efficiency programs overseen by utility regulators, behavioral programs will generally not be approved (even on a pilot basis) unless the benefits are expected to exceed the costs.

Recent studies across different regions suggest that residential behavioral programs are cost-effective, with a cost of saved energy ranging from \$0.01 to \$0.08 of program implementation costs per kWh of energy saved because of the program, according to a 2013 meta-analysis of cost of saved energy for behavior programs.[63] This study examined numerous programs from 50 entities for cost-effectiveness, and identified ten programs that provided both actual savings and program spending data. Given limited data availability of the measure life or savings persistence for behavior programs, the study assumed a standard measure life of 1.5 years. This assumed measure life is based on an assumption that some programs have no follow-up or program intervention (e.g., home energy reports to elicit behavior response) beyond the first year and savings decay in one year, and that other programs have follow-up and thus savings continue for another year or so. However, as discussed previously, a few recent studies found that energy savings continue even after program intervention is stopped. Therefore, one can say this study assumption of a 1.5-year measure life is

62 Smith, et al, at supra footnote 37.

63 Supra footnote 9.

Table 13-4

Cost of Saved Energy for Ten Electric Behavioral Programs[64]

Program Name	Number of Programs	Average CSE (cents/kWh)
Project Porchlight CBSM	4	1
Opower platform programs	3	8
PowerSave and others	3	8
Average		**1.61**

reasonable, but potentially conservative.

The 2013 ACEEE study provides cost of saved energy (CSE) in cents per kWh for ten electric behavioral energy efficiency programs representing three types of programs (see Table 13-4). The weighted average cost of saved energy is just 1.61 cents per kWh. Four of the programs were Project Porchlight programs in four different utilities and have been very cost-effective, at an average CSE of just one cent per kWh. Three programs using Opower's platform have an average CSE of eight cents per kWh. The last three programs, including different program types such as PowerSave Schools, were just under eight cents per kWh.

A recent research paper by ICF International examined the sensitivity of various key variables on the cost-effectiveness of residential behavior and real-time feedback programs using a probabilistic Monte Carlo approach.[65] The key variables include administration costs, discount rate, retail rates, avoided costs, annual savings, and program life. For example, the study considered a savings persistence of behavior programs ranging from one to three years, with two years most likely to occur with a 60-percent probability. There are also three scenarios for annual savings per household, with each scenario having minimum, most likely, and maximum values. The most likely savings values range from 1.38 percent to 2.5 percent, with 1.96 percent for the base case. The study examined cost-effectiveness of different demand-side management program tests and concluded that there is a high chance (71 percent) that behavior programs pass the Total Resource Cost test and Program Administrator Cost test.

It is also worth repeating, as noted in Chapter 11, that saving energy through behavioral or other energy efficiency programs can be considerably less expensive than generating energy by adding new resources to the electric grid. Recent reports from a number of sources estimate that the unsubsidized, levelized cost of energy exceeds six cents per kWh for new, natural gas-fired combined-cycle units and new, supercritical pulverized coal units without carbon capture. Nuclear cost estimates exceed nine cents per kWh for new units.[66] Furthermore, it is important to note that the total benefits of behavioral energy efficiency programs go well beyond the avoided costs of generation and capacity. As shown in Table 13-3, such benefits also include avoided cost of transmission, distribution, and reserves, as well as emissions reductions and various non-energy benefits. Even at the high end of the cited range in cost of saved energy (eight cents per kWh), it is likely that behavioral programs are cost-effective (i.e., the total value of all of the societal benefits exceeds the total costs).

7. Other Considerations

Concerns About Double Counting Savings

One of the key benefits of behavioral energy efficiency programs is that they help to increase participation and savings for energy efficiency programs, such as those described in Chapter 11 that promote more efficient technologies.[67] However, this benefit gives rise to concerns that savings will be double counted, that is, more than one program will take credit for the same unit of saved energy. One way that evaluators have handled this issue is to estimate the amount of these "joint" or "cross-program" savings and remove that amount from the savings credited to the behavioral program. For example, for an evaluation of PSE's Home Energy Reports program, KEMA compiled data on all rebated installations, for both a treatment group that received the energy reports and a control group that did not, to identify increased uptake of other PSE energy efficiency programs by the treatment group. To examine

64 Supra footnote 9.

65 Bozorgi, A., Prindle, W., & Durkee, D. (2014, August). *An Uncertainty-Based Analysis on Cost-Effectiveness of Feedback/Behavior-Based Programs within a DSM Portfolio.* Available at: https://www.aceee.org/files/proceedings/2014/data/papers/7-411.pdf

66 Refer to estimates by US Energy Information Administration at: http://www.eia.gov/forecasts/aeo/electricity_generation.cfm. Also refer to estimates by Bloomberg New Energy Finance, cited in Chapter 6, and by Lazard at: Lazard Ltd. (2014). *Lazard's Levelized Cost of Energy Analysis — Version 8.0.* Available at: http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

67 Supra footnote 13.

double counting attributable to participation in programs for which there was no tracking data (i.e., PSE's lighting programs), KEMA developed estimates of increased uptake of efficiency measures using household survey data. The joint savings from the energy reports and the rebate program, and from the energy reports and lighting programs, were subtracted from the results credited to the energy reports program.[68]

Although subtracting cross-program savings from the savings attributed to a behavioral program avoids double counting, this approach tends to undervalue the contribution made by behavioral energy efficiency programs toward the portfolio. Moreover, their cost of saved energy and benefit-cost ratios look less favorable, because the costs of the behavioral energy efficiency program are compared to the benefits associated with a smaller number of units of saved energy than if the behavioral program was given credit for the increase in savings by other programs. This approach creates a disincentive for program administrators to implement behavioral energy efficiency programs.[69] Goldman and Dougherty propose three different methods for addressing this issue:

1. Allocating benefits to traditional and behavioral efficiency programs based on self-reported level of influence;
2. Attributing a marketing non-energy impact to behavioral energy efficiency programs (based on an estimate of marketing costs that can be avoided by increasing promotion of other programs in behavioral energy efficiency program materials); and
3. Reallocating behavioral energy efficiency program costs to marketing budgets for cross-program participation.

Goldman and Dougherty find that all three methods increase the benefit-cost ratios for the behavioral energy efficiency program, but that the marketing benefits and the marketing costs approaches (points 2 and 3 in the list above) are simpler and less costly to evaluate.[70]

State Plans for 111(d) Compliance

Because behavioral efficiency program savings are difficult to quantify, state regulators may be skeptical about their effects, and their potential use in state compliance plans may be limited. In order for the programs to be included in a state plan, the state will almost certainly need to have a solid plan to track and evaluate energy and emissions savings from such activities when a rate-based compliance approach is adopted.[71] If using a rate-based approach, states would need to include at least the following pieces of information in the plans they submit to the EPA for approval (as suggested by US EPA for a 111(d) plan):

- Description of the programs, and implementation schedules and timeframes;[72]
- Estimates of potential energy and CO_2 emissions savings;[73]
- Impact and process evaluation plans, including evaluation protocols and methods;[74] and
- Discussion of any uncertainty associated with savings and cost estimates.[75]

68 Supra footnote 38 at pp. 2-4, 4-11.

69 Supra footnote 13.

70 Ibid.

71 As noted previously, to some extent this issue could be mitigated if a state chooses a mass-based approach to demonstrate CO_2 emissions reductions. Also note that, although the EPA has not established guidance on appropriate EM&V methods, the EPA's Clean Power Plan draft discusses the industry-standard practices and procedures that are typically defined and overseen by state public utility commissions. See: US EPA, at supra footnote 48.

72 US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. pp. 76-78. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf

73 Ibid.

74 US EPA, at supra footnote 48.

75 Supra footnote 72 at pp. 57-60.

8. For More Information

Interested readers may wish to consult the following reference documents and websites for more information on behavioral efficiency programs:

- Mazur-Stommen, S., & Farley, K. (2013). *ACEEE Field Guide to Utility-Run Behavior Programs.* ACEEE Report No. B132. Available at: http://www.aceee.org/research-report/b132
- Opinion Dynamics Corporation, Navigant Consulting, & Evergreen Economics. (2013, June). *Massachusetts Cross-Cutting Behavioral Program Evaluation Integrated Report.* Available at: http://www.rieermc.ri.gov/documents/2013%20Evaluation%20Studies/ODC_2013_Cross_Cutting_Behavioral_Program_Evaluation.pdf
- Russell, C., Wilson-Wright, L., Krecker, P., & Skumatz, L. (2014). *Behavioral Effects: How Big, How Long, From Whom, How Best?* 2014 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.aceee.org/files/proceedings/2014/data/index.htm
- State and Local Energy Efficiency Action Network (SEE Action) website. Available at: https://www4.eere.energy.gov/seeaction/topic-category/behavior-based-energy-efficiency
- Summit Blue. (2010, April). *Evaluation of Consumer Behavioral Research.* Available at: https://www.nwcouncil.org/media/5449/Consumer_Behavioral_Research_Report___Summit_Blue.pdf
- Vigen, M., & Mazur-Stommen, S. (2012). *Reaching the "High-Hanging Fruit" Through Behavior Change: How Community-Based Social Marketing Puts Energy Savings within Reach.* ACEEE. Available at: http://www.aceee.org/white-paper/high-hanging-fruit

9. Summary

Because of their significant energy savings potential and cost-effectiveness, behavioral energy efficiency programs are becoming increasingly popular with program administrators to improve energy savings results. By avoiding barriers faced by more traditional energy efficiency programs, behavioral energy efficiency programs may be able to tap energy savings potential that has been resistant to other initiatives. However, the energy savings and associated emissions reductions benefits associated with some types of behavioral energy efficiency programs may not persist after the stimulus is removed, and may not be attributed to the behavioral efficiency program if there is overlap with more traditional energy efficiency programs. Nonetheless, these programs appear to be cost-effective with savings from just the first year of operation. Measuring, verifying, and attributing energy and CO_2 emissions savings to these programs, while giving them credit for cross-program effects, is feasible but may pose challenges, given the limited experience in this area.

Chapter 14. Boost Appliance Efficiency Standards

1. Profile

"Energy efficiency" refers to technologies, equipment, operational changes, and in some cases behavioral changes that enable our society to enjoy equal or better levels of energy services while reducing energy consumption.[1] Efforts to improve efficiency in the generation, transmission, or distribution of electricity are covered in Chapters 1 to 5 and in Chapter 10. In contrast, Chapters 11 to 15 address different policy options for making the end-user's consumption of electricity more efficient. Chapter 11 focuses on policies that establish mandatory energy savings targets for electric utilities, the achievement of which is generally funded through revenues collected from customers themselves. Chapter 12 focuses on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency as an alternative or supplement to government-mandated programs or regulatory requirements. Chapter 13 focuses on an emerging type of energy efficiency program, behavioral energy efficiency, that is worthy of separate treatment because it is sometimes included within the mandated programs described in Chapter 11 and sometimes implemented as a voluntary effort outside of those programs. This chapter, Chapter 14, covers mandatory appliance efficiency standards that are imposed on manufacturers, and Chapter 15 covers mandatory building energy codes that are imposed on builders and developers.

Appliance standards set minimum energy and water efficiency requirements for selected appliances and equipment – where cost-effective – and prohibit the production, import, or sale of appliances and equipment that do not meet those requirements. Standards can be adopted by federal or state governments.[2] States cannot set efficiency standards for federally regulated products, but they can adopt standards for products not covered by federal standards. When new federal standards are developed, pre-existing state standards for those products are typically preempted by the federal standards; however, certain products could receive exemptions from this federal preemption.

Appliance standards have been one of the most cost-effective policies to generate significant energy and emissions reductions in the United States.[3] For example, the American Council for an Energy-Efficient Economy (ACEEE) and the Appliance Standard Awareness Project (ASAP) recently estimated that existing federal standards will, at the national level:

- Save consumers and businesses more than $1.1 trillion from products sold through 2035;
- Save enough energy cumulatively through 2035 to meet the current level of US energy consumption for a period of two years;
- Reduce peak demand by about 237 gigawatts (GW), or 18 percent, in 2035; and
- Cut annual carbon dioxide (CO_2) emissions in 2035 by 470 million metric tons, an amount equal to the emissions of 118 coal-fired power plants (nearly

1 In contrast, some people use the term "energy conservation" to refer to actions that reduce energy consumption but at some loss of service. Neither term has a universally accepted definition and they are sometimes used interchangeably.

2 Federal standards prohibit production for domestic sales and import; state standards prohibit the sale of products within a state's borders.

3 Critics of appliance standards dispute this point, typically arguing that the benefits attributed to appliance standards are overstated or that most of the benefits would have occurred even in the absence of such standards. However, as discussed later in Section 6, Costs and Cost-Effectiveness, the US Department of Energy and several states have continued to support cost-effective appliance standards based on strong evidence showing the benefits of these policies.

20 percent of US coal plants).[4,5]

Historically, California has been a leader in establishing state appliance standards. It first adopted standards in the 1970s, and since that time 15 other states have followed suit, many of them adopting California's standards for their own uses.[6]

This activity at the state level led to the establishment of the first federal standards under the National Appliance Energy Conservation Act of 1987, or NAECA. Together with subsequent federal standards, including those in the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, NAECA has preempted many of the original state-specific appliance standards.[7] However, there are still 19 products regulated by state-specific standards in 11 states and the District of Columbia.[8]

Appliance standards offer several key advantages. They can have a significant impact on the market. This is because all of the products produced in or imported into the United States (e.g., refrigerators, lamps, air conditioners, and electronic motors) have to meet the applicable minimum federal efficiency standards once those standards are put into effect.[9] Because standards reduce consumption from all products produced for domestic sale or imported (or sold, in the case of state standards), they also generate significantly more energy savings than traditional energy efficiency programs, which typically target only a small fraction of the products sold in the market. And importantly, appliance standards overcome many of the key barriers that energy efficiency program administrators often encounter, namely:

- Lack of consumer awareness on benefits of efficient products;
- Lack of information on efficient products;
- Split incentives between renters and building owners;
- Financial procedures that overemphasize initial costs and de-emphasize operating costs;
- Limited stock of efficient products; and
- Manufacturer price competition.[10]

The primary challenge to using state-specific appliance standards to reduce CO_2 emissions is political feasibility. The process of adopting new standards may be long and arduous for some states. Thus, states must consider the political feasibility of doing so. States may also encounter challenges related to measuring and verifying energy and CO2 emissions savings from appliance standards, given the limited experience in this area. This is another topic of significant concern. Finally, if states allow or direct utilities and third-party program administrators to take an active role in supporting standard adoption, this approach could complicate planning for the kinds of "programmatic" energy savings described in Chapter 11 of this document. On the other hand, the involvement of additional stakeholders could improve the process and make for better outcomes.

These barriers are not insignificant; however, the incentive for states to address and overcome them is immense. Appliance standards have proven to be very effective policy tools that save tremendous amounts of energy – and thus the associated emissions from power plants – at the lowest possible cost. Standards also improve electric system reliability, generate new jobs, and save consumers significant amounts of money over the life of

4 Lowenberger, A., Mauer, J., deLaski, A., DiMascio, M., Amann, J., & Nadel, S. (2012, March). *The Efficiency Boom: Cashing in on the Savings From Appliance Standards.* ACEEE and ASAP. Available at: http://www.aceee.org/research-report/a123

5 The results presented here represent the study's base case/original scenario. The study also includes an alternative/conservative scenario, which assumes lower-than-expected energy savings attributable to appliance standards. In this alternative scenario, the savings attributable to the standards decline over time and become zero in the 35th year due to naturally occurring energy efficiency improvements. This scenario results in about half of the benefits of the original scenario.

6 ASAP. (2014, February). *Energy and Water Efficiency Standards Adopted and Pending by State.* Available at: http://www.appliance-standards.org/sites/default/files/State_status_grid_Feb_21_2014.pdf

7 US EPA. (2006, April). *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States*, chapter 4, p. 4-56. Available at: http://epa.gov/statelocalclimate/resources/action-guide.html

8 Refer to the ASAP website at: http://www.appliance-standards.org/states

9 Federal standards prohibit the production for domestic sale or import of products not meeting new federal standards, whereas state standards typically prohibit the sales of products not meeting new state standards. Personal communication with Marianne DiMascio of ASAP, August 21, 2014.

10 See detailed discussion of these barriers in: Nadel, S., deLaski, A., Eldridge, M., & Kliesch, J. (2006, March). *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards.* ACEEE and ASAP. Available at: http://www.aceee.org/research-report/a062

the equipment. This chapter discusses in more detail the benefits to be gained from appliance standards, as well as states' experience in addressing political and other barriers to implementation. Lastly, note that although appliance and equipment standards cover products that use electricity, gas, or water, this document and thus this chapter focuses only on electric appliances and equipment.

2. Regulatory Backdrop

Since 1980, manufacturers of certain appliances sold in the United States have been required to attach comparison labels to their appliances to give consumers important information about energy use. The US Federal Trade Commission's Appliance Labeling Rule currently requires EnergyGuide labels on refrigerators, freezers, dishwashers, clothes washers, room air conditioners, water heaters, furnaces, boilers, central air conditioners, heat pumps, pool heaters, and televisions. This labeling requirement is mandatory but is distinct from federal minimum efficiency standards.

More than 50 consumer products are currently subject to federal appliance efficiency standards developed by the US Department of Energy (DOE) pursuant to the National Appliance Energy Conservation Act of 1987, the Energy Policy Act of 2005, or the Energy Independence and Security Act of 2007.[11] Additional federal standards are expected to be developed in the future. However, many energy-consuming products are not subject to current or expected federal standards, including some products with significant annual electricity consumption. As a supplement to federal standards, the DOE and the EPA have collaborated in the development of the voluntary Energy Star® labeling program, which helps manufacturers identify and advertise to consumers the most efficient appliances in the marketplace.[12]

States seeking to update or develop appliance standards don't need to start from scratch. In fact, historically, many states have modeled their appliance standards after California's standards. Third-party entities such as ASAP, the Northeast Energy Efficiency Partnership (NEEP), and the Multi-State Appliance Collaborative also provide useful knowledge and materials that states can rely upon when updating or developing standards. ASAP has published model legislation for appliance standards most years since 2001, and a dozen states have enacted bills based on these models to date.[13]

Although state agencies can initiate an inquiry into appliance standards, most states typically need to go through a legislative process to establish or update appliance standards, and to authorize state agencies to regulate in this area. Depending on the state, the need for legislative action could be a primary barrier to using appliance standards to reduce CO_2 emissions. However, there are a few states – California, Oregon, and Connecticut – that have already provided state agencies (such as state energy commissions) with the administrative authority to set new standards without having to go through a new legislative process. Among these states, California has the broadest authority to adopt new standards, and the most robust rulemaking process.[14]

The determination of which approach – legislative or administrative – is more advantageous for developing new standards will vary depending on the state and its political readiness for such action. In general, the administrative process can develop standards faster than the legislative process; however, both processes are subject to some degree of political involvement. For example, when California adopted the first-ever standards for televisions, industry groups such as the Consumer Electronics Association actively lobbied against the development of the standard.[15]

11 For more detail, refer to the DOE website at: http://energy.gov/eere/buildings/appliance-and-equipment-standards-program

12 Energy Star® is thus distinct from appliance standards, the subject of this chapter. Traditional energy efficiency programs, such as those described in Chapter 11 of this document, often provide incentives for consumers to voluntarily purchase Energy Star® products.

13 Refer to ASAP website at: http://www.appliance-standards.org/content/state-savings-state-appliance-standards.

14 Personal communication with Marianne DiMascio of ASAP, August 21, 2014 and Josh Craft of NEEP, August 26, 2014. Also refer to: General Statute of Connecticut, Section 16a-48(3)B of Chapter 298, and: Oregon Administrative Rules 330-092-0065.

15 Personal communication with Marianne DiMascio of ASAP, August 21, 2014. Also refer to: NRDC. *Fact Sheet on California's Proposed Energy Efficiency Standards for Televisions.* Available at: http://docs.nrdc.org/energy/files/ene_09091801b.pdf, and: California Energy Commission. (2009, November). *California Approves New Energy Efficient TV Regulations.* Available at: http://www.energy.ca.gov/releases/2009_releases/2009-11-18_tv_regulations.html

And although New York gave administrative authority to state agencies to develop standards for certain products in 2005, the agency has not exercised that authority to date.[16,17] In contrast, when there is general support for the effort among legislators, the state energy office, and local and regional advocacy groups, it is possible for a state to pass a new bill through the legislative process in as short as one to two years.[18]

Regardless of the path used (legislative or administrative), states often engage in similar processes to establish new standards. Steps in the process typically include the following, although the level of effort could differ widely by state:

- **Gain stakeholder input.** This process varies widely by state. For example, some states have a series of informal meetings in which a handful of key stakeholders (e.g., key legislators, state agencies, and local and regional public interest groups) convene and draft new legislation. States that don't require new legislation to establish new standards also seek stakeholder input. They may solicit comments from various stakeholders, including manufacturers, or hold formal public hearings.[19] Among such states, California is considered to have the most robust public hearing and stakeholder process.
- **Conduct benefit-cost analysis and related studies.** Several states have conducted benefit-cost analyses of new standards or reviewed such analyses conducted by others. California runs a rulemaking process in which utilities fund Codes and Standards Enhancement (CASE) reports and evaluate benefits and costs of new standards. Many other states typically review existing studies conducted in California or by advocacy and research organizations such as ASAP and ACEEE.[20]
- **Define and establish draft appliance standards.** This process typically defines covered products, effective dates, efficiency standards, test methods, certification and labeling procedures, inspection and enforcement procedures, penalties for noncompliance, procedures for appeals, waivers and other exceptions, and contact information for the agencies involved.
- **Monitor, review, and modify the program as needed.** Based on stakeholder responses and market trends, some states have made specific program modifications, including revisions to covered products, efficiency levels, and effective dates, as well as process improvements such as more frequent stakeholder input cycles and more transparent public information processes.[21]

Another approach to implementing appliance standards is for state public utility commissions to allow or direct utilities and third-party energy efficiency program administrators to support adoption of standards. These program administrators would then receive credit from the associated energy savings toward the kinds of "programmatic" energy savings goals described in Chapter 11. This idea is discussed in more detail later in this chapter.

Following that approach, utilities in California developed a statewide code and standard support program in 2001. Since that time, a growing number of states have examined the role of utilities in supporting codes and standards (C&S). This trend intensified recently because the

16 Refer to the *Database of State Incentives for Renewables & Efficiency (DSIRE)* at: http://www.dsireusa.org/

17 However, some of the standards drafted in New York helped to advance the process for federal appliance standards. Personal communication with Andrew deLaski of ASAP on September 11, 2014.

18 Personal communication with Marianne DiMascio of ASAP, August 21, 2014.

19 In Connecticut, stakeholders always have opportunities to provide public comments. The Department of Energy and Environmental Protection can hold a public hearing to hear their views directly. Depending on the number of requests, the Department also has an obligation to hold a hearing. Personal communication with Michele Melley of Connecticut Department of Energy and Environmental Protection on August 29, 2014.

20 Lee, A., Groshans, D., Gurin, C., Cook, R., & Walker, T. (2012, August). *Raising the Bar – Getting Large Energy Savings Through Programs That Support Energy-Efficiency Codes and Standards.* Proceedings of the 2012 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.cadmusgroup.com/wp-content/uploads/2012/12/590-ACE3-Codes-Standards-Paper-Final.pdf

21 Supra footnote 7 at chapter 4, pp. 4-60 to 4-61.

American Recovery and Reinvestment Act required states to adopt the latest national model energy codes for buildings as a condition of receiving federal American Recovery and Reinvestment Act funds. As a result, more states now focus on exploring the role of building energy codes in utility energy efficiency programs; however, at least Massachusetts, Minnesota, and Arizona established or are exploring frameworks for program administrators to promote both building energy codes *and* appliance standards.[22]

Energy efficiency plays a prominent role in the emissions guidelines for CO_2 emissions from existing power plants that the EPA proposed in June 2014, citing its authority under section 111(d) of the Clean Air Act, as part of its "Clean Power Plan." [23] The EPA determined that the "best system of emission reduction" for existing power plants under the Clean Air Act consists of four "building blocks," one of which is end-use energy efficiency. Although states will not be required to include energy efficiency in their 111(d) compliance plans, the emissions rate goals for each state are based on an assumption that a certain level of energy savings (and thus, emissions reduction) is achievable. The level of savings that the EPA used to set each state's emissions rate goals is based on the demonstrated performance of leading states with respect to the kinds of ratepayer-funded energy efficiency programs described in Chapter 11 and a meta-analysis of energy efficiency potential studies; the EPA did not explicitly consider what is achievable through the adoption of state appliance efficiency standards. However, states will apparently be able to use state appliance efficiency standards to reduce emissions and comply with any final regulation, so long as the standards go beyond "business as usual" projections of energy demand and are enforceable.

3. State and Local Implementation Experiences

According to ASAP, 16 states have adopted appliance and equipment standards since 2001, covering about 35 products.[24] Since then, many of the state standards have been preempted by federal appliance standards (e.g., the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007).

As of September 2014, 11 states and the District of Columbia still have their own appliance standards in effect, covering approximately 20 product types (as shown in Table 14-1).[25] Such standards apply to products not covered by any of the current federal standards, or to those that have greater efficiency requirements than federal standards.

22 NEEP, Institute for Electric Efficiency, & Institute for Market Transformation. (2013, February). *Attributing Building Energy Code Savings to Energy Efficiency Programs.* Available at: http://www.neep.org/attributing-building-energy-code-savings-energy-efficiency-programs. Also see: Supra footnote 20.

23 Refer to: US EPA. (2014, June). *40 CFR Part 60 – Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule.* Federal Register Vol. 79, No. 117. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

24 Supra footnote 6.

25 Supra footnote 8.

Table 14-1

States With Efficiency Standards in Effect[26]

Product	AZ	CA	CT	DC	GA	MD	NV	NH	OR	RI	TX	WA
Battery Chargers		2012							2013			
Compact Audio Equipment		2004 (TBD)	2011						2007			
DVD Players and Recorders		2004	2011 (TBD)						2007			
External Power Supplies		2012										
Faucets				2010								
General Service Lamps: Incandescents plus CFLs, GSLED, GSOLED		2008					2007					
Hot Food Holding Cabinets		2004	2007	2007		2007		2008	2007	2006		2009
Luminaires		2008										
Mercury Vapor Lamp Ballasts										2005		
Metal Halide Lamp Fixtures		2009										
Pool Pumps	2009	2009	2007									2009
Portable Electric Spas	2009	2004	2007						2007			2009
Televisions		2009	2011 (TBD)						2013			
Urinals		2007			2010						2009	
Vending Machines		2004										
Water Closets		2007			2010						2009	
Water Dispensers		2004	2007	2007		2007		2008	2007	2006		2009
Wine Chillers		2002										

Figure 14-1 shows the states that have standards in effect today, as well as states whose standards have been entirely preempted by federal standards since 2001.

Two states that provide useful examples of implementation experiences – demonstrating both the legislative and administrative approaches – are California and Connecticut.

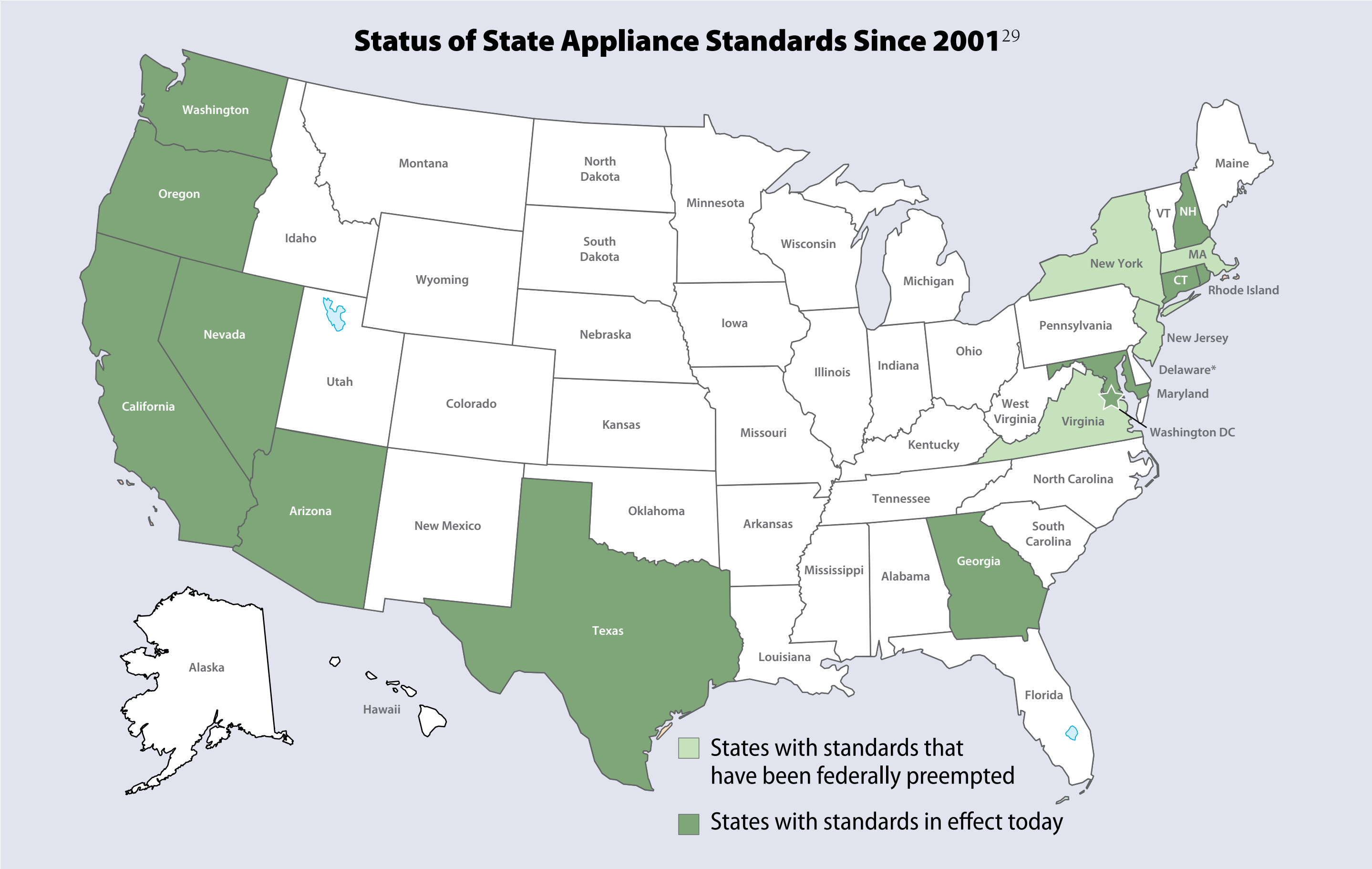
California was the first state in the country to adopt appliance and efficiency standards. Since 1976, California has set minimum energy efficiency standards for a wide range of appliances and equipment, including all major household appliances, air conditioners, furnaces, and water heaters.[27] California paved the way for other states and eventually the federal government to begin setting appliance standards. When the federal government decided not to issue standards under its legislative mandate in 1982, several other states developed appliance standards based on the California standards, which helped create the consensus for new federal legislation in 1987 (the NAECA) and the Energy Policy Acts of 1992 and 2005.[28] More recently, between 2010 and 2012, California introduced efficiency standards for televisions, battery chargers, and external power supplies, making it the first state in the

26 Supra footnote 8.

27 California Energy Commission. (2012, February). *2011 IEPR (Integrated Energy Policy Report)*, p. 66. Available at: http://www.energy.ca.gov/2011_energypolicy/

28 Supra footnote 7 at chapter 4, p. 4-56.

Figure 14-1



nation to set standards for these appliances.[30, 31]

It is also notable that California is the first state that has allowed investor-owned utilities (IOUs) to support the development of new appliance standards and building codes as part of their energy efficiency programs, and to count savings from those policies toward programmatic savings goals. When electric deregulation occurred in California in the 1990s, market transformation – including appliance standards – gained significant attention as an approach to prevent energy efficiency from being lost in the transition to deregulated utilities. California utilities advocated in support of C&S in the process before the California Energy Commission.[32]

Around 2001, the state's four IOUs launched a

29 Synapse Energy Economics (2015). *Status of State Appliance Standards Since 2001*. Based upon information found at http://www.appliance-standards.org/.

30 Refer to ACEEE website at: http://database.aceee.org/state/california

31 The majority of stakeholders supported these standards, although a few opposed them. The supporters of the TV standard (which was adopted by the California Energy Commission by a unanimous 5-0 vote) included the largest manufacturer of flat-screen TVs in the nation, Vizio; television component manufacturers 3M and Agoura Technologies; the LCD Television Association; and all three major California electric utility companies. (See: http://www.energy.ca.gov/appliances/tv_faqs.html) Supporters of the battery standard included the Power Sources Manufacturers Association, which represents companies that manufacture components to enable more efficient battery chargers, and the state's three investor-owned utilities. (See http://www.energy.ca.gov/appliances/battery_chargers/documents/Chargers_FAQ.pdf) The Consumer Electronics Association, among others, opposed this standard and asserted it would have a net negative impact on consumers. For a summary of the public comments in support of and opposed to the battery charger standard, and the California Energy Commission's responses, see: http://www.energy.ca.gov/appliances/battery_chargers/documents/2012-09-14_Summary_and_Response_to_Public_Comments.pdf

32 Supra footnote 20.

coordinated statewide program to advocate for C&S. They engaged in various activities such as preparing technical reports on C&S (titled "Codes and Standards Enhancement [CASE] reports"), testifying in public hearings, and working with industry.[33] These efforts led to adoption of new C&S that became effective in 2005 to 2006. In the 2006 to 2009 program cycle, the California Public Utilities Commission for the first time allowed the utilities to claim 50 percent of the verified savings from C&S toward their goals, and in the next program cycle (2010 to 2012), the Commission allowed 100-percent credit.[34]

California's appliance and equipment standards have significantly reduced energy usage. The California Energy Commission estimated that appliance efficiency standards adopted between 1976 and 2005 saved 18,761 gigawatt-hours (GWh) in 2010. This represents 6.7 percent of the state's electricity peak load and is roughly the amount of energy produced annually by California's two largest power plants. The California Energy Commission estimated these standards saved consumers about $2.68 billion in 2010 based on an average electric rate of 14 cents per kilowatt-hour (kWh). Without including the impact of the latest appliance standards recently adopted, these existing standards were forecast to save 27,116 GWh per year by 2020 (approximately 8.6 percent of projected load in 2020).[35]

Connecticut enacted efficiency standards through legislative actions in 2004, 2007, and 2011. In 2004, Connecticut General Statute 16a-48 established minimum efficiency standards for eight products, under the jurisdiction of the Connecticut Office of Policy and Management and the Department of Public Utility Control.[36] These standards cover torchiere lighting fixtures, building transformers, commercial refrigerators and freezers, traffic signals, exit signs, large packaged air conditioning equipment, unit heaters, and commercial clothes washers. Standards for five of the eight products were preempted by the federal standards included in the Energy Policy Act of 2005.[37] According to NEEP, Connecticut's 2014 appliance standards were projected to save residents and businesses more than $380 million in energy costs by 2020, conserve over 430 GWh of electricity, reduce summer peak electricity demand by over 125 MW, and avoid about 65,000 metric tons of carbon.[38]

In 2007, Connecticut adopted standards for eight additional products; three of these standards were later preempted by the Energy Independence and Security Act of 2007.[39] In January 2011, the Connecticut General Assembly passed Bill 1243 (Public Act No. 11-80) to institute additional standards for compact audio players, televisions, and DVD players and recorders. These standards are based on California Code of Regulations, Title 20. As of today, there are several appliance standards in Connecticut that have not been preempted by any federal appliance standards. They are as follows (dates listed in parentheses signify the year the standard took effect):

- Bottle-type water dispensers (2009);
- Commercial hot food holding cabinets (2009);
- Hot tubs (2009);
- Swimming pool pumps (2010);
- Compact audio equipment (2014);[40]
- DVD players and recorders (2014); and
- Televisions (2014).[41]

Public Act No. 11-80 also includes some language that has provided legislative authority to the Department and the Commissioner of Energy and Environmental Protection to review or adopt appliance standards in Sec. 102. (d)(3)(B):

> *The department, in consultation with the Multi-State Appliance Standards Collaborative, shall identify additional appliance and equipment efficiency standards. The commissioner shall review all California standards and may review standards from other states in such collaborative.*

33 CASE reports evaluate the costs and benefits of specific energy efficient appliances and equipment.

34 Supra footnote 20.

35 Supra footnote 27.

36 Supra footnote 16.

37 Refer to ACEEE website at: http://database.aceee.org/state/connecticut

38 Refer to: Supra footnote 7 at chapter 4, p. 4-63. Also refer to: NEEP. (2004, May). Connecticut Adopts New Energy Efficiency Product Standards. [Press release].

39 Refer to ACEEE website at: http://database.aceee.org/state/connecticut

40 Effective January 1, 2014, Connecticut law required compact audio players, DVD players, and recorders to comply with energy efficiency standards (Connecticut General Statute §16a-48).

41 Refer to Supra footnote 39. Also refer to Supra footnote 16 and Supra footnote 8.

The commissioner shall issue notice of such review in the Law Journal, allow for public comment and may hold a public hearing within six months of adoption of an efficiency standard by a cooperative member state regarding a product for which no equivalent Connecticut or federal standard currently exists, the department shall adopt regulations in accordance with the provisions of chapter 54 adopting such efficiency standard unless the department makes a specific finding that such standard does not meet the criteria in subparagraph (A) of this subdivision.[42]

These examples demonstrate that states can use a variety of approaches to implement appliance standards in support of greenhouse gas (GHG) reduction efforts.

4. GHG Emissions Reductions

As explained in Chapter 11, the magnitude of emissions reductions attributable to energy efficiency measures depends first and foremost on the amount of energy that was (or will be) saved. However, the emissions reductions that result from those energy savings also depend on when energy was (or will be) saved, and which marginal electric generating units (EGUs) reduced (or will reduce) their output at those times. Over the longer term, the more significant impact of energy efficiency programs and policies is that they can defer or avoid the deployment of new EGUs. Over that longer term, the avoided emissions will thus depend not so much on the characteristics of existing EGUs, but on the costs and development potential for new EGUs.

In either the near term or the longer term, GHG emissions reductions are proportional to energy savings, but not necessarily on a one-to-one basis (i.e., a one-percent reduction in energy consumption could reduce emissions by more or less than one percent, depending on how the emissions rates of the marginal or deferred EGUs compare to the system average emissions rates). Chapter 11 describes three methods for quantifying the short-term emissions impacts of energy efficiency programs: the average emissions method, the marginal emissions method, and the dispatch modeling method. Over a longer time period, the emissions rates of new natural gas-fired EGUs may represent a better proxy for avoided emissions.

As previously noted, ACEEE and ASAP recently estimated that existing federal standards will, at the national level, reduce annual CO_2 emissions in 2035 by 470 million metric tons, an amount equal to the emissions of 118 coal-fired power plants (nearly 20 percent of US coal plants).[43] Using the DOE's own estimates, by 2030 federal appliance standards will result in a cumulative reduction of 6.8 billion tons of CO_2 emissions, equivalent to the annual GHG emissions of 1.4 billion automobiles.[44] And as just one example of what's already happening at the state level, according to NEEP, Connecticut's 2014 appliance standards will avoid about 65,000 metric tons of carbon by 2020.[45]

ASAP and ACEEE have also produced several reports analyzing the impacts of both federal and state appliance standards from energy, environmental, and economic perspectives. These include the 2005, 2006, and 2008 "Leading the Way" reports, which estimate the impacts of recommended new appliance standards for each state that went beyond the then-most-recent federal appliance standards – either by implementing more aggressive standards or by covering additional products.

ASAP and ACEEE's most recent publicly available analyses of recommended potential state appliance standards are provided on ASAP's website for each state, and cover 10 consumer products, as shown in Table 14-2.[46] Their latest analysis added a few new consumer products such as double-ended quartz halogen lamps, portable electric spas, and room air cleaners to their previous analysis conducted about two years ago, but also removed several products that were included in the previous analysis for various reasons, including delays in standard development in California and new federal initiatives to establish some of those standards.[47,48]

42 Supra footnote 41.

43 Supra footnote 4.

44 Refer to the DOE website at: http://energy.gov/eere/buildings/appliance-and-equipment-standards-program

45 Supra footnote 38.

46 Refer to Supra footnote 8.

47 Details of the previous analysis are found in: Supra footnote 4.

48 Another reason for excluding some of the products is that, unlike the previous analysis that had a long-term view, the current analysis focuses on near-term standards that ASAP and ACEEE recommends states adopt in the next few years. Personal communication with Marianne DiMascio of ASAP on February 26, 2015.

Table 14-2

Illustrative New State Standards Assessed by ASAP and ACEEE

Consumer Product Types
Battery Chargers
Commercial Dishwashers
Double-Ended Quartz Halogen Lamps
Faucets (lavatory)
Hot Food Holding Cabinets
Portable Electric Spas
Room Air Cleaners
Water Dispensers
Toilets
Urinals

Consistent with the practices of the "Leading the Way" studies, ASAP and ACEEE applied the following four major criteria to select these standards:

- A standard would achieve significant energy savings;
- A standard is known to be very cost-effective for purchasers and users of the product;
- Products meeting the recommended standards are readily available today; and
- A state standard could be implemented at very low cost to the state.[49]

ASAP and ACEEE have estimated savings in electricity, natural gas, water, and CO_2 emissions in 2025 and 2035 for each state. They have also estimated utility bill savings, as well as payback period, benefit/cost ratio, and net present value. As an example, Table 14-3 demonstrates savings in energy and CO_2 emissions for Florida from this analysis. Among other products, battery chargers have the largest energy savings potential.

If these new standards are adopted and become effective in 2017 in Florida, they would be expected to save over 1400 GWh of electricity and 740 thousand metric tons of CO_2 in 2035. The potential electricity savings in 2035 equates to about 0.6 percent of today's electricity consumption in the state. Furthermore, states including Florida are likely to have opportunities to adopt additional standards for other consumer products such as computer equipment and game consoles as California is currently developing standards for these products.[51]

Table 14-3

Potential Energy Savings and CO_2 Reductions From New State Appliance Standards in 2035 for Florida[50]

Products	Electricity (GWh)	Natural Gas (BBTU)	CO_2 (1000 tons)
Battery Chargers	836.5	-	415.7
Small Consumer Chargers	795.1	-	395.1
Small Non-Consumer Chargers	11	-	5.5
Large Chargers	30.4	-	15.1
Commercial Dishwashers	41.1	205.8	31.4
electricity	41.1	-	20.4
natural gas	-	205.8	10.9
Double-Ended Quartz Halogen Lamps	0	-	0
Faucets (lavatory)	67.6	465.5	58.3
electricity	67.6	-	33.6
natural gas	-	465.5	24.7
Hot Food Holding Cabinets	22.9	-	11.4
Portable Electric Spas	10.9	-	5.4
Room Air Cleaners	410	-	203.7
Water Dispensers	37.2	-	18.5
TOTAL	**1,426**	**671**	**744**

5. Co-Benefits

In addition to GHG emissions reductions, appliance standards will provide a variety of co-benefits that are accrued from energy use reduction in buildings and through the power grid to electric generation. These co-benefits include cost savings and reductions in other air pollutant emissions. The air emissions co-benefits depend on the same factors that were discussed with respect to GHG emissions reductions.

The potential co-benefits of appliance standards for society and the utility system are summarized in

49 These criteria are the same as those used for the 2006 ASAP and ACEEE paper: Supra footnote 10. Also based on personal communication with Marianne DiMascio of ASAP.

50 Refer to ASAP analysis for Florida, available at: http://www.appliance-standards.org/states

51 Information on California's standard rulemaking process is available at: http://www.energy.ca.gov/appliances/rulemaking.html

Table 14-4

Co-Benefits of Appliance Standards

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Demand Response-Induced Price Effect	Yes
Other	Yes

Table 14-4.[52] Although not shown in Table 14-4, appliance standards can also produce substantial benefits for the participating customers who purchase an efficient appliance, including reduced future energy bills, other resource savings (e.g., septic, well pumping), reduced operations and maintenance costs, increased employee productivity, and more comfortable indoor environments. Low-income consumers may see additional benefits unique to their circumstances.

6. Costs and Cost-Effectiveness

As noted earlier, federal appliance standards have proven to be one of the most cost-effective policies to generate emission reductions in the United States.[53] ACEEE and ASAP recently estimated that existing federal standards will, at the national level, save consumers and businesses more than $1.1 trillion from products sold through 2035.[54] By the DOE's own estimates, federal standards saved consumers about $55 billion on their utility bills in 2013, and by 2030, cumulative operating cost savings from all standards in effect since 1987 will reach over $1.7 trillion.[55] But as discussed later in this section, another recent research paper

52 Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)*. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6739

53 Critiques against appliance standards argue that regulation is not needed because the appliance market is functioning well to promote optimal levels of energy efficiency, and that most of the efficiency gains from new appliances are due to technological improvements induced by energy price changes, not regulations. For example, see the Consumer Electronics Association's "Innovation is the Real Driver of Energy Savings," available at: http://www.ce.org/News/News-Releases/Press-Releases/2012-Press-Releases/Innovation-is-the-Real-Driver-of-Energy-Savings.aspx. However, there is substantial evidence refuting this view. For example, an August 2014 study by Neubauer of ACEEE, "Cracking the TEAPOT: Technical, Economic, and Achievable Energy Efficiency Potential studies," reviewed 45 recent potential studies and found these studies identified 6 to 32 percent of remaining cost-effective energy savings potential (or 0.3 to 2.9 percent of average annual incremental savings). These studies present strong evidence that the market alone is not sufficient to capture all cost-effective energy savings. In addition, M. Cooper's October 2013 report, "Energy Efficiency Performance Standards: The Cornerstone of Consumer-Friendly Energy Policy," summarizes numerous studies on: (1) benefit/cost analyses of different regulations including appliance standards, and (2) market imperfection and market barriers as reasons for underinvestment in cost-effective energy efficiency products and equipment. This paper is available at: http://www.consumerfed.org/pdfs/Energy_Efficiency_Performance_Standards_Report.pdf

54 Supra footnote 4.

55 Supra footnote 44.

by ACEEE and ASAP found that the DOE predictions have overestimated product prices for recent federal standards for nine products, implying that the DOE's estimates of the benefits of appliance standards may be understated.

State-based appliance standards are also very cost-effective policies. As previously mentioned, the California Energy Commission estimated that the state's appliance standards saved consumers about $2.68 billion in 2010 and NEEP estimated that Connecticut's 2014 appliance standards will save residents and businesses more than $380 million in energy costs by 2020.[56,57]

Implementing standards typically costs significantly less than implementing energy efficiency programs. This is because states don't need to spend much money to promote the adoption of efficient appliances once standards become effective (unlike traditional energy efficiency programs, as described in Chapter 11, that provide rebates and technical support to participants).

Southern California Edison provides a good example of standards' low cost. The utility has spent about $4.7 million in the 2013–2014 program cycle on its Codes and Standards Program as of June 2014, and reported "gross" energy savings of approximately 380 GWh.[58] This program cost just one cent per kWh of savings in the first year. If we assume that the savings last for ten years on average from equipment installed to date in this program cycle, the cost would be about 0.1 cents per lifetime kWh of savings. If we also take into account the fact that the current standards will influence future consumer decisions to purchase new efficient equipment, the cost of implementation per kWh of lifetime savings would be even lower. Even after converting to "net" savings that utilities can claim from the new standards, the implementation cost is very small when compared with the cost of traditional energy efficiency programs.

Although these extremely low costs are impressive, other states will likely spend even less than California, because they can take advantage of California's learning when developing their own standards. Many states have already done so. In addition, as mentioned previously, ASAP has been providing assistance to various states and provides draft model legislation documents.[59] Therefore, the implementation cost of appliance standards could be substantially smaller for other states.

ACEEE and ASAP also describe how the long-term effects of appliance standards on product efficiency offer advantages that traditional ratepayer-funded efficiency programs (such as those described in Chapter 11) cannot:

> *By setting a minimum-efficiency level, standards ensure that efficiency improvements are incorporated into all new products and thus ensure all buyers a minimum level of efficiency performance. Without standards, in many cases, only premium products include efficiency improvements. Standards can help bring down costs for energy-efficient technologies due to economies of scale and because standards encourage manufacturers to focus on how to achieve efficiency improvements at minimum cost as manufacturers compete for the most price-sensitive portion of the market. As a result, higher-efficiency products become more affordable and widely available and all consumers enjoy the benefits from advances in product performance and design.*[60]

A good case in point is the price trend of household refrigerators since the 1970s. Figure 14-2 presents trends in refrigerator price, energy use per unit (kWh per year), and refrigerator size. It illustrates that the price of refrigerators has continued to decrease over time (although there are increases in certain years), and has experienced a 50- to 60-percent reduction over the past 35 years. This reduction is achieved despite the fact that average annual energy use was reduced by nearly 75 percent owing to the past California and federal appliance standards.

Refrigerators provide one of the most successful examples of appliance standards, but other products such as room air conditioners and clothes washers also saw decreasing price trends over many years according to a 2013 ACEEE/ASAP report.[61] The same report also compared the DOE's predicted manufacturer price increase with actual price increases associated with recent federal appliance standards for nine major products, and found that the actual price increase was less than the DOE predicted for all products, with substantial differences in many cases (Figure 14-3). The study observed price

56 Supra footnote 27.

57 Supra footnote 38.

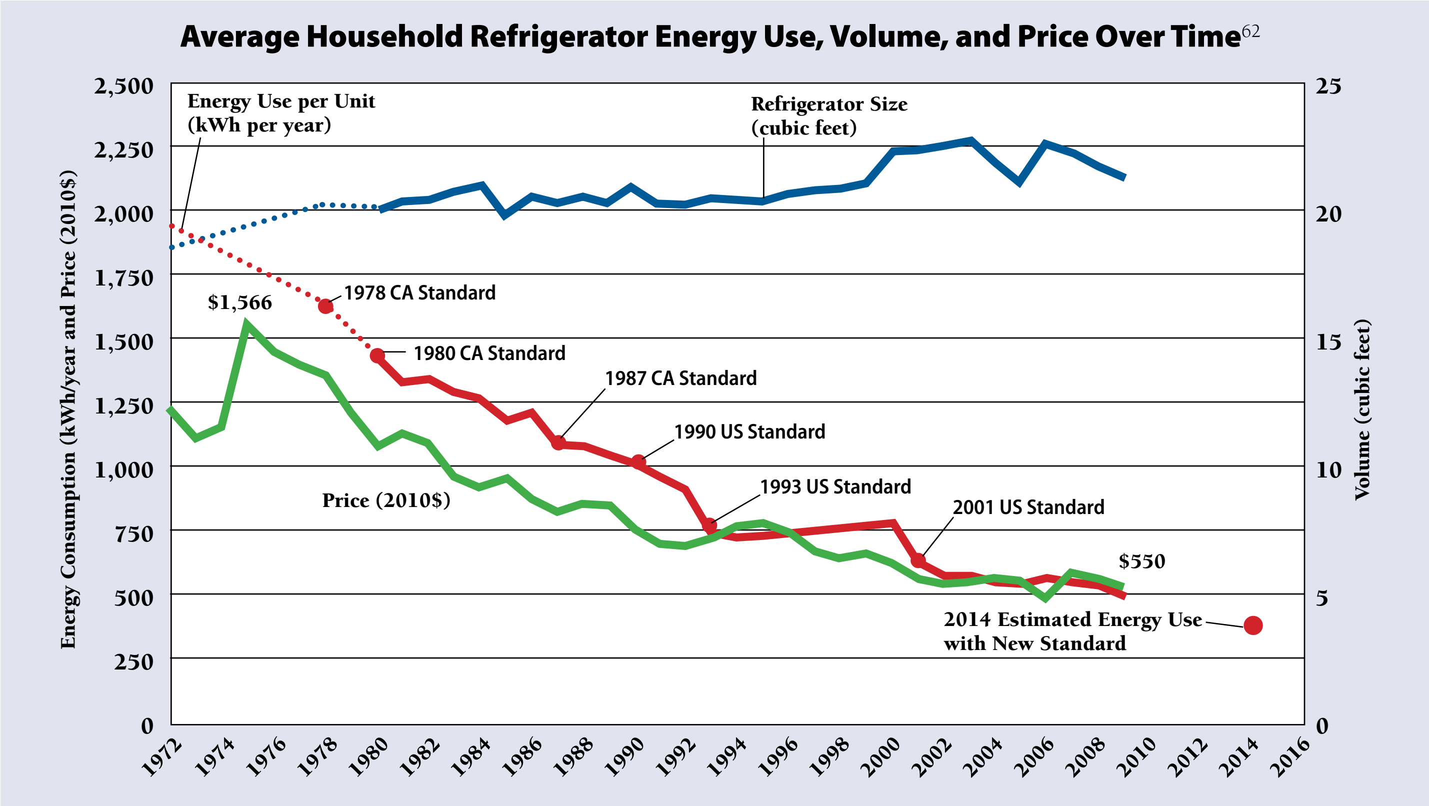
58 Southern California Edison. (2014, June). *2013–2014 Monthly Energy Efficiency Program Report – Report Month: June 2014*. Available at: http://eestats.cpuc.ca.gov/EEGA2010Files/SCE/monthlyReport/SCE.MN.201406.1.xlsx

59 Supra footnote 18.

60 Supra footnote 10.

61 Nadel, S., & deLaski, A. (2013, July). *Appliance Standards: Comparing Predicted and Observed Prices*. ACEEE and ASAP. Available at: http://www.aceee.org/research-report/e13d

Figure 14-2



declines for four out of the nine products, and the actual average price across all products decreased by $12. These are strong indications of price reduction effects owing to economies of scale, and manufacturers' efforts to minimize costs when producing new products that meet new minimum efficiency standards.

ASAP and ACEEE's state-by-state analysis of new state appliance standards explained previously provides projections of economic benefits for consumers using various metrics. Using the Florida case again, Table 14-5 presents economic benefits of the 10 product standards proposed by ASAP and ACEEE. Among all products that save electricity, battery chargers, room air cleaners, and faucets provide the highest economic benefits, ranging from $233 million net present value (NPV) for faucets to $590 million NPV for battery chargers. With all products included, the total consumer economic benefit would be expected to be about $1.8 billion NPV from the new appliance standards just for Florida alone, if these new standards are adopted and become effective in 2017.[63] Simple payback periods and benefit/cost ratios are preferable, and a few products do not have any payback period because meeting the new standards is expected to add no or little incremental costs. For the other products, simple payback periods range from about less than one year to eight years, and benefit/cost ratios range from 1.5 to 20.

Using a similar methodology, ACEEE also developed estimates of the potential impacts that would result if every state adopted the most ambitious appliance efficiency standards that already exist in at least one state for five specific consumer products including three products listed in Table 14-5 (i.e., double-ended quartz halogen lamps,

62 Obtained from ASAP on September 15, 2014. Figure 14-2 is a revised version of a 2011 ASAP graph available at: http://www.appliance-standards.org/sites/default/files/Refrigerator%20Graph_July_2011.PDF. The original data sources are the Association of Home Appliance Manufacturers for energy consumption and volume, and US Census Bureau for price. Although this figure only includes data for one appliance, it refutes one of the core arguments of critics who assert that appliance efficiency standards drive up the cost of appliances and thus harm consumers.

63 NPV is the total monetary value of bill savings achieved by products purchased between the effective date of the standards and 2035 minus the total incremental product cost incurred by purchasers as a result of the standards over the same period.

Figure 14-3

Comparison of Predicted Manufacture Price Increase for Standards With Actual Price Increase[64]

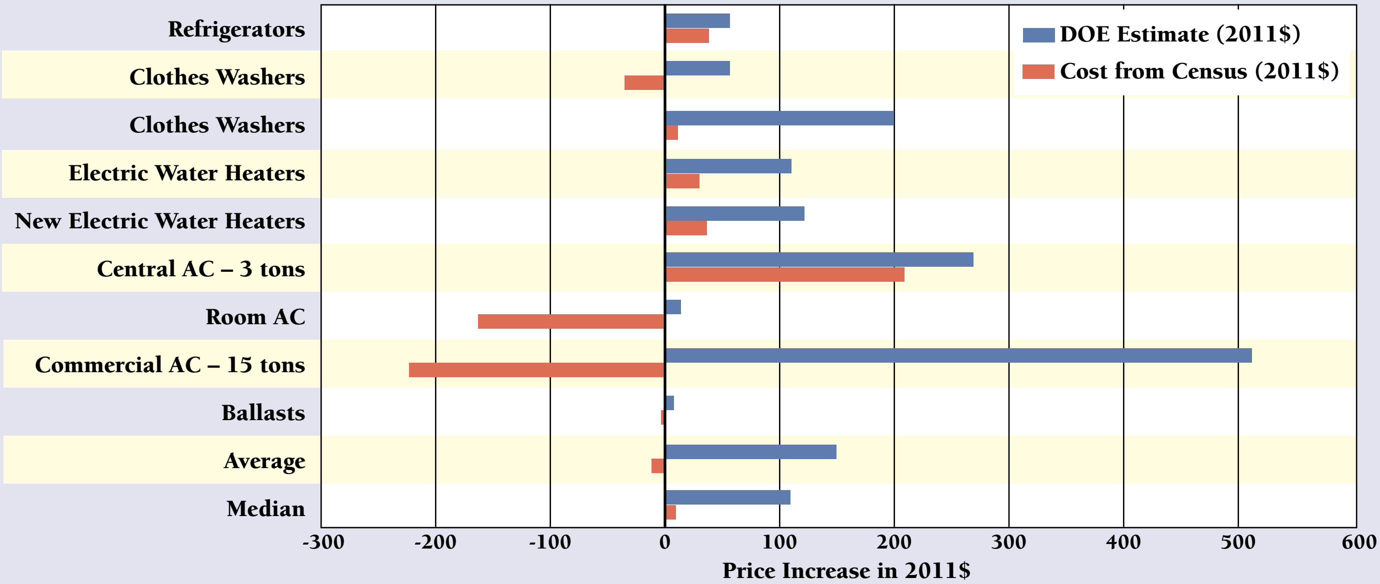


Table 14-5

Potential Economic Impacts of New State Appliance Standards Through 2035 for Florida[65]

Products	Payback Period Years	Benefit/ Cost Ratio	NPV Economic Impact $ Million
Battery Chargers	-	-	592.3
Small Consumer Chargers	1.3	2.7	566.6
Small Non-Consumer Chargers	3.5	2.3	5.2
Large Chargers	1.1	9.9	20.5
Commercial Dishwashers	0.5	20.1	75.1
electricity	-	-	-
natural gas	-	-	-
water	-	-	-
Double-Ended Quartz Halogen Lamps	1.1	1.7	26.4
Faucets (lavatory)	no cost	no cost	233.1
electricity	-	-	-
natural gas	-	-	-
water	-	-	-
Hot Food Holding Cabinets	2.9	3.2	12.6
Portable Electric Spas	7.9	1.5	3.7
Room Air Cleaners	no cost	no cost	415.5
Toilets	no cost	no cost	306.1
Urinals	no cost	no cost	127
Water Dispensers	0.5	15.3	29.1
TOTAL	**-**	**-**	**1,821**

residential lavatory faucets, portable electric spas), and two new products (i.e., commercial hot food holding cabinets and bottle-type water dispensers). ACEEE found that such standards could save more than 112 million MWh of electricity (cumulatively) by 2030, while the ratio of benefits to costs would be somewhere between 1.8 and 9.4. Although the potential MWh savings from appliance standards were not as great as for other energy efficiency policies studied by ACEEE, the benefit/cost ratio was higher than for any other option analyzed.[66]

64 Developed based on Table 1 from: Supra footnote 61.

65 Refer to ASAP analysis for Florida, available at: http://www.appliance-standards.org/states

66 Hayes, S., Herndon, G., Barrett, J. P., Mauer, J., Molina, M., Neubauer, M., Trombley, D., & Ungar, L. (2014, April). *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution.* ACEEE. Available at: http://aceee.org/research-report/e1401

7. Other Considerations

Utility's Involvement in Appliance Standard Adoption

As mentioned previously, a growing number of stakeholders including utilities and third-party efficiency administrators are exploring the role of C&S in existing electric and gas energy efficiency programs such as those described in Chapter 11. Typically adoption of new C&S poses challenges for efficiency program administrators, because such new policies make programmatic savings harder to achieve by raising the minimum efficiency levels of certain products, and by reducing the amount of savings that program administrators can claim result from their own efforts. This is an important challenge to address. However, utilities and third parties can turn this challenge into an opportunity by proactively getting involved in the support of new codes and appliances, and seeking potentially substantial savings from their code and standard efforts.

States may find it advantageous to allow or direct energy efficiency program administrators to support C&S for the following reasons: (1) program administrators in many states already have significant knowledge and expertise about energy efficient products, some of which are suitable candidates for new appliance standards; (2) program administrators have experience assessing feasibility, potential, and benefits and costs of energy efficient products; (3) program administrators have experience in conducting evaluation, measurement, and verification (EM&V) studies; and (4) program administrators have access to funding to support adoption of C&S in various ways.

Specific examples of the role program administrators can play with regard to new C&S include the following:

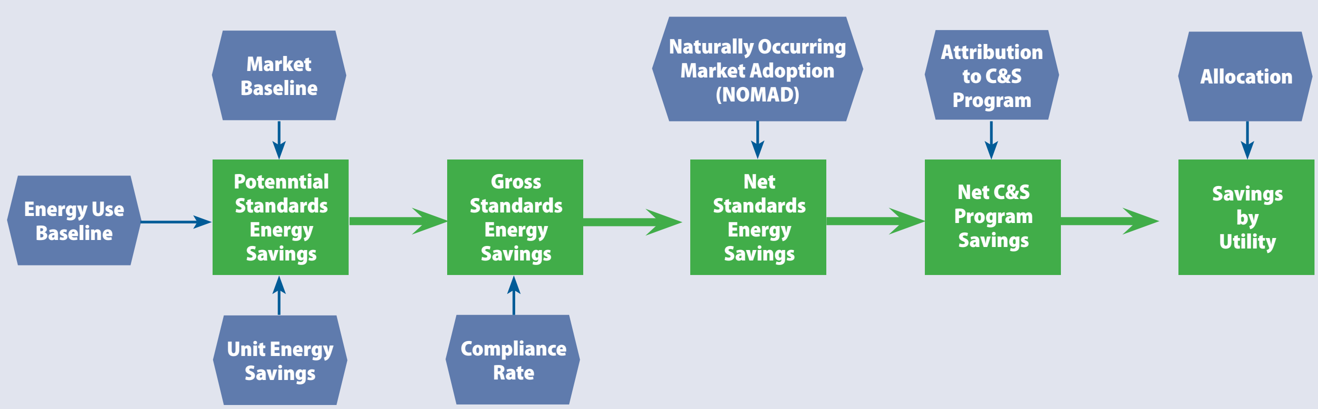
- Holding meetings and working groups to target products ripe for new standards;
- Developing technical reports on the feasibility and potential costs and benefits of candidate products for standards consideration (e.g., CASE reports by California utilities);
- Developing standard testing practices and evaluation tools;
- Conducting EM&V analyses on new standards (e.g., impact evaluation and process evaluation studies); and
- Providing expert witness testimony in regulatory hearings and assisting with consumer and regulator education efforts.[67]

Energy Impact Evaluation

New challenges for policy impact evaluation may arise if C&S are included as part of a state's plan for compliance with the Clean Power Plan emissions guidelines for existing power plants (i.e., the "111(d) rule"). This is partly because

Figure 14-4

California Codes and Standards Evaluation Methodology[68]



67 California utilities are providing these technical support activities for code and standard development. Also refer to: Cooper, A., & Wood, L. (2011, August). *Integrating Codes and Standards Into Electric Utility Energy Efficiency Portfolios.* Institute for Electric Efficiency. Available at: http://www.edisonfoundation.net/iei/Documents/IEE_IntegratingCSin-toEEPortfolios_final.pdf

68 KEMA, Inc., The Cadmus Group, Inc., Itron, Inc., Nexus Market Research, Inc., & ENRG, Inc. (2010, April). *Volume III – Codes & Standards (C&S) Programs Impact Evaluation – California Investor Owned Utilities' Codes and Standards Program Evaluation for Program Years 2006–2008.* CALMAC Study ID: CPU0030.06. Available at: http://www.calmac.org/publications/codes_standards_vol_iii_finalevaluationreport-updated_04122010.pdf

no state except California has done EM&V studies to verify energy savings from C&S, and such EM&V studies could potentially be more complex than conventional EM&V studies for energy efficiency programs owing to the complexity of assessing attribution of program efforts to standard adoption.[69] Fortunately states can learn from California's approach to conducting EM&V studies for appliance standards.

California's C&S evaluation methodology has five core steps, as presented in Figure 14-4, and is explained briefly below:[70]

1) **Potential Savings Analysis.** A per-unit energy savings is calculated for the incremental benefit of adopting a new or more stringent C&S at the statewide level.
2) **Gross Energy Savings and Compliance Rate.** Realized energy savings from C&S are estimated by identifying compliance rates of new C&S, and applying them to potential energy savings estimates. For appliance standards, a priority is placed on high-impact energy savings appliances, and surveys are conducted with vendors regarding those appliances. Lastly, individual vendor data are extrapolated to the statewide level.
3) **Net Energy Savings and Normally Occurring Market Adoption.** Net energy savings are estimated by adjusting gross energy savings for the naturally occurring market adoption (NOMAD) of more efficient appliances, equipment, and building techniques in the marketplace. NOMAD rates are developed based on industry expert opinions on market diffusion curves obtained from a Web-based tool and direct interviews.
4) **Net Program Savings and Program Attribution.** Net program savings that the state's IOUs can claim toward their programmatic energy savings goals are estimated by adjusting net energy savings for program attribution factors. Independent third parties assess attribution by collecting data and documentation on the utilities' activities in three areas: (1) the development of compliance methods and other analytic techniques; (2) the development of C&S language and technical, scientific, and economic information in support of the C&S; and (3) demonstrating the feasibly of C&S adoption.[71]
5) **Savings Allocation Among Utilities.** Final statewide energy savings are assigned to each utility based on the IOU's percentage of statewide electricity sales.

Although determining attribution makes the impact assessment more complex, it is thought to be worthwhile because program administrators' support of C&S adoption is expected to increase the gross savings from adoption of state appliance standards. Furthermore, it is important to note that estimating attribution accurately is a secondary concern from the state's perspective, because a state's main concern is how accurately and reasonably the statewide impact of standards can be estimated.

Coordination With Traditional Energy Efficiency Programs

C&S raise the baseline for energy efficiency programs and make it harder for them to achieve savings. Thus, when C&S are included in program administrators' energy efficiency programs, it is essential that the impacts of such policies are properly and consistently incorporated in the energy savings goals for an entire program portfolio for a given program administrator, as well as in program administrators' program plans. Furthermore, program administrators need to be strategic about which measures and technologies are suitable for code and standard programs, and strategically determine the appropriate program mix.[72]

Addressing Manufacturers' Concerns

An increase in the adoption of state appliance standards across regions owing to the Clean Power Plan regulation for existing power plants may create a new challenge for manufacturers. From the manufacturers' standpoint, federal standards provide more certainty than state standards. If one or only a handful of states in a region adopt new standards or if states adopt standards that vary from one state to another, it would make it harder for manufacturers to produce and deliver their products. Thus, it would be preferable for states to coordinate their efforts and establish similar standards across the same region.[73] Furthermore,

69 "Attribution" in this context refers to the extent to which the utilities' efforts in support of an appliance standard can be credited for the adoption of that standard by the state.

70 Supra footnote 68.

71 The relevant information can be collected from California Energy Commission hearing transcripts, workshop meeting notes, CASE reports, and interviews of various stakeholders involved in the C&S process.

72 Supra footnote 20.

73 Supra footnote 18.

states should make sure that voices of manufacturers are heard in an open public forum, similar to the stakeholder processes in California and other states.

State Plans for 111(d) Compliance

When the time comes for states to prepare plans for compliance with a final 111(d) rule, some states may be interested in including state appliance standards in their plans. However, it is possible that many states will not be able to complete an entire standard development process before the deadline for submitting their plans to the EPA. Thus, states need to be creative in developing their plans if they decide to use standards as a policy option to reduce emissions.

States would need to include at least the following pieces of information in the plans they submit to the EPA for approval:

- Description of the ongoing or expected process to adopt new standards, such as the stakeholder process, including the expected date of each activity and standard implementation;
- Definition of covered products in the new standards;
- Estimates of potential energy and CO_2 emissions savings and costs from the standards;
- Impact and process evaluation plans (as required by the EPA for a 111(d) plan);[74] and
- Discussion of any uncertainty associated with savings and cost estimates (as required by the EPA for a 111(d) plan), as well as the feasibility of adopting and implementing the proposed new standards.[75]

One of the challenges of preparing a state compliance plan appears to be estimating potential savings. However, to the extent states intend to follow what other states have recently implemented, they may be able to rely on ASAP's preliminary estimates of savings from new state standards for each state across the nation.[76] Although states could modify ASAP's analyses based on state-specific sales data (if such data exist), it is conceivable that ASAP's analysis would be sufficient for the purpose of preparing a compliance plan. However, when verifying energy savings, states need to conduct a detailed impact evaluation based on appropriate state-specific data.

Gaining sufficient consensus among stakeholders as to what new standards can and should be adopted would be another challenge of including appliance standards in a 111(d) compliance plan. States may need to assess stakeholder consensus or hear stakeholder views well before the plan submission deadline if they anticipate any reservations from stakeholders, or if they think stakeholder input would be helpful to improve the design of new standards.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on appliance standards.

- Cooper, A., & Wood, L. (2011, August). *Integrating Codes and Standards into Electric Utility Energy Efficiency Portfolios.* Institute for Electric Efficiency. Available at: http://www.edisonfoundation.net/iei/Documents/IEE_IntegratingCSintoEEPortfolios_final.pdf
- Hayes, S., Herndon, G., Barrett, J. P., Mauer, J., Molina, M., Neubauer, M., Trombley, D., & Ungar, L. (2014, April). *Change Is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution.* ACEEE. Available at: http://aceee.org/research-report/e1401
- KEMA, Inc., The Cadmus Group, Inc., Itron, Inc., Nexus Market Research, Inc., & ENRG, Inc. (2010, April). *Volume III – Codes & Standards (C&S) Programs Impact Evaluation – California Investor Owned Utilities' Codes and Standards Program Evaluation for Program Years 2006–2008.* CALMAC Study ID: CPU0030.06. Available at: http://www.calmac.org/publications/codes_standards_vol_iii_finalevaluationreportupdated_04122010.pdf

74 Supra footnote 23.

75 US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-state-plan-considerations.pdf. States may also need to include contingencies in their plans to address the possibility that appliance standards are not ultimately adopted or do not save as much energy as anticipated when the plan was submitted to the EPA.

76 Refer to ASAP website at: http://www.appliance-standards.org/map/benefits-from-state

- Lee, A., Dethman, L., Gurin, C., Burns, D., Filerman (Phi), S., Thomley, D., & Collins, S. (2012, May). *2010–2012 California Statewide Codes and Standards Program Process Evaluation Final Report.* CALMAC Study ID SCE0319.01. Prepared by the Cadmus Group for Southern California Edison and Pacific Gas and Electric. Available at: http://www.calmac.org/publications/SCE-PG%26E_C%26S_Process_Evaluation_FINAL_5-28-12.pdf
- Lee, A., Groshans, D., Gurin, C., Cook, R., & Walker, T. (2012, August). *Raising the Bar – Getting Large Energy Savings Through Programs That Support Energy-Efficiency Codes and Standards.* Proceedings of the 2012 ACEEE Summer Study on Energy Efficiency in Buildings. Available at: http://www.cadmusgroup.com/wp-content/uploads/2012/12/590-ACE3-Codes-Standards-Paper-Final.pdf
- Lowenberger, A., Mauer, J., deLaski, A., DiMascio, M., Amann, J., & Nadel, S. (2012, March). *The Efficiency Boom: Cashing in on the Savings From Appliance Standards.* ACEEE and ASAP. Available at: http://www.aceee.org/research-report/a123
- Nadel, S., deLaski, A., Eldridge, M., & Kliesch, J. (2006, March). *Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards.* ACEEE and ASAP. Available at: http://www.aceee.org/research-report/a062
- US EPA. (2006, April). *Clean Energy-Environment Guide to Action: Policies, Best Practices, and Action Steps for States,* chapter 4. Available at: http://epa.gov/statelocalclimate/resources/action-guide.html

9. Summary

Appliance standards can be an effective policy option to reduce CO_2 at the lowest possible cost. The implementation cost is significantly lower than the cost of utility energy efficiency programs. There is also the potential to reduce the actual cost of efficient products that are subject to new standards owing to economies of scale and manufacturer competition.

One option available to states is to accelerate or enhance standard adoption by allowing or directing utilities and third-party program administrators to support standard adoption and to take credit from the standards toward their programmatic energy savings goals.

The primary challenge to implementing standards is political feasibility. Some state legislatures have granted state agencies authority to adopt new standards, but many others need to pass new legislation to establish new standards. Thus, states must consider the political feasibility of adopting state appliance standards. Another major challenge is to measure and verify energy and CO_2 emissions savings from appliance standards given states' limited experience in this area. However, states can learn from California's example in this regard. Addressing these barriers will allow states to access a highly advantageous, cost-effective policy option to reduce energy and CO_2 emissions.

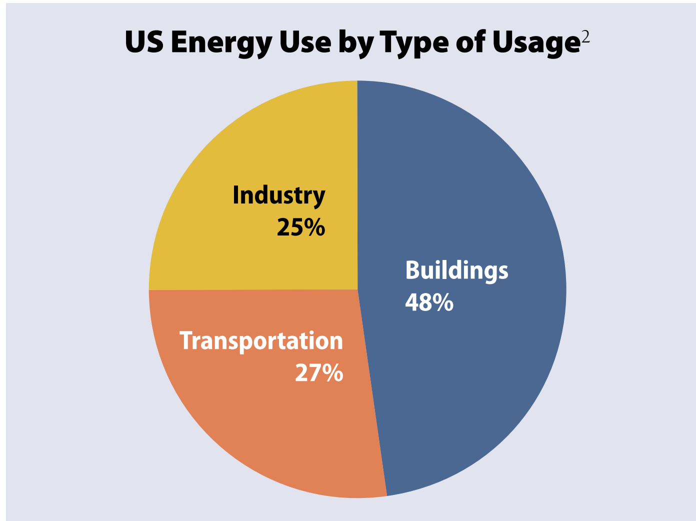
Chapter 15. Boost Building Energy Codes

1. Profile

"Energy efficiency" refers to technologies, equipment, operational changes, and in some cases behavioral changes that enable our society to enjoy equal or better levels of energy services while reducing energy consumption.[1] Efforts to improve efficiency in the generation, transmission, or distribution of electricity are covered in Chapters 1 through 5 and in Chapter 10. In contrast, Chapters 11 through 15 address different policy options for making the end-user's consumption of electricity more efficient. Chapter 11 focuses on policies that establish mandatory energy savings targets for electric utilities, the achievement of which is generally funded through revenues collected from customers themselves. Chapter 12 focuses on policies that create or expand the opportunities for voluntary, market-based transactions that promote energy efficiency as an alternative or supplement to government-mandated programs or regulatory requirements. Chapter 13 focuses on an emerging type of energy efficiency program, behavioral energy efficiency, that is worthy of separate treatment because it is sometimes included within the mandated programs described in Chapter 11 and sometimes implemented as a voluntary effort outside of those programs. Chapter 14 covers mandatory appliance efficiency standards that are imposed on manufacturers. This chapter, Chapter 15, covers mandatory building energy codes that are imposed on builders and developers.

Approximately half of US energy use is in buildings, with the remaining half split about evenly between industry and transportation, as noted in Figure 15-1. Building codes establish mandatory requirements for the building shell, mechanical equipment, and lighting systems. Although the other equipment within buildings, such as appliances and electronics (generally referred to as "plug loads"), may be separately regulated by appliance efficiency standards, the elements regulated by building codes have a very significant impact on building energy use and associated carbon emissions.

Figure 15-1



Building Energy Codes

Building energy codes establish minimum efficiency requirements for new and renovated residential and commercial buildings. This can reduce the need for energy generation capacity and new energy infrastructure while also reducing energy bills. Energy codes lock in future energy savings during the building design and construction phase, rather than through later, more expensive, renovations. By locking in efficiency measures at the time of construction, codes are intended to capture energy savings that are more cost-effective than the more limited retrofit

1 In contrast, some people use the term "energy conservation" to refer to actions that reduce energy consumption but at some loss of service. Neither term has a universally accepted definition and they are sometimes used interchangeably.

2 See: http://www.buildingscience.com/documents/insights/bsi-012-why-energy-matters (from architecture2030.org).

opportunities that are available after a building has been constructed. Energy code requirements are also intended to overcome market barriers to efficient construction in both the commercial and residential sectors. The primary market barrier is that the builder of new buildings is often not the party that will pay the energy bills; homeowners, renters, and business lessors are typically responsible for these operating costs. Builders thus may have no interest in energy-saving design features, especially ones that raise the complexity or costs of construction, and the future occupants of their buildings pay the price.

Over the past 30 years, code improvements have reduced total energy use by new buildings by approximately 40 percent. Planned improvements in Washington state, for example, seek to reduce current usage by an additional 70 percent by the year 2020. In California, the goal is to reduce net building energy usage to zero by 2030.[3]

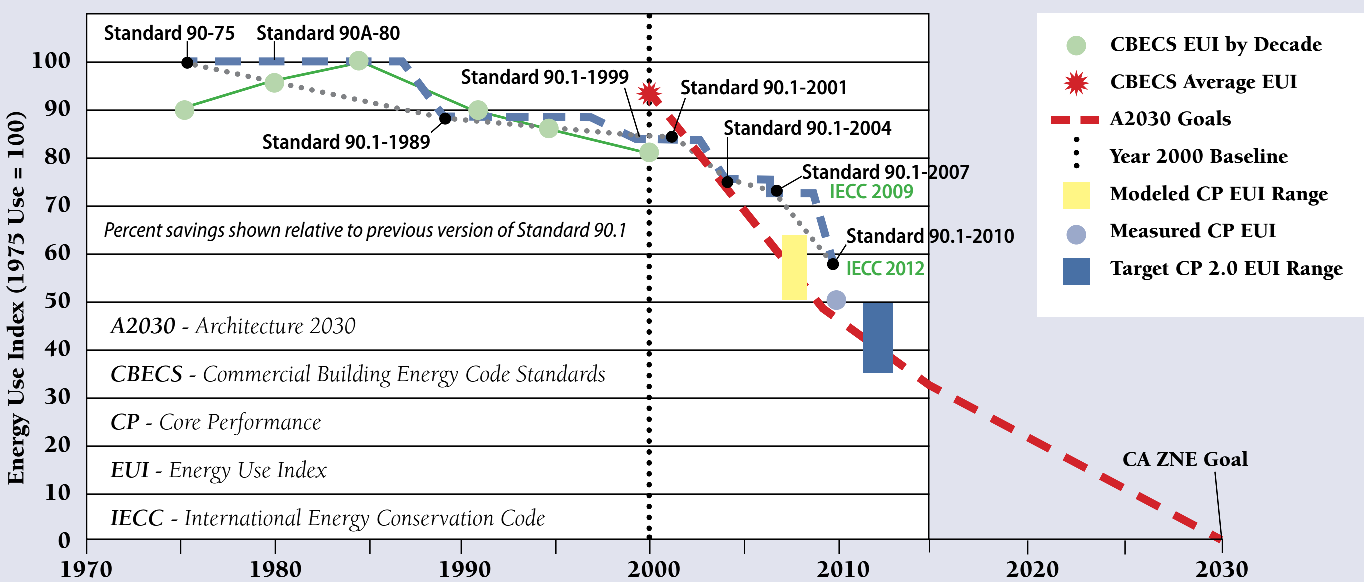
The most advanced building codes today are denoted as zero net energy (ZNE), and lay out standards by which buildings produce as much energy as they use. One of several possible definitions of ZNE is that the amount of energy consumed by a building over the course of a typical year is less than or equal to the amount of renewable energy generated onsite. For example, if a building uses natural gas for space and water heating but has solar panels generating electricity, it could qualify as ZNE if the solar panels typically generate enough electricity annually to equal annual onsite electricity use, plus an additional amount that would be equivalent in energy to the onsite use of natural gas. It should be noted that ZNE codes do not require the building to produce the energy at the same time that it uses the energy.

Even ZNE buildings require connections to electricity grids and often to natural gas pipelines. An excellent example of a ZNE building is the Bullitt Center in Seattle, which incorporates very sophisticated building shell improvements and state-of-the-art heating, ventilation, and air conditioning equipment, captures incoming rainwater for onsite use, and includes a composting sanitary system. Although typical new code-compliant commercial buildings have an energy utilization index of about 50 (thousand British thermal units [BTU[4]]/year/square foot), the Bullitt Center achieves an energy utilization index of 18, and generates that much energy with an onsite photovoltaic solar system.[5]

Figure 15-2

Trajectory of Commercial Building Energy Codes 1975 to 2030[6]

Relationship of 90.1 Commercial Versions, EUI of Commercial Building Stock, IECC Commercial Code Standards, NBI's Core Performance, Architecture 2030 and California Commercial ZNE Policy Goal



3 See: http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/

4 A BTU is the amount of heat required to increase the temperature of a pint of water (which weighs exactly 16 ounces) by one degree Fahrenheit.

5 See: http://www.bullittcenter.org/

6 See: http://newbuildings.org/index.php?q=develop-roadmap

Figure 15-2 shows the actual achievement of commercial building energy codes since 1975, along with the trajectory that California has established to achieve ZNE by 2030. The trajectory of residential building energy codes has been similar.

Other Mandatory Building Efficiency Policies

In addition or as an alternative to building energy codes, another policy option is to establish mandatory energy-use benchmarking and disclosure requirements for building owners. These policies do not require specified levels of efficiency but provide information to consumers that is analogous to the mandatory EnergyGuide labels for appliances described in Chapter 14.[7] For example, Cambridge, Massachusetts adopted a Building Energy Usage and Disclosure Ordinance that requires the benchmarking and disclosure of building energy performance for large commercial, institutional, and multifamily buildings. The ordinance requires owners of the designated property types to annually benchmark and report to the city their properties' energy use, water use, and building information through the US Environmental Protection Agency's (EPA) *Portfolio Manager* tool. A requirement to provide benchmarks helps create awareness of energy use in such buildings.

Another alternative is to require energy audits or retrofit requirements. For example, New York City has established formal energy audit requirements for buildings over a certain size. As with benchmarks, required audits help focus building owners' attention on energy use and the means to improve it. Retrofit requirements were proposed in New York City by former Mayor Michael Bloomberg, but not adopted.

2. Regulatory Backdrop

Building codes and other mandatory building efficiency policies are generally adopted and implemented (and sometimes enforced) at the state and local level.

Building Energy Codes

Most building codes are based on national "model codes" developed by associations of code officials. The exception to this is in the manufactured housing (mobile home) sector, in which standards are adopted by the Federal Housing Administration.

The principal model energy code for residential buildings is the International Energy Conservation Code (IECC) developed by the International Codes Council. The commercial sector relies on either the IECC or a different model standard — ASHRAE 90.1 — that is produced by the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE). Many states customize the model codes in distinct ways for local applicability.[8] Several, for example, including California, Oregon, Washington, Florida, and some New England states, have adopted state-specific residential energy codes.

These codes include extensive requirements for building shell construction and major installed energy systems, including lighting, heating, cooling, and water heating. Table 15-1 identifies the primary elements of residential and commercial energy codes.

The most recent version of the IECC residential code is the "2015 edition," adopted by the Council in 2013.[9] Input

Table 15-1

Components of Building Energy Codes

	Residential	Commercial
Building Shell	Floor Insulation Wall Insulation Ceiling Insulation Glazing area Glazing efficiency	Overall building shell thermal performance Glazing efficiency (heat loss) Glazing reflectivity (heat gain)
Heating	Minimum furnace or heat pump efficiency Equipment sizing standards	Minimum equipment efficiency Equipment Sizing Standards
Cooling	Minimum air conditioner or heat pump efficiency Equipment sizing standards	Minimum equipment efficiency Equipment sizing standards
Water Heating	Equipment efficiency standards Piping insulation	Equipment efficiency standards Piping insulation

7 Note that voluntary labeling and benchmarking programs for buildings and appliances are discussed in Chapter 12. Here in Chapter 15 we address only mandatory policies for buildings.

8 See, for example, Georgia: http://www.dca.state.ga.us/development/constructioncodes/programs/documents/2012effective/effective/IECC-2012-effective.pdf; Washington: http://www.energy.wsu.edu/Documents/2009_2012%20WSEC%20Comparison.pdf; and Hawaii: http://energy.hawaii.gov/hawaii-energy-building-code

9 Note that the year denotes a recommended date of adoption.

to that code was submitted in 2012. Based on experience with past updates, it is likely that only a few states will adopt and enforce that code by its target date of 2015. The IECC provides a website at which the status for each state's energy code adoption can be checked.[10]

The most expedient way to ensure that codes reduce energy use in new buildings is to create a rigorous code enforcement mechanism. Enforcement of building energy codes is often lax, as local government agencies tend to not see this as a key part of their role.[11] Because no other entity is charged with code enforcement, building energy codes are often only as effective as the integrity of the architects, engineers, and builders. Some states have made enforcement of energy codes a priority, but they are the exceptions. As a condition of receiving funding under the American Recovery and Reinvestment Act of 2009, each Governor was required to certify that his or her state was enforcing a minimum energy code for new construction.[12] Although these representations were made, the quality of code enforcement continues to vary around the country.[13]

The typical process for code adoption starts with a national association such as the International Code Council or ASHRAE periodically developing a national model code, along with extensive documentation of the consumer cost-effectiveness of the proposed measures. In the following years, states adopt this code as a local government obligation. Finally, local building officials undertake enforcement of the codes. It is important to note that buildings are normally subject to the code in effect when the building permit is issued; actual construction can lag beyond that date significantly. The result is that the buildings being completed today can be designed and built in conformance with weaker codes that may have been adopted years ago. However, because buildings last for a very long time, even gradual code improvements will pay very large, long-term benefits.

Each stage of this process is critical to code success. Effective enforcement of an obsolete code may in reality be no better than lax enforcement of a very good code. The former can ensure uniform mediocrity, the latter produces uneven results, including some excellent buildings and others less so, because a majority of building designers address code requirements at the design stage, leaving building officials primarily with the task of ensuring that the as-built structure is consistent with the approved plans.

Other Mandatory Building Efficiency Policies

As a supplement or alternative to building energy codes, a number of state and local jurisdictions have adopted mandatory building energy-use benchmarking, audit, and disclosure policies. These policies vary in their applicability to public, commercial, and residential buildings and in the details of the requirements. Generally, building owners covered by such a policy are required to measure their building's energy use, compare it to the average for similar buildings, and disclose the results. This allows the current owners and occupants of these buildings, as well as potential buyers or future occupants, to understand the building's relative energy performance. It also educates owners and occupants and helps them identify opportunities to cut energy waste and energy costs.

It is important to recognize that electric utilities can also take action independently to ensure that newly connected buildings are efficient. A few electric utilities have taken steps to implement energy efficient construction practices in new buildings where state and local government efforts have been inadequate. This may take the form of a surcharge for structures not meeting a standard beyond that enforced by the local government, or an incentive to go beyond the enforced standard (or both).[14] In one

10 See: http://www.iccsafe.org/gr/Pages/adoptions.aspx

11 On the other hand, according to the ICC Code of Ethics, "The protection of the health, safety and welfare of the public by creating safe buildings and communities is the solemn responsibility of the International Code Council ("ICC") and all who participate in ICC activities." See: http://www.iccsafe.org/AboutICC/Documents/CodeOfEthics.pdf

12 Alliance to Save Energy. (2009). Nation's Leading Building Energy Efficiency Experts Clarify ARRA Funding Ties to State Energy Code Adoption and Enforcement [Press release]. Available at: http://www.usgbc.org/Docs/News/State%20Bldg%20Codes%20White%20Paper%2012-1-09%20REV2-usgbc.pdf

13 The Building Codes Assistance Project (BCAP) has developd a series of maps that provide a national snapshot of building energy code adoption and implementation status. See: Online Code and Environment Advocacy Network (Ocean). Available at: http://energycodesocean.org/code-status

14 See, e.g.: Lazar, J. (1991, September). *Utility Connection Charges and Credits: Stepping Up the Rate of Energy Efficiency Implementation.* Presented at the 2nd International Conference On Energy Consulting, Graz, Austria. Available at: raponline.org/document/download/id/4664

case, a local public utility district in Washington adopted a $2000 connection charge for buildings not meeting a superior standard, plus a $2000 incentive for builders that did meet the superior standard. This was challenged by the manufactured housing industry, which asserted unsuccessfully that the utility had overstepped its authority in adopting a code, a function that was reserved to a federal agency for manufactured housing. The Washington Supreme Court ruled that the new facility charge was an exercise of rate-making properly within the authority of the utility, not subject to federal preemption.[15]

Air Pollution Regulations

Energy efficiency plays a prominent role in the emissions guidelines for carbon dioxide (CO_2) emissions from existing power plants that the EPA proposed in June 2014, citing its authority under section 111(d) of the Clean Air Act, as part of its "Clean Power Plan."[16] The EPA determined that the "best system of emission reduction" for existing power plants under the Clean Air Act consists of four "building blocks," one of which is end-use energy efficiency. Although states will not be required to include energy efficiency in their 111(d) compliance plans, the emissions rate goals for each state are based on an assumption that a certain level of energy savings (and thus, emissions reduction) is achievable. The level of savings that the EPA used to set each state's emissions rate goals is based on the demonstrated performance of leading states with respect to the kinds of ratepayer-funded energy efficiency programs described in Chapter 11 and a meta-analysis of energy efficiency potential studies. The EPA did not separately consider building energy codes as a component of the "best system of emission reduction," and the goals proposed for each state do not presume that building energy codes will be adopted or enforced.

States will apparently be able to use building codes and other mandatory building efficiency policies to reduce emissions and comply with any final regulation, so long as the policies go beyond "business as usual" projections of energy demand and are enforceable. However, the EPA offered little guidance in the technical support documents for the 111(d) proposal to help states with some of the particular challenges of evaluation, measurement, and verification (EM&V) for building energy codes and benchmarking requirements, such as the variable levels of code enforcement. For example, in the State Plan Considerations document, the EPA contrasts these kinds of policies with the types of ratepayer-funded energy efficiency policies described in Chapter 11, noting that, "In some cases, appropriate evaluation protocols and approaches have not been developed... In cases where appropriate EM&V methods do exist, there may also be less experience applying them." The EPA then cites two documents that offer examples of EM&V methods.[17] Later in the same document, the EPA characterizes EM&V procedures for building energy codes as "moderately well established" and for benchmarking programs as "less well established," and suggests that "programs and measures with less well developed EM&V approaches would require greater documentation in state plans of EM&V methods that will be applied."[18]

3. State and Local Implementation Experiences

State and local governments across the country have implemented building energy codes and similar policies for decades. These policies are very familiar to local government officials, in particular.

15 Wash. Manufactured Housing Ass'n v. Pub. Util. Dist. No. 3, 124 Wash. 2d 381 (1994).

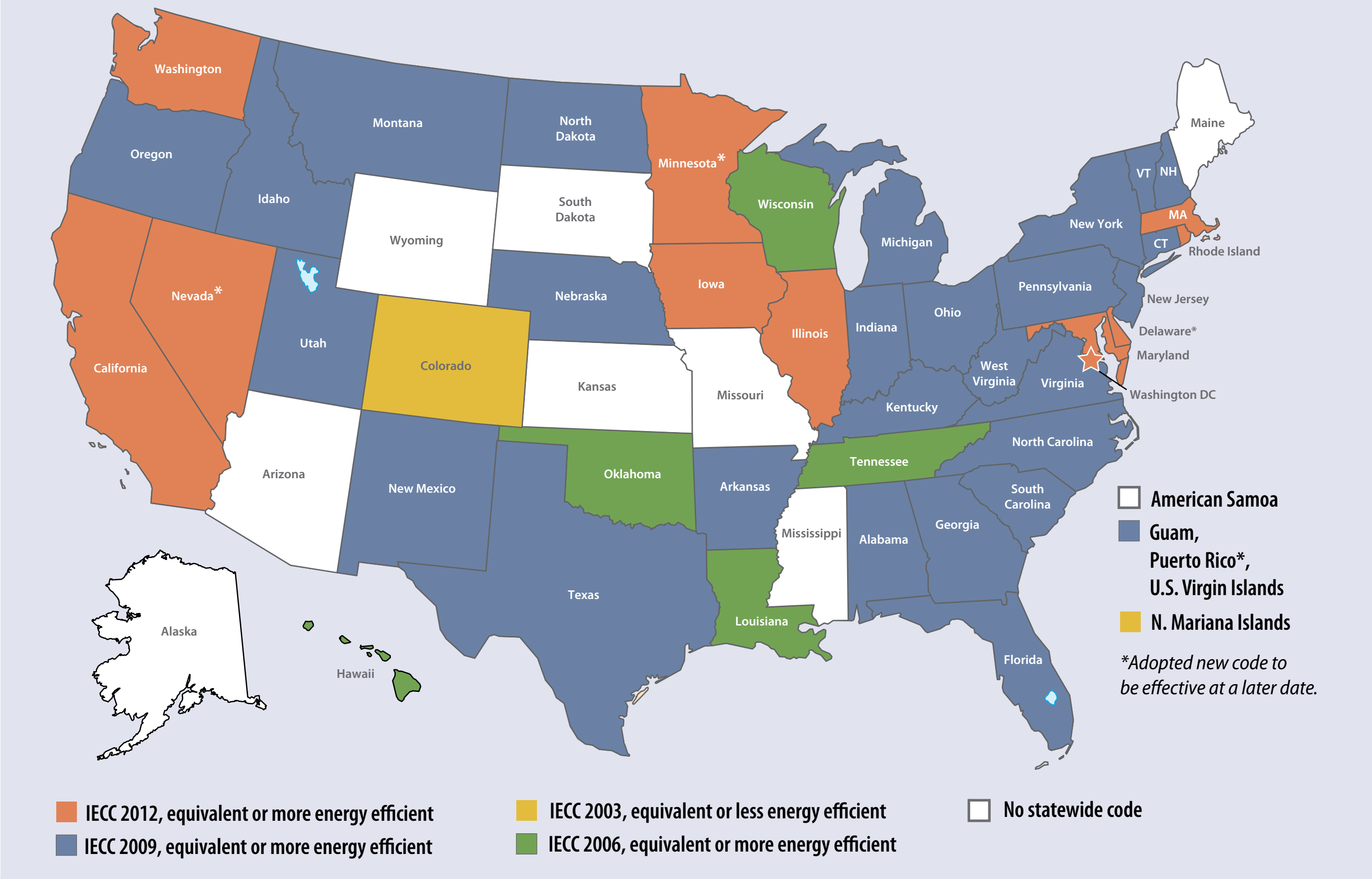
16 Refer to: US EPA. (2014, June). *40 CFR Part 60 – Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule.* Federal Register Vol. 79, No. 117. Available at: http://www.gpo.gov/fdsys/pkg/FR-2014-06-18/pdf/2014-13726.pdf

17 US EPA. (2014, June). *State Plan Considerations – Technical Support Document (TSD) for Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units,* pp. 112-113. Docket ID No. EPA-HQ-OAR-2013-0602, pp. 45-46. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations. The two documents cited by the EPA as examples of EM&V methods are: (1) Livingson, O. V., Cole, P. C., Elliott, D. B., & Bartlett, R. (2014, March). *Building Energy Codes Program: National Benefits Assessment: 1992-2040.* PNNL. Available at: http://www.energycodes.gov/sites/default/files/documents/BenefitsReport_Final_March20142.pdf; and (2) Meyers, S., Williams, A., & Chan, P. (2013, April). *Energy and Economic Impacts of US Federal Energy and Water Conservation Standards Adopted From 1987 Through 2012.* LBNL-6217E. Available at: http://eetd.lbl.gov/sites/all/files/standards_1987-2012_impacts_overview_lbnl-6217e.pdf

18 Supra footnote 17 at pp. 47-50 Docket ID No. EPA-HQ-OAR-2013-0602.

Figure 15-3

Residential Code Adoption by State[19]



Building Energy Codes

Because each state must adopt codes, and local building officials are typically charged with enforcement, the simple directive in the American Recovery and Reinvestment Act of 2009 has limited meaning. Figures 15-3 and 15-4 illustrate state adoption of both residential and commercial energy codes. As is evident, many have obsolete codes in place, and several have no statewide code adoption whatsoever. Those shown in orange are the only states that have a more modern energy code in effect. Note that there is no characterization as to the degree of enforcement in either figure.

As noted previously, building codes are not only adopted by states, but also at the local level. A few local jurisdictions in the United States have adopted stricter energy codes than those promulgated by the state in which they are located.[20] These are known as "stretch codes." The city of Seattle, for example, has typically maintained a nonresidential energy code three to six years "ahead" of the state code.[21] This serves in part as a demonstration project for advanced code concepts.[22] The state of Oregon, which has adopted residential and commercial codes based on the IECC 2009, estimated total savings in 2009 from building energy codes of 1.17 GWh and 2.3 GWh in the residential and commercial sectors, respectively.[23] This was equivalent to more than seven percent of total retail electricity sales in Oregon in 2009.[24] In

19 See: http://www.energycodes.gov/adoption/states

20 For examples, see the ACEEE "Residential Codes" page, available at: http://database.aceee.org/state/residential-codes

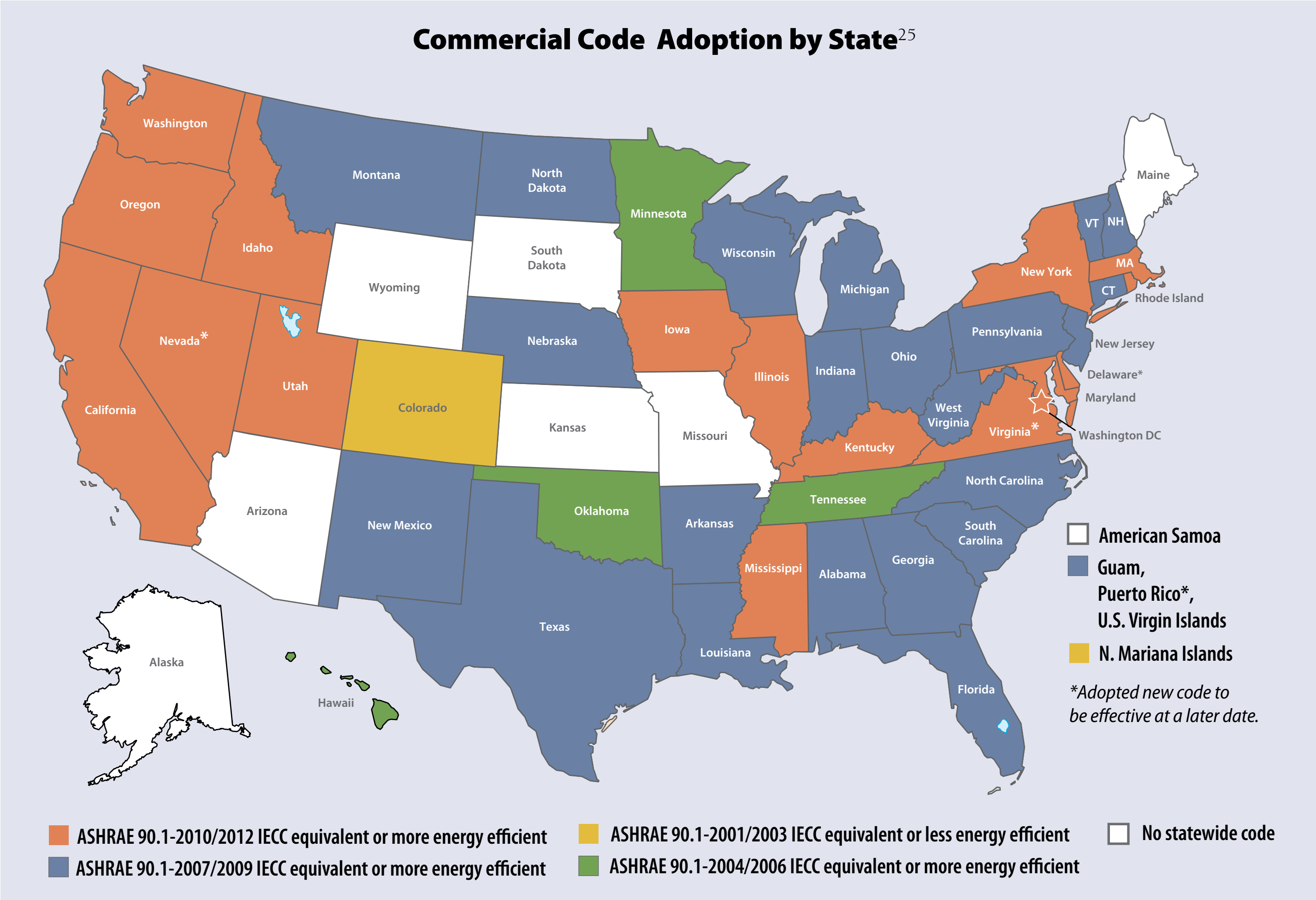
21 The city is precluded by state law from adopting or enforcing a residential energy code that goes beyond the requirements of the state code, but this proscription does not apply to nonresidential codes.

22 See: http://www.seattle.gov/DPD/codesrules/codes/energy/overview/

23 Oregon Department of Energy, 2011-2013 State of Oregon Energy Plan. Available at: http://www.oregon.gov/energy/docs/reports/legislature/2011/energy_plan_2011-13.pdf

24 Supra footnote 23.

Figure 15-4



Massachusetts, the Department of Energy Resources requires municipalities to adopt a stretch code for new buildings. The Green Communities program then assists cities and towns in the implementation of these codes, including funding and technical support.

Based on the implementation experiences of governments around the country, the key elements to code adoption, training, and enforcement include:

- Educating policymakers (legislators or state code agencies) as to the economic and environmental benefits of updated energy codes;
- Educating and training building design professionals and building contractors in the technical aspects of energy codes, so that mistakes that require costly rework are avoided; and
- Educating and training code enforcement officials (generally local government agencies) as to the details of energy code enforcement, and the health and safety benefits (which they consider their principal mission) of advanced energy codes.

Unless all of these elements are addressed, the full potential of code improvements is unlikely to be achieved.

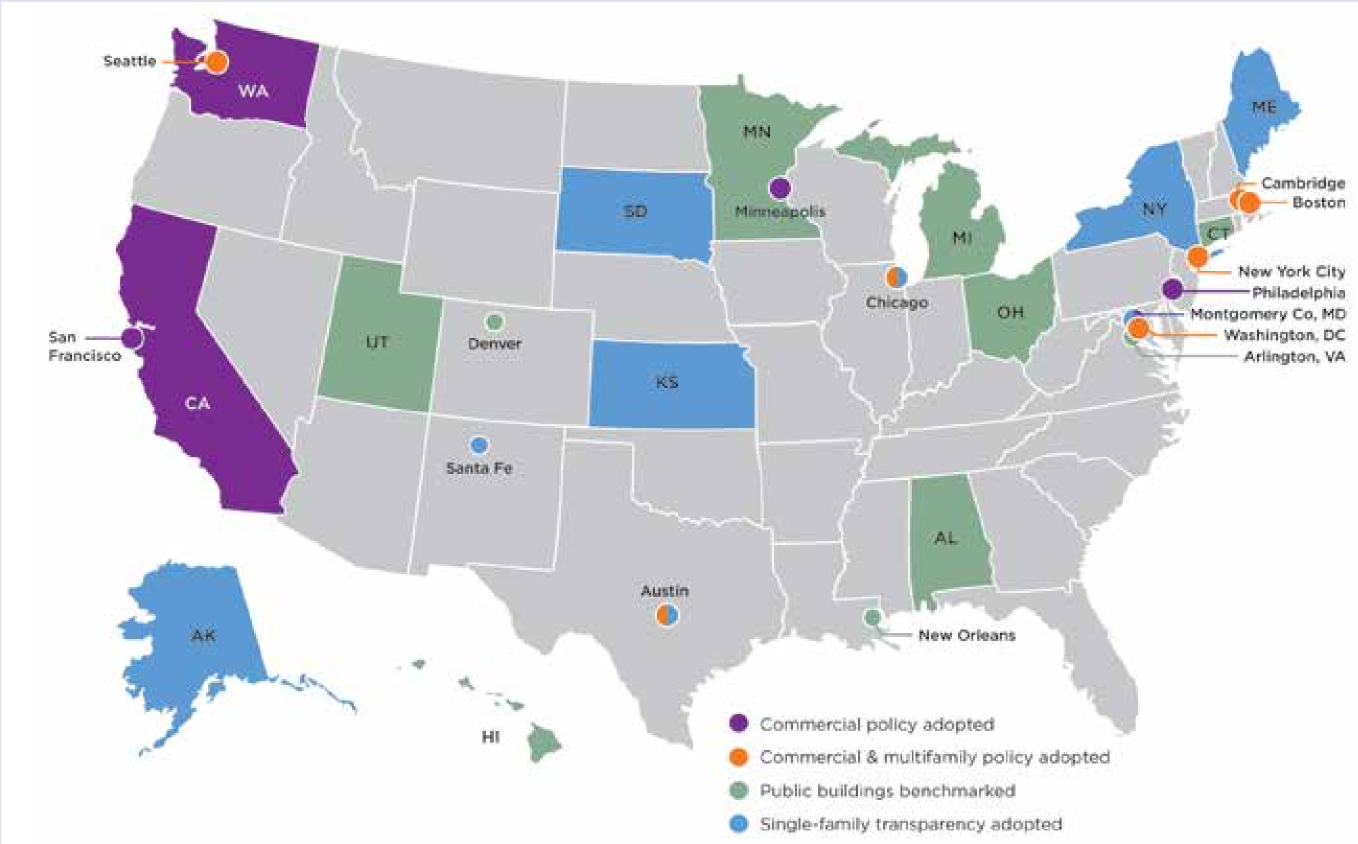
Other Mandatory Building Efficiency Policies

With respect to building energy use disclosure, a growing number of cities, counties, and states have adopted some form of benchmarking, auditing, or disclosure requirement, as depicted in Figure 15-5. Among them are some of the largest cities in the United States, including San Francisco, Boston, New York, Chicago, Austin, Seattle, Philadelphia, Minneapolis, and Washington, DC. The laws vary as to size and type of buildings affected, and whether the energy use data must be disclosed publicly or just to tenants or buyers, among other features. Mandatory benchmarking can help drive builders, owners, and tenants to make better decisions about energy consumption.

25 See: http://www.energycodes.gov/adoption/states

Figure 15-5

US Building Benchmarking and Transparency Policies[26]



4. Greenhouse Gas Emissions Reductions

As explained in Chapter 11, the magnitude of emissions reductions attributable to energy efficiency measures depends first and foremost on the amount of energy that was (or will be) saved. However, the emissions reductions that result from those energy savings also depend on when energy was (or will be) saved, and which marginal electric generating units (EGUs) reduced (or will reduce) their output at those times.[27] Over the longer term, the more significant impact of energy efficiency programs and policies is that they can defer or avoid the deployment of new EGUs. The avoided emissions over that longer term will thus depend not so much on the characteristics of existing EGUs, but on the costs and development potential for new EGUs.[28]

In either the near term or the longer term, greenhouse gas (GHG) emissions reductions are proportional to energy savings, but not necessarily on a one-to-one basis (i.e., a

26 See: http://www.buildingrating.org/file/1538/download

27 For example, the average CO_2 emissions rate from natural gas power generation in the United States is about 1100 lb per MWh, whereas the average emissions rate from coal power plants is twice as much as this rate. See: http://www.epa.gov/cleanenergy/energy-and-you/affect/air-emissions.html

28 The fact that energy efficiency programs can defer the need for new generating capacity means that they can also potentially extend the life of existing EGUs. New EGUs will tend to be lower emitting than the existing EGUs most prone to retirement, and the developers of new EGUs often size the units not only to meet load growth but also to replace an existing EGU. For example, they might develop a 200-MW EGU in anticipation of 150 MW of load growth, and thus some of the existing EGUs would run less or might choose to retire. Air regulators should be cognizant of this possibility, but not view it as a certainty or as an argument against using energy efficiency to reduce emissions. Older, less efficient, higher emitting EGUs will generally be dispatched less often (not more often) as a result of demand reductions, and the economic pressures that lead to a retirement decision will generally arise sooner (rather than later) as a result of energy efficiency programs.

one-percent reduction in energy consumption could reduce emissions by more or less than one percent, depending on how the emissions rates of the marginal or deferred EGUs compare to the system average emissions rates). Chapter 11 describes three methods for quantifying the short-term emissions impacts of energy efficiency programs: the average emissions method, the marginal emissions method, and the dispatch modeling method. Over a longer time period, the emissions rates of new natural gas-fired EGUs may represent a better proxy for avoided emissions.

The diurnal and seasonal "shape" of energy efficiency savings from building energy efficiency policies generally mirrors the usage patterns of the heating, cooling, and lighting loads of buildings. Because these loads are largely daytime and peak-centric, the savings are also peak-oriented. Because EGUs used to meet peak loads generally have higher than average emissions rates, the emissions reductions from efficiency improvements are likely to be above average (either reducing the use of existing peaking power plants, or avoiding the need for construction of new peaking power plants).[29]

Building Energy Codes

The Northwest Power and Conservation Council estimates that building energy codes have provided as much as 25 percent of cumulative energy savings from state energy efficiency policies in its region (Idaho, Montana, Oregon, and Washington) over the last decade.[30] Other studies suggest a range of 13 to 18 percent of achievable efficiency savings may be attributable to building codes.[31]

The difference between energy use in buildings under the IECC 2015 code and that under the 2006 code is approximately a 30-percent reduction. Because many jurisdictions have only adopted the 2006 IECC, upgrading to IECC 2015 is a very real energy savings opportunity with demonstrated cost-effectiveness. Therefore, adoption, implementation, and enforcement of the current energy code can be expected to reduce GHG emissions associated with new buildings by a similar percentage. Given a one- to two-percent rate of new building deployment (as a percentage of the existing building stock), this code upgrade alone could produce an 8- to 15-percent reduction in emissions associated with buildings, or a four- to eight-percent reduction in total emissions.

Going beyond the current code, to ZNE levels, could eliminate substantially all incremental GHG emissions from new buildings. California is expected to adopt such codes. If it does so, all new residential construction in California is expected to be ZNE by 2020 and new commercial construction is expected to be ZNE by 2030.[32]

In a GHG Abatement Measures document published with the 111(d) proposal, the EPA cites two national studies of energy efficiency potential that compared the relative opportunities provided by ratepayer-funded energy efficiency programs (i.e., those described in Chapter 11) and by building energy codes. The results of those two studies are summarized in Table 15-2.[33]

Table 15-2

Relative Savings Potential of Different Energy Efficiency Policy Options

Study	Year	Energy Efficiency Programs	Building Codes	Other
ACEEE	2030	77%	13%	10%
Georgia Tech	2035	82%	18%	0%

29 Evidence for this assertion can be found in data from the US EPA's eGRID database at: http://www.epa.gov/cleanenergy/energy-resources/egrid/. Non-baseload generators emit at levels about 25 percent higher than the average for all generation, nationally. The phenomenon of higher-than-average non-baseload emissions rates holds true in most regions of the country, with only a few exceptions.

30 The Sixth Northwest Electric Power and Conservation Plan (Council Document 2010-09), Northwest Power and Conservation Council. (2010, February). Available at: http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf, cited in EPA GHG Abatement Measures Technical Support Document (Docket ID No. EPA-HQ-OAR-2013-0602), p. 5-10.

31 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602, p. 5-11. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures

32 California Energy Efficiency Strategic Plan, Zero Net Energy Action Plan: Commercial Building Sector 2010-2012. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/6C2310FE-AFE0-48E4-AF03-530A99D28FCE/0/ZNEActionPlanFINAL83110.pdf

33 See: Supra footnote 31 at pp. 5-10 and 5-11.

One issue to consider is how to measure energy savings and emissions reductions from codes, given the possibility of lax enforcement. One approach is to assume compliance with the most current code update, and credit energy savings and emissions reductions only for demonstrated "beyond code" measures achieved under state, local, or utility programs. Although this is not an accurate reflection of savings from codes, it avoids giving "credit" where energy waste results from lax implementation. Another approach is to measure typical performance nationally, and recognize any "above average" achievement as a code-related credit; this more accurately measures the savings, but may be viewed as rewarding compliance with a mandatory obligation.

Other Mandatory Building Efficiency Policies

An analysis by the EPA of 35,000 benchmarked buildings found that those buildings reduced consumption by an average of seven percent over three years.[34] A report commissioned by the California Public Utilities Commission found that benchmarking strongly correlated with building energy improvements and management actions, and was a strong catalyst for customer participation in utility rebate and incentive programs.[35] In addition, work by the Institute for Market Transformation on markets with existing benchmarking laws found that local businesses were experiencing significant new demand for energy efficiency services.

5. Co-Benefits

The implementation and enforcement of building codes can be expected to produce significant co-benefits, similar to those produced by other energy efficiency policies. In addition to the CO_2 emissions reductions noted previously, building codes are likely to result in reduced emissions of other regulated air pollutants associated not only with electricity production but also with the operation of heating, ventilation, and air conditioning, and other building systems (e.g., water supply and treatment). The magnitude of the air emissions co-benefits depends on the same factors that were discussed with respect to GHG emissions reductions.

The full range of co-benefits for society and the utility system that can be realized through building codes is summarized in Table 15-3.[36] Although not shown in

Table 15-3

Types of Co-Benefits Potentially Associated with Building Energy Codes

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Demand Response-Induced Price Effect	Yes
Other	Yes

34 Institute for Market Transformation. (2012). EPA Analysis Shows Big Benchmarking Savings [Press release]. Available at: http://www.imt.org/news/the-current/epa-analysis-shows-big-benchmarking-savings

35 NMR Group, Inc. (2012, April). *Statewide Benchmarking Process Evaluation. Volume 1: Report.* Available at: http://www.calmac.org/publications/Statewide_Benchmarking_Process_Evaluation_Report_CPU0055.pdf

36 For a detailed discussion of energy efficiency benefits, see: Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6739

Table 15-3, building codes can also produce substantial benefits for the owners and occupants of efficient buildings, including reduced future energy bills, other resource savings (e.g., septic, well pumping), reduced operations and maintenance costs, increased employee productivity, higher property values, and more comfortable indoor environments. Low-income consumers may see additional benefits unique to their circumstances.

6. Costs and Cost-Effectiveness

Energy codes are among the most cost-effective sources of energy efficiency for many reasons. First, it is intuitive that the time of design and construction is the most economical time to install energy efficiency measures. Retrofit of state-of-the-art measures into existing buildings is more difficult and expensive, and often impossible. Second, measures installed as part of new construction are typically financed as part of building mortgages, which provide long-term, low-cost interest rates. In 2013, the Institute for Market Transformation found that every dollar spent on code compliance and enforcement efforts returns six dollars in energy savings, an impressive 600-percent return on investment.[37]

More recently, studies of ZNE costs and cost-effectiveness suggest that ZNE may become a cost-effective option for new construction. According to the California Zero Net Energy Buildings Cost Study, research and interviews already reveal "examples where commercial buildings achieved ZNE (or near-ZNE) status at little or no additional cost."[38]

The International Codes Council, developers of the IECC, studies the cost-effectiveness of proposed measures in each of the Council's code cycles. Focusing on consumer cost-effectiveness, they ask the question, "Does the building owner pay less, on a present value basis, over the life of the building for energy efficiency investments plus energy?" They do not consider other societal impacts, such as emissions, health, energy security, or other aspects of energy savings that also add value to energy efficiency.

It is important to appreciate the cost-effectiveness of building codes and the efficiency investment that code adoption can create. If buildings are not designed and constructed to be energy efficient initially, it is far more difficult and expensive to retrofit them to be energy efficient later. Inefficient new buildings represent "lost opportunities," because some energy savings can only be captured at the time of construction. Adding insulation and replacing windows is possible (but more expensive) and both are limited by the design of the structure. One recent study by the Pacific Northwest National Laboratory indicated that energy savings from business-as-usual implementation of building technologies would result in energy consumption levels that are 6.9 percent lower than the Reference Case by 2025. But in a scenario in which a greater effort is made to avoid "lost opportunities" in new buildings, primary energy consumption would be 17.8 percent lower than the Reference Case in 2025. Total primary energy savings are estimated to be 8.5 quadrillion BTU (QBTU) by 2025 in this more aggressive building efficiency scenario. In perspective, 8.5 QBTU is about equal to the total primary energy consumed by the state of California annually. The results of this study are summarized in Figure 15-6.[39]

Replacing lighting, heating, and cooling equipment is also possible, but more expensive and similarly constrained by design. The incremental cost of incorporating high-efficiency equipment during construction is relatively small, however – and often zero or negative. For example, improving building shell performance adds to the construction cost, but often enables installation of a smaller heating and cooling system, providing offsetting capital cost savings and space savings. Research by the Pacific Northwest National Laboratory published in 2008 found that there were limited data on the actual incremental costs of efficient building construction, but the data that were available indicated that in most cases, the cost premium for a building that achieved 30- to 50-percent energy savings

37 Stellberg, S. (2013, February). *Assessment of Energy Efficiency Achievable from Improved Compliance with US Building Energy Codes: 2013-2030.* Institute for Market Transformation. p.4. Available at: http://www.imt.org/uploads/resources/files/IMT_Report_Code_Compliance_Savings_Potential.pdf, citing to Institute for Market Transformation. (2010). *Policy Maker Fact Sheet Building Energy Code Compliance.*

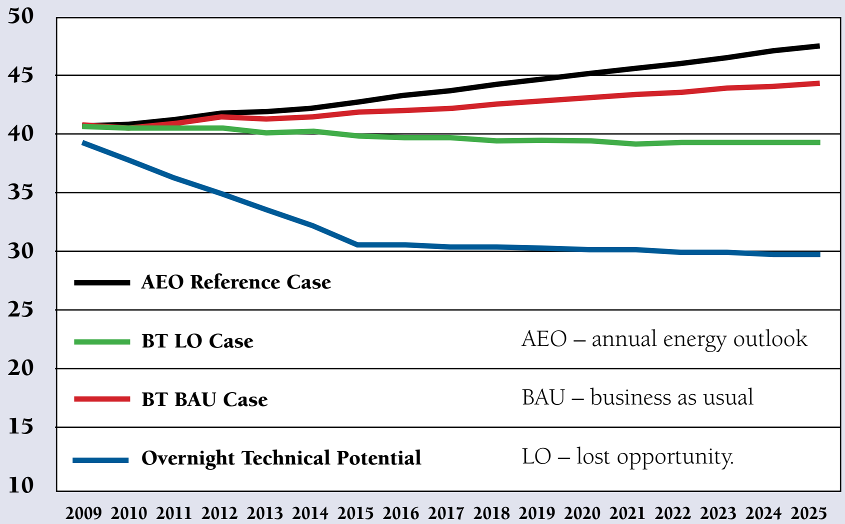
38 *California Zero Net Energy Buildings Cost Study.* Pacific Gas and Electric Company Zero Net Energy Program. (2012, December). p. 3. Available at: http://www.cpuc.ca.gov/NR/rdonlyres/2CDD0FB7-E871-47C0-97D0-A511F5683B57/0/PGECAZNECostStudy.pdf

39 Pacific Northwest National Laboratory. (2008, September). *Lost Opportunities in the Buildings Sector: Energy-Efficiency Analysis.* Available at: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17623.pdf

Figure 15-6

Potential Lost Opportunity Savings[40]

Integrated Commercial+Residential Energy Consumption (QBTU, Primary)



Technical potential shown does not include the effect of overnight saturation of PV in the residential sector. See text for further discussion. Note also the Y-axis is truncated for display purposes.

when compared to a building built to ASHRAE Standard 90.1-2004 was less than four percent of total construction costs.[41] For this reason, building codes are sometimes referred to as "lost-opportunity" measures. This means that they prevent "lost opportunities" to reduce energy consumption after the fact.

7. Other Considerations

Some early efforts at building energy efficiency resulted in moisture buildup in buildings, mold, and other adverse impacts. In some cases, this led to structural damage and adverse health impacts, both of which required expensive remedies.[42]

The most current energy codes address this issue through a combination of materials specification, design requirements, and ventilation measures. This is one reason it is essential that the most current energy codes be adopted and enforced. Jurisdictions that choose to enforce prior energy codes rather than first upgrading them may not receive the benefit of improved or corrective materials, design, and techniques learned from earlier experience. As a result, they may put their constituents who build or acquire buildings at unnecessary health and financial risk.

The ZNE standards under consideration in California only require that a building produce enough energy to offset its consumption over a year. Hour-to-hour operation of buildings that produce power, however, may result in substantial export of power to the grid at certain times and substantial import of power from the grid at other times. Therefore, the achievement of ZNE goals in any jurisdiction depends heavily on grid operators having sufficient flexibility in the dispatch of storage and renewable resources in order to be able to actually accept surplus power *from* buildings (generally at mid day and on weekends), and to deliver renewable energy to those buildings during hours when their onsite energy demands exceed their ability to self-generate. This balancing effort is an important grid issue addressed in Chapters 20 and 23, and an important reason that utility involvement in energy code development and enforcement is important.

Thermal Storage Capacity

Air conditioning and water heating loads occur primarily during periods of high electricity use and are both candidates for thermal energy storage technologies that allow these loads to be served with intermittent renewable energy (wind and solar) or with off-peak excess generation from more efficient generating plants.[43]

Currently, the ASHRAE and IECC model codes do not

40 Supra footnote 39.

41 Hunt, W. (2008, May). *Literature Review of Data on the Incremental Costs to Design and Build Low-Energy Buildings.* Pacific Northwest National Laboratory. Available at: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17502.pdf

42 Meres, R., & Makela, E. (2013, July). *Building Energy Codes: Creating Safe, Resilient, and Energy-Efficient Homes.* p. 11. Institute for Market Transformation & Britt/Makela Group, Inc. Available at: http://www.imt.org/uploads/resources/files/non-energy_benefits_of_energy_codes_report.pdf

43 In some regions, the incremental resources dispatched to serve off-peak loads may be more polluting coal units; in other regions, these loads may be served with wind, solar, or combined-cycle gas generation with low emissions.

require thermal storage within new buildings. Thermal storage (in the form of hot water, chilled water, or ice) can enable buildings to receive power at times when the incremental electricity supply resource is a lower cost and/or lower emitting generating unit, and deliver the desired end-use when it is needed.

Thermal storage resources can be as simple as residential electric water heaters controlled by a central utility dispatch system so that they heat water when low-cost/low-emission resources are available, and store that hot water for later use.[44] More sophisticated chilled water and ice storage systems can be added to commercial cooling systems.[45]

Use of thermal storage can enable a utility system to better manage the variable production of wind, solar, and other intermittent generating resources more easily, enabling a higher level of renewable energy production (refer to Chapter 20 for more information on this challenge). Although the storage systems may not save significant kilowatt-hours, the economic and environmental benefits can be significant.

Augmenting the model building energy codes with requirements for thermal energy storage may be one way for states to integrate more variable renewable generators and significantly reduce electric system emissions.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on building codes.

- International Codes Council: Association of code officials that develops model codes for energy efficiency, as well as structural, fire, and other building attributes. (www.iccsafe.org)
- American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE): Association of energy professionals that develops model code for commercial building energy efficiency. (www.ashrae.org)
- New Buildings Institute: Non-profit organization dedicated to advancing the state of the science in new building design, construction, and equipment. (www.newbuildings.org)
- Energycodes.gov: Website operated by the US Department of Energy on the status of building code activity for each state.
- State and Local Energy Efficiency Action Network (SEE Action): Website operated by the US Department of Energy on innovative energy efficiency strategies being pursued by state and local entities. (https://www4.eere.energy.gov/seeaction/topic-category/commercial-and-public-building-energy-efficiency)
- Building Codes Assistance Project (BCAP): BCAP was founded as a joint initiative of the Alliance to Save Energy, the Natural Resources Defense Council, and the American Council for an Energy-Efficient Economy. BCAP hosts an Online Code Environment and Advocacy Network (OCEAN). (http://energycodesocean.org)

9. Summary

About half of US energy consumption is in buildings, and much of this is consumed in the heating, cooling, and lighting of those buildings, all aspects that are addressed by building energy codes. Modern energy efficiency codes can reduce building energy use dramatically; the most recent national code would reduce usage by about 30 percent below conventional building standards. Innovative "Zero Net Energy" codes can reduce net building use to zero.

Three key steps are necessary to achieve such savings:

- States and local governments must adopt current codes, such as the 2015 IECC and ASHRAE 90.1;
- Architects, engineers, builders, and local government building officials must be trained to successfully design, build, and inspect new buildings to ensure that they realize potential energy savings; and
- Local building officials must assertively enforce the codes.

44 Steffes Corp. (2013). *Grid-Interactive Renewable Water Heating*. Available at: www.steffes.com/LiteratureRetrieve.aspx?ID=72241

45 Calmac Corp. (2014). *Frequently Asked Questions About Thermal Energy Storage*. Available at: http://www.calmac.com/frequently-asked-energy-storage-questions

16. Increase Clean Energy Procurement Requirements

1. Profile

Increasing the proportion of clean energy resources (i.e., zero- and low-emission technologies) in the electricity supply portfolio is among the most promising ways to reduce carbon emissions from the levels currently produced by a fossil-fuel–heavy portfolio.[1] The technical potential for renewable technologies is considerable, especially for wind and solar, exceeding existing electric demand by orders of magnitude, and far exceeding all other categories of clean energy resources. Chapter 6 focused on the inherent potential of these technologies to reduce greenhouse gases (GHGs) and other air pollutant emissions, and the costs and cost-effectiveness of the technologies themselves. Chapter 6 also considered public policies that can reduce the costs of these technologies.

In this chapter, we focus on a different set of public policy measures that may be used to accelerate deployment of clean energy technologies at a large "utility" scale. Specifically, this chapter focuses on policies that mandate that electric utilities and competitive retail suppliers procure clean energy in specified amounts, or in a specified order of priority, or at specified prices.

In some jurisdictions, electricity is sold at retail by monopoly utilities that procure and deliver electricity to end users. These utilities are obligated to procure and deliver enough electricity to meet the demands of all paying customers within their service territory. In other locations, multiple retail suppliers compete for the right to sell energy to customers, and the monopoly utility's role is limited to *delivering* that energy over a transmission and distribution system. The concept of procurement is relevant in either model. When we speak of "procurement," what we mean is that the utility or retail supplier obtains wholesale energy from generating assets that they own, or through bilateral contracts with other utilities or "independent power producers" that own generating assets, or through purchases in an organized wholesale energy commodity market. The mix of assets procured by a utility or competitive supplier is its "portfolio."

Many states have adopted public policies that require utilities to procure clean energy in specified amounts, or give preference to clean energy procurements. Procurement requirements for utility-scale clean energy resources can be a cost-effective way to reduce carbon emissions. Some of the frameworks for promoting utility-scale projects through procurement requirements include renewable portfolio standards (RPS), clean energy standards, legislative targets for renewables, loading orders, emissions performance standards (EPS), and feed-in tariffs (FITs) (also referred to as standard offers).[2] Each of these frameworks is addressed in this chapter. Also featured in this chapter are various regulatory frameworks that can be used as a complement to procurement frameworks to help reduce barriers to participation by independent power producers. These include timely and well-formed interconnection policies.[3]

Several policies featured in this chapter have been particularly instrumental in moving emerging technologies forward and hold significant promise for air regulators exploring avenues to reduce power sector carbon dioxide (CO_2) emissions. In particular, electricity portfolio standards (i.e., RPS and clean energy standards) that apply to the purchasing requirements of utilities and competitive retail suppliers have a proven track record of strong results.

1 Energy efficiency, however, provides the most cost-effective path with the longest list of co-benefits for meeting energy portfolio requirements.

2 FITs are more often associated with the procurement of smaller distributed resources rather than utility-scale resources, and so are mentioned only briefly in this chapter but are discussed in more detail in Chapter 17.

3 Additional complementary policies that are necessary or helpful to integrate higher levels of renewable resources into the power system are addressed in Chapter 20.

2. Regulatory Backdrop

Under US law, the Federal Energy Regulatory Commission (FERC) has nearly exclusive jurisdiction and fairly broad authority to regulate *wholesale* electricity transactions. *Retail* energy transactions are generally the purview of state governments, with regulatory authority residing in a state public utility commission (PUC).[4] Procurement is an issue addressed under both federal and state laws.

Under federal law, specifically the Public Utility Regulatory Policy Act of 1978 (PURPA) and administrative rules promulgated by FERC, utilities must offer to purchase electric energy from most "qualifying small power production facilities" (80-megawatt [MW] capacity or less) and "qualifying cogeneration facilities" at rates that are just and reasonable to the utility's customers and in the public interest, and nondiscriminatory toward qualifying facilities. There are limited exceptions to this federal purchase obligation. FERC does not, however, decide what those "just and reasonable" rates should be. That authority remains in the hands of states, but with one important limitation. State regulators may not require utilities to offer to purchase energy at rates in excess of the utility's "avoided costs." The net effect of this federal law is that utilities have an obligation to *offer* to procure clean energy from most qualifying facilities, but they do not have to offer a price that is above what it would otherwise cost the utility to produce or procure that clean energy from other sources.[5]

The development of independent power projects, largely in the form of hydroelectric, biomass, and natural gas cogeneration (a.k.a. combined heat and power) projects, was impacted significantly by PURPA. Non-utility generation stimulated by PURPA was responsible for 6.7 percent of total generation in the United States by 1995, much of which was from smaller hydro and biomass projects.[6] But despite the concerted efforts of Congress and the federal government to foster more deployment of hydro, and to a lesser degree biomass, the total contribution of these resources to the national electricity portfolio remains modest and stable to this day (at roughly 8.2 percent) with only limited prospects for growth.[7]

In contrast, emerging technologies like wind and solar generation are seeing rapid growth with considerable potential for further expansion looking forward. Estimates of the central policy case or reference case scenarios from both the International Energy Agency and the US Energy Information Administration show increasing potential with the passage of time with respect to these technologies. The policy frameworks designed to spur these technologies are working and have largely focused on state-regulated procurement strategies.

State procurement requirements tend to be very different from the PURPA purchase obligation in scope and structure. To begin with, states have the legal authority to impose portfolio requirements on utilities and retail suppliers that mandate procurement of specified amounts or types of clean energy. States can also impose requirements on utilities to conduct long-term resource planning, including energy procurement plans.[8]

States have enacted a variety of procurement policy frameworks in statutes and regulations to spur the acquisition of lower-carbon resources. These frameworks include portfolio requirements, loading order requirements, emissions performance standards, dedicated funds for clean energy procurement, performance-based incentives for clean energy, and interconnection rules. Even in states that lack these mandatory requirements, regulators can have an indirect impact on clean resource procurement by imputing a carbon value into the evaluation of alternatives in the planning and procurement phase of resource acquisition. Another option is to facilitate the procurement of clean energy by utilities or competitive retail suppliers

4 For a more detailed and nuanced discussion of this complicated subject, refer to: The Regulatory Assistance Project. (2011, March). *Electricity Regulation in the US.* Available at: http://www.raponline.org/document/download/id/645.

5 The impact of PURPA and the federal purchase obligation is more pronounced for distributed generators and less important for utility-scale procurement. For that reason, the topic is covered in more detail in Chapter 17.

6 Refer to: Hirsh, R. (1999). *Power Loss: The Origins of Deregulation and Restructuring in the American Electric Utility Industry*. Figure 6.8, p. 116. Also refer to electricity net generation data published by the US Energy Information Administration at: http://www.eia.gov/electricity/data.cfm#generation.

7 Hydro still accounts for only approximately 7 percent of generation and biomass only 1.4 percent, with biomass seeing little growth in recent decades.

8 Broader utility planning frameworks like integrated resource planning can be used to promote lower-cost, low-carbon technologies over the long term, without clean energy procurement policies in place or as a complement to those policies. Integrated resource planning is the subject of Chapter 22.

on behalf of customers who voluntarily agree to pay a higher "green price" to purchase renewable energy (RE). This can be accomplished by approving "green price" tariffs proposed by utilities, allowing competitive suppliers to offer "green price" products, and allowing large customers or aggregations of customers to buy energy directly from renewable generators.

Portfolio Requirements

Electricity portfolio standards are by far the most common formulation for a state procurement requirement. In most cases, these standards are expressed as a requirement that regulated utilities or retail suppliers procure a specified percentage of the retail energy they sell to end-use consumers from qualifying resources in a given calendar year. Market forces can then operate to enable development of the more economic resources to meet the standard. So, for example, a utility might be required to procure 20 percent of retail energy from qualifying resources in the year 2020. A few states have procurement requirements that are expressed not as a percentage of retail sales but as a total installed capacity requirement, for example 1100 MW by 2015. Most states limit the qualifying resources to renewable resources, and thus the policies are referred to as Renewable Portfolio Standards or RPS policies. Some states have extended the framework of qualifying resources to include other technologies, including nuclear, "clean coal," and natural gas generation. Where the list of qualifying resources includes non-renewable resources, the policies are sometimes referred to as Clean Energy Standards, Alternative Energy Standards, and so on.[9] But for the purposes of simplicity, all RPS and Clean Energy Standards policies will be described as RPS policies for the remainder of this chapter.

Portfolio requirements are typically established first in state law (with the broad legal mandates established in state law, and the finer details of implementation left for the utility regulator). States like Arizona have also established such requirements through PUC-level regulation. Federal RPS requirements have been featured in numerous bills introduced in the US Congress over the past decade, but no such requirements have ever been enacted.

Most state policies rely on renewable energy credit (REC) systems that enable trading of credits among regulated entities. Each REC represents one megawatt-hour (MWh) of qualifying generation.[10] Tracking systems keep track of the creation and disposition of RECs. Regulated utilities and retail suppliers are generally allowed to purchase, trade, and bank RECs, and they demonstrate compliance with state requirements by retiring RECs.[11] Some states also allow regulated entities to comply by making alternative compliance payments in lieu of retiring RECs. Compliance with state electricity portfolio standards is normally monitored and enforced by state PUCs or state energy offices.

In the Clean Power Plan emission guidelines that the Environmental Protection Agency (EPA) proposed on June 2, 2014 using its authority under section 111(d) of the Clean Air Act, the EPA determined that increasing generation from renewable resources is an adequately demonstrated and cost-effective measure for reducing power sector CO_2 emissions.[12] Although the proposed 111(d) regulation would not require states to include increased renewables in their compliance plans, the emissions targets that the EPA proposed for each state are based on assumed levels of RE deployment that could be achieved in each state. The levels assumed by the EPA for each state are based on the average requirements of state RPS policies in different geographic regions of the country. In a technical support

9 These states include Michigan, Ohio, Pennsylvania, and West Virginia. The first three propose a clean energy standard that operates in parallel to the RPS, whereas West Virginia's operates in lieu of an RPS. Refer to: Barbose, G. (2012, December). *Renewables Portfolio Standards in the United States: A Status Update.* Presented at 2012 National Summit on RPS, Washington D.C. Available at: http://www.cesa.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf.

10 Some states (e.g., Arizona) allow non-electric technologies such as solar hot water heating to earn RECs and contribute toward RPS compliance. Each state that does this has its own methods for converting a quantity of eligible non-electric energy into a number of RECs.

11 The trading of RECs enables markets to separate the "renewable" attributes of these resources from the flow of the electrons. The effect is to facilitate the liquid flow of these attributes in markets that ease the ability of obligated entities to meet requirements under a state RPS policy.

12 US Environmental Protection Agency. (2014, June). *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

document, the EPA asserts that "[t]hese state-level goals and requirements have been developed and implemented with technical assistance from state-level regulatory agencies and utility commissions such that they reflect expert assessments of RE technical and economic potential that can be cost-effectively developed for that state's electricity consumers… Because the EPA did not quantify potential that could be tapped through any [other RE] policy approaches, the agency believes that the RE targets derived from RPS mandates represent a conservative estimate of cost-effective generation that could actually be developed by states."[13]

Loading Order Requirements

A few states have adopted a "loading order" policy, generally through state legislation, that establishes a priority order for the different types of resources from which a utility or retail supplier might procure energy. The highest priority is generally assigned to energy efficiency, with second priority assigned to some or all forms of RE. Fossil generation tends to be the lowest priority. Loading order requirements are not dispatch order requirements – they don't dictate which power plants operate on an hourly or daily basis. Instead, loading order requirements focus on the decisions that are made when new resources are procured through a construction project or power purchase agreement. Loading order tends to be an investment guideline for state utilities and utility regulators. It should also be noted that loading order requirements are not absolute – costs are considered in such a way that the highest priority resource is not procured in every case.

Emissions Performance Standards

In September 2013, the US EPA released a proposed rule creating federal New Source Performance Standards (NSPS) limiting GHG emissions from new electric generating units (EGUs).[14] The proposed rule would set separate standards for certain natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and integrated gasification combined-cycle units. The emissions limits in these proposed standards range between 1000 and 1100 pounds of CO_2 per gross MWh. We include the proposed NSPS rule in this chapter because any federal rule that limits the emissions of new EGUs will also restrict the future energy procurement options of utilities and retail suppliers. The connection between these concepts becomes even more apparent when we consider state EPS.

Several states have already adopted an EPS policy that is similar to the proposed federal NSPS in form and scope, that is, a policy that establishes a maximum level of CO_2 emissions per unit of output from EGUs. However, there are significant differences between some EPS policies and the proposed NSPS rule. California, Washington, and Oregon have each adopted an EPS that applies to new and existing baseload generation for which electric utilities enter into long-term commitments. This would include not just new construction, as would be covered by the NSPS rule, but also long-term power purchase contracts. In other words, the EPS in these states regulates the procurement of energy.[15]

The EPA's proposed 111(d) emission guidelines for existing sources would also create an EPS, but in this case the EPS would apply to existing EGUs in each state. Because the standards are developed with an assumption that states can increase generation from clean energy resources, as previously noted, they would certainly provide an impetus for the procurement of new clean energy. However, unlike EPS policies for new resources, the 111(d) standards would not impose an emissions limit on individual EGUs but instead would impose a limit on the average emissions across all covered EGUs, with certain adjustments specified in the proposal. In other words, new resources could be added to the system that emit more than the state 111(d) goals, provided that the average emissions of all covered sources (with adjustments) meet the goals. This makes the 111(d)

13 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures.

14 The proposed rule was published in the Federal Register on January 8, 2014.

15 Massachusetts also enacted legislation calling for the promulgation of "rules and regulations to adopt and implement for fossil fuel-fired electric generation facilities uniform generation performance standards of emissions produced per unit of electrical output on a portfolio basis for any pollutant determined by the department of environmental protection to be of concern to public health, and produced in quantity by electric generation facilities." (Massachusetts General Laws, Chapter 111, Section 142N.) Such rules and regulations have yet to be implemented.

proposal significantly different from any of the existing state EPS policies.

Public Benefits Funds

About 20 states and the District of Columbia have some form of public benefits fund that is leveraged to foster the development of clean energy projects. Public benefits funds are typically supported through one or more of the following sources: a surcharge on retail utility bills; federal funding;[16] auction revenues from a GHG cap-and-trade program;[17] or an alternative compliance payment framework in conjunction with an RPS. The Clean Energy States Alliance reports that, since 1998, roughly $3.4 billion has been used from these funds to support the development of approximately 130,000 clean energy projects with a total capital investment of $16 billion.[18] Public benefits funding for clean energy development can be viewed as analogous to a mandatory procurement policy; a public benefit fund for clean energy requires ratepayer money to be invested to procure clean energy, energy efficiency, and associated research and development that may foster clean energy investment. However, much the same result could be achieved by simply requiring the utility to make clean energy investments and allow recovery of those investments as a matter of rate recovery, rather than separating the collection to pay for such investments in a directed way.

Performance-Based Incentives

In this chapter, we use the term "performance-based incentives" to refer to a variety of policies that simultaneously require utilities to procure clean energy and provide incentives to the generators for each kilowatt hour (kWh) generated. Although PURPA creates an obligation in most cases for utilities to offer to procure energy from qualifying facilities, PURPA rates are not incentive rates because the purchasing utility does not have to offer a price higher than its avoided costs (i.e., what it would cost to procure energy from an alternative source).[19] In contrast, FITs are an example of a performance-based incentive. Under a FIT policy, the utility is required to offer to purchase energy from specified clean energy sources at rates that include an incentive in the form of a higher price for each kWh than the utility's avoided costs.[20] The FIT concept is conceivably applicable to clean energy sources of all types and sizes, and thus is suitable for inclusion in this chapter. However, in the United States, nearly all examples of FIT policies to date have restricted the scope of the policy to small distributed generation sources. For this reason, the concept is mentioned briefly here but addressed in more detail in Chapter 17. Production tax credits are another form of performance-based incentive, but their primary impact is that they reduce the effective cost of the technology, and thus were addressed in Chapter 6. An RPS with an accompanying framework for trading RECs creates an associated premium for attributes of qualifying generation, and therefore could also be viewed as a performance-based incentive. However, for purposes of this discussion we treat RPS policies not as performance-based incentives but as a portfolio requirement. Green pricing schemes can also be viewed in a similar vein.

Interconnection Rules

FERC has authority to regulate the interconnection of generators to all transmission facilities that are subject to FERC jurisdiction. FERC has established separate rules and procedures for smaller generators (less than 20 MW)

16 Notably, the American Recovery and Reinvestment Act of 2009 provided $3.1 billion in State Energy Program grants.

17 The nine states currently participating in the Regional Greenhouse Gas Initiative use the funds generated from allowance auctions to support a variety of clean energy initiatives, including investments in energy efficiency and renewable projects. Refer to Chapter 24 for details.

18 Refer to the Clean Energy States Alliance website at: http://www.cesa.org/about-us/what-we-do/.

19 Although, as we note below, FERC has made provision for differentiating the costs of procuring energy from an alternative source by technology. The effect of this latitude is to allow for state consideration of cost differences above an undifferentiated avoided cost rate. In other words, if a state has an RPS policy, the cost of procuring RPS-eligible energy can be differentiated from the cost of procuring ineligible energy.

20 The establishment of a state FIT may, however, need to navigate the respective legal authorities reserved for states and FERC. In an October 21, 2010 Order, FERC provided clarification on how states can navigate the legal limits through the use of a multi-tiered, avoided cost designation that is consistent with PURPA. For a discussion and further clarification, see: Passera, L. (2010, October). *FERC Provides Clarification on Feed-In Tariff Options for States.* Interstate Renewable Energy Council. Available at: http://www.irecusa.org/2010/10/ferc-provides-clarification-on-feed-in-tariff-options-for-states/.

and larger generators (greater than 20 MW). Independent system operators (ISOs) and regional transmission organizations have also established comprehensive interconnection requirements to assure all aspects of the grid and the generator are adequately protected and uniformly treated consistent with FERC requirements. The FERC and ISO/regional transmission organizations procedures can potentially serve as models for states that wish to regulate interconnection to state-jurisdictional facilities, largely distribution and sub-transmission–level facilities. In addition, the Energy Policy Act of 2005 ensured that the IEEE 1547 standard would serve as the engineering standard for interconnecting distributed generation.[21] And finally, the Mid-Atlantic Distributed Resources Initiative has also developed model procedures for interconnecting small generators.[22] Forty-four states have now established some form of regulation over distributed generation. However, the applicability of existing state requirements varies on a size basis from state to state. The detailed requirements of interconnection procedures for larger generation among the states also varies. States that have not adopted interconnection regulations or that have substantial gaps between coverage of smaller generation and FERC jurisdictional facilities, can look to either the FERC model or to states with "best practices" such as Oregon, Virginia, Connecticut, Maine, and Massachusetts that are considered best practices among the states.[23]

3. State and Local Implementation Experiences

As shown in Figure 16-1, most regions of the United States are covered by RPS policies. Details on each state policy are available at www.dsireusa.org. Figure 16-1 clearly shows that the stringency of state requirements varies dramatically, from 10 percent requirements or goals in several states up to a 40-percent requirement in Hawaii. What is not evident from the figure is that states vary widely in terms of qualifying resources, whether all utilities and retail suppliers are regulated, and other details.

One noteworthy area of variation in state policies is the treatment of hydro projects. Almost all such projects predate the adoption of state RPS policies, and the policies – which are intended to spur new clean energy resource deployment – generally exclude existing large hydro projects from the list of qualifying resources. Large hydro projects have been incorporated in the definition of renewables in certain states as part of either an RPS goal (Vermont) or a mandatory RPS requirement (New York, Wisconsin, and Montana). This is relevant mostly because of the potential for imports from new, large hydro projects in Canada. The potential for hydro in the United States will likely be limited to community-based projects and expansion of preexisting dam projects; these smaller hydro resources qualify for compliance under many state RPS laws.

To date, only Ohio has included advanced nuclear energy as a qualifying resource in a clean energy standard. Still, the long lead times in development, combined with cost, concerns for safety, and uncertainty around disposal of spent fuel and high-level waste, may present formidable barriers going forward. Almost all nuclear power in the United States is generated from facilities that came on line between 1967 and 1990. Currently five nuclear projects are under construction in Tennessee, Georgia, and South Carolina, but plans for further development may be hindered by long lead-time requirements, challenges associated with permitting, and low wholesale costs resulting from competitive natural gas prices.[24]

Twenty-nine states and the District of Columbia have implemented an RPS, and RPS requirements have now

21 Refer to: Basso, T., & Friedman, N. (2003, November). *IEEE 1547 National Standard for Interconnecting Distributed Generation: How Could It Help My Facility?* National Renewable Energy Laboratory. NREL/JA-560-34875. Available at: http://www.nrel.gov/docs/fy04osti/34875.pdf. Also refer to Energy Policy Act of 2005 at Section 1254, available at: http://www.gpo.gov/fdsys/pkg/BILLS-109hr6enr/pdf/BILLS-109hr6enr.pdf.

22 Mid-Atlantic Distributed Resources Initiative. (2005, November). *MADRI Model Small Generator Interconnection Procedures.* Available at: http://sites.energetics.com/MADRI/pdfs/inter_modelsmallgen.pdf.

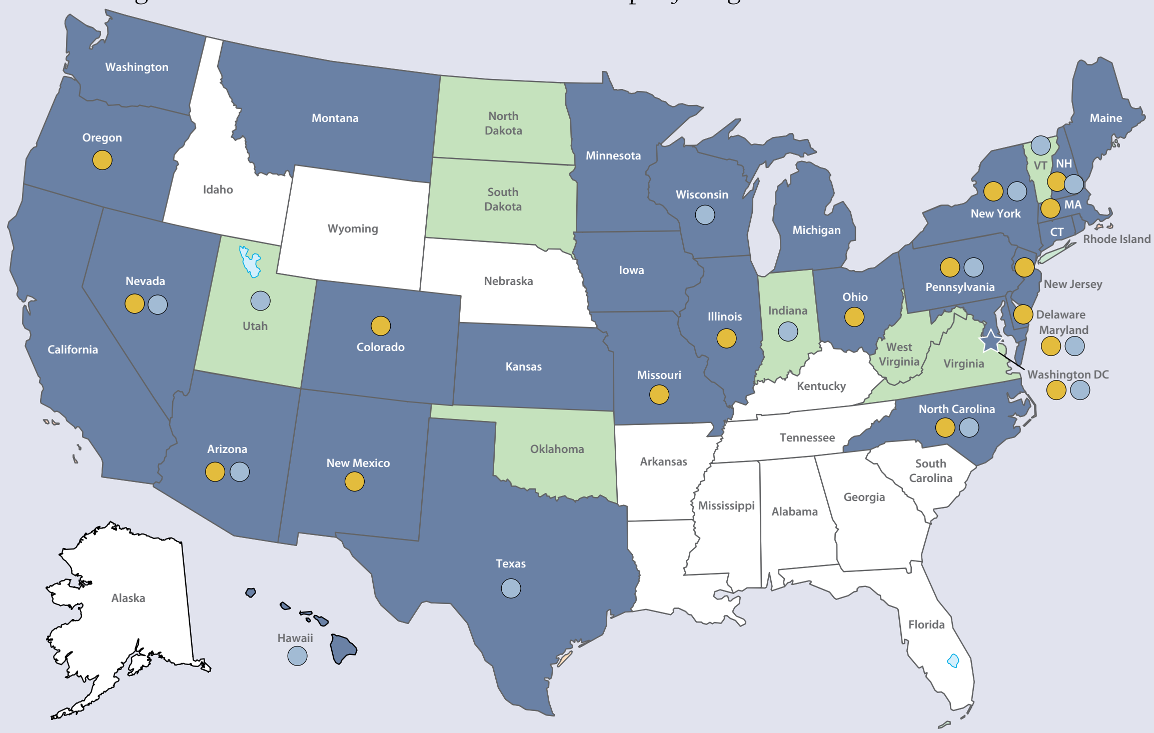
23 Sheaffer, P. (2011, September). *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues.* Montpelier, VT: The Regulatory Assistance Project, page 7. Available at: http://www.raponline.org/document/download/id/4572.

24 World Nuclear Association. (2014, July). *Nuclear Power in the USA.* Available at: http://www.world-nuclear.org/info/Country-Profiles/Countries-T-Z/USA--Nuclear-Power/.

Figure 16-1

States With RPS Policies[25]

29 states, Washington DC, and two US Territories have renewable portfolio standards. Eight states and two territories have renewable portfolio goals.



Renewable portfolio standard
Renewable portfolio goal
Solar water heating eligible
Minimum solar or customer-sited requirement
*** Extra credit for solar or customer-sited renewables**
† Includes non-renewable alternative resources

Arizona: 15% by 2025
California: 33% by 2020
Colorado: 30% by 2020 (IOUs), 10% by 2020 (co-ops and large munis)*
Connecticut: 27% by 2020
Delaware: 25% by 2026*
Hawaii: 40% by 2030
Illinois: 25% by 2025
Indiana: 10% by 2025†
Iowa: 105 MW
Kansas: 20% by 2020
Maine: 30% by 2000. New RE: 10% by 2017
Maryland: 20% by 2022
Massachusetts: 22.1% by 2020. New RE: 15% by 2020 (plus 1% annually thereafter)
Michigan: 10% and 1,100 MW by 2015*
Minnesota: 25% by 2025 (Xcel: 30% by 2020)
Missouri: 15% by 2021
Montana: 15% by 2015
Nevada: 25% by 2025*
New Hampshire: 24.8% by 2025
New Jersey: 20.38% RE by 2021 plus 4.1% solar by 2028
New Mexico: 20% by 2020 (IOUs), 10% by 2020 (co-ops)
New York: 29% by 2015
North Carolina: 12.5% by 2021 (IOUs), 10% by 2018 (co-ops and munis)
North Dakota: 10% by 2015
Ohio: 12.5% by 2024
Oklahoma: 15% by 2015
Oregon: 25% by 2025 (large utilities)* 5% - 10% by 2025 (smaller utilities)
Pennsylvania: ~18% by 2021†
Rhode Island: 16% by 2020
South Dakota: 10% by 2015
Texas: 5,880 MW by 2015*
Utah: 20% by 2025*
Vermont: 1.) RE meets any increase in retail sales by 2012; 2.) 20% RE and CHP by 2017
Virginia: 15% by 2025*
Washington: 15% by 2020*
Washington DC: 20% by 2020
West Virginia: 25% by 2025*†
Wisconsin: varies by utility; ~10% by 2015 statewide

US Territories:
Northern Mariana Islands: 80% by 2015
Puerto Rico: 20% by 2035
Guam: 25% by 2035 (goal)
US Virgin Islands: 30% by 2025 (goal)

been in place for more than five years in 22 states. More than half of all retail sales in the United States are made by a utility or retail supplier subject to an RPS requirement.[26] Figure 16-2 shows the pattern of commitments to this policy approach that has evolved with time. As the figure shows, most of the states that committed to an RPS policy eventually revised the policy, usually because early successes revealed that more ambitious requirements could be imposed without significant additional costs or system performance problems.

RPS data compiled by the Lawrence Berkeley National Laboratory (LBNL) and others offer strong evidence that RPS requirements are in fact a primary driver for renewable resource deployment. To date, states with RPS policies

25 North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

26 Supra footnote 9.

Figure 16-2

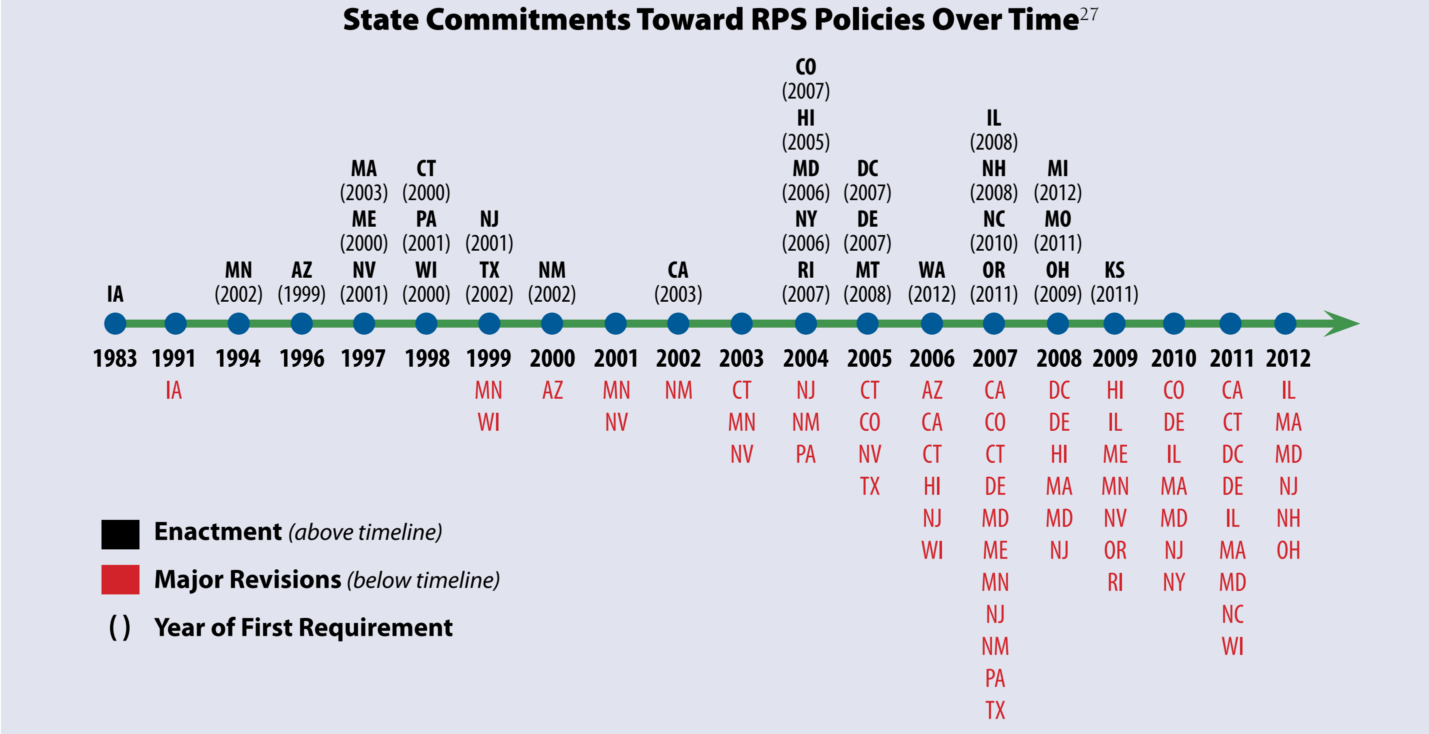
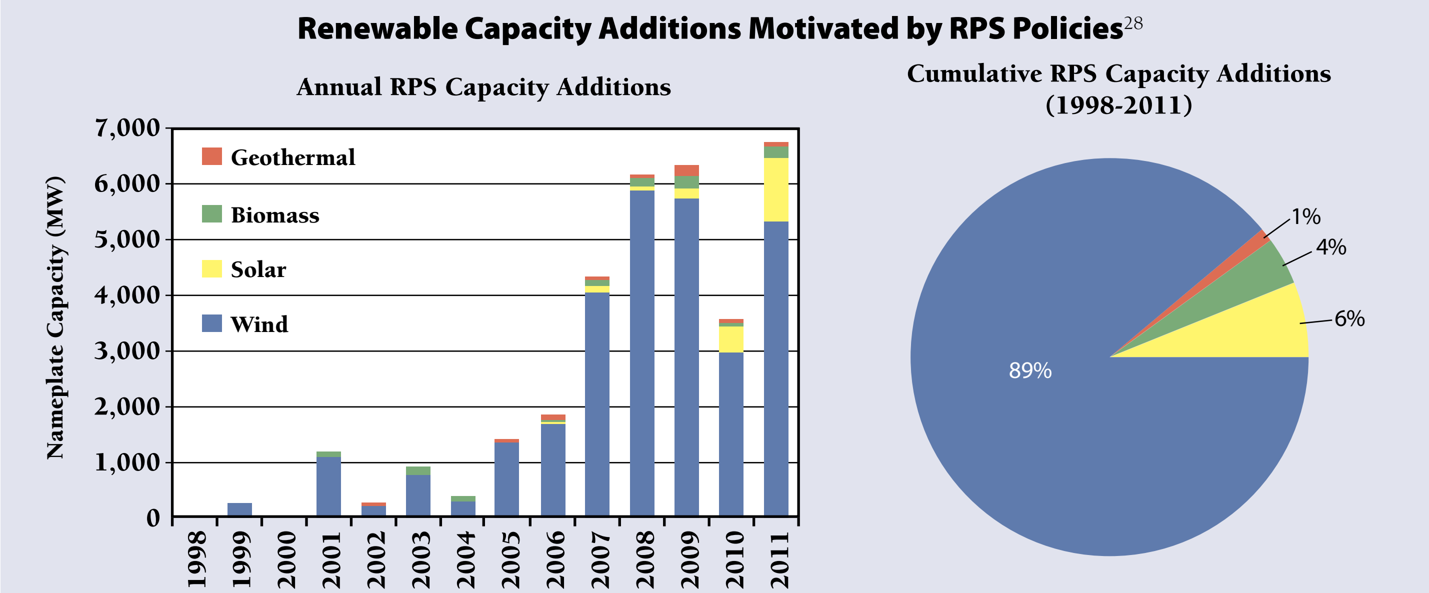


Figure 16-3

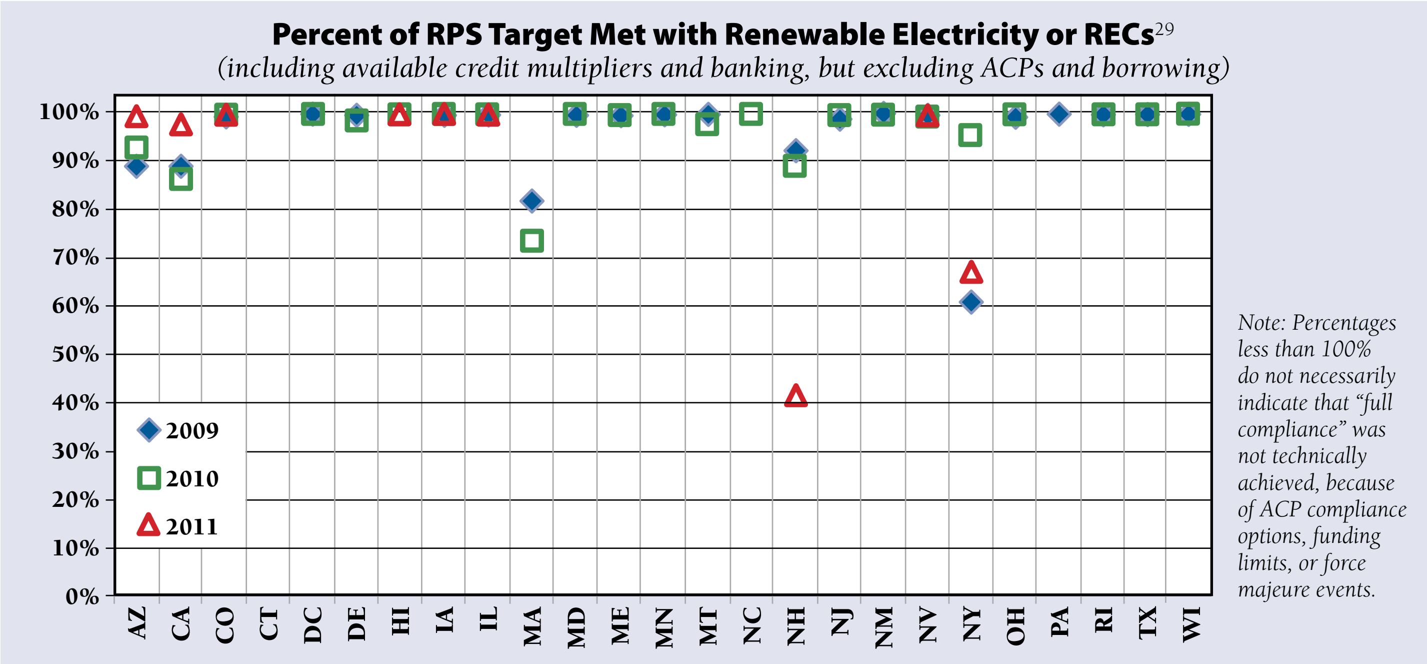


Renewable additions are counted as "RPS-motivated" if and only if they are located in a state with an RPS policy and commercial operation began no more than one year before the first year of RPS compliance obligations in that state. On an energy (as opposed to capacity) basis, wind energy represents approximately 86%, biomass 8%, geothermal 3%, and solar 3% of cumulative RPS-motivated renewable energy additions from 1998-2011, if estimated based on assumed capacity factors.

27 Supra footnote 9.

28 Ibid.

Figure 16-4



are credited with the addition of 46,000 MW of new renewable generation.[30] Between 1998 and 2011, most of the renewable capacity additions in the United States (63 percent) occurred in states with an RPS.[31] Figure 16-3 summarizes the amount of renewable capacity additions that were motivated by state RPS policies, as determined by LBNL.

Experience to date also indicates very high levels of compliance with state RPS policies, as summarized in Figure 16-4.

As noted earlier, RPS policies are not the only means of influencing RE procurement. EPS policies, or similar policies that create incentives for utilities to procure energy from better-performing generating units, have been adopted in six states. In California, Oregon, and Washington, the EPS policy specifies emissions limits applicable to the construction of new power plants and to procurement of

Colorado – Renewable Portfolio Standards

In 2004, Colorado became the first state to adopt an RPS via ballot initiative. The standard initially applied only to the state's investor-owned utilities, but was extended to cover electric cooperatives in March of 2007. At that juncture, the state also expanded the range of eligible renewable technologies consistent with the standard. Further modifications and expansion of the program took place in 2013. Each successive action to update and expand the goals has been the result of changes to state statutes. The yearly RPS schedule for investor-owned utilities is currently as follows:

- 3 percent of retail sales procured from eligible renewable resources for the year 2007;
- 5 percent for the years 2008 to 2010;
- 12 percent for the years 2011 to 2014;
- 20 percent for the years 2015 to 2019; and
- 30 percent for the year 2020 and thereafter.[32]

The RPS requirements established a different schedule for electric cooperatives and municipal utilities. Separate procurement requirements were established specifically for distributed generation.

Special multipliers were established for solar projects, community-based projects, in-state generation, and projects implemented prior to 2014 such that more than one REC is awarded per MWh of generation from those resources.

RECs can be applied to meet the standard.

29 Supra footnote 9. "ACP" refers to alternative compliance payments used for compliance in lieu of renewable electricity or RECs.

30 Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K., & Wiser, R. (2014, May). *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards.* National Renewable Energy Laboratory and LBNL. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6589e.pdf.

31 Supra footnote 9.

32 Supra footnote 25.

energy from existing power plants. Illinois, Montana, and New Mexico have policies that don't include emissions limits but instead create requirements or incentives for utilities to procure energy from new, coal-fired power plants with carbon capture and storage capabilities.[33]

Another approach that has been useful in stimulating investment in renewables is to address the initial costs of adding transmission capacity to facilitate the integration of new generating capacity. Transmissions enhancement costs may serve as a barrier to individual renewable generation projects, if the first new project that requires an enhancement is expected to pay for the enhancement. On the other hand, transmission enhancements can be an enabler of multiple renewable generation projects if they can be done cost-effectively and as part of a plan to connect resource-rich areas to customers. In 2005, Texas passed a law requiring a minimum installation of renewable generating capacity of 5880 MW by 2015 through the establishment of Competitive Renewable Energy Zones (CREZ). (California implemented a similar initiative in 2007.) The Texas law also required that the Public Utilities Commission of Texas designate CREZ throughout the state and develop a plan to construct transmission capacity necessary to deliver the output from RE technologies in the CREZ. The Electric Reliability Council of Texas, the state's market and grid operator, released a CREZ Transmission Optimization Study in 2008 that identified and quantified transmission costs of four different CREZ scenarios previously chosen by the Utilities Commission. The cost estimates for the transmission plans ranged from $2.95 billion to $6.38 billion. The Public Utilities Commission of Texas, which regulates utilities in the state, then granted approval for an approximate cost of just over $5 billion and awarded the development of the transmission plan segments to several transmission developers.[34] More discussion of transmission planning processes and how they affect GHG emissions can be found in Chapter 22.

Finally, eight states have adopted a performance-based incentive policy that involves a FIT arrangement: California, Hawaii, Maine, Minnesota, Oregon, Rhode Island, Vermont, and Washington. Some of these state policies do not apply to all utilities and retail suppliers in the state. A relatively small number of utilities that are not subject to state performance-based incentive policies also offer FITs. National data on the impact of FIT policies are currently not available, but anecdotal evidence suggests that FITs, where they are offered, can effectively motivate the deployment of a balanced mix of renewable technologies. Because FIT policies in the United States are generally targeted toward distributed renewable resources, more information on this topic will be found in Chapter 17.

4. Greenhouse Gas Emissions Reductions

The inherent potential of clean energy *technologies* to reduce GHG emissions was addressed in detail in Chapter 6, and will not be repeated here. Instead, this section will focus on some of the specifics related to clean energy *procurement policies.*

The principal difficulty in assessing the GHG reduction potential of clean energy procurement policies stems from the fact that the mix of resources that will be procured is uncertain. Some "clean" resources, notably solid biomass and any fossil fuel resources that might meet a state's definition of clean energy or satisfy a state EPS, emit GHGs in varying amounts. Other clean resources emit no GHGs at all. The expected electricity output of some clean resources can also vary with time of day or vary seasonally, as is the case for solar, wind, and hydro technologies. Projecting the emissions reductions from a procurement policy like an RPS is therefore challenging.

Regardless of the challenge, the GHG emissions reduction potential from clean energy procurement strategies like an RPS is potentially substantial. Clean energy technologies operating in the United States usually displace energy from combustion-based resources, typically fossil fuel generation. Because the observed effect of RPS policies to date has predominantly been to increase wind generation, and to a lesser extent solar and geothermal generation, the impacts of these policies can readily be approximated using representative production profiles of

33 Simpson, C., Hausauer, B., & Rao, A. (2010, August). *Research Brief: Emissions Performance Standards in Selected States.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/250.

34 The Regulatory Assistance Project. (2011). *Securing Grids for a Sustainable Future: Case Studies.* Available at: www.raponline.org/document/download/id/4624. See also: Fink, S., Porter, K., Mudd, C., & Rogers, J. (2011, February). *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations.* Exeter Associates, Inc. for the National Renewable Energy Laboratory. NREL/SR-5500-49880. Available at: http://www.nrel.gov/docs/fy11osti/49880.pdf.

these technologies. As seen in Figure 16-3, 89 percent of capacity additions associated with an RPS to date have been from wind generators, whereas only 4 percent have come from biomass technologies. However, the mix of clean resources can and does vary geographically, and that variation can shape the emissions impact of the policy.

Thus, the GHG reduction potential of clean energy procurement policies ultimately depends on the mix of resources procured, as well as the mix of fossil fuel resources that are displaced (or never procured) when clean energy generation increases. The specifics vary not just geographically but also with time (as noted in Chapter 6). Regional grid operators and ISOs may be in the best position to provide data or estimate the GHG reduction potential from the addition of specific categories of renewable technologies, considering all of these factors. These operators have developed and refined the modeling tools to conduct such analyses for their own planning purposes.

A recent analysis of PJM, the largest ISO in the United States, is instructive. Analysts from GE Energy Consulting found that the GHG reduction potential from a 30-percent renewable mix in some scenarios could lead to a 41-percent reduction in GHG emissions at the high end and a 27-percent reduction at the low end.[35]

In nearly all of the states that have RPS policies, future clean energy procurement requirements will increase well above the requirements that are in effect in 2014. This suggests that these policies will continue to drive thousands of megawatts of clean energy deployment and their contribution to GHG emissions reductions will increase with time.

5. Co-Benefits

Some of the co-benefits associated with clean energy technologies were detailed in Chapter 6 and need not be repeated here. Table 16-1 summarizes the co-benefits that are relevant to policies specifically designed to encourage procurement of utility-scale, clean energy generation resources.

6. Costs and Cost-Effectiveness

The inherent costs and cost-effectiveness of clean energy *technologies* were addressed in detail in Chapter 6, and will not be repeated here. Instead, this section will focus on some of the specifics related to clean energy *procurement policies.*

The costs and cost-effectiveness of state efforts to rely on zero and low-emission resources vary by category of technology, geographic regions of the United States, and pre-existing state and federal support for these initiatives. They can also be quite variable and depend in large measure on the characteristics of eligible resources in each procurement policy. But irrespective of those differences, one of the virtues of procurement policies used in utility regulation, notably RPS policies, is that they tend to promote competition among qualifying renewable or clean energy resources. This competition leads to the procurement of clean energy at least cost, and it also tends to promote innovation, supply chain improvements, and economies of scale that drive down the costs of clean technologies. Utility procurement initiatives have fostered the development of a thriving marketplace for clean energy. In the United States, for example, 83 percent of all wind generation is owned by independent power producers, and 95 percent of new wind power capacity installed in 2013 was developed by independent power producers.[36] RPSs have also promoted a competitive market for the trading of RECs that similarly serves to drive down the costs of RECs and thus the costs of RPS compliance.

The National Renewable Energy Laboratory and LBNL recently completed the most comprehensive review to date of the incremental costs of state RPS policies.[37] The methodology used to estimate costs in these studies most closely reflects the incremental costs to the utility of complying with the policy, as might be reflected in rates, rather than the costs to society as a whole. Figure 16-5 provides a state-by-state visual summary of these costs alongside state objectives.

In most regions of the country, the RPS obligations have been met primarily with wind generation (see Figure 16-3). In those cases, the costs of the RPS can be viewed as strongly correlated with the costs of new wind energy

35 General Electric International, Inc. (2014, February). *PJM Renewable Integration Study.* Available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx.

36 Wiser, R., & Bolinger, M. (2014, August). *2013 Wind Technologies Market Report.* LBNL for the US Department of Energy, p. vi. Available at: http://eetd.lbl.gov/sites/all/files/2013_wind_technologies_market_report_final3.pdf.

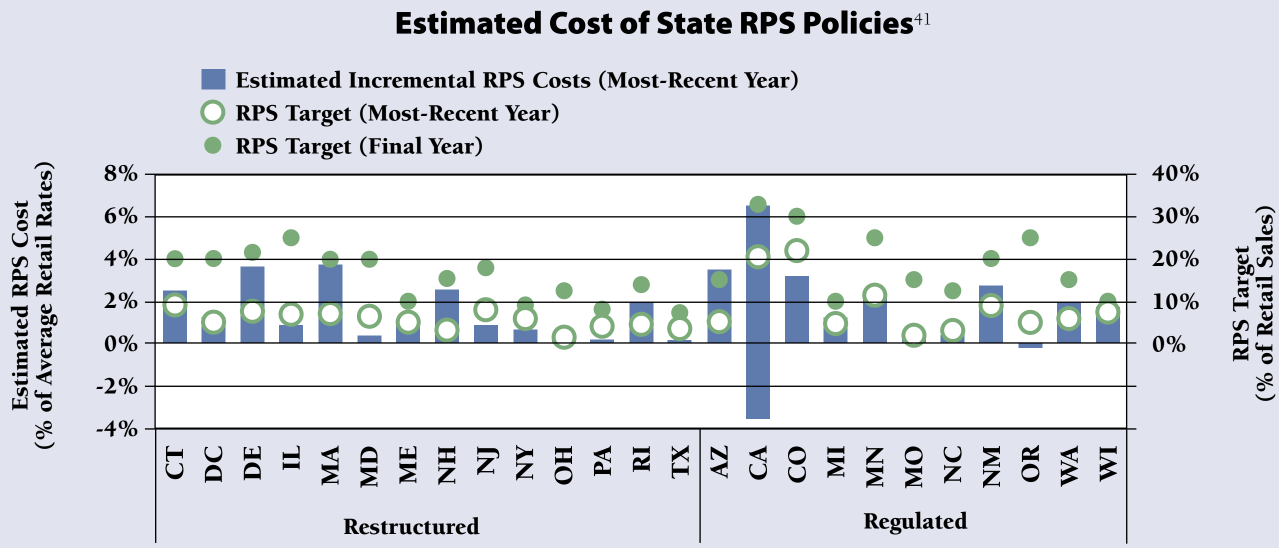
37 Supra footnote 30.

Table 16-1

Types of Co-Benefits Potentially Associated With Clean Energy Procurement Requirements

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	*Yes*[38]
Nitrogen Oxides	*Yes*
Sulfur Dioxide	*Yes*
Particulate Matter	*Yes*
Mercury	*Yes*
Other	*Yes*
Water Quantity and Quality Impacts	*Yes – varies by technology*
Coal Ash Ponds and Coal Combustion Residuals	*Yes*
Employment Impacts	*Yes – varies at the local level*
Economic Development	*Yes (the economic development impacts will vary at the local and regional level and can be positive or negative)*[39]
Other Economic Considerations	*Maybe*
Societal Risk and Energy Security	*Yes*
Reduction of Effects of Termination of Service	*Only for some customer-owned distributed generation*
Avoidance of Uncollectible Bills for Utilities	*Likely limited*
Benefits to the Utility System	
Avoided Production Capacity Costs	*No*
Avoided Production Energy Costs	*Yes – the primary technologies relied on (wind and solar) are typically capital-intensive and with no energy and small operating costs*
Avoided Costs of Existing Environmental Regulations	*Yes*
Avoided Costs of Future Environmental Regulations	*Yes*
Avoided Transmission Capacity Costs	*Not generally – transmission capacity may be needed to help increase system flexibility to accommodate certain categories of variable energy resources*
Avoided Distribution Capacity Costs	*Generally applies for low to moderate levels of distributed generation and varies by technology*
Avoided Line Losses	*Generally applies for low to moderate levels of distributed generation and varies by technology*
Avoided Reserves	*No – the details matter, but the addition of variable energy resources, in isolation of other changes, could increase the need for more system flexibility and capacity during periods of system stress*
Avoided Risk	*Yes, but specific risks are particular to the circumstances*
Increased Reliability	*Maybe*
Displacement of Renewable Resource Obligation	*No*
Reduced Credit and Collection Costs	*No*
Price Suppression Effect	*The addition of variable energy renewables is typically associated with wholesale price reduction and stabilization effects*[40]
Other	*No, in most cases*

Figure 16-5



**For most states shown, the most-recent year RPS cost and target data are for 2012; exceptions are CA (2011), MN (2010), and WI (2010). MA does not have single terminal year for its RPS; the final-year target shown is based on 2020. For CA, high and low cost estimates are shown, reflecting the alternate methodologies employed by the CPUC and utilities. Excluded from the chart are those states without available data on historical incremental RPS costs (KS, HI, IA, MT, NV). The values shown for RPS targets exclude any secondary RPS tiers (e.g., for pre-existing resources). For most regulated states, RPS targets shown for the most-recent historical year represent actual RPS procurement percentages in those years, but for MO and OR represent REC retirements (for consistency with the cost data).*

contracts over and above the costs of alternative market-based technologies, likely natural gas in most regions.[42] But as noted in Chapter 6, the costs of wind power have decreased over time and are increasingly competitive with all other technologies; thus, in an increasing number of cases the incremental cost of procuring wind energy is zero.

Some states have created specific requirements for solar energy procurement within a broader RPS policy. These kinds of "set-aside" or "carve-out" requirements were designed to increase procurement from what is still a more expensive resource than wind in most locations, and thus they generally increase the overall cost of an RPS policy. As solar costs decrease (refer again to Chapter 6), the incremental costs of a solar set-aside policy will decrease.[43]

Many state RPS policies include a legislated cap on compliance costs, expressed in either of two common ways. First, some policies automatically suspend compliance requirements, or allow the regulated entity to request suspension of compliance requirements, if the costs of compliance exceed some specified amount (typically a value roughly equal to six to nine percent of retail rates). Second, some policies allow regulated entities to comply by making an alternative compliance payment (ACP), which requires a payment of some specified amount for each MWh that the obligated entity falls short of its RPS target.[44] The ACP sets a *de facto* cap on compliance costs.

In summary, the costs of an RPS policy depend critically on three important factors among many others that affect the costs and cost-effectiveness of the policy. The first factor is the resource base. Even ambitious targets like those of Minnesota and Oregon can be met with modest impacts on rates if there are ample resources. Both states appear to be

38 Non-GHG impacts will vary with respect to generation technologies that rely on biomass or fossil fuel resources that qualify under some state RPS policies.

39 One survey suggested an economic development benefit range of between $22 and $30 per MWh. Supra footnote 30 at page vii.

40 One survey estimated the impacts at about $1/MWh of total wholesale generation in specific markets. Ibid.

41 Ibid.

42 Oregon, for example, uses a natural gas combined-cycle generator as the proxy (counterfactual) generator for estimating incremental costs. Michigan, on the other hand, relies on coal generation as a proxy.

43 A graphic representation of the solar REC price levels can be seen in various LBNL presentations on the topic. See, for example: Supra footnote 9.

44 Supra footnote 30.

in proximity of good wind resources. Second, the targets themselves can be a factor. Massachusetts and Colorado, for example, have relatively ambitious near-term targets and are seeing a larger effect on rates. Third, cost mitigation strategies can be a factor. Most states have established an alternative compliance payment framework that serves to cap the cost impacts at the level of the alternative compliance payment.[45]

7. Other Considerations

Most of the considerations associated with clean energy *technologies* were discussed in Chapter 6 and need not be repeated here. One additional point that is associated specifically with *procurement policies* is that the policies can be (and in some cases, have been) designed to simultaneously meet multiple public policy objectives. Some states, for example, have designed their policies to favor instate deployment of clean energy resources in the hope of spurring economic development.[46]

8. For More Information

Interested readers may wish to consult the following reference documents for more information on clean energy procurement requirements:

- Barbose, G. (2012, December). *Renewables Portfolio Standards in the United States: A Status Update.* Presented at 2012 National Summit on RPS, Washington D.C. Available at: http://www.cesa.org/assets/2012-Files/RPS/RPS-SummitDec2012Barbose.pdf.
- Simpson, C., Hausauer, B., & Rao, A.. (2010, August). *Research Brief: Emissions Performance Standards in Selected States.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/250.
- General Electric International, Inc. (2014, February). *PJM Renewable Integration Study.* Available at: http://www.pjm.com/~/media/committees-groups/committees/mic/20140303/20140303-pris-executive-summary.ashx.
- Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K., & Wiser, R. (2014, May). *A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards.* National Renewable Energy Laboratory and Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6589e.pdf.
- North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE).* Available at: www.dsireusa.org.
- Sheaffer, P. (2011, September). *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues.* Montpelier, VT: The Regulatory Assistance Project, page 7. Available at: http://www.raponline.org/document/download/id/4572.
- US Environmental Protection Agency. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures.

9. Summary

The last decade has been marked by the widespread introduction and expansion of renewable and clean energy procurement requirements, in particular RPS policies, which now exist in a majority of states. Purchase obligations imposed on utilities and retail suppliers by state governments have been arguably the most successful legal and regulatory policy mechanism for spurring growth in clean energy technology deployment, especially wind turbine deployment. In most states, regulated entities have shown a willingness and ability to comply with procurement requirements. Evidence suggests that RPS policies have led to small increases in retail electricity rates where they exist, in most cases amounting to an increase of less than two percent.

45 For a summary of alternative compliance payment levels across all state RPS policies, refer to: http://www.dsireusa.org/rpsdata/RPSspread042213.xlsx.

46 It is worth noting that policies that explicitly favor instate resources over imported resources have been questioned on constitutional grounds.

17. Encourage Clean Distributed Generation

1. Profile

"Distributed generation" (DG) is a widely used term that has been defined and interpreted in significantly different ways across federal, state, and local jurisdictions. For the purposes of this document, we use DG to refer to generating facilities with a rated capacity of 20 megawatts (MW) or less that are interconnected to a distribution system (i.e., not directly connected to transmission lines). Most DG is not owned by the distribution utility, but it is possible that some DG will be partially or fully owned by a utility in some places. Solar photovoltaic (PV) DG systems are prominent today and thus DG is assumed by some to be limited to PV, but the use of the term "DG" in this chapter is intended to encompass all DG technologies that contribute to reducing greenhouse gas (GHG) emissions in the power sector. This definition includes generating systems using PV, wind, biomass, anaerobic digestion, geothermal, fuel cell, and efficient combined heat and power (CHP) technologies.[1,2]

DG investment is on the rise because the cost of DG is declining and the value of DG to the electricity system, consumers, and society is increasing. The cost of DG is declining at different rates for different technologies, and for a variety of reasons. The cost of fuel cells and CHP systems fueled by natural gas has declined because the cost of the fuel itself has declined. Economies of scale and technological advances have reduced the cost and improved the efficiency of most DG technologies in recent years. Public support for clean energy has also created a favorable policy environment at the federal level and in many states that has led to favorable interconnection rules, tax treatments, incentive payments, and tariffs in the places where the respective policies apply. In addition, the value of DG to customers, the electric system, and society is rising because environmental and public health concerns have translated into a consumer preference for clean, distributed energy resources; severe weather events have revealed the value that DG can add to grid security and grid resiliency; and grid modernization is providing opportunities for DG and other customer resources to provide additional energy, capacity, and ancillary service values.

At the same time, DG is encountering headwinds in some states. Some consumer advocates are concerned that Net Energy Metering (NEM) may impose customer cross-subsidies and some utilities are concerned that NEM constitutes a subsidy to PV adopters. The validity of this claim depends on valuation studies being conducted to assess the costs and benefits created by PV adoption. In addition, some utilities allege that DG resources (especially distributed PV systems) impose electric system operational impacts that cause incremental costs. The validity of this claim depends on system studies that investigate high-penetration DG impacts. Both of these assertions are being investigated in a number of states by public utility commissions (PUCs).

The effects of decreasing costs and increasing value have been especially dramatic for PV DG. Over the last six years PV installed capacity in the United States has jumped from 1 gigawatt (GW) to 3 GW as module costs dropped from about \$4 per Watt (W_{DC}) to about \$1/W_{DC} and the installed cost of small systems dropped from about \$9/W_{DC} to about \$5/W_{DC}.[3] Although cost reductions for new installations of other DG technologies have not been as dramatic, some technologies are experiencing significantly improved

1 For the purposes of this document, we exclude consideration of distributed diesel generators, as this technology does not significantly contribute to power sector emissions reductions and may in some cases lead to increased emissions.

2 CHP technologies are discussed in detail in Chapters 2 and 3. In this chapter, references to CHP are limited and focus on smaller, distributed CHP systems.

3 Barbose, G., Darghouth, N., Weaver, S., & Wiser, R. (2013, July). *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012.* LBNL-6340E. Berkeley, CA: Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

economics. For example, distributed CHP system operating costs have taken a favorable turn with natural gas prices declining (more than two-thirds of CHP systems in the United States are fueled by natural gas) and the costs of anaerobic digesters and wind turbines have continued to decline.

The policy tools used by federal and state governments to encourage DG have been important to increasing clean DG deployment. The federal government has established favorable investment and production tax credits. Most states have adopted favorable NEM policies and some states have implemented incentive programs for some DG technologies that provide direct incentive payments to adopters. In addition, some states allow clean DG to count toward Renewable Portfolio Standard (RPS) requirements, some states have established Feed-In Tariffs (FITs) and Value of Solar Tariffs (VOSTs) to complement or replace NEM, and some states are broadening the ability of DG resources to participate in energy, capacity, and ancillary service markets. Some states have also passed regulations or laws that allow new business models for delivering DG services such as third-party leasing, on-bill financing, and virtual net metering or community solar programs. Taken together, the suite of policy programs is transitioning clean DG from a technology in which few benefits are formally recognized or compensated toward a future in which the full range of clean DG benefits to the electric system and to society are becoming recognized and compensated.[4]

Clean DG adoption indirectly reduces GHG emissions by reducing the need to dispatch (operate) fossil-fueled generation resources that emit GHG, and by displacing the future need for incremental fossil-fueled generation resources. In addition, clean DG has line loss reduction and reserve requirement reduction benefits that further increase the GHG reduction benefit. As grid modernization takes hold in states, clean DG and other customer resources will be able to provide services that have historically been provided exclusively by fossil fuel generation technologies and thus the GHG reducing potential of clean DG will increase over time.

2. Regulatory Backdrop

Most of the significant regulatory issues associated with DG are issues of energy/economic regulation rather than air pollution/environmental regulation. Both types of regulation are discussed here.

Overview of Energy Regulation

The regulatory framework for clean DG consists of a mix of federal and state energy legislation and regulations, as well as state PUC orders. The topics addressed in this complex framework include state and federal tax provisions and incentive programs, business model policies, interconnection rules, utility tariffs, and utility procurement policies. As explained in Chapter 16, the Federal Energy Regulatory Commission (FERC) has nearly exclusive jurisdiction and fairly broad authority to regulate wholesale electricity transactions in the United States, whereas retail energy transactions are generally the purview of state governments.[5]

Tax Provisions, Incentive Programs, and Business Model Policies

Many state governments and the federal government have provided tax treatments and incentive programs that benefit DG adopters. Financial incentives for clean energy technologies are addressed in Chapter 6 and are not repeated in this chapter, except to underscore that these policies can dramatically alter the costs and benefits, and thus the deployment, of DG.

Some state governments have also developed "business model" policies that affect the interaction between potential DG developers and the incumbent utility. Examples that have had an impact on DG deployment include allowing on-bill financing (i.e., financing of DG systems through the customer's electric bill), allowing customers to lease DG systems from nonutility third parties, and authorizing virtual net metering programs for community solar projects.[6] Each of these business model options has

4 Favorable tax treatment and other financial incentives for clean energy technologies are addressed in Chapter 1, and specifically for CHP in Chapter 3. RPS policies are addressed in Chapter 6. Capacity markets are discussed in Chapter 19.

5 For a more detailed and nuanced discussion of this complicated subject, refer to: The Regulatory Assistance Project. (2011, March). *Electricity Regulation in the US: A Guide.* Available at: http://www.raponline.org/document/download/id/645.

6 Traditional net metering policies are discussed later in this chapter. There is no standard terminology at this time for "virtual net metering" or "community solar." Different terms are used by states for variations on similar (but not always identical) concepts. Generally speaking, the business model we refer to here is one in which the output of a DG system, almost always a PV system, is credited against the electric bills of more than one metered account.

the effect of facilitating financing for DG projects. The "community solar" business model further allows for economies of scale in building DG systems, it allows for optimal siting of DG systems, and it allows customers who can't install a system on their own property to benefit from DG.[7]

Interconnection Rules

Historically, almost all of the components of the electric grid have been designed, installed, and operated by utilities in a very carefully coordinated way to ensure electric reliability. The installation of DG systems introduces a new and unplanned-for complexity. Whereas customers historically were one-way receivers of energy from the grid and their demand for electricity was fairly predictable, we now see two-way flows of electricity to and from customers with DG, and the quantities have become harder to predict. Unless safeguards are in place, the variability and relative unpredictability of power flows to and from DG customers could potentially lead to voltage instability, power flow or reactive power problems, or other challenges to reliable utility service.

Electric utilities are responsible for ensuring that any generating facility connected to the grid will not jeopardize the safety of utility employees or the public and will not impair the reliability of service. To meet that obligation, utilities establish standards and procedures that third parties must satisfy before interconnecting new resources with the grid. The details of those utility standards and procedures must conform to federal and state interconnection regulations.

The FERC has jurisdiction over interconnections to the high-voltage interstate transmission system. States have jurisdiction, usually exercised by the PUC, over interconnections to the lower-voltage utility distribution system. In this chapter, we have defined DG to include only resources that connect to a distribution system, so our discussion of interconnection will be limited to state requirements.[8]

The interconnection standard adopted in most states is based on a version of the Institute of Electrical and Electronics Engineers' (IEEE) standard IEEE 1547 that was updated in 2004. This version of the standard does not address the very specific types of impacts that may result when there are high levels of DG adoption in concentrated areas of the distribution system. This older version focuses on disconnecting PV systems when grid conditions become stressed. Ironically, this approach can exacerbate system reliability problems rather than relieve them. In states like California, where higher levels of DG adoption are occurring, a revised standard is already in effect that addresses these problems.[9] Standard IEEE 1547 is also in the process of being updated (as of July 2014) to reflect the capabilities of new technologies and to address situations that arise in higher DG penetration situations, and it is expected that states will begin adopting the new version of IEEE 1547 later in 2014.[10] Interconnection of very small systems usually does not require the utility to perform a special study of safety and reliability issues, but larger DG systems may have unique local electric system impacts and thus these larger systems are often required to pay for a system impact study. Sometimes the DG investor must incur additional costs necessary to protect the electric system as a condition of interconnecting.

Utility Tariffs

Policies governing the design of tariffs are perhaps the most important aspect of the DG regulatory framework. In the context of electric utilities, a "tariff" is a package of standard rates (prices) and terms of service that is

7 A complete discussion of business model issues specifically for PV can be found at: Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013, November). *Regulatory Considerations Associated With the Expanded Adoption of Distributed Solar.* National Renewable Energy Laboratory and The Regulatory Assistance Project. NREL/TP-6A20-60613. Available at: http://www.raponline.org/document/download/id/6891.

8 Although excluded from our discussion of DG, it is worth noting that the FERC has promulgated Small Generator Interconnection Procedures and a Small Generator Interconnection Agreement that govern the interconnection of generators with a rated capacity of less than 20 MW directly to the high-voltage interstate transmission system.

9 In California this standard is called Rule 21.

10 One aspect of interconnection that is being updated is the specifications for inverters that convert Direct Current (DC) power from the DG unit into Alternating Current (AC) power that is used on the grid. Revised standards will take intelligent inverters into account. Intelligent inverters allow the system operator to monitor the DG system's power production and allow the electricity from the DG unit to be controlled more flexibly.

applicable to a defined group of customers.[11] Customers who install a DG system will generally require a special kind of tariff to account for the fact that the customer is generating electricity and not merely purchasing electricity. As a practical matter, the terms of these tariffs can either encourage or discourage the deployment of DG. The regulatory structure governing tariffs consists of both federal and state requirements.

In most cases, electric utilities are required by federal law to provide service to customers who choose to install DG. Pursuant to rules authorized by the Public Utility Regulatory Policy Act of 1978 (PURPA) and promulgated by FERC, utilities must offer to sell electric energy to and purchase electric energy from "qualifying small power production facilities" and "qualifying cogeneration facilities" at rates that are just and reasonable to the utility's customers and in the public interest, and non-discriminatory toward qualifying facilities (QFs). With respect to this "purchase obligation," regulators may not require utilities to offer to purchase energy at rates in excess of the utility's "avoided costs" (i.e., "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the QF or QFs, such utility would generate itself or purchase from another source").[12]

Table 17-1

Summary of Utility Purchase Obligation Under PURPA and FERC Rules

Rated Capacity of QF Generator	Location of QF Generator	Utility Purchase Obligation?
≤100 kW	Any	Yes, at standard rates
100 kW to 20 MW	Any	Yes (rebuttable by utility), but not necessarily at standard rates
>20 MW	Midcontinent ISO PJM New York ISO ISO New England Electric Reliability Council of Texas	No (rebuttable by QF)
	Everywhere else	Yes, but not necessarily at standard rates

There are some instances in which utilities do not have to meet this federal purchase obligation. This happens if a small power production facility or cogeneration facility has nondiscriminatory access to wholesale markets for the sale of electric energy and capacity. The FERC's current rules establish a rebuttable presumption that facilities with a rated capacity of 20 MW or less do not have nondiscriminatory access to markets, and a rebuttable presumption that facilities greater than 20-MW capacity do have nondiscriminatory access in five of the seven US wholesale electricity markets: the Midcontinent ISO, PJM Interconnection, New York ISO, ISO New England, and Electric Reliability Council of Texas.[13,14] Furthermore, FERC rules require each utility to offer standard rates for purchases from all QFs with a design capacity of 100 kilowatts (kW) or less.[15] The FERC gives utilities discretion on whether to offer standard rates or to individually negotiate rates for purchases from QFs larger than 100-kW capacity, but state laws and regulations may further limit that discretion. These federal requirements are summarized in Table 17-1.

In summary, utilities have an obligation in almost all

11 In jurisdictions that allow for competition in the provision of retail electric services, contracts between a non-utility provider and its customers are also relevant to this discussion. For simplicity, the remainder of this chapter uses "tariffs" to refer to either a tariff or a similar contractual arrangement for electric services.

12 The question of how to interpret and calculate avoided costs is a contentious one and is beyond the scope of this document.

13 A rebuttable presumption is an assertion that is presumed by the FERC to be true unless and until a party comes forward to prove it is not true. The burden of proof falls on the party asking the FERC to override the presumption. The FERC's rationale for these two rebuttable presumptions is explained in Order No. 688 (Docket No. RM06-10-000). The 20-MW dividing point in FERC rules is the primary reason this chapter limits the term "distributed generation" to generating facilities with a rated capacity of 20 MW or less.

14 For a map showing the territories served by these markets, refer to the ISO/RTO Council at http://www.isorto.org/Images/IRCmap.png.

15 The FERC rules for small power production facilities are codified at 18 C.F.R. §§CFR 292.

cases to offer to purchase energy from DG systems. For the smallest DG systems, including almost all residential and commercial customer PV systems, utilities must offer standard rates for purchasing energy from the customer. However, federal law and regulations leave ample discretion to states and utilities on the details of how they will fulfill the PURPA purchase obligation. The issues that states and utilities grapple with are not whether utilities should have to buy energy from DG systems, but under what terms and at what prices.

In practice, customers who own QFs generally have three options for selling the energy or excess energy that they generate:

- Accept an *ex ante* administratively determined tariff or standard offer contract offered by the customer's utility. (For the reader's convenience, we consider standard offer contracts to be a type of tariff.) The customer accepts a standard price (which may be fixed or variable) and other standard terms previously established by the utility that are identically applicable to all similarly situated customers who choose to accept the tariff.
- Enter into a Power Purchase Agreement with a utility or wholesale electricity trader. Some of the terms of the agreement may be predetermined by regulators, whereas others, including the price, are negotiated between the buyer and seller on a case-by-case basis.
- Sell directly into an organized wholesale electricity market, if located where such a market exists. The price the generator receives will be determined by market forces and will vary over time and place based on market supply and demand conditions.

The second and third options listed above are not generally realistic choices for owners of DG systems, so the remainder of this discussion focuses on common ways of implementing the first option.

- **NEM Tariffs –** A NEM tariff bills the customer, or provides a credit to the customer, based on the net amount of electricity consumed during each billing period (i.e., the kilowatt-hour [kWh] difference between electricity consumed and electricity produced). Provisions are made for periods in which the net amount consumed is negative (production exceeds consumption). NEM does not require separate metering of consumption and production. NEM is also referred to more simply as "net metering."

  NEM is being challenged by consumer advocates and utilities in some states based on the assertion that the value of DG to the electricity system is less than the compensation that NEM adopters receive, thus constituting a cross-subsidy from non-adopters to adopters. A number of state PUCs are testing this assertion. Determining whether PV adopters are undercompensated or overcompensated requires a comprehensive valuation study that takes all relevant sources of cost and benefit into account.
- **Standard Offer Contracts –** A standard offer contract or tariff pays the customer for all of the electricity he or she generates under terms that are different from the customer's tariff for purchasing energy. This kind of tariff requires separate metering of consumption and production. If the price the utility pays the customer is set at or below the utility's avoided costs of procuring energy and capacity from unspecified (or least-cost) resources,[16] the tariff will satisfy PURPA requirements and might be considered a "PURPA tariff." But some states and utilities have established special tariffs for specified sources like renewable DG systems. These special tariffs come in several forms, with the FIT being the most recognizable, and more recently a variation on standard offer contracts called a VOST. The state experiences with FITs and VOSTs are discussed later in this chapter.

Utility Procurement Policies

As noted in Chapter 16, some states have adopted procurement policies that require regulated utilities to procure specified amounts of electricity specifically from DG resources as part of a broader RPS. These RPS "carve out" or "set aside" policies have a fairly direct impact on DG deployment because they create a differentiated market for electricity from DG.

16 Various states have interpreted the term "avoided cost" differently in PURPA implementation, with some states setting standard offer contracts based on short-run avoided cost and some based on long-run avoided cost. Short-run avoided cost implies the PURPA qualifying resource is not displacing utility generation in the long term, and thus it should only be paid for providing short-term energy. States adopting long-run avoided cost compensation are asserting that the PURPA resource will displace or defer a future generation addition.

Air Pollution Regulations

As noted in Chapter 6, some of the "clean" generating technologies (e.g., PV and wind) do not emit any air pollution and are not directly subject to air pollution regulations. Other technologies, including some that are applicable to DG, are considered clean because they emit fewer GHGs, but they do emit other air pollutants and may be subject to emissions limits and control requirements, as well as permitting, monitoring, recordkeeping, and reporting obligations. These topics are covered in a general way in Chapter 6 and need not be repeated here. It is worth noting, however, that because DG systems are smaller in size than utility-scale systems, they will generally have lower annual emissions (although potentially higher instantaneous or hourly emissions rates), and they are more likely to be exempt from air pollution regulations.

Chapter 6 also notes that in the Clean Power Plan proposed by the Environmental Protection Agency (EPA) in June 2014 (a.k.a. the proposed "111(d) rule," because it is based on authority under Section 111(d) of the Clean Air Act), the EPA proposed GHG emissions guidelines with emissions rate performance goals for each state that are based on assumed levels of zero-emissions resource deployment. When determining compliance with the goals, states will be allowed to add megawatt hours (MWh) of generation from zero-emissions resources to the MWh of generation from affected sources to get an "adjusted" carbon dioxide emissions rate in pounds per MWh. This formula for compliance determinations has ramifications for DG, specifically, because the output of small DG systems is not always metered. If states wish to include the output from non-metered DG systems in their plans for compliance with the performance goals, they will need to develop a method for estimating or calculating the MWh of output that can meet the EPA's standards for approvable plans. A number of states received American Recovery and Reinvestment Act funding to deploy advanced metering and some additional states with higher levels of PV adoption are implementing advanced metering requirements. In these states the metering of small systems will become routine. In states without advanced metering, statistical approaches can be proposed or air directors might collaborate with PUC officials to consider advanced metering requirements. Alternatively, the EPA could address the issue of non-metered DG in the final rule and relieve states of this burden.

3. State and Local Implementation Experiences

As noted in the previous section, states vary considerably in the policies they have adopted with respect to business models, interconnection, tariffs, and utility procurement policies for DG. The state experiences with these policies are summarized in the sections below and in Figures 17-1 through 17-7, along with the impact that some of these policy choices appear to have had on DG deployment.

Business Model Policies

Most public utilities operate as state-authorized monopolies within a designated service territory. In areas of the country that have not implemented retail competition, this means that the laws preclude other parties from selling power directly to customers. States are finding that they can accelerate the deployment of DG, especially PV systems, by authorizing new business models that allow third parties to install DG systems on customers' premises for the customers' benefit. This helps projects get financed, lowers installation costs, and expands opportunities to more customers. States vary in whether they allow this kind of third-party arrangement, as shown in Figure 17-1. Some states welcome third-party ownership (TPO), some effectively preclude it, and most states are somewhere in between with no explicit law or policy that encourages or precludes TPO. In the states authorizing TPO, air regulators can expect to see higher DG penetration levels, all else being equal. In the states without an explicit policy, air regulators will have to work with PUCs and legislatures to address ambiguities of TPO if they want to use TPO of DG as part of a GHG reduction or state 111(d) compliance plan.

In recent years, TPO of residential PV systems has become the norm in the states that have the highest levels of PV deployment. Examples of this phenomenon are indicated in Figure 17-2 for four states: Arizona, California, Colorado, and Massachusetts. These states ranked second, first, eighth, and sixth, respectively, at the end of 2013 in total installed PV capacity, suggesting that TPO can be a significant accelerator of deployment.[17]

17 GTM Research. (2013). *US Solar Market Insight Report: Q3 2013.* Produced for Solar Energy Industries Association. Available at: http://seia.us/1nnAjVq.

Figure 17-1

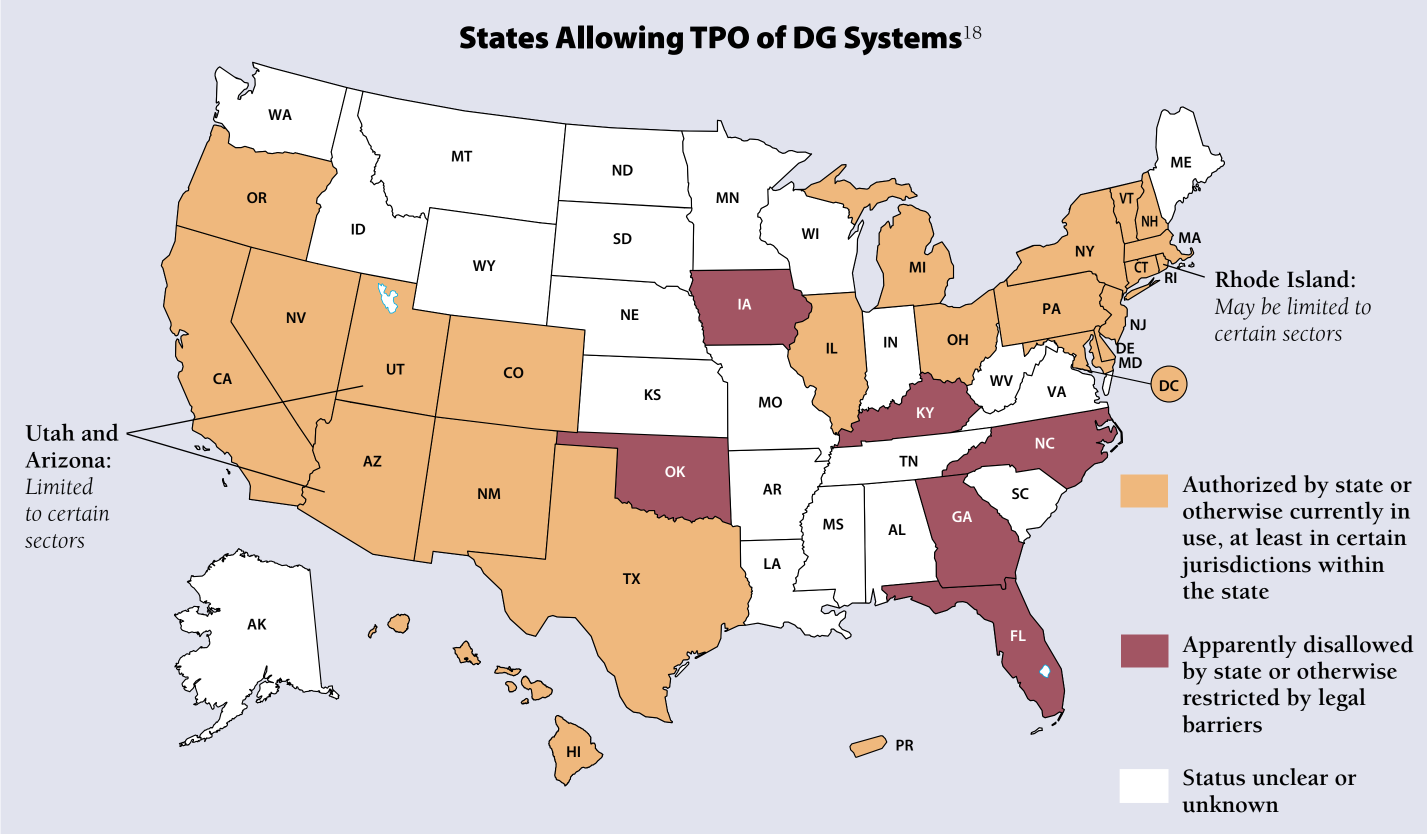
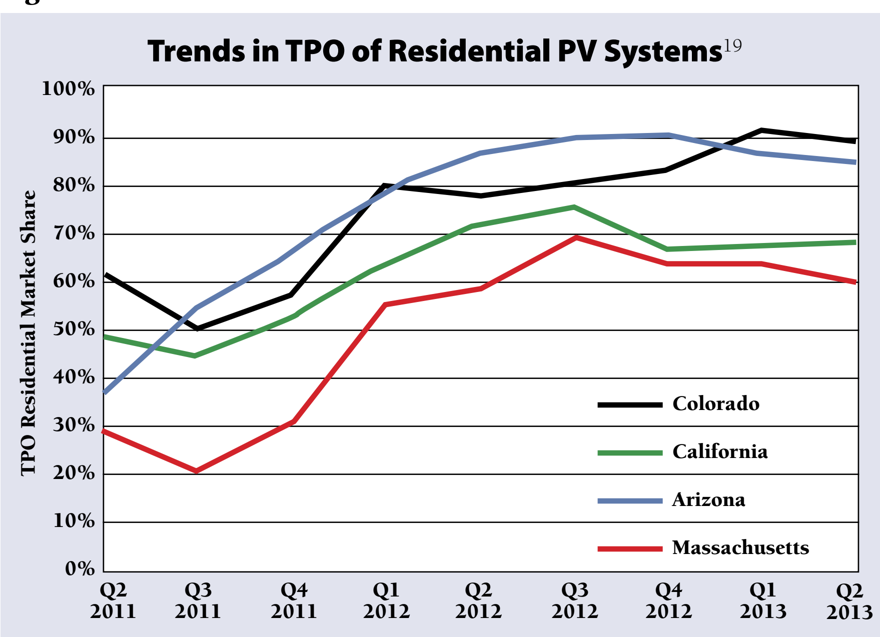


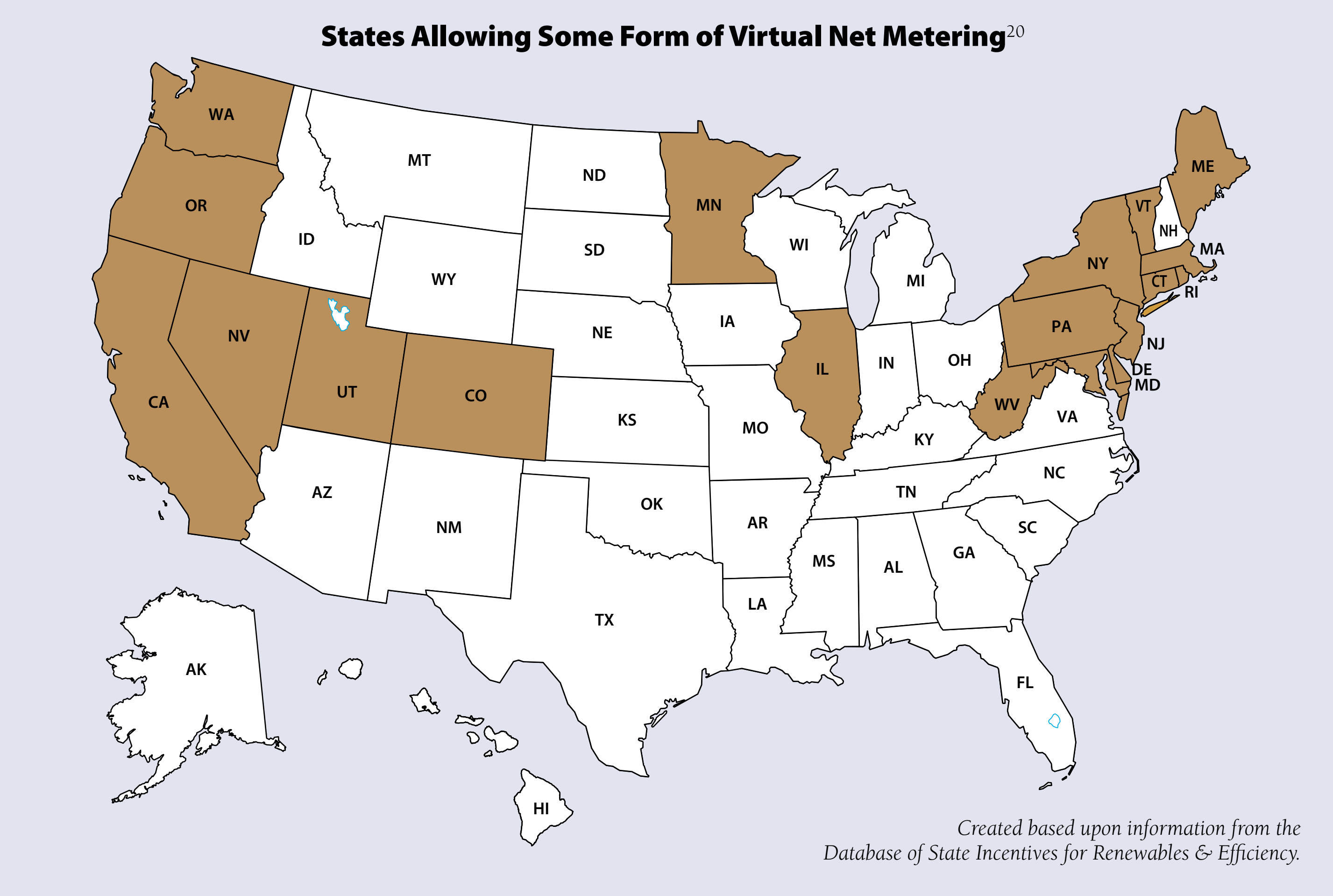
Figure 17-2



18 Based on data from: North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

19 Solar Energy Industry Association. (2013). *Market Insight Report, Quarter 2, 2013.* Available at: http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

Figure 17-3



Another business model option that makes DG more affordable and practical for customers is to allow virtual net metering (a.k.a. community solar, group net metering, or solar gardens). This option essentially allows customers to "buy a share" of a DG system, and then apply their share of the system output to their electric bill just as a net-metered customer who has an onsite DG system would. The states that have authorized some form of virtual net metering or community solar policy are indicated in Figure 17-3.

Interconnection

Forty-three states have adopted standard interconnection rules for DG systems. As noted earlier, these state interconnection policies are typically based on IEEE Rule 1547, but the size of the DG system covered by those policies varies, as summarized in Figure 17-4. Where state interconnection rules do not exist or where utility responsiveness to interconnection requests is nonexistent or excessively slow, the DG investor has more uncertainty about what it will take to get interconnection approval from their utility, and that uncertainty can delay projects or add to project costs. Improvements to state interconnection policies can thus play a role in supporting increased levels of clean DG deployment. Policies in Oregon, Virginia, Connecticut, Maine, and Massachusetts have been cited by at least one source as representing current best practices among the states.[21]

20 Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6898.

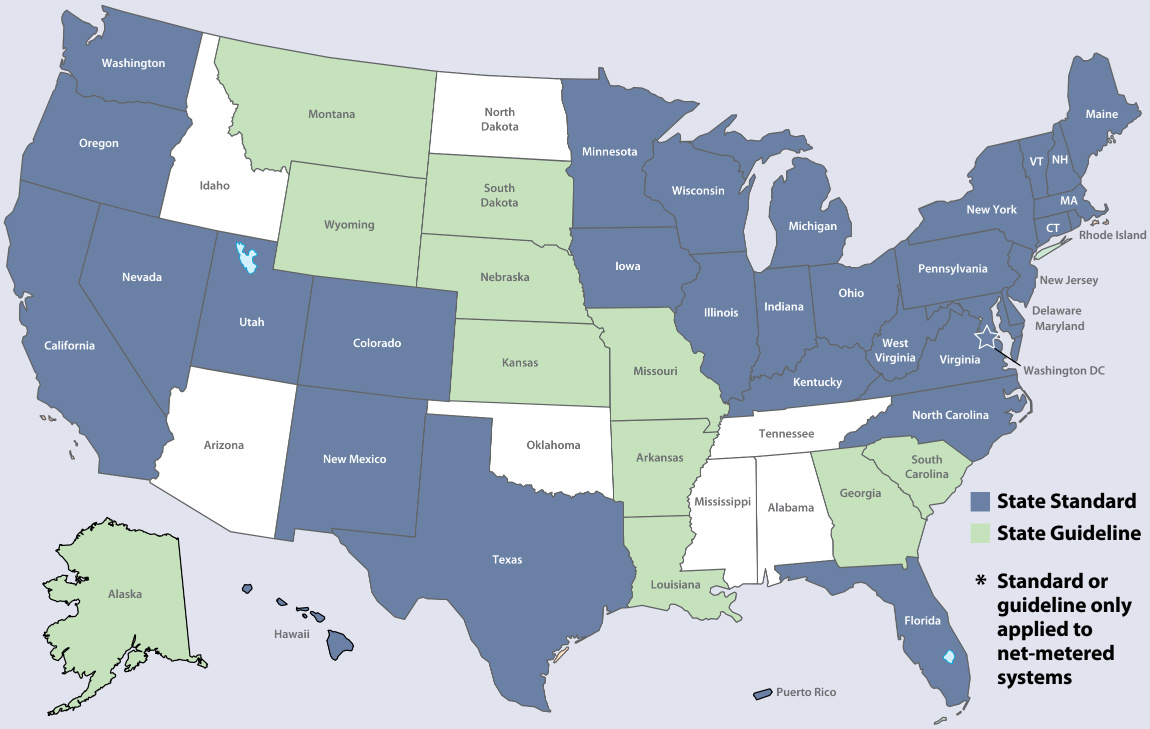
21 Sheaffer, P. (2011, September). *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues.* Montpelier, VT: The Regulatory Assistance Project, page 7. Available at: http://www.raponline.org/document/download/id/4572.

Figure 17-4

States With Interconnection Standards or Guidelines[22]

43 states plus Washington DC and Puerto Rico have adopted an interconnection policy.

Alaska: 25 kW*
Arkansas: 25/300 kW*
California: No limit
Colorado: 10,000 kW
Connecticut: 20,000 kW
Delaware: 20,000 kW*
Florida: 2,000 kW*
Georgia: 10/100 kW*
Hawaii: No limit
Illinois: No limit
Indiana: No limit
Iowa: 10,000 kW
Kansas: 25/200 kW*
Kentucky: 30 kW*
Louisiana: 25/300 kW*
Maine: No limit
Maryland: 10,000 kW
Massachusetts: No limit
Michigan: No limit
Minnesota: 10,000 kW
Missouri: 100 kW*
Montana: 10,000 kW
Nebraska: 25 kW*
Nevada: 20,000 kW
New Hampshire: 1,000 kW
New Jersey: No limit
New Mexico: 80,000 kW
New York: 2,000 kW
North Carolina: No limit
Ohio: 20,000 kW
Oregon: 10,000 kW
Pennsylvania: 5,000 kW*



Notes: Numbers indicate system capacity limit in kW. Some states limits vary by customer type (e.g., residential versus non-residential) "No limit" means that there is no stated maximum size for individual systems. Other limits may apply. Generally, state interconnection standards apply only to investor-owned utilities.

Rhode Island: No limit
South Carolina: 20/100 kW
South Dakota: 10,000 kW
Texas: 10,000 kW
Utah: 20,000 kW
Vermont: No limit
Virginia: 20,000 kW
Washington: 20,000 kW
Washington DC: 10,000 kW
West Virginia: 2,000 kW
Wisconsin: 15,000 kW
Wyoming: 25 kW*
US Territories:
Puerto Rico: No limit

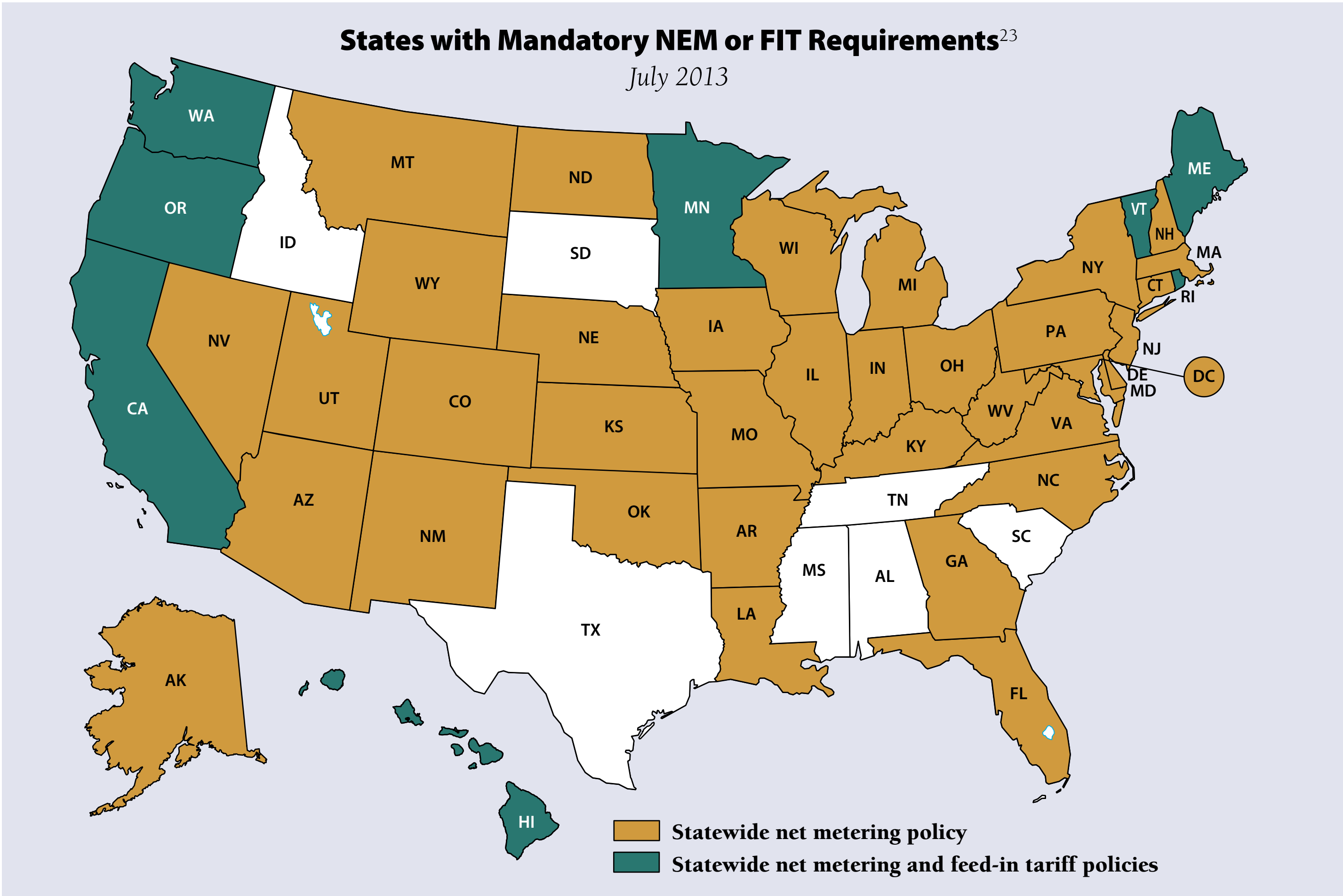
Utility Tariffs

Most states have adopted a policy requiring utilities to offer NEM tariffs for customers who have DG, as shown in Figure 17-5. The figure also indicates that relatively few states have adopted policies requiring utilities to offer FITs. What is not obvious from the figure is that there is considerable variation in these state policies on a number of key tariff design issues that influence the deployment of DG. To be more specific, these state policies vary in terms of whether they cover some or all types and sizes of utilities; the types and sizes of generating systems that are eligible for the tariff; the maximum amount of generating capacity that utilities must enroll under the tariffs; and the basis for rates and compensation. With respect to NEM tariffs, the key variable for rates and compensation is the treatment of net excess generation (i.e., what happens when the customer generates more electricity than he/she consumes during a billing period). For FITs, the key variable is the price paid to the customer for each kWh of generation.

There is little doubt that NEM tariffs in particular are a driving force for the deployment of DG in the United

22 North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

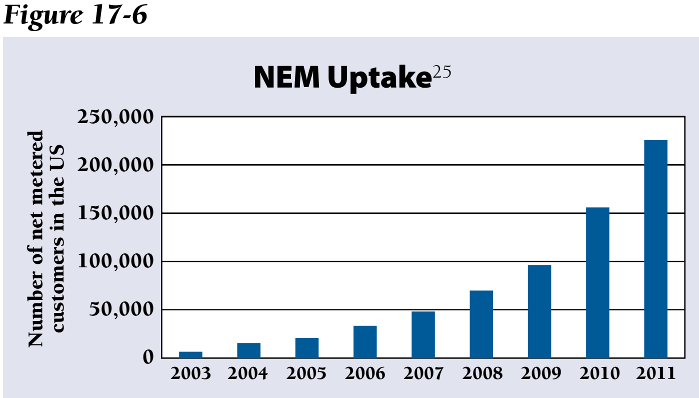
Figure 17-5



States. Figure 17-6 summarizes the number of customers enrolled under NEM tariffs. In 2003, fewer than 7000 customers in the entire country were net metered. In 2005, the federal Energy Policy Act of 2005 created a new requirement for states to formally consider (but not necessarily adopt) NEM tariffs. Less than ten years later, the number of net-metered customers had grown to more than 225,000, a thirtyfold increase. In terms of capacity, the same data show that 2688 MW of generating capacity was enrolled in NEM tariffs at the end of 2011.[24]

NEM tariffs have been especially popular as an option for customers owning PV systems. The US Energy Information Administration found that 97 percent of the customers under NEM tariffs in 2011 had PV systems, representing 93 percent of the total net-metered capacity. Furthermore, the Solar Electric Power Association estimates that as of the end of 2012, 99 percent of installed PV systems in the United States were on NEM tariffs, totaling approximately 3.5 GW

Figure 17-6



23 Supra footnote 20. Information in the figure was compiled by the authors from DSIRE data: North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE)*. Available at: www.dsireusa.org.

24 These data are from US Energy Information Administration statistics. Available at: http://www.eia.gov/.

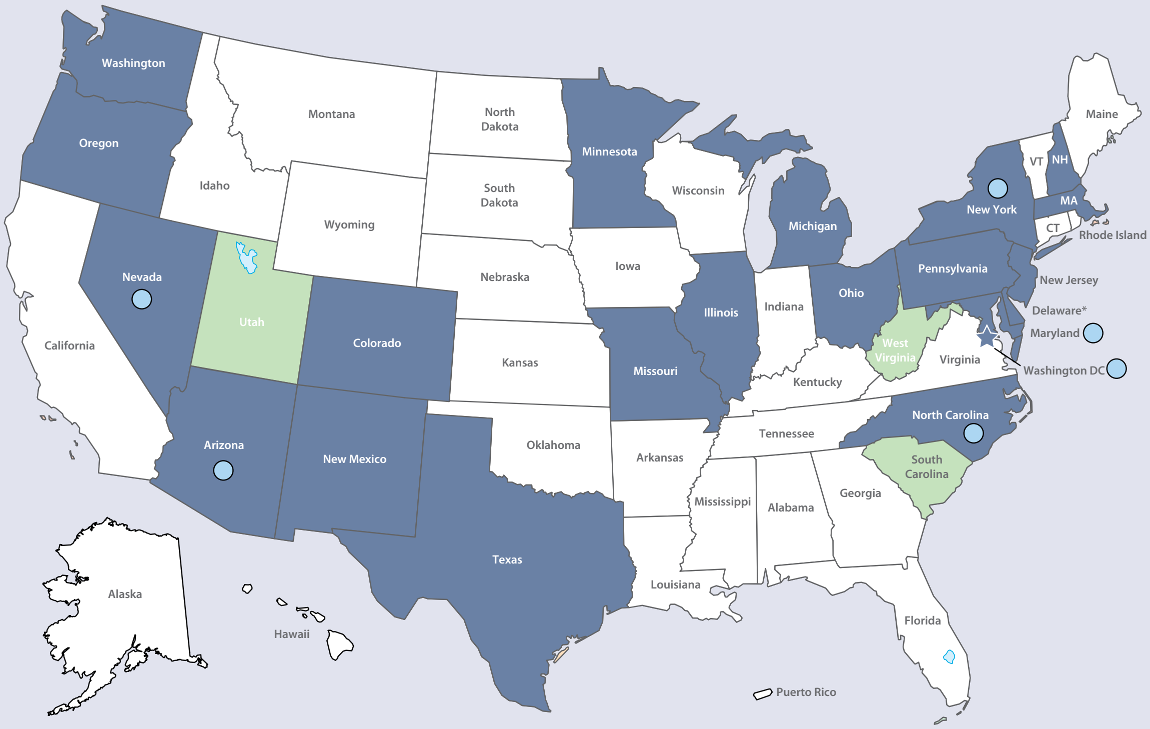
25 Supra footnote 20. Information in the figure was compiled by the authors from data published by the US Energy Information Administration (2013).

Figure 17-7

States With Solar or DG Provisions in Their RPS Policies[28]

23 states plus Washington DC have a renewable portfolio standard with solar or distributed generation provisions.

Arizona: 4.5% DG by 2025.
Colorado: 3.0% DG by 2020. 1.5% customer-sited by 2020, various multipliers
Delaware: 3.5% PV by 2026; 3.0 multiplier for PV*
Illinois: 1.5% PV by 2026. 0.25% DG by 2026
Maryland: 2% solar by 2020
Massachusetts: 400 MW PV by 2020
Michigan: 3.2+ multiplier for solar-electric
Minnesota: 1.5% solar by 2020. 0.15% PV DG by 2020
Missouri: 0.3% solar-electric by 2021
Nevada: 1.5% solar by 2025; 2.4+ multiplier for PV
New Hampshire: 0.3% solar-electric by 2014
New Jersey: 4.1% solar-electric by 2028
New Mexico: 4% solar-electric by 2020. 0.6% DG by 2020
New York: 0.58% customer-sited by 2015
North Carolina: 0.2% solar by 2018
Ohio: 0.5% solar-electric by 2026
Oregon: 20 MW solar PV by 2020; 2.0 multiplier for PV
Pennsylvania: 0.5% PV by 2021



Renewable portfolio standard with solar/distributed generation (DG) provision
Renewable portfolio goal with solar/DG provision
Standard or guideline only applied to net-metered systems

* *Delaware allows certain fuel cell systems to qualify for the PV carve-out*

South Carolina: 0.25% DG by 2021
Texas: 2.0 multiplier for non-wind (non-wind goal: 500 MW by 2015)
Utah: 2.4 multiplier for solar-electric
Washington: 2.0 multiplier for DG
Washington DC: 2.5% solar by 2023
West Virginia: Various multipliers

of capacity.[26] This suggests that more than 1 MW of new PV systems enrolled in NEM tariffs in 2012 alone.

There are fewer examples of FIT policies and consequently fewer data available on the impact of those policies. Anecdotal evidence suggests that the uptake of FITs is strongly dependent on the price paid for customer-generated electricity; different prices are necessary to encourage deployment of different types of DG resources; and uptake of FITs can be rapid when the prices are set high enough to attract investment.[27]

One important innovation in utility tariffs for DG is the VOST. The VOST concept borrows from both NEM tariffs and FITs. It was first introduced by Austin Energy in 2012. It sets the compensation for solar energy produced by DG systems at the value that the energy provides to the utility system. The utility customer buys all of its energy from the utility under a regular tariff, but the customer's bill is then credited with the value of solar produced and exported to the grid. It is like a FIT in that the customer sees a specified price for generation and pays a standard rate for consumption, but it is like a NEM tariff in that the customer's bill is credited for the value of generation. (The customer isn't actually paid for generation.) Several

26 For more information, refer to http://www.solarelectricpower.org/media/51303/sepa-top-10-executive-summary_final-v2.pdf.

27 Supra footnote 20. Information in the figure was compiled by the authors from data published by the US Energy Information Administration (2013).

28 Supra footnote 22.

other states are examining a VOST approach. Most notably, Minnesota recently adopted a VOST that utilities can propose as an alternative to offering NEM tariffs.

Utility Procurement Policies

Another category of support for DG can be found in the inclusion of carve-outs or set-asides for DG within state RPS programs. Figure 17-7 shows how DG is or is not allowed to participate in RPS programs around the country. Inclusion of clean DG in RPS or other clean energy standards is thus another tool in the 111(d) implementation tool kit.

The state of New Jersey offers one example of the significance of having a solar carve-out in a state RPS policy. As Figure 17-7 indicates, New Jersey has one of the most ambitious solar/DG provisions of any state. New Jersey was also one of the first states to adopt this policy approach. Over time, the RPS policy has been a strong driver for distributed PV deployment, and as a result New Jersey ranked third among the states in total installed PV capacity at the end of 2013.[29]

4. GHG Emissions Reductions

The inherent potential of clean energy *technologies* to reduce GHG emissions is addressed in detail in Chapter 6 and need not be repeated here. But DG systems differ from utility-scale, central station generation in one important respect that affects GHG emissions. Because DG systems produce electricity closer to where it is consumed, far less electricity is lost (or none is lost at all) in the transmission and distribution system than occurs when central station generation is delivered to customers. To the extent that the central station generators emit GHGs, reduced line losses equate to reduced emissions. In this way, a kWh of DG can reduce the GHG emissions associated with greater than 1 kWh of system-supplied electricity.[30]

5. Co-Benefits

The co-benefits associated with clean energy technologies, including solar and wind energy, are detailed in Chapter 6. Here we only note some of the co-benefits that are unique to clean DG, or significantly different for DG than for utility-scale installations.

The two most significant differences with DG (compared to utility-scale investment in clean energy) are that the generation is sited coincident with customer load (in nearly all cases), and the customer invests all or most of the capital to build a resource that provides system benefits. The significance of the first point is that DG, by generating electricity where it is used, reduces the amount of electricity that is unavoidably lost in the electric transmission and distribution system. The significance of the second point is that customers usually only invest in DG when it makes economic sense for them to do so, and this guarantees that the participating customer benefits from DG in ways that it might not benefit from utility-scale investments in clean technologies. For example, the customer investing in DG will expect its energy bills to decrease, whereas bills may or may not decrease as a result of utility-scale investment in the same technologies.

Clean DG is sometimes compared to energy efficiency because both are customer-focused, customer-driven, voluntary options, and they possess many of the same potential benefits. Although some of the co-benefits of efficiency are not applicable to clean DG, other co-benefits are arguably greater for clean DG than for efficiency. For example, some sources of clean DG have a greater potential to provide electric system services that protect the reliability, resiliency, and security of the grid.

The full range of co-benefits that can be realized by encouraging or incentivizing clean DG is summarized in Table 17-2.

29 Supra footnote 17.

30 Although most of the benefit of DG comes from displacing utility-scale fossil-fueled generation with inherently lower-emitting forms of generation, it is possible that in some cases well-placed fossil-fueled DG could produce some emissions reduction benefits by virtue of avoided line losses. Clean DG would, of course, provide far more emissions reduction benefit than fossil-fueled DG, all else being equal.

Table 17-2

Types of Co-Benefits Potentially Associated With Clean DG

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	Yes
Avoidance of Uncollectible Bills for Utilities	Yes
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Maybe – DG may allow utilities to avoid infrastructure investments, but at high penetration levels additional investments in infrastructure may be necessary to manage variable generation and power flows
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes – interconnection rules are designed to prevent DG from compromising reliability, but in some ways DG can enhance reliability
Displacement of Renewable Resource Obligation	Yes
Reduced Credit and Collection Costs	Yes
Price Suppression Effect	Yes
Other	

6. Costs and Cost-Effectiveness

As explained in Chapter 6, the concept of levelized costs of electricity (LCOE) was created to facilitate comparisons of the costs of different electric generation technologies. LCOE reflects the average cost of producing each unit of electricity over the life of a typical generator. LCOE estimates include consideration of all costs (including capital, financing, operations and maintenance, and fuel costs) and the amount of electricity produced from a particular type of generation.

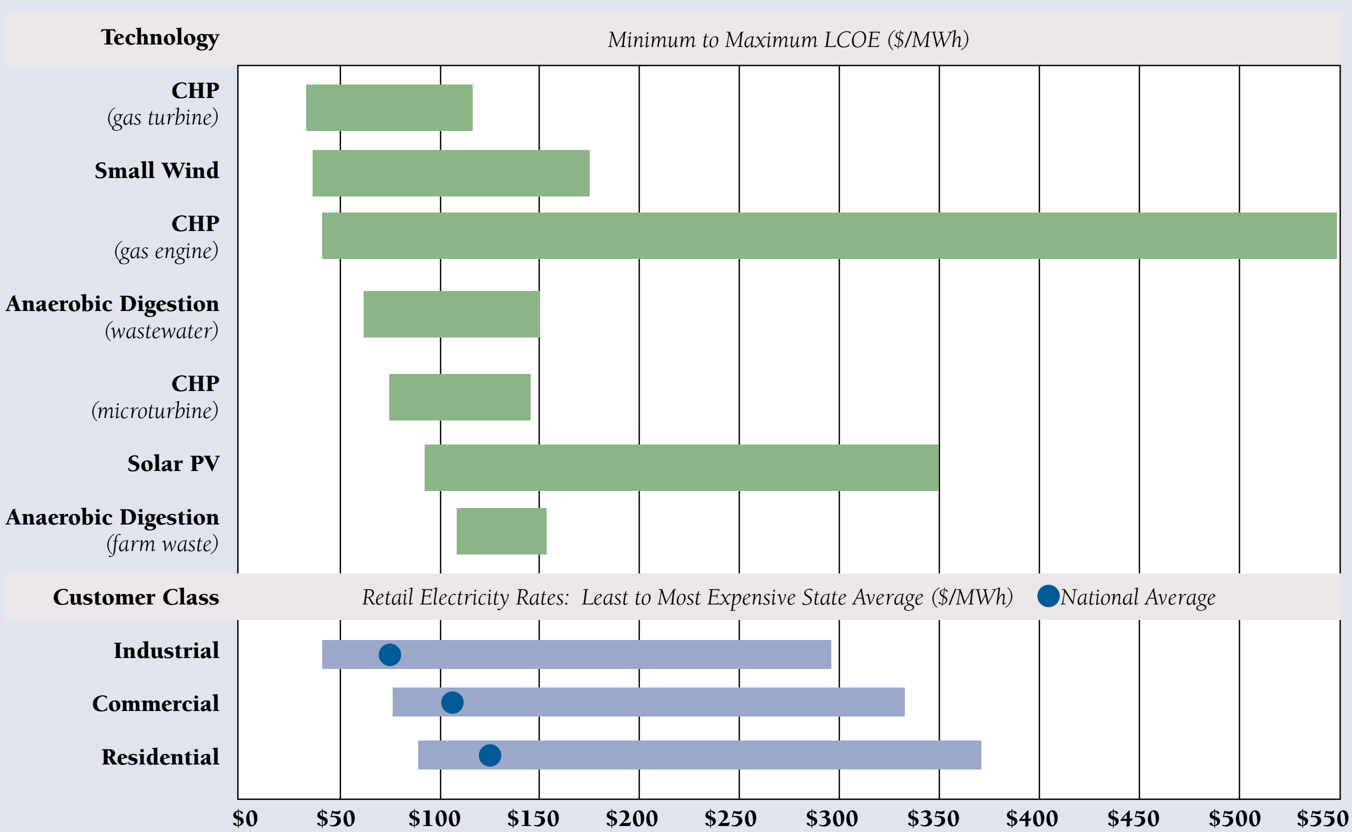
When utility-scale investments are made by electric utilities or independent power producers, LCOE data can be useful for evaluating generating technologies to get the best value out of limited capital. The investing entity will compare the costs of different technologies to each other, and to expected wholesale power prices, before deciding whether an investment could be a good choice for consumers (in the case of a utility) or profitable (in the case of an independent power producer).

When DG investments are made by customers, LCOE values can be different than for utility-scale investments in the same technologies, and the values can have a different significance. When customers invest in DG, they don't compare the LCOE of all of the different technologies to wholesale prices. Instead, they compare the LCOE of their realistic DG options (in some cases, solar PV being the only realistic option) to their expected costs as a retail electricity customer. In other words, the customer wants to know if generating electricity will save them money compared to buying power at retail rates.

Figure 17-8 shows the LCOE for selected DG technologies as compared with retail electricity rates. The chart indicates that some forms of clean DG are currently competitive with national average retail rates, especially for the more expensive residential customer rates. And all of the selected

Figure 17-8

Levelized Costs of Energy for DG Technologies in the United States[31]



31 Supra footnote 20. LCOE data in the figure are based on: Bloomberg New Energy Finance. (2013, August). *Small Distributed Power Generation in the United States – Is It Competitive?* (Subscription required). Retail rates data were compiled by the authors from data published by the US Energy Information Administration (2013).

DG technologies can be competitive with retail rates in the right circumstances – wherever the LCOE (which can vary based on geography and other factors) is less than the retail rate (which varies geographically and by customer class).

It is also interesting to compare the LCOE data presented here in Figure 17-8 to the LCOE data included in Figure 6-7 in Chapter 6. The comparison is imprecise because the studies were conducted with different assumptions, but the comparison does convey the general notion that some clean DG technologies appear to be cost-effective even when compared to utility-scale investments in fossil and renewable generating technologies. In making these comparisons, one should remember that the value of clean DG includes some avoided cost benefits (e.g., deferred transmission investment) that can be significantly different or nonexistent for utility-scale investments in generation capacity. It is equally important to recognize that the cost and value of DG vary by location and so it is not accurate to say that all clean local DG adds incremental value relative to utility-scale, central station generation.

7. Other Considerations

Like energy efficiency, DG leads to reduced retail electricity sales. Concerns are sometimes raised that this in turn creates the need for an increase in retail electric rates to ensure stable revenues for utilities. For clean DG adopting customers, any increase in rates needs to be evaluated in light of the net reduction in the participants' electricity bill. For non-adopting customers, any possible rate increase arising from reduced revenues needs to be evaluated in the context of a comprehensive study of sources of cost and value for DG. For example, can the cumulative effects of DG avoid or significantly delay capital investments in the power grid that would have been paid for by customers, including customers without DG? The Rocky Mountain Institute examined how the sources of cost and value have been computed for solar PV systems in 15 recent studies.[32] These studies indicate that accounting for the utility's "lost revenues" is one of a number of impacts that can affect the calculation of benefits and costs of PV DG to non-adopting customers. The studies indicate that the results are dependent on the terms of DG tariffs, and that one cannot make a universal statement that increasing DG penetrations either hurt or benefit nonparticipating customers. Similar conclusions were reached by Keyes and Rábago in a separate publication.[33] But even in those situations in which nonparticipating customers may be harmed, tariffs can be amended to ensure that participants, nonparticipants, and utility shareholders can pay for and be compensated fairly for the services they receive or provide to others.[34]

Clean DG that is targeted to meet temporal or geographic needs of the electric system can be highly cost effective, even as DG penetration increases. So programs that can target clean DG deployment to provide energy at high-cost times, receive energy at low-cost times, and provide energy services locationally to meet reliability challenges (like local frequency support or reactive power) should be considered. The ability of DG to provide these high-value services will be enhanced as the electric grid modernizes and smart inverters and bidirectional flow meters become standard. These grid enhancements increase the "visibility" of customer generation to the grid operator and allow the customer resources to become more fully integrated into grid operations. Furthermore, these enhancements also allow DG to be "islanded" and operate in parallel to the grid. This is especially important for improving grid resiliency. The grid may experience problems while islanded generation continues to produce electricity for local demand.

Distributed energy storage technologies are often paired with DG to enhance the value of DG to the customer and the grid. Batteries are, of course, the best known of these storage technologies, but other options such as flywheels and compressed air systems are now commercially available. Storage systems allow the customer to use the electricity produced by their DG system at different times than when it is generated, but they also offer potential solutions to some of the challenges of integrating large

32 Hansen, L., & Lacey, V. (2013, September). *A Review of Solar PV Benefit and Cost Studies, 2nd Edition.* Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

33 Keyes, J., & Rábago, K. (2013, October). *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* Interstate Renewable Energy Council, Inc. Available at: http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.

34 For a detailed examination of tariff design issues for DG, refer to: Supra footnote 20.

amounts of DG into the utility system. Storage systems can smooth out the variation in the amount of electricity exported and imported by a customer who has DG over the course of a day, making grid integration and utility system planning easier and further facilitating the use of DG to provide energy services.

Clean DG installations also have the benefit of providing small incremental additions to capacity (e.g., in 5-kW or 5-MW increments) that defer or obviate the need for large, lumpy investments in central station fossil generation (e.g., in 250-MW increments). These DG installations can be operational in a matter of months, whereas utility-scale investments typically require multiple years for planning, permitting, and construction. The matching of changes in load with changes in supply has long been an inherently imprecise exercise where large incremental generation facilities get built in advance of the need for the full capacity of the resource. Thus, consumers are paying for capacity they do not need for some time until load growth catches up with capacity. This "lumpy" nature of generation investment is not present with DG. DG installations happen in small increments, so they have the potential to better match need with resources than large lumpy investments. This value of clean DG is often captured in an estimate of the benefits to all consumers of deferring the need for new generation capacity, transmission capacity, or distribution system capacity. As clean DG constitutes a larger proportion of the resource mix, the value paid to DG will have to be refined to reflect the evolution of system benefits it provides. Some of these impacts are positive, for example, obviating the need for a new large generation facility, and some are negative, for example, creating the need for local distribution system investment that would not have been necessary but for the growth of DG.

More extensive treatments of all of the issues discussed in this section can be found in the recent literature on DG.[35]

8. For More Information

Interested readers may wish to consult the following reference documents for more information on encouraging or incentivizing clean DG:

- Barbose, G., Darghouth, N., Weaver, S., & Wiser, R. (2013, July). *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012.* LBNL-6340E. Berkeley, CA: Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.
- Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013, November). *Regulatory Considerations Associated with the Expanded Adoption of Distributed Solar.* National Renewable Energy Laboratory and The Regulatory Assistance Project. NREL/TP-6A20-60613. Available at: http://www.raponline.org/document/download/id/6891.
- Bloomberg New Energy Finance. (2013, August). *Small Distributed Power Generation in the United States – Is It Competitive?* Subscription newsletter and proprietary data service.
- Costello, K. (2014, June). *Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do?* National Regulatory Research Institute. Available at: http://www.nrri.org/documents/317330/16dd1f89-c8ec-44db-af73-7c6473a3ef09.
- Hansen, L., & Lacey, V. (2013, September). *A Review of Solar PV Benefit and Cost Studies, 2nd Edition.* Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

35 See the following, for example: Bird, L., McLaren, J., Heeter, J., Linvill, C., Shenot, J., Sedano, R., & Migden-Ostrander, J. (2013, November). *Regulatory Considerations Associated With the Expanded Adoption of Distributed Solar.* National Renewable Energy Laboratory and The Regulatory Assistance Project. NREL/TP-6A20-60613. Available at: http://www.raponline.org/document/download/id/6891. Hansen, L., & Lacey, V. (2013, September). *A Review of Solar PV Benefit and Cost Studies, 2nd Edition.* Rocky Mountain Institute. Available at: http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue. Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6898.

- Keyes, J., & Rábago, K. (2013, October). *A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation.* Interstate Renewable Energy Council, Inc. Available at: http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.
- Linvill, C., Shenot, J., & Lazar, J. (2013, November). *Designing Distributed Generation Tariffs Well: Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6898.
- North Carolina State University. (2014). *Database of State Incentives for Renewables & Efficiency (DSIRE).* Available at: www.dsireusa.org.
- Selecky, J.,Iverson, K., & Al-Jabir, A. (2014, February). *Standby Rates for Combined Heat and Power Systems: Economic Analysis and Recommendations for Five States.* Prepared by Brubaker & Associates, Inc. and The Regulatory Assistance Project for Oak Ridge National Laboratory. Available at: http://www.raponline.org/document/download/id/7020.
- State and Local Energy Efficiency Action Network. (2013, March). *Guide to the Successful Implementation of State Combined Heat and Power Policies.* Available at: https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.

9. Summary

Clean DG technologies are cost-competitive in some states today and are becoming increasingly competitive as technology costs decline, technology performance improves, grid modernization better allows the potential value of local DG to be captured, and state policies toward DG evolve.

Improvements in interconnection policies, effective tax and incentive policies, state policies preferring clean energy sources such as RPS policies, and the terms and conditions of DG tariffs and contracts can each contribute to increasing the deployment of clean DG. NEM, FIT, and VOST tariffs, virtual NEM policies such as community solar and solar gardens, third-party leasing and on-bill financing, best practice standby rates, and evolution of markets to allow clean DG to more fully participate in providing energy, capacity, and ancillary services can each contribute to increasing clean DG adoption.

Clean DG displaces the need for some fossil fuel-based, central station generation and thus can contribute to GHG reductions and 111(d) compliance. Most forms of DG also reduce other air pollutant emissions. The benefits of clean DG are amplified to some extent by the fact that DG avoids most or all of the transmission and distribution line losses that are associated with central station generation. DG systems can also be deployed in much smaller increments than utility-scale, central station generation, which reduces the risk and expense of developing more capacity than utility customers need. DG penetration is still small today almost everywhere, but higher levels of PV adoption will present challenges to utility revenues and electric system operations when penetrations become substantially higher. Fortunately, there are utility business model adaptations that can address utility revenue sufficiency in the face of high DG adoption and there are electric system improvements (e.g., smart inverters and improved DG visibility) that can address the reliability challenges.

18. Revise Transmission Planning and Cost Allocation[1]

1. Profile

Transmission is an essential component of the modern electric grid, but one that is perhaps little understood by air pollution regulators, as the transmission lines themselves do not emit air pollution. This chapter explores a wide range of issues associated with transmission system planning and transmission cost allocation. These issues strongly influence how electric generating units are sited, built, and operated. Because electric generating units are the largest source of US greenhouse gas (GHG) emissions, public policies regarding transmission can facilitate or hinder GHG (and other air pollutant) emissions reductions.

As noted in Chapter 6, increasing the proportion of total electric generation that comes from zero-emissions resources can be a cost-effective way to reduce GHG emissions. In some cases, building new transmission lines and fairly allocating their costs is a necessary key to unlocking access to large quantities of low-cost, low-emitting resources. Lack of transmission can be a significant impediment to new, utility-scale renewable energy plants, because some of the highest quality renewable resources are located in remote areas, away from load centers. For example, Figure 18-1 shows how the best wind resources tend to be located in offshore areas and areas of the Great Plains that have relatively small population centers.

Clean energy resources that might be location-constrained but accessed by expanded transmission lines include wind, solar photovoltaic, solar thermal, geothermal, and biomass generating units. (The mature zero-emissions technologies of hydro and nuclear will continue to play an important role, but are unlikely to require any incremental transmission capacity in the near future.) It is important to address shortages in transmission capacity in the near term, because the development of new renewable energy plants takes only a few years, whereas transmission lines typically take seven to ten years to develop. In sum, transmission expansion that facilitates interconnection of cost-effective, low-emissions generation or that improves the energy efficiency of system operations is complementary to the resources themselves.

Transmission expansion can also support greater resource efficiency and lower carbon emissions by expanding the possibility of energy exchanges between regions. For example, regional exchange tools such as energy imbalance markets and dynamic transfers can facilitate the use of high-quality renewable resources with different production profiles (e.g., wind in Wyoming and Montana is a high-quality resource that produces wind at different times than West Coast wind).[2] Targeted transmission investment can increase the transmission capacity available for use and bring high-quality renewable energy into the mix of resources in a timely fashion. For example, as coal plants retire in the Midwest, additional firm transmission capacity is likely to be necessary to ensure wind resources can be delivered into load centers in the Northeast.

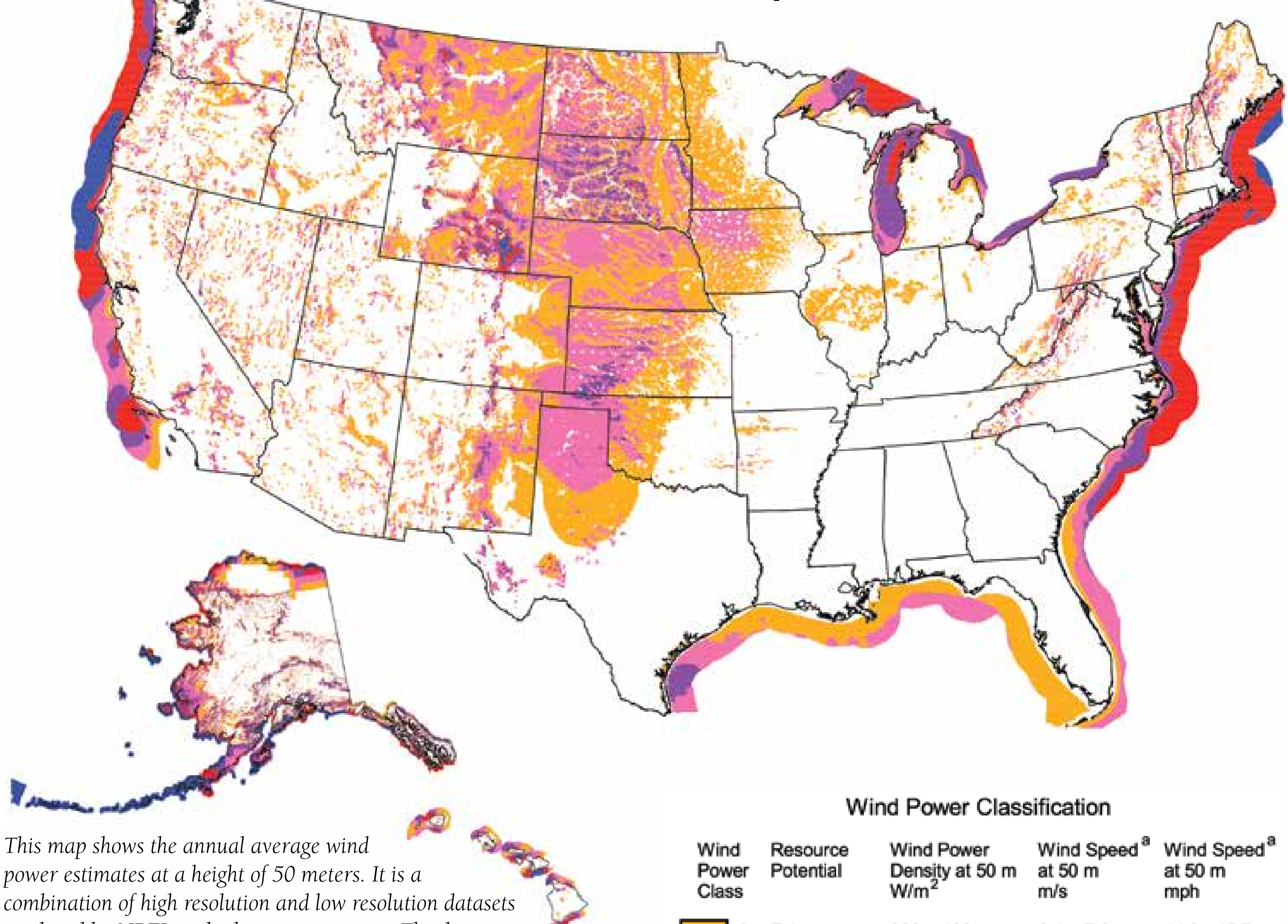
New transmission development has slowed in the United States over the last several decades, as the electric power industry has wrestled with much slower demand growth,

1 This chapter benefits from previous work done by Kevin Porter and Sari Fink (Exeter Associates), Philip Baker, and The Regulatory Assistance Project.

2 Normally, each balancing authority balances electricity supply and demand mostly by dispatching the least costly available resources on its own system to meet demand on its own system. In some cases, two balancing authorities may schedule a transfer of a known amount of electricity in advance (e.g., a day ahead). Dynamic transfers offer a way to transfer electricity from one balancing authority to another with little advance notice or when the amount of electricity to be transferred from a variable energy resource cannot be precisely predicted in advance. Doing so can provide reliability and economic benefits to both balancing authorities. Energy imbalance markets have been established in some locations to create a more formal, system-wide market mechanism for transferring electricity between balancing authorities on short notice.

Figure 18-1

US Wind Resource Map[3]



This map shows the annual average wind power estimates at a height of 50 meters. It is a combination of high resolution and low resolution datasets produced by NREL and other organizations. The data was screened to eliminate areas unlikely to be developed onshore due to land use or environmental issues. In many states, the wind resource on this map is visually enhanced to better show the distribution on ridge crests and other features.

Wind Power Classification

Wind Power Class	Resource Potential	Wind Power Density at 50 m W/m^2	Wind Speed[a] at 50 m m/s	Wind Speed[a] at 50 m mph
3	Fair	300 - 400	6.4 - 7.0	14.3 - 15.7
4	Good	400 - 500	7.0 - 7.5	15.7 - 16.8
5	Excellent	500 - 600	7.5 - 8.0	16.8 - 17.9
6	Outstanding	600 - 800	8.0 - 8.8	17.9 - 19.7
7	Superb	800 - 1600	8.8 - 11.1	19.7 - 24.8

[a] Wind speeds are based on a Weibull k value of 2.0

generation overcapacity, designing and implementing wholesale markets, restructuring, and retail competition (in some US states). Additionally, transmission development in the United States from the 1950s through early in this century focused on delivering power from centrally located, baseload power stations, which were generally the most efficient and cost-effective sources of electric generation at that time. Because renewable technologies were immature, the need to access areas with high-quality renewable resources had not yet emerged. Developing transmission to location-constrained resources presents a "chicken-and-egg" problem: renewable resource developers cannot guarantee firm delivery from potential new projects without transmission, and transmission companies cannot develop transmission because of uncertainty about whether sufficient generating-plant development will occur. Uncertainties over transmission siting and cost allocation, especially for multistate transmission lines, can also be a barrier to new transmission that reinforces the chicken-and-egg dilemma.

Combinations of factors make transmission expansion more time-consuming than building new generation. A

3 National Renewable Energy Laboratory. (2009). *US 50m Wind Resource Map.* Available at: http://www.nrel.gov/gis/pdfs/windsmodel4pub1-1-9base200904enh.pdf

lack of flow control means that transmission is inherently a regulated network asset and not an individual, for-profit investment. Accordingly, transmission expansion decisions in the United States typically go through a public process involving the Federal Energy Regulatory Commission (FERC), state utility commissions, and stakeholders. This process can be lengthy; new transmission development often takes much longer than the construction of new generation facilities (which are usually not subject to direct federal regulation).[4] Compounding this problem is the high capital cost (and low operating cost) and long project life of transmission assets. Taken together, these issues require policymakers to make a difficult collective decision about the need for an asset up to 50 years in the future where virtually all the costs are incurred upfront. There are also very strong economies of scale, which, coupled with the long project life, makes coming to consensus even tougher.

Nonetheless, in recent years, state and federal regulators and transmission companies have increasingly engaged in regional transmission planning processes to determine how best to unlock areas of rich renewable resources. This trend has been driven in part by state renewable portfolio standard (RPS) policies, the emergence of offshore wind plants, and concerns over global climate change. Some experimentation with cost allocation policies is also taking place in an attempt to overcome the chicken-and-egg problem. These recent efforts are pointing toward some public policy approaches for transmission planning and cost allocation that can facilitate greater deployment and use of clean energy resources as a strategy to reduce GHG emissions.

2. Regulatory Backdrop

Transmission planning starts with identifying the need for new transmission. Establishing the need for transmission is essential to all regulatory decisions that follow. The determination of need justifies the use of land and natural resources, supports the allocation of costs, and motivates financing. Thus, the interests of a wide range of stakeholders are affected, and the regulators charged with guiding the transmission planning process must therefore ensure an open and transparent public process.

The responsibility for transmission planning is not uniform in the United States, but state and federal regulators are important participants in every venue. Transmission delivers wholesale electric power and FERC has jurisdiction over wholesale electricity markets, so FERC is integral to transmission planning and approval. However, states also get involved. Many states still have integrated resource planning requirements (refer to Chapter 22), and transmission projects are often offered to state regulators as a resource option to help meet an anticipated need for new energy or capacity. Even in states that do not have an integrated resource planning requirement, the state regulators often get involved in transmission planning and approval because costs are allocated to electric customers in each state that benefits.

FERC and state regulators oversee decisions regarding the determination of need, but the responsibility for formulating a transmission plan that becomes the basis for asserting need resides with different entities around the country. The responsibility for planning new transmission may reside with regional transmission organizations (RTOs) where they exist, regional transmission planning groups (particularly in the non-RTO regions of the West and the Southeast), and with individual transmission line owners. Individual transmission owners include investor-owned utilities, public power utilities, federal Power Marketing Administrations (the Western Area Power Administration, Bonneville Power Administration, and Tennessee Valley Authority), and independent transmission companies. Some of these entities raise financing and build transmission after a need has been identified. Others focus on identifying the need but depend on individual developers and transmission owners to finance and build needed projects.

There are different types of "needs" that motivate a transmission project, and who builds, finances, and pays for a project varies by the type of need. Projects generally fall into one of the following categories:

- *Reliability-based projects* are transmission upgrades and new transmission needed to ensure that the transmission system meets reliability criteria established and enforced by the North American Electric Reliability Corporation, particularly the expectation that the system will fail to meet customer demand no more than one day in every 10-year period.
- *Generation interconnection projects* are upgrades to transmission or new transmission assets needed

4 There are exceptions. Hydroelectric plants require an operating license from FERC, nuclear power plants require approval by the Nuclear Regulatory Commission, and generating units located on federal lands require approvals from one or more federal agencies.

to hook up generating projects that will be, or are expected to come, online.

- *Economic-based projects* are for new transmission or transmission upgrades aimed at some combination of reducing transmission congestion costs, accessing new generating resources, or making markets more competitive by accessing other markets or existing generating resources.
- *Customer-funded transmission projects* are those sponsored by transmission customers, such as within an RTO.
- *Merchant transmission projects* are privately owned transmission projects that are usually quite sizable and cross multiple states to transmit new generation and/or to arbitrage against differing prices in different regions.

Although state regulators may, and often do, become involved in evaluating the need for each of these categories of projects, FERC's jurisdiction over wholesale markets and interstate exchanges has made FERC the primary actor driving the regulatory context of transmission planning over the last decade. The remainder of this section focuses on explaining the regulatory foundation laid by FERC and concludes with a summary of the role that air regulators can play in these FERC-led processes.

FERC issued three orders that have shaped recent transmission planning activities in the United States. In July 2003, FERC issued Order No. 2003 directing transmission providers to revise their open access transmission tariffs to include the standardized Large Generator Interconnection Procedures contained in the Order. Included in Order 2003 are policies for how interconnection and transmission grid reinforcement costs should be allocated. The order identifies two types of construction costs that are associated with generation interconnection:

- *Direct connection facilities* — all equipment and construction required to connect the new generating facility to the first point of interconnection with the transmission grid.
- *Network transmission upgrades* — the equipment and construction required to reinforce the existing transmission system in order to accommodate the new generation project.

Under Order 2003, the generators are responsible for the cost of all direct connection facilities between the generator and the transmission grid. Generators must also provide the upfront funding for the cost of any network upgrades and new additions to the transmission network that are required as a result of the interconnection. However, Order 2003 states that generators should be fully reimbursed for the network upgrade costs by transmission providers within five years, with interest. The reimbursement can be in the form of credits against the costs of transmission service or, if available, financial transmission rights.

Order 2003 allows RTOs to propose variations to the interconnection policies and procedures contained in Order 2003.[5] Most of the nation's RTOs have gained approval from FERC to modify their large generator interconnection procedures. These modifications have included alternative cost allocation methodologies for transmission upgrades and for interconnecting new generators; increases to the initial study deposit amounts; inclusion of group studies; and adding requirements for generation developers to meet certain milestones prior to being able to proceed to subsequent study stages.

FERC Order No. 890, issued in February 2007, enhanced the stakeholder process for all public utilities by directing transmission providers to conduct local and regional level transmission planning in a coordinated, open, and transparent manner while allowing for regional differences.[6]

In July 2011, FERC issued Order No. 1000, which outlined several additional requirements for transmission planning and cost allocation. First, Order 1000 requires that transmission providers participate in regional planning processes that meet Order 890 requirements for transparency and stakeholder inclusion. Second, Order 1000 requires that these regional transmission planning processes consider transmission needs driven by public policy requirements established through state or federal

5 FERC: (2003, July 24). *Order No. 2003: Standardization of Generator Interconnection Agreements and Procedures;* (2004, March 5). *Order No. 2003-A;* (2004, December 20). *Order No. 2003-B;* and (2005, June 16). *Order No. 2003-C.* Available at: http://www.ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp. FERC set out nine criteria for transmission plans: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional coordination, economic planning studies, and cost allocation.

6 FERC. (2007, February 16). *Order No. 890: Preventing Undue Discrimination and Preference in Transmission Service.* Docket Nos. RM05-17-000 and RM05-25-000. Available at: http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf

laws or regulations. These public policy requirements could include state energy policies, such as RPS requirements and energy efficiency resource standards, but could also include state air pollution policies, such as a state implementation plan for ozone or a GHG emissions policy. Third, as part of the planning process, transmission providers must consider non-transmission alternatives (NTAs) (e.g., energy efficiency, demand response, distributed generation, and so on) that can efficiently and cost-effectively satisfy reliability needs, as well as conventional energy supply and transmission projects. Finally, Order 1000 requires that neighboring transmission regions coordinate their planning processes to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.

In addition to the transmission planning processes mandated by Order 1000, both the regional plans and the inter-regional plans must have a cost allocation method in place; otherwise, FERC will set the cost allocation method for them based on the case record. Participant funding (in which all transmission costs are assigned to participants in a transmission project, such as the transmission sponsors or generators) is allowed but not as the default regional or inter-regional cost allocation method. Interconnection-wide transmission cost allocation (in which all costs are allocated equally to all load) is not permitted.[7] Order 1000 prescribes six cost allocation principles for regions to consider:

- The costs of new transmission projects should be allocated to load-serving entities in a way that is "roughly commensurate" with the estimated benefits of the project to those entities.
- Those that do not benefit from transmission upgrades should not be required to pay for them.
- Project screening methods must not exclude projects with significant net benefits (i.e., benefits minus costs) even if the benefit-cost ratio (i.e., benefits divided by costs) is only slightly greater than 1.0.
- No allocation of costs outside a region unless the other region agrees.
- Cost allocation methods and identification of beneficiaries must be transparent.
- Different allocation methods could apply to different types of transmission facilities.[8]

In the context of Order 1000, air pollution regulators are "stakeholders" and they may be able to participate directly in regional transmission planning processes, to ensure that the costs associated with air pollutant emissions – which have historically been dismissed as "externalities" – are considered when the cost-effectiveness of various transmission and non-transmission alternatives is evaluated. Air pollution regulators can elevate awareness of key risks (e.g., the potential air quality impacts of diesel backup generators as an NTA) and opportunities (e.g., the potential multipollutant reduction benefits of energy efficiency as an NTA). Air regulators' participation in transmission planning processes can help guarantee appropriate consideration of these resources.

3. State and Local Implementation Experiences

States have demonstrated several possible paths for developing and implementing transmission plans to access renewable energy over the past ten years. In some cases, these efforts started with state-led initiatives, such as the Renewable Energy Transmission Initiative (RETI) in California and the Competitive Renewable Energy Zone (CREZ) efforts in Texas. Examples can also be found of similar, regional efforts, such as the Upper Midwest Transmission Development Initiative (UMTDI) and the Regional Generator Outlet Study (RGOS). All of those state-led renewable energy zone (REZ) projects are described in detail in this chapter. But more recently, comprehensive planning efforts in each of the interconnections have been driven primarily by FERC Order 1000 requirements. Compliance filings for FERC Order 1000 regional transmission plans were made in October 2012, and compliance filings for inter-regional transmission plans were made in May 2013. In November 2013, more than two dozen parties filed briefs with a federal appellate court challenging FERC's authority to require the filing of transmission plan cost allocation proposals.[9] But in August

7 Allocating costs "to load" means that the costs are apportioned to load-serving entities (utilities, or in some states, non-utility competitive retail electric service companies) in proportion to the amount of load they serve.

8 FERC. (2011, July 11). *Order No. 1000: Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities.* Docket No. RM10-23. Available at: http://ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

9 Coalition for Fair Transmission Policy. (2013). CFTP Files Reply Briefs in US Court of Appeals Challenging FERC's Defense of Order 1000. [Press release]. Available at: http://www.prnewswire.com/news-releases/cftp-files-reply-briefs-in-us-court-of-appeals-challenging-fercs-defense-of-order-1000-232533521.html

2014, the US Court of Appeals for the DC Circuit affirmed the authority of FERC to implement Order 1000 in its entirety, including the cost allocation principles.[10]

Besides transmission planning as required by Order 1000, the US Department of Energy (DOE) issued grants to each of the three interconnections in the United States — Eastern, Western, and Texas — to devise an interconnection-wide plan. In December 2011, the Eastern Interconnection Planning Collaborative (EIPC) submitted its Phase One report to the DOE, which focused on the integration of regional plans and long-term macroeconomic analysis. EIPC submitted its Phase Two report to the DOE in December 2012. That report focused on transmission studies for three scenarios: a national carbon constraint with increased energy efficiency and demand response; a national RPS; and business as usual.[11] Also in 2011, the Texas Interconnection's Long-Term Study Task Force submitted to the DOE its interim status report for the Electric Reliability Council of Texas (ERCOT) Long-Term Transmission Analysis. ERCOT is the independent system operator serving most of the State of Texas. On October 2013, ERCOT's task force submitted its final report to DOE.[12]

The Transmission Expansion Planning and Policy Committee of the Western Electric Coordination Council (WECC) performed a comprehensive planning process in the Western Interconnection between 2009 and 2013 and produced 10-year and 20-year West-wide transmission plans to meet a wide range of scenarios.[13] All data in the plans were updated on a state-by-state, utility-by-utility basis so that, for the first time, the West has a consistent set of data vetted by diverse stakeholders that is suitable for planning. The data recognize all forthcoming approved plans. The planning tool developed by WECC staff and its consultants uses the data and future scenario assumptions to generate different generation futures for the West. A number of these futures are motivated by understanding what new transmission will be needed to achieve much lower carbon emissions in the West. For example, some futures investigate the transmission implications of using much more renewable energy and energy efficiency in place of coal generation. The planning process culminated in the production of a 2013 transmission plan for the Western Interconnection, and a 2015 planning process has now been initiated.

Renewable Energy Zones

To assist with transmission planning, a number of regions have initiated REZ activities in the last decade. These efforts begin with the identification of "renewable energy zones" that are rich in renewable energy development potential. Following identification of the zones, transmission plans are then drawn up to create the much-needed transmission infrastructure in order to facilitate renewable energy project construction in the zones.

In 2007, the California Public Utility Commission, the California Energy Commission, California Independent System Operator, and three publicly owned utilities[14] launched the California RETI. RETI is organized as a stakeholder collaborative to create support for the transmission projects that are needed to meet state RPS and GHG reduction goals. The first phase of the project identified several CREZs, both in and out of state, and then ranked them with respect to environmental impacts and development economics. In the second phase, a conceptual transmission plan was developed, including the outline of a plan designed to facilitate California meeting its RPS goal (33 percent by 2020). The plan consists of a set of transmission projects costing about $6.6 billion to access 82,739 gigawatt-hours of energy from 11 CREZs.[15] RETI was subsequently incorporated into the California Transmission Planning Group, which in February 2012

10 *S.C. Pub. Serv. Auth. v. Fed. Energy Regulatory Comm'n,* No. 12-1232. DC Circuit. (2014, August 15).

11 EIPC. (2012, December). *Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios.* Available at: http://eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf

12 ERCOT. (2013, October). *Long Term Transmission Analysis 2010-2030 Final Report. ERCOT Interconnection, October 2013. Long-Term Transmission Analysis 2012-2032 - Volume 1* [online]. Available at: http://www.ercot.com/content/committees/other/lts/keydocs/2013/DOE_LONG_TERM_STUDY_-_Draft_V_1_0.pdf

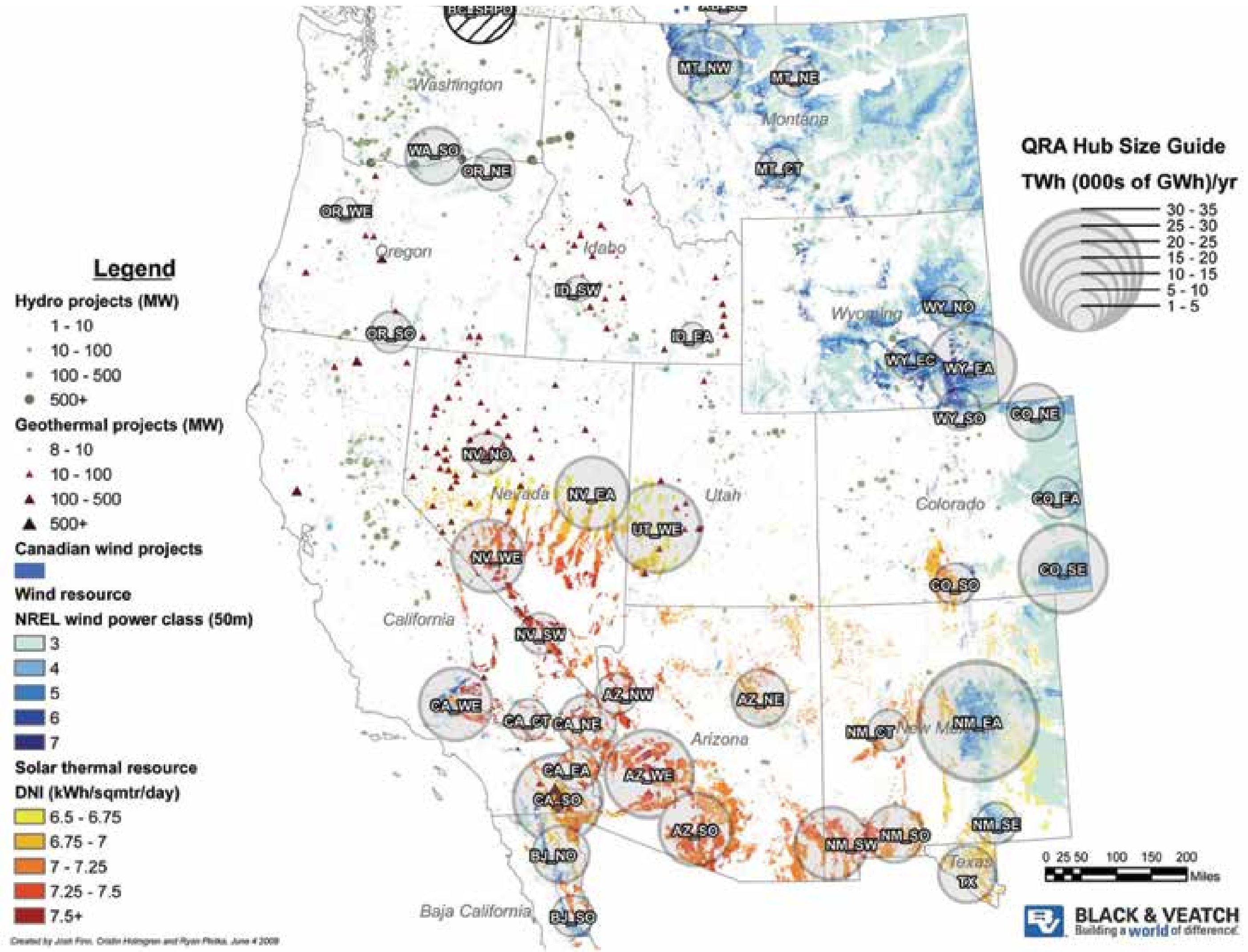
13 The WECC common case transmission plan for 2022 can be found at: https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/TEPPC_2022_StudyReport_PC1%20Common%20Case.docx&action=default&DefaultItemOpen=1; and the 2032 scenarios are described at: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Scenario-Planning.aspx

14 Sacramento Public Utility District, Southern California Public Power Authority, and Northern California Power Agency.

15 CPUC RETI website. Available at: http://www.energy.ca.gov/reti/index.html

Figure 18-2

Qualified Resource Areas Identified in WREZ Phase I[16]



issued its final comprehensive Statewide Transmission Plan.[17] Environmental and land use approvals are key to getting transmission approved in environmentally sensitive areas, and so California followed up the RETI process with a detailed look at the desert regions of California. The Desert Renewable Energy Conservation Plan is identifying transmission paths for accessing high-quality renewables in the desert region of the state.[18] The set of transmission segments that accesses about 4000 megawatts (MW) of wind and solar in the Tehachapi region in California was a notable success of the RETI initiative.

In recognition of RPS adopted in California and other western states, the Western Governors Association obtained funding from the DOE to characterize REZs across the western United States. The initiative is referred to as the Western Renewable Energy Zone (WREZ) initiative. The WREZ initiative leveraged work from the RETI process in California and hired Black & Veatch to perform a renewable energy characterization study for the footprint of the

16 Western Governors' Association & US Deparment of Energy. (2009, June). *Western Renewable Energy Zones – Phase 1 Report.* Available at: http://www.westgov.org/component/content/article/102-initiatives/219-wrez

17 California Transmission Planning Group website. Available at: http://www.ctpg.us/index.php?option=com_content&view=article&id=4&Itemid=4

18 A description of the Desert Renewable Energy Conservation Plan activities and the Draft conservation plan can be viewed at: http://www.drecp.org/

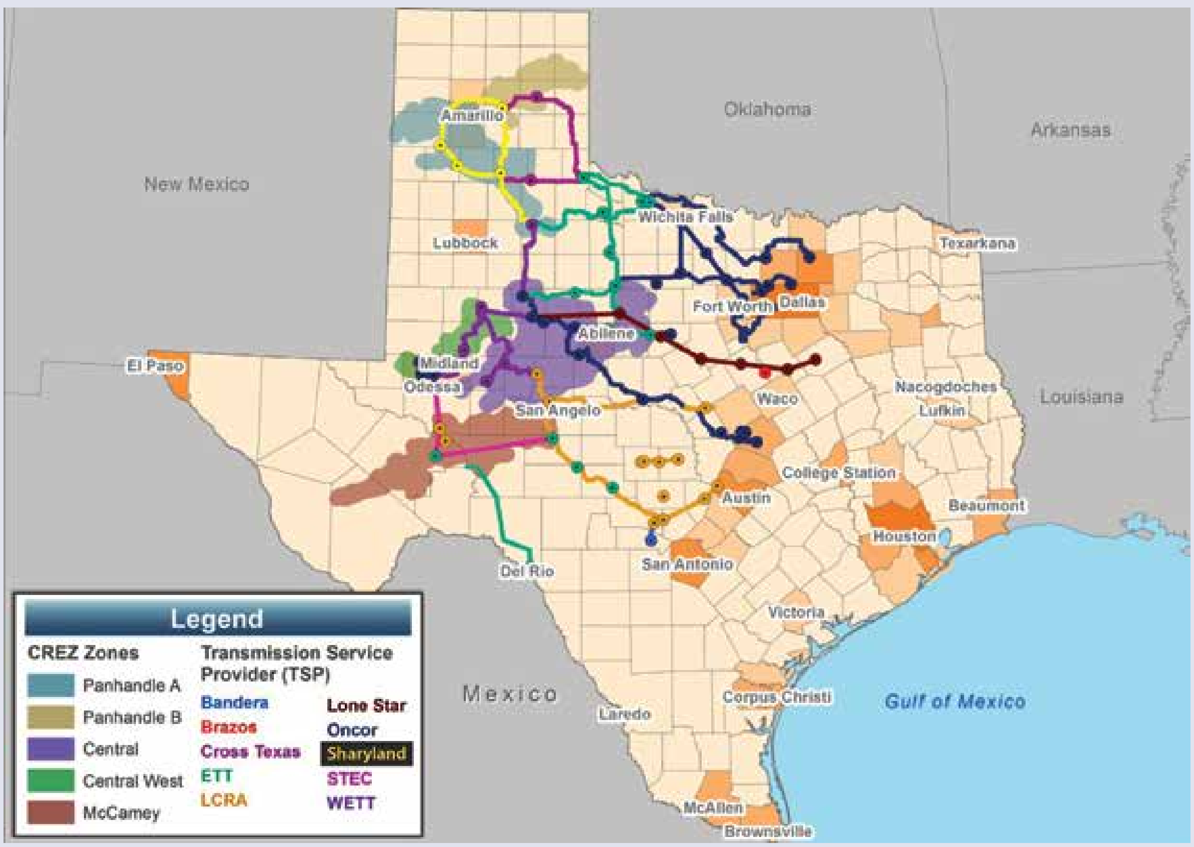
Western Interconnection. The resulting map of Qualified Resource Areas is depicted in Figure 18-2. Additional work in characterizing environmental, land, wildlife and cultural resources in the West to follow up the WREZ work is being conducted by the Environmental Data Task Force at WECC, with federal funding from the American Recovery and Reinvestment Act of 2009.[19] Several transmission projects being designed to deliver power from Arizona, Wyoming, Colorado, and New Mexico have benefitted from the WREZ resource characterization and subsequent conceptual transmission planning process.

Perhaps the most successful transmission initiative to date was launched in Texas in 2005, when the legislature authorized the creation of CREZs in that state. In 2007, ERCOT submitted a report to the Public Utility Commission of Texas identifying five CREZs in the Texas Panhandle, West Central Texas, and the McCamey area, as well as four different wind energy and transmission development scenarios. The Public Utility Commission of Texas chose to grant approval for development of a scenario that included up to 18,456 MW of wind power, along with an extensive transmission development plan estimated to cost about $4.93 billion.[20] A total of 186 CREZ transmission projects were ultimately proposed. As of October 2013, 139 have been completed, 15 have been canceled, and 32 are still in progress, as shown in Figure 18-3.[21]

The UMTDI was started in September 2008 by the Governors of Iowa, Minnesota, North Dakota, South

Figure 18-3

Texas CREZ Project Status as of October 2013[22]



19 For more information, see Western Electricity Coordinating Council, Environmental and Cultural Considerations webpage. Available at: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Environmental-and-Cultural-Considerations.aspx

20 ERCOT. (2008, April 15). *CREZ Transmission Optimization Study Summary*. Presentation by Dan Woodfin to the ERCOT Board of Directors. Available at: http://66.128.17.81/content/meetings/board/keydocs/2008/B0415/Item_6_-_CREZ_Transmission_Report_to_PUC_-_Woodfin_Bojorquez.pdf

21 RS&H. (2013, October). CREZ Progress Report (October Update). Prepared for the Public Utility Commission of Texas. Available at: http://www.texascrezprojects.com/page29605445.aspx

22 Ibid.

Dakota, and Wisconsin. The objective of the project was to promote renewable energy development, primarily wind projects, by identifying REZs within the footprint of the Midwest Independent System Operator (MISO),[23] determining transmission needs to access those REZs, and proposing an equitable cost allocation formula for those transmission projects. The UMTDI project identified 20 REZs and six transmission corridors in the five-state region that could deliver as much as 15 GW of wind capacity. The cost of building the necessary transmission lines was estimated to be approximately $3 billion.

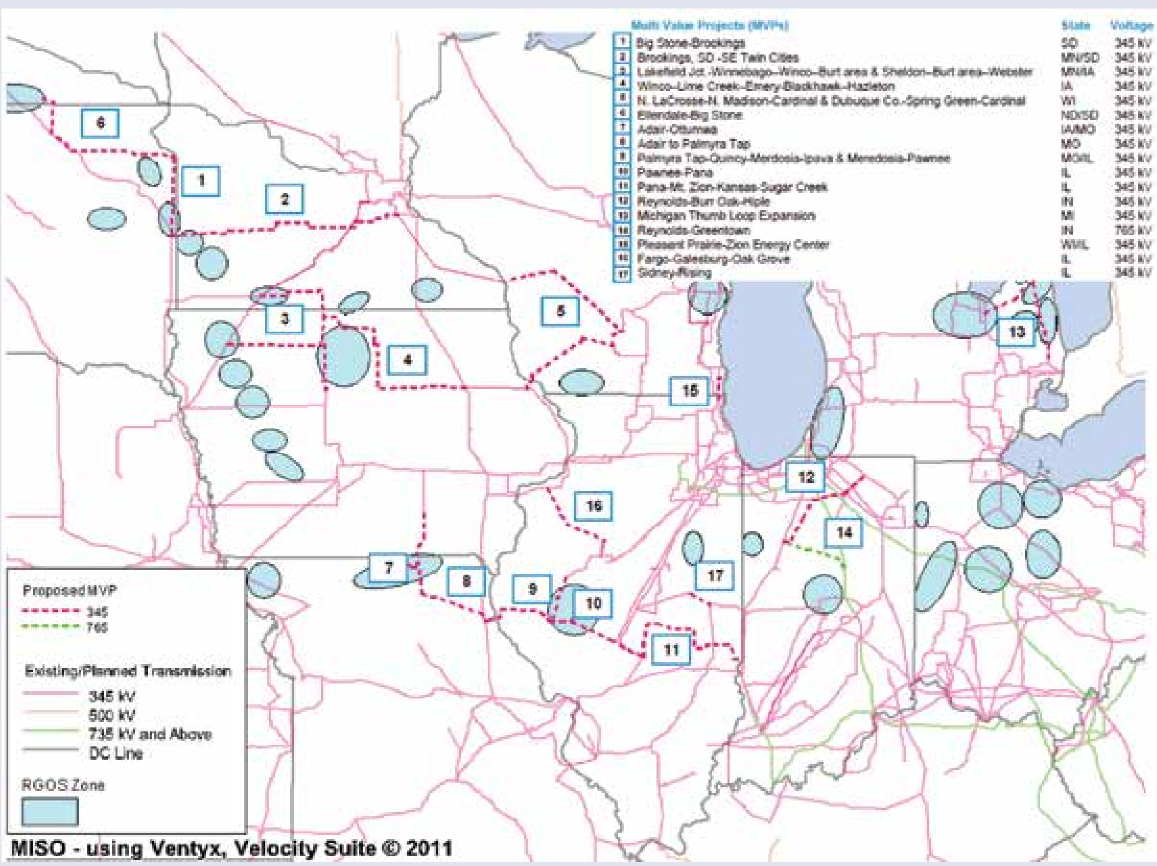
The UMTDI project provided policy direction for a similar but broader planning effort undertaken by MISO called the Regional Generator Outlet Study, or RGOS. The objectives of RGOS included:

- Analyzing and planning for each state's RPS;
- Setting goals for meeting load-serving entities' RPS;
- Balancing distribution of wind zones to consider local desires, optimal wind conditions, and distances from load;
- Providing consumers with energy solutions at the least possible cost; and
- Identifying transmission expansion starter projects.

MISO used the results of the UMTDI and RGOS studies to identify and initiate several near-term, "multi-value transmission projects" (MVPs) designed to simultaneously address current state RPS needs and regional reliability needs, shown in Figure 18-4. As of December 2014, 1 of the 17 MVPs was complete, 5 more were under construction, and 5 others had all of the necessary regulatory approvals.[24] MISO estimates

Figure 18-4

Multi-Value Projects Selected by MISO[25]



23 MISO later changed its name to *Midcontinent ISO* after adding parts of Arkansas, Louisiana, Mississippi, and Texas to its territory.

24 Refer to MISO's MVP dashboard. Available at: https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=181351

25 MISO. (2012). *Multi Value Project Portfolio – Results and Analyses.* Available at: https://www.misoenergy.org/Library/Repository/Study/Candidate%20MVP%20Analysis/MVP%20Portfolio%20Analysis%20Full%20Report.pdf

that when fully implemented, these 17 MVPs will enable access to 2230 MW of additional renewable capacity and 41 million megawatt-hours of annual renewable generation to serve future renewable energy mandates.

Cost Allocation

As noted earlier, FERC's Order 1000 dictates that the costs of new transmission projects should be allocated to load-serving entities in a way that is "roughly commensurate" with the estimated benefits of the project to those entities. Socializing all of the costs of transmission equally to all load is not an acceptable default solution. However, this question of "who benefits and how much" is a controversial one (see text box), and does not lend itself to a simple and universal answer.

Without question, transmission cost allocation methods can influence whether transmission to facilitate renewable energy development is built. If a transmission project will benefit a large number of load-serving entities, its costs can be shared among a large customer base, and the impacts on any individual load-serving entity and its customers' bills may be acceptable. On the other hand, if a project is deemed to benefit only a small subset of customers, the impact on their bills could be large and they may oppose the project.

FERC has approved a variety of transmission cost allocation methods for different regions of the country. The MISO MVPs provide an interesting example. MISO argued that all customers would benefit from these carefully selected projects, and developed a tariff spreading the costs of those projects equally among all load. Some utilities opposed the tariff, claiming that they and their ratepayers were not beneficiaries and thus the tariff did not comply with Order 1000 principles for cost allocation. However, FERC sided with MISO and approved the tariff for MVP projects, and FERC's decision was upheld in subsequent legal challenges.

NTAs are seriously disadvantaged by current cost allocation methods, and this is perhaps one reason NTAs are generally not being included in transmission plans (despite the Order 1000 requirement to consider them). Because NTAs are by definition not transmission, the costs of implementing them are not recovered through regional transmission tariffs. Even if an NTA (e.g., an energy efficiency project that is targeted to defer the need for a new transmission line) costs less to implement than a new transmission line, it may be that the costs of the NTA are allocated entirely to the customers of a single utility while the costs of the transmission line would be spread across multiple utilities. In this example, the customers that would be asked to pay for the NTA will often be better off paying for a share of the transmission line than paying for all of the NTA – and thus the NTA is never implemented.

Who Benefits From Transmission Investments?[26]

The parties that benefit from transmission upgrades or new transmission lines depend on the perspective from which the question is viewed. On a general level, beneficiaries can be defined as users of the transmission system who actually affect flows on a particular transmission facility in service. From a transmission power flow perspective, generators and loads can be identified as impacting flows on various transmission facilities through distribution factors. From this perspective, beneficiaries may be seen as "cost causers" – the parties using the facility are causing the costs on that facility.

In identifying beneficiaries as those affecting flows on transmission facilities, it can be argued that it is these parties who are enjoying the majority of the reliability and/or monetary benefits of the new transmission assets. Beneficiaries can be identified through power flow studies and market efficiency analyses that are used in transmission planning.

Yet another perspective is that beneficiaries may also be defined more broadly. There may be benefits that accrue to all parties connected to the transmission system regardless of impacts on power flows, such as enhanced reliability, reduced impact of fuel price and fuel market variations, reduced opportunity for market power, and the ability to better meet public policy goals. These beneficiaries cannot be identified through power flow studies or market efficiency analyses; rather, they are one or more steps removed from transmission planning analyses.

26 PJM. (2010). *A Survey of Transmission Cost Allocation Issues, Methods and Practices.* Available at: http://ftp.pjm.com/~/media/documents/reports/20100310-transmission-allocation-cost-web.ashx

Lessons Learned From Good Transmission Planning Exercises

States, regions, or countries can adopt policies that encourage transmission planners to consider how to access larger quantities of cost-effective, low-carbon resources. These policies and the resulting planning processes should include all of the following elements:

- Conduct renewable energy mapping exercises that identify regional, low-cost resources that can replace higher-emitting fossil resources.
- Participate in regional transmission planning and cost allocation problem-solving exercises to identify the beneficial transmission projects that could unlock large quantities of low-emitting resources.
- Institute clear criteria for siting transmission and for the entities that evaluate and rule on applications for transmission. Ensure that a wide range of stakeholders and members of the public can participate in the transmission siting process.
- Support making the data and assumptions used in transmission planning as transparent and open as possible.
- Reduce transmission project uncertainty and mitigate potential delays in transmission construction by opening up the transmission planning process to include state and/or federal regulators, independent transmission and generation project developers, utilities, technology companies, environmental advocates, and consumer advocates.
- Support the acquisition of data, modeling tools, and forecasts necessary to complete regional transmission planning exercises.
- Ensure that NTAs are evaluated comparably against transmission to ensure that a least-cost portfolio of local and regional resources are chosen to meet emissions reduction targets.
- Support transmission plan periodic updates, such as annually, biennially, or triennially, to ensure plans are updated to reflect advances in technologies and discoveries of new resource zones.
- Support clear transmission cost allocation policies that implement “beneficiary pays” principles in light of the full range of local and regional costs and benefits, including reliability benefits, market development benefits, public policy compliance benefits, consumer benefits, and environmental, land, wildlife, and cultural benefits.
- Recognize that building transmission to access prospective renewable resources may require broad sharing of transmission costs in order to make projects economically feasible.
- Consider oversizing new transmission facilities to support least-cost development of low-emitting resources over a 20-year time horizon and to mitigate the need for additional transmission corridors in the future.

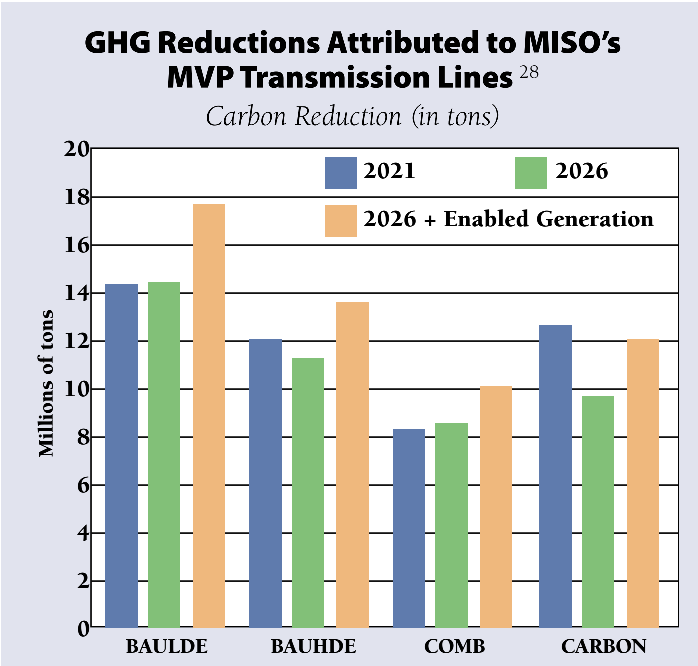
4. GHG Emissions Reductions

Transmission planning and cost allocation policies are complementary to other GHG emissions reduction policies. As previously noted, transmission improvements can facilitate the interconnection of new, low-emitting but location-constrained resources, such as wind, solar, geothermal, and biomass generating units. In addition, transmission expansion can support greater regional exchanges of energy and more efficient use of dispatchable generation assets. Curtailments of existing zero-emissions resources, which sometimes must occur when their potential output exceeds local energy demand, can also be reduced by increasing the capacity to transmit electricity to more distant load centers. Planning processes that consider energy efficiency as a transmission alternative can also help to reduce system-wide emissions by reducing demand for electricity.

The potential GHG emissions reductions that can be achieved through greater deployment of clean energy technologies are detailed in Chapters 6, 16, and 17. The potential GHG emissions reductions associated with energy efficiency are detailed in Chapters 11 to 15. Effective transmission planning and cost allocation policies will increase the likelihood that the full potential of those strategies is reached, even though the transmission policies will not, in and of themselves, reduce GHG emissions.

Quantitative data showing the impact of transmission system improvements on GHG emissions are scarce. However, MISO included an assessment of the GHG emissions reductions that could be attributed to full implementation of its 17 MVP transmission lines in a 2012

Figure 18-5



report, as shown in Figure 18-5.[27] As the figure shows, the reductions attributable to building those transmission lines depend on assumptions about future electricity demand and future energy and climate policies. The "BAULDE" scenario considered "business as usual" (BAU) with "low" demand for energy; "BAUHDE" considered BAU with "high" demand for energy; "CARBON" considered BAU energy policies but with a hypothetical national carbon cap; and "COMB" considered a hypothetical federal RPS and other energy policy changes along with a national carbon cap. In every scenario, these 17 carefully selected transmission lines are estimated to support at least ten million tons of GHG emissions reductions from 2026 onward.

5. Co-Benefits

The co-benefits that can be realized by increasing renewable generation and energy efficiency are identified and explained in detail in Chapters 6 and in Chapters 11 to 17. Those benefits include potentially significant reductions in criteria and hazardous air pollutant emissions. Transmission planning and cost allocation policies that enable and facilitate increased renewable generation and energy efficiency enable and facilitate a greater level of those same co-benefits. In fact, in some cases the potential co-benefits of renewable generation simply can't (or won't) be realized unless appropriate transmission planning and cost allocation policies are in place.

Table 18-1 summarizes the most likely co-benefits associated with revised transmission planning and cost allocation policies. Obviously, some of these benefits do not derive from the policy or process itself, but rather from the fact that it results in increased deployment of

Table 18-1

Types of Co-Benefits Potentially Associated With Revised Transmission Planning and Cost Allocation

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Maybe
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	Maybe – if NTAs are identified
Avoided Distribution Capacity Costs	Maybe – if NTAs are identified
Avoided Line Losses	Maybe – if NTAs are identified
Avoided Reserves	Maybe – if NTAs are identified
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Maybe
Other	

27 Supra footnote 25.

28 Ibid.

renewable generation or energy efficiency. However, transmission planning is a useful tool for enhancing electric reliability and capturing other utility system benefits, even if the emphasis is not on policies to facilitate renewable generation or energy efficiency.

6. Costs and Cost-Effectiveness

The costs and cost-effectiveness of renewable generation vary by category of technology, geographic regions of the United States, and pre-existing state and federal support for these initiatives, and were identified in Chapter 6. State RPS requirements and other mandatory renewable procurement policies were described in Chapter 16, along with an assessment of the costs of such policies. But the key point in this current chapter is that the cost of delivering energy from renewable resources, and the cost of meeting states' renewable energy and climate goals, can be reduced through transmission system improvements. Without such improvements, states will be limited in what they can achieve by the capacity and capabilities of the existing transmission system, and they will need to rely disproportionately on intrastate resources even if lower-cost renewable resources are available elsewhere.

If a transmission project can provide GHG reduction benefits by accessing renewable energy or by improving system efficiency, then it should be considered as a potential vehicle for reducing GHG emissions. But once again, it should be noted that transmission does not by itself reduce emissions. Instead, it enables additional options for reducing emissions that would not be possible absent a strong transmission system, and it facilitates greater potential reductions at lower costs than would otherwise be possible. Therefore, the question of cost-effectiveness turns on the incremental costs incurred to garner any incremental GHG reduction benefits. For example, imagine two transmission alternatives, Alternative A and Alternative B, either of which is sufficient to meet a demonstrated transmission need. Although Alternative A costs more than Alternative B, it might provide more GHG benefits. The incremental costs and benefits of Alternative A could be compared to the costs and benefits of other GHG emissions reduction strategies to determine if this option is cost-effective in light of GHG policy goals.

If a project is cost-effective without considering GHG reduction benefits and if the project facilitates GHG reductions that would not be possible absent the project, then the incremental GHG reductions are essentially "free." Any cost-effective project providing these "free" incremental GHG reductions should factor into a state's GHG emissions reduction strategies. However, if the project is not cost-effective absent the incremental GHG reduction benefits, the analysis is more complicated. One needs to consider the cost of the project, the non-incremental GHG benefits produced by the project, and the incremental GHG benefits of the project to determine whether the project is a cost-effective strategy for reducing GHG.

The first step in such an analysis is to determine the incremental GHG benefits accruing from the project in question, the second step is to determine the project cost, and the third is to account for all non-incremental GHG benefits of the project. With these three sources of information, an evaluation of cost-effectiveness relative to other GHG reduction strategies is possible. Establishing the incremental GHG benefits is self-explanatory, but assessing the other two steps requires some explanation.

Transmission projects differ substantially in their costs and in the benefits they deliver, thus generic statements using average numbers are meaningless. The cost of building or upgrading transmission lines is extremely variable, based on terrain, population density, and other factors. A decade ago, it was common to assume that a transmission project would cost $1 million per mile of transmission, but many projects built over the last decade exceeded that cost by five times or more. One can easily understand why the costs of building a transmission line in New York City, northern Alaska, or rural Kansas would be considerably different. Thus, simply quoting an average cost per mile is not particularly relevant to this document, but establishing the cost of a specific project relevant to your state's compliance strategy is important.

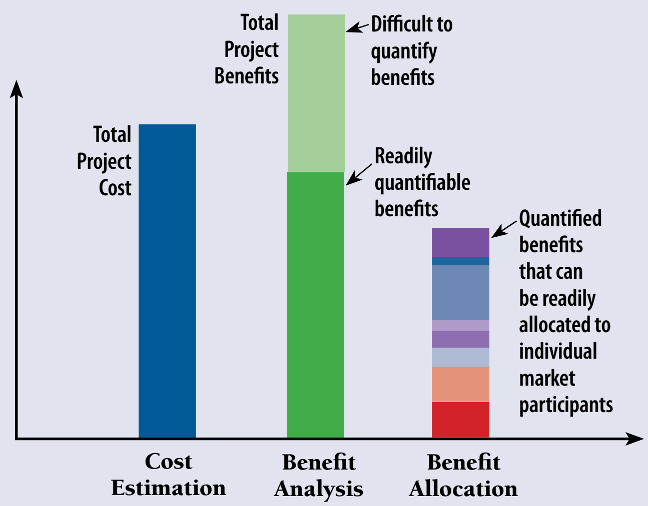
Similarly, transmission projects differ considerably in the benefits they deliver, and accounting for the full range of benefits is a technically challenging exercise. A recent report by the Brattle Group enumerates the sources of benefits arising from a new transmission project and provides guidance on how the benefits should be calculated.[29] Figure 18-6 illustrates the challenge in

29 Chang, J., Pfeifenberger, J. P., & Hagerty, J. M. (2013, July). *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments.* Brattle Group for WIRES (Working group for Investment in Reliable and Economic electric Systems). Available at: http://www.wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf

identifying the net value of a transmission project – the benefits can be substantial, but many benefits are difficult to quantify, and many benefits do not accrue to separable beneficiaries. If the project benefits fall short of the project cost, then the incremental cost attributable to the incremental GHG benefits is the difference between these costs and non-incremental GHG benefits.

Figure 18-6

Importance of Considering All Economy-Wide Benefits When Evaluating Cost-Effectiveness of Transmission Projects[30]



Examples that illustrate how such an analysis might be undertaken exist, although not in the narrow context of incremental GHG improvement. For example, in 2012, MISO published an assessment of the costs and benefits of the MVPs it selected to simultaneously address current state RPS needs and regional reliability needs.[31] Overall, MISO found that the MVPs would provide electricity system benefits in excess of the costs under a variety of future policy and economic assumptions (including scenarios in which a cost was assigned to emitting carbon dioxide). The net benefit of these projects over their expected lifetimes was estimated to fall between $8 billion and $104 billion (net present value in 2011 dollars), with a benefit/cost ratio between 1.8 and 5.8, depending on the scenario. The MVPs were thus cost-effective under every scenario considered and supporting a project like this one on the basis of incremental GHG improvement would thus be straightforward if incremental GHG benefits are in fact produced.

In addition to facilitating the deployment of renewable generation, good transmission planning processes can reveal the value of incremental energy efficiency. FERC Order 1000 mandated that transmission planners *consider* NTAs, such as energy efficiency, but those alternatives will not be included in transmission plans and implemented unless they lower transmission system costs. The only real issue with NTAs is not whether they will be cost-effective, but whether potentially cost-effective NTAs will be ignored in favor of more expensive solutions because of the discouraging approach to cost allocation that was explained in section 2.

7. Other Considerations

In addition to facilitating increased deployment of renewables, transmission system improvements directly address one of the greatest concerns associated with reducing power sector GHG emissions: reliability. Although some transmission projects may be primarily motivated by economic considerations or, as noted herein, by public policy considerations, they all make the grid more resilient and promote greater reliability.

As a practical matter, the costs, cost-effectiveness, and emissions savings associated with low-emissions sources of generation should also account for the costs of system integration, including transmission needs. These costs are not unique to low-emissions resources. Integration costs are also an issue with more traditional forms of generation, which, owing to size and inflexibility, may impose additional costs on the system. Most integration studies performed to date on renewable energy have focused on wind turbines, as wind has been the predominant variable renewable energy technology to date. Many global studies suggest that the costs are between $1 and $7 per megawatt-hour for the relevant study ranges of 10- to 20-percent penetration of variable renewable energy technologies.[32] Higher penetrations of variable renewables lead to higher costs, but experience is limited with high penetrations, and time and experience with integration techniques are likely to bring down the costs. State-specific and utility-specific studies in the United States show considerable variability in

30 Supra footnote 29.

31 Supra footnote 25.

32 International Energy Agency. (2011). *Harnessing Variable Renewables: A Guide to the Balancing Challenge*. Available at: http://www.iea.org/publications/freepublications/publication/Harnessing_Variable_Renewables2011.pdf

these integration costs, again based on the increasing wind penetration.

Job creation is often mentioned as an additional consideration of transmission system improvements. Transmission construction projects are often very large in scale and may last for several years. There is some evidence that, for each million dollars of investment in transmission, local investment increases an additional $0.2 million to $2.9 million, and employment increases by somewhere between 2 and 18 job-years.[33]

As is the case with almost all large infrastructure projects, the siting of a transmission line is often very controversial, irrespective of the technical merits of the project. Projects are often opposed by local landowners because of aesthetic and natural resource impacts, property value concerns, and other reasons. Regulation over transmission siting may be fragmented and involve multiple federal, state, and local governmental agencies, making transmission siting both time- and resource-intensive.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on transmission planning and cost allocation.

- Chang, J., Pfeifenberger, J. P., & Hagerty, J. M. (2013, July). *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments.* Brattle Group for WIRES (Working group for Investment in Reliable and Economic electric Systems). Available at: http://www.wiresgroup.com/docs/reports/WIRES%20Brattle%20Rpt%20Benefits%20Transmission%20July%202013.pdf
- ERCOT. (2008, April 15). *CREZ Transmission Optimization Study Summary.* Presentation by Dan Woodfin to the ERCOT Board of Directors. Available at: http://www.ercot.com/content/meetings/board/keydocs/2008/B0415/Item_6_-_CREZ_Transmission_Report_to_PUC_-_Woodfin_Bojorquez.pdf
- CPUC RETI website. Available at: http://www.energy.ca.gov/reti/index.html
- EIPC. (2012, December). *Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios.* Available at: http://eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf
- Fink, S., Porter, K., Mudd, C., & Rogers, J. (2011, February). *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations.* National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy11osti/49880.pdf
- Lopez, A., Roberts, B., Heimiller, D., Blair, N., & Porro, G. (2013). *US Renewable Energy Technical Potentials: A GIS-Based Analysis.* National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy12osti/51946.pdf
- Hand, M. M., Baldwin, S., DeMeo, E., Reilly, J. M., Mai, T., Arent, D., Porro, G., Meshek, M., & Sandor, D., eds. (2012). *Renewable Electricity Futures Study.* 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/analysis/re_futures/
- Porter, K., Mudd, C., Fink, S., Rogers, J., Bird, L., Schwartz, L., Hogan, M., Lamont, D., & Kirby, B. (2012). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge.* Western Governors Association. Available at: http://www.uwig.org/variable2012.pdf
- Western Electricity Coordinating Council, Environmental and Cultural Considerations webpage. Available at: https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Environmental-and-Cultural-Considerations.aspx
- Wiser, R., & Bolinger, M. (2014, August). *2013 Wind Technologies Market Report.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/publications/2013-wind-technologies-market-report
- Baker, P., Bird, L., Buckley, M., Fink, S., Hogan, M., Kirby, B., Lamont, D., Mansur, K., Mudd, C., Porter, K., Rogers, J., & Schwartz, L. (2014, December). *Renewable Energy Integration Worldwide: A Review.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org
- National Renewable Energy Laboratory website on Transmission Grid Integration Projects. Available at: http://www.nrel.gov/electricity/transmission/projects.html
- E3G, ECN, RAP, and ECF. (2010). *Roadmap 2050: A Practical Guide to a Prosperous Low-Carbon Europe. Policy Recommendations.* European Climate Foundation. Available at: http://www.roadmap2050.eu/attachments/files/Volume2_Policy.pdf

33 Pfeifenberger, J. P., & Hou, D. (2011, May) *Employment and Economic Benefits of Transmission Infrastructure Investment in the US and Canada.* The Brattle Group for WIRES. Available at: http://www.wiresgroup.com/docs/reports/Brattle_WIRES_JobsStudy_May2011.pdf

9. Summary

Transmission lines don't directly reduce GHG emissions, but they make many of the options that can potentially reduce GHG emissions more reliable and more cost-effective.

Some of the low-emissions generation technologies, like wind, solar, and geothermal technologies, are already cost-effective (compared to fossil fuel generation technologies) when sited in optimal locations. However, if those optimal locations are far from load centers, transmission is a necessary complement to developing these resources. In some cases, the best sites for these technologies simply cannot be developed at all unless new transmission lines are built. And in other cases, improvements to the transmission system are necessary (or will be) to enable grid operators to integrate more and more variable energy resources while maintaining system reliability.

Transmission planning processes can identify the best options for tapping the potential of low-emitting electric generation resources, while maintaining reliability and containing costs. A variety of federal and state regulators are likely to be involved in overseeing these processes, and the policies that those regulators choose to make and enforce (including cost allocation policies) can strongly influence the outcomes.

Some transmission options that facilitate GHG emissions reductions will make economic sense even if those reductions are not needed or are considered to have no value. But other options may only be considered cost-effective when the value of GHG emissions reductions is considered along with all other relevant costs and benefits. Good planning processes will not only consider all of the costs and benefits of transmission, including GHG benefits, but will allocate costs fairly to all beneficiaries. Good planning processes will also identify the potential to meet customer demand through NTAs, such as energy efficiency, that also reduce GHG emissions but may be more cost-effective.

19. Revise Capacity Market Practices and Policies

1. Profile

In some parts of the United States, "capacity markets" have been established as a mechanism for promoting competition in the electric power sector while ensuring reliable electric service. This chapter explains what capacity markets are, where they have been instituted, and – most importantly – how capacity market rules can have an impact on greenhouse gas (GHG) emissions.

Air pollution regulators should understand at the outset that the existence of a capacity market does not by itself imply reduced GHG emissions, and establishing a capacity market is not necessarily a policy tool for reducing emissions. However, where capacity markets exist, the specific practices and policies (i.e., market rules) can and do affect GHG emissions, so it is legitimate to consider capacity market rule reforms as a tool for supporting and enhancing other GHG emissions reduction strategies. This chapter identifies some capacity market rules that support emissions reductions, as well as some market rules that can inhibit emissions reductions. But at the outset, it is necessary to understand why capacity markets exist, and that requires an explanation of the concepts of "resource adequacy" and "competitive wholesale electricity markets."

Resource Adequacy

In industrialized societies, power system reliability is treated as a public good, requiring that customers' collective demand for electricity is met when they turn on their appliances and electric heating or cooling systems, subject to a socially acceptable standard for involuntary service interruptions (i.e., "blackouts"). Energy regulators therefore set reliability standards that apply to the system. In the United States, reliability standards require adequate resources sufficient to provide reliable supply 99.7 percent of the time.[1] This high standard of reliability reflects the unique "serve all, or serve none" nature of the electric system: if it falls short in meeting even one customer's power needs, all customers relying on that electric circuit are literally left "sitting in the dark."

To meet these strict reliability requirements, load-serving entities (LSEs) are required to have a certain amount of generation capacity in reserve to be called upon when needed.[2] This "resource adequacy" requirement is an essential component of reliability, but is not by itself sufficient to ensure reliability. Other features of system reliability are collectively referred to as system quality, and address questions about whether the right mix of resource *capabilities* is available to ensure that in every moment supply can be balanced with demand.

How LSEs meet resource adequacy requirements varies widely across the US capacity market. Capacity markets, the subject of this chapter, are one option that has been employed within the context of competitive wholesale electricity markets.

Competitive Wholesale Electricity Markets

Historically, utilities throughout the United States were responsible for generation, transmission, and distribution of power to retail customers. These utilities were "vertically

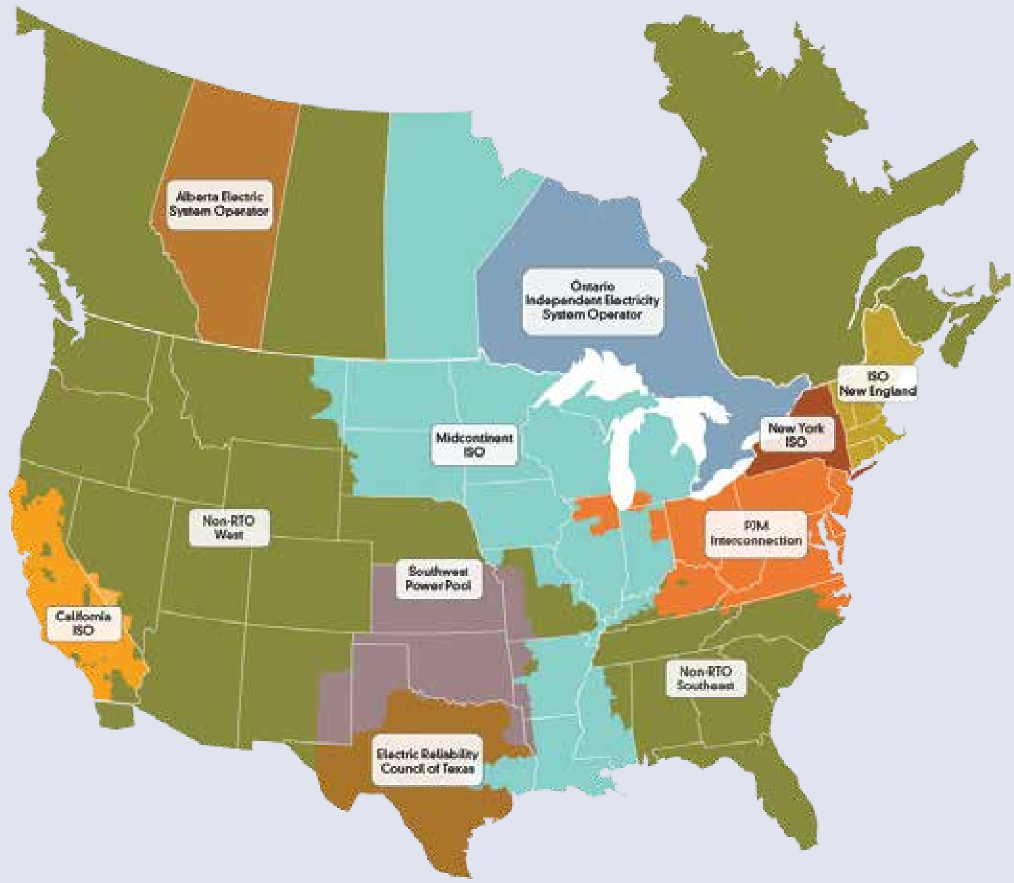
1 North American Electric Reliability Council. (2015, March 3). *Glossary of Terms Used in Reliability Standards.* Available at: http://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf. Put another way, "resource adequacy" means having sufficient electric supply resources in place to maintain a "loss of load expectation" of no more than one day in 10 years. See, for example: ISO-NE. *Market Rule 1, Section III.12.1.* Available at http://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1

2 Some states have implemented "retail choice," that is, a policy allowing customers to choose their power supplier and rates from a variety of competitive offers by non-utility businesses. Regardless of the choice of supplier, power is still delivered to the customer via a utility's distribution system. The customer pays the power supplier for power and pays the utility for distribution services. The term "load-serving entities" is a catch-all phrase that includes competitive suppliers in retail choice states, as well as utilities in states that don't allow retail choice.

integrated," and they owned some or all of the generation and transmission assets needed to meet their customers' needs, as well as the local distribution system. But in the 1990s, many parts of the United States decided to restructure their power sectors so that different entities would be responsible for generation, transmission, and distribution services. Competitive wholesale electricity markets were an offshoot of this industry restructuring, born on the premise that competitive markets would be better than regulators at revealing the costs of generating and transmitting energy at different hours of the day and in different seasons.[3]

Figure 19-1

North American ISOs[6]



Today, two-thirds of the population of the United States and more than one-half of Canada's population are served by competitive wholesale electricity markets run by Regional Transmission Organizations or Independent System Operators (ISOs).[4] Currently seven ISOs operate in the United States, as shown in Figure 19-1: PJM Interconnection (PJM), Midcontinent ISO (MISO), Electric Reliability Council of Texas (ERCOT), California ISO (CAISO), Southwest Power Pool, New York ISO (NYISO), and ISO New England (ISO-NE).[5] Within these ISO regions, generators compete to sell wholesale power to LSEs. Some states allow vertically integrated utilities to continue to own generation assets, but the ISO now controls when those generators are dispatched. Outside of the ISO regions, vertically integrated utilities can still own and control their generation, transmission, and distribution system assets.

3 As noted in footnote 2, some states also opted for retail competition. Although the differences between wholesale competition and retail competition are often misconstrued or ignored, the existence or absence of retail competition is not relevant to the wholesale capacity markets that are the focus of this chapter. For more information on restructuring in the United States, see: Moskovitz, D., Bradford, P., & Shirley, W. (2000). *Best Practices Guide: Implementing Power Sector Reform.* Montpelier, Vermont: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/9; and Lazar, J. (2011). *Electricity Regulation in the US: A Guide.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/645

4 The distinction between Regional Transmission Organizations and ISOs is subtle and, for the purposes of this chapter, not particularly relevant. For simplicity, the remainder of this chapter will refer to either type of organization as an ISO.

5 Federal Energy Regulatory Commission. (2012). *Energy Primer: A Handbook of Energy Market Basics.* Available at: http://www.ferc.gov/market-oversight/guide/energy-primer.pdf

6 Sustainable Federal Energy Regulatory Commission Project. Available at: http://sustainableferc.org/iso-rto-operating-regions/

ISO operations encompass multiple services at the wholesale level that are needed to provide reliable and economically efficient electric service to retail customers. Each of these services has its own parameters and pricing. The ISOs use competitive markets to determine the providers and prices for many of these services. These markets include day-ahead energy markets (sometimes called a Day 2 market), real-time energy markets (sometimes called a Day 1 or balancing market), capacity markets (designed to ensure resource adequacy), ancillary services markets (designed to ensure system quality), financial transmission rights (contracts for hedging the cost of limited transmission capability), and virtual trading (financial instruments to create price convergence in the day-ahead and real-time markets). Not all of these markets are available in each of the ISOs listed previously, and they function differently in each ISO depending on the design decisions each ISO made.

Capacity Markets

Energy and the capacity to generate energy are treated differently by ISOs, and both are important to maintaining the electrical system in different ways. A power plant generates electricity that is used instantaneously in a home, factory, or office building — and the generator needs to be paid for that electricity. This payment happens in the energy markets, such as the day-ahead or real-time markets noted previously. In these markets, electricity is like any other commodity, bought wholesale by LSEs and resold to consumers at retail prices.

LSEs are also required to maintain adequate reserves to ensure that sufficient capacity will be available to meet future peak loads and reliability requirements. LSEs have traditionally satisfied their reserve obligations with generation they already own, or bilateral contracts with other suppliers. Today, however, some ISOs run a capacity market to allow LSEs within their region a different way to satisfy their reserve obligations. Those ISOs have created mechanisms to competitively procure capacity commitments on behalf of LSEs. These mechanisms, such as capacity auctions and capacity payments, can supplement or supplant the traditional LSE approach to resource adequacy.

For a capacity auction, the ISO will calculate how much capacity needs to be procured to meet the resource adequacy requirements of all the LSEs on the system.[7] The ISO will then accept competitive bids from potential suppliers of capacity through one of several possible price-setting mechanisms. Although the nature of these mechanisms varies, what they all produce is a way for the ISO to identify the least expensive bids that will collectively meet the resource adequacy requirements of all the LSEs on the system. Another common feature of capacity auction mechanisms implemented to date is that all accepted bids are paid the same price, the auction "clearing price."[8]

Capacity markets cover short-term capacity, such as a month, season, or year. In addition, PJM and ISO-NE run forward capacity auctions to procure commitments up to three years before the capacity is needed. The near-term focus of these markets is consistent with providing payments to existing generation, or generation such as combustion turbines that can be sited and built within three years.[9] This is important, as power plants are expensive and can take a long time to build; adding the additional risk that they may not even be used can obviously discourage investment.[10] Capacity mechanisms are intended to provide a price signal in today's market to incentivize new capacity to be built and available to meet future needs.

Impact of Capacity Markets on Greenhouse Gas Emissions

The design and rules of a capacity market can strongly influence the amount and types of resources that are used to meet future electric demand. This, in turn, can positively or negatively affect power sector GHG emissions. The main

7 This calculation accounts for capacity that has already been procured by LSEs through "self-supplied" resources and through bilateral contracts. Bilateral contract prices are not impacted by auction prices.

8 For a more thorough discussion of how capacity market auctions work, refer to: Gottstein, M., & Schwartz, L. *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/docs/RAP_Gottstein_Schwartz_RoleofFCM_ExperienceandProspects2_2010_05_04.pdf

9 Based on: Supra footnote 5.

10 Based on: James, A. (2013). *How a Capacity Market Works.* The Energy Collective. Available at: http://theenergycollective.com/adamjames/237496/energy-nerd-lunch-break-how-capacity-market-works-and-why-it-matters

factors at play include all of the following:

- Some capacity markets allow energy efficiency and demand response (DR) to be bid into the market as capacity resources if they can reduce demand below the amount the ISO is projecting. This creates the possibility that providers of these resources will receive capacity market payments, which, when added to the other benefits of energy efficiency and DR can make implementation more cost-effective and attractive for customers. Energy efficiency and DR can indirectly facilitate emissions reductions by reducing electric demand and helping to integrate high penetrations of zero-emission, variable energy resources (VERs)[11] like wind and solar.[12] Rules that permit energy efficiency and DR participation in capacity markets can help to reduce GHG emissions by contributing to increased energy efficiency and DR deployment.
- In some markets, backup generators may be eligible for capacity market payments as a generation resource. In addition, some customers may be offering to participate in a DR program for capacity payments, but with the expectation that they will run a backup generator if they are called to reduce demand.[13] In either circumstance, diesel-fired backup generators can potentially *increase* GHG and other air pollutant emissions, relative to other capacity resources that might be deployed if the diesel generators are not accepted in the market. Rules that permit diesel generators and other high-emitting customer-sited generation to participate as DR without recognizing the costs being imposed by these dirty resources can increase GHG emissions.
- Because of the near-term (three years or less) focus of existing capacity markets, electric generating units (EGUs) that take a long time to construct would have to begin construction without any certainty about future capacity payments. This arguably disadvantages such resources, compared to EGUs that can be built more quickly, even if they might be cheaper capacity resources in the long term. This is relevant to emissions because of the long lead-time needed to construct nuclear and hydro units, and fossil EGUs with carbon capture systems. However, this same near-term focus may work to the advantage of other low-emissions resources that can be deployed relatively quickly, such as energy efficiency, DR, and small-scale renewables. Forward capacity markets (FCMs) should be designed with due consideration of how the selection of a time horizon will affect different resources.
- The argument is often made that capacity markets can prop up older EGUs that are less thermally efficient than an average EGU, and have higher-than-average emissions and operating costs. In the context of competitive wholesale energy markets, EGUs that are costly to operate tend to be dispatched less often than average EGUs, which means they get paid less often. In some cases, these energy market revenues may not be enough to cover all of the EGU's fixed and variable costs. In the absence of other revenue streams, the continued operation of such an EGU is not economically sustainable and the unit may be retired.[14] However, where a capacity market exists, an inefficient EGU that is usually too expensive to operate might still qualify as a capacity resource and receive capacity market payments – perhaps even enough to forestall retirement. This can discourage the construction of new, lower-emitting resources that might otherwise be built to meet capacity

11 "Variable" as used in this chapter refers to any source of electricity production in which the availability to produce electricity is largely beyond the direct control of operators. It can be simply variable – changing production independently of changes in demand, or variable and uncertain – variable and, in relevant timeframes, unpredictable. Another term for this latter category of sources is "intermittent." The challenge and opportunities for integrating VERs is discussed in more detail in Chapter 20.

12 For more information on how these resources indirectly affect emissions, refer to Chapters 11 to 15 for energy efficiency and Chapter 23 for DR.

13 For example, in the PJM market, backup generators have been estimated to comprise 30 to 50 percent of the total DR resource. Verified data are not yet available to test these estimates.

14 Chapter 8 includes a more thorough discussion of the factors that influence a decision to retire an EGU.

needs.[15] Capacity market design that props up old, inefficient EGUs at the expense of more efficient EGUs can increase GHG emissions.

- Distributed generators (DG), combined heat and power (CHP), and electricity storage units may not be able to fairly compete in capacity markets, despite the fact that they are interconnected to the system and have a generating capacity. Renewable DG technologies and all types of CHP resources can reduce GHG emissions, as explained in Chapter 17 (DG) and Chapters 2 and 3 (CHP). Storage units can help with the integration of VERs, as explained in Chapter 20. Because these resources are sited on the customer's side of the electric meter, the ISO may assert that they are features of customer demand that are already included in its projections of future demand, and thus not available to serve unmet capacity needs. But capacity market rules that permit renewable DG, CHP, and storage to compete in capacity markets can promote greater deployment of these resources that will help to reduce GHG emissions.
- Capacity market rules will include a standard discounting of the capacity value of VERs like wind and solar. This is a way of acknowledging that a 100-megawatt (MW) VER has some capacity value, but is not always capable of providing 100 MW of capacity. The discount factor applied to VERs can significantly affect the payments that are received, and those payments of course influence the cost-effectiveness and competitiveness of VERs relative to higher-emitting fossil EGUs. Rules that fairly establish the capacity contribution of VERs can reduce GHG emissions relative to rules that give no or inadequate capacity value to VERs.

Finally, the existence of capacity markets and the rules of those markets can encourage or discourage procurement of capacity resources that have different *capabilities* that affect system quality. This is especially relevant to the topic of integrating zero-emission VERs like wind and solar (treated in more depth in Chapter 20). "Traditional" capacity mechanisms focus only on a simple version of resource capacity, ensuring there are enough firm, dispatchable[16] energy resources available to meet peak demand during a relatively limited number of hours in the year, irrespective of their operating capabilities in other hours. These traditional capacity mechanisms have historically resulted in the construction of new baseload power plants, usually coal or natural gas. However, the changing nature of power generation sources is straining this traditional model. The reliability challenges of the power system are changing with a growing share of VERs, requiring that the capabilities of physical capacity change. These traditional mechanisms are not designed to elicit the operation of or investment in capacity with the flexible capabilities that will be required with increasing frequency, and at multiple times of the day or year, as the share of VERs in the power mix increases.

An emerging issue is whether the basic definition of the capacity product should account for specific operational

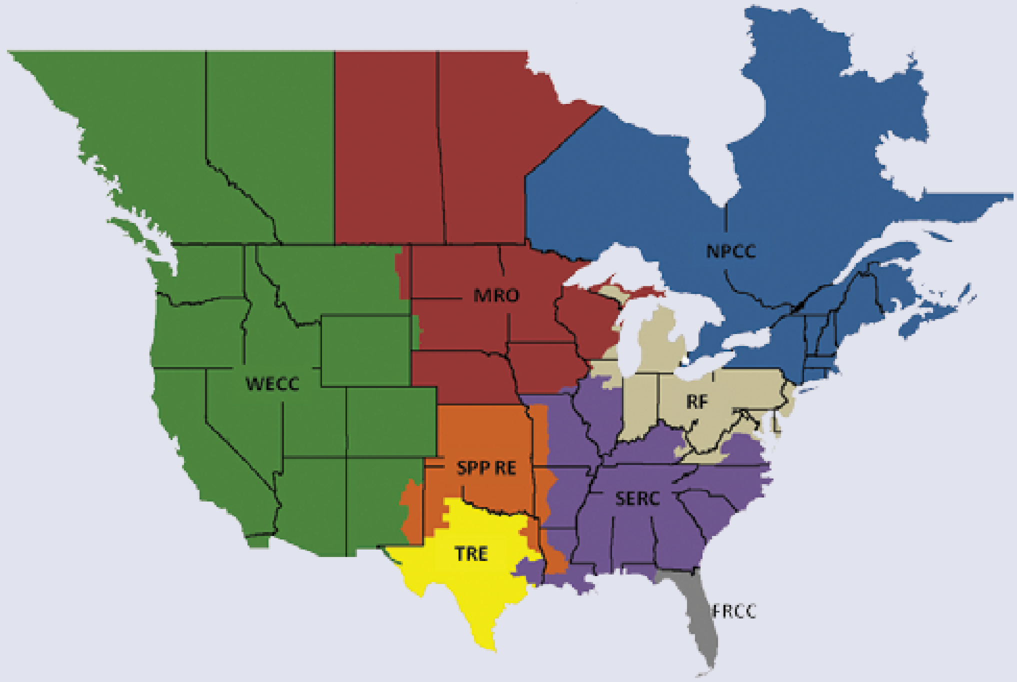
15 Some observers of wholesale markets have suggested that the inclusion of energy efficiency and DR in capacity markets could also discourage the construction of new, lower-emitting EGUs. This may be possible, but there are several factors working in opposition to the proposition. To begin with, energy efficiency and DR resources only clear in the capacity market if they are less expensive than other options. If energy efficiency and DR are removed from the capacity market, the gap will almost certainly be filled by a combination of existing and new EGUs, all of which can provide capacity but at a higher cost. The clearing price may rise significantly. (An example of this dynamic is detailed later in this chapter.) So not only will *more EGUs* be able to earn capacity payments, but they will also receive *larger* payments. Some of those larger payments will go to older, higher-emitting EGUs that would receive a *smaller* capacity payment (or none at all) if energy efficiency and DR were allowed to compete. And then there are the energy market impacts, which mirror those in the capacity market. If energy efficiency and DR cannot receive capacity payments, they will be less cost-effective and less of each resource will be deployed. This means that EGUs will collectively have to generate more electricity to meet demand, and energy market clearing prices will also rise. Some of that extra generation may come from new EGUs, but the output (and revenues) of existing, inefficient, higher-emitting EGUs might also increase. The combined impact of higher capacity prices and higher energy prices might be enough to keep older, inefficient resources in business even as new, cleaner EGUs are built.

16 "Dispatchable" refers to the ability to increase or decrease electricity output on command (i.e., the resource is controllable). "Firm" refers to the volume of MWs that the system operator can rely on being available to provide energy to the system at any moment in time, including generation or reduction of demand for energy (through demand-side resources like energy efficiency and DR).

attributes needed to address system quality. For example, as noted previously, changes in the electric industry have created additional operational and system requirements, including an increased need for more responsive and flexible resources, for example, quick start and fast ramp capability, responsiveness in providing regulation or load following, and so on. In particular, the rapid growth in VERs creates a greater need for flexible resources to balance load instantaneously and to smooth fluctuations in output during the operating day. To address these emerging needs and challenges, new product definitions could be developed that specify offer parameters such as startup time, minimum run time, minimum down time, or other operational parameters that would address specific system needs such as quick-start and fast-ramping capability, or load-following ability.[17] Another approach is to apportion the capacity mechanism into tranches based on the target mix of resource capabilities derived from the net demand forecast. All firm resources, including qualifying DR and energy efficiency resources, would bid into the highest-value tranche for which they could qualify. The most flexible tranche of firm resources would be cleared first, followed by the next most flexible, and so on.[18]

Figure 19-2

Regional Entities With Delegated Responsibility for Reliability[21]



FRCC – Florida Reliability Coordinating Council
MRO – Midwest Reliability Organization
NPCC – Northeast Power Coordinating Council
RF – ReliabilityFirst
SERC – SERC Reliability Corporation
SPP – Southwest Power Pool, RE
TRE – Texas Reliability Entity
WECC – Western Electricity Coordinating Council

2. Regulatory Backdrop

The North American Electric Reliability Corporation (NERC) has chief responsibility for establishing reliability standards for the bulk (wholesale) power system that must be met throughout the continental United States and Canada, in regions with and without ISOs. NERC delegates its responsibility for monitoring and enforcing reliability standards to eight regional entities, depicted in Figure 19-2.[19] In the United States, the Federal Energy Regulatory Commission (FERC) has regulatory authority to oversee the decisions of NERC and the regional entities. A detailed discussion of the roles and responsibilities of FERC, NERC, and the regional entities is beyond the scope of this chapter, but can be obtained by visiting the NERC website.[20]

NERC's reliability standards are imposed on a wide variety of entities. Depending on the standard in question,

17 Supra footnote 5.

18 For more information on this option, see Hogan, M., & Gottstein, M. (2012, August). *What Lies "Beyond Capacity Markets?" Delivering Least-Cost Reliability Under the New Resource Paradigm. A "straw man" proposal for discussion.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6041

19 As Figures 19-1 and 19-2 indicate, the NERC regions do not align in all cases with the regions served by ISOs. Some regional entities (e.g., NPCC) have responsibilities that span more than one ISO, and some ISOs (e.g., MISO) are overseen by more than one regional entity.

20 See: http://www.nerc.com/pa/Stand/Pages/default.aspx

21 NERC. Available at: http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Regions_Color.jpg

responsibility may fall on EGU operators, transmission operators, distribution utilities, ISOs, or others. Capacity markets were created as a mechanism for ensuring that regions where competitive wholesale markets have been established through ISOs will have enough available generating capacity to comply with NERC's reliability standards (i.e., "resource adequacy").

Competitive wholesale electricity markets grew out of FERC Order No. 888, issued in April 1996, which required utilities to offer open access to their transmission lines to all generators.[22] Order 888 did not explicitly require the formation of ISOs, or require the formation of competitive wholesale markets. Rather, utilities in some parts of the country elected to form ISOs and create competitive wholesale markets as a means of complying with Order 888 and subsequent FERC orders. As discussed earlier, there are currently seven ISOs operating in the United States, as well as several regions that have not formed ISOs.

ISOs, on behalf of their members, develop tariffs and wholesale market rules, in addition to operating the bulk power system. Capacity markets are one of the options available to ISOs for ensuring resource adequacy within their systems. In the United States, market rules and tariffs associated with transmission and competitive wholesale markets, including capacity markets, mostly fall within FERC's regulatory jurisdiction. FERC can approve or reject transmission tariffs and wholesale market rules proposed by ISOs (or by utilities operating outside ISO regions). Exceptions to FERC's authority exist in states that are islands (Hawaii) or that are electrically separate from the remainder of the continental 48 states (Alaska and parts of Texas), because electricity in those jurisdictions is not traded in interstate commerce. In those exceptional areas, the state Public Utility Commission has regulatory authority similar to FERC's over most aspects of transmission tariffs and competitive wholesale markets.

3. State and Local Implementation Experiences

Capacity markets, to date, have not been implemented at the state or local level, but rather at the ISO level. There are four capacity markets in operation in the United States currently, in the regions operated by ISO-NE, MISO, PJM, and NYISO. CAISO has a bilateral capacity mechanism to ensure resource adequacy, but it is not considered a full capacity market. CAISO worked with the California Public Utilities Commission and other stakeholders from 2007 to 2010 to explore development of a long-term resource adequacy framework. The discussion included consideration of multiyear forward procurement of resource adequacy capacity and potentially a capacity market. But on June 3, 2010, the California Public Utilities Commission issued a decision in the long-term resource adequacy proceeding that leaves the current resource adequacy program essentially unchanged.[23] Capacity mechanisms are also present in a handful of European countries and in Brazil. Table 19-1 provides an overview and comparison of the key features of current US capacity markets.

In addition to the details presented in Table 19-1, these existing capacity markets differ in some ways that may have specific (albeit indirect) impacts on GHG emissions. Some of the key differences are noted below.

22 FERC. (1996). *Order No. 888 - Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities.* Available at: http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp

23 For more information, see: California ISO. (2014). *Capacity Markets.* Available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedStakeholderProcesses/CapacityMarkets.aspx

Table 19-1

Overview of US Capacity Markets				
	PJM	**ISO-NE**	**NYISO**	**MISO**
Overview	The Reliability Pricing Model (RPM) comprises a series of forward-looking auctions, including one Base Residual Auction (BRA) three years in advance and at least three Incremental Auctions (IAs) per Delivery Year (DY). In addition, there is a Bilateral Market that provides resource providers an avenue to cover shortages or monetize surpluses. It also allows LSEs to hedge against Locational Reliability Charges (LRCs) that could be levied against them via the RPM auctions.	The ISO-NE capacity market is called a Forward Capacity Market (FCM). It functions with an annual Forward Capacity Auction held in February three years in advance of a Capacity Commitment Period. The FCM also includes reconfiguration auctions and bilateral exchanges to facilitate trading of capacity supply obligations.	The NYISO installed capacity market provides a backstop to fulfill an LSE's capacity obligations that aren't satisfied through self-supply or bilateral contracts. The installed capacity market consists of three auctions: The Capability Period Auction (6-month term), the Monthly Auction, and the Spot Auction (2–4 days prior to start of month).	The MISO resource adequacy requirement construct allows LSEs to meet their capacity obligations as defined by the sum of LSEs load projections and a reserve margin calculated by MISO or a state. LSEs are able to meet these obligations by: 1. Acquiring capacity from annual Planning Resource Auctions; 2. Self-scheduling capacity resources; or 3. Submitting Fixed Resource Adequacy Plans.
Market Composition	The RPM market is broadly composed of generation, DR, and energy efficiency resources. Although generation resources represent the overwhelming majority of capacity that cleared the 17/18 BRA (93%), DR also played a meaningful role (6%).	Existing generation and demand resources accounted for 95% of total capacity that cleared in the 17/18 forward capacity auction. Of the new resources that cleared, imports represented 75%. New and existing DR represented 9.1%.	Also allows DR to participate.[25]	Generating resources represented the vast majority of what cleared in the 13/14 Planning Resource Auctions. DR represented 4%.
Locational Constraints	All costs associated with the resources procured in RPM auctions are allocated proportionally among LSEs who serve load in PJM through the LRC. This charge is billed weekly during the DY and is calculated for each LSE daily. Since Final Zonal Capacity Prices are determined as a blend of zonal resource clearing prices across auctions, LSEs don't know exactly what their LRC costs will be until the completion of a DY's final IA.	Locational information is provided for specific capacity zones (i.e., geographic subregions of the New England Balancing Authority Area that may represent load zones that are export constrained, import constrained, or contiguous—neither export nor import constrained.)[26]	Addressing the fact that certain areas within the New York Control Area have acute transmission constraints, NYISO establishes locational requirements that dictate specific percentages of an LSE's minimum unforced capacity requirements that must be procured from resources located within such constrained areas.	

24 Unless otherwise noted, information in this chart is from: Karbone Research and Advisory. (2014). *Capacity Market Primer: PJM, MISO, NYISO & ISO-NE.* Available at: http://www.karbone.com/wp-content/uploads/2014/12/Capacity-Primer-Research-Report-7.10.14.pdf

25 NYISO. (2014). *About the NYISO.* Capacity Market webpage. Available at: http://www.nyiso.com/public/about_nyiso/understanding_the_markets/capacity_market/index.jsp.

26 ISO-NE. (2012). *Overview of New England's Wholesale Electricity Markets and Market Oversight.* Available at: http://www.iso-ne.com/static-assets/documents/pubs/spcl_rpts/2013/markets_overview_051513_final.pdf

Eligible Resources

Demand response resources are now eligible to participate in all four capacity markets, but the markets differ in the eligibility requirements and performance expectations they impose on DR resources. Those differences can influence the amount of DR procured through the capacity market. DR has been most successful in the PJM market, where 10,975 MW of DR cleared in the 2014 capacity auction for DY 2017/2018. This represented more than six percent of all capacity procured through the auction. In contrast, in the 2014 ISO-NE auction for DY 2017/2018, 810 MW of DR cleared. This represented a little more than two percent of total acquired capacity. However, a May 2014 decision by the US Court of Appeals for the District of Columbia Circuit vacated the FERC order governing energy market compensation for DR resources.[27] The Court issued a temporary stay of this decision in October 2014 pending a possible FERC appeal to the US Supreme Court, but if the decision is upheld many observers believe the logic of the ruling will eventually extend to capacity market compensation as well. This calls into question whether DR (and perhaps all demand-side resources) can continue to participate in FERC-regulated capacity markets.

ISO-NE and PJM also allow energy efficiency providers to participate in forward capacity auctions. The other ISOs do not. Under PJM's rules, energy efficiency resources may participate in Base Residual Auctions (BRAs) only up to four years. This means that energy efficiency measures are limited to receiving compensation for their capacity contribution for just four years of their measure life, rather than their full measure life. In contrast, energy efficiency providers in ISO-NE are eligible to bid capacity for their full measure life, an approach that recognizes the full contribution of these resources to regional resource adequacy requirements and that encourages investment in long-lived energy efficiency assets.[28] Figure 19-3 summarizes the amount of energy efficiency that has cleared the ISO-NE and PJM capacity markets in the last six auctions. Energy efficiency resources have provided a greater share of acquired capacity than DR resources in the last four ISO-NE auctions, but have always provided a much smaller share of capacity in PJM. Market rules may explain some of the difference.

Figure 19-3

Energy Efficiency Procured in Forward Capacity Markets (in MW)[29]

	Market	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018
Total Capacity	ISO-NE	36,996	37,501	36,918	36,309	36,220	33,702
	PJM	139,487	156,493	153,683	168,631	173,313	171,129
EE Capacity	ISO-NE	1,062	1,295	1,486	1,770	1,752	2,059
	PJM	569	679	822	923	1,117	1,340
EE Capacity as a % of overall obligation	ISO-NE	2.9%	3.5%	4.0%	4.9%	4.8%	6.1%
	PJM	0.4%	0.4%	0.5%	0.5%	0.6%	0.8%

27 *Elec. Power Supply Ass'n v. Fed. Energy Regulatory Comm'n,* No. 11-1486 (D.C. Cir. May 23, 2014).

28 For more information on energy efficiency in FCMs, and FCMs in general, see: Supra footnote 8. Also see: Neme, C., & Cowart, R. (2014). *Energy Efficiency Participation in Electricity Capacity Markets – The US Experience.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7303

29 Knight, P., Hurley, D., & Fields, S. (2014, May). *Energy Efficiency in US Capacity Markets.* Synapse Energy Economics. Available at: http://www.synapse-energy.com/sites/default/files/SynapseReport.2014-05.0.EE-in-Capacity-Markets.14-035.pdf

Time Scale

NYISO's installed capacity market is short-term in nature, with the longest forward period being at least 30 days prior to its Capability Period Auction, sometimes called the six-month strip auction. PJM and ISO-NE use a three-year forward period. A longer forward period (such as the three years currently utilized in PJM and ISO-NE) provides more lead time to allow new resources that can be constructed or activated within that period to compete with existing capacity resources, thus increasing competition among different capacity supply options. If the forward period is not sufficiently long to develop capacity resources that need relatively longer lead times, then market participants may have to commit to developing these resources and incur significant costs prior to participating in the auction and without the benefit of auction results. For example, the three-year forward period adopted by PJM and ISO-NE is based on the average lead-time for a new gas-fired combustion turbine or a gas-fired combined-cycle generator, and is viewed as providing sufficient time for those resources to arrange for financing and to complete construction. Similarly, a longer forward period provides more time for an existing resource considering whether to exit a market to make decisions to either retrofit or retire if it does not clear in the auction. However, a longer forward period can result in increased risk for customers when compared to a shorter forward period. Forecasts of planning reserve margins are generally more accurate closer to the period in which capacity resources are needed, when market conditions are better known. More accurate forecasts lead to more accurate procurements of capacity, helping to mitigate economic and resource adequacy risk for customers. PJM and ISO-NE's use of realignment auctions closer to the commitment period is intended, in part, to address this concern.[30]

Capacity Credit for Variable Energy Resources

A capacity factor is a measure of how often an electric generator runs for a specific period of time. It indicates how much electricity a generator actually produces relative to the maximum it could produce at continuous full power operation during the same period.[31] Capacity markets assign a capacity credit to various types of generation that may be based on the capacity factor. The assigned value can have a huge implication for the price a generation source commands and how frequently it is deployed. Capacity markets have recognized some capacity value for VERs, either through a deemed on-peak capacity factor or a demonstration of claimed capacity for specified on-peak periods. Policymakers need to pay attention to how these values are established so they can be confident the committed capacity will be available when called on, while at the same time encouraging the participation of all low-carbon resources in the market.[32] The capacity credit assigned can discount the capacity value of VERs like wind and solar in favorable or unfavorable ways. For example, MISO assigns a system-wide capacity credit for wind generators that is equal to 14.1 percent of rated capacity. In ISO-NE, all VERs are assigned unique capacity credit values based on their most recent five years of site-specific generation data during winter and summer peaks.[33] So a VER generator can get more or less capacity credit (and thus more or less market revenue) depending on the ISO region it serves.

4. GHG Emissions Reductions

Quantitative data showing the impact of capacity market rules on GHG emissions do not exist. This is not surprising, because capacity markets have been created as a mechanism for ensuring resource adequacy and electric system reliability. They have not been created specifically as

30 FERC Commission Staff Report. (2013). *Centralized Capacity Market Design Elements. Report AD13-7-000.* Available at: http://www.ferc.gov/CalendarFiles/20130826142258-Staff%20Paper.pdf

31 US Energy Information Administration. (2014). *Frequently Asked Questions.* Available at: http://www.eia.gov/tools/faqs/faq.cfm?id=187&t=3

32 Supra footnote 8.

33 The Electric Reliability Council of Texas, which does not operate a capacity market but is still responsible for ensuring resource adequacy, assigns a capacity value of 14.2 percent of rated capacity to non-coastal wind generators, 32.9 percent of rated capacity to coastal wind generators, and 100 percent of rated capacity to solar generators up to 200 MW in size.

a means to reduce GHG emissions, and the mere creation of a capacity market is unlikely to have a direct or predictable impact on emissions. Nevertheless, the market design and rules of a capacity market will, inevitably, have a material impact on the carbon emissions profile of a given state or region. The size and character of that impact is difficult to characterize in a general way, as much of the impact will depend on the details of the market mechanism and the resources that are close to participating or withdrawing from participation in the market. In a capacity market like those operated by ISO-NE and PJM, the market provides an additional source of revenue for all firm capacity used to meet loads during system peaks. The additional source of revenue applies equally to all generation sources that can contribute to meeting loads at peak, whether the capacity is zero-emitting or a source of high GHG emissions. In such a framework, the capacity market may actually perpetuate the existence of aging fossil fuel generation by providing a lifeline of revenue for a facility that is otherwise on the road to retirement. Of course the same may be true for an aging zero-emissions generator like an aging nuclear facility. Regardless of whether the facility is a high or low emitter, the additional source of revenues can have a substantial impact on the bottom line and longevity of generation.[34]

If energy efficiency programs are allowed to participate in capacity markets, as is the case in ISO-NE and PJM, investment in energy efficiency is likely to increase and the GHG emissions reduction benefits can be material. If the introduction of energy efficiency creates competition that removes the lifeline for aging, inefficient fossil generation, the GHG emissions benefits are even greater as a zero-carbon resource replaces a high-emitting one. The links between energy efficiency and GHG emissions are described in detail in Chapters 11 to 15.

The inclusion of DR in capacity markets can also have GHG emissions impacts. Chapter 23 explains the complicated links between DR and GHG emissions in detail, but a brief summary can be repeated here. DR programs may reduce energy consumption, but they are more likely to shift the timing of energy consumption from peak demand periods to off-peak periods. The emissions impact of such a shift will depend on the relative emissions rates of EGUs that operate on-peak versus off-peak, and could be positive or negative. On the clearly positive side of the ledger, DR programs can help the ISO integrate higher penetrations of VERs, which tend to reduce system-wide emissions. And on the negative side of the ledger, DR programs may encourage some customers to replace on-peak energy purchases from the grid with generation from high-emitting backup generators. (Air pollution regulations and wholesale electricity market rules can mitigate this last possibility, as noted in the text box.)[35,36] Designing rules that favor inclusion of low-emitting DR and are detrimental to high-emitting customer generation can together lead to

ISO-NE Rules for Emergency Generators Advance Environmental Goals

Emergency ("backup") generators typically are diesel-fired, and states in New England and elsewhere in the US have restricted the number of hours and days they may be operated through the state permitting process. At the time the first regional DR tariffs were being designed in New England, a collaborative of energy regulators, environmental regulators, the ISO, utilities, and other stakeholders realized that active DR programs could lead to substantial incentives for diesel-fired backup generators to operate more often, when air quality was at its worst. Regulators and the ISO proposed a rule limiting those generators to run for reliability purposes during system emergencies.

34 For example, in 2013, capacity market revenues comprised 12 to 13 percent of the total revenues in both the ISO-NE and PJM wholesale electricity markets. An EGU that has a higher-than-average capacity factor will earn relatively more of its total revenues from the energy markets and less from the capacity market than this system-wide average would suggest, whereas a generator that has a lower-than-average capacity factor will earn relatively less from energy markets and more from the capacity market. An EGU with a very low capacity factor could potentially earn more revenues from the capacity market than from actually selling energy. This dynamic is especially important for large, aging, inefficient fossil plants that no longer operate as baseload generators.

35 Cowart, R., & Raab, J. (2003, July 23). *Dimensions of Demand Response: Capturing Customer-Based Resources in New England's Power Systems and Markets - Report and Recommendations of the New England Demand Response Initiative.* The Regulatory Assistance Project and Raab Associates, Ltd. Available at: http://www.raponline.org/docs/RAP_Cowart_DemandResponseAndNEDRI_2003_07_23.pdf

36 See: The Regulatory Assistance Project. (2002, October). *Model Regulations for the Output of Specified Air Emissions From Smaller Scale Electric Generation Resources.* Available at: http://www.raponline.org/document/download/id/421

lower GHG emissions than would be expected absent these rule changes.

Perhaps the most material contribution to GHG emissions reductions that can be realized through a capacity market is in addressing the needs of a system with higher levels of zero-emissions VERs, like wind and solar generators. The GHG emissions benefits of those resources are detailed in Chapters 6, 16, and 17. Allowing DR resources and electricity storage systems to compete in capacity markets is helpful but is only a partial solution to this challenge. As noted previously, the characteristics that are likely to be needed most in such a system focus on the residual flexibility of the system (stop/start capabilities, ramping capabilities up and down, and load shifting). The next big challenge in resource adequacy is to understand and address how the growing share of variable renewable production will require us to rethink our capacity market rules and, indeed, all of the mechanisms used throughout the US to ensure resource adequacy and system quality.[37]

37 Interested readers can learn more about this at: Supra footnote 18.

5. Co-Benefits

The co-benefits that can be realized by increasing renewable generation and energy efficiency are identified and explained in detail in Chapter 6 and in Chapters 11 to 17. Those benefits include potentially significant reductions

Table 19-2

Types of Co-Benefits Potentially Associated With Capacity Market Practices and Policies

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe – market rules can encourage or discourage energy efficiency and low-emissions generators
Nitrogen Oxides	Maybe – market rules can encourage or discourage energy efficiency and low-emissions generators
Sulfur Dioxide	Maybe – market rules can encourage or discourage energy efficiency and low-emissions generators
Particulate Matter	Maybe – market rules can encourage or discourage energy efficiency and low-emissions generators
Mercury	Maybe – market rules can encourage or discourage energy efficiency and low-emissions generators
Other	Maybe – market rules can encourage or discourage energy efficiency and low-emissions generators
Water Quantity and Quality Impacts	Maybe – market rules can encourage or discourage energy efficiency and low-water-use generators
Coal Ash Ponds and Coal Combustion Residuals	Maybe – if energy efficiency can participate or if market rules extend the life of coal EGUs
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Maybe – if energy efficiency can participate
Avoided Costs of Existing Environmental Regulations	Maybe – if energy efficiency can participate
Avoided Costs of Future Environmental Regulations	Maybe – if energy efficiency can participate
Avoided Transmission Capacity Costs	Maybe – if energy efficiency or DR can participate
Avoided Distribution Capacity Costs	Maybe – if energy efficiency or DR can participate
Avoided Line Losses	Maybe – if energy efficiency or DR can participate
Avoided Reserves	Maybe – if energy efficiency or DR can participate
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe – if energy efficiency can participate
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Maybe – if energy efficiency or DR can participate
Other	

in criteria and hazardous air pollutant emissions. Capacity market policies that enable and facilitate increased renewable generation and energy efficiency enable and facilitate a greater level of those same co-benefits.

Including DR resources in a capacity market can facilitate greater levels of renewable resource deployment, as explained in Chapter 23, but if DR program participants use backup diesel generators instead of temporarily reducing load, it can result in increased emissions of criteria and hazardous air pollutants. This is especially worrying because most DR events happen during hot weather peaks when ozone concentrations may already be at unhealthy levels. Diesel generators also tend to have short stacks, which leads to more concentrated emissions plumes. Capacity market rules that encourage or reward the use of diesel generators can thus be counterproductive in terms of environmental impacts, even though those resources can contribute to increased reliability, energy security, and some other economic co-benefits.

Table 19-2 summarizes the most likely co-benefits associated with capacity markets. Obviously, most of these benefits do not derive from the capacity market itself, but rather from the fact that it can encourage and enable increased deployment of renewable generation and energy efficiency. Some of the benefits relating to electric reliability can be expected regardless of whether the market rules allow for the participation of energy efficiency or DR resources.

6. Costs and Cost-Effectiveness

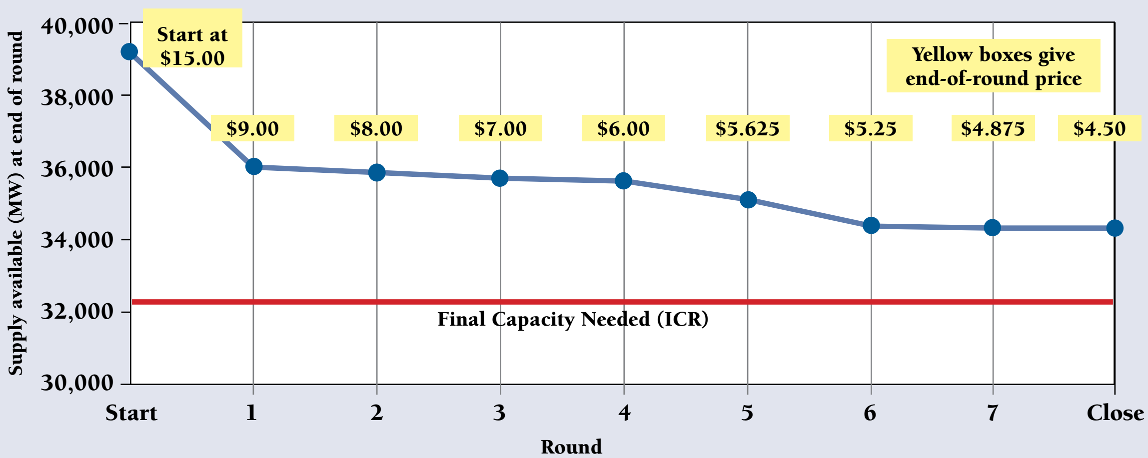
The costs and cost-effectiveness of capacity markets can be considered from several different perspectives, beginning with the perspective that motivated their creation. Capacity markets are intended to meet the resource adequacy requirements of LSEs at a lower cost than the traditional method whereby each LSE acquired all of its capacity through self-supply or bilateral contracts. Capacity markets are designed to reduce resource adequacy costs through economies of scale (addressing capacity needs across the footprint of an ISO serving many LSEs) and by fostering competition. So long as LSEs retain the right to meet some or all of their requirements through self-supply and bilateral contracts, the existence of a capacity market should only add to their options and reduce costs.

Another perspective that can be assessed based on actual market data is the impact on capacity market costs of rules *that include or exclude certain types of resources.* As noted previously, the inclusion of demand-side resources (DR and energy efficiency) in the market has the potential to decrease costs for consumers. For example, in the ISO-NE capacity market, demand-side resources made up 2279 MW of cleared capacity in Forward Capacity Auction 1. The clearing price in this auction was $4.50/kilowatt (kW)-month. Without the participation of demand-side resources, the system would have been more than 500 MW short at the prescribed floor price of $4.50/kW-month.[38]

Figure 19-4

Final Results of ISO-NE Forward Capacity Auction 1[39]

(Prices in Dollars/kW-Month)



38 Jenkins, C., Neme, C., & Enterline, S. *Energy Efficiency as a Resource in the ISO New England Forward Capacity Market.* Proceedings of the ECEEE 2009 Summer Study, pp. 175–183. Available at: http://www.eceee.org/library/conference_proceedings/eceee_Summer_Studies/2009/Panel_1/1.313/paper

39 Neme & Cowart, at supra footnote 28.

As a result, the price would have had to rise to somewhere between $5.25 and $5.625/kW-month, as illustrated in Figure 19-4. The participation of DR and energy efficiency in the auction thus translates to between $290 million and $435 million in savings to consumers in just that year.[40]

Similar results have been observed in the PJM capacity market, which also allows demand-side resources to participate. The independent market monitor reported after the most recent forward capacity auction that consumer costs would have been more than $9.3 billion higher if capacity offers from DR and energy efficiency resources had not been accepted, as indicated in Table 19-3. (The savings in PJM are considerably bigger than those in ISO-NE in part because it is a much larger electricity market.)

The final perspective we consider is the cost-effectiveness of achieving GHG emissions reductions. Here again we repeat the fact that the creation of a capacity market is not likely to materially affect GHG emissions, but the rules governing a capacity market (where one exists) can significantly influence emissions. If a state is developing a GHG reduction plan and the state is served by an ISO that has a capacity market, regulators should understand that the cost-effectiveness of supply-side and demand-side resources (energy efficiency, renewable generation, nuclear power, coal with carbon capture, and so on) will be partially dependent on capacity market rules, because those rules determine some of the revenues that will be earned by each resource. Any change to capacity market rules could thus result in more clean energy deployment, and thus indirectly result in GHG emissions reductions. (Or the opposite could occur, depending on the rule changes.) However, predicting in a quantitative way how existing market actors and potential new market actors will respond to a change in market rules may prove to be impossible. Regulators may need to focus instead on changes that nudge the market toward more clean energy resources without knowing how significant the impact will be.

7. Other Considerations

Although the majority of the loads in the United States exist in regions that are currently served by competitive wholesale markets, the remainder do not. A resource adequacy framework that enables and encourages the addition of cost-effective technologies to support the introduction of high levels of VERs will be needed in non-ISO markets as well.

One idea that may be worthy of further exploration and consideration would be to develop capacity market rules that in some way explicitly favor zero- and low-emitting resources, in the same way that "environmental dispatch" rules for energy markets (discussed in Chapter 21) might. This has not been done or even proposed in any market to date, so it remains to be seen what such rules might look like. Proponents of wholesale electricity markets would likely resist such an idea as a manipulation of the market, unless it were shown to be an efficient way of using the markets to achieve a regulatory requirement.

Table 19-3

Sensitivity Results for PJM's 2017/2018 Base Residual Auction[41]

		Difference from Actual Results	
Scenario Description	**RPM Revenue ($ per Delivery Year**	**RPM Revenue ($ per Delivery Year**	**Percentage**
Actual Results	$7,512,229,630	NA	NA
Annual Resources Only	$9,738,222,922	$2,225,993,292	29.6%
No Offers for DR or EE (Generation Resources Only)	$16,859,658,203	$9,347,428,573	124.4%

40 Neme & Cowart, at supra footnote 28.

41 Monitoring Analytics. (2014, July). *The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses.* The Independent Market Monitor for PJM. Available at: http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf

8. For More Information

- Cowart, R., & Raab, J. (2003, July 23). *Dimensions of Demand Response: Capturing Customer-Based Resources in New England's Power Systems and Markets — Report and Recommendations of the New England Demand Response Initiative.* The Regulatory Assistance Project and Raab Associates, Ltd. Available at: http://www.raponline.org/docs/RAP_Cowart_DemandResponseAndNEDRI_2003_07_23.pdf
- Baker, P., & Gottstein, M. (2013, March). *Capacity Markets and European Markets Coupling — Can they Coexist?* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6386
- Gottstein, M., & Schwartz, L. (2010, May). *The Role of Forward Capacity Markets in Increasing Demand-Side and Other Low-Carbon Resources: Experience and Prospects.* Montpelier, VT: The Regulatory Assistance Project. Available at http://www.raponline.org/docs/RAP_Gottstein_Schwartz_RoleofFCM_ExperienceandProspects2_2010_05_04.pdf.
- Hogan, M., & Gottstein, M. (2012, August 14). *What Lies "Beyond Capacity Markets"? Delivering Least-Cost Reliability Under the New Resource Paradigm: A "Straw Man" Proposal for Discussion.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6041
- Keay-Bright, S. (2013, October). *Capacity Mechanisms for Power System Reliability.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6805

9. Summary

Industrialized societies place a high value on system reliability. Resource adequacy, meaning the availability of sufficient resources to meet peak loads, is a necessary precondition of reliability. Capacity markets have been created in some regions as a mechanism to unleash competitive forces to reduce the costs of ensuring resource adequacy. The existence or absence of such markets does not directly impact GHG emissions, but the rules that govern the markets (where they exist) can favor or disfavor certain types of resources in ways that can facilitate or hinder GHG emissions reductions.

Capacity markets focus on procuring adequate capacity, but have not to date considered the varying capabilities of different types of capacity resources. As the share of VERs in the US generation portfolio increases, we may need to retool electricity markets to cost-effectively spur the introduction of a resource mix with the capabilities necessary to assure an efficient and reliable system. Capacity markets may need to be reformulated or abandoned in favor of more robust markets capable of supporting higher levels of VERs. Demand-side resources such as energy efficiency and DR are likely key to any market formulation that attempts to cost-effectively deliver the level of system flexibility needed to support clean energy resources. Policies that ease the integration of VERs, such as those discussed in Chapter 20, will likely be integral to this effort as well.

20. Improve Integration of Renewables Into the Grid

1. Profile

State and federal electricity regulation is founded on principles intended to ensure reliable and affordable electric service. Previous chapters in this document demonstrate that renewable resources like wind and solar generation hold tremendous potential for reducing greenhouse gas (GHG) emissions in the power sector. The question electricity regulators face is, "Can we use these tools to meet GHG reduction goals and ensure reliable and affordable electric service at the same time?" Answering this question is sometimes referred to as the "integration challenge," in which "integration" refers to the process of accepting much higher levels of renewable energy and other low-carbon resources without compromising the reliability and affordability of electric service.

This chapter focuses on a suite of policies and mechanisms that can help to ensure continued electric system reliability as the electric system changes to include a higher penetration of variable energy resources (VERs), particularly wind and solar electric generating units (EGUs).[1] These policies and mechanisms do not reduce GHG emissions in and of themselves, but they are necessary complements to many GHG-reducing actions because they enable the electric system to continue to reliably function with a much lower GHG-emitting portfolio of generation resources. However, it is also important to recognize that competing integration strategies often have different GHG footprints, so considering the GHG emissions of the strategies themselves is relevant. For example, natural gas-fired generation can be a powerful tool to help with integration, but sometimes other approaches like energy efficiency, demand response (DR), time-varying rates, and energy storage can meet the electricity system integration requirements with a much lower carbon footprint.

As this chapter demonstrates, this is a time of rapid technology innovation, new market developments, and new thinking about ways to integrate renewable resources. At the same time, the plethora of unique system needs and options to address the integration challenges must be tailored to specific electric systems and regulatory structures. Solutions that work in one locale may be infeasible in another. In addition, choices in one locale can ripple through the interconnected grid, requiring grid operators to carefully coordinate their operations. Air regulators and the energy community will need to work together to understand how to best address integration challenges without imposing unintended consequences.

2. Regulatory Backdrop

This section describes how the federal government and states regulate electric system reliability, provides a basic explanation of what it means to keep the electric system "reliable," and describes the integration challenge in more detail. It concludes with an introduction to a number of policies and mechanisms that can be tailored to the reliability requirements of a specific place.

Who Regulates Reliability?

The Federal Energy Regulatory Commission (FERC) has primary authority to regulate interstate wholesale energy transactions. Market rules and tariffs associated with transmission and competitive wholesale markets mostly fall within FERC's regulatory jurisdiction. Exceptions to FERC's authority exist in states that are islands (Hawaii) or that are electrically separate from the remainder of the continental 48

1 The term "variable energy resource" as used in this chapter refers to any EGU whose output varies over time based on factors that are outside of the control of a system operator and that may be difficult to forecast. Although the VER definition is generic, wind turbines and solar photovoltaic systems, which vary with wind speed and insolation, currently represent virtually all of the installed VERs in the United States. The VER concept is important for any discussion of power sector GHG emissions because VERs are zero-emissions resources.

states (Alaska and parts of Texas), because electricity in those jurisdictions is not traded in interstate commerce. In those exceptional areas, the state Public Utility Commission (PUC) has regulatory authority similar to FERC's over most aspects of transmission tariffs and competitive wholesale markets.

Under FERC direction, the North American Electric Reliability Corporation (NERC) has been given chief responsibility for establishing reliability standards that must be met by all regions throughout the continental United States.[2] NERC delegates its responsibility for monitoring and enforcing reliability standards to eight regional entities, depicted in Figure 20-1. The eight regional entities enforce the standards within their respective boundaries. A detailed discussion of the roles and responsibilities of FERC, NERC, and the regional entities is beyond the scope of this chapter, but can be obtained by visiting the NERC website.

States have independent regulatory authority over the provision of electricity service to retail customers. Typically, investor-owned utilities operate under the jurisdiction of state PUCs, whereas publicly owned utilities and electric cooperatives are governed by local boards. These utilities operate the distribution system and conduct planning for loads and generation resources, but they must do so in a manner consistent with state and local regulations. Many states have instituted policies that encourage or require utilities to procure energy from renewable resources (see Chapter 16), but it is the responsibility of the utilities to integrate those resources in a manner that doesn't compromise reliability. State regulators are pursuing renewable integration by working with system operators and utilities at both the wholesale and retail levels. Policies and approaches vary among the states. Some states favor local development of renewables, whereas others are open to developing remote renewable resources with energy transmitted over long-distance transmission lines.

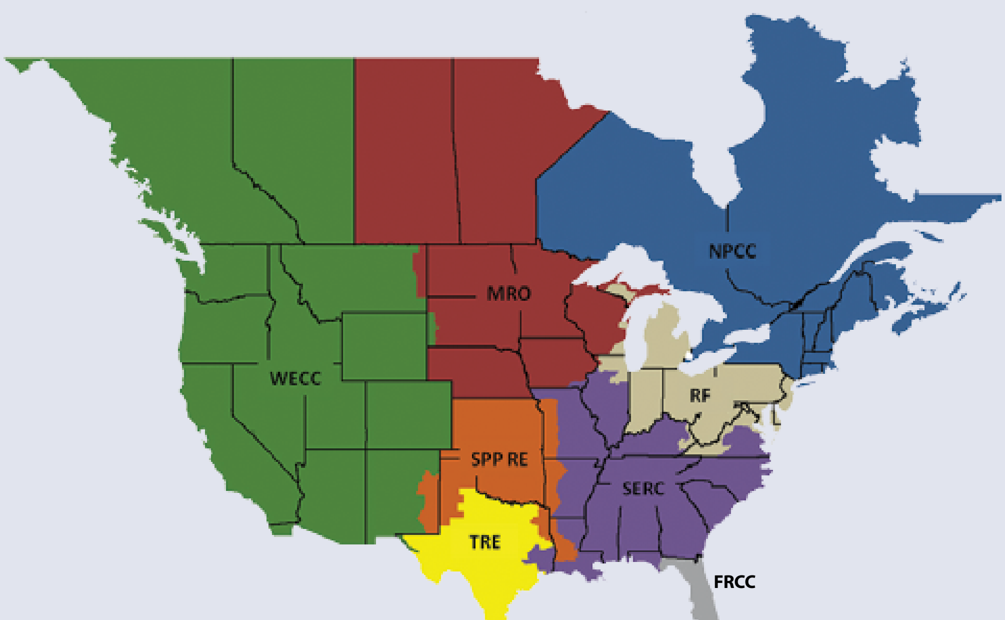
Successfully deploying the various tools and techniques that are effective for integrating renewable resources will require that federal and state regulators, NERC, the regional entities, and utilities cooperate and seek solutions that address fundamental regulatory goals.

What is Energy System Reliability?

Ensuring reliable electric service requires that the supply of electricity almost perfectly matches the demand for electricity at every second of operation in every location.[4] Demand for electricity changes on a second-by-second basis as weather conditions change or as the activities of people and businesses change. Supply of electricity can also change moment-to-moment owing to unexpected generator outages, fuel supply issues, or any number of

Figure 20-1

Regional Entities With Delegated Responsibility for Reliability[3]



FRCC – Florida Reliability Coordinating Council
MRO – Midwest Reliability Organization
NPCC – Northeast Power Coordinating Council
RF – ReliabilityFirst
SERC – SERC Reliability Corporation
SPP – Southwest Power Pool, RE
TRE – Texas Reliability Entity
WECC – Western Electricity Coordinating Council

2 The Canadian government has similarly vested NERC with responsibility for reliability standards in Canada.

3 NERC. Available at: http://www.nerc.com/AboutNERC/keyplayers/Documents/NERC_Regions_Color.jpg.

4 When supply and demand are not equal, the operating parameters of the electric system will deviate from design values. The system can tolerate narrow deviations from design values, but larger deviations can lead to brownouts or blackouts and may damage electrical equipment connected to the grid.

weather-related issues. VERs like wind and solar EGUs are highly dependent on the season and time of day, as well as weather conditions, and thus the supply from these resources can also change quickly. Thus, although the challenge of maintaining supply and demand balance is longstanding, the introduction of VERs adds additional sources of variability.

The US bulk electric grid is divided into dozens of different "balancing authority areas" (BAAs). Within each BAA, a single "balancing authority" acts as the electric system operator and is responsible for balancing supply and demand.[5] Some balancing authorities are large Regional Transmission Organizations or Independent System Operators (ISOs),[6] some are operated by an entity that encompasses the service territories of a number of utilities (e.g., Balancing Area of Northern California), and some are operated by a utility that serves the vast majority of their BAA (e.g., Arizona Public Service and Xcel Energy). The system operator is like an air traffic controller, in that he or she needs to be aware of the electric system status at all times and needs to issue orders to maintain safe operation. In the case of the electric system operator, maintaining awareness involves monitoring the frequency, voltage, power, and availability of system resources at all times. Based on system conditions and available resources, the system operator can issue orders to electricity suppliers and electricity demand managers to adjust supply and demand in order to maintain reliability. The scope of activities performed by system operators is referred to as "balancing."

One aspect of balancing supply and demand involves planning for local and system-wide "resource adequacy" a year or more in advance of real-time operations, as discussed in Chapter 19. Resource adequacy is based on the availability of sufficient generating capacity to meet the anticipated annual and seasonal peak demand, plus an adequate "reserve margin" (i.e., surplus capacity) for unplanned contingencies. Resource adequacy is an essential component of reliability, but is not by itself sufficient to ensure reliability.

System operators must also maintain system balance by issuing orders in much shorter time frames, ranging from one day ahead down to "real time" (i.e., every few seconds). Resources with specific capabilities must be kept in reserve to ensure that supply can adjust to meet demand and maintain system quality in these very short time frames. The services maintained by electric system operators to ensure that supply and demand will always be able to adjust to protect system quality are called "ancillary services." Ancillary services ensure reliability by maintaining frequency, voltage, and power quality on the electric system.

The ancillary services that system operators need are defined primarily by the response speed, the duration of the response, and the time between cycles when the service might be needed. Furthermore, some ancillary services are used routinely during normal conditions, whereas others are only called on during contingency conditions when something has gone unexpectedly wrong on the system (like an unplanned EGU outage). Table 20-1 describes several of the most common types of ancillary services and the capabilities that are required. Another type of ancillary service not shown in Table 20-1 is "black start" capability, that is, the ability of a shut-down EGU to begin operating without drawing electric power from the grid.

Historically, system operators have relied primarily on fossil-fueled or hydroelectric EGUs to provide these ancillary services. Where large hydroelectric EGUs were not available, system operators often relied heavily on natural gas-fired combustion turbines. Renewable technologies with advanced control capabilities and other options like particular DR programs (the subject of Chapter 23) and storage technologies (addressed in Chapter 26) are also capable of providing some of these services, but have been relied on much less frequently.

Most ISOs operate markets that attract competitive bids from qualified resource providers to meet ancillary service needs. Some ISOs and most non-ISO balancing authorities do not operate competitive ancillary service markets but have established other mechanisms for ensuring that

5 Balancing authorities grew out of electric utilities and their commitment to provide reliable power to their customers.

6 There are currently seven Regional Transmission Operators and ISOs in the United States: California ISO (CAISO), Electric Reliability Council of Texas, ISO New England, Midcontinent ISO, New York ISO, PJM Interconnection, and Southwest Power Pool. For a map showing the territories served by these markets, refer to the ISO/RTO Council at http://www.isorto.org/. The distinction between Regional Transmission Operators and ISOs is subtle and, for the purposes of this chapter, not particularly relevant. For simplicity, the remainder of this chapter refers to either type of organization as an ISO. All generation and load is under the management of a balancing authority, but not all balancing authorities are members of ISOs.

Table 20-1

Description of Different Ancillary Services[7]

Service	Service Description			
	Response Speed	*Duration*	*Cycle Time*	*Price Range* (Average, Max) $/MW-hr*
Normal Conditions				
Frequency Regulation	Online resources, on automatic generation control, that can respond rapidly to changes in frequency.			
	<30 seconds	*Seconds to Minutes*	*Seconds to Minutes*	
Regulating Reserve	Online resources, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output.			
	4 Seconds to 5 minutes	*Minutes*	*Minutes*	*$35-$40 $200-$400*
Load Following	Similar to regulation but slower. Bridges between regulation service and hourly energy markets. This service is performed by the real-time energy market in regions where such a market exists.			
	~10 minutes	*10 min to hours*	*10 min to hours*	-
Contingency Conditions				
Spinning Reserve	Online generation, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 min.			
	Seconds to <10 min	*10 to 120 min*	*Hours to Days*	*$7-$7 $100-$300*
Non-Spinning Reserve	Same as spinning reserve, but need not respond immediately; resources can be offline but still must be capable of reaching full output within the required 10 min.			
	<10 min	*10 to 120 min*	*Hours to Days*	*$3-$6 $100-$400*
Replacement or Supplemental Reserve	Same as spinning reserve, but with a 30-60 min response time; used to restore spinning and non-spinning reserves to their pre-contingency status.			
	<30 min	*2 hours*	*Hours to days*	*$0.4-$2 $2-$36*

ancillary services are made available to the system operator. In some areas, the utility that operates the balancing authority self-provides all ancillary services. In others, the balancing authority requires each load-serving entity that operates within its boundaries to provide its pro rata share of some or all of the ancillary services needed by the system operator, and the system operator dispatches those services as necessary.

What is the Renewable "Integration Challenge"?

The United States has seen tremendous growth in wind and solar power over the past decade, as indicated in Figures 20-2 and 20-3. In the first half of 2014, more than half of all newly installed electric capacity in the United States came from solar power.[8]

This growth in VERs is having a positive impact on power sector GHG emissions, but it also creates new challenges for electric system operators. It has become common to discuss the challenge of meeting variations in supply arising from VER production as the "Integration Challenge." Air regulators who hope to see even greater use of renewable energy to reduce GHG emissions need to understand the different dimensions of this integration challenge and some of the potential solutions.

Because the output of wind and solar EGUs cannot be perfectly predicted or controlled, electric system operators need to manage the system around whatever output those EGUs produce or require the VERs to provide their own ancillary services as a condition of interconnection. One way to visualize this is to think not in terms of the gross demand for electricity, but in terms of a "net demand" or "residual demand" that remains after the output of VERs is subtracted from gross demand. As the penetration of VERs on the grid

7 Hurley, D., Peterson, P., & Whited, M. (2013). *Demand Response as a Power System Resource*. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6597

8 Solar Energy Industries Association. (2014). *Solar Energy Facts: Q2 2014*. Available at: http://www.seia.org/research-resources/solar-market-insight-report-2014-q2

Figure 20-2

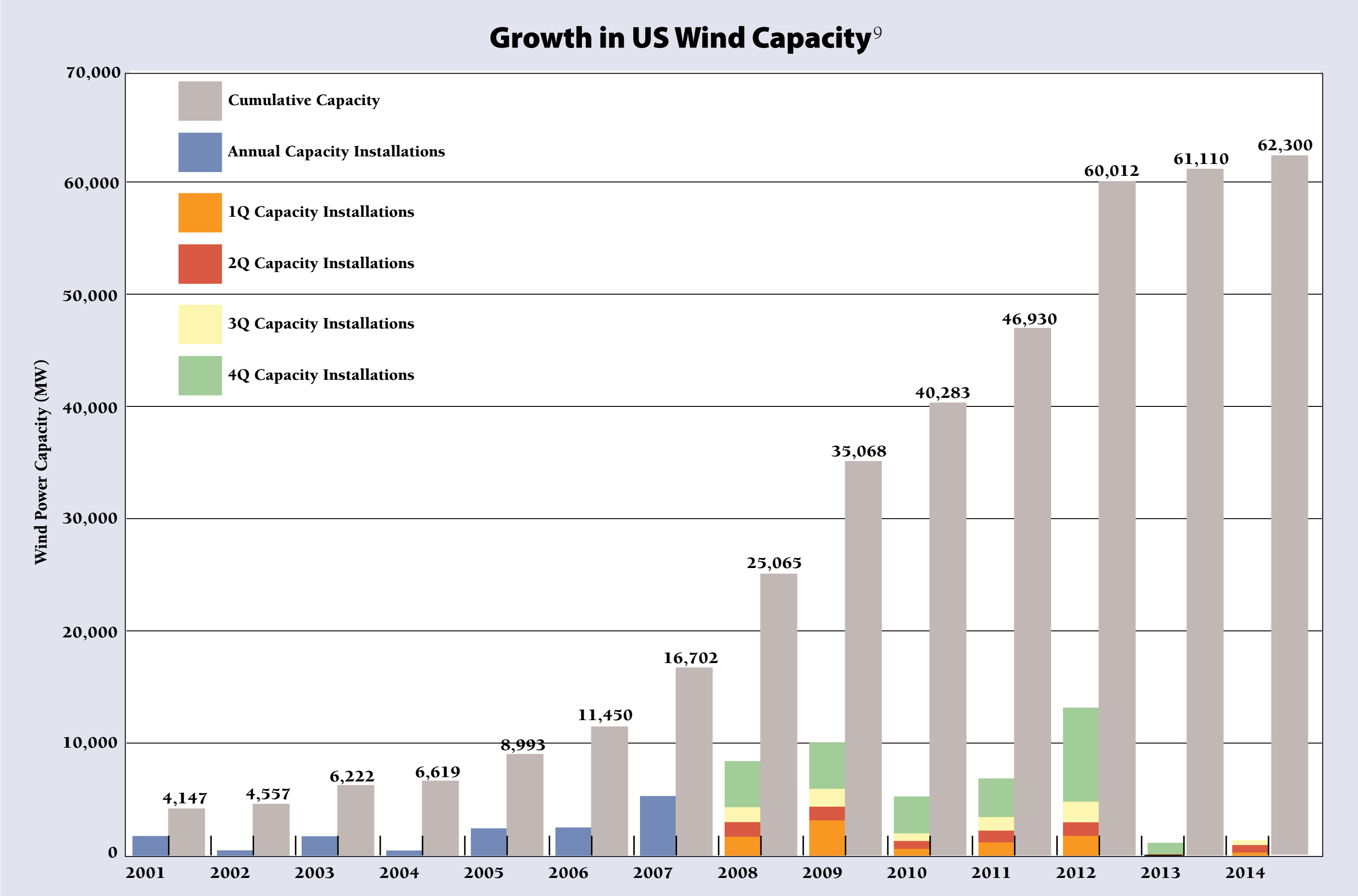
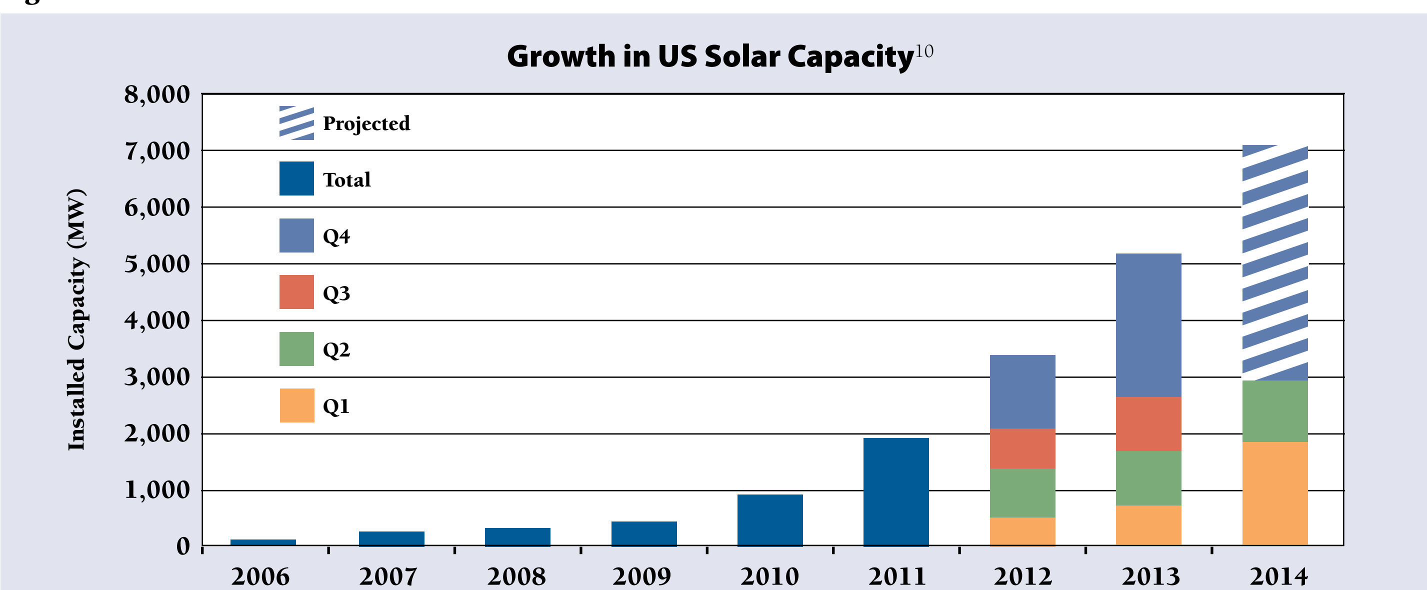


Figure 20-3

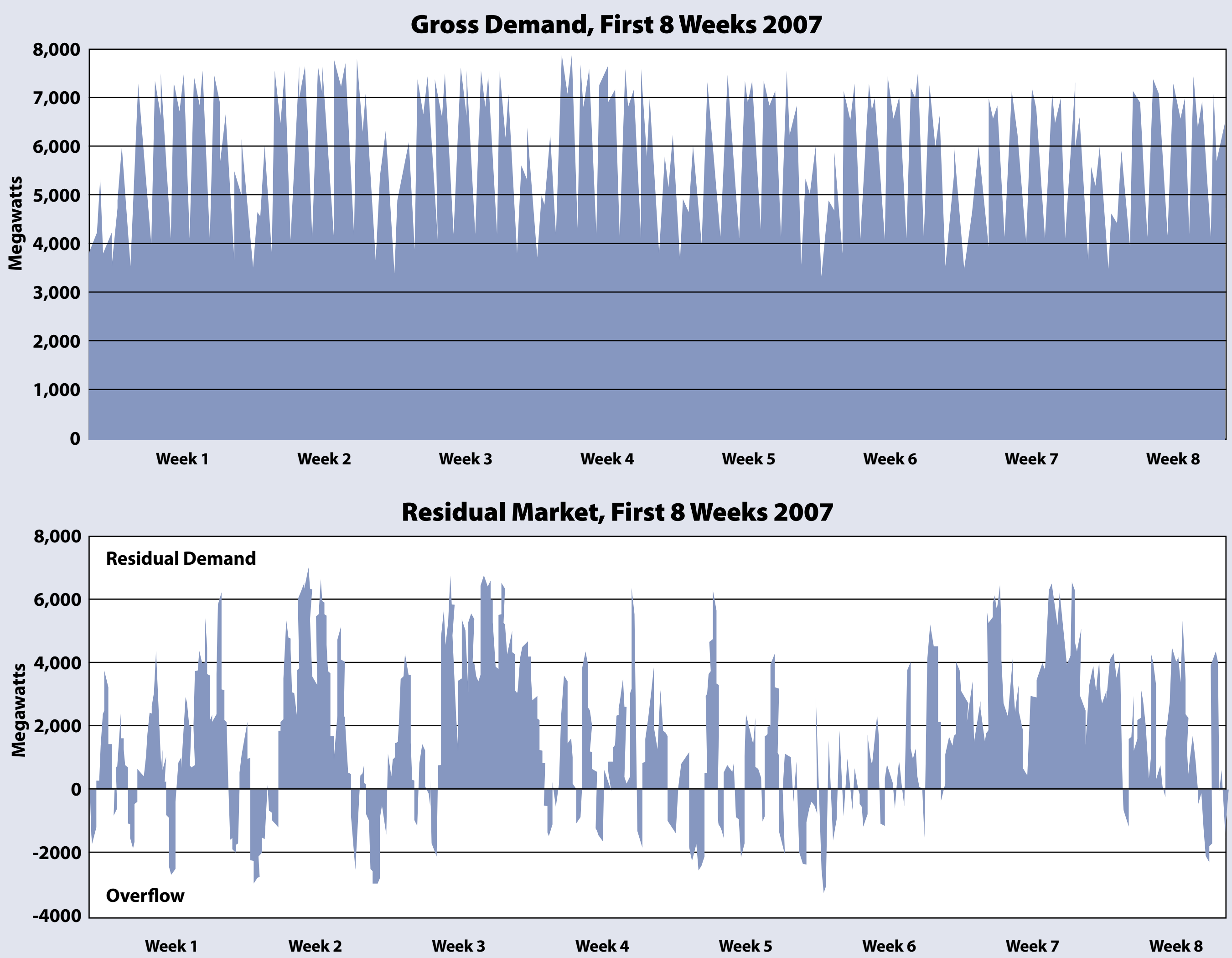


9 American Wind Energy Association. (2014). *US Wind Industry Third Quarter 2014 Market Report.* Available at: http://www.awea.org/3Q2014

10 Supra footnote 8.

Figure 20-4

Gross Demand vs Net (Residual) Demand at High Penetrations of VER[11]



increases, the differences between operating the system to meet gross demand and operating the system to meet net demand become dramatic. These differences are illustrated in Figure 20-4, which shows an actual example of gross and net (residual) demand during an eight-week period in Denmark, where VERs were already producing more than 20 percent of energy on an annual basis and producing more than enough energy to meet total demand during some periods.

What Figure 20-4 shows is that the need for ancillary services that keep the system in balance is very different and much greater as the penetration of VERs increases. When the penetration is sufficiently high, as in the example, there will even be times when the output of VERs exceeds demand. In those cases, the system operator will need to be able to export the surplus energy to an adjoining system, temporarily *increase* demand (e.g., through a DR program that shifts energy consumption from times of high net demand to times of low net demand), rely on storage, or curtail the output of the VERs. According to a National Renewable Energy Laboratory (NREL) report, system operators in the United States are commonly forced to curtail roughly one to four percent of annual wind energy

11 Hogan, M., & Gottstein, M. (2012, August). *What Lies "Beyond Capacity Markets"? Delivering Least-Cost Reliability Under the New Resource Paradigm. A "straw man" proposal for discussion.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6041

output.[12] From the perspective of reducing GHG emissions, curtailing the output of zero-emissions VERs is a very undesirable outcome.

Integrating new resources in a way that maintains reliable system operation is not unique to VERs. In fact, the legacy of a system dominated by very large, inflexible resources contributes to the integration challenge, and the addition of new, large, inflexible EGUs has historically required extensive system planning. However, the variable and weather-dependent nature of some renewable resources presents a different kind of integration challenge. Electric system operators will have to adopt more flexible operational practices and they will need access to more flexible resources in order to maintain system balance as the quantity of VERs grows. System operators will need to work with states and the energy industry to choose integration approaches that provide the best solution, develop ways to implement them, and identify the necessary mechanisms to pay for them in a fair and non-discriminatory way.

The introduction of greater variability in net demand underscores the need to ensure that system reserves have adequate flexibility. Table 20-1 defined several types of reserves but a flexibility reserve category does not exist in most places. The "traditional" capacity mechanisms discussed in Chapter 19 focus only on a simple version of resource capacity, aimed exclusively at procuring enough capacity to meet peak demand during a relatively limited number of hours in the year, irrespective of the EGUs' operating capabilities in other hours. This traditional definition of capacity has historically determined the reserve requirement. These traditional mechanisms are not designed to elicit the operation of or investment in capacity with the flexible capabilities that will be required with increasing frequency, and at multiple times of the day or year, as the share of VERs in the power mix increases. Although most system operators do not currently offer an ancillary service called "flexibility service," the increasing presence of VERs in the portfolio of resources is likely to cause such a service to be offered in an increasing number of electric systems. Changes to capacity markets and changes to ancillary services are needed.

Fortunately, different policies and mechanisms are being tested throughout the country and some are available now to help states meet the new integration challenge with a minimal carbon footprint. States, working with many regulatory and market stakeholders, can adopt long-term strategies that allow low-carbon resources to meet system flexibility needs, as well as smart planning options that limit the amount of variability present on the system. Transitional issues are expected to occur, largely because the system already has an extensive fleet of conventional resources and VERs with established operating parameters and contracts that were designed before integration challenges were fully recognized. However, new technologies, market rules, and payment methods are being worked out to address integration challenges. Solutions will need to be tailored to the different resource mixes, grid and infrastructure designs, as well as the market designs and regulatory requirements for both state and regional solutions. We now briefly introduce several categories of actions that are being tested or used throughout the country.

Using Low-Carbon Flexible Resources

Electricity systems have traditionally relied on fossil resources like gas-fired combustion turbines to provide quick-start or quick-adjusting capabilities needed for some ancillary services and to provide flexibility service, but other low-carbon resources can also provide these capabilities. For example, DR resources, storage, distributed solar resources with smart inverters, and wind resources equipped with advanced control technologies (refer to text box) can each offer dispatchable ancillary services and each contribute to increased system flexibility. It is important not to overlook the capabilities of these low-carbon resources in helping to meet the integration challenge. Retrofitting of some VERs to take advantage of these services may be possible, whereas others will become available as new manufacturing, permitting, or interconnection rules are revised or new rules established. Flexible resources are discussed in more detail later in this chapter.

12 Bird, L., Cochran, J., & Wang, X. (2014). *Wind and Solar Energy Curtailment: Experience and Practices in the United States.* National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy14osti/60983.pdf

Advanced Control Technologies for Wind Turbines[13]

Wind power is "variable" in the sense that maximum available power varies over time (variability), it cannot be predicted with perfect accuracy (uncertainty), and it is not synchronized to the electrical frequency of the power grid and is generally unresponsive to system frequency (asynchronicity). However, Active Power Controls for wind turbines are being developed to address variability, uncertainty, and asynchronicity. The New York ISO has been calling on wind power with just five minutes' notice to relieve congestion on its transmission system since 2008 and several other ISOs have followed suit. These regions have found the tremendous capability that wind power can provide in controlling its output (within the range of what is possible at any time based on wind speeds) to be extremely beneficial. Other Active Power Control capabilities being demonstrated today include synthetic inertia, Primary Frequency Control, and Automatic Generator Control. Proven experience and ongoing demonstrations indicate wind power's potential to economically support power system reliability by adjusting power output. These adjustments can mitigate the need to completely curtail a turbine or offer opportunities to provide ancillary services that may be more valuable than energy.

Using Smart Low-Carbon Integration Planning

The amount of variability in net demand that needs to be accommodated by the system operator can also be mitigated with smart, clean energy strategies that smooth out demand on a regional and local basis. On a regional basis, ten specific tools available for meeting the integration challenge have been illustrated in a paper from The Regulatory Assistance Project, *Integrating Renewables.*[14] (See text box that follows.) Although a detailed description of each strategy is beyond the scope of this short chapter, the strategies involve investing in more intelligent grid systems, modifying regional operational practices to take advantage of a smarter grid, and introducing more cooperation among electric system operators to leverage regional resource diversity and the capabilities of existing resources.

Ten Strategies for Meeting the Integration Challenge at Least Cost

1. Intra-Hour Scheduling
2. Dynamic Transfers
3. Energy Imbalance Markets
4. Improve Variable Generation Forecasting
5. Increase Visibility of Distributed Generation
6. Improve Reserves Management
7. Retool Demand Response to Meet Variable Supply
8. Utilize Flexibility of Existing Plants
9. Encourage Flexibility in New Plants
10. Improve Transmission for Renewables

Increasing the visibility of distributed generation (DG) (strategy 5) and retooling DR (strategy 7) will allow the system operator to anticipate, address, and in some cases reduce local net demand variability. Additional strategies like using time varying prices and energy storage technologies are also available to smooth net demand.

An example of how energy efficiency, DR, storage, pricing, and DG can be combined to smooth local net demand is illustrated in another Regulatory Assistance Project publication, *Teaching the Duck to Fly.*[15] The text box below summarizes the ten local strategies illustrated in that publication; each is fully explained in the paper. For now it is sufficient to say that taking actions like investing in specific types of energy efficiency, adapting how solar energy panels are used, using time-varying pricing, installing storage, and taking advantage of underutilized DR resources can be powerful tools for meeting the new integration challenge. Some of these strategies are already underway in some places, and others are emerging as a

13 Ela, E., Gevorgian, V., Fleming, P., Zhang, Y. C., Singh, M., Muljadi, E., Scholbrook, A., Aho, J., Buckspan, A., Pao, L., Singhvi, V., Tuohy, A., Pourbeik, P., Brooks, D., & Bhatt, N. (2014, January). *Active Power Controls from Wind Power: Bridging the Gaps.* National Renewable Energy Laboratory, University of Colorado, and Electric Power Institute. Available at: http://www.nrel.gov/docs/fy14osti/60574.pdf

14 Baker, P., Bird, L., Buckley, M., Fink, S., Hogan, M., Kirby, B., Lamont, D., Mansur, K., Mudd, C., Porter, K., Rogers, J., & Schwartz, L. (2014, December). *Renewable Energy Integration Worldwide: A Review.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org

15 Lazar, J. (2014). *Teaching the "Duck" to Fly.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6977

Ten Strategies to Align Loads to Resources

1. Targeted Energy Efficiency
2. Orient Solar Panels
3. Use Solar Thermal With Storage
4. Manage Electric Water Heat
5. Require New Large Air Conditioners to Include Storage
6. Retire Older Inflexible Power Plants
7. Concentrate Rates Into "Ramping" Hours
8. Deploy Electricity Storage in Targeted Locations
9. Implement Aggressive Demand Response Programs
10. Use Inter-Regional Exchanges of Power

straightforward evolution of current practice, but some will require new procedures, monitoring technologies and regulatory approval. The amount of time and effort required to implement the strategies is location-specific, and those specifics should be considered as one decides what combination of strategies can accommodate the greatest amount of variable energy while meeting reliability goals at the most reasonable cost.

Regulators need to ensure through their oversight of utilities and ISOs that any low-carbon resources that have flexibility and ancillary services capabilities are eligible to offer these capabilities to BAA operators. Regional and local system operations practices also need to evolve so that low-carbon strategies can be used to mitigate variability in net demand.

3. State and Local Implementation Experiences

As discussed in Chapters 16 and 17, many states are choosing to implement policies that support increased adoption of distributed and large-scale renewable energy, and as the costs of these resources continue to decline, the opportunity for relying on them more heavily to meet carbon reduction goals will grow. These policies can be very effective in promoting carbon reduction, but increasing levels of variable resources will affect how electricity systems are operated. The level of variable energy that can be accommodated on electric systems without significant changes in practices varies, but electricity system operators throughout the country will face an integration challenge at some point, and thus every state will eventually focus on using new technologies, improving operating practices, and improving ancillary service mechanisms. Vertically integrated utilities are affected by integrated resource planning processes, and even some utilities that operate in a competitive market footprint seek authorization from their state PUC to procure new resources from a third party in order to ensure adequate availability of resources. These requests by utilities to build or buy new resources are often motivated by the need to have adequate resources to ensure reliability. Although most utility requests focus on ensuring adequate capacity to meet peak demand periods, it has always been true that local reliability issues associated with the need to maintain voltage or frequency are sometimes offered by utilities as a justification to build or buy new resources. With increasing VER penetration, utilities have also offered the need to integrate renewables as a justification for building or buying new resources. Although some new fossil resources may be required to integrate renewables, many solutions to ensure reliability in the presence of high penetration of VERs at least-cost exist or are under development.

Recently, some states with retiring large central-station resources, such as large coal or nuclear plants, have heard from their utility or system operator that these EGUs provide system inertia that is helpful in maintaining reliability, and the effect of the loss of those plants on inertia needs to be taken seriously.[16] But at the same time, studies in the Electric Reliability Council of Texas, California, PJM, and in the Western Interconnection each affirm that penetrations of VERs up to 35 percent can be

16 Synchronous generators, including coal-fired and nuclear power plants, rely on massive, rapidly spinning rotors to generate electricity. In the first few seconds following the unexpected loss of power from a large generating unit, the frequency of electricity on the entire grid begins to drop. When the frequency drops, all of that spinning mass will begin to slow down as an inherent and automatic physical reaction, but as it does so it will also release some of its inertial energy to the grid. This temporarily and partially mitigates the loss of power in what is known as synchronous inertial frequency response or simply "inertia." If there is enough inertia in the system, the frequency will remain at an acceptable level until slower forms of frequency response such as governors can be activated. NREL is investigating this issue in Phase 3 of the Western Wind and Solar Integration Study, and the results of that study are expected to illuminate whether there is indeed a problem with reduced system inertia and, if so, how large the problem is.

accommodated without compromising reliability, and even higher levels of renewables have been shown to be technically feasible while maintaining reliability.[17,18] Getting to the bottom of these reliability concerns is vital, and integration strategies that meet the reliability challenge posed will need to be tailored to local circumstances to ensure the challenge is met at a reasonable cost.

As noted previously, the integration challenge requires utilities and system operators to think in terms of system flexibility. Most of the ten strategies for meeting the integration challenge at least cost (listed earlier) have been implemented at least to some degree in a variety of locations and have helped to increase system flexibility to more easily and cost-effectively incorporate the resources available to system operators. State and local implementation experiences, as well as descriptions of changes that may be needed but have not yet happened, are provided below.

Intra-Hour Scheduling

With more varied sources and sizes of generation, tighter control of the system is needed even with improved forecasting to reduce the uncertainty associated with VERs. Sub-hourly dispatch refers to the practice of changing generator outputs at intervals less than an hour. Intra-hour scheduling refers to the practice of changing transmission schedules at intervals less than an hour. Because most generation is delivered with transmission, sub-hourly dispatch of generation can only be effectively used if transmission schedules can be modified within the hour. Thus, sub-hourly dispatch and intra-hour scheduling are "hand-in-glove" practices that are fundamentally interdependent. Sub-hourly dispatch and intra-hour scheduling reduce the quantity of balancing reserves required and thus can provide significant cost-saving benefits to consumers. Grid operators can also benefit from greater access to more generation and demand resources that ease the challenge of integrating variable generation. Additional benefits include lower energy imbalance costs for all generators, including VERs, and greater access to transmission if scheduling and dispatch are effectively combined.

In the competitive wholesale markets operated by ISOs, system operators dispatch generation at five-minute intervals and coordinate transmission with dispatch. In contrast, most transmission outside of the ISO territories (in the Western and Southeastern United States) is scheduled in hourly intervals, which makes the integration challenge more difficult.[19] However, because of existing contracts and regulatory treatment of certain generation assets, many resources are self-scheduled by the owner and do not make themselves available for re-dispatch by the system operator except in times of transmission constraints or system emergencies.

Dynamic Transfers

A "dynamic transfer" is a coordinated transfer of firm energy between BAAs. In the absence of dynamic transfers, all energy transferred between BAAs operates on a "static" schedule. A static schedule is submitted 20 to 75 minutes before the onset of the hour for which the schedule will apply, and it is not adjusted during that hour. With dynamic transfers, energy can be scheduled more than an hour ahead or within the hour down to intervals as brief as four seconds.

The Sutter Energy Center (which is in California but outside of the CAISO BAA boundary) is an example where dynamic transfer is being used by an ISO to support operating reserve, regulation, energy imbalance, and load-following services. The BC Hydro System in British Columbia and the Hoover Dam in Nevada are other examples of resources that provide regulation service,

17 See the following document for summaries and citations to major studies all showing that penetrations of this size do not propose insurmountable problems to grid reliability. Linvill, C., Midgen-Ostrander, J., & Hogan, M. (2014, May) *Clean Energy Keeps the Lights On.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7175

18 National Renewable Energy Laboratory. (2014, September). *Renewable Electricity Futures Study.* Available at: http://www.nrel.gov/analysis/re_futures/ McKinsey & Company, KEMA, The Energy Futures Lab at Imperial College London, Oxford Economics, & the ECF. (2010, April). *Roadmap 2050: A Practical Guide to a Prosperous, Low-Carbon Europe. Volume 1: Technical and Economic Analysis, Full Report.* Available at: http://www.roadmap2050.eu/reports

19 Utilities outside of ISO territories are equally capable of intra-hour scheduling, but traditionally have not seen the need for it as they have been dependent primarily on dispatchable resources that they themselves own. As these utilities begin to rely more on variable resources and on purchased power, intra-hour scheduling gains importance.

energy imbalance service, and load-following service to proximate and remote BAAs. Dynamic transfer can also be used to support renewable or VER import scheduling. Examples of renewable resources that are dynamically scheduled to serve a remote BAA include: Argonne Mesa Wind in New Mexico; Copper Mountain Solar in Nevada; Arlington Valley Solar in Arizona; CE Turbo Geothermal in California; and Hudson Ranch Geothermal in California.[20]

Energy Imbalance Markets

Energy imbalances are the difference between advance generation schedules and what is actually delivered within the scheduled period. The scheduled period may be an hour ahead or may be as little as five minutes ahead.

In November 2014, CAISO and PacifiCorp launched a regional real-time energy imbalance market (EIM). It uses an automated system to dispatch resources across multiple BAAs in real time for use as short-term balancing resources to ensure that supply matches demand. This helps reduce costs by broadening the pool of low-cost resources that can be accessed to balance the systems. The market design is based on a conceptual proposal from CAISO that will provide ease of future entry for other balancing authorities. The EIM makes the CAISO five-minute market available to other entities so their resources can be economically and automatically dispatched in real time, thus optimizing the level of available resources and reducing the quantity of required reserves. The Northwest Power Pool is also developing a platform for facilitating intra-hour exchanges among BAAs.[21]

Improve Variable Generation Forecasting

Variable generation forecasting uses weather observations, meteorological data, Numerical Weather Prediction models, and statistical analysis to generate estimates of wind and solar output to reduce system reserve needs. Such forecasting also helps grid operators monitor system conditions, schedule or de-commit fuel supplies and power plants in anticipation of changes in wind and solar generation, and prepare for extreme high and low levels of wind and solar output. Federal and state research and development has brought VERS forecasting to the level it can be today, as there are so many variables and measurements that need to be taken into account. For example, wind speeds depend on the height of the turbine, the variety of the terrain, and the efficiency of the turbine. Continued advances in forecasting efforts are anticipated.

Table 20-2 presents general wind forecast errors in the United States by Mean Absolute Error for hour-ahead and day-ahead forecasts, by individual wind plant and for all wind plants in a large region, as well as forecast errors by energy and by capacity.[22] The table presents two important findings: (1) forecast errors for a single wind plant are larger than for multiple wind plants in a region; and (2) forecast errors are smaller the closer to the time generation serves demand.

Table 20-2

Average Wind Forecast Error by Time Frame[23]

	Forecast Error	
	Single Plant	**Region**
Hour-Ahead		
Energy (percent actual)	10 to 15 percent	6 to 11 percent
Capacity (percent rated)	4 to 6 percent	3 to 6 percent
Day-Ahead		
Hourly Energy (percent actual)	25 to 30 percent	15 to 18 percent
Hourly Capacity (percent rated)	10 to 12 percent	6 to 8 percent

20 For more information on dynamic transfers, see: Coffee, K., McIntosh, J., Hoffman, K., & Nagel, J. (2013). *Dynamic Transfers for Renewable Energy in the Western Interconnection.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6603

21 The EIM is currently limited to intra-hour imbalances and thus covers a limited set of resources. The EIM is an incremental addition to a much larger set of dispatch rules for energy, capacity, and ancillary services.

22 The Mean Absolute Error takes the absolute values of the individual wind forecast errors divided by the predicted or reference value. Another measure, the Root Mean Square Error, involves obtaining the total square error first, dividing by the total number of individual errors, and then taking the square root.

23 Marquis, M., Wilczak, J., Ahlstrom, M., Sharp, J., Stern, A., Smith, J. C., & Calvert, S. (2011). Forecasting the Wind to Reach Significant Penetration Levels of Wind Energy. *Bulletin of the American Meteorological Society,* 92(9), pp. 1159-1171. Available at: http://uvig.org/wp-content/uploads/2013/01/BAMS-Wind_Forecasting.pdf

Larger balancing areas can smooth the variability of wind and solar output through geographic diversity. In turn, that reduces forecasting errors. Generally, forecast errors can be reduced 30 percent to 50 percent by aggregating multiple wind plants as compared to wind forecast errors of individual or geographically concentrated plants.[24] As an example, combining the control areas of Eastern and Western Denmark added about 100 kilometers, and resulted in the total cancelling out of day-ahead wind forecast errors at least one-third of the time.[25]

Increase Visibility of Distributed Generation

Distributed generation operating on the customer side of the meter is commonly "invisible" to system operators. These generators must be interconnected by a utility to ensure they operate safely. But once they are interconnected, unless advanced two-way metering is installed, combined with devices such as smart inverters with communication capabilities, these generators do not usually have the capability to respond to dispatch commands from a system operator. This is particularly true for behind-the-meter resources connected at customer sites, which are netted out with customer load.

Solar DG systems may also be geographically concentrated, and can increase concerns about local over-voltages and distribution equipment overload. These issues are currently dealt with during interconnection. Although this has generally posed little problem in the past and is not a problem in places with modest DG adoption, the projected rapid growth of DG in some places has prompted

Adding Smart Inverters to Interconnection Standards in California[26]

Achieving the state's renewable energy goal requires a fundamental paradigm shift in the technical operation of the distribution system in California. The technical operating standards set out in California's interconnection rules accommodate small amounts of power flows from distributed energy resource (DER) systems, but have not adequately coped with the expected large amounts of DG in a way that supports the paradigm shift in distribution system operations. Technical steps for the paradigm shift were needed as California approached greater numbers of installed DER systems, higher penetrations on certain circuits, and the implementation of a smart distribution system that optimizes interconnected resources were necessary. On December 18, 2014 California took a step forward in making these changes when the California PUC approved advice letters directing the utilities to use inverters with autonomous controls.

The inverter component of DER systems (a.k.a. I-DER) can be programmed to support distribution system operations.[27] Collectively, these programmable functions are called "smart inverter functionalities." Smart inverter functionalities are separated into three groups: autonomous functionalities, communications capabilities, and advanced inverter functionalities that sometimes utilize communications. As California approaches greater numbers of installed DER systems and higher penetrations on certain circuits, enabling the use of smart inverter functionalities will assist with the transition to smarter distribution grid operation that optimizes the DG of interconnected resources.

24 Lew, D., Milligan, M., Jordan, G., & Piwko, R. (2011, April). *The Value of Wind Power Forecasting.* Golden, CO: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy11osti/50814.pdf

25 Holttinen, H., & Hirvonen, R. (2012). Power System Requirements for Wind Power. In T. Ackermann (Ed.), *Wind Power in Power Systems* (pp. 143-165). West Sussex, England: John Wiley & Sons, Ltd. Available at: http://onlinelibrary.wiley.com/doi/10.1002/9781119941842.ch6/summary

26 Adapted from: California Energy Commission and California Public Utilities Commission. (2013, December). *Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources. Smart Inverter Working Group Recommendations.* Executive Summary, pp. 1-2. Available at: http://www.energy.ca.gov/electricity_analysis/rule21/documents/recommendations_and_test_plan_documents/CPUC_Rule_21_Recommendations_v7.docx

27 The Smart Inverter Working Group has used the term "I-DER system" to propose that the inverter-based DER systems are able to take advantage of recent technological advances to actively enhance power system operations.

state and local regulatory agencies to begin evaluating whether system upgrades will be necessary and how these system upgrade costs will be allocated.

With the rapid projected growth of DG, the lack of visibility for system operators is becoming cause for concern. System operator and utility concerns can be divided into the impact of DG on load forecasting and the potential for large amounts of DG to be dropped from the grid by system operators in response to system disturbances. However, it should be noted that some solar photovoltaic inverters can autonomously react to local system variations and others are capable of controlling active and reactive power. Various regions or countries are requiring or thinking of requiring smart inverters, because they allow operators to maintain visibility and control in real time. With “dumb” inverters, curtailment is the blunt instrument used when disturbances occur, so installing smart inverters reduces curtailment events and can enable safe low-voltage ride-through, which is beneficial to the electric system and to the DG owner.

Improve Reserves Management

Higher penetrations of wind and solar resources increase the variability and uncertainty of the net load served by the system, either causing the existing level of balancing reserves to be called upon more frequently or increasing the required quantity of balancing reserves. However, as described in this chapter, the need for additional balancing reserves can be reduced through operational mechanisms to manage reserves more efficiently.

Retool Demand Response to Meet Variable Supply

Where the fuel that drives a growing share of supply is beyond the control of system operators, as is the case with wind and solar energy, it is valuable to have the ability to shift load up and down by controlling water heaters, chillers, and other energy-consuming services. Time-varying rates can provide for beneficial load shape modification, and additional integration benefits can be achieved by implementing either direct control of the load or preprogrammed responses to real-time prices. Experience suggests that DR can be a key component of a low-cost system solution for integrating variable generation. DR also provides many other benefits, including increased customer control over bills, more efficient delivery of energy services, and a more resilient power system. Defining DR well is important, as in some places inefficient, high-emitting fossil-fueled backup generators qualify as DR resources, and increased use of these resources can be counterproductive to meeting climate and air quality goals. For specific examples of state and local implementation of DR programs, refer to Chapter 23.

Utilize Flexibility of Existing Plants

Output control range, ramp rate, and accuracy — along with minimum run times, off times, and startup times — are the primary characteristics of generating plants that determine how nimbly they can be dispatched by the system operator to complement wind and solar resources. In addition, some generation can provide local reactive power. There are economic tradeoffs between plant efficiency, emissions, opportunity costs (the revenue lost when a generator foregoes energy production in order to provide flexibility), capital costs, and maintenance expenses, but there can be cost savings associated with making the most of the fleet we already have.

The first step in maximizing the use of existing generation is to encourage market mechanisms that recognize the value of flexible generation capabilities. In the United States, there has been a tendency to focus on capacity markets (see Chapter 19) to ensure resource adequacy, but it is clear that we need to move beyond capacity markets so that the full range of generation capabilities that have value become expressed. Some ISOs have taken steps in that direction, but more could be done. Once capabilities are properly valued, use of the existing fleet will be optimized and the value of retrofitting existing generation will be clarified. Although selecting technologies that are inherently flexible will be possible over time, some plants can be retrofitted to increase flexibility by lowering minimum loads, reducing cycling costs, and increasing ramp rates, and for some plants this will be a cost-effective alternative to commissioning a new facility.

Encourage Flexibility in New Plants

Traditionally, system operators relied on controlling the output of power plants — dispatching them up and down — to follow fairly predictable changes in electric loads. First, based on load forecasts, generating plants were scheduled far in advance to operate at specified output levels. Then, in real time, these generators would automatically or manually adjust their output in response to a dispatch signal sent by the system operator as needed to balance supply with actual load.

With an increasing share of supply from VERs, grid operators will no longer be able to control a significant portion of generation capacity. At the same time, renewable resources are among the most capital-intensive and lowest-cost to operate. Once built, typically the least-cost approach is to run them as much as possible. Therefore, grid operators will need dispatchable generation with more flexible capabilities for following the less predictable net demand.

New dispatchable generation will need to frequently start and stop, change production to quickly ramp output up or down, and operate above and below standard utilization rates without significant loss in operating efficiency. Flexible resources that can meet increased system variability needs with high levels of wind and solar generation will enable more efficient system operation, increased use of variable zero-cost resources, and lower overall system operating costs.

A significant challenge is establishing what generator capabilities are needed to maintain reliable electric service in the operating and planning time frames and then establishing markets to communicate the value of these attributes to supply- and demand-side resource providers. Once these flexibility capabilities are defined, a further challenge lays in assessing how much flexible capacity already exists and how much will be needed — and when. Resource planning and procurement processes typically have not been focused on flexible capability. New metrics and methods are needed to assess flexibility of resource portfolios and resource capabilities needed in the future. However, FERC and many states have been experimenting with pilots and concepts of what might be workable approaches. States will benefit from those experiments and may wish to undertake their own investigations on this tricky issue. In the meantime, a potentially helpful interim step would be for states to review whether their current policies in any way encourage or promote inflexible capacity, and if so to consider modifications.

Improve Transmission for Renewables

Lack of transmission can be a significant impediment to new utility-scale renewable energy plants, as the locations of renewable energy plants are limited to areas with sufficient renewable energy resources, which tend to be located in more remote areas, away from load centers. Typically, transmission planning is an established, multiyear process that takes into account the impact of various alternatives on the grid. After a transmission line makes it through the planning process a route must be permitted. The whole process can take up to a decade to complete and can involve multiple federal and state agencies. This issue is explained in detail in Chapter 18, along with some potential solutions.

4. GHG Emissions Reductions

The strategies described in this chapter do not directly reduce GHG emissions. Rather, these strategies indirectly reduce GHG emissions by reducing the curtailment of existing, zero-emissions EGUs and facilitating the deployment of more zero-emissions EGUs. The potential GHG emissions reductions that can be achieved through greater deployment of clean energy technologies are detailed in Chapters 6, 16, and 17. Effective VER integration policies and mechanisms will increase the likelihood that the full potential of those strategies is reached, whereas ineffective integration will undermine those strategies.

Ensuring reliability by effectively using supply- and demand-side resources to maintain system balance is a necessary condition for supporting any portfolio of generation resources. Maintaining system balance with a generation portfolio that has a high proportion of VERs will require evolution of operating practices and addition of some ancillary service capabilities. Such a portfolio may also require the explicit recognition of new categories of ancillary services. For example, recent studies of areas with high penetrations of solar generation indicate that having resources that can support a sustained ramp-down of dispatchable generation in the morning and a sustained ramp-up of resources through the evening hours is likely required to ensure reliability. (See the Duck Curve Text Box on page 20-9). Therefore, reducing GHG emissions by transitioning to a high variable-energy portfolio will depend on the proper development of the necessary ancillary resources, and regulators should be aware that enjoying the carbon reduction benefits of increased VERs depends on these ancillary service investments.

At the same time, it is important to recognize that low-carbon resources can provide some of the capacity reserves and ancillary resources required by a portfolio high in variable renewable energy. As previously noted, there are operational changes (such as improved forecasting and intra-hour scheduling), changes in regional coordination (such as taking advantage of regional renewable resource diversity and trading energy imbalances among balancing authorities), and improvements in the use of DR resources that can help mitigate the need for ancillary services, or, in some cases, even provide ancillary services that require intra-hour or real-time dispatch capability. The size and character of that impact are difficult to characterize in a general way, as much of the impact will depend on the details of the mechanism and the resources that are close to participating or withdrawing from the participation in the market. If low-carbon resources are qualified to modify the net demand in a way that reduces the need for ancillary services, and if those low-carbon resources that are dispatchable are qualified to provide ancillary services, then the carbon emissions associated with ancillary services provision will be reduced.

5. Co-Benefits

The co-benefits that can be realized by increasing renewable generation (or reducing curtailment) are identified and explained in detail in Chapters 6, 16, and 17. Those benefits include potentially significant reductions in criteria and hazardous air pollutant emissions. VER integration strategies that enable and facilitate increased renewable generation will facilitate a greater level of those same co-benefits. In fact, in some cases the potential co-benefits of renewable generation simply can't (or won't) be realized unless appropriate integration strategies are in place.

Some air regulators will have heard claims that integrating large amounts of VER generation in coal-heavy regions can lead to increased emissions of criteria and hazardous air pollutants, because the pollution control equipment on coal-fired plants cannot operate efficiently if these plants are constantly varying their output in response to variations in VER output. Although this possibility cannot be dismissed entirely, this chapter has described a broad range of strategies for integrating VERs and it is wrong to assume that the only way to integrate VERs is by ramping coal-fired power plants up and down more frequently than already occurs.

Table 20-3 summarizes the most likely co-benefits associated with improved integration of VERs. Obviously some of these benefits do not derive directly from the integration mechanisms, but rather from the fact that they result in increased deployment and reduced curtailment of renewable generation. However, many of the integration strategies are useful for enhancing electric reliability and capturing other utility system benefits even if the emphasis is not on facilitating renewable generation.

Table 20-3

Types of Co-Benefits Potentially Associated With Improved Integration of Renewables Into the Grids

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	Yes
Economic Development	Yes
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Maybe
Other	

6. Costs and Cost-Effectiveness

As a practical matter, when determining the costs, cost-effectiveness, and emissions savings associated with VERs, the costs of integration (including transmission needs) should be included. However, these costs are not unique to low-emissions resources. Integration costs are also an issue with more traditional forms of generation, which, because of size and inflexibility, may impose additional costs on the system. Most integration studies performed to date on renewable energy have focused on wind turbines, as wind has been the predominant variable-energy renewable technology to date. Many global studies suggest that the costs are between $1 and $7 per megawatt-hour for the relevant study ranges of 10- to 20-percent VER penetration.[28] Higher penetrations of variable renewables lead to higher costs, but experience is limited with high penetrations, and time and experience with integration techniques are likely to bring down the costs. State-specific and utility-specific studies in the United States show considerable variability in these integration costs, again based on the increasing wind penetration.

The role that integration measures and ancillary service mechanisms play in supporting the deployment of zero- and low-emissions resources is both design- and situation-dependent. Well-designed mechanisms can encourage improved operations, improved regional coordination, and the use of demand-side and other low-carbon resources to cost-effectively meet ancillary service needs.

Intra-Hour Scheduling

A technical report for the Western Electric Coordinating Council (WECC) compiled the results of three studies on the potential benefits associated with intra-hour scheduling, shown in Figure 20-5. These studies used dispatch models to compare the total costs of serving load in the Western Interconnection using hourly schedules versus the total costs using ten-minute schedules. The stated benefit of ten-minute scheduling is equal to the difference in these total costs. In addition to facilitating greater penetration of VERs, intra-hour scheduling alone could save consumers hundreds of millions of dollars per year.

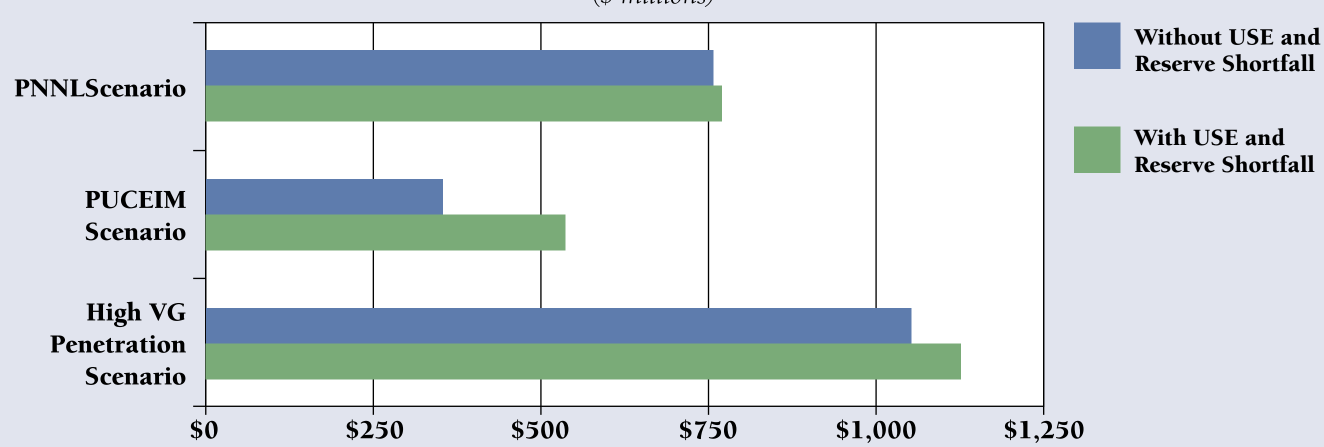
Dynamic Transfers

Dynamic transfers increase the supply of regional resources that can be delivered as a firm resource and thereby reduce cost, defer investment in new facilities, and increase access to high-quality renewable resources. Dynamic transfers can

Figure 20-5

Estimated Cost Savings for Intra-Hour Scheduling in the Western Interconnection[29]

($ millions)



28 International Energy Association. (2011). *Harnessing Variable Renewables: A Guide to the Balancing Challenge.* Available at: http://www.iea.org/publications/freepublications/publication/harnessing-variable-renewables.html

29 Hunsaker, M., Samaan, N., Milligan, M., Guo, T., Guangiuan, L., & Toolson, J. (2013). *Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling.* DOE Award DE-EE0001376. Available at: http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf. The two bars in each scenario reflect cost estimates with and without an assumption that utilities would pay a penalty for unserved energy and failing to maintain adequate reserves.

directly reduce the cost of renewable energy procurement by making transfers of energy from BAAs where sun- and wind-resource quality is high to BAAs where renewable energy is in high demand. Dynamic transfer can also reduce the cost of integrating VERs in two ways. First, dynamic transfer increases the availability of regulation and flexibility resources that may be required at higher levels of VER penetration and thus keeps ancillary service costs down. Second, dynamic transfer ensures real-time firm delivery of the remote resources, and thus the integration services can be provided by the consuming BAA rather than the producing BAA.[30]

Energy Imbalance Markets

E3 estimated that the benefits of an EIM between CAISO and PacifiCorp could range from $21 million to $129 million for the year 2017, as depicted in Figure 20-6.

Improve Variable Generation Forecasting

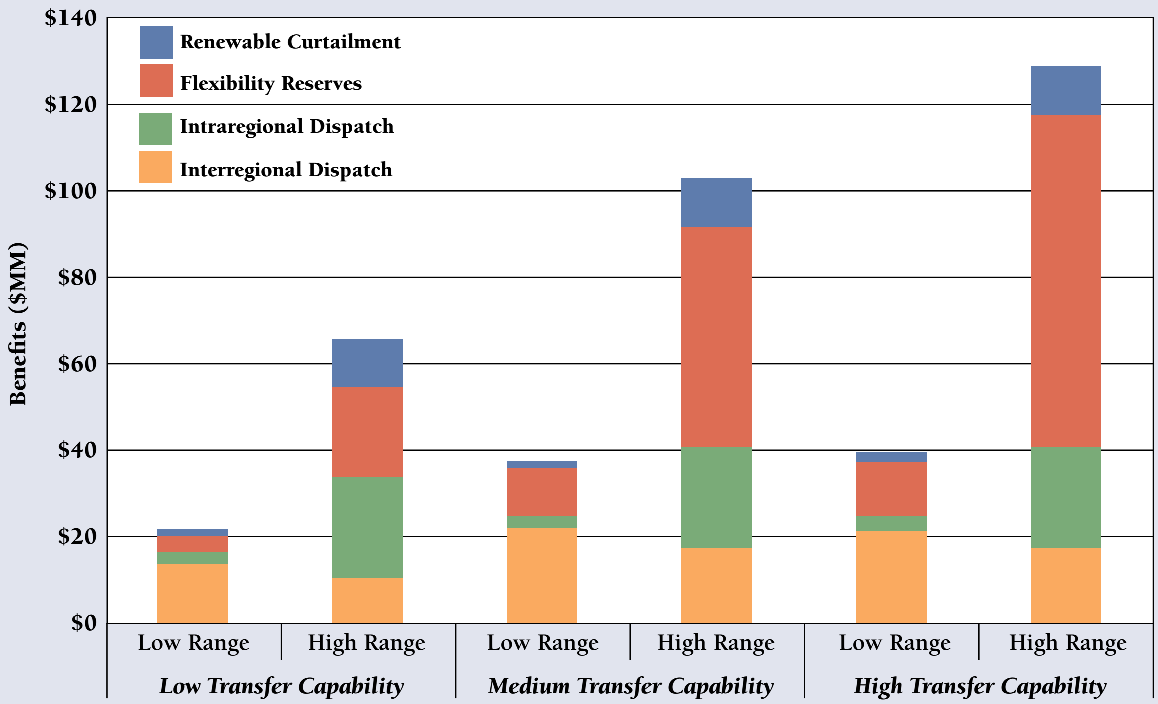
An NREL study of the WECC region found that improved day-ahead wind forecasts can significantly reduce operating costs and increase the reliability of large interconnected power systems.[32] Even a relatively modest ten-percent improvement in wind generation forecasts would reduce WECC operating costs by about $28 million per year when wind energy penetration is at 14 percent. For the entire US power system, the corresponding operating cost reduction would be about $140 million per year.

The impacts would be even greater at higher penetrations of wind energy. A ten-percent wind forecast improvement would reduce WECC operating costs by about $100 million per year with 24-percent wind energy penetration. For the entire US power system, the corresponding operating cost reduction would be about $500 million per year. These findings are summarized in Table 20-4.

Improved wind generation forecasts can reduce the amount of curtailment by up to six percent, thereby increasing the overall efficiency of the power system. Improved wind forecasts also increase the reliability of power systems by reducing operating reserve shortfalls. A 20-percent wind forecast improvement could decrease

Figure 20-6

Low- and High-Range Benefit Estimates Under Low (100 MW), Medium (400 MW), and High (800 MW) PacifiCorp-California ISO Transfer Capability Scenarios (2012$)[31]



30 Supra footnote 20.

31 Energy and Environmental Economics, Inc. (2013, March 13). *PacifiCorp-ISO Energy Imbalance Market Benefits.* Available at: http://www.caiso.com/Documents/PacifiCorp-ISOEnergyImbalanceMarketBenefits.pdf

32 Supra footnote 24.

Table 20-4

Annual Cost Reductions Attributable to Improved Day-Ahead Wind Generation Forecasts

Reduction in Forecast Error	Wind Energy Penetration	WECC Annual Operating Cost Savings ($M)	Estimated US Annual Operating Cost Savings ($M)
10%	14%	$28M	$140M
20%	14%	$52M	$260M
10%	24%	$100M	$500M
20%	24%	$195M	$975M

Source: Hogan, et al, at supra footnote 11.

reserve shortfalls by as much as two-thirds with 24-percent wind energy penetration.

Increase Visibility of Distributed Generation

In a study completed by KEMA for CAISO, the benefits of DER visibility were estimated through several 2020 simulations of production costs for different levels of DER penetration and to isolate the net benefits for each type of DER penetration. Costs of proposed communication architectures and monitoring devices were then compared to the benefits to determine:

- The greatest benefit of visibility would occur in the High DER Penetration Case, in which production costs of $391 million in 2020 could be saved through reduced load-following and regulation-reserve requirements. Of the DER profiles examined in the High Case, the greatest benefits would occur with photovoltaic system visibility ($176 million), followed by DR ($149 million), and then distributed storage ($63 million).
- For the Low DER Penetration Case, the benefits of improved visibility for all DER were projected to be $90 million. For the Medium DER Penetration Case, net benefits of improved visibility for all DER were projected to be $159 million.
- Costs of communications architectures to improve visibility were estimated at $37 million in capital costs and $1.3 million in operating expenditure in the High DER Penetration Case.[33]

Improve Reserves Management

The Western Wind and Solar Integration Study (Western Study) found that balancing authority cooperation can lead to operating cost savings because reserves can be pooled. To estimate the savings, the Western Study performed a sensitivity analysis modeling the Western Interconnection as five large regions instead of a system designed to approximate today's 37 BAAs. In the ten-percent renewable energy penetration scenario, the analysis found $1.7 billion (2009$) in operating cost savings region-wide as a result of larger balancing areas. Overall, the study found that significant savings can be gained from reserve sharing over larger regions with or without renewable resources on the system.[34]

Retool Demand Response to Meet Variable Supply

A widely respected study recently completed for the European grid provides further insight. Figure 20-7 shows the difference in system investment required between two scenarios with high penetrations of VERs – one in which demand is treated more or less as it is today, and the other in which DR programs are assumed to be able to move ten percent of the aggregate demand in the course of a day from periods when supply is less available to periods when it is more available. The result is less need for backup capacity, less need for curtailment of least-operating-cost resources like wind and solar, and less need for transmission, all leading to a net reduction in investment needs of more than 20 percent over the next 15 to 20 years.[35] If these types of

33 KEMA, Inc., National Renewable Energy Laboratory, and Energy Exemplar LLC. (2012). *Final Report for Assessment of Visibility and Control Options for Distributed Energy Resources.* For the California ISO. Available at: http://www.caiso.com/Documents/FinalReport-Assessment-Visibility-ControlOptions-DistributedEnergyResources.pdf

34 GE Energy for National Renewable Energy Laboratory. (2010, May). *Western Wind and Solar Integration Study.* Available at: http://www.nrel.gov/electricity/transmission/western_wind.html, cited in Porter, K., Mudd, C., Fink, S., Rogers, J., Bird, L., Schwartz, L., Hogan, M., Lamont, D., & Kirby, B. (2012). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge.* Western Governors' Association. Available at: http://www.uwig.org/variable2012.pdf

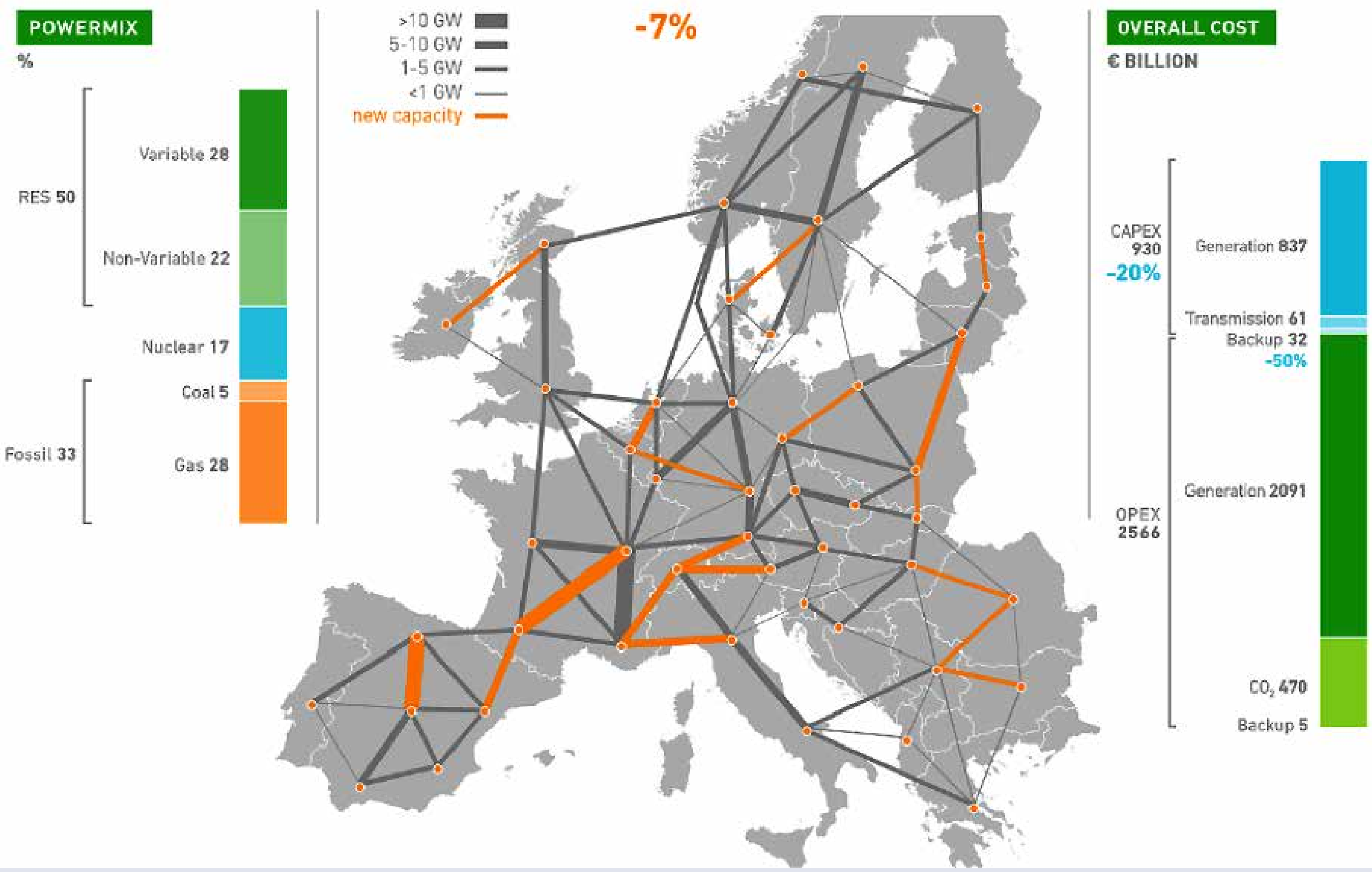
35 McKinsey & Co., KEMA, Imperial College London, and European Climate Foundation. (2011, October). *Power Perspective 2030: On the Road to a Decarbonized Power Sector.* Available at: http://www.roadmap2050.eu/project/power-perspective-2030

Figure 20-7

Effect of Demand Response on Future Investments in Resource and Transmission in the European Union[36]

2030 — Reducing the challenge: higher demand response

New grid capacity decreases by 7%. Overall investments decrease by 20%, with a 50% decrease in back-up capacity.



investment savings can be captured and passed through to retail customers, the benefits to consumers should be significant. The costs and cost-effectiveness of DR are addressed in greater detail in Chapter 23.

Utilize Flexibility of Existing Plants

It is difficult to estimate the potential cost, integration benefits, and implementation timetable for adding flexibility to existing plants. The costs are unique to individual plants, and modifications are a plant-by-plant decision. The authors of a report on the integration challenge produced for the Western Governors Association assumed the cost of minor retrofits from a regional perspective will be low if only a few plants undertake such retrofits and medium if more plants make minor retrofits. Integration benefits are projected to be low to medium, depending on the scope of the retrofits and how many generating plants undertake them. Confidence in both cost and integration benefit is low because of uncertainties about the scope and number of retrofits that may be undertaken. It is assumed minor retrofits could be implemented in a short to medium time frame.

Major retrofits are capital-intensive, so cost is rated medium to high. Authors also rated integration benefits medium to high, as more flexibility is presumed to be made available from major retrofits. But because retrofits are plant-specific and there is uncertainty about how many major retrofits may be performed, confidence in these

36 Supra footnote 35.

estimates is low. Implementation time is assumed to be medium to long.[37]

Encourage Flexibility in New Resources

The same report for the Western Governors Association on the integration challenge also looked at the potential for encouraging flexibility in new resources.[38] Although flexible capacity resources may cost more than other capacity resources, optimization of the electric power system as a whole should reduce costs in the long run. First, acquiring the best mix of resources, including those that complement wind and solar, will lead to more efficient system operation. Flexible, dispatchable resources that ramp up and down as needed to fill in around renewable energy production and meet net demand will allow increased utilization of low-cost energy.

Second, capacity resources that are designed from the outset to be flexible will provide these services at a lower cost than thermal plants that lose efficiency at lower utilization rates and have increased operating costs as a result of frequent starts and stops. When thermal plants are operated at partial loads during periods of high variable-generation output and low loads, fuel efficiency decreases and emissions increase, offsetting some of the benefits associated with renewable energy generation. Maximizing the benefits of renewable resources requires adaptation of thermal plants to meet new operating requirements.[39]

Power Perspectives 2030, a study of the feasibility of Europe's plan to reduce overall GHG emissions 80 percent by 2050, found that a more flexible portfolio of non-renewable supply resources is a key component of an economic long-term solution. Although some of this increased flexibility will come from an increase in the number of back-up generators with very low levels of use, the study found that more efficient options such as flexible gas-fired combined-cycle plants can continue to realize annual load factors comparable to what they see today – although with more erratic day-to-day operating profiles – and should therefore constitute the core of the non-renewable supply portfolio. Together with more responsive demand, expanded transmission systems and larger balancing areas, more flexible generating resources are needed to optimize production and consumption. Essentially, what is needed is a portfolio of "flexible base-load" supply resources capable of matching net demand without compromising efficiency.[40]

Energy storage devices can be extremely flexible but are currently more expensive in most applications than DR programs and other types of flexible resources. However, costs of storage technologies are declining and their potential is enormous. The emergence of energy storage resources is detailed in Chapter 26.

Improve Transmission for Renewables

The Western Wind and Solar Integration Study and the Eastern Wind Integration and Transmission Study both developed conceptual transmission overlays to test the viability of increasing the penetration of variable renewable generation in each interconnection. Although no optimization study was performed, both studies concluded that it may often be more economical to build transmission from sites with high-quality renewable resources (or to use existing lines more efficiently), than to site wind or solar installations in locations with lower-quality resources that are nearer to load. The cost of additional transmission is often a small fraction of the cost of additional generation equipment at the lower-quality site needed to provide equivalent amounts of electrical energy. Hence, the delivered cost of energy produced at the higher-quality site is lower than the energy cost from the lower-quality site, even though the former requires additional transmission.[41] This topic is covered in more detail in Chapter 18.

37 Porter, et al, at supra footnote 34.

38 Information in this section is from: Ibid.

39 MIT Energy Initiative. (2011, April 20). *Managing Large-Scale Penetration of Intermittent Renewables,* p 3. Available at: http://mitei.mit.edu/publications/reports-studies/managing-large-scale-penetration-intermittent-renewables

40 Supra footnote 35.

41 Milligan, M., Ela, E., Hein, J., Schneider, T., Brinkman, G., & Denholm, P. (2012). *Exploration of High-Penetration Renewable Electricity Futures.* Vol. 4 of Renewable Energy Futures Study. NREL/TP_6A20-52409-4. Golden, CO: National Renewable Energy Laboratory. Available at: http://www.nrel.gov/docs/fy12osti/52409-4.pdf

7. Other Considerations

The strategies that are available to integrate VERs are fairly universal, but the methods for procuring ancillary services, the costs of those services, and the allocation of costs to consumers could be quite different from one ISO to another and even more different when ISOs are compared to other balancing authorities. Some of these mechanisms, such as intra-hour scheduling, have already been fully implemented in many jurisdictions, whereas other mechanisms have yet to be fully tested anywhere.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on integrating renewables into the grid.

- *California ISO Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources.* (2013). Available at: http://www.caiso.com/documents/dr-eeroadmap.pdf
- Cowart, R., & Raab, J. (2003, July 23). *Dimensions of Demand Response: Capturing Customer-Based Resources in New England's Power Systems and Markets: Report and Recommendations of the New England Demand Response Initiative.* The Regulatory Assistance Project and Raab Associates, Ltd. Available at: http://www.raponline.org/docs/RAP_Cowart_DemandResponseAndNEDRI_2003_07_23.pdf
- Hogan, M. (2012, August 14). *What Lies "Beyond Capacity Markets"? Delivering Least-Cost Reliability Under the New Resource Paradigm: A "Straw Man" Proposal for Discussion.* Available at: www.raponline.org/document/download/id/6041
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9. Summary

As regulators tackle the challenge of reducing GHG emissions, the need to ensure reliable electric service will remain. This chapter focuses on a suite of policies and mechanisms that can help to ensure continued electric system reliability as the electric system changes to include a higher penetration of VERs, particularly wind and solar EGUs.

Traditionally, system operators relied on controlling the output of power plants — dispatching them up and down — to follow fairly predictable changes in electric loads. First, based on load forecasts, generating plants were scheduled far in advance to operate at specified output levels. Then, in real time, these generators would automatically or manually adjust their output in response to a dispatch signal sent by the system operator as needed to balance supply with actual load. The need for ancillary services was usually modest. But today, as the penetration of VERs increases, the challenge of balancing electric system supply and demand is growing and changing. With an increasing share of supply from VERs, grid operators will no longer be able to control a significant portion of generation capacity. Therefore, grid operators will need new strategies for matching supply to a less predictable and much more variable net demand.

Although some new, flexible, fossil-fueled EGUs may be required to integrate renewables, many other strategies exist that can also ensure reliability in the presence of high penetration of VERs at least cost. The challenge for system operators (and air regulators) is to maximize the use of strategies that support GHG reductions. Broadly stated, these strategies involve DR programs that adjust demand to match supply (rather than the other way around), better use of existing system resources, and procurement of new resources that are more flexible.

The full potential of renewable resources to reduce GHG emissions simply cannot be captured unless these resources can be integrated cost-effectively and without impairing reliability. Fortunately, many of the integration strategies described in this chapter not only facilitate higher penetrations of renewables but also reduce system costs.

Chapter 21. Change the Dispatch Order of Power Plants

1. Profile

One option for reducing carbon dioxide (CO_2) emissions in the power sector is to change the order in which power plants are dispatched, so lower emitting power plants operate more frequently and higher emitting power plants operate less frequently. A number of different policies can accomplish this goal. Before explaining those policy options, we will first explain the status quo approach to dispatch.

Because large batteries and pumped storage dams are currently expensive, electricity generally cannot be stored economically. The supply of electric energy from power plants must be in balance at all times with the demand for electricity from consumers, accounting for losses in the transmission and distribution system.[1] This requires sophisticated control of power plants and transmission lines to provide reliable service.

The North American power system or grid is divided into dozens of balancing areas (also known as control areas). Within each balancing area, supply and demand are kept in balance by an entity called a balancing authority, who issues dispatch orders to power plant operators to turn on a generator, ramp its output up or down, or turn it off.

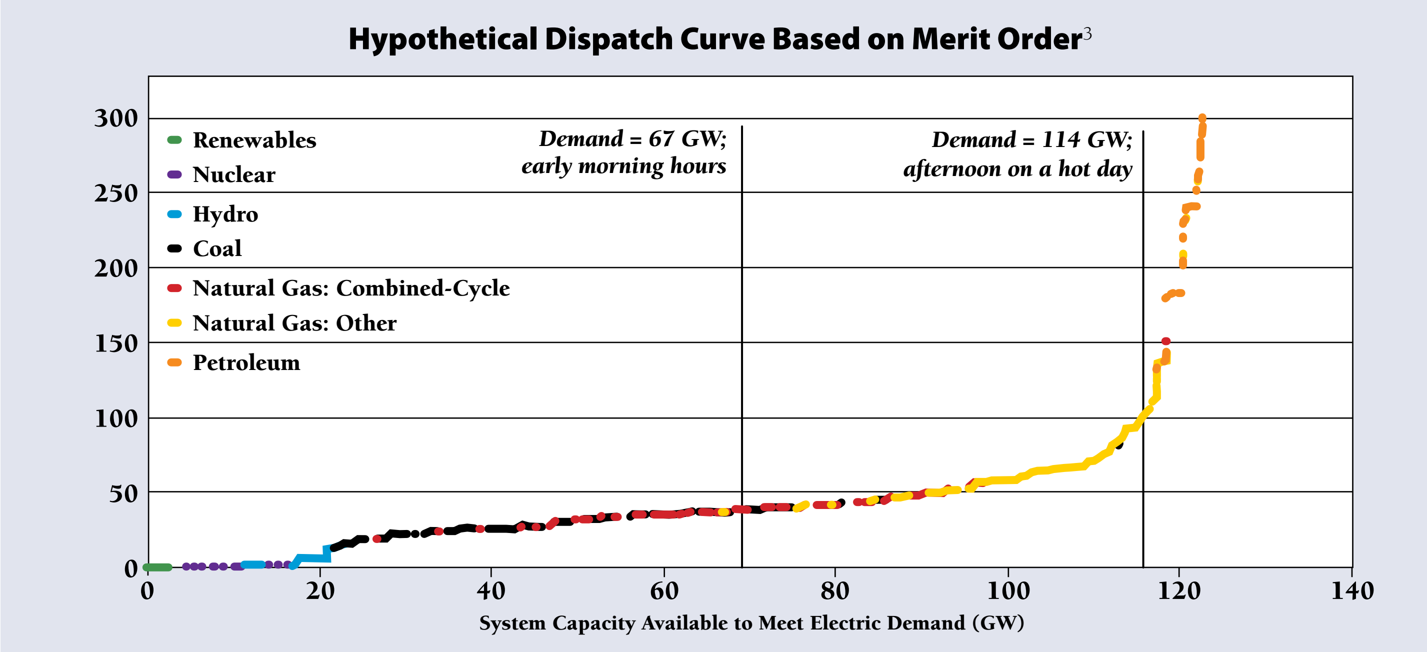
The role of a balancing authority is filled by different types of entities in different parts of the country. In some places, balancing is done by a vertically integrated utility that owns generation (i.e., power plants), transmission, and distribution system assets. These utilities control the dispatch of their own power plants and those of independent power producers (IPPs) that are connected to their system, and they are required by law to provide nondiscriminatory access to IPPs. In many other places, utilities have voluntarily agreed to cede this balancing authority to an independent system operator (ISO) or regional transmission organization (RTO) that oversees a competitive market for the wholesale generation of electricity by utilities and IPPs. Lastly, there are parts of the country where a federal power marketing agency serves as the balancing authority, controlling the output of federal hydropower projects and the output of power plants owned by utilities or IPPs.

Regardless of who does the balancing, an approach known as "security-constrained economic dispatch" is the norm for controlling power plant output. First, the system operator identifies the generating capabilities and the variable operating costs of all of the available electric generating units (EGUs). The capabilities of interest for each EGU include its maximum and minimum generation levels, ramp rate (how quickly its output can be changed up or down), minimum notification time for startup, minimum amount of time it must run once started, and minimum amount of time it must stay off once switched off.[2] In addition, some EGUs might have operating restrictions associated with air pollution control permits or other regulatory approvals. Variable operating costs include all of the categories of costs that vary depending on whether and at what capacity the EGU is operated, including startup costs. The biggest category of variable costs for fossil-fueled EGUs is the cost of fuel. Environmental compliance costs are included to the extent that they are variable, but externalities such as the social cost of carbon would not be included because the generator does not have an associated compliance cost. Capital costs, such as the costs of constructing the EGU or its pollution control equipment, are not variable and would

1 When supply and demand (plus losses) are not in balance, the frequency of delivered power will increase above or decrease below the design frequency. Most equipment can handle very narrow deviations from electrical specifications, and thus the supply and demand do not need to be *exactly* equal at all times. But if the changes in frequency go beyond those narrow tolerances, this can damage electrical equipment or cause system failure.

2 This explanation of economic dispatch is adapted from: Federal Energy Regulatory Commission Staff. (2005, November). *Economic Dispatch: Concepts, Practices, and Issues.* Available at: http://www.ferc.gov/eventcalendar/Files/20051110172953-FERC%20Staff%20Presentation.pdf.

Figure 21-1



also be excluded. In areas governed by an ISO or RTO, operating costs are revealed through competitive bids made by generators.

With all of the information on capabilities and costs in hand, the system operator then ranks the available EGUs in merit order from the least costly to the most costly, as depicted in Figure 21-1.

Ideally the system operator would want to minimize the costs of meeting electric demand by scheduling EGUs for dispatch based on merit order. The least costly EGU would be scheduled first, and then the next least costly EGU, and so forth until enough generation was scheduled to meet the expected demand. This concept is shown in Figure 21-1 for two different hypothetical demand levels.[4] However, before the system operator actually schedules the dispatch of any EGUs, he or she will complete a reliability assessment that considers, among other key factors, the capabilities of the transmission system.

Based on the reliability assessment, system operators sometimes must deviate from merit order dispatch. One of the more common reasons this can happen is because of security constraints. For example, there can be cases in which a more expensive EGU is dispatched to meet load and ensure reliability in a specific geographic area because there is inadequate transmission capacity to deliver less expensive power from an EGU located outside the area. Another reason an EGU might be temporarily operated out of merit order is that the EGU is economical to dispatch in almost all hours, but does not have the flexibility to ramp down for a few hours and then ramp back up when it merits dispatch. For example, this may happen in the case of nuclear power plants.[5]

Although EGUs are sometimes dispatched out of merit order, merit order itself is a purely economic consideration. The emissions that result from the dispatch of any particular EGU are only considered to the extent that there

3 US Energy Information Administration. (2012, August). *Today in Energy.* Available at: http://www.eia.gov/todayinenergy/images/2012.08.17/DispatchCurve.png.

4 The description here mostly describes day-ahead scheduling of EGUs to meet forecasted demand. System operators make similar decisions in hour-ahead scheduling adjustments and real-time balancing decisions based on actual demand, except that the capabilities most needed in those shorter time frames can be different (e.g., ramp rate can be more important), and the variable costs can be different (e.g., if a unit is already operating, its startup costs are not part of its variable costs over the next hour).

5 There are a variety of other reasons EGUs might be dispatched out of merit order. Those reasons can be extremely important for ensuring reliable operation of the system, but are generally beyond the scope of this chapter and need not be explained to understand the potential to reduce CO_2 emissions by changing dispatch order.

is a variable regulatory compliance cost associated with emissions. Fortunately, many of the renewable technologies that produce no emissions also have no fuel costs and near-zero variable operating costs. Nuclear EGUs also tend to have very low variable operating costs, because their fuel costs are considerably less than those of fossil-fueled EGUs. Consequently, renewable and nuclear EGUs generally rank very high on merit order and tend to be among the first EGUs dispatched by the system operator, as shown in the hypothetical dispatch curve in Figure 21-1. However, after those options are exhausted, if more supply is still needed to meet demand, we find that the least-cost EGUs are not always the lowest emitting EGUs. For example, in the hypothetical dispatch curve, we see that coal-fired units have lower variable costs than gas-fired units, but we know that the coal-fired units also have approximately double the CO_2 emissions of gas-fired units. In other words, emissions could be reduced (at some economic cost) if the dispatch order were changed.

There are several ways to address this issue and change the order in which power plants are dispatched. In some jurisdictions, emissions pricing policies are in place for CO_2. These policies include emissions taxes or, more commonly in the United States, emissions trading programs that directly or indirectly place a price on emissions.[6] If an EGU must pay a tax on each ton of CO_2 emissions, or must obtain an allowance for each ton, this regulatory requirement is "internalized" and adds to the EGU's variable operating costs. This, in turn, leads to lower emitting EGUs ranking higher in the merit order and being dispatched earlier and operating for more hours. Putting such emissions pricing policies in place in more jurisdictions is thus an effective way to reduce CO_2 emissions from power plants.

The electric cooperative Great River Energy and the consulting firm Brattle Group have proposed a variation on emissions pricing in response to the Clean Power Plan that the Environmental Protection Agency (EPA) proposed in June 2014 to regulate CO_2 emissions from existing power plants. Great River Energy operates within the Midcontinent ISO (MISO), where MISO uses security-constrained economic dispatch based on competitive bids made by EGUs. The cooperative has proposed that the MISO could impose a CO_2 emissions price on EGUs under its control. The price would be determined based on simulation models, and set at whatever level would be necessary to change dispatch order enough to ensure compliance with Clean Power Plan regulations across the system.[7]

An alternative to emissions pricing that also shifts the dispatch order toward lower emitting EGUs is called "environmental dispatch." Environmental dispatch is a policy in which the system operator explicitly considers environmental criteria (primarily air emissions) when making dispatch decisions, *even if the environmental impacts do not lead to an actual regulatory compliance cost.* EGUs that have lower environmental impacts can potentially be operated out of economic merit order. There are many possible scenarios under which environmental dispatch could be implemented, and the scenarios vary based on which variable(s) are being emphasized. For example, some of the possible approaches to environmental dispatch include:

- Preferentially dispatching certain resources first;
- Imputing a cost adder (dollars per megawatt-hour [MWh]) in the variable costs of fossil-fuel EGUs to account for environmental and public health externalities; and
- Optimizing dispatch for one variable, such as heat rate or CO_2.

Dispatching resources based on heat-rate (British thermal units [BTUs] per kilowatt-hour [kWh]) could be a relatively straightforward way to introduce environmental dispatch, because there is a good correlation between those units that consume the least fuel to generate electricity and those with the lowest CO_2 emissions.[8]

6 Cap-and-trade programs are described in more detail in Chapter 24, and carbon taxes are described in more detail in Chapter 25.

7 Chang, J., Weiss, J., & Yang, Y. (2014, April). *A Market-Based Regional Approach to Valuing and Reducing GHG Emissions from Power Sector: An ISO-Administered Carbon Price as a Compliance Option for EPA's Existing Source Rule.* Discussion paper prepared by Brattle Group for Great River Energy. Available at: http://www.brattle.com/system/news/pdfs/000/000/616/original/A_Market-based_Regional_Approach_to_Valuing_and_Reducing_GHG_Emissions_from_Power_Sector.pdf?1397501081.

8 Minimizing a unit's heat rate is one of the mechanisms the EPA has evaluated to determine the degree of greenhouse gas emissions improvement that is possible. Assuring that a unit operates at the lowest heat rate for its boiler type and fuel also helps to reduce fuel costs for the generator.

2. Regulatory Backdrop

Economic dispatch based on merit order is the norm in the United States. The regulatory basis for this norm can be found in federal and state energy policies.

To begin with, in the case of state regulated, vertically integrated electric utilities, the principle of "prudency" is important to understand. Utilities are allowed to recover the cost of prudently incurred expenses in the rates that they charge to retail customers. But if a utility is paying more than is necessary to serve customer demand while complying with all applicable regulations, and considering security constraints, the additional costs (in theory) will be deemed imprudent and the utility will not be able to recover those costs. Therefore, any deviation from economic dispatch based on variable operating costs (which includes variable regulatory compliance costs) puts the utility at risk for losing money.

In areas where utilities have voluntarily formed an ISO or RTO, the ISO/RTO must establish market rules that are subject to approval by the Federal Energy Regulatory Commission. These market rules are intended to ensure that wholesale generation and transmission costs are minimized and that the market cannot be manipulated by any party. Generators must make bids to the ISO/RTO based on their variable operating costs if they are available for dispatch, and the ISO/RTO must dispatch generation based on the principle of security-constrained economic dispatch.

In both of the above cases, transmission owners and operators (utilities, ISOs, and RTOs) are also required by federal law to provide nondiscriminatory and open access to all generators. They cannot favor certain types of generators (e.g., lower emitting generators) over others.

Under the current regime of federal and state energy policies, the first of the options listed in the preceding section (preferentially dispatching certain resources first) thus may not be feasible. Changing the dispatch order of power plants might only be possible where it is done in response to a regulatory requirement that imposes either an explicit variable operating cost (e.g., through a carbon tax), a market-based variable operating cost (e.g., through a cap-and-trade program), or an imputed variable operating cost (e.g., where a vertically integrated utility can show that dispatching power plants out of merit order is prudent because it costs less than other alternatives for complying with a regulation). Optimizing dispatch based on one variable might be possible if it is similarly in response to a regulatory requirement, even if a cost adder is not involved. In any event, changes to wholesale energy market rules for an ISO/RTO would have to be approved by the Federal Energy Regulatory Commission.

Changing dispatch order is a central component of the emissions guidelines for CO_2 emissions from existing power plants that the EPA proposed on June 2, 2014 (a.k.a. the Clean Power Plan). The EPA determined that the best system of emission reduction for existing power plants is one that comprises a combination of four building blocks determined to have been adequately demonstrated to reduce CO_2 emissions, with due consideration for impacts on the cost of electricity and electricity system reliability. One of those four building blocks consists of increasing the use of low emitting, natural gas-fired combined-cycle (NGCC) EGUs. Although the proposed regulation would not require states to change the dispatch order of power plants, the emissions targets that the EPA proposed for each state are based in part on the EPA's assumption that dispatch can be shifted from coal-, oil-, and gas-fired steam EGUs to NGCC EGUs up to the point at which the NGCC EGUs are operating at an annual average of 70 percent of rated capacity. The impact of this building block on the state goals is variable and depends on the amount of installed combined-cycle capacity and the historic amount of steam EGU generation. In some states, the assumption is that literally all of the steam EGU generation could be re-dispatched to combined-cycle EGUs. However, the EPA did not specify how states would implement or enforce a change in dispatch order in view of the regulatory limitations discussed previously.

It is perhaps worth mentioning here that several states have enacted a loading order policy that is similar in some respects to an environmental dispatch policy, but also has key differences. Loading order policies regulate the procurement of energy resources by utilities, and explicitly favor low emitting resources over higher emitting resources. However, these policies are limited in scope to the construction of new power plants by utilities or the acquisition of energy through contractual arrangements with IPPs. The day-to-day dispatch of these resources is not affected in the way that it would be under an environmental dispatch policy. Loading order policies are also described in Chapter 16.

3. State and Local Implementation Experiences

In this chapter, we have explained how the merit order concept is based on variable operating costs, including variable regulatory compliance costs. In a certain sense, virtually all of the states have experience with changing the dispatch order of power plants to reduce emissions because regulatory compliance costs are ubiquitous. For example, EGUs regulated under the Acid Rain Program can be found in 48 states. And looking specifically at CO_2 emissions, we see examples of cap-and-trade programs affecting EGUs in nine northeastern states and in California. The variable costs of complying with the Acid Rain Program and complying with regional CO_2 cap-and-trade programs already factor into dispatch decisions in those jurisdictions.[9]

Other than emissions trading policies that indirectly impose a variable regulatory compliance cost on EGUs, there are relatively few examples of policies in the United States that are designed to change the dispatch order of power plants to reduce emissions. Examples from other countries, including China, may offer further insights into this approach.

California has had a loading order policy since 2004. To implement the policy, the California Public Utilities Commission requires investor-owned utilities to include a

The California Public Utilities Commission ordered utilities to include an imputed dollar-per-ton cost adder for CO_2 emissions when evaluating resources to procure. Table 21-1 provides an example of how this cost adder contributes to variable operating costs for two types of EGUs.

In this example, although both units use natural gas as a fuel, their heat rates differ: 7 million BTU per MWh (MMBtu/MWh) for the combined-cycle plant, versus 11 MMBtu/MWh for the combustion turbine. The heat rate difference affects their emissions rates, which are 819 pounds of CO_2/MWh for the combined-cycle plant, versus 1287 pounds of CO_2/MWh for the combustion turbine. Likewise, the heat rate also affects emissions costs, which end up being $4/MWh for the combined-cycle EGU, and $6/MWh for the combustion turbine.

California used this approach in the context of making resource procurement decisions rather than dispatch decisions. But if California wished to implement environmental dispatch to optimize CO_2 emissions, the same CO_2 price adders (of $4 and $6 per MWh, respectively) could be added to the fuel costs, resulting in an imputed variable operating cost of $39 per MWh for the combined-cycle plant and $61 per MWh for the combustion turbine. Examples could be similarly derived for all of the available generating options, and these imputed costs could be used in lieu of actual variable operating costs in making dispatch decisions.

Table 21-1

Example of Imputed Cost Adder for CO_2 Emissions[10]

Factor	Units	Formula	Combined-Cycle Plant	Combustion Turbine
Gas Price	$/MMBtu		$5	$5
CO_2 Price	$/ton		$10	$10
CO_2 Price	$/lb	(=10/2000)	$0.005	$0.005
Emissions Factor	lbs/MMBtu		117	117
Heat Rate	MMBtu/MWh		7	11
Emission Rate	lbs/MWh	(=Emissions Factor x Heat Rate)	819	1287
Emissions Cost	$/MWh	(=Emissions Rate x CO_2 Price/lb)	$4	$6
Fuel Cost	$/MWh	(=Heat Rate x Gas Price)	$35	$55

9 Cap-and-trade programs and other market-based approaches to reducing emissions are treated in much greater detail in Chapter 24. They are mentioned briefly here simply to underscore that such programs have an impact on variable operating costs and thus on dispatch order. Understanding merit order helps one understand how market-based programs actually result in emissions reductions.

10 The example is based on: Sterkel, M. (2006, March). *Climate Action at the CPUC.* Presentation to the Public Service Commission of Wisconsin. Available at: https://psc.wi.gov/initiatives/cleanCoal/documents/3-10-06Meeting/CAClimate.pdf.

cost adder when evaluating the potential procurement of resources to reflect the risk for *future* greenhouse gas (GHG) legislation or standards. In other words, this cost adder reflects externalities beyond current regulatory compliance costs. The carbon price adder was initially set at $8 per ton of CO_2 emissions, with an escalation of approximately five percent each year. An example of how this price adder works, and its effect on the cost of generation and dispatch, is shown in the text box.[11]

California has also adopted a companion policy to its state cap-and-trade program that imposes a tariff on electricity imports from other states. This is intended to put out-of-state generators on an even footing with in-state generators subject to the state cap. Most of the electricity imported into California is generated by fossil-fueled EGUs. A rate of $17.92 per MWh is applied to unspecified out-of-state imports to account for their CO_2 emissions. However, power imported from the Pacific Northwest is discounted by 80 percent, to $3.58 per MWh, to reflect the low GHG emissions characteristics of power coming from the Northwest, most of which is generated by hydroelectric EGUs.[12]

At the local level, from 2000 to 2001 California's South Coast Air Quality Management District implemented a temporary policy to dispatch generators based on their nitrogen oxide (NO_X) emissions. This occurred during a time period when market manipulation by certain IPPs and failure by some generators to install emissions controls in time to comply with air quality regulations raised electric reliability concerns. The South Coast Air Quality Management District settled enforcement cases with some power producers that required their EGUs to operate on environmental dispatch principles based on minimizing NOx emissions, until the required emissions controls were installed and operating.

As part of the Ozone Transport Commission efforts to characterize emissions associated with "high electric demand days," the New York ISO and the utility Consolidated Edison analyzed the effects of a potential regional policy that would use a multivariate analysis to minimize regional NO_X emissions through dispatch decisions. This framework was based on:

- A robust air quality forecast, which is already in place in the Ozone Transport Commission region;
- A near-term load forecast from the regional electricity grid operator, currently standard practice in several regions; and
- An emissions forecast based on predicted dispatch from the load forecast.[13]

In this example, the New York research effort optimized dispatch on NO_X emissions, which can vary from less than 0.10 pounds per MWh (lbs/MWh) for a new NGCC EGU to more than 25 lbs/MWh for a diesel engine. Although NO_X was optimized in the New York research, CO_2 could similarly be optimized. CO_2 emissions fall in a tighter range, from approximately 750 lbs/MWh for an NGCC EGU to more than 2100 lbs/MWh for the average US coal-fired EGU.[14]

In fact, today's computing powers would permit optimization across multipollutants so that dispatch would reduce CO_2 emissions and, at the same time, not result in increased criteria pollutant emissions.[15] Although such analyses would indeed be complicated, transmission system operators routinely deal with complex, diverse, and rapidly changing conditions (e.g., management of the generation from wind turbines as it varies over the course of each day).

Outside the United States, China took a significant step in 2007 to adopt a groundbreaking environmental dispatch rule, and today the policy is being piloted in several Chinese

11 Supra footnote 10.

12 Western Electricity Coordinating Council. (2011, December). *Scoping Document for California AB32 Sensitivity for 2011 TEPPC Study Program.*

13 Zhang, K. M., Schuler, R., Nguyen, M., Chen, C., Palacio, S., & Valentine, K. (2012). *Dynamic Energy and Environmental Dispatch: Achieving Co-Benefits of Power Systems Reliability and Air Quality.* Cornell University, US Department of Energy, and Consortium for Electric Reliability Technology Solutions. Available at: http://energy.gov/sites/prod/files/1-7%20Dynamic%20Energy%20and%20Environment%20Dispatch%20PRESENTATION.pdf.

14 The Regulatory Assistance Project. (2001, November). *Model Regulations for the Output of Specified Air Emissions from Smaller-Scale Electric Generation Resources: Model Rule and Technical Support Documents.* Available at: http://www.raponline.org/document/download/id/421. Refer to emissions data from Figures 2 (NO_X) and 4 (CO_2), on pages 33 and 34.

15 Aribia, H., Derbel, N., & Abdallah, H. (2013). *The Active-Reactive: Complete Dispatch of an Electrical Network.* Electrical Power and Energy Systems, Volume 44, pp. 236–248. Available at: http://www.researchgate.net/publication/256970301_The_activereactive__Complete_dispatch_of_an_electrical_network

provinces.[16] The rule, developed jointly by energy and environmental regulatory authorities, establishes a mandatory dispatch order based on a combination of thermal efficiency and pollutant emissions. Whereas the standard international practice of security-constrained economic dispatch seeks to minimize total variable costs on the system – which in practice are mostly fossil fuel costs – this approach aims to include consideration of emissions. Specifically, where environmental dispatch is applied, generating units are scheduled according to the following priority ranking:

- Non-dispatchable renewable energy generating units (e.g., wind);
- Dispatchable renewable energy generating units (e.g., biomass);
- Nuclear power plants;
- Combined heat and power facilities that meet specified thermal efficiency criteria;
- Natural gas, coal-bed gas, and gasification generating units;
- Coal-fired power plants – within this category facilities are ranked by thermal efficiency, and plants with the same thermal efficiencies are ranked according to sulfur dioxide emissions rates; and finally
- Oil-fired generating facilities.[17]

In order for Chinese regulators to collect the necessary data to implement this dispatch approach, the regulations require installation of real-time emissions and heat-rate monitors at all thermal units and data sharing across agencies to establish and maintain an index of generating units for each provincial or regional grid.

4. GHG Emissions Reductions

Very little empirical work has been done on the potential GHG reductions from changing the dispatch order of power plants in the United States, partly because there is little direct experience with environmental dispatch in the United States. Potential reductions from this practice would depend on what variables are accounted for in determining generator costs, at what cost level they are incorporated (e.g., are public health impacts or other externalities factored in and, if so, at what cost?), and what resources are available to meet load. The sum of fuel, capital, and internalized costs of current externalities for each generating unit would determine dispatch order, from which GHG reductions would follow.

A 2010 report by the Congressional Research Service (CRS) looked at the potential emissions reductions that

Table 21-2

Estimate of Maximum Displaceable CO_2 Emissions From a US Re-Dispatch Strategy, Based on 2007 Data[19]

(1)	(2)	(3)	(4)	(5)	(6)
Estimated Hypothetical Coal Generation Displaced by Natural Gas (MWh)	Estimated CO_2 Emissions From Displaced Coal Generation (Million Metric Tons)	Estimated CO_2 Emissions From NGCC Generation Used to Displace Coal (Million Metric Tons)	Net Reduction in Emissions of CO_2 by Natural Gas Displacement of Coal (Million Metric Tons) (2) - (3)	Total CO_2 Emissions From Coal for Power Generation, 2007 (Million Metric Tons)	Hypothetical Net Reduction in CO_2 Emissions as a Percentage of 2007 Total Electric Power Coal Emissions of CO_2 (4) / (5)
640,128,780	**635.7**	**253.6**	**382.1**	**2,002.4**	**19%**

16 See: The Regulatory Assistance Project. (2013, October). *Recommendations for Power Sector in China: Practical Solutions for Energy Climate and Air Quality and Integrating Energy and Environmental Policy.* Available at: http://www.raponline.org/document/download/id/6869

17 China National Development and Reform Commission, State Environmental Protection Agency, State Electricity Regulatory Commission, and the National Energy Bureau, 2007. Available at: http://en.ndrc.gov.cn/

18 Kaplan, S. (2010, January). *Displacing Coal With Generation From Existing Natural Gas-Fired Power Plants.* Congressional Research Service. Available at: http://assets.opencrs.com/rpts/R41027_20100119.pdf.

19 Supra footnote 18 at page 9.

could be achieved from changing the dispatch of existing EGUs to maximize the output of NGCC EGUs.[18] The CRS evaluated a hypothetical scenario in which all existing NGCC EGUs were assumed to operate at 85-percent capacity factors (i.e., operate at 85 percent of their rated capacity on an annual average basis). The increases in NGCC dispatch were offset by decreases in the dispatch of coal-fired steam EGUs. The CRS analyzed this scenario to provide an estimate of the theoretical maximum reduction in emissions from re-dispatch strategies, but acknowledged that "it is unlikely that this maximum could actually be achieved" for a number of technical reasons. The results of this maximum potential scenario, showing a 19-percent reduction in CO_2 emissions from coal-fired power plants, are summarized in Table 21-2.

In the same report, the CRS also looked at two re-dispatch scenarios that used the proximity of NGCC EGUs to coal-fired EGUs as a proxy for assessing one of the most significant constraints on maximum potential: transmission system limitations. In these scenarios, the CRS used the same assumptions as in the maximum potential scenario, but with the added assumption that re-dispatching from coal to gas EGUs is only feasible when the EGUs are within 10 miles (one scenario) or 25 miles (the other scenario) of each other. The results, showing a more modest three- to five-percent reduction in CO_2 emissions, are summarized in Table 21-3.

In the proposed Clean Power Plan, the EPA established goals for each state based on an assumption that NGCC EGUs could feasibly operate at a 70-percent capacity factor. The EPA summarized the potential emissions reduction and costs of this strategy in an associated technical support document. The EPA's modeling results indicated that a potential 11-percent reduction in emissions was possible through this strategy, compared to a base case without re-dispatching. If NGCC EGUs were assumed to operate at an even higher 75-percent capacity factor, a 14-percent reduction in CO_2 emissions was found to be possible.[21]

The Brattle Group conducted "proof of concept" modeling in support of the environmental dispatch concept it developed with Great River Energy.[22] As a reminder, the cooperative proposed that MISO could impose a CO_2 emissions price on EGUs under its control, which would then affect dispatch order. The price would be set at whatever

Table 21-3

Estimate of Displaceable CO_2 Emissions From a US Re-Dispatch Strategy Constrained for Proximity, Based on 2007 Data[20]

Case (1)	Category (2)	Amount Displaced (3)	Amount Displaced as a % of the Maximum Potential Displacement of Coal by Existing NGCC Plants (4)	Amount Displaced as a % of Total Electric Power Sector Coal MWh and Associated CO_2 Emissions (5)
Generation and CO_2 Displaced for Coal Plants Within 10 Miles of a NGCC Plant	Generation	101.8 Million MWh	16%	5%
	CO_2 Emissions	58.1 Million Metric Tons	15%	3%
Generation and CO_2 Displaced for Coal Plants Within 25 Miles of a NGCC Plant	Generation	181.5 Million MWh	28%	9%
	CO_2 Emissions	104.8 Million Metric Tons	27%	5%

20 Supra footnote 18.

21 US EPA. (2014, June). *GHG Abatement Measures – Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions From Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602 at page 3-26. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-ghg-abatement-measures.

22 Supra footnote 7.

level would be necessary to change dispatch order enough to ensure compliance with Clean Power Plan regulations across the system. The Brattle Group developed three different illustrative pricing scenarios, all of which would achieve (according to the modeling results) at least a 30-percent reduction in MISO-wide GHG emissions by 2035.

There has been some analysis of the impacts of environmental dispatch in China. Initially the environmental dispatch method was implemented in five provinces. The experience across those five initial provinces generally showed that more efficient coal units displaced dirtier units, resulting in significant reductions in coal combustion and CO_2 emissions. The average rate of coal consumption in Guangdong province, for instance, declined 3.4 percent from 323 grams per kWh to 312 grams per kWh in the first two years of implementation from 2007 to 2009.[23] Simulation studies for a selection of provinces have produced similar estimates of potential coal savings, suggesting that CO_2 emissions could be reduced by about three percent if the policy was broadly adopted across the nation.[24] The dispatch rule also may have the effect of driving future investment toward cleaner and more efficient units, as is already being seen in the pilot provinces – although this is clouded by a contention over how negatively affected plants will be "compensated" for decreased operating hours.

As noted previously, dispatch order can also change as an indirect result of imposing a price on emissions through a cap-and-trade policy or carbon tax. The emissions reductions that are achievable through either of those policies are explored in more detail in Chapters 24 and 25.

5. Co-Benefits

Any policy that changes the dispatch order of power plants for the purpose of reducing CO_2 emissions is likely to simultaneously reduce the emissions of other air pollutants. Other environmental impacts associated with some of the higher emitting sources of generation, such as

23 Gao, C. & Li, Y. (2010). *Evolution of China's Power Dispatch Principle and the New Energy Saving Power Dispatch Policy.* Energy Policy, 38, 7346–7357. Available at: http://www.sciencedirect.com/science/article/pii/S0301421510006257

24 Mercados Energy Markets International. (2010, August). *Improving the Efficiency of Power Generation Dispatch in China.* The World Bank. Policy Note.

Table 21-4

Types of Co-Benefits Potentially Associated With Changing the Dispatch Order of Power Plants

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Yes
Coal Ash Ponds and Coal Combustion Residuals	Yes
Employment Impacts	No
Economic Development	No
Other Economic Considerations	No
Societal Risk and Energy Security	No
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	No
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	No
Other	No

the need for cooling water and the production of coal ash, may also be reduced.

For environmental dispatch policies, the magnitude of these complementary co-benefits would depend upon the specific variables on which the environmental dispatch were based, and how those variables were valued in determining dispatch order. To the extent that low or zero emissions supply options are available (e.g., wind or solar photovoltaic generation), multipollutant emissions reductions could be substantial. For example, modeling work completed for proposed implementation of the 1990 US Clean Air Act Amendments reflected that, for the state of Ohio, NO_X reductions of up to 50 percent were possible from a combination of environmental dispatch and energy conservation programs.[25]

The full range of co-benefits that can be realized through changing dispatch order is summarized in Table 21-4.

6. Costs and Cost-Effectiveness

Changing the dispatch order of power plants will by its very nature increase the overall short-term cost of electric power, because EGUs will be dispatched in new ways that are not based solely on their short-term variable costs. The costs and cost-effectiveness of these policies will vary greatly depending on the specific location, situation, the EGUs available and their costs, and the policy design itself. As such, it is not possible to draw general conclusions about costs and cost-effectiveness; however, specific examples are examined here.

As noted earlier, one way to change dispatch order is to impose a cost on emissions indirectly (through a cap-and-trade system) or directly (through a tax). The cost of a cap-and-trade policy is ultimately reflected in the market price of emissions allowances. This is true because generators will include the market value of allowances in their calculation of variable operating costs even if allowances are allocated at no cost, because any allowance that isn't used can be sold. Of course, the price of allowances will in large part depend on the stringency of the cap relative to expected levels of emissions. If generators expect that the industry as a whole will have little problem complying with the cap, allowances will have little value; if they see the cap as being very challenging, allowances will have a greater value. The Northeastern and Mid-Atlantic states participating in the Regional Greenhouse Gas Initiative (RGGI) use auctions to distribute allowances. Since the first auction in 2008, allowance prices have ranged from $1.86 to $5.02, with a noticeable increase in prices since the cap was made more stringent in 2013.[26] In California, allowance prices for the AB32 trading program have ranged between about $10 and $12 since the first auction in November 2012.

Of course, in the case of a carbon tax, the cost of changing dispatch will be predetermined by the amount of the tax, as that amount will be directly added to variable operating costs when dispatch decisions are made. With a carbon tax, what is uncertain is the extent to which emissions will decrease.

Although cap-and-trade systems and carbon taxes add to the short-term price of wholesale electricity, they also create a revenue stream that can be used to offset such price increases. The RGGI states, for example, use allowance auction revenues to fund consumer energy efficiency programs that reduce electric demand. Evidence to date suggests that this reduction in demand more than offsets the added cost of CO_2 allowances, as wholesale energy prices in the region have declined since the start of the program. In this manner, the RGGI states get the emissions benefits of imposing an emissions cost that changes dispatch order, without increasing total system costs. More details on the costs and cost-effectiveness of cap-and-trade programs can be found in Chapter 24. Details on carbon taxes are found in Chapter 25.

In a technical support document that was published with the proposed Clean Power Plan, the EPA describes its use of computer modeling to assess the potential costs of the building block that focuses on changing dispatch order: "EPA employed the Integrated Planning Model (IPM), a multi-regional, dynamic, deterministic linear programming model of the US electric power sector that the EPA has used for over two decades to evaluate the economic and emissions impacts of prospective environmental policies. IPM provides a wide array of projections related to the electric power sector and its related markets (including least cost capacity expansion and electricity dispatch

25 Heslin, J., & Hobbs, B. (1990). *Application of a Multi-Objective Electric Power Production Costing Model to the US Acid Rain Problem.* Case Western Reserve University. Engineering Costs and Production Economics, 20, 241–251. Available at: http://econpapers.repec.org/article/eeeecpeco/v_3a20_3ay_3a1990_3ai_3a2_3ap_3a241-251.htm

26 Auction results are summarized at: http://www.rggi.org/market/co2_auctions/results.

projections) while meeting fuel supply, transmission, dispatch, and reliability constraints… In executing this analysis, the EPA conducted a number of scenarios to quantify the relationship between the amount and cost of re-dispatch."[27] The results from three of these scenarios, in which the dispatch of NGCC EGUs was assumed to reach national average capacity factors of 65 percent, 70 percent, and 75 percent, are summarized in Table 21-5.

Table 21-5

Modeled Impacts of Re-Dispatch Scenarios[28]

NGCC EGU Average National Capacity Factor (%)	Average CO_2 Emissions, 2020–2029 (Million Metric Tons)	Emissions Reduction From Base Case, 2020–2029 (%)	Average Cost of Emissions Reductions, 2020–2029 ($ per metric ton)
Base Case	2215	N/A	N/A
65	2022	9	$21
70	1969	11	$30
75	1915	14	$40

In the "proof of concept" modeling that it conducted in support of the environmental dispatch concept it developed with Great River Energy, the Brattle Group developed three different illustrative pricing scenarios.[29] In one scenario, the CO_2 emissions price started at $5 per ton in 2013 and grew by five percent each year. In the second scenario, the price started at $10 per ton and grew at six percent per year. And in the third scenario, the price didn't start until 2030, but began at $30 per ton and grew at ten percent per year. Each of these pricing pathways was found to be sufficient to alter dispatch enough to reduce MISO-wide GHG emissions in the year 2035 by at least 30 percent.

The cost-effectiveness of environmental dispatch policies will always depend on which of the external environmental, climate, public health, and social costs policymakers include in the total cost that will determine the new dispatch order of EGUs. Discussing costs and cost-effectiveness of environmental dispatch has a different flavor than such discussion applied to traditional end-of-pipe emissions controls, where the dollars per ton of pollutant(s) reduced can be readily determined. With environmental dispatch, proponents argue that EGUs impose external environmental, climate, public health, and social costs that today are borne by society as a whole. This policy recommends that these societal costs, to the extent that they can be quantified, be included in the operating costs of EGUs. Doing so will change the relative order of what units are dispatched. Units with higher heat rates and greater external effects will have the costs of those effects reflected in their operating costs, and such units will operate fewer hours than units that have lower costs.

To incorporate these external costs, policymakers must identify which of the external variables should be associated with electricity generation, quantify their costs, and reflect some or all of the costs into the operating costs of EGUs. Several states and regions now either require that costs for these externalities be calculated, or include them in cost-effectiveness calculations to the extent that such values can be determined.[30] Recent work by the National Academy of Sciences and by Synapse Energy Economics enables metrics to be developed on the public health impacts per kWh of electricity generated, as well as the

27 Supra footnote 21.

28 Adapted from Table 3-7 at: Supra footnote 21.

29 Supra footnote 7.

30 See, for example: Delaware and Delmarva integrated resource planning (IRP) requirements. Delaware Department of Natural Resources and Environmental Control, comments on Delmarva's IRP, September 16, 2013. Available at: http://depsc.delaware.gov/electric/12-544%20DNREC%20Comments.pdf. Another example comes from the Northwest Power Act, which requires the Northwest Power and Conservation Council to account for environmental externalities in their resource costs and benefits calculations, to the extent to which these things can be monetized. Refer to the Regional Technical Forum's Recommendations to the Bonneville Power Administration Regarding Conservation and Renewable Resources Eligible for Conservation and Renewable Resources Rate Discount and Related Matters, RTF Meeting August 2000. Available at: http://rtf.nwcouncil.org/meetings/2000/08/rtfcrdrecmd.doc.

costs of various generating technologies (including wind, solar, and biomass). For example, the National Academy of Sciences report reflects a median impact of coal-fired electricity generation of 4.36 cents per kWh, with a 95th-percentile cost of over 12 cents per kWh (which is higher than the retail cost of electricity in many states).[31] The Synapse report includes all supply-side resources (coal, oil, gas, solar, wind, biomass, nuclear); their costs; subsidies provided; and climate change, air, land, and water impacts.[32]

Determining the external costs associated with various EGUs should not be a major obstacle in light of the wealth of existing research and data. For example, transmission operators in New England routinely calculate the system's marginal emissions rate to help air regulators assess the benefits of energy efficiency and renewable energy programs. The Northwest Power and Conservation Council's definition of cost-effectiveness allows the inclusion of external costs and benefits from energy efficiency programs. The EPA's Environmental Benefits Mapping and Analysis Program enables air regulators to calculate the public health benefits of emissions control measures they are evaluating.[33] The Regulatory Assistance Project identified more than two dozen categories of costs associated with power generation, including several categories of externalities that could potentially factor into dispatch decisions.[34]

7. Other Considerations

Seeking to maximize GHG reductions, including externalities (uncaptured societal costs imposed by EGUs) in dispatch decisions, is consistent with how good integrated resource plans are being prepared today, how cost-effectiveness screens for energy efficiency programs are determined, and how transmission planning is conducted. The complementary nature of environmental dispatch policies with related energy policies makes for a comprehensive package on which to engage energy regulators and electricity grid operators.

Although the cost impacts of changing dispatch order have already been acknowledged in this chapter, a few other considerations regarding the potential of this strategy bear mentioning. Most of the recent analyses of re-dispatch opportunities in the United States have focused on the potential to increase generation from lower emitting NGCC EGUs and reduce generation from higher emitting EGUs, especially coal-fired EGUs. One limitation on the potential of this strategy that is generally noted is that the supply of natural gas, the capacity to transport the gas to NGCC EGUs, and the capacity to store natural gas at or near NGCC EGUs may not allow for across-the-board, sustained, high capacity factor use of NGCC EGUs. Regional and seasonal limitations on the natural gas supply chain could come into play as capacity factors increase. In addition, if the amount of natural gas used for electric generation increases dramatically, there would likely be impacts on the commodity price of natural gas that would affect other uses of the fuel, notably for industrial processes and space heating.[35]

Large-scale changes in dispatch order could also have consequences for the viability of some EGUs. Fossil-fueled EGUs subject to new environmental requirements may choose retirement over pollution control retrofits if they expect to run at a lower capacity factor in the future. Even in the absence of new environmental requirements, some owners of fossil-fueled EGUs that move lower in the dispatch order may find that they are now losing money and choose to cut their losses by retiring the unit. This could conceivably raise new problems with resource adequacy (i.e., the ability to satisfy peak demand for electricity). However, safeguards are in place. Balancing authorities (e.g., an ISO or RTO such as PJM Interconnection) and regional reliability organizations are

31 National Academy of Sciences. (2010). *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.* ISBN 978-0-14640-1.

32 Keith, G., Jackson, S., Napoleon, A., Comings, T., & Ramey, J. A. (2012, September). *The Hidden Costs of Electricity: Comparing the Hidden Costs of Power Generation Fuels. Prepared by Synapse Energy Economics for the Civil Society Institute.* Available at: http://www.civilsocietyinstitute.org/media/pdfs/091912%20Hidden%20Costs%20of%20Electricity%20report%20FINAL2.pdf.

33 Refer to the EPA website at: http://www.epa.gov/air/benmap/.

34 Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits).* Montpelier, VT: The Regulatory Assistance Project. Available at www.raponline.org/document/download/id/6739.

35 For more information on these limitations, refer to: Supra footnote 18.

ultimately responsible for ensuring that grid reliability will not suffer as a result of an unexpected or abruptly planned unit retirement. Requests to deactivate an EGU are reviewed by the balancing authority, who identifies any potential impacts on grid reliability. If problems are identified, deactivation of the EGU will not be allowed until steps are taken to alleviate the problem, such as changes in transmission, addition of new generating capacity, and the like.[36] Reliability must-run units are subject to special wholesale energy market rules that allow them to operate out of merit order until required actions are taken to ensure grid reliability. Those rules also dictate who pays for the costs of uneconomic dispatch.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on changing the dispatch order of power plants.

- Bernow, S., Biewald, B., & Marron, D. (1991, March). *Full Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation.* The Electricity Journal, 20–33. Available at: http://econpapers.repec.org/article/eeejelect/v_3a4_3ay_3a1991_3ai_3a2_3ap_3a20-33.htm
- Federal Energy Regulatory Commission Staff. (2005, November). *Economic Dispatch: Concepts, Practices, and Issues.* Available at: http://www.ferc.gov/eventcalendar/Files/20051110172953-FERC%20Staff%20Presentation.pdf.
- Kaplan, S. (2010, January). *Displacing Coal With Generation From Existing Natural Gas-Fired Power Plants.* Congressional Research Service. Available at: http://assets.opencrs.com/rpts/R41027_20100119.pdf.
- Li, X. (2009). *Study of Multi-Objective Optimization and Multi-Attribute Decision-Making for Economic and Environmental Power Dispatch.* Electric Power Systems Research, 79, 789–795.
- Palinachamy, C., & Sundar Babu, N. (2008). *Analytical Solution for Combined Economic and Emissions Dispatch.* Electric Power Systems Research, 78, 1129–1137. http://www.sciencedirect.com/science/article/pii/S0378779607001939
- Yalcinoz, T., & Koksoy, O. (2007). *A Multiobjective Optimization Method to Environmental Economic Dispatch*. Electrical Power and Energy Systems, 29, 42–50. http://www.sciencedirect.com/science/article/pii/S0142061506001086

9. Summary

A strategy in which environmental and public health variables are priced and included as part of a generator's operating costs – thereby affecting their dispatch order – could help a state to reduce GHG and criteria pollutant emissions, and contribute to the state's air quality plan as a valid control measure.

To the extent that costs in addition to the operating costs of an EGU can be determined, they can be included as part of the variable operating costs associated with that particular unit. This can be done across the entire fleet of generating units that are dispatched by a grid operator. In practice, economic dispatch would still be used, but now each unit's costs would be more reflective of the environmental and public health effects associated with its generation of electricity. The unit's operation would, in turn, hinge on its new, imputed or "full-cost" place in the dispatch order.

Environmental dispatch is just one policy in a suite of electric grid operation and transmission policies that could help states reduce their GHG emissions. Together with the complementary policies (described in other chapters) of revised transmission pricing, revised capacity market practices, revised ancillary services, and revised transmission siting and pricing, environmental dispatch would form a package that adds value to the role of energy regulators and electricity grid operators, while also maintaining and improving electric reliability.

36 Units that are not allowed to retire for reliability-related reasons are given a special designation and are subject to special wholesale energy market rules. A generic term for this designation is "reliability must-run," but other terms are used regionally. For example, MISO uses the designation "system support resource."

22. Improve Utility Resource Planning Practices[1]

1. Profile

This chapter examines the potential for utility resource planning processes to support the efforts of states to reduce greenhouse gas (GHG) emissions from the electric power sector. It will focus on a particular type of planning process called integrated resource planning. This process, as well as any plan produced by the process, is commonly referred to by the acronym "IRP."

An IRP is a long-range utility plan for meeting the forecasted demand for energy within a defined geographic area through a combination of supply-side resources (i.e., those controlled by the utility) and demand-side resources (i.e., those controlled by utility customers). Generally speaking, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.[2] Most IRPs look 10 to 20 years into the future, and are updated every two to three years.

An IRP may be developed by a utility or power marketing administration for its service territory in one or more states, or by a utility commission for its entire state. In some states, utility plans serve as a blueprint for resource acquisition decisions and are subject to approval by the public utility commission (PUC). Plans covering a multistate area are more likely to be used for educational purposes only.

In the process of developing an IRP, planners may consider a wide range of alternatives to meet future energy needs. The alternatives can include reducing demand through energy efficiency programs or rate design, adding generation capacity, encouraging customer-owned generation and combined heat and power facilities, adding transmission and distribution lines, reducing line losses in the transmission and distribution system, and implementing demand response programs.[3] Planners can also consider relevant state and federal policy requirements, such as state renewable portfolio standards, state energy efficiency resource standards, and federal acid rain program requirements.

1 Portions of this chapter are adapted from three publications for which The Regulatory Assistance Project was lead author or client: (1) State and Local Energy Efficiency Action Network. (2011, September). *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* Available at: https://www4.eere.energy.gov/seeaction/publication/using-integrated-resource-planning-encourage-investment-cost-effective-energy-efficiency; (2) Wilson, R., & Biewald, B. (2013, June). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics for The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6608; (3) Farnsworth, D. (2013, March). *Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses and Administrative Processes.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6455

2 Nearly all utilities and utility regulators across the country have practiced some form of least-cost resource planning for decades. But in the past, many of these least-cost resource plans exclusively considered procurement of supply-side resources. The availability of energy efficiency and other demand-side resources at very low costs and in significant quantities was often ignored in the planning process. An IRP can be very similar to a traditional least-cost resource plan, with the distinction that a process or plan that doesn't consider demand-side resources is not an IRP. Although "traditional" least-cost planning continues in some locations and may be relevant to this chapter, IRP is much more widely practiced and more suitable for use in the context of GHG emissions reductions.

3 Not every IRP considers every alternative listed. The alternatives considered will vary based on state and local regulatory requirements and based on what type of entity is developing the plan. In particular, the planning for transmission lines in areas served by a regional transmission organization is commonly done through a separate process as described in Chapter 18.

The basic steps in an IRP process have been summarized by one expert as follows:[4]

1. Forecast load, fuel and market power prices, and other key factors, such as likely environmental regulations or market changes;
2. Document costs and benefits of existing supply-side and demand-side resources, including existing generation and transmission facilities, purchase contracts, energy efficiency and demand response programs, and market purchases of power; study their strengths and weakness, challenges and opportunities;
3. Identify and characterize new supply-side and demand-side resources that could be acquired over the life of the IRP;
4. Develop different resource plans that could meet future load requirements, and screen them based on cost;
5. Select the best resource plans and test their sensitivity to risk factors such as load uncertainty, fuel price volatility, and regulatory uncertainty;
6. Select a preferred plan, usually based on a combination of lowest present value life-cycle cost (under one or another definition of cost) and risk profile; and
7. Develop an action plan for the near term, often three to five years, depending on the construction lead-time of the selected resources.

Figure 22-1

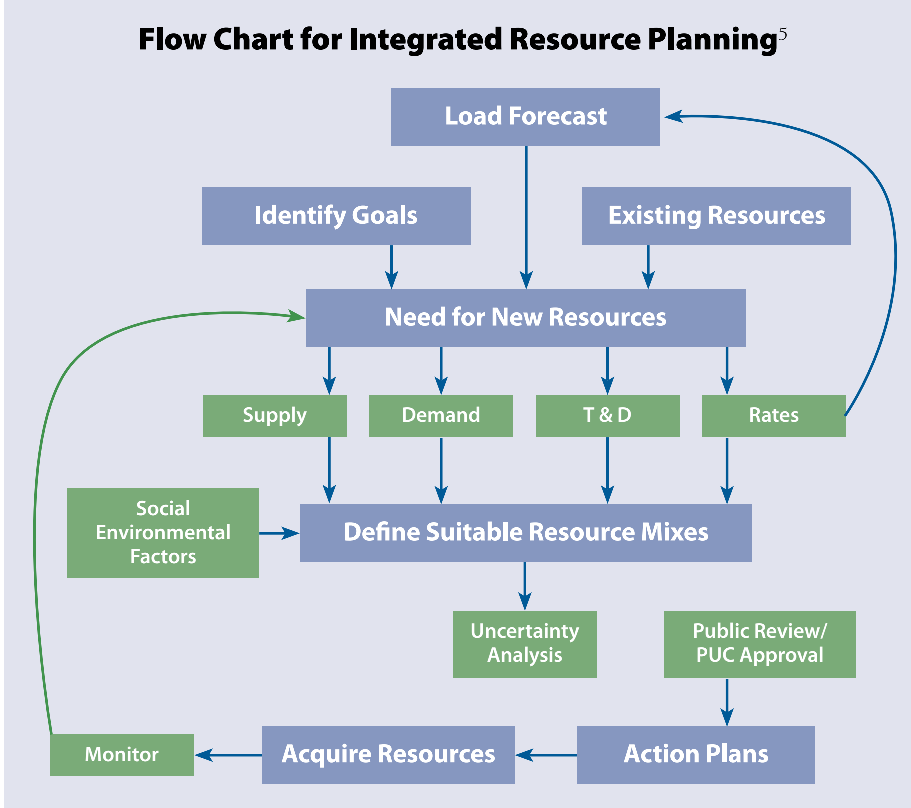


Figure 22-1 depicts a similar interpretation of the steps in an IRP process by a different expert.

In a 2013 publication, The Regulatory Assistance Project and Synapse Energy Economics provided recommendations for the substantive aspects of IRPs that are designed to result in responsible and comprehensive plans:[6]

1. **Load Forecast.** A company's load forecast (annual peak and energy) is one of the major determinants of the quantity and type of resources that must be added in a utility's service territory over a given time period, and has always been the starting point for resource planning.

4 Biewald, B. (2011, October 17). *Review of Resource Planning Around North America.* Synapse Energy Economics, Inc. Available at: http://synapse-energy.com/project/review-resource-planning-around-north-america The seven specific process steps referenced also appear in: Resource Insight, Inc. and Synapse Energy Economics, Inc. for the Ohio Consumers Council. (2006, June). *Integrated Portfolio Management in a Restructured Supply Market*, pp. 37–38. Available at: http://www.occ.ohio.gov/reports/ipm/pdfs/irp_report.pdf

5 Adapted from: Hirst, E. (1992, December). *A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators.* Oak Ridge National Laboratory. The figure as shown here appears in: Harrington, C., Moskovitz, D., Austin, T., Weinberg, C., & Holt, E. (1994, June). *Integrated Resource Planning for State Utility Regulators.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://raponline.org/document/download/id/817

6 Wilson, R., & Biewald, B. (2013, June). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics for The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6608

Projections of future load should be based on realistic assumptions about local population changes and local economic factors and should be fully documented.

2. **Reserves and Reliability.** Reserve requirements should provide for adequate capacity based on a rigorous analysis of system characteristics and proper treatment of intermittent resources. The system characteristics affecting reliability and reserve requirements include load shape, generating unit forced-outage rates, generating unit maintenance-outage requirements, number and size of the generating units in a region or service territory, transmission interties with neighboring utilities, and availability and effectiveness of intervention procedures.
3. **Demand-Side Management.** The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies.
4. **Supply Options.** A full range of supply alternatives should be considered in utility IRPs, with reasonable assumptions about the costs, performance, and availability of each resource.
5. **Fuel Prices.** Fuel prices can shift as a result of demand growth, climate legislation, development of export infrastructure, and supply conditions. It is thus extremely important to use reasonable, recent, and consistent projections of fuel prices in IRP.
6. **Environmental Costs and Constraints.** Utility IRPs should include a projection of environmental compliance costs – including recognition, and evaluation where possible – of all reasonably expected future regulations.
7. **Existing Resources.** Examination of existing resources in utility IRPs has become especially important as the mandated emissions reductions associated with the Mercury and Air Toxics Standards have led to utility decisions across the country to install pollution control retrofits, repower, or retire their coal units.
8. **Integrated Analysis.** There are various reasonable ways to model plans, generally requiring the use of optimization or simulation models. Common models used throughout the industry include Strategist, Electric Generation Expansion Analysis System, System Optimizer, MIDAS, AURORA, PROMOD, and Market Analytics.
9. **Sufficient Time Frame.** The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio – typically at least 20 years – and should consider an "end effects" period to avoid a bias against adding generating units late in the planning period.
10. **Uncertainty.** At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values. These assumptions include, but are not limited to, load forecasts, fuel prices, emissions allowance prices, environmental regulatory regimes, costs and availability of demand-side management measures, and capital and operating costs for new generating units.
11. **Valuing and Selecting Plans.** There are often multiple stages of running scenarios and screening in developing an IRP, and there are various reasonable ways to approach this. Traditionally, the present value of revenue requirements is the primary metric that is analyzed, and minimized, in utility IRPs. This metric alone may not, however, sufficiently address uncertainties. It may be useful also to evaluate plans along other dimensions such as environmental cost or impact, fuel diversity, impact on reliability, rate or bill increases, or minimization of risk.
12. **Action Plan.** A good plan will include a specific discussion of the implications of the analysis for near-term decisions and actions, and will also include specific plans for getting those near-term items accomplished.
13. **Documentation.** A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.

A utility resource plan does not compel emissions reductions, but the utility's decisions on how to treat each of the elements listed previously will greatly influence the perceived feasibility of unit retirements, the relative benefits of demand-side resources, the need to deploy new supply-side resources, the selection of the preferred resources, and – importantly for the purposes of this document

– the resulting air quality impacts. Done poorly, an IRP could result in increased emissions of GHGs and other air pollutants. However, an IRP based on the previous 13 recommendations will give due consideration to emissions and air pollution regulatory requirements and will reveal the impacts of different potential resource portfolios in a way that can aid utility planners and air quality planners. Best of all, it creates a means for utility planners to incorporate environmental considerations in routine processes that are core (not peripheral) to their mission.

As indicated in Figure 22-1, a good IRP process will include at least two steps that create the possibility of *directly* addressing emissions. First, regulatory requirements and public policy preferences – including those for GHG emissions – can be identified as conditions that must be met by any selected resource plan. For example, a goal could be established for the overall GHG emissions or emissions rate that must be achieved through the IRP, and any resource portfolios that fail to meet that goal will be rejected. Second, regardless of whether explicit emissions goals are identified, social and environmental factors (including GHG emissions) can be introduced into the analysis to influence the final selection of the preferred resource mix. For example, without establishing a hard limit on GHG emissions, an assumed regulatory cost or social cost could be assigned to each ton of GHG emissions, which would increase the relative cost of resource portfolios that have relatively high emissions and make those portfolios less likely to be selected for the plan.

2. Regulatory Backdrop

Integrated resource planning rules were first established in many states in the late 1980s or early 1990s. At that time, the electric power sector was dominated by vertically integrated monopoly utilities that owned and had responsibility for generation, transmission, and distribution assets. Many state policymakers saw the value of requiring these utilities to adopt formal, comprehensive IRP processes to ensure reliable and affordable service.

Significant changes to the electric power industry occurred in the ensuing decades. During the mid to late 1990s, electric restructuring occurred in parts of the country, with competitive service providers taking over some of the roles that had been filled by vertically integrated utilities. The wholesale generation side of the industry became competitive in many states, and retail competition was introduced in a smaller but still significant number of states. Although all of these changes affected the scope of the utility's role and in some cases relieved the utility from its responsibility for certain aspects of long-term planning, a majority of states continued to see value in some form of planning process and retained mandatory requirements with changes to the original rules as necessary. For example, in states that have introduced retail competition, utilities may be required to develop long-term plans for their distribution system along with a plan for providing comprehensive service to customers who don't choose a competitive energy supplier.

State IRP rules in their current forms have been established in a number of ways. In certain states, legislatures passed bills into law mandating that utilities engage in resource planning; in others, IRP rules were codified under state administrative code. Some state PUCs adopted IRP regulations as part of their administrative rules, or ordered it through docketed proceedings. Rules have also been developed through a combination of these processes.[7,8]

Figure 22-2 shows the states that have instituted requirements for IRPs, or similar documents, to be prepared by some or all electric utilities. Each state has its own requirements for the scope, timing, and contents of an IRP, and its own requirements as to how that state's PUC analyzes and reviews the IRP once it is submitted.[9] Section 3 provides best practice IRP examples and regulatory or statutory citations for several states and two regional transmission organizations (RTOs).

There is also one notable example of a federal resource planning requirement. *The Pacific Northwest Electric Power Planning and Conservation Act of 1980* requires the Northwest Power and Conservation Council, a regional planning organization, to develop IRPs for the Bonneville Power Administration (BPA). BPA transmits and sells wholesale electricity from federal hydroelectric and nuclear generating stations to utilities in eight western states. These

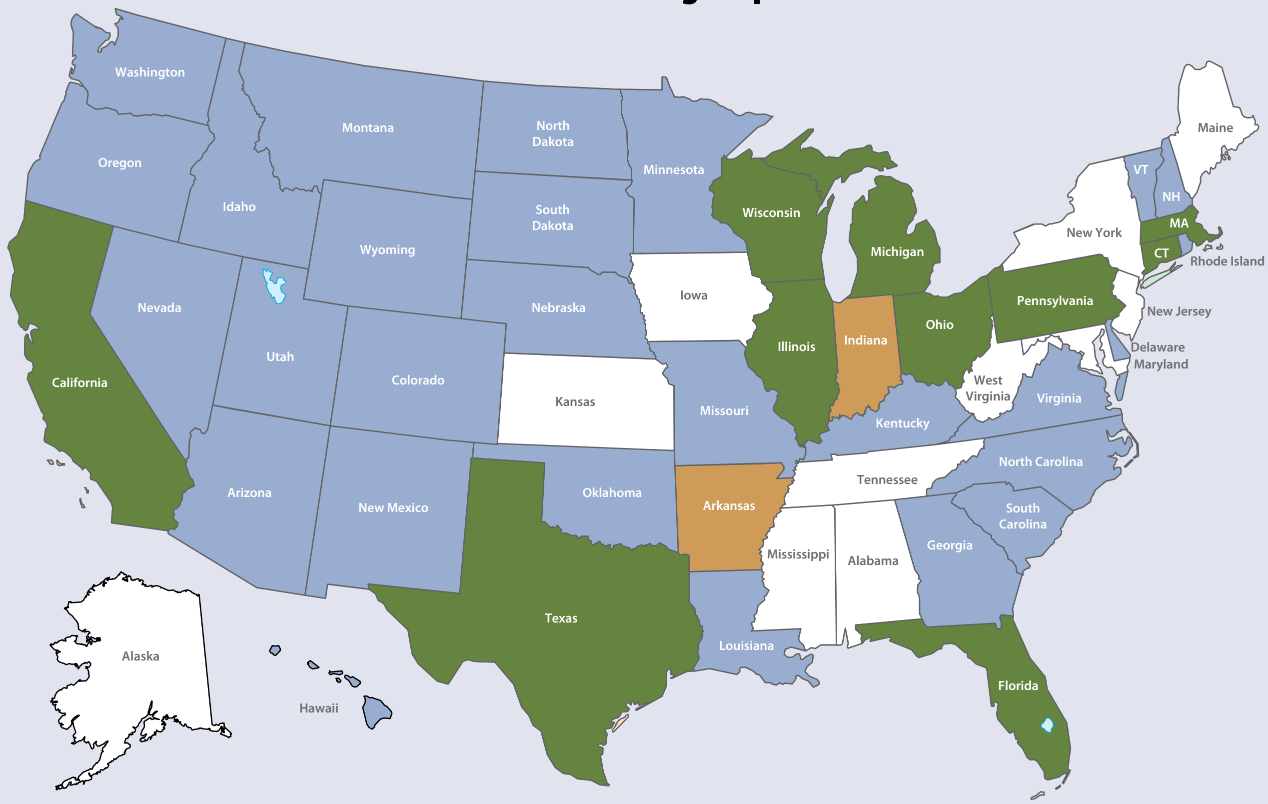
7 Supra footnote 6, at p. 6.

8 In addition, some states have adopted special studies or special planning requirements outside of routine IRP requirements to address air pollution issues or other issues of particular concern to policymakers. Although this chapter focuses primarily on IRP, some of these special planning exercises are particularly relevant to GHG emissions reduction planning and are noted throughout the chapter where appropriate.

9 Many of these details are summarized in Supra footnote 6.

Figure 22-2

State Resource Planning Requirements[10]



State has an IRP rule and filing requirement

State is developing or revising an IRP rule and filing requirement

State has a filing requirement for long-term plans

State does not have filing requirements for long-term plans

plans have a profound effect on the operations of BPA and its client utilities, especially in Washington, Oregon, Idaho, and Montana.

Today, climate change, national security concerns, distributed generation, and volatility in fuel and commodity markets are adding to the challenges of forecasting and planning for the future. These challenges do not detract from the value of IRP, but rather make it more valuable even as it becomes more difficult. This underscores the point that IRP rules need to be reexamined periodically to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs.[11]

One important area in which state IRP requirements differ significantly is the extent to which stakeholders can engage in the process. Typically the process begins when the PUC opens a docket and requires a utility to prepare (or update) an IRP. In some states, the utility will be required to engage stakeholders at the beginning of the planning process, but other states only engage stakeholders after the IRP is drafted. Stakeholders (including air pollution experts) can add value to the IRP early in the process by raising issues and providing data that might otherwise be excluded from consideration. After the utility has completed its analysis, it typically submits the IRP in draft or final form to the PUC. At that point, the PUC may open a comment period, or schedule (or require the utility to schedule) hearings, technical conferences, or workshops to inform stakeholders about the IRP and give them an opportunity to comment. However, states will vary in how many of the data in the analysis are treated as confidential, and this can limit the meaningful participation of stakeholders. The final step in the review process also varies considerably from state to state. Some PUCs will

10 Supra footnote 6.

11 Ibid.

merely review and "acknowledge" the IRP, whereas others will judge the merits of the plan and may order the utility to make changes to the plan or conduct additional analysis.

Expanding on this last point, air pollution regulators need to understand that IRPs are not intended to be enforceable documents that can be used against a utility that deviates from the plan, nor are they intended to give the utility unconditional approval to implement whatever is in the plan. Approval of an IRP by a PUC generally does not relieve the utility from the need to ultimately demonstrate to the PUC that its investments are optimal and consistent with the plan, given *actual* (as opposed to *forecast*) conditions. PUC approval may, however, convey a rebuttable presumption that the projects described in the plan are necessary and prudent. In Oregon, for example: "Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan."[12] Similarly, in Idaho the PUC stated that it would "continue to hold that the plans are not to be given the force and effect of law, [but] we presume that utilities intend to follow the plans after they have been filed for our acceptance. Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in a general rate case or other proceeding in which the issue is noticed."[13]

3. State and Local Implementation Experiences

IRPs are routinely developed and updated on a regular basis by hundreds of utilities across the country. Rather than summarizing all of those experiences, this section offers an example from Arizona of established good practices for IRP that have been used to explore interconnected environmental, energy, and ratepayer issues.[14] In addition, this section features examples of some utility resource planning exercises that were instituted to specifically address air quality issues and supplement normal IRP processes. These special planning exercises not only demonstrate what is possible through separate, air quality-related planning efforts, but also suggest ways in which routine IRP processes can be modified to better account for air quality goals and regulations.

Arizona[15]

Arizona Public Service (APS) is the state's largest electric utility, and has been serving retail and wholesale consumers since 1886. In March 2012, APS filed the first formal resource plan in 17 years with the Arizona Corporation Commission. This IRP was also the first to be filed under the Arizona Corporation Commission's revised rules. From the time when the Corporation Commission issued the final IRP rules to the date that APS filed its resource plan, the utility was "engaging key stakeholders to gain an understanding and appreciation of their areas of concern."[16] The plan also serves as a framework to evaluate APS's resource plans as they relate to other policy requirements for renewable-sourced generation and regulator-imposed energy efficiency obligations.

APS had forecast three percent average statewide annual growth in nominal electricity requirements through 2027. Energy efficiency and distributed generation, in the form of rooftop solar installations, will help offset some of this growth, but APS expects that it will need to add additional conventional supply-side resources, in the form of natural gas-fired generation, in 2019. APS has created four resource portfolios to evaluate: a base case, a "four corners contingency," an "enhanced renewable" case, and a "coal retirement" case.

Each resource plan created by APS was analyzed using a production simulation model, which dispatches the energy resources in each portfolio and generates system costs, or likely future revenue requirements, associated with each. Calculation of system revenue requirements demonstrated that the APS base case portfolio was the most cost-effective of the resource plans evaluated. APS also monitors specific metrics to provide a context for comparing and evaluating the portfolios. In addition to revenue requirements, those metrics include fuel diversity, capital expenditures, natural gas burn, water use, and carbon dioxide (CO_2) emissions.

APS selected major cost inputs and evaluated several sensitivity scenarios, setting the assumptions for these variables higher or lower to test the impacts on the specific metrics being evaluated. These major cost inputs include

12 Oregon PUC Order No. 89-507 at 7.

13 Order 25260 from Case #GNR-E-93-3.

14 Other examples can be found at: Supra footnote 6.

15 Adapted from: Ibid.

16 Arizona Public Service. (2012, March). *2012 Integrated Resource Plan,* p 2.

natural gas prices, CO_2 prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter, and water. APS also created low-cost and high-cost scenarios, which incorporate the low and high values for all of the variables mentioned previously rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of revenue requirements, which fluctuate 11 to 12 percent as compared to 6 to 7 percent for the base case and enhanced renewable portfolios. Natural gas price changes caused the largest impact on sensitivity results.

Under the base case plan, APS achieves compliance with energy efficiency requirements and slightly exceeds compliance levels for renewable energy. Consistent with the intent of the revised rules, APS's reliance on coal-fired generating resources drops by 12 percent between 2012 and 2027. Use of natural gas increases slightly over the course of the planning period under this scenario, but by 2027, no single fuel source makes up more than approximately 26 percent of the APS resource mix.

APS had approximately 600 megawatts (MW) of excess capacity in 2012, heading into the summer peak. In the short term – over the next three years – the company planned to continue to pursue energy efficiency and renewable energy resources. During the intermediate term, years 4 to 15 of the planning period, APS plans to add 3700 MW of natural gas capacity and 749 MW of renewable capacity. However, "[i]n the event that solar, wind, geothermal, or other renewable resources change in value and become a more viable and cost-effective option than natural gas, future resource plans may reflect a balance more commensurate to the Enhanced Renewable Portfolio."[17]

Several features of the IRP efforts of APS are worth highlighting. The first of those is the comprehensive stakeholder process. Not only were stakeholders invited to listen and offer feedback, they were also invited to present their points of view on a subset of these important issues. In the IRP itself, APS provides all non-confidential input and output data for stakeholder review.

APS continues to pursue energy efficiency, renewable energy, and distributed generation resources in each of the resource portfolios it analyzed, meeting or exceeding regulator-identified goals.

APS has also analyzed portfolios that meet the Commission goals of promoting fuel and technology diversity as the utility lowers its reliance on coal-fired generation and increases its use of energy efficiency and renewable energy resources.

In addition, APS takes environmental costs into account when evaluating its resource plans. The company uses a CO_2 adder consistent with the assumption that federal regulation of CO_2 will occur within the 15-year planning period.[18] In sensitivity scenarios, APS analyzes alternative prices for CO_2 emissions, and also includes adders for SO_2, NO_X, particulate matter, and water. Emissions costs and water consumption are also two metrics by which APS evaluates its resource portfolios.

Colorado[19]

Colorado, the seventh-largest coal-producing state in the United States, passed the "Clean Air – Clean Jobs Act" ("the Act") in April 2010, targeting regional haze and ozone, and establishing a 70- to 80-percent reduction target for NO_X emissions from 2008 levels. Denver and Colorado's "Front Range" had been designated under the Clean Air Act as "non-attainment" areas for ground-level ozone.

In the absence of final federal regulations, the Act anticipated new EPA standards for criteria air pollutants (NO_X, SO_2, and particulates), mercury, and CO_2, and

17 Supra footnote 16.

18 APS completed this IRP before the US Environmental Protection Agency (EPA) proposed emissions rate limitations for existing electric generating units under section 111(d) of the Clean Air Act. Not knowing what the EPA would propose, APS made reasonable assumptions about the cost impacts of future regulation and tested different scenarios.

19 Farnsworth, at supra footnote 1.

20 The "Clean Air – Clean Jobs Act," HB 10-1365, requires " [b]oth of the state's two rate-regulated utilities, Public Service Company of Colorado (PSCo), and Black Hills/Colorado Electric Utility Company LP … to submit an air emissions reduction plan by August 15, 2010, that cover[s] the lesser of 900 megawatts or 50% of the utility's coal-fired electric generating units." Legal Memorandum, Office of Legislative Legal Services on H.B. 10-1365 and Regional Haze State Implementation Plan. (2011, March 16). Available at: http://www.leg.state.co.us/clics/clics2011a/cslFrontPages.nsf/FileAttachVw/SIP/$File/SIPMeetingMaterials.pdf

required the utility company[20] to: (1) consult with the Colorado Department of Public Health and Environment (DPHE, the state air pollution regulatory agency) on its plan to meet current and "reasonably foreseeable EPA clean air rules," and (2) submit a coordinated multipollutant plan to the state PUC.[21]

The Act mandated that DPHE participate in the PUC process, and conditioned PUC action on the DPHE's review of utility proposals, affirmatively linking the two agencies' actions. This mandate resulted in the PUC being unable to approve a company plan that the DPHE did not agree would meet future Clean Air Act requirements, and the company not being able to build anything without the PUC's approval and issuance of a certificate of public convenience. The Act also required the DPHE Air Quality Control Commission to incorporate approved plans into Colorado's State Implementation Plan (SIP) for addressing regional haze for ultimate EPA approval.

Colorado utilities are not required to adopt any particular plan, just one that meets DPHE's requirements and meets with PUC approval. The Act also encourages utilities to enter into long-term contracts for natural gas supplies by providing protection against possible future prudence challenges by stakeholders. It allows utilities to recover, in rates, costs associated with approved long-term contracts, "notwithstanding any change in the market price during the term of the agreement."

The Act encourages companies to evaluate alternative compliance scenarios, but requires each company to develop and evaluate an "all emissions control" case (i.e., a scenario calling for installation of pollution controls on the coal fleet, plus an assessment of different ranges of retirements).

In the administrative process, the state's largest utility (Public Service of Colorado, doing business as Xcel Energy) was given four months to report to the PUC with analysis results and a proposed compliance plan. The company divided its analysis into four steps (see Table 22-1). In Step 1, the company collected data regarding: (1) the coal plants for which the company might take "action" (i.e., install controls, retire, or retrofit for fuel switching); (2) emissions control options and associated costs; (3) possible generation technologies that would replace retired capacity; and (4) transmission reliability requirements.

Step 2 involved developing combinations of various actions on coal plants, assessing replacement generation (i.e., developing "Capacity Portfolios"), and testing the feasibility of approaches for reducing emissions while maintaining reliable service.

Table 22-1

Public Service of Colorado's Analysis[22]

1. Data Collection
- Identify Candidate Coal Units
- Emissions Control Options and Costs
- Replacement Capacity Options
- Transmission Reliability Requirements

2. Scenario Development
- Meet NO_X Reduction Targets
- Feasibility of Emissions Controls
- Replace Retired Coal MW
- Transmission Needs Analysis

3. Dispatch Modeling of Scenarios
- Long-term Capacity Expansion Plan
- Cost of Transmission Fixes
- Coal and Gas Price Forecasts
- Customer Load Forecasts

4. Sensitivity Analysis
- Construction Costs
- Coal and Gas Prices
- Emissions Costs (NO_X, SO_2, CO_2)
- Replacement MW for retirements
- Addition of renewable resources

In Step 3, the company used its dispatch modeling capability to evaluate the effects of various scenarios (articulated partly by statute, the company, the PUC, and stakeholders) on the company's entire system.

Step 4 involved the development of sensitivity analyses. At this step, the company performed analyses by varying certain key assumptions to see how the scenarios it developed and modeled under Steps 2 and 3 would perform in different futures.

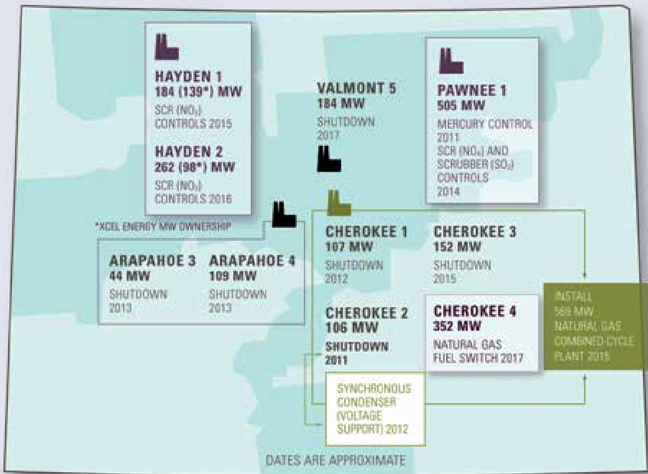
The overall undertaking required cooperation between the regulatory commission and Colorado's environmental regulator, and significant effort by Public Service of Colorado. The process, including a PUC investigation, company analysis of alternative compliance strategies, issuance of a final order, and subsequent adoption of changes to Colorado's SIP, occurred in less than eight

21 Colorado's Clean Air – Clean Jobs Act was specifically identified as a "best practice" by the EPA in its 111(d) proposal.

22 Supra footnote 19.

Figure 22-3

Major Elements of Public Service of Colorado's Approved Plan[23]



months, demonstrating the feasibility of such a cooperative effort and the ability of decision makers to address the challenges related to maintaining system reliability while responding to (as yet unarticulated) health and environmental regulatory compliance challenges. Figure 22-3 provides a visual summary of the major impacts of this planning process.

On March 12, 2012, the EPA approved Colorado's SIP for addressing regional haze around the state's national parks and wilderness areas. Governor John Hickenlooper noted at the time, "EPA's approval of the Regional Haze Plan is a ringing endorsement of a comprehensive and collaborative effort between many different groups… Colorado's utilities, environmental community, oil and gas industry, health advocates and regulators all came together to address air quality. We embrace this success as a model for continuing to balance economic growth with wise public policy that protects community health and our environmental values."[24] Another source quoted in the media at that time said, "The adoption of Colorado's state implementation plan – unlike other states' proposals – went smoothly in large part because of Colorado's 2010 Clean Air – Clean Jobs Act."[25]

The same process steps discussed previously for regional haze and NO_X could also be followed to assess compliance options for the EPA's proposed Clean Power Plan. Step 1 would include data on Colorado's existing renewable energy and energy efficiency programs. Step 2 results would focus on meeting the GHG emissions reduction trajectory from 2020 to 2030 as provided for in the proposed existing source performance standards. The sensitivity analysis in Step 4 could assess the contributions from varying levels of energy efficiency and renewable energy (low, medium, and high), their costs, and effects on Colorado's generating resources. Step 4 could also evaluate the regional effects from energy efficiency and renewable energy, and from improvements to the regional transmission grid (i.e., reduced line losses and improvements to local distribution systems).[26]

It is important to note that the Colorado process:

- Took place in less than one year;
- Went ahead, absent certainty as to precisely what EPA regulations would require; and
- Mandated coordination between environmental and energy regulators, owing to the subject matter of the challenges being addressed by the state.

Michigan[27]

Michigan provides a unique model of regulatory coordination. Executive Directive No. 2009-2 requires the state environmental regulator, the Michigan Department of Environmental Quality (DEQ), to "conduct analysis of electric generation alternatives prior to issuing an air discharge permit." As part of this inquiry, the directive also

23 See: http://www.xcelenergy.com/Environment/Doing_Our_Part/Clean_Air_Projects/Colorado_Clean_Air-Clean_Jobs_Plan

24 Refer to: Colorado.gov. (2012, September 11). Colorado's Air Quality Plan Receives Final Approval from U.S. Environmental Protection Agency. [Press release]. Available at: http://www.colorado.gov/cs/Satellite?c=Page&childpagename=GovHickenlooper%2FCBONLayout&cid=1251630618478&pagename=CBONWrapper

25 Jacobs, J. (2012, March 15). EPA Signs Off on Colorado's Plan for Clearing Haze Near Parks. *Greenwire*. Available at: http://www.rlch.org/news/epa-signs-colorados-plan-clearing-haze-near-parks

26 The EPA's 111(d) proposal did not include transmission and distribution system improvements as part of the four building blocks, but specifically mentions it as a policy that states could evaluate to assess whether such improvements could help reduce GHG emissions.

27 Farnsworth, at supra footnote 1.

requires the Michigan Public Service Commission (PSC) to provide DEQ with technical assistance.[28]

The two agencies entered into a memorandum of understanding in which respective roles were articulated: DEQ would undertake air quality determinations, and the PSC would provide assistance related to determining need for new generation, and analyze alternatives, including options for energy efficiency, renewable energy, and other generation. [29]

The value of this coordinated process was demonstrated when Consumers Energy proposed to construct a new 930-MW coal-fired power plant at the existing Karn-Weadock Generating Station. The utility submitted an Electric Generation Alternatives Analysis to the DEQ and PSC on June 5, 2009. Pursuant to the memorandum of understanding, PSC staff reviewed the Electric Generation Alternatives Analysis and evaluated the long-term capacity need asserted by Consumers Energy as justification for the project. The PSC staff concluded in September 2009 that the project couldn't be justified unless the utility committed to retire certain existing coal-fired units, because of expected low growth rates in electric demand and the potential to meet demand growth less expensively through a combination of energy efficiency, load management (demand response), renewable energy, and purchased power agreements.

Following the PSC staff report, Consumers Energy worked with PSC staff to develop a plan for retiring 958 MW of coal-fired generation capacity as a modification to its original proposal. With those units retired, the need for a new power plant could be demonstrated. DEQ then issued a permit for the new unit on December 29, 2009. But two years later, in December 2011, Consumers Energy canceled the project before construction ever began because of reduced customer demand for electricity and surplus generating capacity in the Midwest market.[30]

Michigan's Executive Directive No. 2009-2, like Colorado's Clean Air – Clean Jobs Act, underscores the value of developing a process that links both environmental and energy regulators to analyze company electric generation choices. In the example provided previously, Michigan avoided the expense and environmental impact of a large coal-fired power plant by coordinating the expertise of the two regulatory agencies and explicitly considering alternatives for meeting project energy demands. A variation on this kind of coordinated process could help Michigan (and other states) develop a feasible and cost-effective state strategy for complying with the EPA's 111(d) rule.

Oklahoma[31]

In June 2011, the Oklahoma Corporation Commission issued a notice of inquiry (NOI) in order to examine existing and pending federal regulations and legislation that could impact regulated utilities and their customers in the state of Oklahoma.[32] The primary purpose of the NOI is to determine whether any amendments to the rules of the Commission are necessary.

In its first of a series of questions, the Commission asked:

> *Are there alternative planning processes other than a regulated utility's Integrated Resource Plan (IRP) as described in OAC 165:35-37 that could be considered in determining the most effective strategy to include a holistic approach to Oklahoma's generation fleet and an analysis of the overall cost impact or benefits to ratepayers as it relates to federal mandates, fuel switching (converting from one fossil fuel to another type of fossil fuel), renewable portfolio standards, fuel diversity, system efficiency improvements, transmission expansions and other upcoming issues? If so, what kind?*

28 Executive Directive No. 2009–2. *Consideration of Feasible and Prudent Alternatives in the Processing of Air Permit Applications from Coal-Fired Power Plants.* Available at: http://www.michigan.gov/granholm/0,1607,7-168-36898-208125--,00.html

29 NARUC Task Force Webinar 3, State Case Studies. (2010, December 17). *Statutory and Administrative Review of Power Plants in Michigan.* Greg White, Commissioner, Michigan Public Service Commission. Available at: http://www.naruc.org/Publications/White_%20Michigan%20Coal%20Plant%20Review%20Processes.pdf

30 Refer to: Consumers Energy. (2011, December 2). Consumers Energy Announces Cancellation of Proposed New Coal Plant, Continued Substantial Investments in Major Coal Units, Anticipated Suspension of Operation of Smaller Units in 2015. [Press release]. Available at: http://www.consumersenergy.com/News.aspx?id=5167&year=2011

31 Farnsworth, at supra footnote 1.

32 Cause No. PUD 201100077, "In Re: Inquiry of the Oklahoma Corporation Commission to Examine Current and Pending Federal Regulations and Legislation Impacting Regulated Utilities in the State of Oklahoma and the Potential Impact of Such Regulations on Natural Gas Commodity Markets and Availability in Oklahoma."

In response, one participant, Sierra Club, proposed that the Oklahoma Corporation Commission adopt "Integrated Environmental-Compliance Planning."[33] This is an approach that, in many ways, works like an IRP. It considers supply-side, demand-side, and delivery options in an integrated manner. It focuses, however, more closely on the requirements of forthcoming public health and environmental regulations and the imminent need to take actions such as retiring, retooling, or investing in new resources. Whether a commission uses IRP or integrated environmental-compliance planning, reviewing investments in an *integrated* manner is the key. According to Sierra Club, this approach will help ensure a greater understanding of all options available that might otherwise be missed with a narrower approach:

> *Responding to these requirements piecemeal will result in inefficient and unnecessarily expensive decisions. The sheer number and wide coverage of these pending rules mandates that the Commission and the utilities consider their potential impact in a comprehensive, rather than case-by-case basis, for both planning and cost recovery. The Commission should expect to see the anticipated costs and the potential risks of existing and emerging regulations for the whole range of pollutants in utility evaluations of their investment proposals. Given the capital-intensive and long-lived nature of investments in the electric industry, if the final form or timing of a regulation is unknown, the analysis should include both an expected value of the cost of compliance and the range of plausible costs.*[34]

Oklahoma's process initially looks much like an NOI that any administrative agency around the country might undertake. However, one key difference is that the Oklahoma Corporation Commission asked upfront whether its existing planning process is capable of addressing these issues. As noted in the discussion of the Colorado Clean Air – Clean Jobs Act, an inquiry such as this opens up the possibility of a state- or region-wide view of alternatives.[35] Oklahoma and other states could potentially use a process like the proposed integrated environmental compliance planning process to develop resource plans that meet 111(d) requirements, ozone requirements, and the like.

Midwest Independent System Operator Analysis[36]

The Midwest Independent System Operator (MISO) conducted an analysis of potential effects of EPA regulations on its system. MISO's analysis was broken into three phases. Using the Electric Generation Expansion Analysis System model, MISO's first step looked at the effects of several EPA regulations on generation in MISO from a regional perspective. Using results from the first phase, MISO's next step focused on energy and congestion impacts in the MISO system, using a production cost model and transmission adequacy model.[37] In the third phase, MISO developed compliance and capital cost requirements, and analyzed system adequacy, system reliability, and impacts on customer rates.[38]

The MISO process offers an example of how states served by an ISO or RTO might engage their respective ISO or RTO to help assess the potential effects of GHG emissions-reduction policy options on state and regional electricity grids. ISOs routinely use and have great familiarity with electricity dispatch models. Such models require training and a license; gaining competency in these models can be expensive for a single state. However, states can work with their regional ISO to develop inputs and assumptions about various policy options, and the models can be run by the ISOs.

33 See: Comments of Sierra Club in "In Re: Inquiry of the Oklahoma Corporation Commission to Examine Current and Pending Federal Regulations and Legislation Impacting Regulated Utilities in the State of Oklahoma and the Potential Impact of Such Regulations on Natural Gas Commodity Markets and Availability in Oklahoma," Cause No. PUD 201100077. (2011, July 18). Available at: http://imaging.occeweb.com/AP/CaseFiles/03000E8D.pdf

34 Ibid.

35 There are other notable examples that are not described in detail here. See, for example: Iowa Utilities Board Docket NOI-2011-0003, "Utility Coal Plant Planning," a process designed to gather "Information Related to the Potential Impact of the New EPA Regulations on Iowa Generation Plants." Available at: https://efs.iowa.gov/efs/ShowDocketSummary.do?docketNumber=NOI-2011-0003

36 This discussion is based on a MISO analysis entitled: *EPA Impact Analysis: Impacts From the EPA Regulations on MISO.* (2011, October). Available at: https://www.misoenergy.org/_layouts/miso/ecm/redirect.aspx?id=119399

37 Respectively, the PROMOD IV production cost model and the PSS/E transmission adequacy model.

38 In addition to the aforementioned models, in analyzing system adequacy, MISO also used GE-MARS model.

The MISO process recognized:

- The role of market dynamics;
- That gas prices relative to coal are a key driver; and
- The importance, for scheduling purposes, of knowing when a plant will need to go offline (whether permanently or for retrofitting), and that this can be modeled but that it also needs to be ascertained plant-by-plant from utility companies.

4. GHG Emissions Reductions

As stated earlier, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.[39] The goal is not to specifically reduce GHG emissions. However, compliance with current air pollution regulations will normally be established as a condition that must be met before any resource portfolio or action plan is approved. The process can also give due consideration to possible future GHG regulations, such as those proposed by the EPA in the Clean Power Plan. Proposed regulations, as well as a range of possible future regulations, can be included among the base case modeling assumptions or tested as alternative scenarios. The modeling can also test the sensitivity of results to unknown compliance costs, for example, the future cost of an emissions allowance under a trading program. In summary, the IRP process can help a state assess a range of possible policies that can effectuate GHG emissions reductions, while studying their influence on electricity reliability and their costs.

How might a utility prepare an IRP today in a way that helps state air regulators evaluate options and develop a plan for complying with the EPA's proposed GHG rules for existing electric generating units (EGUs)? To begin with, the IRP could specifically include the GHG emissions rate targets proposed by the EPA out to 2030 (or equivalent mass-based limits) as boundary conditions that must be met by any approvable resource plan. The rest of the planning process might proceed as it normally would, but the process would be iterative if the studied resource portfolios failed to comply with the emissions limits.

Alternatively, a default or baseline scenario could be developed based on the mix of resources assumed by the EPA when it developed the proposed emissions rate targets for the state (i.e., the four "building blocks" that the EPA included in its determination of the best system of emissions reduction). Alternative resource portfolios could then be developed and analyzed to see if compliance could be achieved through less expensive means. For example, the EPA assumes in "building block 4" that states will ramp up their existing energy efficiency programs at an annual energy savings rate of 0.3 percent each year until the end goal of 1.5-percent annual energy savings is met. The EPA also posited a ramp rate of 0.5 percent per year as a possible alternative. A third possibility would be to assume zero increase in energy efficiency programs. These three alternatives could be tested (in conjunction with alternative mixes of supply-side resources) in pursuit of a least-cost compliance plan. Similar thinking could be applied to the other building blocks in the 111(d) rule:

- **Heat Rate Improvements.** The IRP could identify affected EGUs, and develop short-, medium-, and long-term assumptions for the timing to complete heat rate improvements, and the potential heat rate improvement for each EGU.
- **Re-dispatch.** The IRP could identify affected natural gas EGUs and develop low, medium, and high assumptions on how quickly these units can reach the requisite capacity factors provided for in the EPA 111(d) rule.
- **Renewable and Nuclear Energy Generation.** For renewable energy generation, the ramp rate assumptions could be analogous to the process used for energy efficiency programs. For nuclear, it could be assumed that future generation will be available at the same rate. A "worst case" assumption of a nuclear unit closing or being shut down would reveal gaps in GHG emissions reductions for that time period and would help a state to plan ahead, as the EPA is proposing that states would have to address GHG emissions gaps that are ten percent or greater in any particular year.

Electricity is often transmitted across multiple states, so the IRP process can also be used by states seeking to develop regional plans to comply with 111(d) requirements. The IRP process can also be used to communicate assumptions and their influence on a regional transmission and distribution system. Where applicable, the appropriate ISO or RTO can work with stakeholders and the utilities to

39 US EPA. (2014). *Survey of Existing State Policies and Practices that Reduce Power Sector CO_2 Emissions.* Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/existing-state-actions-that-reduce-power-sector-co2-emissions-june-2-2014_0.pdf

share assumptions, and evaluate potential regional impacts of various compliance options that are being considered.[40]

5. Co-Benefits

An IRP can simultaneously consider and provide results for many energy, economic, and environmental variables. For example, and as noted in the example from Colorado, an IRP or similar process can reveal cost-effective strategies for addressing multiple air pollutants simultaneously. One scenario that forward-looking states might wish to develop as part of an IRP exercise is to evaluate the effects of the four building blocks in the EPA's 111(d) proposal not only for their GHG emissions impacts, but also for NO_X and SO_2 emissions. This could be particularly important in light of the fact that the EPA proposed to revise the ozone National Ambient Air Quality Standards in November 2014. Depending on the outcome of the rulemaking process, the ozone standard could be tightened to a level that will create many new non-attainment areas and require many areas to develop ozone SIPs again – or for the first time. The timing may be such that states are working on 111(d) compliance plans and SIPs simultaneously, and a coordinated planning approach could reveal cost savings over a pollutant-by-pollutant approach.

In some western states, the IRP process has been enhanced in recent years to more explicitly consider water quantity issues. PUCs in Arizona and Colorado, for example, are requiring utilities to provide data about the water needs associated with meeting electric demand and any vulnerabilities or risks that may be associated with possible droughts or water price increases.

Environmental issues are not the only issues that can be illuminated through smart planning processes. At its core, the IRP process is designed to protect reliability and contain costs for consumers and society. A wide range of co-benefits can be realized through a sound utility resource planning process. The co-benefits of a process that follows the recommendations noted earlier in this chapter are shown in Table 22-2.

Table 22-2

Types of Co-Benefits Potentially Associated With Integrated Resource Plans

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	Maybe
Sulfur Dioxide	Maybe
Particulate Matter	Maybe
Mercury	Maybe
Other	Maybe
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	Maybe
Avoidance of Uncollectible Bills for Utilities	Maybe
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Yes
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Yes
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Maybe
Other	

40 The ISO RTO Council, a national organization that represents the RTOs, has offered to serve as a resource to state policymakers to help them to assess various 111(d) compliance options. ISO RTO Council. (2014). *EPA CO_2 Rule: ISO/RTO Council Reliability Safety Valve and Regional Compliance Measurement and Proposals.* Available at: http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf

6. Costs and Cost-Effectiveness

Integrated resource planning has been adopted by many utilities and mandated by many states precisely because it seeks to identify cost-effective options for meeting electricity demand, while giving due consideration to risks and uncertainty. Although an IRP process does not in and of itself reduce emissions, where effectively used it can point toward a strategic long-term vision of how to address GHG emissions reduction objectives at lowest costs. Establishing and integrating this routine utility planning framework with federal and state environmental requirements can substantially lower the overall burden of environmental compliance while continuing to satisfy the core power sector goal of providing safe, reliable, and affordable electricity.

The mere process of completing an IRP does not guarantee a cost-effective outcome. The details of the IRP process, as well as the data assumptions, will always matter. But the strength of the process is that it is capable of simultaneously evaluating several different policy options and scenarios and a wide range of supply-side and demand-side resource options. Costs and cost-effectiveness are common outputs from IRP modeling exercises.

Although an IRP process often ranks preferred options by overall utility costs, the least-cost option is not universally selected as the preferred resource portfolio. Risk reduction and avoidance of certain environmental costs are often difficult to quantify with precision, especially when future regulatory requirements are unknown, but these factors can be highly valuable to utilities. In some cases, the utility (or regulators) may prefer a resource portfolio that is not strictly the least-cost portfolio under base case assumptions, but is among the lowest cost portfolios across a broad range of scenarios. This may happen in cases in which the least-cost portfolio under base case assumptions turns out to be very expensive under some of the possible future scenarios.

For state air quality agencies that decide to engage with their utilities and PUC in an IRP process, there are, of course, labor costs associated with such participation. However, similar costs will arise from any of the possible ways in which a state air agency might evaluate policies for inclusion in a 111(d) plan or a SIP. Furthermore, if a state uses the IRP process wisely, following recommendations cited in this chapter, it may be able to address energy, 111(d), ozone, fine particle, and regional haze requirements in a coordinated, cost-effective manner.

7. Other Considerations

Integrated resource planning processes offer an interesting and perhaps ideal platform for states to develop 111(d) compliance plans that are sensitive to the need for reliable, affordable electricity.

Unfortunately, in some cases the timing for the preparation or revision of an IRP or regional utility resource plan may not be coincident with that for the preparation of a state 111(d) plan. Each state has its own requirements as to when IRPs must be prepared, and in some cases, it may be that an IRP is required only when a new capital-intensive resource addition is being considered. In other cases, IRPs are required to be submitted or revised every two or three years. If a utility needs to update its IRP at a time when future GHG reduction requirements are not yet certain, it can still evaluate a range of possible regulatory scenarios and assumptions, as Public Service of Colorado did in the example offered in Section 3. The lack of regulatory and legal certainty is no reason to ignore the possible impacts of proposed rules or rules that may be proposed. Ignoring such possibilities could expose the utility to significant risk if it invests in resources that might cost much more to operate under future GHG regulations.

If a utility is not creating or updating its IRP during the time period when state air pollution regulators need to develop a 111(d) compliance plan, the data contained in an existing IRP should still be analyzed for possible use or reference, especially if the utility has already modeled the impacts of possible GHG regulatory scenarios.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on utility resource planning practices.

- Chernick, P., & Wallach, J. (1996). *The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities.* American Council for an Energy-Efficient Economy Summer Study. Available at: http://aceee.org/files/proceedings/1996/data/papers/SS96_Panel7_Paper06.pdf
- Farnsworth, D. (2013, March). *Addressing the Effects of Environmental Regulations: Market Factors, Integrated Analyses and Administrative Processes.* Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6455

- Kushler, M., & York, D. (2014). *Utility Initiatives: Integrated Resource Planning. American Council for an Energy-Efficient Economy.* Available at: http://www.aceee.org/policy-brief/utility-initiatives-integrated-resource-planning
- Olson, D., & Lehr, R. (2012). *Transition Plan Policies – Lower Risk, Lower Cost Electric Service: Policies Western States Can Build On.* Western Grid Group. Available at: http://www.westerngrid.net/wp-content/uploads/2012/12/Transition-Plan_Policies.pdf
- State and Local Energy Efficiency Action Network. (2011, September). *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures.* Available at: https://www4.eere.energy.gov/seeaction/publication/using-integrated-resource-planning-encourage-investment-cost-effective-energy-efficiency
- Wilson, R., & Biewald, B. (2013, June). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics for The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6608

9. Summary

Integrated resource planning is a comprehensive energy planning process routinely used in most states to determine what combination of supply- and demand-side resources are most cost-effective to satisfy multiple and sometimes competing energy, economic, and environmental objectives. IRPs and similar utility resource planning processes can have substantial value for state air agencies that are preparing 111(d) plans and SIPs. The IRP process is ideal for identifying resources and strategies that can simultaneously meet multiple energy and environmental objectives at least cost.

Air quality agencies can engage in the IRP process and contribute ideas and data that improve the process and the results. Air pollution regulators have insights and data relating to regulatory requirements, emissions reduction strategies, and costs of compliance that might not otherwise factor into utility resource planning. In addition, air regulators can seek to ensure that multiple air quality problems (e.g., climate change, ozone pollution, and regional haze) are addressed simultaneously and in a coordinated fashion.

23. Improve Demand Response Policies and Programs

1. Profile

Demand response (DR) refers to the intentional modification of electricity usage by end-use customers during periods of system stress, system imbalance, or in response to market prices.[1] DR policies and programs were initially developed to help support electric system reliability by reducing load during peak hours. More recently, technical innovations have made it possible to expand DR capabilities to provide an array of ancillary services necessary to maintain grid reliability. The focus is no longer exclusively on peak reduction. DR is also capable of promoting overall economic efficiency, particularly in regions that have wholesale electricity markets.

Ancillary services, for example, include system balancing – actions to ensure that electricity supply is equal to demand in real time – and the regulation of frequency and voltage so they remain within acceptable limits.[2] Efficient ancillary services markets for balancing ensure adequate electricity supply at least cost, and they can deliver environmental benefits by reducing the need for reserves or backup generation. Frequency and voltage levels are maintained through automatic and very fast response services and fast reserves (which can provide additional energy when needed), the provision of reactive power, and various other services. Historically, balancing and regulation were managed primarily through supply-side resources; today, DR enables customers to change their operating patterns (in return for compensation) to aid in system balancing and regulation, giving grid operators greater flexibility and potentially reducing costs and emissions.

DR programs can take many forms. As illustrated in Figure 23-1, the North American Electric Reliability Corporation (NERC) categorizes different forms of DR in relation to overall demand-side management strategies. Within the broad category of DR, the management of end-use loads can either be initiated by end-users (referred to as "Non-Dispatchable" in the figure) or by the distribution utility, a third-party aggregator, or the transmission system operator (shown as "Dispatchable" in the figure). Dispatchable DR programs can be further categorized based on the purpose they serve for the utility or system operator. Some programs focus on maintaining reliability by using DR resources to provide capacity, reserves, energy reductions, or frequency regulation services (labeled as

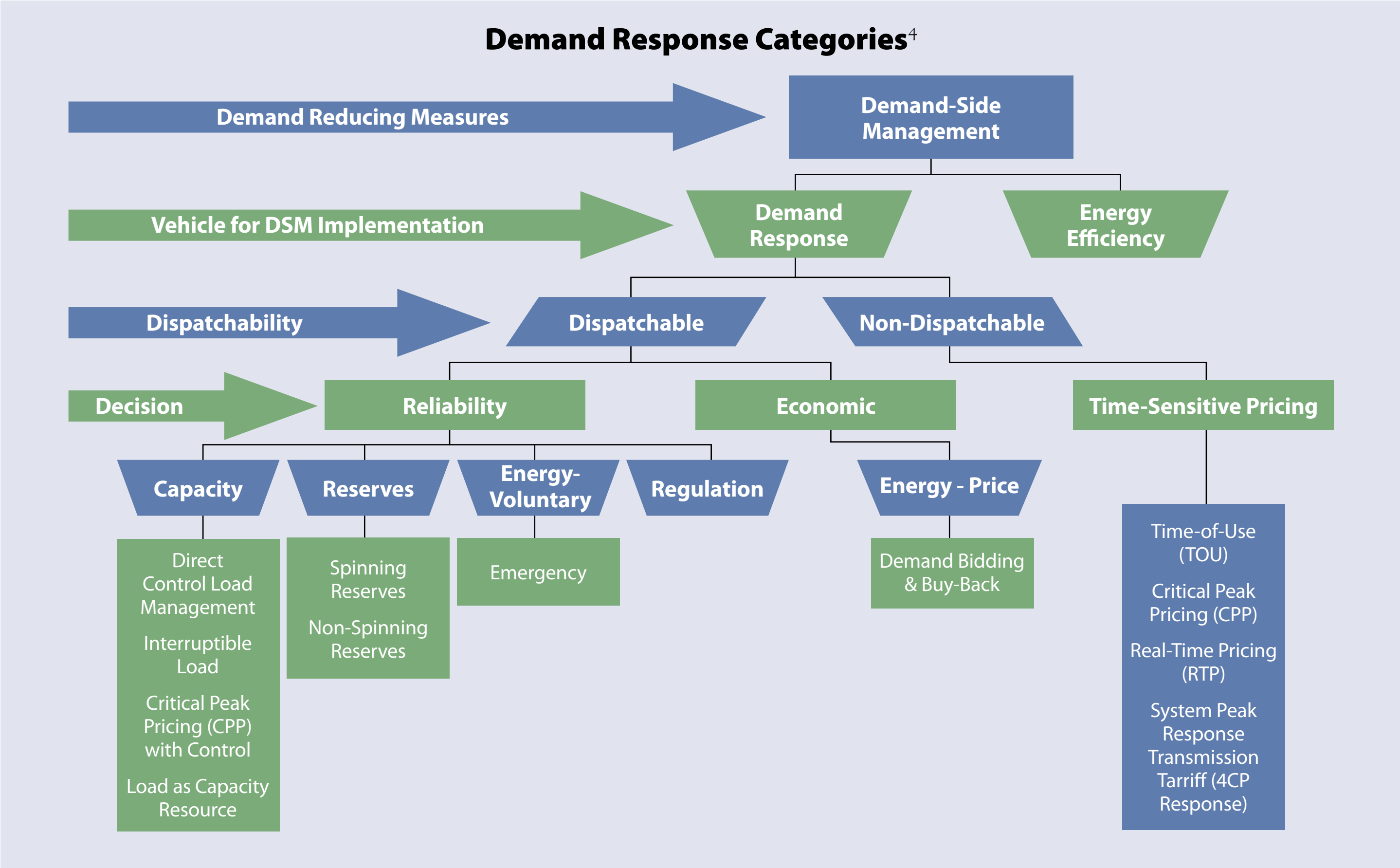
1 The Federal Energy Regulatory Commission characterizes DR more narrowly as "changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments *designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized* [emphasis added]." See: Federal Energy Regulatory Commission. (2011, February). *2010 Assessment of Demand Response and Advanced Metering–Staff Report.* Available at: http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf The broader definition used in this chapter recognizes the expanding role of DR in ancillary service markets. Refer to: Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States,* p. 8. The Regulatory Assistance Project and Synapse Energy Economics. Available at: www.raponline.org/document/download/id/6597

2 The main purpose of the grid is to efficiently deliver reliable electricity to consumers. Voltage and frequency are the main variables to guarantee grid stability, so it is important to regulate the amplitude and frequency of the voltages throughout the system. Historically, regulation has been accomplished by adjusting generation and through various control devices. Now, however, demand response is able to provide regulation services through modifications to load. Using load response to provide ancillary services is often better for the grid because its faster, shorter response capability offers greater reliability value than slower, longer supply-side response capability; it frees up generation to supply energy; and it can often reduce emissions.

"Regulation" in the figure). Other programs focus on using DR resources to reduce wholesale electricity prices and provide economic benefits. But in all forms of DR, end-users intentionally modify their consumption in order to reduce their costs or to receive some form of compensation. Further information, including detailed definitions and data relating to each category of DR, can be found in the NERC report cited.[3]

DR policies and programs can play a crucial role in any plan to reduce power-sector greenhouse gas (GHG) emissions. To begin with, DR programs can mitigate the cost impacts of GHG reduction efforts to make them more acceptable to consumers and policymakers. In addition, under certain circumstances explained later in this chapter, DR programs can reduce net emissions of GHGs and other air pollutants from existing sources. Finally, and perhaps even more importantly, DR programs can facilitate the use of various emissions reductions strategies while ensuring reliable electric service. For example, DR programs can facilitate integration into the grid of greater amounts of zero-emissions electric generation, namely variable energy resources (VERs) (like wind and solar generators) and inflexible resources (like nuclear generators). It is important to note, however, that DR programs may not automatically result in lower emissions of GHGs or criteria pollutants, depending upon the practices used to achieve the electric service benefits. As detailed later in this chapter, air quality regulatory oversight may be necessary in some cases to ensure that DR programs do not have a negative impact on emissions and air quality.

Figure 23-1



3 NERC. (2013, March.) *2011 Demand Response Availability Report.* Available at: http://www.nerc.com/docs/pc/dadswg/2011%20DADS%20Report.pdf. In addition to the categories described by NERC, "behavioral DR" programs are emerging as a new category of DR. These programs are similar to the behavioral energy efficiency programs described in Chapter 13.

4 Ibid.

Mitigating Cost Impacts

DR programs can significantly reduce the costs of serving electricity demand, principally by reducing the usage of the electric generating units (EGUs) that are most costly to operate.

As explained in detail in Chapter 21, an approach known as "security-constrained economic dispatch" is the norm for scheduling the operation of EGUs. First, the system operator identifies the generating capabilities and the variable operating costs of all of the available EGUs.[5] With all of the information on capabilities and costs in hand, the system operator then ranks the available EGUs in "merit order" from the least costly to operate to the most costly, as depicted in Figure 23-2.

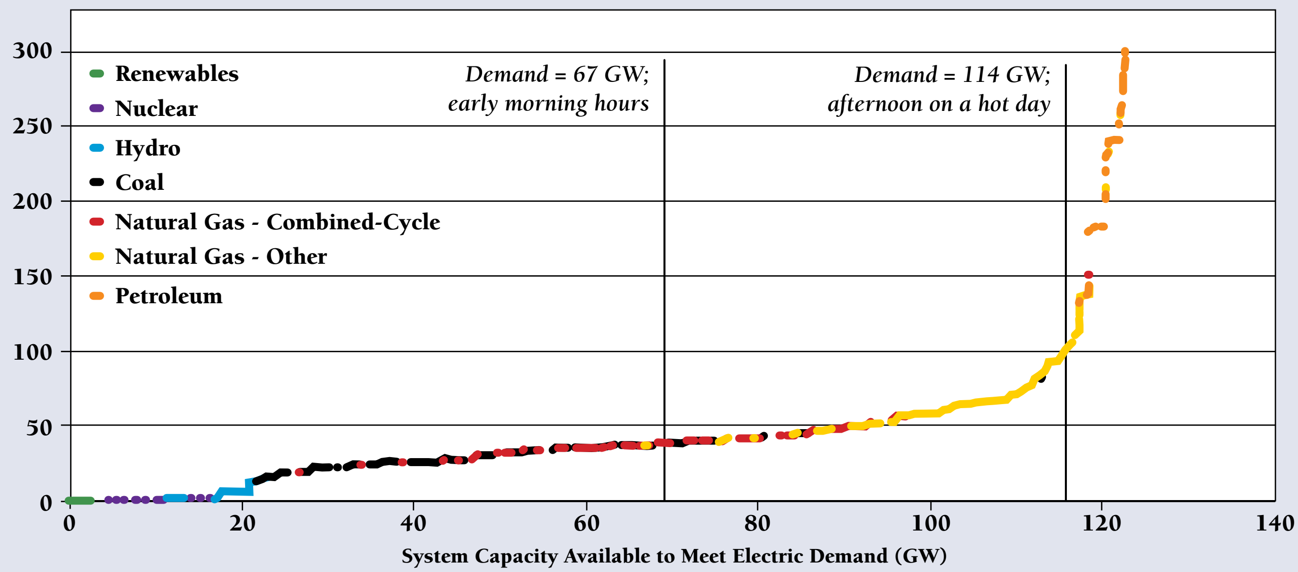
To minimize the costs of meeting electric demand, the system operator will first try to schedule EGUs for dispatch based on merit order. The least costly EGU will be scheduled first, and then the next least costly EGU, and so forth until enough generation is scheduled to meet the expected demand. This concept is shown in Figure 23-2 for two different hypothetical demand levels.[7] However, before the system operator actually schedules the dispatch of any EGUs, he or she will complete a reliability assessment that considers, among other key factors, the capabilities of the transmission system. Based on the reliability assessment, system operators sometimes must deviate from merit order dispatch, but this is generally the exception rather than the rule. Thus, the last unit dispatched to meet demand in a given hour (often referred to as the "marginal unit") will generally have the highest price. When demand is reduced through DR or energy efficiency programs, this most expensive marginal EGU may not need to operate and a different, less expensive EGU will be on the margin.

The cost of operating the marginal unit is especially

Figure 23-2

Hypothetical Dispatch Curve Based on Merit Order[6]

Summer 2011; Variable Operating Cost (dollars per MWh)



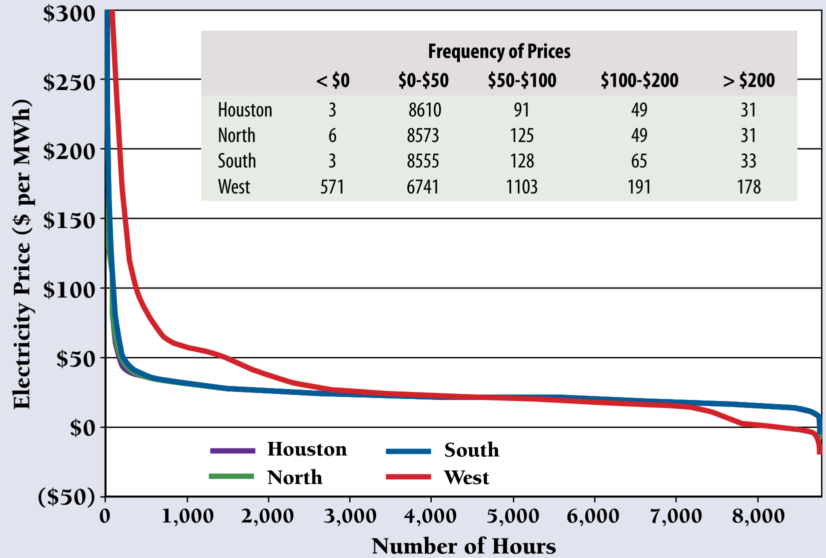
5 In areas that have established wholesale electricity markets, these capabilities and operating costs are revealed through competitive bids made by generators.

6 Note that this hypothetical illustration shows coal to be quite low in the dispatch order. Owing to recent price decreases in natural gas, coal is now much higher up in the dispatch order, at least in several jurisdictions. US Energy Information Administration. (2012, August). *Today in Energy.* Available at: http://www.eia.gov/todayinenergy/images/2012.08.17/DispatchCurve.png

7 The description here mostly describes "day-ahead" scheduling of EGUs to meet forecasted demand. System operators make similar decisions in "hour-ahead" scheduling adjustments and "real-time" balancing decisions based on actual demand, except that the capabilities most needed in those shorter time frames can be different (e.g., ramp rate can be more important), and the variable costs can be different (e.g., if a unit is already operating, its startup costs are not part of its variable costs over the next hour).

Figure 23-3

Hourly Average Price Duration Curves in 2012 for Four ERCOT Load Zones[8]



Frequency of Prices	< $0	$0-$50	$50-$100	$100-$200	> $200
Houston	3	8610	91	49	31
North	6	8573	125	49	31
South	3	8555	128	65	33
West	571	6741	1103	191	178

significant in areas that have established competitive wholesale electricity markets, because the price bid by the marginal EGU establishes a "market clearing price" and all generators (even the ones that are less costly to operate) are paid that price. As a result, electricity prices can rise exponentially during the highest few hours of peak demand in the year. Figure 23-3 offers one example of this phenomenon from the Electric Reliability Council of Texas (ERCOT) competitive wholesale market. The figure shows on the x-axis how many hours of the year the wholesale price of electricity exceeded a value specified on the y-axis (in dollars per megawatt-hour [MWh]). Through most of the year, prices fell within a fairly narrow range, but for a relatively small number of hours when more costly EGUs had to be dispatched to meet high demand, prices spiked dramatically.

DR programs can mitigate electricity costs by reducing demand during those relatively few hours when prices (or operating costs) would otherwise spike. The impacts will tend to be most dramatic in areas that have competitive wholesale electricity markets where all EGUs are paid the bid price of the marginal EGU.

Reducing Emissions

When electric demand is decreased through a DR program, the immediate impact is that the output of the marginal EGU is curtailed. If the marginal EGU is a fossil-fueled unit, as is usually the case,[9] this means that emissions also decrease in that hour.[10] However, it is often the case that a DR program participant will temporarily curtail its demand in order to reduce costs or earn a DR program incentive, but will make up for that reduced electricity use in a future hour. For example, a manufacturer may cut back production for two hours during a DR event, but increase future production to compensate. Thus, when considering the emissions impact of DR programs, air regulators will want to consider not just the immediate decrease in emissions from a marginal EGU, but also the possible increase in emissions at a later date from whatever EGU is marginal at that time. The net impact of a DR program on emissions will depend on how much of this load shifting occurs, and which EGUs are marginal at the times that loads are shifted. Although this is an important consideration, logic suggests that in most cases the net impact will be a reduction in emissions.

Generally speaking, DR events happen at times of peak demand. If a manufacturer or other DR program participant shifts load away from this peak demand period, they are

8 Potomac Economics, Ltd. (2013, June). *2012 State of the Market Report for the ERCOT Wholesale Electricity Markets.* Available at: https://www.potomaceconomics.com/uploads/ercot_reports/2012_ERCOT_SOM_REPORT.pdf

9 Zero-emissions resources are rarely marginal. Most of the renewable generating technologies have no fuel costs and near-zero variable operating costs. Nuclear EGUs also tend to have very low variable operating costs, because their fuel costs are considerably less than those of fossil-fueled EGUs.

10 This assumes that the DR participant does not shed its load from the grid and switch to onsite diesel generators that would otherwise not be in operation. Diesel generator sets can have relatively high emissions rates during startup, shutdown, and under load. If such units were operated in quantity in response to a DR call, emissions reductions, if any, might be minimal. The reader's attention is called to this concern repeatedly throughout the chapter.

unlikely to shift it to another time of peak demand. Instead, they will shift load to a period when system demand (and in competitive markets, the wholesale power price) is lower. And more often than not, the marginal unit in a time of peak demand will have a higher emissions rate than the marginal unit during times of lower demand. This is because the units that have the highest operating costs (and thus get dispatched only during times of peak demand) tend to be the least efficient ones (i.e., those with the highest heat rate). Because of their inefficiency, these EGUs can also have very high carbon dioxide (CO_2) and criteria pollutant emissions.[11] Actual case studies and data are presented later in this chapter to substantiate this claim.

The emissions benefits of shifting load away from times of peak demand are compounded when one considers avoided line losses. As explained in Chapter 10, system *average* line losses are in the range of 6 to 10 percent on most US utility grids, but they can reach as much as 20 percent during the highest peak hours. In other words, it can take fully 5 MWh of generation from an EGU to serve the last 4 MWh of load at peak times, whereas it may take only a little more than 4 MWh of generation from an EGU to do so during off-peak periods. Often, the generation resources called upon at peak times are also less efficient, higher emitting EGUs, such as simple-cycle gas plants. This is not always the case, however; prior to the decline in natural gas prices in recent years, efficient, lower-emitting combined-cycle gas plants often ran at the margin in favor of lower cost but less efficient and higher emitting coal-fired units.

From the perspective of air regulators, some caution must be exercised in the development of DR policies, because some often-deployed DR resources can *increase* criteria and GHG pollutant emissions. For example, some customers participating in DR programs may curtail their use of grid-supplied electricity but switch to onsite backup generators. These generators are typically less efficient than EGUs serving the grid, and uncontrolled or marginally controlled for criteria pollutants. They can have significant emissions impacts, especially when fueled with diesel. DR customers who curtail their use of grid-supplied electricity by switching to onsite diesel generators may exacerbate several air quality concerns:

- Emissions of nitrogen oxides (NO_X), particulate matter (PM), and CO_2 are likely to increase;[12]
- The time periods when these engines are used is likely to coincide with periods of already unhealthy air quality, because peak demand in most parts of the country correlates with the same weather conditions that lead to high ambient air pollution concentrations; and
- Pollutants are emitted at ground level rather than from a high stack, and this can increase the risk of exposure to individuals living or working nearby.

In some cases, DR programs could also shift loads from relatively clean peaking resources (e.g., hydro or combined-cycle gas turbines) to dirtier baseload resources (e.g., coal), as might occur if a company temporarily shifted a production operation from peak daytime hours to nighttime. State environmental regulators have an important role in ensuring that customer backup generation is clean, and relied upon sparingly when there are material environmental concerns in play. Across its many manifestations, however, DR is increasingly recognized as offering potential environmental benefits when properly controlled and may contribute to a cleaner generation mix with the passage of time.[13]

Ensuring Reliability

One of the strategies for reducing GHG emissions that features prominently in this document is to increase generation from zero-emitting VERs like wind and solar.

11 Fuel costs generally comprise the largest portion of variable operating costs. Heat rate measures the amount of energy (in BTUs) used by an EGU to generate one kilowatt-hour (kWh) of electricity. An EGU with a high heat rate has to burn more fuel to generate one kWh than an EGU with a lower heat rate, and thus will emit more GHGs. Obviously, for criteria pollutant emissions, the types of installed control equipment on any given EGU will also bear heavily on emissions levels.

12 Hibbard, P. (2012, August). *Reliability and Emissions Impacts of Stationary Engine-Backed Demand Response in Regional Power Markets.* The Analysis Group. Prepared as comments on the US EPA's proposed regulations for Reciprocating Internal Combustion Engines. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/August_2012_Hibbard_DemandResponseReport.pdf

13 Nemtzow, D., Delurey, D., & King, C. (2007). The Green Effect: How Demand Response Programs Contribute to Energy Efficiency and Environmental Quality. *Public Utilities Fortnightly, 45.* Available at: http://www.fortnightly.com/fortnightly/2007/03/demand-response-green-effect

Demand Response as Balancing Resource for the Grid

The potential to expand DR as a resource for balancing services exists across all customer classes. The nature of their loads, the untapped DR potential, and the means for accessing it vary, however.

Large Industrial Customers

Historically, most DR has come from large industrial customers with electricity-intensive processes. These customers typically have some discretion over when they run certain processes within a day, and they are more likely to have the infrastructure, expertise, and resources needed to contract with vendors for DR services. The large average size of these interruptible loads offers logistical and administrative advantages, but they have not generally been well matched for day-to-day balancing operations because they tend to be geographically concentrated, are typically on-or-off arrangements (rather than adjustable), and limited in the number of times they can be called on. Some facilities may also have operations with smaller loads similar to those of commercial customers; most of this potential remains similarly untapped.

Commercial, Small Industrial, and Government Customers

These nonresidential customers are typically smaller and less electricity-intensive, and therefore more challenging to access. However, in the aggregate they represent significant DR potential. They tend to be more business-savvy than residential consumers, but not as sophisticated as large industrial customers and with fewer technical, financial, and legal resources. These customers normally have fewer options for shifting demand, but they may have loads that can be modulated over short periods of time, such as variable-speed drives, area lighting, and space conditioning. They may also have loads such as commercial chillers or processes that are well suited to thermal energy storage applications.

The size and nature of these individual loads make them a good fit for day-to-day balancing operations, but this potential remains untapped owing to historical logistical, administrative, and regulatory barriers. Technology is rapidly reducing the cost and increasing the functionality of real-time automated control of smaller loads with little or no perceptible impact on the quality of energy services, and entrepreneurs are beginning to innovate ways to access this potential. Regulatory barriers and resistance from electricity suppliers remain, however.

Residential Customers

Residential customers are the largest untapped pool of DR potential. They are highly diffuse; vary widely in their levels and patterns of consumption; have low response to electricity prices; lack information, time, and specialized expertise; face financing constraints; and often do not have access to competitive wholesale markets like large customers. Because of technical constraints and regulatory practices, household energy consumption has largely been insulated from conditions on the power grid at any given time.

Some loads with the greatest DR potential, such as water heating and refrigeration, are non-seasonal uses and thus well placed to provide balancing services. Electric vehicles hold great potential for flexible loads and storage services, but broad commercial application is likely several years away. The residential sector nevertheless offers rich potential today at a fraction of the cost of other alternatives for expanding balancing services for the grid. Accessing that potential, however, will require a reconsideration of the potential uses of DR, how to expose the relative value of DR to all concerned, who has access to the market, what it will take to gain consumer acceptance, and how individual households can expect to be compensated for providing services that may initially benefit grid operators but ultimately all consumers.

Realizing DR benefits from this large untapped pool of residential load appears daunting today. However, the grid is rapidly transitioning to digital, multidirectional communication between devices, and the power sector to new business models and new market entrants. Emerging technologies, policies, and markets (discussed further in Chapter 26) will soon provide residential customers new options to manage their energy use, possibly including "apps" that send real-time pricing data to controllers that customers can "set and forget" to respond automatically to DR opportunities on the grid.

(For a more thorough treatment of this topic, see: Hurley, et al, at supra footnote 1.

However, as the penetration of VERs increases, it becomes increasingly challenging for grid operators to schedule the dispatch of EGUs to balance supply with demand in real time. The array of alternatives to deliver this flexibility are typically limited and expensive, except in systems like the Pacific Northwest, Quebec, and Brazil, which are dominated by flexible, large hydro systems. (This challenge is described in detail in Chapter 20.)

DR may have an important role to play in creating cost-effective ways of meeting system needs for greater flexibility. DR programs can make that challenge more manageable, and less expensive, because they provide the system operator with additional options. Instead of always adjusting generation levels to meet demand, DR programs create the possibility of adjusting demand to meet supply. Whichever option is less expensive at any given time can be used. DR programs can also provide a range of ancillary services that are essential for maintaining system quality, sometimes at lower costs than obtaining those services from supply-side resources (see text box p. 6).

2. Regulatory Backdrop

Regulatory oversight of DR programs can be complex, reflecting the complex landscape of US electricity markets and the variety of types of DR programs depicted in Figure 23-1. At the core of this complexity is a fundamental jurisdictional split, wherein states have authority to regulate retail electricity transactions and the Federal Energy Regulatory Commission (FERC) has authority to regulate interstate wholesale markets and transactions.[14] There is also significant variation in the extent to which states allow competition in retail electricity markets, and the extent to which states regulate the retail activities of consumer-owned utilities (e.g., municipal electric utilities and electric cooperatives) versus allowing those utilities to self-regulate. These jurisdictional distinctions are relevant because some categories of DR programs operate at the wholesale level, whereas others operate at the retail level. This means different types of DR programs can be subject to different regulatory oversight.

States have exclusive jurisdiction over the rates that are paid to end-use customers by utilities for participating in DR programs. This is relevant to most of the categories of DR programs shown in Figure 23-1, and especially the time-sensitive pricing options. This regulatory authority is generally vested in a state public utility commission (PUC). Traditional principles of public utility regulation apply, namely, that the PUC must determine that the rates for DR programs are just and reasonable, nondiscriminatory, and in the public interest. For the most part, this means that the benefits of DR programs will have to exceed the costs. Furthermore, any costs that utilities incur to support DR programs (e.g., metering or communications equipment, customer acquisition and enrollment, and so on), will have to be deemed prudent.

Some of the categories of DR programs are unrelated to retail rates and operate instead in a wholesale market context. Currently, DR can participate in all of the wholesale energy markets in the United States, and in some of the wholesale capacity markets. (Capacity markets are discussed in detail in Chapter 19.) Wherever wholesale markets have a mechanism for compensating DR customers, the terms of that compensation are subject to exclusive FERC jurisdiction under the Federal Power Act and based on two FERC orders, described below. However, the terms by which a utility or competitive retail electricity supplier (i.e., a "load serving entity") *purchases* DR from the wholesale market is subject to concurrent FERC and state jurisdiction.

In 2008, the FERC issued Order 719, which required the operators of competitive wholesale electricity markets – regional transmission organizations (RTOs) and independent system operators (ISOs) – to treat DR bids as comparable to generators' bids in hourly energy markets.[15] In essence, this decision held that offering to reduce demand by one MWh is comparable to offering to increase generation by one MWh. DR would therefore be treated like any other resource, and bids could come directly from end-use customers, or could be offered by "aggregators" who manage the wholesale market transaction on behalf of multiple end-use customers. States, however, retained the

14 Case law has established that, owing to the interconnected nature of the US electricity grid, all electricity transactions meet the definition of interstate commerce, regardless of the origin or destination of the electricity, except for transactions occurring entirely within Alaska, Hawaii, and the ERCOT portion of Texas.

15 FERC. (2008, October). *Order No. 719: Wholesale Competition in Regions with Organized Electric Markets – Final Rule.* Available at: http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf

authority to prohibit end-users in their state from offering DR in the wholesale markets.

In 2011, in Order 745, the FERC expanded on its earlier ruling and ordered RTOs and ISOs to set compensation for wholesale DR bids in the hourly energy markets at the *same price* given to generators (the "locational marginal price"), so long as the DR helped balance supply with demand and was cost-effective.[16] Generators sued the FERC over Order 745, and in May 2014 the US Court of Appeals for the DC Circuit ruled that Order 745 was unlawful because the FERC was trying to regulate the level of compensation for what was effectively a retail transaction, and therefore the exclusive purview of state regulators (because the FERC's jurisdiction is limited to wholesale transactions in the bulk power system).[17] Although Order 745 is limited in scope to compensation in wholesale energy markets, many legal observers expect that the same reasoning will eventually be applied to compensation for DR in wholesale capacity markets as well. The FERC appealed the DC Circuit decision to the Supreme Court, and the DC Circuit decision is currently stayed. However, the uncertain status of Order 745 further complicates what was already a complicated regulatory landscape for DR programs. It may be that in the near future, the existence of most or all DR programs and the levels of compensation paid to participants will be exclusively regulated by states.

Oversight of environmental concerns can add to the complexity of DR regulation, especially if there is little coordination between environmental regulators and energy regulators. In general, federal and state utility regulators make no distinction between DR participants who might replace grid-supplied electricity with electricity from backup generators and those who truly curtail their consumption. From the perspective of utilities and electricity markets, curtailment looks the same as onsite generation. However, these two things are very different to environmental regulators if the onsite generation comes from a fossil-fueled generator. Backup generators, especially those fueled by diesel, often emit GHG and criteria pollutants at even higher rates than some of the least efficient generators selling power to the grid.

Over the course of the past decade, the US Environmental Protection Agency (EPA) has promulgated a variety of regulations for stationary internal combustion engines of varying designs and sizes at major and area sources.[18] The emissions limits in these rules generally cannot be met by an uncontrolled backup generator burning ordinary diesel fuel, but the rules exempt "emergency engines" from those limits. This exemption covers two kinds of operation. First, the rules allow for unlimited operation of emergency engines, even those with very high emissions rates, in true emergencies (e.g., power outages, fires, or floods). Next, emergency engines can operate for up to a combined total of 100 hours per year for maintenance and testing, blackout prevention,[19] and non-emergency (economic) DR, or non-emergency operation without compensation, for up to 50 hours of the 100-hour annual limit.[20] These rules are currently being litigated in the DC Circuit; the exemption for operation of emergency engines in nonemergency situations is one of the principal points of contention.[21]

Some states have adopted more stringent limitations on

16 The order explicitly instructs the wholesale market administrator (ISO or RTO) to put the energy market offers from DR providers into the stack with the generation offers, and if they are less expensive than the marginal unit, they will be dispatched and be paid the same price (subject to a minimum offer price to prove that it is cost-effective). FERC. (2011). *Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets,* 134 FERC ¶ 61,187. Available at: http://www.ferc.gov/whats-new/comm-meet/2011/121511/E-4.pdf

17 See: (2014, May 27). *DC Circuit Vacates FERC Rule on Pricing of Demand Response in Organized Energy Markets.* Available at: http://www.vnf.com/2909

18 This includes regulations on reciprocating internal combustion engines, commonly referred to as the RICE rule, which is among those being litigated by some states.

19 Blackout prevention refers to emergency demand response for Energy Emergency Alert Level 2 situations and situations when there is at least a five-percent or greater change in voltage. Energy emergency alert levels are defined in NERC Reliability Standards. A Level 2 situation occurs when a balancing authority or load serving entity is no longer able to satisfy its customers' expected energy demand, but has not yet forced involuntary curtailment of load.

20 Refer to the EPA website at: http://www.epa.gov/ttn/atw/icengines/

21 Delaware Department of Natural Resources and Environmental Control v. EPA, No. 13-1093. Available at: http://www.foley.com/files/Publication/d5db8cb7-233b-48d3-8356-909b9a488adc/Presentation/PublicationAttachment/c20daba5-c948-481a-87aa-ae97050379cf/DE_DNREC_v_EPA_13-1093.pdf

the operation of backup generators,[22] especially where the intersection of decades of unhealthy levels of ozone and a need to diversify energy resources has created an excellent crucible for air quality regulators, energy regulators, and system operators to analyze ways to assure electricity reliability without increasing emissions further. An example of such coordination was the New England Demand Response Initiative (NEDRI) that was convened in 2002 to develop a comprehensive set of energy and environmental policies that would:[23]

- Increase the quantity of resources available to quickly mitigate electricity price spikes;
- Amend state air quality regulations to permit clean, standby generating resources to operate for a defined number of hours in non-emergency conditions; and
- Require best available control technology-level emissions limits for resources qualified to operate during emergencies that also seek to run during non-emergency conditions.

NEDRI was monitored by the FERC and the EPA. The NEDRI process and progress informed national efforts by both regulatory agencies to develop a DR program and rules covering small generating resources. Shortly after NEDRI began, a similar effort commenced in the mid-Atlantic states, the Mid-Atlantic Distributed Resources Initiative,[24] followed later by the Pacific Northwest Demand Response Project, both of which continue today.

Turning specifically to the question of GHG regulation, it bears mentioning that in the proposed Clean Power Plan rules for GHG emissions from existing EGUs, the EPA did not include DR programs within the defined "best system of emission reduction." However, the EPA notes throughout the proposed rule that many strategies not included in the best system of emission reduction have the potential to reduce power-sector GHG emissions in the right circumstances.

3. State and Local Implementation Experiences

DR in the United States originated in the 1970s, in part because of the spread of central air conditioning which resulted in declining load factors and needle peaks during hot summer days. The advent of "integrated resource planning" in the late 1970s and 1980s drew attention to the high system costs of meeting these peak loads and encouraged utilities to look for load management alternatives.[25] Rate design (particularly time-of-use pricing) and incentive programs became standard DR programs at many regulated utilities. Most of these early programs served industrial end-users that curtailed their load in exchange for compensation from utilities during peak periods so that the utilities could avoid brown-outs or black-outs.

The DR programs of the 1970s through much of the 1990s were largely conducted by vertically integrated utilities in a structured, regulated environment, and therefore consumers were not exposed to real-time wholesale price signals, nor were consumers compensated for the full system value of their demand reduction. This began to change in the 1990s as the US electric industry initiated the restructuring process. Driven in large part by FERC Order 719 and Order 745, DR is now a crucial feature in all organized wholesale markets in the United States.

Currently there are numerous ways in which dispatchable DR can operate. In regions with organized wholesale markets, DR resources can typically bid

22 For examples, refer to: NESCAUM. (2012, August). *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast.* Available at: http://www.nescaum.org/documents/nescaum-aq-electricity-stat-diesel-engines-in-northeast_20140102.pdf/download

23 The complete list of NEDRI policy documents, framing papers, presentations, and meeting notes is located at http://nedri.raabassociates.org. NEDRI's process was led by The Regulatory Assistance Project, facilitated by Jonathan Raab, with assistance from the Lawrence Berkeley National Laboratory, Efficiency Vermont, and Jeff Schlegel (consultant to several state energy efficiency programs).

24 The Mid-Atlantic Distributed Resources Initiative was established in 2004 by the public utility commissions of Delaware, District of Columbia, Maryland, New Jersey, and Pennsylvania, along with the US Department of Energy, the EPA, the FERC, and PJM Interconnection.

25 As discussed in detail in Chapter 22, integrated resource planning refers to the evaluation of demand and supply resources by public utilities and state regulatory commissions to cost-effectively provide electricity service. Integrated resource planning differs from earlier planning techniques in that it also considers environmental factors, demand-side alternatives, and risks posed by different investment portfolios.

Table 23-1

Customer Enrollment in Demand Response Programs (2012)[27]

By North American Electric Reliability Corporation Region

Code	NERC Region Name	Incentive-Based (Dispatchable) Programs	Time-Based (Non-Dispatchable) Programs
AK	Alaska	2,432	38
FRCC	Florida Reliability Coordinating Council	1,328,487	27,089
HI	Hawaii	36,703	323
MRO	Midwest Reliability Organization	795,345	82,310
NPCC	Northeast Power Coordinating Council	54,413	293,721
RF	ReliabilityFirst Corporation	1,398,341	433,879
SERC	SERC Reliability Corporation	715,225	180,619
SPP	Southwest Power Pool	91,585	61,618
TRE	Texas Reliability Entity	109,875	604
WECC	Western Electricity Coordinating Council	884,299	2,601,112
	Unspecified	15,004	57,435
	TOTAL	**5,431,709**	**3,738,748**

directly into energy, capacity, and ancillary services markets or be dispatched in response to market signals. However, the degree to which DR is integrated into the wholesale market varies, with some regions allowing DR to set the market clearing price, whereas other regions restrict DR's ability to influence market prices. Finally, across the United States, and particularly in areas without wholesale markets, utilities may maintain their own DR programs such as direct load control for water heaters and air conditioning units.

Participation by third-party (i.e., non-utility) providers of DR services has been an important factor in bringing DR services to scale, especially in wholesale markets. These "curtailment service providers" or "DR aggregators" seek out customers who have some flexibility in their load but are also large enough to make curtailment worthwhile to the system operator. Participating end-use customers are typically large commercial or industrial facilities. The aggregator can offer DR services to a vertically integrated utility on behalf of participating customers, or bid those services into competitive wholesale electricity markets where they exist. This lowers the transaction costs for participating end-users and increases participation. Aggregators can also make arrangements that give customers more flexibility than they might get if they contracted directly with a utility to provide DR services. Most importantly, loads can be aggregated and packaged in a way that provides the utility or system operator high confidence that the contracted load reductions or modifications will be realized whenever called upon.

Pursuant to a requirement of the Energy Policy Act of 2005, the FERC staff produce an annual assessment of DR and advanced metering implementation in the United States. The most recent such report was published in December 2014 and includes summary data on recent levels of DR deployment.[26] As shown in Table 23-1, more than 5.4 million customers participated in incentive-based DR programs in 2012. These include all of the DR program categories described in Figure 23-1 as dispatchable. In addition, more than 3.7 million customers participated in time-based DR programs. These include all of the DR program categories described in Figure 23-1 as non-dispatchable. Participants were broadly (but not evenly) distributed across all customer classes and all regions of the country (refer to Figure 23-4).

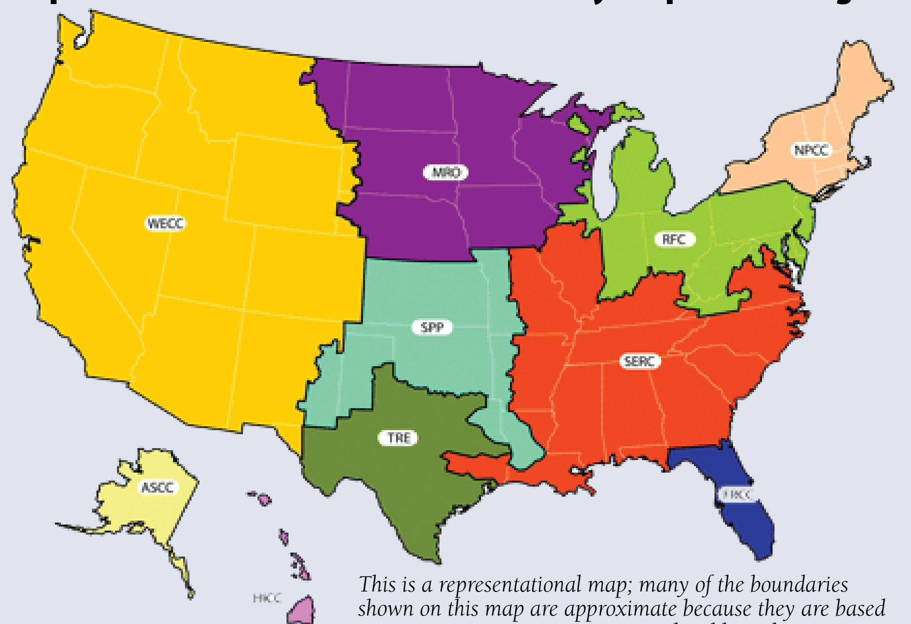
The FERC assessment also summarizes the total demand reduction that could occur at the time of the system peak if all DR program participants were called on to act. These data are broken down between the retail DR programs operated by utilities and other load-serving entities (shown in Table 23-2), and the wholesale DR programs operated by ISOs and RTOs (shown in Table 23-3). Nationwide, these two types of programs totaled almost 55,000 MW of potential peak demand reduction in 2012. In the competitive wholesale electricity markets, DR provided between 2.9 and 10.2 percent of each region's peak demand in 2013. In previous annual assessments, FERC staff have estimated that the contribution of DR to meeting peak

26 FERC. (2014, December). *Assessment of Demand Response & Advanced Metering: Staff Report.* Available at: http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf

27 Ibid.

Figure 23-4

Map of North American Electric Reliability Corporation Regions



This is a representational map; many of the boundaries shown on this map are approximate because they are based on companies, not on strict geographical boundaries.

US EPA. *Emissions and Generation Resource Integrated Database (eGRID).* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/faq.html

demand nationally could be more than doubled, to 14 percent, and the Electric Power Research Institute (EPRI) estimates that DR could reduce nationwide summer peak demand seven to nine percent below what is otherwise projected by 2030.[28] As shown in Table 23-3, wholesale DR programs grew by 0.5 percent from 2012 to 2013 alone.

There is a wealth of data, especially from competitive wholesale markets, proving that DR is a reliable resource that delivers demand reductions when called upon to do so. Numerous examples are provided in a 2013 report by Synapse Energy Economics for The Regulatory Assistance Project of DR participants delivering 100 percent of their load reduction commitment, or more, in ISO New England, PJM Interconnection, ERCOT, and elsewhere.[30]

Despite the stated concerns of air pollution regulators about the use of backup diesel generators in association with DR programs, comprehensive data on this topic are currently lacking. Because of wholesale market rules and the role of DR aggregators, there are no standard data sources for identifying the extent to which backup generators are used during DR events. Efforts have been initiated by some states in the PJM Interconnection market to gather this information. Early results suggest that backup generators may comprise 30 to 50 percent of the total DR resource in some states, but these estimates have yet to be confirmed across the entire market.

Table 23-2

Potential Peak Reduction (MW) From Retail Demand Response Programs in 2012[29]

By North American Electric Reliability Corporation Region

NERC Region	Customer Class: Residential	Commercial	Industrial	Transportation	All Classes
AK	5	13	9	0	27
FRCC	1,762	1,097	447	0	3,306
HI	17	25	0	0	42
MRO	1,869	1,141	2,557	0	5,567
NPCC	84	421	88	14	606
RFC	1,520	815	3,502	0	5,836
SERC	1,399	1,170	3,475	2	6,046
SPP	172	391	760	0	1,323
TRE	88	333	59	0	480
WECC	1,684	1,056	2,365	165	5,269
All Regions	**8,600**	**6,462**	**13,261**	**180**	**28,503**

28 Refer to: FERC, at supra footnote 26.

29 Ibid.

30 Hurley, et al, at supra footnote 1.

Table 23-3

Potential Peak Reduction From Wholesale Demand Response Programs[31]

RTO/ISO	2012 Potential Peak Reduction (MW)	2012 Percent of Peak Demand[h]	2013 Potential Peak Reduction (MW)	2013 Percent of Peak Demand[h]
California ISO (CAISO)	2,430[a]	5.2%	2,180[i]	4.8%
Electric Reliability Council of Texas (ERCOT)	1,800[b]	2.7%	1,950[j]	2.9%
ISO New England, Inc. (ISO-NE)	2,769[c]	10.7%	2,100[k]	7.7%
Midcontinent Independent System Operator (MISO)	7,197[d]	7.3%	9,797[l]	10.2%
New York Independent System Operator (NYISO)	1,925[e]	5.9%	1,307[m]	3.8%
PJM Interconnection, LLC (PJM)	8,781[f]	5.7%	9,901[n]	6.3%
Southwest Power Pool, Inc. (SPP)	1,444[g]	3.1%	1,563[o]	3.5%
Total ISO/RTO	**26,346**	**5.6%**	**28,798**	**6.1%**

Sources:

a California ISO 2012 Annual Report on Market Issues and Performance

b ERCOT Quick Facts (Nov. 2012)

c 2012 Assessment of the ISO New England Electricity Markets

d 2012 State of the Market Report for the MISO Electricity Markets

e 2012 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc. under ER01-3001, et al. (Jan, 15, 2013). Figure includes ICAP/Special Case Resources (1,744 MW), Emergency DR (144 MW), and Day-Ahead Demand Response (37 MW)

f PJM 2012 Load Response Activity Report, Delivery Year 2012-2013 Active Participants in PJM Load Response Program at 2-3, (Apr. 9, 2013). Figure includes all resources registered as Emergency DR (8,552 MW), plus the difference between resources registered as Economic DR and both Emergency & Economic DR (229 MW)

g SPP Fast Facts (Mar. 1, 2013)

h Peak demand data are from the following: California ISO 2012 & 2013 Annual Reports on Market Issues and Performance; ERCOT 2013 Demand and Energy Report; ISO-NE Net Energy and Peak Load Report (Apr. 2013 & Apr. 2014); 2012 & 2013 State of the Market Reports for the MISO Electricity Markets; 2012 & 2013 State of the Market Reports for the New York ISO Markets; 2012 & 2013 PJM State of the Markets Reports, Vol. 2; SPP 2012 & 2013 State of the Market Reports

i CAISO 2013 Annual Report on Market Issues & Performance

j ERCOT Quick Facts (Nov. 2013) http://www.ercot.com/content/news/presentations/2013/ERCOT_Quick_Facts_November%20 2013.pdf

k ISO-NE Demand Response Asset Enrollments at 2, (Jan. 2014)

l 2013 State of the Market Report for the MISO Electricity Markets at 72. This figure excludes 366 MW of emergency demand response that is also classified as LMR

m 2013 Annual Report on Demand Side Management programs of the New York Independent System Operator, Inc. under ER01-3001, et al. (Jan. 15, 2014)

n PJM 2013 Demand Response Operations Markets Activity Report at 3-4 (Apr. 18, 2014), Figure represents "unique MW."

o SPP Fast Facts (as of Dec. 2013)

Note: *Commission staff has not independently verified the accuracy of RTO, ISO and Independent Market Monitor data for purposes of this report. Values from source data are rounded for publication.*

According to FERC, remaining barriers to DR include:

- The limited number of retail customers on time-sensitive rates;
- Measurement and cost-effectiveness of DR energy savings;
- Lack of uniform standards for communicating DR pricing signals and usage information; and
- Lack of customer engagement.

4. GHG Emissions Reductions

This section focuses on the GHG emissions reductions that result from and are directly attributable to DR policies and programs. Before diving into that topic, however, it bears repeating that DR programs can also be used to maintain reliability and lower electric system costs as other GHG reductions strategies, particularly those involving

31 Supra footnote 26.

variable or inflexible energy resources, are deployed. The potential of those other strategies is documented in other chapters.

Several factors will influence the GHG emissions impact attributable to a DR program:

- The amount of demand curtailed in each DR event;
- The emissions profile of the marginal emissions unit(s) operating at the time each DR event is called, which varies by time of day, time of year (summer vs. winter, or ozone season vs. non-ozone season), and geographic location;
- The extent to which participants replace grid-supplied electricity with electricity from backup generators, and the emissions characteristics of those backup generators; and
- Assuming some load is shifted to another time, as is normally the case, the emissions profile of the marginal emissions unit(s) operating at that time.

For example, if a very inefficient, high-emitting EGU is operating on the margin when a DR event is called, and all of the participating customers shift their load to times when more efficient, lower-emitting EGUs operate on the margin, the net effect will be a decrease in emissions. The amount of the decrease could be substantial, if the emissions rates of the marginal EGUs in question are very different. But the opposite case (shifting load to a time when a higher-emitting EGU is marginal) can also occur, or some customers could shift load to backup generators, and emissions could increase.

Quantifying the emissions impacts of DR can be complex and may require some level of active engagement by both environmental regulators and system operators. However, evidence suggests that the GHG emissions impact of DR programs can be positive.

For example, a recent study conducted by Navigant Consulting examined both the direct and indirect emissions impacts of DR programs, in part by modeling the impacts of demand reduction in the wholesale markets operated by PJM Interconnection, the Midcontinent Independent System Operator, and ERCOT. Navigant estimates that "DR can directly reduce CO_2 emissions by more than 1 percent through peak load reductions and provision of ancillary services, and that it can indirectly reduce CO_2 emissions by more than 1 percent through accelerating changes in the fuel mix and increasing renewable penetration."[32]

Another study by Pacific Northwest National Laboratory used modeling to estimate the expected emissions impacts of shifting roughly ten percent of load in each US region during peak hours (on average, 168 hours per year). This was equivalent to shifting about 0.04 percent of total annual load. Pacific Northwest National Laboratory found a positive result for GHG emissions, specifically a reduction of 0.03 percent of total annual emissions. The point to emphasize here is not the magnitude of the numbers but the fact that the modeling results found that load shifting resulted in decreased GHG emissions.[33]

In a third example, EPRI found that DR programs focused on peak load reduction generally resulted in net energy savings and net emissions reductions. EPRI estimated that these programs could save up to four billion kWh of energy in 2030 and that doing so could reduce CO_2 emissions by two million metric tons.[34]

These results may seem surprising, until one considers that most DR events occur at or near times of peak demand, when even the least efficient EGUs may be dispatched. This means the marginal unit could be an inefficient, high-emitting coal-fired or oil-fired unit, or it could be a simple-cycle combustion turbine that has such a high heat rate that its emissions rate in pounds per MWh is comparable to that of an average coal- or oil-fired EGU. In the next section, a case study of this phenomenon (focused on criteria pollutant emissions rather than GHG emissions) is presented. Some support for this idea can also be inferred from the EPA's eGRID database of EGU emissions rates.[35]

32 Navigant Consulting, Inc. (2014, November). *Carbon Dioxide Reductions From Demand Response: Impacts in Three Markets.* Prepared for the Advanced Energy Management Alliance. Available at: http://www.ieca-us.com/wp-content/uploads/Carbon-Dioxide-Reductions-from-Demand-Response_Navigant_11.25.14.pdf

33 Pratt, R., Kintner-Meyer, M. C. W., Balducci, P. J., Sanquist, T. F., Gerkensmeyer, C., Schneider, K. P., Katipamula, S., & Secrest, T. J. (2010). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Publication no. PNNL-19112, prepared for the US Department of Energy. Available at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf

34 Electric Power Research Institute. (2008). *The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid.* EPRI-1016905. Available at: http://assets.fiercemarkets.net/public/smartgridnews/SGNR_2009_EPRI_Green_Grid_June_2008.pdf

35 US EPA. (2010). *Emissions and Generation Resource Integrated Database (eGRID).* Available at: http://www.epa.gov/cleanenergy/energy-resources/egrid/

Although the EPA does not identify or collect data on marginal EGUs, eGRID does provide summary data for "non-baseload" EGUs.[36] In most regions of the country, the weighted average CO_2 emissions rate of non-baseload generators is higher than the weighted average CO_2 emissions rate for all generation. On average for the entire country, these non-baseload generators emit at levels about 25 percent higher than the average for all generation. However, there is significant regional variation. In parts of Alaska and New York, for instance, the non-baseload emissions rate is more than *twice as high* as the average for all generation, whereas in a few regions it is as much as ten percent *lower* than the average for all generation. This suggests that the GHG emissions impact of a DR program in one region could be substantially different from the impact in another region, and the impact overall could be positive or negative.

The best data for a state to use to assess the benefits for a DR program would be state-specific and for the most recent year. However, such granularity is not available for many parts of the United States today, and states may have to default to regional-level statistics.

ISOs and RTOs, where they exist, may offer another good source of emissions data. For example, ISO New England has worked with regional air quality regulators since 1993 to calculate marginal emissions rates for NOX, sulfur dioxide, and CO_2.[37] This information has helped regulators to assess the benefits of energy efficiency and renewable energy programs and, more recently, of "clean" DR programs (i.e., those that do not rely on or encourage the use of uncontrolled backup generators). The accuracy and granularity of ISO New England's data have improved over time, taking advantage of improved modeling and computing power such that today, the regional algorithm for marginal emissions estimates is grounded on hourly data from dispatched generation.[38] Other regions could benefit from replicating the kind of work that has been done in New England.

Regardless of whether state-specific or regional-level emissions data are available, the basic process steps for quantifying the emissions impacts of DR are the same for each region:

- Obtain the best-quality data profiles for the marginal units dispatched in your state. In order of preference, starting with the highest quality:[39]
  - Nodal[40] information differentiated by season, time of day, and type of EGU (i.e., baseload vs. peak, or baseload vs. non-baseload);
  - State-level information differentiated by season, time of day, and type of EGU;
  - State-level seasonal data (i.e., ozone vs. non-ozone season) differentiated by type of EGU;
  - Regional data differentiated by type of EGU;
- Compare emissions between baseloaded and marginal EGUs (or baseloaded and non-baseloaded EGUs if marginal data are not available);
- If marginal or non-baseloaded EGU emissions are higher than those of baseloaded EGUs, then a DR program will likely have an emissions benefit;
- If marginal or non-baseload EGU emissions are lower than those of baseload EGUs, then a DR program will likely increase emissions.

36 Non-baseload EGUs include both load-following generators and peaking plants, all of which could potentially operate on the margin in some hours. This does not imply that non-baseload emissions rates are the same as marginal emissions rates.

37 See, for example: ISO New England. (2014, January). *2012 ISO New England Electric Generator Air Emissions Report.* Available at: http://www.iso-ne.com/system-planning/system-plans-studies/emissions

38 Initial marginal emissions data were based on assessments of the last 500 MW of generation that were dispatched, and comparing marginal emissions data with and without nuclear and hydroelectric generation included. Because the latter units in New England operate as baseload EGUs, these are not affected by DR programs. Discussions with regional air and energy regulators, as part of ISO New England's Environmental Advisory Group, have led to continual improvement of the methodologies used to calculate the marginal emissions, and to joint understanding of what units comprise the marginal unit and their emissions profile.

39 This hierarchy of the relative precision of emissions factors is analogous to that for AP-42 emission factors, which is a very familiar topic to air regulators.

40 Electric grid operators configure their transmission and distribution systems based on the densities of energy use. These are referred to as "nodes," which often are coincident with the boundaries of major urban areas.

5. Co-Benefits

DR policies and programs can reduce costs for participants and deliver a wide variety of economic benefits across the electric power system. They can also help to maintain reliability as more VERs are added to the grid.

DR programs can also reduce emissions of criteria and hazardous air pollutants, in the same manner that they can reduce GHG emissions. As with GHG emissions, the results depend on several variables and may not always be positive. Nevertheless, carefully designed DR programs with appropriate limitations and controls on backup generators could potentially be useful in criteria pollutant planning.

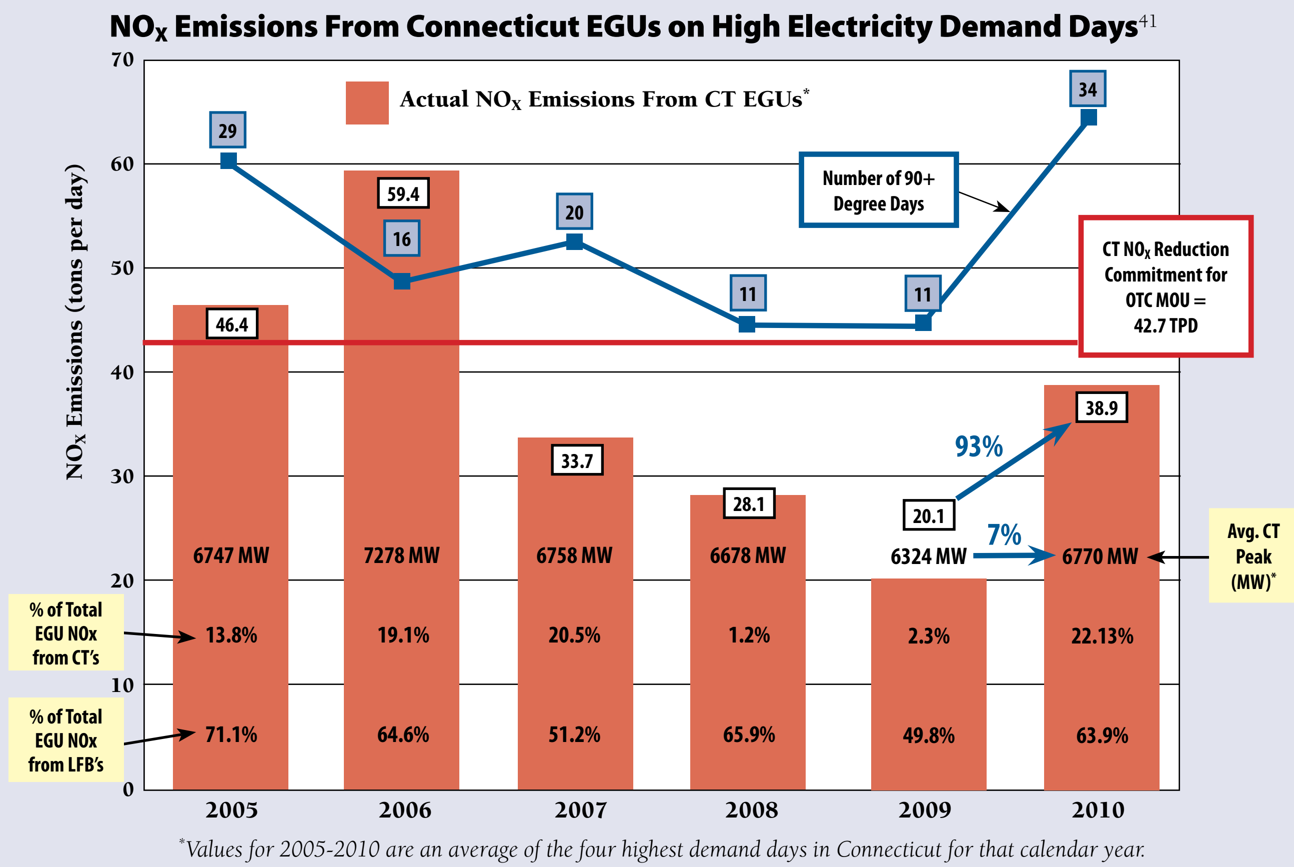
Figure 23-5 offers an illustrative example, based on actual data from Connecticut, of how NO_X emissions can increase significantly during high electricity-demand days when even the least efficient EGUs must be dispatched.

The orange bars in the figure show the average NO_X emissions from EGUs located in Connecticut on the four highest demand days of each year from 2005 through 2010. The figure also indicates for those four highest demand days in each year what the average peak demand was, the percentage of emissions coming from simple-cycle combustion turbines, and the percentage of emissions coming from load-following boilers.

Figure 23-5 reveals two important points:

- A seven-percent increase in the average of the four highest days of electricity demand (from 6324 MW in 2009 to 6770 MW in 2010) caused NOx emissions to nearly double, from 20.1 tons per day to 38.9 tons per day.
- Simple-cycle gas-fired combustion turbines were the marginal units in Connecticut during this time period. These units typically had not installed best available control technology for NO_X emissions, and their

Figure 23-5



*Values for 2005-2010 are an average of the four highest demand days in Connecticut for that calendar year.

OTC – Ozone Transport Commission; MOU – Memorandum of Understanding; CTs – Combustion Turbines; LFBs – Load-Following Boilers.

41 Rodrigue, R. (2011, May 4). Connecticut Department of Energy and Environment, personal communication.

contribution to total NOx emissions from all EGUs increased from 2.3 percent in 2009 to 22.13 percent in 2010.[42]

The Connecticut example points to an obvious conclusion: reducing demand during peak days can avoid reliance on uncontrolled simple-cycle turbines, producing multiple benefits (e.g., lower NOx emissions, decreased hourly electricity costs, and so on). Of course, the data shown in the figure are specific to Connecticut, and each state will be different. In fact, the results may not be positive in every single case. But the potential to reduce criteria pollutant emissions on high-demand days (which often coincide with exceedances) is clearly present in some regions, and air regulators are recognizing the potential of DR programs to support their efforts.[43]

The environmental benefits of DR hold great promise over time, as some of the previously discussed long-term projections (e.g., by EPRI) indicate. But some forms of DR create environmental risks that may need to be addressed by energy and air quality regulators. As noted previously, load shifting runs the risk for increasing emissions through the dispatch of higher-emitting generation resources, in some circumstances, and the use of uncontrolled diesel backup generators may have significant air quality impacts. Air regulators should be careful to minimize the risk for inadvertent net GHG and criteria pollutant emissions increases when considering DR options.

The full range of co-benefits relating to DR is summarized in Table 23-4; many entries cite "Maybe" reflecting the variety of possible DR strategies (i.e., some approaches will decrease GHG emissions but others may increase emissions).

42 The magnitude of the increase shown, although large, may be somewhat overstated, because the "marginal" simple-cycle combustion turbines may have utilized default NOx emissions-rate values, instead of actual emissions measurements, to estimate and report their emissions (as permitted by EPA regulations). The NOx emissions reported from these units may be exaggerated by the use of a default 1.2 lb/MMBTU NOx emission rate, which would tend to increase the percentage of NOx emissions shown from these units relative to entire EGU fleet emissions.

43 In March 2007, several member states of the Ozone Transport Commission signed a Memorandum of Understanding that agreed to limit emissions during high electricity demand days. A copy of the signed MOU is available at: http://www.ct.gov/deep/lib/deep/air/climatechange/otcheddmou070307.pdf

Table 23-4

Types of Co-Benefits Potentially Associated With Demand Response

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Maybe
Nitrogen Oxides	Maybe
Sulfur Dioxide	Maybe
Particulate Matter	Maybe
Mercury	Maybe
Other	Maybe
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Yes
Societal Risk and Energy Security	Yes
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	Yes
Avoided Production Energy Costs	Yes
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	Yes
Avoided Distribution Capacity Costs	Yes
Avoided Line Losses	Yes
Avoided Reserves	Yes
Avoided Risk	Maybe
Increased Reliability	Yes
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	No
Demand Response-Induced Price Effect	Yes
Other	Maybe

6. Costs and Cost-Effectiveness

DR programs generally incur one-time, upfront costs and ongoing or recurrent costs. Depending on the category of DR program, one-time costs can include equipment and devices for communicating with participating customers or automatically curtailing load, program marketing costs, and participant sign-up incentives. For example, a utility might pay a residential customer a $25 sign-up incentive and spend $300 on equipment to automatically curtail the customer's air conditioner during peak events. Recurrent costs can include incentive payments to participants, program administrative costs, and program evaluation costs. Because of this combination of fixed and variable costs, the total costs of a DR program will depend to a great extent on the category of program, the number of participants, and the level of incentives offered. In areas where peak energy prices are unusually high, or extremely expensive system upgrades can be avoided, the utility or DR aggregator may be able to offer more lucrative incentives than a utility or DR aggregator working in an area with low electricity costs. The key consideration then is not the costs of DR programs, but their cost-effectiveness.

When DR programs are offered by a regulated utility, the utility will generally have to demonstrate to the state PUC or its governing board that the programs are cost-effective (i.e., the benefits exceed the costs). In competitive wholesale markets, DR aggregators and other participants don't have to prove that programs are cost-effective, but they will lose money if the costs exceed the benefits over the long run.

In 1983, the California Public Utilities Commission

Table 23-5

The Five Principal Cost-Effectiveness Tests[44]

Test	Key Question Answered	Summary Approach	Implications
Societal Cost	*Will total costs to society decrease?*	Includes the costs and benefits experienced by all members of society	Most comprehensive comparison but also hardest to quantify
Total Resource Cost	*Will the sum of utility costs and program participants' costs decrease?*	Includes the costs and benefits experienced by all utility customers, including program participants and non-participants	Includes the full incremental cost of the demand-side measure, including participant cost and utility cost
Program Administrator Cost	*Will utility costs decrease?*	Includes the costs and benefits that are experienced by the utility or the program administrator	Identifies impacts on utility revenue requirements; provides information on program delivery effectiveness (i.e. benefits per amount spent by the program administrator)
Participant Cost	*Will program participants' costs decrease?*	Includes the costs and benefits that are experienced by the program participants	Provides distributional information; useful in program design to improve participation; of limited use for cost-effectiveness screening
Rate Impact Measure	*Will utility rates decrease?*	Includes the costs and benefits that affect utility rates, including program administrator costs and benefits and lost revenues	Provides distributional information; useful in program design to find opportunities for broadening programs; of limited use for cost-effectiveness screening

44 Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013, February). *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Prepared for the National Forum on the National Action Plan on Demand Response: Cost-Effectiveness Working Group. Available at: http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf

adopted a *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs.* This Standard Practice Manual described five different "tests" that could be used to determine whether an energy efficiency or DR program was (or will be) cost-effective.[45] The California manual has been revised over time and adapted for use in many states. More recently, the question of cost-effectiveness specifically for DR programs was addressed by a working group convened by the FERC and the US Department of Energy as part of the National Action Plan on Demand Response. That working group found that the five tests in the Standard Practice Manual were still largely relevant, but it offered a new way of thinking about the five tests and insights on some of the unique costs and unique benefits of DR programs. The five standard tests, as described by this working group, are summarized in Table 23-5.

Although a detailed description of these tests and their use is beyond the scope of this chapter, it is important for air regulators to know that each state PUC uses some or all of the five cost-effectiveness tests to evaluate whether DR programs save money or not, that each state is different, that the PUC review process is open for public comment and input, and that air regulators have an opportunity to submit comment and testimony in PUC review processes. Used properly, the societal cost or total resource cost test permits the broadest and most comprehensive evaluation of the costs and benefits of DR programs.

The environmental costs and benefits of DR programs are components of these standard cost-effectiveness tests, but in practice they – as well as other non-energy benefits[46] – are difficult to quantify and frequently overlooked in even the most thorough evaluations of DR programs. Part of the reason is the complexity of quantifying environmental impacts, as was explained in previous sections of this chapter. Program evaluators and regulators often put these costs and benefits down as unquantifiable. The state of California addressed this challenge with legislation that specifically requires assessments of the GHG and criteria pollutant impacts of DR programs (see text box).

With greater participation from air quality regulators, the environmental benefits of DR programs could be better quantified and included in cost-effectiveness tests. Programs that encourage the use of backup diesel generators might end up being less cost-effective than they appear to be when emissions impacts are ignored, whereas programs that shift load away from system peaks could potentially be even more cost-effective and changes could be made to increase participation.

Requiring Demand Response Providers to Calculate Environmental Benefits

The state of California public utilities code specifically requires DR providers to calculate criteria pollutant and GHG emissions reduction benefits:

743.1. (a) Electrical corporations shall offer optional interruptible or curtailable service programs, using pricing incentives for participation in these programs. These pricing incentives shall be cost effective and may reflect the full range of costs avoided by the reductions in demand created by these programs, including the reduction in emissions of greenhouse gases and other pollutant emissions from generating facilities that would have been required to operate but for these demand reductions, to the extent that these avoided costs from reduction in emissions can be quantified by the commission. The commission may determine these pricing incentives in a stand-alone proceeding or as part of a general rate case.

California Public Utilities Commission. (2010, December). *Demand Response Cost-Effectiveness Protocols.* Available at: http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm

45 The manual was revised and updated in 1987-1988 and again in 2001, and corrections were made in 2007. The current version is available at: http://www.cpuc.ca.gov/NR/rdonlyres/004ABF9D-027C-4BE1-9AE1-CE56ADF8DADC/0/CPUC_STANDARD_PRACTICE_MANUAL.pdf

46 The identification and quantification of non-energy benefits is an ongoing endeavor, with progress slowly but regularly achieved. Many non-energy benefits of DR programs resemble those for energy efficiency programs. Readers interested in more details on this subject may wish to consult a comprehensive treatment of energy efficiency non-energy benefits: Lazar, J., & Colburn, K. (2013, September). *Recognizing the Full Value of Energy Efficiency (What's Under the Feel-Good Frosting of the World's Most Valuable Layer Cake of Benefits)*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6739

7. Other Considerations

As noted throughout this chapter, air quality regulators may find it difficult to project the future emissions impacts of DR programs and policies, or to quantify and verify the impacts after the fact. There are many variables in the equation, few rules of thumb, and the analytical techniques are still evolving. This is not surprising, given that DR programs were created fundamentally for reliability and economic purposes, not environmental purposes.

As noted previously, greater participation from air quality regulators in program review processes could lead to greater attention and more rigorous quantification of the environmental benefits of DR programs. State regulators have less opportunity for involvement, however, where an RTO, ISO, or similar regional grid organization contracts with aggregators or others who bid DR resources into the market. In these cases, the regional authority contracts to attain only "load service," with little to no knowledge or control of how the "additional load capacity" or "load reduction" will be provided. In such cases, the emissions of any fossil-fueled generators providing the contracted DR services will be governed only by existing federal, state, or local regulations applicable to those units during DR events. In some instances, these existing regulations are insufficient to protect air quality downwind. Through Title V permitting processes, impacted downwind states may have opportunity for input regarding the operations of EGUs located in an upwind state, but they may have no similar opportunity regarding the operation of DR resources in the upwind state. These circumstances result in significant air quality issues for states served by a regional grid operated by an ISO or RTO.

Understanding several factors that influence marginal emissions requires at least a basic appreciation of how electricity is transmitted and how generators are dispatched to satisfy hourly and daily demand. Intimate knowledge of energy principles is not a prerequisite, but it is important for air quality regulators to know where and from whom to get answers in their state. The collaboration between air and energy regulators and the grid operator in New England provided benefits that are readily available to other regions as well. To echo the efforts of regulators in New England, and now in the Middle Atlantic, air regulators could engage with their energy regulators and the regional grid operators on these key topics:

- Discuss how emissions data are used and key principles concerning data precision and accuracy;
- Work with energy regulators and grid operators to identify and prioritize the critical variables needed by air regulators to assess the emissions benefits from clean DR;
- Advocate for improving data capture and quality over time; and
- Sustain engagement with these officials over the long term to assure that data continue to be useful for air regulators.[47]

Quantifying the emissions impacts of DR in a way that could garner approval from EPA (e.g., in the context of a state plan for compliance with the Clean Power Plan rules) and withstand potential legal challenges might prove to be extremely challenging. The EPA can now point to examples of approved state implementation plans that have included energy efficiency or renewable energy as a criteria pollutant control measure, but there are no proven examples for using DR to reduce emissions in a regulatory context. DR was not considered by the EPA to be a component of the best system of emissions reduction for GHG emissions in the power sector, and thus the EPA has offered little guidance on the subject.

Even if a state is leery of including DR in a GHG emissions reduction compliance plan, there is still a role for DR as a complementary policy. A strong DR policy can keep costs down and keep the lights on as other strategies are deployed and the status quo changes.

Regulators will also benefit from staying informed about the influence of new and developing technologies on DR. Innovations in the power sector are coming at a fast pace, from smart grids to the "Internet of things."[48] Some of these emerging technologies are discussed in more detail in Chapter 26. Collectively, the advances in technology are making it increasingly possible for both end-use customers

47 For additional details and a complete list of actions, see: Colburn, K., & James, C. (2014). *Preparing for 111(d): 10 Steps Regulators Can Take Now.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7208

48 The "Internet of things" is a term used to describe an increasingly interconnected, responsive, and dynamic world in which many millions of new devices capable of two-way communication with each other (not just with humans) are being connected to the Internet every year. This interconnectedness offers convenience and comfort, but can also be designed to reduce costs and improve efficiency economy-wide.

and system operators to see the potential economic value of DR, act on that information, and document and quantify those actions and their impacts.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on DR policies and programs.

- EPRI. (2008). *The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid.* EPRI-1016905. Available at: http://assets.fiercemarkets.net/public/smartgridnews/SGNR_2009_EPRI_Green_Grid_June_2008.pdf
- EPRI. (2009, January). *Assessment of Achievable Potential From Energy Efficiency and Demand Response Programs in the US (2010–2030).* Available at: http://www.edisonfoundation.net/iee/Documents/EPRI_SummaryAssessmentAchievableEEPotential0109.pdf
- FERC. (2014, December). *Assessment of Demand Response & Advanced Metering: Staff Report.* Available at: http://www.ferc.gov/legal/staff-reports/2014/demand-response.pdf
- Hurley, D., Peterson, P., & Whited, M. (2013, May). *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States.* The Regulatory Assistance Project and Synapse Energy Economics. Available at: www.raponline.org/document/download/id/6597
- Navigant Consulting, Inc. (2014, November). *Carbon Dioxide Reductions From Demand Response: Impacts in Three Markets.* Prepared for the Advanced Energy Management Alliance. Available at: http://www.ieca-us.com/wp-content/uploads/Carbon-Dioxide-Reductions-from-Demand-Response_Navigant_11.25.14.pdf
- NESCAUM. (2012, August). *Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast.* Available at: http://www.nescaum.org/documents/nescaum-aq-electricity-stat-diesel-engines-in-northeast_20140102.pdf/download
- Pratt, R., Kintner-Meyer, M. C. W., Balducci, P. J., Sanquist, T. F., Gerkensmeyer, C., Schneider, K. P., Katipamula, S., & Secrest, T. J. (2010). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Publication no. PNNL-19112. Prepared for US DOE. Available at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf
- Woolf, T., Malone, E., Schwartz, L., & Shenot, J. (2013, February). *A Framework for Evaluating the Cost-Effectiveness of Demand Response.* Synapse Energy Economics and The Regulatory Assistance Project for the National Forum on the National Action Plan on Demand Response: Cost-Effectiveness Working Group. Available at: http://emp.lbl.gov/sites/all/files/napdr-cost-effectiveness.pdf
- California has an extensive DR history. The December 2013 California ISO report, *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources,* recognizes the role of demand-side resources to achieve a better environmental outcome and to integrate with the increased presence of renewable generation in that state. More information is available at: http://www.caiso.com/Documents/DR-EERoadmap.pdf
- The California Energy Commission's *Integrated Energy Policy Report 2013* is a comprehensive treatise on that state's energy resources and requirements, including DR. More information is available at: http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF-small.pdf

9. Summary

DR resources are capable of providing numerous services that can enhance the efficiency and reliability of bulk power systems. These services span the range of resource adequacy, energy, and ancillary services. The DR opportunity faces some legal turmoil as authority issues are adjudicated, and its application shares the collective uncertainty facing the electric power industry (changing business models, disruptive technologies, new markets and market entrants, and so on), but its economic performance to date ensures that it has a secure place in grid operations going forward. DR will play a larger, not smaller, role as a grid resource.

On a regional and on a state-by-state basis, DR is already providing substantial contributions to resource adequacy mechanisms as both a capacity and reserve resource. In wholesale markets, DR also participates as an energy resource (both day-ahead and real-time). There are many new DR applications being tested and developed that can provide specialized operational services (including load-following, frequency regulation, and special reserves) to system operators. DR is reliable, can provide a significant amount of a region's resource adequacy needs, can achieve participation in market areas, and can lower the cost of reliability.

The exact GHG and criteria pollutant benefits of DR will vary by region, as the marginal units dispatched also vary. Air regulators can improve the accuracy and usefulness of GHG and criteria emissions data from energy saved by following the example of New England's regulators to work directly with their energy and grid operator counterparts.

DR offers the potential for significant environmental benefit. Load curtailment typically results in load reductions with little or no environmental harm. DR programs that avoid the need to dispatch less efficient small-scale generation can reduce GHG emissions. These programs also have the potential to significantly reduce NO_X emissions, and to do so during time periods that are often coincident with unhealthy ambient concentrations of ozone. Load shifting often translates into shifting loads from higher emitting fossil generation to lower emitting sources. DR can also enhance opportunities for integrating clean energy renewable resources.

Environmental benefits from DR are not a given, however. They are only guaranteed if sufficient policy direction or regulatory oversight (from legislative bodies, environmental agencies, or PUCs) is provided to ensure that: (1) actual load curtailment occurs (rather than a shift to onsite generation); (2) load shifting results in lower emissions or emissions at less dangerous times or places; or (3) any substitute generation resources used by DR participants are lower-emitting than those that shed load under the program. With the prospective implementation of the Clean Power Plan and many other emerging power sector issues, air quality regulators would be wise to engage regularly with their state PUC counterparts to ensure that DR programs provide economic and environmental/public health benefits in equal measure.

Chapter 24. Adopt Market-Based Emissions Reduction Programs

1. Profile

One of the ways to reduce greenhouse gas (GHG) emissions is to effectively put a price on emissions, and then rely on market forces that incent and reward innovation, competition, and customized solutions to reducing costs. A price can be directly imposed through a tax (as discussed in Chapter 25), or indirectly imposed through a market-based program such as those described in this chapter.

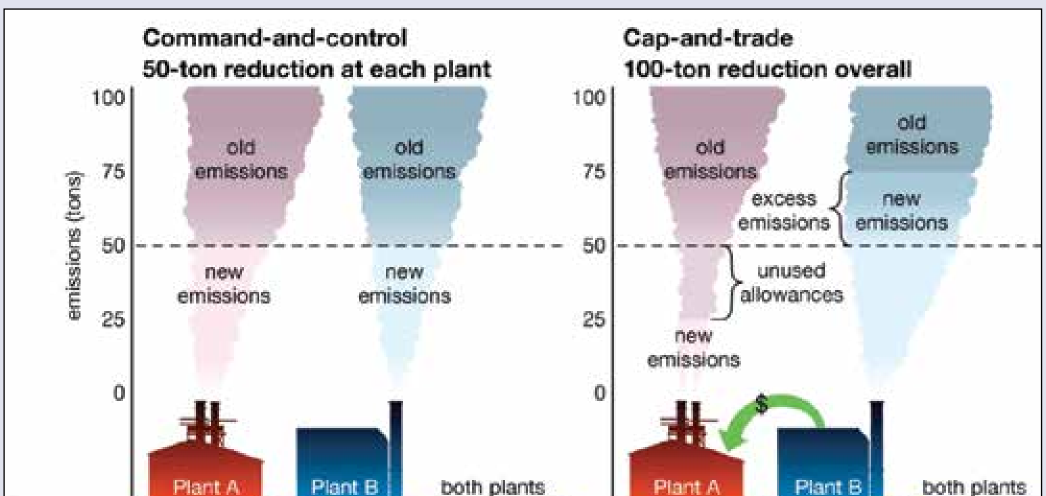
The most familiar market-based program is the cap-and-trade system. Cap-and-trade systems have been successfully used for two decades to control air pollution from electric power plants in the United States. These systems can be simple, transparent, and relatively straightforward to implement.

A cap-and-trade system indirectly puts a price on carbon (i.e., carbon dioxide [CO_2] emissions) by setting caps (i.e., limits) on the total quantity of emissions that all regulated polluters may produce, and creating a commodity (called an allowance) for each allowable unit of emissions (generally one ton of emissions) under the cap. Allowances are initially distributed through an auction mechanism, direct allocation to regulated entities or other parties, or a combination of auction and allocation. Allowances can then be bought, sold, and traded privately or in commodity markets. At the end of each compliance period, regulated entities must surrender a number of allowances equal to their actual emissions. The cap can decline over time, in effect requiring polluters to reduce their aggregate levels of pollution.[1]

A cap-and-trade system is more flexible than prescriptive, command-and-control approaches to regulation that individually impose a technology standard or a unit-specific performance standard on each regulated entity. This is why a cap-and-trade mechanism incents low-

Figure 24-1

How Cap-and-Trade Reduces Compliance Costs[2]



	Plant A	Plant B	both plants	Plant A	Plant B	both plants
tons reduced	50	50	100	75	25	100
cost per ton reduced	$100	$200	—	$100	$200	—
cost of reduction	$5,000	$10,000	$15,000	$7,500 – payments from Plant B	$5,000 + payments to Plant A	$12,500

1 For a more thorough treatment of this topic, see: Johnston, L., & Wilson, R. (2012, November). *Strategies for Decarbonizing the Electric Power Supply.* Montpelier, VT: The Regulatory Assistance Project. Global Power Best Practice Series. Available at: http://www.raponline.org/document/download/id/259.

2 Encyclopaedia Britannica. (2012). *How Emissions Trading Works.* Available at: http://www.britannica.com/media/full/167322. In this limited example, both Plant A and Plant B would come out ahead if Plant A's unused allowances were sold to Plant B for any price between $2500 and $5000.

cost compliance solutions. Although this approach creates a disincentive for pollution by putting a price on emissions, it puts no limits on the various and combined compliance approaches that regulated entities can pursue, including the purchase of allowances, installation of emissions controls, or emissions avoidance through retirement or fuel switching. Each regulated entity can pursue its own best option for complying at the least cost. The better performers under this approach — those with lower emissions — will be able to benefit economically from their performance, which spurs innovation and competition. Figure 24-1 illustrates how an allowance trading system can reduce costs for individual entities and reduce the aggregate cost of compliance for all covered entities.

In addition to providing a lower-cost means of achieving air pollution objectives, cap-and-trade systems compare favorably to some other regulatory approaches in the way that they provide certainty about the total amount of pollution that will occur. The same cannot be said of technology standards, performance standards, or carbon taxes (see Chapter 25). On the other hand, despite providing certainty about the level of expected emissions reductions, a "simple" cap-and-trade system provides less certainty about compliance costs, which is one of the arguments used in favor of carbon taxes and technology standards.[3]

In the last ten years the cap-and-trade model has undergone significant modifications in recognition of the value of a coordinated effort to both discourage the use of carbon-intensive resources and encourage investment alternatives. "Cap-and-invest" programs provide one example of these kinds of modifications. The idea behind a cap-and-invest model is that the government initially distributes allowances through an auction, and then invests the auction revenues in activities that also reduce emissions but are not covered by the trading program or are not sufficiently incented solely by a carbon price mechanism.

2. Regulatory Backdrop

There are numerous examples of cap-and-trade programs from around the United States and the world. In the United States, following the Clean Air Act Amendments of 1990 that authorized the use of market-based regulatory approaches, a number of federal, and later state, cap-and-trade programs were developed. Examples of federal cap-and-trade regulations include the Acid Rain Program, the Nitrogen Oxides (NO_X) Budget Trading Program, the Clean Air Interstate Rule, and the as yet unimplemented Cross State Air Pollution Rule. At the state level, examples include California's Assembly Bill (AB) 32 cap-and-trade program, the Regional Greenhouse Gas Initiative (RGGI), and Texas' Emissions Banking and Trading Programs. Each trading program sets limitations on the emissions of certain pollutants (e.g., sulfur dioxide [SO_2] and NO_X for the federal programs, CO_2 for AB 32 and RGGI, and NO_X and volatile organic compounds for the Texas programs) and imposes those standards on certain classes of emitters. For example, the Acid Rain Program and RGGI apply to fossil generation units with rated capacities of at least 25 megawatts (MW).

To date, all of the federal cap-and-trade regulations in the United States have focused on criteria pollutants rather than carbon.[4] However, the concept and design of cap-and-trade programs has evolved to meet other regulatory needs, most recently in the form of state programs to address CO_2 emissions. The RGGI program started as a collaboration of nine Northeastern and Mid-Atlantic states in 2003, and is the only US example of a regional carbon cap-and-trade effort. California's AB 32 cap-and-trade program, which is linked with a similar program in the Canadian province of Quebec and will encompass energy producers and transportation, started in 2012. A number of other countries have also adopted cap-and-trade programs for

3 The emphasis here is on a "simple" cap-and-trade approach. Cap-and-trade programs built on extensive modeling of carbon allowance prices, with mechanisms such as a "cost containment reserve," an allowance auction "reserve price," or an allowance "price collar" can address and largely overcome the price uncertainty argument traditionally raised by carbon tax supporters against cap-and-trade. Examples are cited later in this chapter.

4 The US Environmental Protection Agency (EPA) proposed an allowance trading program for mercury emissions in the 2005 Clean Air Mercury Rule. 70 Fed. Reg. 28,606 (May 18, 2005). The Clean Air Mercury Rule was challenged in court, ultimately vacated, and never implemented. New Jersey v. EPA, 517 F.3d 574, 583-84. (DC Cir. 2008). The court rejected the proposed trading program because the EPA inappropriately "delisted" fossil generators as mercury emitters under Section 112 of the Clean Air Act (regulating hazardous air pollutants). The legality of the proposed trading system within the context of New Source Performance Standards was not addressed in the court decision.

GHG emissions; refer to the text box: *Selected Examples of Carbon Emissions Trading Systems Outside the United States*.[5]

Cap-and-trade programs can vary extensively in scope, coverage, and execution. For example, programs can vary in the pollutants they address, such as SO_2, which is the focus of the federal Acid Rain Program, or CO_2, the focus of RGGI, AB 32, and many international programs. The programs can also vary in the types of entities that are covered by the regulations, such as energy-producing entities regulated under RGGI, the Acid Rain Program, the European Union's Emissions Trading System (EU ETS), and so forth; transport sectors, which will be covered by an extension of California's AB 32 cap-and-trade program in 2015; and buildings and industrial facilities, which are covered by the Tokyo Metropolitan Government program. Programs can make further distinctions within the categories that they cover, such as focusing on emitters of a certain size. RGGI and the Acid Rain Program apply to generators with rated capacities of 25 MW and larger. Another critically important variable in program design relates to the way allowances are initially distributed. Under the Acid Rain Program, allowances are initially allocated for free to regulated entities. Under the RGGI program, allowances are initially auctioned. The EU ETS and the linked California/Quebec programs currently use a combination of allocations and auctions. In programs in which allowances are auctioned, there is variability in what happens to the auction revenues. Revenues can be used by the government for complementary, emissions-reducing purposes (cap-and-invest), for other government programs, or for tax relief or budget balancing. And finally, some cap-and-trade programs include "cost containment" mechanisms that seek to limit the economic impact of the policy.

Selected Examples of Carbon Emissions Trading Systems Outside the United States

European Union (EU) – The EU's Emissions Trading System (ETS) has been in operation since 2005, and currently covers CO_2 emissions in 30 countries representing about 45 percent of all EU GHG emissions – mainly electricity generators and energy-intensive industries.

China – China's central government in 2011 asked seven regional governments to develop "pilot" carbon emissions trading schemes covering large emitters in several major industrial sectors as well as electricity generation with caps unclearly defined but described as supportive of provincial energy intensity goals (energy per unit of gross domestic product) that the central government has allocated to the regions.

New Zealand – The New Zealand ETS first took effect in January 2008; initially covering only the forestry sector, it has expanded to include industry, transportation, and the power sector.

Tokyo – The Tokyo Metropolitan Government initiated a cap-and-trade program in 2010, targeting "downstream" instead of "upstream" energy use, covering large buildings (both commercial and noncommercial) and large industrial facilities, together comprising about 20 percent of Tokyo's carbon emissions.

3. State and Local Implementation Experiences

Although the federal Acid Rain Program is often cited as the first application of the cap-and-trade concept, it is important to recognize that the US Environmental Protection Agency (EPA) and a few states had experimented with aspects of market-based alternatives to command-and-control regulation before Congress authorized the program via the Clean Air Act Amendments of 1990. The lessons that the EPA and states learned from these earlier efforts informed the debate and opened the door to a full-fledged, market-based Acid Rain Program.

For example, the EPA introduced an emissions offset concept in the 1970s as a way of allowing new sources of emissions to locate in nonattainment areas. Under this approach, any source (new or existing) seeking permission to increase emissions above a threshold amount in a nonattainment area was required to more than offset its emissions by acquiring emissions reductions credits from existing sources in that area. With this approach, the EPA first put a price on (some) emissions. At roughly the same time, the EPA started to allow facilities to treat their existing emissions sources as though they were under a giant enclosure or "bubble," allowing reduced controls relative to a defined benchmark rate of emissions on some smokestacks in ex-

5 For more information on the European Union's ETS, see: http://ec.europa.eu/clima/policies/ets/index_en.htm; for China's "pilot" carbon emissions trading schemes, see: http://www.wri.org/blog/2014/01/emissions-trading-china-first-reports-field; for the New Zealand Emissions Trading System, see: http://www.epa.govt.nz/e-m-t/Pages/default.aspx; and for the Tokyo cap-and-trade program, see: http://www.kankyo.metro.tokyo.jp/en/climate/cap_and_trade.html.

change for compensating higher-than-benchmark controls on other stacks. This would allow a source within a bubble, or what might be considered a "limited geographic cap," to reduce emissions and get credit elsewhere within its system (i.e., allow emissions from another source). One example of an early market-based program implemented by a state can be found in Wisconsin's 1986 Acid Rain law, which (like the later federal program) created a cap on SO_2 emissions in the power sector and allowed trading of emissions reduction credits among regulated utilities.

As noted previously, market-based programs now exist in many jurisdictions. In order to explore the concepts more fully, the following discussion first focuses in some detail on the major aspects of three well-established examples of cap-and-trade: the federal Acid Rain Program, the RGGI, and the linked California/Quebec cap-and-trade programs. The Acid Rain Program is noteworthy, even though it does not regulate GHG emissions, because it is the only US cap-and-trade program that is nearly nationwide in scope. The RGGI program is included here because it is the longest-running GHG cap-and-trade program in the United States. The California AB 32 cap-and-trade program is included because it is an economy-wide program that is linked with a subnational program outside of the United States. Following those three detailed examples, a very brief summary of Texas' Emissions Banking and Trading Programs is presented to give an even broader sense of the variety of programs currently in existence. The section concludes with a description of rate-based trading programs, a potentially interesting alternative to mass-based cap-and-trade programs that has not yet been implemented in any jurisdiction.

The Acid Rain Program

When authorized by Congress in 1990, the Acid Rain Program represented an historic change in regulatory approach from traditional command-and-control regulatory methods. Instead of establishing specific emissions limitations with which each individual affected source must comply, the Acid Rain Program introduced an allowance trading system intended to reflect market incentives to reduce pollution at lowest cost. It also reflected a new understanding about the appropriate point of regulation. Details of the program design and results are summarized below.

Applicability

The Acid Rain Program uses allowances and an SO_2 emissions cap that applies to new utility units and to existing utility units serving generators with an output capacity of greater than 25 MW. Each year an emitter subject to the program is required to surrender a number of SO_2 "allowances" equal to its annual emissions. Although all the emitters covered by the program are subject to a single cap, each individual may emit whatever amount it wants, so long as it obtains and surrenders a number of allowances that corresponds to the tons of pollutant it emits.

Phases

The Clean Air Act Amendments of 1990 set a goal of reducing annual SO_2 emissions by ten million tons below 1980 levels, requiring a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Beginning in 1995, reductions were required from 263 "Phase I" electric generating units (EGUs) at 110 mostly coal-burning power plants located in 21 Eastern and Midwestern states. The list of covered sources under Phase I ultimately grew to 445 EGUs. In Phase II, starting in 2000, the program expanded to regulate more than 2000 fossil-fueled EGUs across the continental United States.[6] Today the Acid Rain Program is fully implemented with regulated EGUs in each of the 48 continental states and an annual cap on SO_2 emissions of 8.95 million tons, approximately a 50-percent reduction from 1980 levels.[7]

Initial Allowance Distribution

Each affected EGU is allocated a number of allowances each year for free, but if the owner of the EGU needs more, he or she must buy allowances from a willing seller in a national market. Thus each emitter has an incentive to reduce emissions to avoid having to buy additional allowances, and to be positioned to sell excess allowances.[8]

Evaluation, Measurement, and Verification

The Acid Rain Program requires coal-fired EGUs to install and operate continuous emissions monitoring systems (CEMS). The Act requires the EPA to specify

6 Based on EPA Acid Rain Program data available at: http://www.epa.gov/airmarkets/progsregs/arp/basic.html.

7 EPA. (2010). *SO_2 Emission Reductions from Acid Rain Program Sources and Improvements in Air Quality.* Available at: http://www.epa.gov/captrade/maps/so2.html.

8 The Acid Rain Program also established SO_2 and NOx emissions limitations for covered sources, and a nationwide NOx reduction goal, separate from the SO_2 cap-and-trade program. The emissions limitations and the NOx goal are not discussed in this chapter.

the requirements for such equipment and to specify any alternative monitoring system that is demonstrated as providing information with the same precision, reliability, accessibility, and timeliness as CEMS.

The EPA has also developed recordkeeping and reporting requirements for CEMS. The emissions monitoring rules for this program are found in federal regulations at 40 C.F.R. Part 75, and the data produced pursuant to these regulations are often referred to as "Part 75 data." Each source must continuously measure and record its emissions of SO_2, NO_X, and CO_2, as well as heat input, volumetric flow, and opacity.[9]

Enforcement

Unlike command-and-control programs in which individual emitters have to demonstrate compliance with a specified emissions limitation for each pollutant, under a cap-and-trade program compliance is determined differently. It is structured to ensure that emitters have the requisite allowances at the end of the compliance period, and so there are no economic benefits associated with not having sufficient allowances.

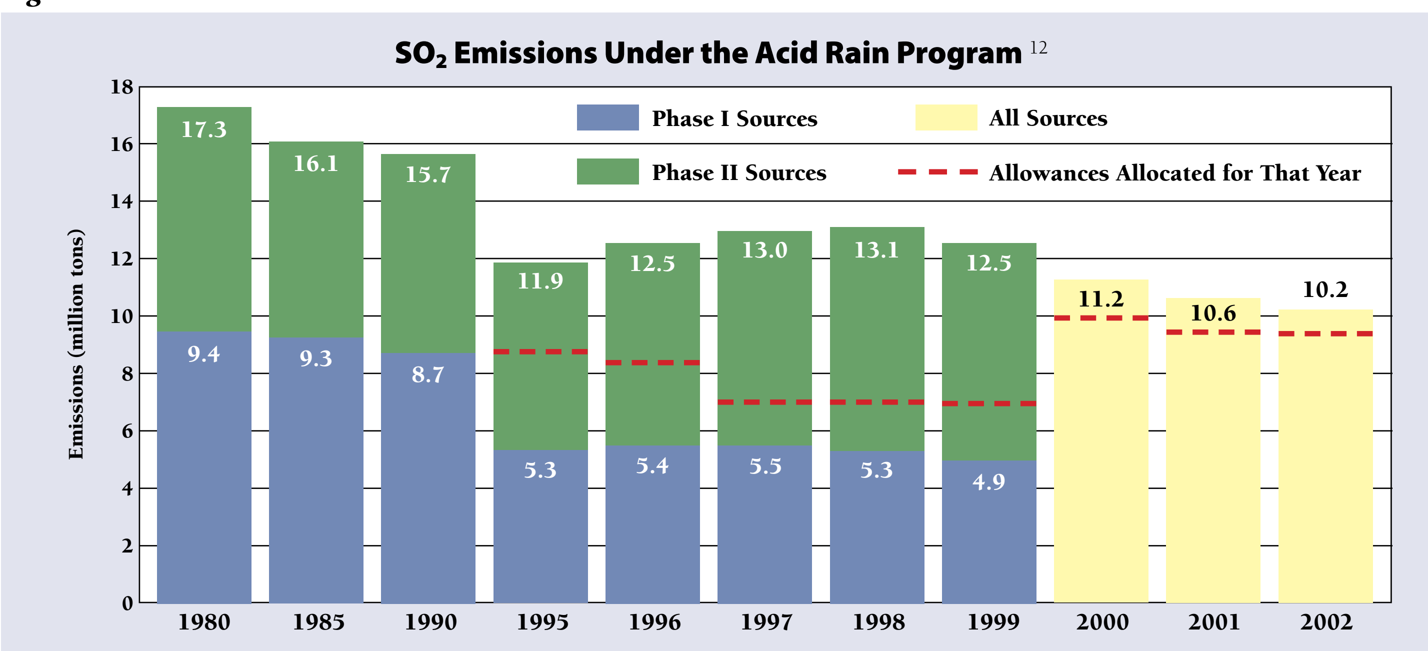
If an emitter fails at the end of a compliance period (one year in the Acid Rain Program) to surrender the number of allowances that corresponds to its emissions, the EPA imposes an automatic excess emissions penalty for each ton of excess SO_2 emissions. The penalty is currently $3754 per ton, but it is adjusted for each compliance year based on changes in the Consumer Price Index.

The Act also imposes an "excess emissions offset"[10] requiring the emitter to compensate for its excess emissions from the current compliance period by surrendering an equal amount of emissions allowances in the next compliance period, in addition to its normal compliance obligation.

Results

The purpose of the Acid Rain Program is to address acid rain problems by reducing SO_2 and NO_X emissions, and it has been very successful. For example, in 2002 the EPA reported that SO_2 emissions had decreased 5.5 million tons from 1990 levels and more than 7 million tons from 1980 under the federal Acid Rain Program, as shown in Figure 24-2.[11]

Figure 24-2



9 As described by the EPA, under this program, which is coordinated between the federal government and state environmental agencies, there are provisions for "initial equipment certification procedures, periodic quality assurance and quality control procedures, recordkeeping and reporting, and procedures for filling in missing data periods." Refer to the EPA Continuous Emissions Monitoring Fact Sheet at: http://www.epa.gov/airmarkets/emissions/continuous-factsheet.html.

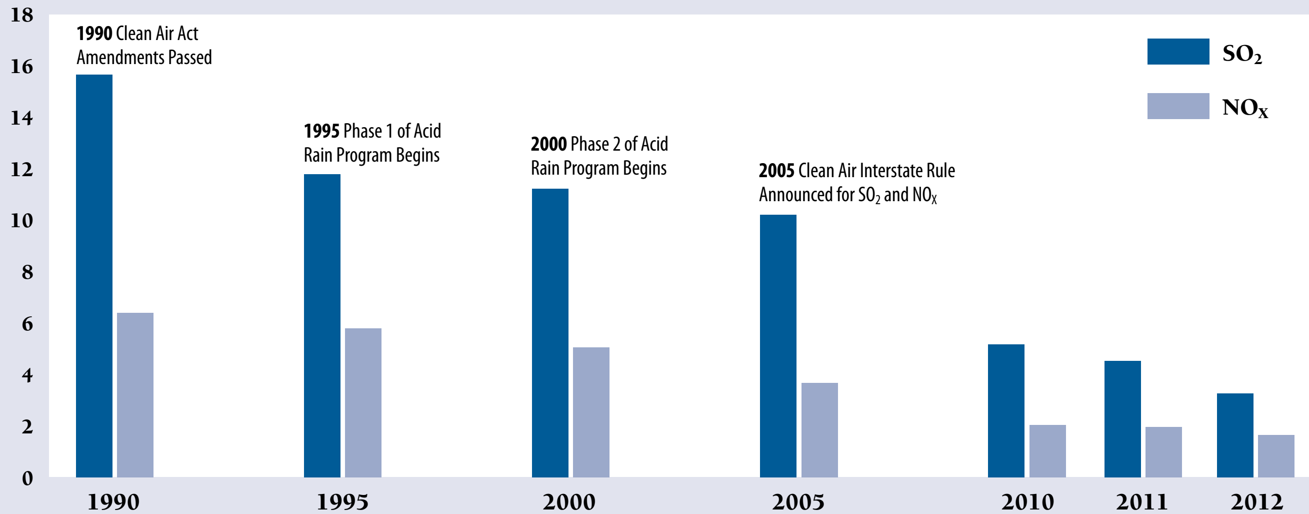
10 Not to be confused with RGGI "offset allowances" discussed below.

11 EPA. (Undated). *Cap and Trade: Acid Rain Program Results.* Clean Air Markets Division. Available at: http://www.epa.gov/capandtrade/documents/ctresults.pdf.

12 Ibid.

Figure 24-3

SO_2 and NO_X Emissions From Electric Power Plants (in Million Short Tons)[13]



In 2013, the US Energy Information Administration (EIA) reported that emissions of SO_2 and NO_X from the electric power sector in 2012 declined to their lowest level since the passage of the Clean Act Amendments of 1990, as shown in Figure 24-3.

Although these declines occur concurrently with the phasing in of the program, it is important to remember that, despite the cap, there is other economic activity that can contribute to achieving the program's goals. Consequently, it is difficult to separate the SO_2 and NO_X declines resulting from the program and those that could be attributed to, for example, an increasing number of coal-fired power plant retrofits with flue-gas desulfurization (scrubbers), fuel switching to low-sulfur coal and natural gas, and investment in selective catalytic reduction and selective non-catalytic reduction to limit NO_X emissions.[14]

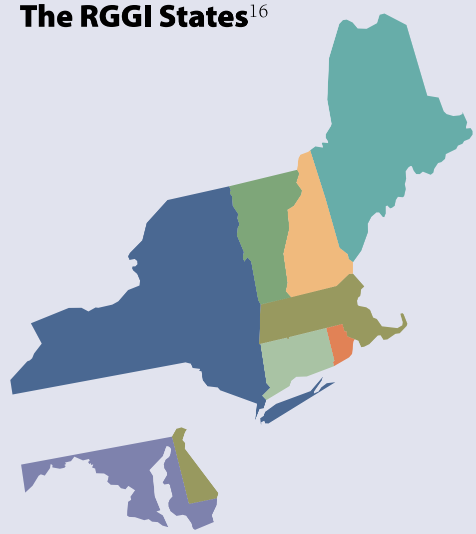
Regional Greenhouse Gas Initiative

RGGI is our second example of the evolution of market-based cap-and-trade mechanisms. RGGI is a cooperative effort of nine Northeast and Mid-Atlantic states to reduce CO_2 emissions from EGUs, and was developed pursuant to each state's independent legal authority.[15] The participating

Figure 24-4

The RGGI States[16]

Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont form the Regional Greenhouse Gas Initiative.



13 US EIA (2013). *Power plant emissions of sulfur dioxide and nitrogen oxides continue to decline in 2012.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=10151.

14 Ibid. The EIA also recognizes that additional major reductions in these two pollutants can be attributed to lower overall electricity generation with coal and historically low gas prices that have contributed to a shift from coal- to gas-fired generation.

15 The nine states are Connecticut, Delaware, Massachusetts, Maryland, Maine, New Hampshire, New York, Rhode Island, and Vermont. New Jersey previously participated but withdrew from RGGI in 2011.

16 Regional Greenhouse Gas Initiative, Inc. (2014, February). *Regional Investment of RGGI CO_2 Allowance Proceeds, 2012.* Available at: http://www.rggi.org/docs/Documents/2012-Investment-Report.pdf.

states are depicted in Figure 24-4.

The program is based on provisions agreed to by the RGGI member states in a Memorandum of Understanding (MOU) signed in December 2005.[17] The program is structured largely on a Model Rule developed by the states to provide guidance and consistency to signatory states.[18] States agreed in the MOU to "propose the Program substantially as reflected in the Model Rule." States also agreed to revisit all elements of the program design in 2012.

RGGI's Model Rule was based on the EPA's Part 96 rule, also known as the "NO_X Budget Rule."[19] The EPA rule served as the structure for RGGI's basic cap-and-trade program administrative functions, including the process for establishing authorized account representatives, compliance certification, the allowance tracking system, and allowance transfers.

The Model Rule was developed by the RGGI Staff Working Group, composed of staff members from the environmental and energy regulatory agencies in each signatory state. This effort was supported by an extensive regional stakeholder process that engaged the regulated community, environmental nonprofits, and other organizations with technical expertise in the design of cap-and-trade programs.

Applicability

RGGI applies to fossil fuel-fired EGUs serving a generator of 25 MW or larger, and relies on CEMS data made available through the Acid Rain Program. RGGI determined that units of that size in the RGGI region were responsible for approximately 95 percent of the electric generation sector's CO_2 emissions. RGGI defined the term "fossil fuel-fired" depending on a unit's in-service date.[20] RGGI also excluded "eligible biomass" from the list of applicable sources.[21]

In order to establish a region-wide list of affected sources, RGGI states conducted an inventory of all units and relied on established data sources.[22] To fill in data gaps in its inventory, the RGGI states revised unit lists to add missing units and remove units that shouldn't be included, used additional unit-level state data (where available), incorporated stakeholder feedback, and also obtained generation data from wholesale market independent system operators.

Compliance Periods

RGGI's first three-year compliance period started in January 1, 2009. The RGGI MOU established a stable

17 This discussion is based on RGGI "Program Overview" materials available at: http://www.rggi.org/design/overview. The MOU was signed by the Governors of the participating states and outlines the program in detail, including the framework for a Model Rule. The states made substantial revisions to the draft Model Rule in response to public comments. As a result, amendments to the MOU were agreed to and signed by the heads of the energy regulatory and environmental agencies in each participating state. The MOU and amendments are available at: http://www.rggi.org/design/history/mou.

18 The Model Rule was not intended to supplant any state regulatory or legislative efforts, but instead seeks to facilitate them by including the types of provisions necessary to implement RGGI. RGGI notes that the Model Rule seeks to "preserve state sovereignty and provides certainty and consistency to the regulated community and to the public." More information about RGGI's Model Rule is available at: http://www.rggi.org/design/history/model_rule.

19 The NOx budget rule was developed as part of the Acid Rain Program. 40 C.F.R. Part 96, NO_X Budget Trading Program and Clean Air Interstate Rule, and NO_X, and SO_2 Trading Programs for State Implementation Plans. See: http://www.access.gpo.gov/nara/cfr/waisidx_06/40cfr96_06.html.

20 If a unit commenced service on or after January 2005, it would be considered fossil fuel-fired provided that fossil fuel comprised more than five percent of its total annual heat input. If a unit commenced service on or before January 2005, it would be considered fossil fuel-fired provided that fossil fuel comprised more than 50 percent of its total annual heat input.

21 This definition includes sustainably harvested woody and herbaceous fuel sources that are available on a renewable or recurring basis (excluding old growth timber), including dedicated energy crops and trees, agricultural food and feed crop residues, aquatic plants, unadulterated wood and wood residues, animal wastes, other clean organic wastes not mixed with other solid wastes, biogas, and other neat liquid biofuels derived from such fuel sources. RGGI preserved determinations as to what constitutes sustainably harvested biomass to the applicable regulatory agencies in each participating state.

22 These sources included the US EIA's Form EIA-767 data: Annual Steam-Electric Plant Operation and Design Data (http://www.eia.gov/electricity/data/eia767/); the EPA's Air Markets Program Data (http://ampd.epa.gov/ampd/); the EPA's Emissions & Generation Resource Integrated Database (http://www.epa.gov/cleanenergy/energy-resources/egrid/); and state emissions inventories and fuel consumption data where available.

cap for the ten states' electric sector CO_2 emissions of approximately 188 million tons per year from 2009 through 2014. The cap was to then decline at a rate of 2.5 percent per year for four years from 2015 through 2018. This approach was intended to result in a 2018 annual emissions budget that would be ten percent lower than the initial 2009 annual emissions budget.[23] At the end of the first compliance period, in 2011, the State of New Jersey ended its membership in RGGI. More recently, in 2014, the nine remaining RGGI states reset (lowered) the cap at 91 million tons per year (to reflect current emissions), while retaining a declining trajectory of 2.5 percent per year from 2015 through 2020.[24]

Use of Offsets

RGGI allows limited use of CO_2 offset allowances, which it defines as "project-based greenhouse gas emission reduction outside of the capped electric power generation sector."[25] RGGI developed offset protocols primarily as a cost-containment mechanism. The ability to increase the number of allowances through limited development of offset projects was considered to be a way in which to mitigate price increases associated with capping CO_2 emissions.[26] RGGI states limit the award of offset allowances to five project categories, each of which is designed to reduce or sequester emissions of CO_2, methane, or sulfur hexafluoride within the nine-state region. RGGI recognizes five offset categories:

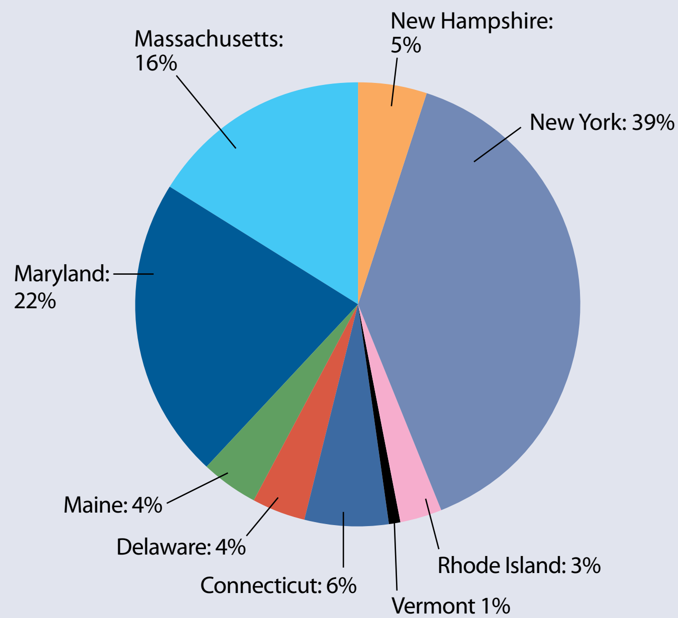
- Landfill methane capture and destruction;
- Reduction in emissions of sulfur hexafluoride in the electric power sector;
- Sequestration of carbon attributable to US forest projects (reforestation, improved forest management, avoided conversion) or afforestation (for Connecticut and New York only);
- Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion attributable to end-use energy efficiency in the building sector; and
- Avoided methane emissions from agricultural manure management operations.[27]

Initial Allowance Distribution

The RGGI cap covers aggregated emissions from all of the participating states, and each allowance permits a regulated source to emit one ton of CO_2. Allowances are first apportioned among the states based on proportional CO_2 emissions, as shown in Figure 24-5.

Figure 24-5

RGGI 2014 CO_2 Allowance Allocation by State[28]



Rather than following the model established by the Acid Rain Program and allocating allowances to affected EGUs for free, RGGI states chose to distribute the majority of allowances through regional auctions. RGGI auctions follow a single-round, uniform-price, sealed-bid auction format. They are conducted in accordance with the statutory and/or regulatory authority of each state offering CO_2 allowances for sale in that auction, and each state retains its authority

23 RGGI's initial regional cap was 188 million short tons of CO_2 per year, which RGGI indicated was approximately four percent above annual average regional emissions during the period of 2000 through 2004.

24 Refer to: RGGI 2012 Program Review: Summary of Recommendations to Accompany Model Rule Amendments. Available at: http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf. RGGI's Program Review is discussed further below.

25 For more on the RGGI approach to CO_2 offsets, refer to: http://www.rggi.org/market/offsets.

26 Offsets, by definition, are out-of-sector GHG reductions. Encouraging offsets is one way to mitigate price effects without reducing the program impact.

27 Supra footnote 25.

28 Supra footnote 16.

to make regulatory determinations related to the conduct of the auction.[29] Auction proceeds are then returned to the states based on the proportion of the allowances they contributed to the auction.

RGGI adopted this approach because, in a competitive wholesale market, electric generators will reflect the market value of free allowances in the price they bid into the market. The RGGI region contains three wholesale electricity markets operated by independent system operators, depicted in Figure 24-6. RGGI reasoned that, because "allowances can be traded to other parties," they have market value:

> Generators expend an asset – emission allowances – when generating electricity. As such, the use of freely allocated allowances has an "opportunity cost" since revenue from the potential sale of the allowance is foregone. In a competitive wholesale market, generators therefore pass on the cost of allowances as a cost of generating electricity, whether allowances were received for free or were purchased. RGGI is being implemented in a region with deregulated wholesale electricity markets, which warrants a design approach that includes the auctioning of allowances.[30]

Figure 24-6

Independent System Operators in the RGGI Region[31]

In its 2011 study, *The Economic Impacts of the Regional Greenhouse Gas Initiative,* the Analysis Group observed that "[a]uctioning allowances and distributing allowance proceeds to states in this way had an important impact on program outcomes since it meant, in effect, that the public benefitted by transferring the value of allowances to market at market prices (rather than for free, as was done in the SO_2 and NO_X allowance programs)."[32]

Between September 2008 and December 2013, the RGGI states held 22 auctions in which they sold current and future compliance period (also called "control period") allowances. First control period (January 1, 2009 to December 31, 2011) allowances sold at a weighted average price of $2.31, with prices ranging from $3.51 to $1.86. Second control period (January 1, 2012 to December 31, 2014) allowance prices ranged from $3.21 to $1.86 and sold at a weighted average price of $2.52.[33] Through 2012, the RGGI raised just under $1 billion for the participating states, as noted in Table 24-1.

Table 24-1

Cumulative RGGI Auction Proceeds[34]

State	Reporting Basis	Cumulative Auction Proceeds Received Through 2012 Reporting Period
Connecticut	Calendar Year	$65,167,703
Delaware	Calendar Year	$29,690,897
Maine	Calendar Year	$34,246,622
Maryland	Fiscal Year	$197,434,494
Massachusetts	Calendar Year	$178,921,781
New Hampshire	Calendar Year	$42,452,629
New York	Calendar Year	$410,586,620
Rhode Island	Calendar Year	$17,977,845
Vermont	Calendar Year	$8,284,461
Total Nine-State RGGI Region		**$984,763,052**

29 For further information on RGGI auction processes and results, see: http://www.rggi.org/market/co2_auctions.

30 Regional Greenhouse Gas Initiative. (2007, October). *Overview of RGGI CO_2 Budget Trading Program.* Footnote 6. Available at: http://www.rggi.org/docs/program_summary_10_07.pdf.

31 More information about ISOs is available at: http://www.isorto.org/about/default.

32 Hibbard, P., Tierney, S., Okie, A., & Darling, P. (2011, November). *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States.* Analysis Group. Page 31. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Economic_Impact_RGGI_Report.pdf.

33 Supra footnote 16 at page 6.

34 Supra footnote 16 at page 7.

Allowance Tracking

The RGGI's CO_2 Allowance Tracking System or "COATS" is an electronic platform that records and tracks data for each state's CO_2 Budget Trading Program. RGGI COATS enables the public to view, customize, and download reports of CO_2 allowance market activity and RGGI program data. COATS enables the public to view program and market data reports regarding:

- CO_2 allowance transactions (the date, price, and type of transaction);
- RGGI COATS accounts, showing a list of every account registered in RGGI COATS;
- RGGI COATS account representatives, showing individual contact details for all accounts;
- RGGI sources, listing each regulated power plant and its location;
- Owners/operators of RGGI sources, showing the corporate affiliation of owners and operators for each regulated power plant;
- Special approvals, detailing allowance allocations made by states;
- Offset project applications and approvals; and
- CO_2 emissions from RGGI sources, showing emissions for each regulated power plant and summary CO_2 emissions for the nine-state region.

Evaluation, Measurement and Verification

As previously noted, under the existing federal Acid Rain Program, fossil-fueled EGUs 25 MW and larger are required to report their CO_2, NOx, and SO_2 CEMS data to the EPA and the states each quarter. The EPA maintains the data system and performs quality assurance and quality control (QA/QC) tests on the CEMS data to ensure its accuracy. States also perform QA/QC tests.[35] Because RGGI units are also fossil-fueled EGUs 25 MW or larger, the program can use CEMS data to track emissions from RGGI jurisdictional units. Furthermore, because the program is mass-based, regulators need ultimately only check the bottom line (i.e., the overall emissions, and the regulated entities' progress in achieving them) at the end of each compliance period.

Enforcement

RGGI has established enforcement rules for various aspects of its program including emissions reporting, allowance tracking, and auction participation. No RGGI provisions excuse RGGI jurisdictional units from compliance with any other provisions of applicable state and federal laws or regulations.

For example, states can take direct enforcement action for failure of the source to perform QA/QC tests each quarter and more robust tests (measured against a stack test) each year. Enforcement can also be taken for emissions exceedances or the absence of backup proxy data for periods when the CEMS is not operating or available.

The RGGI program uses a market monitor to protect and foster competition, and to increase the confidence of the states, participants, and the public in the allowance market. RGGI contracts with Potomac Economics for independent monitoring of the competitive performance and efficiency of the RGGI Allowance Market. The market monitor:

- Identifies attempts to exercise market power, collude, or otherwise manipulate prices in the auction and/or the secondary market;
- Assesses whether the auctions are administered in accordance with the noticed auction rules and procedures; and
- Makes recommendations regarding proposed market rule changes to improve the economic efficiency of the market for RGGI Allowances.

Use of Allowance Revenues

The RGGI states initially agreed that RGGI member states would have full discretion on how to use the revenues raised from allowance auctions. However, based on modeling, stakeholder input, and the recognition that state clean energy programs could deliver more CO_2 emissions reductions than would result from the modest price on carbon created by the RGGI cap, the RGGI states agreed to use allowance value to provide incentives for end-use energy efficiency and other clean energy measures, thus lowering the impact of the program on electricity consumers. This decision was consistent with third-party research indicating that end-use energy efficiency measures provide by far the greatest potential for GHG emissions reductions at least cost, as depicted in Figure 24-7.

Signatories to the RGGI MOU agreed to allocate a minimum of 25 percent of allowance value to support what they called "consumer benefit programs." The RGGI MOU defines

35 The CEMS procedures are modeled after the EPA's NO_X budget program, another market-based cap-and-trade program created to reduce the regional transport of NO_X emissions from power plants and other large combustion sources that contribute to ozone nonattainment in the Eastern United States.

Figure 24-7

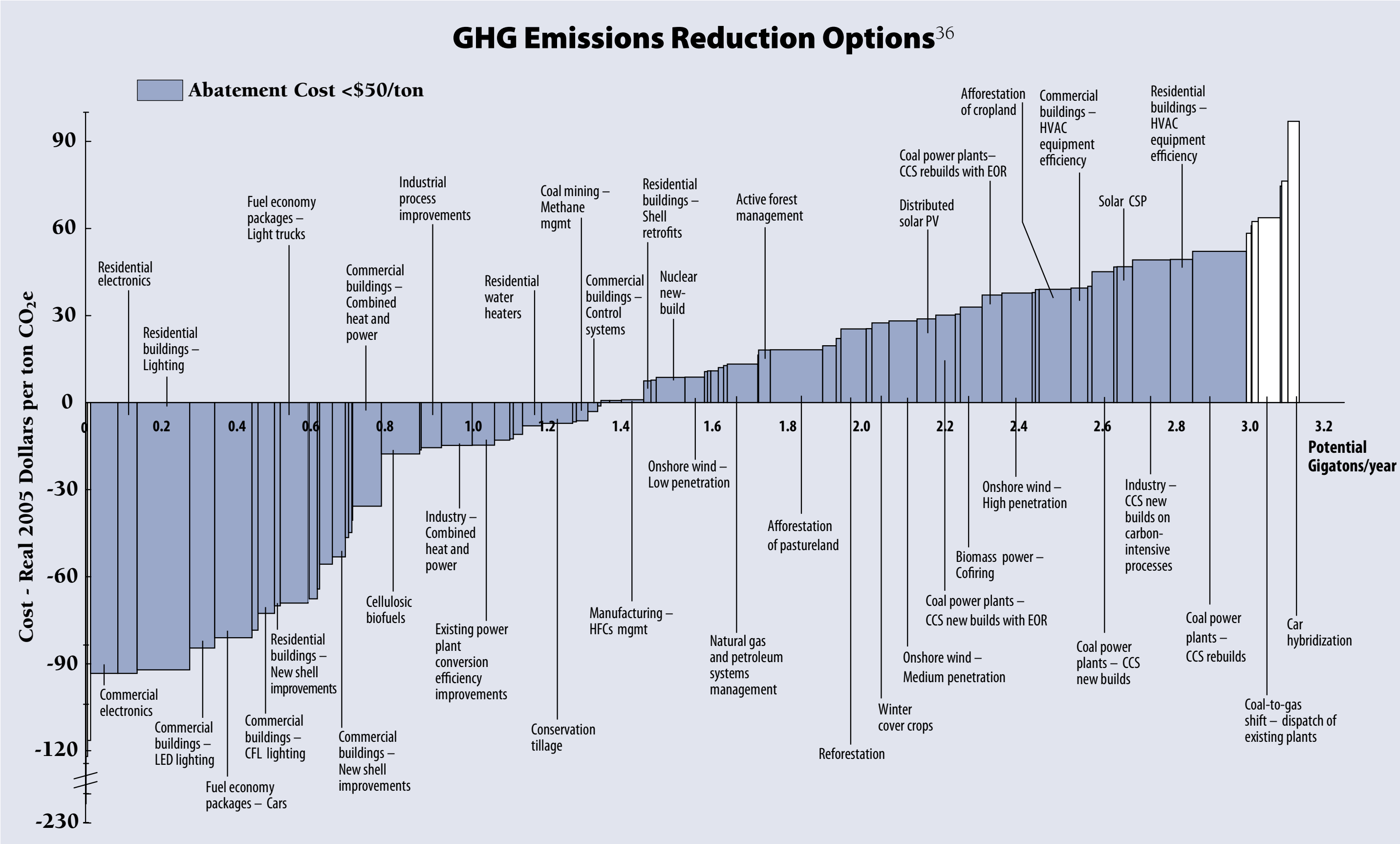
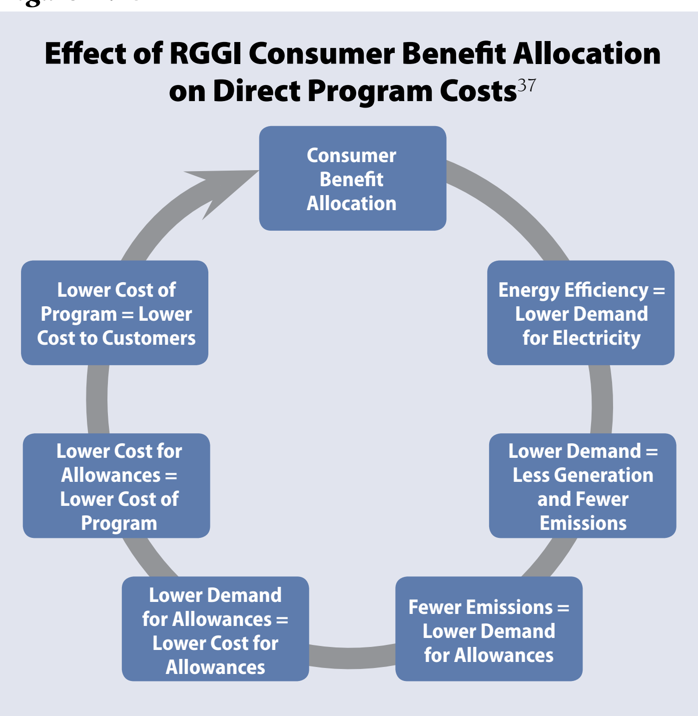


Figure 24-8



"consumer benefit or strategic energy purposes" as the:

> …use of allowances to promote energy efficiency, to directly mitigate electricity ratepayer impacts, to promote renewable or non-carbon emitting energy technologies, and to stimulate or reward investment in the development of innovative carbon emissions abatement technologies.[38]

The RGGI states further concluded that, "allocating allowances to support consumer benefits leads to lowering of electricity demand, reducing the overall compliance costs of the RGGI program and its impact on electricity

36 McKinsey & Company. (2007, December). *Reducing US Greenhouse Gas Emissions: How Much at What Cost?* Exhibit 11. Available at: http://www.mckinsey.com/client_service/sustainability/latest_thinking/~/media/mckinsey/dotcom/client_service/sustainability/pdfs/reducing%20us%20greenhouse%20gas%20emissions/us_ghg_final_report.ashx.

37 Farnsworth, D., D'Antonio, B., & Pike-Biegunska, E. (2009, September). *Climate Policy and Affordability: Advocacy Opportunities in the Northeast.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/docs/RAP_Farnsworth_ClimatePolicyinNortheast_2009_09_18.pdf.

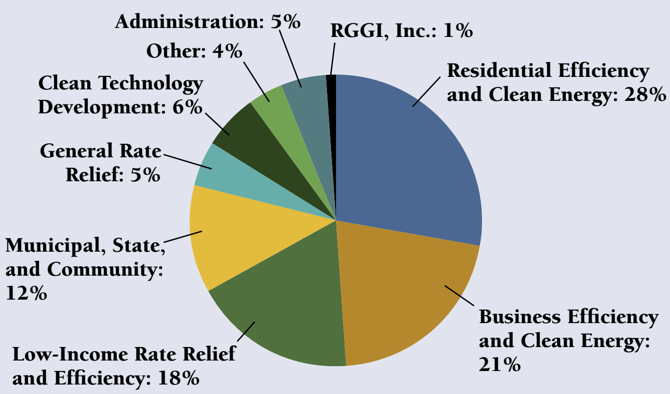
38 Supra Footnote 17.

ratepayers." This virtuous cycle is illustrated in Figure 24-8.

From 2009 through 2012, the RGGI states raised over \$984.7 million in auction proceeds, \$707.2 million of which was invested largely in state clean energy programs, as shown in Figure 24-9.[39]

Figure 24-9

RGGI Investments by Program Type[40]



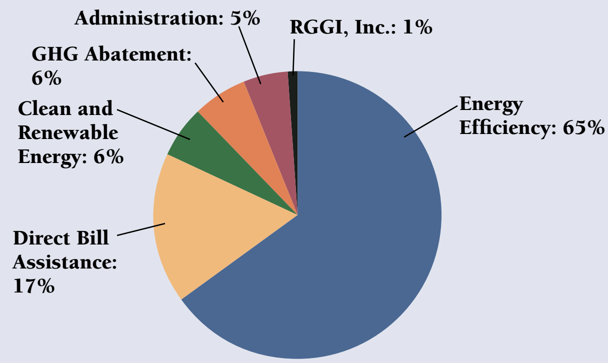
Total Invested: \$707,225,905

RGGI further reports that "more than 73 percent of 2012 RGGI investments, and approximately 65 percent of cumulative RGGI investments to date, fund energy efficiency programs in the region." More than six percent of RGGI investment in 2012, and six percent to date, funds clean and renewable energy programs, including grants and low-interest loans.[41] Figure 24-10 shows the portion of total RGGI auction proceeds directed toward different categories of investment.

Using state projections of cumulative and lifetime benefits of RGGI investments, RGGI reports that investments to date of auction proceeds in state clean energy programs will avoid "the release of approximately 8 million short tons of CO_2 pollution into the atmosphere over their lifetime."[42]

Figure 24-10

RGGI Investments by Category[43]



2012 Program Review

As called for in the MOU, the RGGI states conducted a program review at the end of the first three-year compliance period (2012/2013) to correct any faults and to consider changes to improve the program.[44] The review revealed that there was a "significant excess supply of allowances relative to actual emission levels in the region," and recommended that the program consider cost-control measures other than those that had been developed based on the availability of offset allowances. RGGI states, in response, revised the program cap to reflect lower regional emissions levels while accounting for allowances already held. Furthermore, in an effort to put in place a mechanism to control program costs expected from lowering the emissions cap, the RGGI states established a "cost-containment reserve," which would make available an additional amount of allowances for the market if a defined allowance trigger price is exceeded. Finally, in order to continually monitor program effectiveness, the RGGI states agreed to conduct another program review no later than 2016.[45]

39 RGGI reports that a total of \$984.7 million in auction proceeds was received by the RGGI states through the period covered by this report. Of that, \$707.2 million was invested in state clean energy programs and \$93.1 million was transferred to state general funds by acts of state legislatures. The remaining \$184.4 million was committed to 2013 and future programs.

40 Supra footnote 16. RGGI Investments by Program Type are cumulative to date (2009-2012).

41 Ibid.

42 Ibid.

43 Ibid.

44 Refer generally to the RGGI 2012 Program Review at: http://www.rggi.org/design/program-review.

45 In addition to lowering the cap, the RGGI states agreed to address the bank of unused allowances held by market participants with two interim adjustments for banked allowances from the two compliance periods. The cost containment reserve would make available five million short

continued on page 24-13

Results

The results achieved by the RGGI program to date are highlighted in Sections 4 through 6.

California Cap-and-Trade Program

In 2006 California enacted AB 32, the California Global Warming Solutions Act. AB 32 was the first statutory obligation in the country to take a comprehensive, long-term approach to addressing climate change across all GHG-emitting sectors. This legislation required the state's Air Resources Board (ARB) to plan and implement measures that would return California to 1990 levels of GHG emissions by 2020.

In December 2008, the Board approved an initial planning document, known as the AB 32 Climate Change Scoping Plan, that identified a suite of measures to cut GHG emissions.[46] AB 32 authorized market-based measures but did not require them. The Scoping Plan process determined that a cap-and-trade program and a portfolio of other complementary policies should be developed. In the electric sector, significant complementary policies for California include a 33-percent renewable portfolio standard and energy efficiency programs. In May 2014, the Board approved the First Update to the Scoping Plan, which builds on the initial Scoping Plan with new strategies and recommendations.[47]

Between 2009 and 2012 the Board undertook a series of rulemakings to develop and implement the cap-and-trade program.[48] In 2014 California linked its program with a very similar program in the Canadian province of Quebec.

Applicability

The AB 32 cap-and-trade program covers approximately 85 percent of the GHG emissions in California. Major sectors include electricity, industry, and distributed use of natural gas, propane, gasoline, and diesel fuels. For the electric sector, California's program accounts for both imported electricity and electricity produced instate. The threshold for direct inclusion in the program is 25,000 metric tons of CO_2 equivalent (CO_2e) GHG emissions per year. Emissions generated from the use of eligible biomass fuels are not assessed an obligation.

Compliance Periods

California, like RGGI, established multiyear compliance periods to increase flexibility with respect to annual variation in emissions. The first period, from 2013 through 2014, covers only electricity and industry, and has a declining annual program cap of approximately 160 million metric tons of CO_2e. The second period covers 2015 through 2017. The third period runs from 2018 through 2020. The program expands in the second period to cover distributed fuel use. The cap covering this broader scope begins at 395 million metric tons CO_2e in 2015 and declines to 334 million metric tons CO_2e in 2020. Allowances are fully bankable between periods.

Price Containment

California's program contains both a floor and a soft ceiling on allowance prices. This "price collar" approach gives greater investment certainty that allowance prices will remain within a specified band. The floor is enforced through a reserve price at auction in a fashion similar to RGGI's system. High price protection is provided by a reserve of allowances set aside from future year caps and only made available for sale by the state at higher prices. This mechanism ensures that additional allowance supply is available if demand to emit is greater than expected.

Use of Offsets

Similar to RGGI, California allows limited use of offset credits as a cost-containment mechanism. All compliance offset projects must be developed according to approved Compliance Offset Protocols.

Footnote 45, continued from page 24-12

tons in 2014, and ten million short tons per year each year thereafter. The next program review will consider "program successes, impacts, potential additional reductions to the cap post-2020, and other program design elements." Refer to: Regional Greenhouse Gas Initiative. (2013, February). *RGGI 2012 Program Review: Summary of Recommendations to Accompany Model Rule Amendments*. Available at: http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.

46 Refer to the California Air Resources Board (ARB) website at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

47 Refer to the ARB website at: http://www.arb.ca.gov/cc/scopingplan/document/updatedscopingplan2013.htm.

48 Refer to the ARB website at: http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

Table 24-2

California Offset Volumes as of September 10, 2014[50]

Project Type	ODS	Livestock	US Forest	Urban Forest	MMC
Compliance	1,343,588	—	3,378,928	—	—
Early Action	3,954,477	474,657	2,618,389	—	—

One offset credit = one metric ton CO_2e
MMC, mine methane capture; ODS, ozone-depleting substances.

The eligible offset project types are currently

- US Forest Projects;
- Urban Forest Projects;
- Livestock Projects;
- Ozone-Depleting Substances Projects; and
- Mine Methane Capture Projects.[49]

Because of historically higher allowance prices in the AB 32 program than in the RGGI system, California has seen more offset project activity. Offsets generated to date are shown in Table 24-2.

Unlike any other regulatory cap-and-trade program, California's offset program includes provisions for offset buyer liability. This means that any offset used for compliance that is later found to be fraudulent or not generated in accordance to the Board-approved protocols must be replaced by another valid compliance offset or allowance. This ensures the environmental integrity of the program and promotes due diligence in the regulated entities that choose to pursue the use of lower-cost offsets for compliance.

Initial Allowance Distribution and Use of Allowance Revenues

Similar to RGGI and the EU ETS, California relies on auctions to distribute allowances to EGUs. California arrived at this approach after a stakeholder process that recognized the monetary value of the allowances, opportunity cost arguments, and the benefits of an auction-based distribution for smooth functioning of wholesale electric markets.[51] Like RGGI, California AB 32 cap-and-trade program auctions follow a single-round, uniform-price, sealed-bid auction format.

California also took the unique step of freely allocating allowances to the regulated electric utilities in the state on behalf of customers. The largest utilities are required to sell these allowances at the auction and use the proceeds on behalf of their customers, as specified by the California Public Utilities Commission. This allows the state utility regulators to consider both the carbon cost and the value of the allowances when determining retail rate impacts, funding for efficiency programs, and customer dividends. California utility customers now receive biannual "climate credits" funded through utility auction proceeds on their April and October electric bills.[52] These credits, shown in Table 24-3, are non-volumetric, meaning they are independent of how much electricity a customer uses. This approach to returning allowance value to customers maintains the conservation incentive created by carbon pricing.

Table 24-3

Climate Credits Returned to California Electricity Customers[53]

California Electric Utility	Biannual Climate Credit in 2014
Pacific Gas and Electric	\$29.81
Southern California Edison	\$40.00
San Diego Gas and Electric	\$36.24

49 Refer to the ARB website at: http://www.arb.ca.gov/cc/capandtrade/offsets/offsets.htm.

50 Supra footnote 45.

51 Refer to the ARB website at: http://www.arb.ca.gov/regact/2010/capandtrade10/capv4appj.pdf and http://www.arb.ca.gov/regact/2010/capandtrade10/candtappa2.pdf.

52 Refer to the California Public Utilities Commission website at: http://www.cpuc.ca.gov/PUC/energy/capandtrade/climate-credit.htm. Also refer to: http://www.energyupgradeca.org/en/learn/energy-impact-on-our-climate/what-is-california-climate-credit.

53 Supra footnote 52.

Allowance Tracking

California's Compliance Instrument Tracking System Service or "CITSS" is an electronic platform that records and tracks data for California and Quebec with functionality similar to RGGI's COATS. CITSS is used to:

- Register entities participating in the California cap-and-trade program;
- Track the ownership of compliance instruments;
- Enable and record compliance instrument transfers;
- Facilitate emissions compliance; and
- Support market oversight.

Evaluation, Measurement, and Verification

AB 32 required that, prior to the beginning of any market system, a robust reporting program be developed to help establish accurate emissions inventories. California's power plants began reporting their GHG emissions beginning with the 2008 data year under California's Mandatory Greenhouse Gas Reporting Program.[54] CEMS installed for the federal Acid Rain Program are used by many facilities but are not explicitly required by California's program. Third-party verification is required to ensure data quality and that state staff perform QA/QC tests and check verifier work. California's third-party verification program is consistent with international standards and procedures similar to those used in the EU ETS.

Enforcement and Market Monitoring

California recognized that a well-functioning market was fundamental to the implementation of the California AB 32 cap-and-trade program. As one component of the AB 32 approach to ensure that the markets are free from abuse and disruptive activity, the California ARB conducts market surveillance and analysis.[55] The Board's trained surveillance staff work closely with an independent market monitor, Monitoring Analytics, to monitor the auctions and all holding and trading of compliance instruments for the program. Activities in related markets are also tracked and analyzed.

The ARB works with several California state and federal agencies to ensure robust oversight, including the California Attorney General's Office, the California Independent System Operator, the Commodity Futures Trading Commission, and the Federal Energy Regulatory Commission.

The ARB can also take direct enforcement action for failure to properly report or verify emissions each year. The Board has already taken such enforcement action for those who failed to meet reporting and verification deadlines.[56]

In addition to the active surveillance, the program has a fundamental design to ensure that the ability to exercise market power is limited through the use of position limits, referred to as holding limits in the regulation. All compliance instruments, both allowances and compliance offsets, have unique serial numbers and are created, tracked, and retired within CITSS. Anyone registering for an account in CITSS must pass know-your-customer requirements.

Results

Because California's program is still in the midst of the first compliance period, it is too early to report on results.

Texas Emissions Banking and Trading Programs

The State of Texas provides some final examples of market-based approaches, which we will mention but not describe in significant detail. Texas has various Emissions Banking and Trading programs overseen by the Texas Commission on Environmental Quality.[57] For example, its Mass Emissions Cap and Trade and Highly-Reactive Volatile Organic Compound Emissions Cap and Trade Programs apply to the Houston-Galveston-Brazoria 2008 eight-hour ozone nonattainment area.[58] Program allowances are used to satisfy the offset requirements for new or modified facilities subject to federal nonattainment new source review requirements under Texas and federal law.[59] Mass Emissions Cap and Trade allowances are used to satisfy NO_X offset requirements for facilities in the geographic area subject

54 Refer to the ARB website at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

55 Refer to the ARB website at: http://www.arb.ca.gov/cc/capandtrade/market_oversight.pdf.

56 For examples, see: http://www.arb.ca.gov/enf/casesett/sa/pge_sa.pdf or http://www.arb.ca.gov/enf/casesett/sa/chev_nea_sa.pdf.

57 See generally the Mass Emissions Cap and Trade Program website at: http://www.tceq.texas.gov/airquality/banking/mass_ect_prog.html.

58 For more details, refer to: http://www.tceq.texas.gov/assets/public/implementation/air/banking/guidance/allowances-offsets.pdf.

59 Refer to: 30 Texas Administrative Code Chapter 116, Subchapter B, Division 7.

to the emissions requirements. Likewise, Highly-Reactive Volatile Organic Compound Emissions Cap and Trade allowances are used to satisfy volatile organic compound offset requirements for facilities in specified areas.

Rate-Based Trading Programs

Examples of cap-and-trade programs that have already been implemented have been described in detail. All of those programs focus on capping the mass of emissions and allowing trading of mass-based emissions allowances. However, alternative versions of cap-and-trade have been proposed by some environmental groups. These alternatives have not been implemented in any jurisdiction, but are sufficiently different and interesting as to merit mention here.

Western Resource Advocates has proposed an alternative to cap-and-trade programs that focuses on the trading of credits based on emissions rates rather than the trading of allowances based on mass emissions.[60] Its *Carbon Reduction Credit Program* is intended to offer states another option for use in implementing the Clean Power Plan that the EPA proposed in June 2014 to regulate CO_2 emissions from existing power plants pursuant to section 111(d) of the Clean Air Act. The program is designed to be flexible, technology-neutral, and market-based.

Under the proposed *Carbon Reduction Credit Program*, for each megawatt-hour (MWh) of electricity produced by a regulated generator, air pollution regulators would award one carbon reduction credit (CRC) for each pound of emissions less than that permitted under the Clean Power Plan. For example, if the applicable Clean Power Plan emissions rate were 1200 pounds per MWh in a particular year, and a regulated generator produced 1000 MWh with an emissions rate of 1000 pounds per MWh, the generator would receive 200,000 CRCs for that year.

Regulated generators that emit CO_2 at a rate greater than the Clean Power Plan standard for that year would receive negative credits, using the same approach. Zero-emissions resources (e.g., renewable energy, nuclear energy, or energy efficiency) could also be awarded CRCs; for every MWh produced by an eligible zero-emissions generator or saved by eligible energy efficiency measures in a given year, the program could provide credits equal to the applicable Clean Power Plan emissions for that year. For example, assuming again that the applicable emissions rate were 1200 pounds per MWh in a particular year, if an eligible renewable resource produced 1000 MWh or an eligible efficiency measure reduced consumption by 1000 MWh, it would be awarded 1,200,000 CRCs.

The CRC Program would accommodate trading, either intrastate or interstate, to enable excess reductions from one facility to be used for compliance at a deficient facility. Demonstrating compliance under the CRC Program would require a regulated generator to retire an amount of credits equal to the amount of negative credits, if any, that it has accumulated during a compliance period. For example, if a generator receives 100,000 negative CRCs, the generator would need to acquire 100,000 CRCs from some other party and retire those credits.

The CRC Program is designed to be developed incrementally, starting with individual state programs that over time would be able to link together into multistate and regional efforts (if states decided to pursue that outcome). An alternative compliance payment feature could be added to the program design if necessary to protect electricity customers from excessive rate impacts.

Resources for the Future has also proposed a similar rate-based trading program, which the group calls a "tradable standard."[61] Given the similarities, the details of the tradable standard concept will not be presented here. Interested readers are encouraged to review Resources for the Future's discussion paper. Other observers have suggested that a "fleet average emission rate" approach could be applied to power plants in specific state or regional jurisdictions. This approach would establish and enforce an overall target carbon dioxide emission rate for EGUs based on the model implemented for motor vehicle corporate average fuel economy standards. Covered individual plants might emit at a level significantly higher or significantly lower than the target rate, but as a group they would be required to meet the target rate.

4. GHG Emissions Reductions

The foundational premise underlying market-based emissions trading programs is that regulators determine *a priori* the aggregate level of emissions (or emissions reductions) that is to be achieved by the policy. Market

60 Michel, S. and Neilsen, J. (2014) *Carbon Reduction Credit Program: A State Compliance Tool for EPA's Clean Power Plan Proposal*. Western Resource Advocates.

61 Burtraw, D., Fraas, A., & Richardson, N. (2012, February). *Tradable Standards for Clean Air Act Carbon Policy*. Resources for the Future. Discussion Paper RFF DP 12-05. Available at: http://www.rff.org/rff/Documents/RFF-DP-12-05.pdf.

mechanisms are then unleashed as the means of achieving the expressed goals at least cost. And although it is certainly possible that regulators could establish a cap-and-trade policy that includes caps that prove to be unattainable, this hypothetical problem has not been observed with respect to existing programs. Instead, the record to date for existing GHG cap-and-trade programs is one in which policy goals of fairly modest ambition have proven to be achievable, and the costs of compliance have consistently been less than was forecasted before the programs were implemented. The most notable examples can be found in the EU ETS and RGGI programs.

In phase one of the EU ETS (from 2005 through 2007), the cap (and thus the number of allowances distributed) turned out to be so unambitious that regulated sources had little trouble complying. Very few sources needed to buy allowances, and the market value of allowances eventually fell to zero. In phase two (from 2008 through 2012), the cap was reduced by 6.5 percent, but once again compliance proved to be easier than expected for most regulated sources. This led to a glut of unused allowances and, once again, a drop in allowance prices. Ironically, the minimal value attached to EU ETS allowances in the first two phases was described by many observers as evidence that the program was not changing energy market fundamentals and thus had fallen short of its goals. Reforms were introduced for phase three, which will run from 2013 through 2020, that are intended to bolster short-term allowance prices and motivate more significant and faster changes in emissions. During phase three, the cap will decline by 1.74 percent per year.

Like the European nations participating in the EU ETS, the RGGI states have also experienced the need to adjust their emissions cap. As previously noted, the ten-state RGGI cap for the period from 2009 through 2014 was set at 188 million tons per year, and then the cap was to decline at a rate of 2.5 percent per year for four years from 2015 through 2018. Compliance with the cap turned out to be far easier than expected, a large amount of unused allowances accumulated, and the prices bid for allowances in the regional auctions fell to minimal levels. In 2012, actual emissions from regulated sources in the nine RGGI states plummeted to 91 million tons. Consequently, the RGGI states, in the context of their planned 2012 program review, agreed to reforms for 2014 that reset (lowered) the cap to 91 million tons per year, while retaining and extending the 2.5-percent annual decline in the cap from 2015 through 2020.

One aspect of the RGGI cap-and-invest approach that is not always sufficiently appreciated is that the program achieves GHG reductions separate from and additional to the reductions in the capped sector by reinvesting some of the auction revenues in other sectors. For example, some of the energy efficiency investments that states have made with RGGI auction proceeds have been targeted to reducing the consumption of oil, propane, and natural gas for space heating. This reduces GHG emissions outside of the electricity sector without in any way relaxing the cap. It is a promising result and one that cannot be achieved if allowances are allocated for free, as in other cap-and-trade programs.

5. Co-Benefits

There are two different ways to think about the co-benefits of market-based GHG emissions reduction programs. If one assumes that the desired emissions reductions must happen *by some means* and then compares the results of a market-based approach to command-and-control alternatives, the co-benefits are virtually all economic benefits. Economic theory (and the demonstrated record to date) suggests that a market-based approach will achieve results at a lower cost, generating direct and indirect economic and employment impacts. On the other hand, one could focus on the actions taken by regulated entities to reduce GHG emissions and comply with an emissions cap. Almost any action that will help sources comply with a GHG cap will simultaneously reduce emissions of other air pollutants and other environmental impacts, and contribute to public health improvements.

The two cap-and-trade examples illustrated in this chapter have a proven record of providing significant co-benefits. Throughout all of the chapters of this document, we have considered "co-benefits" to be the non-GHG benefits that derive from a GHG emissions reduction technology or policy. Because the Acid Rain Program is not a GHG reduction program, we don't consider its tremendous impact on criteria air pollutant emissions to be a "co-benefit" but we will briefly note some of the public health benefits associated with the program. The EPA reports that the Acid Rain Program "reduced SO_2 emissions faster and at far lower costs than anticipated, yielding wide-ranging health and environmental improvements."[62]

62 Refer to the EPA's website, *SO_2 Emission Reductions from Acid Rain Program Sources and Improvements in Air Quality,* at: http://www.epa.gov/captrade/maps/so2.html.

A 2003 Office of Management and Budget study found that the program "accounted for the largest quantified human health benefits – over $70 billion annually – of any federal regulatory program implemented in the last ten years, with annual benefits exceeding costs by more than 40:1 – for every dollar spent on implementing this cap and trade program, 40 dollars are returned in health and environmental benefits."[63]

The RGGI program offers a better illustration of the co-benefits that can be achieved with a market-based GHG emissions reduction program. In February 2014, RGGI reported that investments of RGGI proceeds "to date are projected to return more than $2 billion in lifetime energy bill savings to more than 3 million participating households and more than 12,000 businesses in the region."[64] "These programs are projected to offset the need for approximately 8.5 million MWh of electricity generation, [and] save more than 37 million MMBTU[65] of fossil fuels…."[66]

Conducting an independent study in 2011 of the economic effects of the RGGI's program, the Analysis Group reported that over 16,000 new job-years were being "created as a result of investments made during the first three years of the program."[67] It concluded:

> Based on the initial three years of experience from the nation's first mandatory carbon control program, market-based programs are providing positive economic impacts while meeting emission objectives. The pricing of carbon in Northeast and Mid-Atlantic electricity markets has been seamless from an operational point of view and successful from an economic perspective.[68]

The full range of co-benefits that can be realized through market-based GHG reduction programs is summarized in Table 24-4. Most of the potential co-benefits are only likely to be achieved if a market-based program generates revenues that are invested in energy efficiency or other clean energy programs.

Table 24-4

Types of Co-Benefits Potentially Associated With Market-Based Programs

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
Nitrogen Oxides	Yes
Sulfur Dioxide	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	Maybe
Economic Development	Maybe
Other Economic Considerations	Maybe
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	Maybe
Avoidance of Uncollectible Bills for Utilities	Maybe
Benefits to the Utility System	
Avoided Production Capacity Costs	Maybe
Avoided Production Energy Costs	Maybe
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Maybe
Avoided Transmission Capacity Costs	Maybe
Avoided Distribution Capacity Costs	Maybe
Avoided Line Losses	Maybe
Avoided Reserves	Maybe
Avoided Risk	Maybe
Increased Reliability	Maybe
Displacement of Renewable Resource Obligation	Maybe
Reduced Credit and Collection Costs	Maybe
Demand-Response-Induced Price Effect	Maybe
Other	Maybe

6. Costs and Cost-Effectiveness

In general, cap-and-trade programs have proven to be cost-effective mechanisms for decreasing pollutants including carbon. They allow regulated entities to weigh all available options and choose the least-cost means of compliance. They also allow differential costs of emissions reduction between two regulated entities to be exploited to

63 Supra footnote 62.

64 RGGI. (2014). RGGI Investments Provide Region's Families and Businesses with $2 Billion in Lifetime Energy Bill Savings. [Press release]. Retrieved from: http://www.rggi.org/docs/PressReleases/PR022414_2012ProceedsReport.pdf.

65 MBTU stands for one million BTUs, which can also be expressed as one decatherm (10 therms). MBTU is occasionally expressed as MMBTU, which is intended to represent a thousand thousand BTUs.

66 Supra footnote 63.

67 Supra footnote 32 at page 6.

68 Ibid.

the benefit of both parties.

The Acid Rain Program has been rigorously analyzed, and has enough of a track record to determine the cost-effectiveness of the program. Entities subject to the Acid Rain Program have successfully used least-cost approaches including lowering emissions by fuel switching from high-sulfur content Illinois Basin and Appalachian coal to low-sulfur coal produced in the Powder River Basin.[69] In addition to fuel switching, entities also can acquire allowances and install emissions controls to comply with the program. Before the electric industry restructuring in the mid 1990s, generators were able to rely on integrated utilities with utility commission approval to pay for these investments.

One study estimated the program's benefits at $122 billion annually in 2010, while cost estimates were approximately $3 billion annually (in 2000 dollars).[70] The study also recognized that these benefits included additional mercury reductions and health benefits attributable to reduced fine particle and ozone pollution. In 2007, annual ecological and health benefits resulting from the Acid Rain Program emissions reductions were estimated at $142 billion (2006 dollars) by 2010, compared with annual compliance costs of $3.5 billion.[71]

In 2011, the Analysis Group produced a comprehensive evaluation of the costs and benefits (and thus the cost-effectiveness) of the RGGI cap-and-invest program through the first three years:

> Our analysis tracks the path of RGGI-related dollars as they leave the pockets of generators who buy CO_2 allowances, show up in electricity prices and customer bills, make their way into state expenditure accounts, and then roll out into the economy in one way or another. Our analysis is unique in this way – it focuses on the actual impacts of economic activity: known CO_2 allowance prices; observable CO_2 auction results; dollars distributed to the RGGI states; actual state government decisions about how to spend the allowance proceeds; measurable reductions in energy use from energy efficiency programs funded by RGGI dollars; traceable impacts of such expenditures on prices within the power sector; and concrete value added to the economy.[72]

The Analysis Group found that power plant owners spent $912 million to purchase CO_2 allowances in the first three years of RGGI, but the reinvestment of these revenues by states added $1.6 billion in *net* economic value to the region.[73]

7. Other Considerations

Market-based approaches to electric sector carbon management should not be disruptive of electric system reliability because they open the door to a broad range of flexible compliance options. These approaches allow states to consider various emissions reduction options and can drive compliance from actions taken within the power plant fence-line, including improvements in heat rate, fuel switching, and other operational efficiencies, as well as actions taken beyond the fence such as energy efficiency, renewable resources, and changes in dispatch. Because market-based programs do not impose a standard that must be met solely by actions taken at individual units, they can avoid outcomes that could threaten system reliability reminiscent of command-and-control regulation, in which significant amounts of generating capacity are put in the position where they are unable to produce power owing to being out of service to install control equipment.

Emissions sources subject to cap-and-trade programs also have the flexibility to avoid a group of regulatory issues that sometimes arise in relation to compliance with federal New Source Review preconstruction permitting requirements or New Source Performance Standards, each of which could impose significant compliance costs. A command-and-control approach that imposes technology standards or unit-specific performance standards requiring plant modifications and new construction could trigger

69 Refer to Chapter 9 of this document for more information on fuel switching under the Acid Rain Program.

70 Chestnut, L., & Mills, D. (2005). *A Fresh Look at the Benefits and Costs of the US Acid Rain Program.* Journal of Environmental Management, Vol. 77. Pages 252–266. Available at: http://www.epa.gov/airmarkt/presentations/docs/jemarpbenefitsarticle.pdf.

71 Napolitano, S., Schreifels, J., Stevens, G., Witt, M., LaCount, M., Forte, R., & Smith, K. (2007). *The US Acid Rain Program: Key Insights From the Design, Operation, and Assessment of a Cap-and-Trade Program.* The Electricity Journal, Vol. 20, Issue 7. Available at: http://www.epa.gov/airmarkets/resource/docs/US%20Acid%20Rain%20Program_Elec%20Journal%20Aug%202007.pdf.

72 Supra footnote 32.

73 Ibid.

these additional regulatory requirements. A cap-and-trade program, as noted earlier, affords sufficient flexibility to emissions sources, allowing them to avoid triggering compliance obligations with these other programs.[74]

In developing a regulatory program and choosing a startup date, policymakers often have to make concessions for early action, that is, efforts made that are consistent with the program that has yet to get underway. The rationale behind recognizing early action is that a program should not discourage early action by regulated entities simply because they might not get credit before a program begins, nor should it penalize actors for having taken positive steps before a program's startup. There are examples of air programs recognizing and accommodating consistent early actions by related pollution control programs.

The NO_X Budget Trading Program credited early actions, as did RGGI.[75] The NOx Budget Trading Program allowed states to receive compliance allowances for distribution to emissions sources during the startup phase of the program for the purpose of rewarding early NO_X reduction for actions that had taken place before the start of the NO_X budget program.[76] RGGI likewise made provisions to recognize CO_2 early reductions that took place in the two years before the 2009 program startup date in member states. RGGI adopted a two-part approach in which in order to get credit one had to demonstrate both a reduction in mass emissions (total tons reduced), and a reduction in emissions rate (pounds of CO_2 per MWh). The two-part test ensured that early reduction credits would not be awarded simply for a reduction in capacity utilization (i.e., lower emissions resulting from an economic downturn) or conversely for reducing one's emissions rate while increasing capacity utilization. To the extent that emissions increased from capacity utilization, RGGI required those amounts of emissions to be subtracted from the overall emissions number for which the emitter sought credit.

In addition to the two-part test for early action credits, RGGI also accommodated the State of Massachusetts, which had a CO_2 reduction regulation (310 CMR 7.29) in place before the RGGI program's inception. The accommodation essentially allowed Massachusetts emissions sources that had invested in the 7.29 Program to exchange program "credits" for RGGI allowances. This was done with a "set-aside" account, which ensured that these emissions came out of the state's total allowance budget.

It is also important to recognize that market-based solutions are imposed on markets that can be very dynamic and subject to various factors that affect how markets operate. As noted, in the case of the Acid Rain Program and RGGI, there are many factors that can affect power markets. Railroad deregulation and the subsequent availability of low-sulfur Powder River Basin coal disrupted the Eastern market for higher-sulfur content Illinois Basin and Appalachian coal. The availability of industry-proven compliance technology affected generators' choices. Similar compliance technology driven by New Source Performance Standards affected new capacity that displaced older, higher-emitting units.

The RGGI states were able to lower their cap considerably in response to lower emissions in the region, owing in part to greater availability of natural gas-fired generation replacing coal-fired units. Weather and an underperforming economy characterized by reduced demand for electricity were other factors. Foresight by the RGGI states to conduct a 2012 review, after the initial three-year compliance period, allowed them to take stock of their program and the relevant market conditions, and to reset the RGGI cap to better reflect regional emissions.

74 For example, where a unit engages in construction that exceeds 50 percent of the capital cost that would be required to construct a comparable new facility, the unit could become subject to a determination that the modification resulted in it being effectively a new unit, thereby triggering New Source Performance Standards requirements.

75 See, e.g., NOx SIP Call Final Rule, 63 Fed. Reg. 57,356, 57,428–29 (October 27, 1998).

76 The allowances issued were for use only within a limited time. Refer to: Foster, J., & Tarr, J. (2014). *Promoting Innovative and Clean Energy Technology Deployment in Conjunction With GHG Regulation of Stationary Sources Under Section 111 of the Clean Air Act.* NI R 14-01. Durham, NC: Duke University.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on market-based programs.

- Burtraw, D., Fraas, A., & Richardson, N. (2012, February). *Tradable Standards for Clean Air Act Carbon Policy.* Resources for the Future. Discussion Paper RFF DP 12-05. Available at: http://www.rff.org/rff/Documents/RFF-DP-12-05.pdf.
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- European Commission. (2013, October). *The EU Emissions Trading System* (EU ETS). Available at: http://ec.europa.eu/clima/publications/docs/factsheet_ets_en.pdf.
- Hibbard, P., Tierney, S., Okie, A., & Darling, P. (2011, November). *The Economic Impacts of the Regional Greenhouse Gas Initiative on Ten Northeast and Mid-Atlantic States.* Analysis Group. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Economic_Impact_RGGI_Report.pdf.
- Regional Greenhouse Gas Initiative. (2013). *Model Rule.* Available at: http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Model_Rule_FINAL.pdf.
- US Environmental Protection Agency. (2003, June). *Tools of the Trade: A Guide to Designing and Operating a Cap and Trade Program for Pollution Control.* Office of Air and Radiation. EPA 430-B-03-002. Available at: http://www.epa.gov/airmarkt/resource/docs/tools.pdf.
- Michel, S. and Neilsen, J. (2014) *Carbon Reduction Credit Program: A State Compliance Tool for EPA's Clean Power Plan Proposal.* Western Resource Advocates.

9. Summary

The use of a market-based regulatory approach like a cap-and-trade model by the EPA and the states provides policymakers with important insights into the effectiveness and limitations of such a mechanism as part of a GHG reduction strategy for the electric sector. The cap-and-trade approach demonstrates the value of allowing regulated entities the flexibility to meet requirements in a manner that best suits their specific needs. As noted, Acid Rain units have used various approaches or combinations of approaches to reduce their emissions in the most cost-effective manner. At a program design level, the Acid Rain Program has demonstrated that giving emissions sources a choice in the manner in which they comply can lead to cost-effective solutions without compromising environmental goals.

The use of the cap-and-invest variant of cap-and-trade by the RGGI states provides policymakers with important insights into the effectiveness of this mechanism as part of a GHG reduction strategy for the electric sector. The cap-and-invest approach demonstrates the value of a coordinated effort to both discourage the use of carbon-intensive resources and to encourage alternatives. Complementary policies that reduce the cost of achieving emissions reduction goals under the cap are able to spur emissions reductions from activities that are not covered or are not sufficiently incentivized solely by a carbon price mechanism.

At a program design level, the RGGI experience demonstrates the importance of getting the cap and the baseline right, and a willingness to make necessary adjustments mid-course in a fashion that results in a carbon price that can be expected to affect operational and investment decisions in the electric sector. The emissions limit should reflect actual emissions levels in order to create a clear and sustained incentive to reduce emissions.

Because of the significance of complementary policies in a cap-and-invest framework, auctioning allowances, instead of freely allocating them, has emerged as a key component in an effective carbon cap mechanism. Auctioning creates a level playing field for program participants and new entrants, as well as the critical funding source for complementary policies, such as those that promote energy efficiency and renewable energy — programs that lower the overall program price and provide economic benefits in the region in which they operate.

In reviewing results of RGGI's first three-year compliance period, the Analysis Group reached the following conclusions:

> The use of RGGI allowance revenues has produced positive economic impacts while administration of the RGGI program has proceeded smoothly. Thirteen auctions have been held, and the auctions resulted in the distribution of the majority of available allowances. Allowances have been traded in the secondary market throughout the first compliance period, and the market monitor has found no evidence of market power in the RGGI auctions or the secondary market. Allowance revenues were quickly and efficiently distributed to states, and states have disbursed nearly all of the allowance revenues for various uses. The carbon cap established by RGGI has been met (in part because of

stagnant economic conditions). RGGI, Inc. and the states have effectively tracked the use of allowance proceeds, and states continue to work cooperatively towards evolution of the program.

In short, based on a review of RGGI's first three years, it would seem that the design, administration, and implementation of a market-based carbon control mechanism can be an effective way to control carbon emissions, while potentially providing additional economic and policy benefits.[77]

77 Supra footnote 32.

Chapter 25. Tax Carbon Dioxide Emissions

1. Profile

Pricing mechanisms can be an important element in any effort to reduce electric-sector greenhouse gas (GHG) emissions. Pricing will be most effective when combined with related policies to encourage the use of other, less carbon-intensive resources. Policies that provide a real or implicit price of carbon internalize the cost of carbon emissions and can make renewables or other low-carbon resources more cost-competitive with other energy sources. This in turn creates incentives for producers and consumers to invest in low GHG products, technologies, and processes. Policies that provide a carbon price can also serve as a source of revenue for funding low-carbon technologies and programs.[1]

In its Fourth Assessment Report, the Intergovernmental Panel on Climate Change suggests that carbon prices have mitigation potential in all sectors. Modeling studies show that global carbon prices rising to $20 to $80 per metric ton of carbon dioxide (CO_2)-equivalent (CO_2-e) by 2030 are consistent with stabilization at around 550 ppm CO_2-e in the atmosphere by 2100.[2] Although this range of prices would seem politically infeasible in the United States, it is not necessary or even prudent to rely on a pricing mechanism alone. A carbon pricing policy can be combined with complementary measures to significantly lower the cost of achieving a given level of carbon reduction. Pricing mechanisms can work well in the context of market-based approaches, for example, which are discussed in Chapter 24.

Taxes and emissions caps are the two primary policy tools for placing a price on carbon emissions, and they can be applied to a specific sector or economy-wide. A tax provides price certainty, although the resulting quantity of emissions reduced may vary. A cap, on the other hand, provides certainty on the quantity of emissions to be reduced, but prices (and costs to emitters and consumers) are difficult to predict. Another mechanism for introducing a price on carbon emissions in the power sector is the use of a carbon adder in evaluating supply resources. This mechanism could be used to alter the order in which power plants are dispatched (discussed in Chapter 21) or incorporated into integrated resource planning (discussed in Chapter 22).

Carbon taxes have existed internationally for several decades, and more recently have been considered and implemented in limited contexts in the United States.[3] Any governmental entity – local, state, or federal – may seek to reduce CO_2 emissions through the levy of a tax on that pollution.

Economists characterize this approach as a "Pigovian tax" – a tax designed to reduce negative externalities associated with an activity – in this case, the consequences of putting carbon in the atmosphere.[4] The degree to which a carbon tax could reduce CO_2 emissions is determined in large part by the relationship between the level of the carbon tax and the cost of reducing emissions. In theory, reductions costing less than the tax would be implemented by emitters. An economically efficient tax would be set to equal the marginal benefit of reducing emissions (i.e., the cost of the damage avoided). Determining that number is no small task, however. The marginal benefit of reducing carbon emissions – also known as the "social cost of carbon" – is discussed in Section 6.

1 See the discussion of cap-and-invest in Chapter 24.

2 For the same stabilization level, induced technological change may lower these price ranges to $5 to $65 per metric ton of CO_2-e equivalent in 2030. See: IPCC (2007) Climate Change 2007: Synthesis Report. Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Pachauri, R. K. & Reisinger, A.(eds.)]. IPCC, Geneva, Switzerland.

3 See: Sumner, J., Bird, L., & Smith, H. (2009, December). *Carbon Taxes: A Review of Experience and Policy Design Considerations.* National Renewable Energy Laboratory. Technical Report NREL/TP-6A2-47312.

4 So named after British economist Arthur C. Pigou, who originated this concept in the early 1900s.

There are numerous advantages attributable to a carbon tax. In a 2008 survey of the literature, the Congressional Budget Office concluded that the "net benefits … of a tax could be roughly five times those of an inflexible cap."[5] Revenue generation is one key benefit because tax proceeds can be used to lessen the price of other goods or services, or returned to taxpayers who have the least ability to modify their behavior in the face of a carbon tax.[6] Price stability is another benefit. When compared with a cap-and-trade program whose prices can vary significantly, a carbon tax provides a relatively stable price upon which compliance entities can plan.[7]

As a policy mechanism, a carbon tax and its benefits and drawbacks are frequently discussed in comparison with cap-and-trade systems.[8] A key criticism of a carbon tax is that it cannot provide the same certainty with regard to the level of emissions reductions that will occur that a cap-and-trade program can provide. This puts a carbon tax at a distinct disadvantage compared to several other policy options that states might use for complying with federal regulations for CO_2 emissions from existing power plants. In addition, a carbon tax, like all taxes, is often viewed with skepticism politically.

2. Regulatory Backdrop

Point of regulation is one way of thinking about how a carbon tax might be applied. A carbon tax can be focused on upstream, midstream, or downstream entities relative to their positions in the supply chain of producing and consuming fossil fuels. An upstream tax might apply to coal mines, oil wells, and the like, whereas a midstream approach might be directed at fossil fuel-fired power plants and industrial facilities. A downstream tax would apply to the ultimate consumers of fossil fuels (e.g., electric and natural gas customers and vehicle drivers).

In general, the further downstream a tax is applied, the greater the number of covered sources there would be, and hence the more extensive the administrative requirements. For example, in 2009 there were only 150 petroleum refineries in the United States, but there were 211 million drivers.[9] This does not mean that carbon pricing proposals always address upstream operators, however. There may be good reasons to choose a point of regulation further downstream, including the presence of existing infrastructure to facilitate administration or the desire to focus on or exclude certain sectors of the economy.

At whichever level a carbon tax may be enacted, mandatory reporting by covered sources is essential to the success of the tax. If, for example, the tax applies to sales of coal or gasoline, there must be some reporting of how many tons of coal or gallons of gasoline are sold. Additional questions might include how often covered sources need to report, to whom they report, and how that information would be shared with the tax administrator. Other important questions include whether there should be verification of reporting and a penalty for noncompliance, and whether the public should have access to these data. Depending on the point of regulation, existing reporting and taxation infrastructure may already be sufficient. For example, fossil electricity generators currently report their CO_2 emissions to the Environmental Protection Agency (EPA), thereby providing a sound basis on which to impose a carbon-related tax.[10]

Based on the EPA's proposed rule from June 2014, carbon taxes are one mechanism that could be available

5 In other words, a cap-and-trade program without, for example, banking or other cost containment mechanisms typically found in those programs. Congressional Budget Office. (2008, February). *Policy Options for Reducing CO_2 Emissions.*

6 The Congressional Budget Office assumes that revenue generation is not necessarily a part of a cap-and-trade program.

7 For example, over the period of 2006 to 2013, Acid Rain Program sulfur dioxide (SO_2) allowances have traded on the spot market at prices between $860.00 and $0.17. Although these changes are not necessarily examples of price volatility or even price instability, they still do constitute significant variations. EPA. (2014). *Acid Rain Program Allowance Auctions.* Available at: http://www.epa.gov/airmarkets/trading/auction.html

8 Nordhaus, W. D. (2007). *To Tax or Not to Tax: Alternative Approaches to Slowing Global Warming.* Review of Environmental Economics and Policy. 1(1), pp. 26–44. See also: Morris, A., & Mathur, A. (2014, May). *A Carbon Tax in Broader US Fiscal Reform: Design and Distributional Issues.* Available at: http://www.c2es.org/publications/carbon-tax-broader-us-fiscal-reform-design-distributional-issues#endnote43.

9 See: https://www.census.gov/compendia/statab/2012/tables/12s1114.pdf; http://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_nus_a.htm.

10 See: http://www.house.leg.state.mn.us/hrd/pubs/ss/ssgastax.pdf

to states for complying with emissions guidelines for CO_2 emissions from existing power plants. (This proposal is often referred to as the proposed "111(d) rule," because the EPA is citing its authority under section 111(d) of the Clean Air Act; it is also referred to as the EPA's "Clean Power Plan.") However, under the EPA's proposal, states would be required to demonstrate how their compliance plans are expected to achieve specified emissions rates for affected sources. As noted in Section 1, the difficulty in using a carbon tax for this purpose is that the emissions reductions that will occur as a result of any specific level of taxation are difficult to predict. It would thus be challenging for states to demonstrate that a carbon tax will result in compliance with the specified emissions rates.

3. State and Local Implementation Experiences

The most comprehensive carbon tax in North America is at the provincial level in British Columbia (BC). This tax was enacted in 2008 and is based on the following principles:[11]

- All carbon tax revenue will be "recycled" by dedicating it to reductions in other taxes;
- The tax rate will start low and increase gradually;
- Low-income individuals and families will be protected;
- The tax will have the broadest possible base; and
- The tax will be integrated with other measures.

Every three years, BC's Minister of Finance is required to prepare a plan showing how the revenues from the tax will be recycled back to taxpayers through reductions in other taxes. In the current plan, the revenue is returned through a combination of measures, including corporate and personal income tax reductions and tax credits to low-income residents and homeowners in northern and rural BC.[12]

The level of BC's carbon tax was established as follows:

Table 25-1

British Columbia's Carbon Tax[13]

Effective Date	Dollars per Metric Ton CO_2-e*
July 1, 2008	$10
July 1, 2009	$15
July 1, 2010	$20
July 1, 2011	$25
July 1, 2012	$30

In Canadian dollars.

The tax is applied on the consumption of fossil fuels, however, so it is necessary to translate it into the amount per unit of fuel. This translation is shown in Table 25-2.

Table 25-2

British Columbia's Carbon Tax by Fuel Type

Fuel Type	Unit for Tax Rate*	Tax Rate as of July 1, 2008[14]	Tax Rate as of July 1, 2012[15]
Gasoline	¢/liter	2.41	6.67
Diesel	¢/liter	2.76	7.67
Jet Fuel	¢/liter	2.62	7.83
Natural Gas	¢/gigajoule	49.88	148.98
Propane	¢/liter	1.53	4.62
Coal, Canadian Bituminous	$/ton	20.79	62.31
Coal, Sub-bituminous	$/ton	17.72	53.31

In Canadian dollars.

BC's carbon tax has been in place for six years and all available evidence indicates it has been successful.[16] It received a 64-percent approval rating in a 2012 poll,[17] and is credited for effectively reducing provincial gasoline consumption.[18] It covers approximately 70 percent of the province's GHG emissions, exempting carbon emissions from biofuels, landfills, air and marine travel outside the province, and certain industrial facilities.[19] Per capita fossil fuel combustion is down and the economy has performed

11 BC Budget and Fiscal Plan: http://www.bcbudget.gov.bc.ca/2008/bfp/2008_Budget_Fiscal_Plan.pdf

12 See: http://bcbudget.gov.bc.ca/2014/bfp/2014_budget_and_fiscal_plan.pdf#page=74

13 Supra footnote 11.

14 Ibid.

15 See: http://www.fin.gov.bc.ca/tbs/tp/climate/A4.htm

16 Horne, M., & Sauve, K. (2014, November 5). *The BC Carbon Tax Backgrounder.* Available at: http://www.pembina.org/pub/the-bc-carbon-tax

17 See: http://www.theguardian.com/sustainable-business/2014/jul/28/carbon-tax-australia-british-columbia-business-revenue-neutral

18 Rivers, N., & Schaufele, B. (2013, June 10). *Salience of Carbon Taxes in the Gasoline Market.* Available at: http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2131468

19 Supra footnote 11.

well relative to the rest of Canada. The policy has survived two provincial elections and a change in Premier. No studies have identified significant negative impacts.[20]

Finland, Netherlands, Norway, Sweden, Denmark, the United Kingdom, and Quebec are among the provinces and nations that also have or have had carbon taxes. Reports produced by the National Renewable Energy Laboratory (NREL) and Resources for the Future provide further details on these programs and are listed in Section 8.

In the United States, the city of Boulder, CO was the first municipality to tax CO_2. In 2006, voters approved a measure to levy a carbon charge on electricity use, and then renewed the tax at increased rates in 2012.[21] Although it is ostensibly a tax on carbon, Boulder's tax is, in fact, applied to electricity consumption. The ordinance, however, exempts the amount of wind-powered electricity that Boulder residents purchase from their power company, focusing instead on more carbon-intensive sources of electricity.

The current rate is \$0.0049 per kilowatt-hour (kWh) for residential customers, \$0.0009 per kWh for commercial customers, and \$.0003 per kWh for industrials.[22] Boulder directs these revenues to fund its Climate Action Plan, which includes, among other things, programs to promote energy efficiency and renewable energy.[23]

There continues to be interest in implementing carbon taxes in the United States. Oregon, for example, is investigating a carbon tax similar to BC's.[24] The legislature commissioned a state carbon tax study that is due in late 2014 and may result in proposed legislation in the 2015 session.[25] The tax level to be analyzed in the report starts at \$10 per ton of CO_2-e and escalates by \$10 per year until it reaches \$60 per ton. A citizens' initiative has also been active in Washington State under the name of Carbon Washington (www.carbonwa.org), developing state legislation that it hopes to introduce in an upcoming legislative session, perhaps as early as 2015.

Prominent economists, both Republican and Democratic, have endorsed the idea of a carbon tax as an effective way to address climate change, and several carbon tax proposals have been made in Congress. In 2013, US Senators Sanders and Boxer introduced the Climate Protection Act of 2013. The Act would have taxed fossil fuels based on their carbon content at the rate of \$20 per metric ton of CO_2 starting in 2014 and increasing 5.6 percent per year through 2023.[26] Two discussion drafts of alternative carbon taxes have also been released; one in 2013 by US Representative Waxman and US Senator Whitehouse, and another in 2014 by US Representative Delaney.[27] None of these proposals have yet been enacted.

4. GHG Emissions Reductions

The NREL, in reviewing nine carbon tax programs in 2009, observed that, "while the primary purpose of carbon taxes is to reduce GHG emissions, most existing carbon policies introduce no processes or specific requirements to evaluate policy effectiveness in reducing emissions...."[28] The NREL study concluded that making a determination as to overall carbon reductions attributable to a tax is especially difficult because numerous factors other than the

20 Supra footnote 16.

21 Meltzer, E. (2012, November 6). Boulder Issue 2A: Votes approve carbon tax extension by wide margin. *Boulder Daily Camera.* Available at: http://www.dailycamera.com/ci_21941854/boulder-issue-2a-carbon-tax-appears-likely-be

22 Boulder City Code: http://www.colocode.com/boulder2/chapter3-12.htm

23 Community Guide to Boulder's Climate Action Plan: https://www-static.bouldercolorado.gov/docs/community-guide-to-boulders-climate-action-plan-1-201305081129.pdf

24 Oregon lawmakers call for carbon tax study. (2013, December 6). *The Register-Guard.* Available at: http://registerguard.com/rg/news/30881173-76/story.csp

25 Liu, J. H. and Renfro, J. (2013) *Carbon Tax and Shift: How to make it work for Oregon's Economy.* Northwest Economic Research Center Report. http://www.pdx.edu/nerc/carbontax2013.pdf. See also http://gov.oregonlive.com/bill/2013/SB306/

26 Wara, M. W., Cullenward, D., Wilkerson, J. T., & Weyant, J. (2013, June 18). *Analysis of the Climate Protection Act of 2013.* Stanford Law and Economics Olin Working Paper No. 459. Available at SSRN: http://ssrn.com/abstract=2392656 or http://dx.doi.org/10.2139/ssrn.2392656. An analysis of the bill estimates that it would reduce CO_2 emissions from energy consumption by 16.8 percent below 2005 levels in 2020, return \$744 billion in rebates to households over ten years, and result in impacts to GDP of less than one half of one percent in 2020.

27 For a comparison of all three draft bills, see: http://www.c2es.org/publications/carbon-pricing-proposals-113th-congress

28 Supra footnote 3. NREL examines carbon taxes in Finland, Netherlands, Norway, Sweden, Denmark, United Kingdom, Quebec, British Columbia, and Boulder, CO. See id. at Table 6.

tax itself can affect emissions. Economic changes and other programs directed at carbon reduction or clean energy promotion are examples of such factors.[29]

Despite this difficulty, jurisdictions use various metrics to characterize emissions reductions from carbon taxes. A common approach relies on the use of emissions inventories, although as noted earlier, this approach captures not only emissions reductions attributable to a tax, but also those that may have resulted from other reasons, including other carbon policies or unrelated macroeconomic factors. Modeling can also be used to characterize the effectiveness of a tax at reducing emissions. Taking this approach, a 2013 Resources for the Future study found that a tax of $20 per ton at the federal level could reduce emissions 12 to 13 percent from business as usual and a tax of $50 per ton could reduce emissions 22 to 24 percent.[30]

5. Co-Benefits

The scope of a carbon tax's co-benefits will depend on the details of the tax. For instance, if the tax were sufficient to promote fuel switching from coal to natural gas, then air quality-related co-benefits would likely materialize. In a 2001 study, Resources for the Future found that a tax of $25 per ton would result in likely ancillary benefits of $13 to $14 per ton of carbon.[31] These benefits arose from avoided abatement costs for sulfur dioxide (SO_2) and nitrogen oxide (NO_X), as well as health-related impacts.

Other types of co-benefits also hinge on the nature of the policy implemented. A 2012 study by the Brookings Institution found that when revenues from a $15 per ton carbon tax are directed toward deficit reduction, lump-sum rebates to households, or payroll tax reduction, gross domestic product (GDP) and employment would shrink slightly on net.[32] When directed toward reducing corporate taxes, however, GDP and employment would increase for several

Table 25-3

Types of Co-Benefits Potentially Associated With Carbon Taxes

Type of Co-Benefit	Provided by This Policy or Technology?
Benefits to Society	
Non-GHG Air Quality Impacts	Yes
NO_X	Yes
SO_2	Yes
Particulate Matter	Yes
Mercury	Yes
Other	Yes
Water Quantity and Quality Impacts	Maybe
Coal Ash Ponds and Coal Combustion Residuals	Maybe
Employment Impacts	Possible disbenefit
Economic Development	Maybe
Other Economic Considerations	No
Societal Risk and Energy Security	Maybe
Reduction of Effects of Termination of Service	No
Avoidance of Uncollectible Bills for Utilities	No
Benefits to the Utility System	
Avoided Production Capacity Costs	No
Avoided Production Energy Costs	No
Avoided Costs of Existing Environmental Regulations	Maybe
Avoided Costs of Future Environmental Regulations	Yes
Avoided Transmission Capacity Costs	No
Avoided Distribution Capacity Costs	No
Avoided Line Losses	No
Avoided Reserves	No
Avoided Risk	Maybe
Increased Reliability	No
Displacement of Renewable Resource Obligation	No
Reduced Credit and Collection Costs	No
Demand-Response-Induced Price Effect	No
Other	

29 The observation about the difficulty of attributing emissions reductions to the tax is broadly true for any type of mass-based emissions reduction policy. For example, as noted in Chapter 24, the costs and emissions reductions attributable to a cap-and-trade program can also be significantly affected by various external forces.

30 Carbone, J. C., Morgenstern, R. D., Williams, R. C., III, and Burtraw, D. (2013, August). *Deficit Reduction and Carbon Taxes: Budgetary, Economic, and Distributional Impacts.* An RFF Report. Available at: http://www.rff.org/RFF/Documents/RFF-Rpt-Carbone.etal.CarbonTaxes.pdf

31 Dallas, B., Krupnick, A., Palmer, K., Paul, A., Toman, M., & Bloyd, C. (2001, December). *Ancillary Benefits of Reduced Air Pollution in the United States from Moderate Greenhouse Gas Mitigation Policies in the Electricity Sector.* RFF Discussion Paper. Available at: http://www.rff.org/Documents/RFF-DP-01-61.pdf

32 McKibbin, W., Morris, A., Wilcoxen, P., & Cai, Y. (2012, July 24).*The Potential Role of a Carbon Tax in US Fiscal Reform.* Climate and Energy Economics Discussion Paper. Available at: http://www.brookings.edu/~/media/Research/Files/Papers/2012/7/carbon%20tax%20mckibbin%20morris%20wilcoxen/carbon%20tax%20mckibbin%20morris%20wilcoxen.pdf

decades relative to projected baseline performance.

The full range of co-benefits that might be realized through carbon taxes are summarized in Table 25-3.

6. Costs and Cost-Effectiveness

As mentioned in Section 1, the most efficient carbon tax would be set at a price reflecting the marginal benefit of reducing CO_2 emissions. Put differently, an environmental policy is considered economically efficient when the cost of reducing one more unit of pollution is equal to the benefit of doing so. This marginal benefit is also called the "social cost of carbon" (SCC).

Although reasonably straightforward from a theoretical perspective, calculating the SCC is enormously difficult in practice. It requires an analyst to make assumptions about the stock of CO_2 in the atmosphere over many years, the nature of climate change's impacts to the environment and economy and, because this occurs over a long period of time, a discount rate.[33] As a result, there are a wide range of SCC estimates.

In the United States, the use of an SCC number is not just an academic exercise; it is used in cost-benefit analyses for a wide variety of federal initiatives from appliance standards to vehicle fuel economy standards. The federal government determines its own SCC, and in 2013 it updated its estimates to $46 per ton of CO_2 in 2020, assuming a three-percent discount rate (in 2011 dollars).[34]

7. Other Considerations

There are a number of implementation-related considerations that raise questions about the suitability of a carbon tax for the electric sector. For example, a carbon tax may be designed to apply to a broad economic base or just a single industry. Research on this topic tends to conclude that covering multiple sectors would reduce costs, but this could raise the possibility of "leakage" (i.e., emissions increases in non-covered sectors as a result of economic activity shifting to avoid sectors subject to the tax).[35] For instance, if electric heating is taxed but natural gas heating is not, consumers may shift toward natural gas heating, increasing emissions from that sector. Leakage can occur geographically across borders as well. If one state taxes gasoline but a neighboring state doesn't, increased purchases of gasoline – and associated emissions – can be expected in the latter state.

The inability to cover all sources is one of the reasons that pricing CO_2 emissions, regardless of the mechanism used, may not in and of itself be sufficient to address climate change. Market failures also suggest the need for "complementary policies."[36] Complementary policies like end-use energy efficiency programs help address barriers that a carbon tax cannot. Examples of these barriers include split incentives, such as when the builder of a new home is not the owner and therefore has no incentive to spend more on energy-efficient design, or tenant-landlord issues in which tenants are reluctant to invest in property they don't own, and landlords are little concerned because they don't pay the energy bill for the property. Lack of basic information can also be a barrier when, for example, homeowners do not recognize that the purchase of a more efficient refrigerator would lower their electric bills.[37]

Broadly applied, a carbon tax could also be "regressive," with disproportionate effects on lower-income segments of the affected population. By returning the revenue collected to taxpayers in the form of tax credits or other support, however, regressive impacts can be mitigated or even reversed.[38]

33 The discount rate assumes that we value a dollar in the future less than a dollar today. By the same token, damage from climate change would be more costly today than the same damage would be in the future.

34 See: http://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf, and http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf

35 Pizer, W. *Scope and Point of Regulation for Pricing Policies to Reduce Fossil-Fuel CO_2 Emissions: Issue Brief 4*. Available at: http://www.rff.org/RFF/Documents/CPF_6_IssueBrief_4.pdf

36 Because of the focus here on a carbon tax policy, the term "complementary policy" implies policies of secondary value. This, however, would be a mistaken interpretation. Complementary policies have the potential to be lower cost and more effective. See the discussion of market-based approaches in Chapter 24.

37 Western Climate Initiative, see: http://www.westernclimateinitiative.org/document-archives/Complementary-Policies-Committee-Documents/Final-Complementary-Policies-Whte-Paper/ Market failures are not limited to electricity production; complementary policies can also include such sectors as transportation, agriculture, and industry.

38 Williams, R. C., III, Gordon, H., Burtraw, D., Carbone, J. C., & Morgenstern, R. D. (2014, August). *The Initial Incidence of a Carbon Tax Across Income Groups*. RFF. Available at: http://www.rff.org/RFF/Documents/RFF-DP-14-24.pdf

Addressing this inequality could help to create a broad base of support for a tax.[39,40] However, there are good reasons to also devote revenue to carbon reduction measures such as research in and development of clean technologies and implementation of complementary energy efficiency programs. Doing so can also reduce the cost of the policy, making a carbon tax more politically palatable.[41]

There are also a number of implementation-related considerations that are specific to electricity markets in the United States and the manner in which electricity is sold. In 2008 and 2009, when Congress started considering developing a nationwide carbon policy, a number of critiques of carbon pricing in organized wholesale markets emerged identifying reasons a carbon tax might be a less than optimal carbon policy to apply in parts of the country.[42] This is partly attributable to the manner in which electricity is sold in the United States, and the disproportionately high cost that a carbon tax could impose on some ratepayers.

Only part of the electric power produced in the United States comes from traditionally regulated electricity markets. In these vertically integrated utility service areas, fossil generators subject to a tax would be able to pass through their direct costs via rate cases under traditional cost-of-service regulation. These utilities could charge consumers only their direct compliance costs.

In "restructured" or "organized" markets, however, a large amount of the power generated is provided by merchant generators not subject to rate regulation. In these markets, the effect of a carbon tax would be to raise the clearing price of all power sold in the market, including power from plants that have no carbon costs (e.g., nuclear, wind). As a result, a carbon tax that might be reasonably applied in the portion of the nation with traditionally regulated markets could confer windfall gains on generators and inequitable results for consumers in restructured areas of the country. In short, "whether firms can pass through the entire cost of the tax and emissions abatement to their customers depends on how prices are determined in their market."[43]

A second cause for concern about the suitability of a carbon tax for the electricity sector has to do with the actual manner in which carbon reductions in the electric sector could occur. Compliance controls for conventional pollutants like SO_2 and NO_X are different from those available for carbon reduction. With conventional pollutants, reductions can usually be achieved by generators at power stations through changes in fuel inputs — switching to low-sulfur coal, for example — or "end-of-pipe" plant modifications, such as scrubbers or selective catalytic reduction. In contrast, there may currently be limited economic practicality in adding a carbon scrubber to a conventional power plant.[44] As explained in Chapters 1 and 9, limited operational efficiencies at fossil plants and

39 Supra footnote 38.

40 Harrison, K. (2012). *A Tale of Two Taxes: The Fate of Environmental Tax Reform in Canada.* Review of Policy Research. 29(3). Available at: http://www.standupeconomist.com/pdf/carbon/2012.Harrison.TaleofTwoTaxes.pdf

41 Burtraw, D., & Setraw, S. (2013, October). *Two World Views on Carbon Revenues.* RFF Discussion Paper. Available at: http://www.rff.org/rff/Documents/RFF-DP-13-32.pdf

42 For a more extensive critique of carbon pricing effects in organized wholesale markets, see Testimony of Sonny Popowski, Consumer Advocate of Pennsylvania, Subcommittee on Energy and Environment, US House Energy and Commerce Committee, March 12, 2009; see also: Cowart, R. (2008). *Carbon Caps and Efficiency Resources.* 33 Vermont Law Review 201–223.

43 Morris, A., & Mathur, A. (2014, May). *A Carbon Tax in Broader US Fiscal Reform: Design and Distributional Issues.* Available at: http://www.c2es.org/publications/carbon-tax-broader-us-fiscal-reform-design-distributional-issues#endnote43

44 Scrubbing emissions of conventional pollutants may not materially alter the carbon content of the emission stream. As discussed further in Chapter 7, carbon capture and storage (CCS) has the potential to be a long-term carbon management solution in the electric sector. For example, on September 3, 2014, Power Engineering reported that the EPA has approved permits allowing FutureGen Industrial Alliance Inc. to inject CO_2 underground in Illinois. See: "FutureGen project approved to sequester carbon underground." Available at: http://www.power eng.com/articles/2014/09/futuregen-project-approved-to-sequester-carbon-underground.html?cmpid=enl-poe-weekly-september-04-2014. While, at present, CCS appears too costly to be considered a readily available and economic add-on option for existing power plants, CCS linked with enhanced oil recovery opportunities, despite uncertain net carbon benefits, is more likely to be economical. "CO_2-Enhanced Oil Recovery (EOR) storage has a 'negative cost' because of the value of the additional crude oil produced." Current State and Future Direction of Coal-fired Power in the Eastern Interconnection, Final Study Report. (2013, June). ICF Incorporated For EISPC and NARUC, Funded by the US Department of Energy. Page 35. Available at: http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf

fuel switching and co-firing are available alternatives, but they also come with challenges.

As the EPA outlined in the broad definition of "best system of emission reduction" embodied in its proposed Clean Power Plan, reductions in carbon intensity will come not only from generation sources, but also from actions taken by power buyers. These actions include substituting gas or renewables in the resource mix of a load-serving entity or adding more efficiency and reducing consumption generally. For these reasons, it is apparent that a carbon tax — owing to the manner in which electricity is sold in many parts of the country, and the limited ability of individual power plants to invest in and produce significant (and economic) emissions reductions — will need to be thoroughly vetted against other compliance options before being implemented.

8. For More Information

Interested readers may wish to consult the following reference documents for more information on carbon taxes:

- Aldy, J. E., & Stavins, R. N. (2011, October 27). *The Promise and Problems of Pricing Carbon: Theory and Experience.* The Journal of Environment and Development. Available at: http://www.rff.org/RFF/Documents/RFF-DP-11-46.pdf
- *Testimony of Sonny Popowski, Consumer Advocate of Pennsylvania.* Subcommittee on Energy and Environment, US House Energy and Commerce Committee. (2009, March 12).
- Ramseur, J. L., Leggett, J. A., & Sherlock, M. F. (2012, September 17). *Carbon Tax: Deficit Reduction and Other Considerations.* Congressional Research Service. Available at: http://fas.org/sgp/crs/misc/R42731.pdf
- Sumner, J., Bird, L., & Smith, H. (2009, December). *Carbon Taxes: A Review of Experience and Policy Design Considerations.* National Renewable Energy Laboratory. Technical Report NREL/TP-6A2-47312.
- Cowart, R. (2008). *Carbon Caps and Efficiency Resources.* 33 Vermont Law Review, 201–223.
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9. Summary

David Stockman, former Congressional Budget Office director under President Reagan, has said, "If you want less of something, tax it more." Conceptually, carbon taxes can help correct the negative externalities associated with climate change, but taxing emissions is likely to have some economic consequences. Recycling of tax revenues, however, can help ensure that the tax is equitable and effective. The choice of these will impact such important questions as whether the tax is politically palatable and whether it positively or negatively impacts the economy. Although, in certain contexts, the level of the tax and its coverage of sources is a strong predictor of its success in reducing emissions, complementary policies must be included if a government seeks to correct market failures that promote CO_2-emitting activities.[45] The special market and technological contexts in which a carbon tax would be imposed on electricity producers should also be thoroughly analyzed.

45 Carbon tax revenues could be used, for example, to fund weatherization, energy efficiency improvement projects, and the installation of zero-carbon emitting generation.

26. Consider Emerging Technologies and Other Important Policies

1. Introduction

The previous chapters offer a wide array of options to reduce greenhouse gas (GHG) emissions from the electric power sector through existing technology-based and policy-oriented solutions. The electricity sector is undergoing dramatic change, however, morphing from an analog unidirectional system to a digital multidirectional system. Traditional unidirectional systems are characterized by centralized electric generating units (EGUs) providing electricity to end-users through radial transmission and distribution grid networks. These systems have historically managed supply in order to meet demand. By contrast, currently emerging digital multidirectional systems will utilize distributed grid networks and manage both supply and demand through two-way communications and smart devices.

These changes will profoundly alter the electric power system as we have known it for the last century. Neither the form these changes take, nor their impacts and ramifications, are predictable or understandable at this point in any accurate or comprehensive way. However, several technology and policy trends and developments are increasingly evident. Although some may not achieve material penetration in the existing electric power system for a decade or more, many are already becoming widely commercialized. Because major air quality regulatory processes often operate on decadal timescales,[1] it is important to introduce several of these developments for regulators' awareness in air quality planning. The sections that follow do so, first for technology considerations and then for policy considerations.

It is also important to note that new technologies and new policy ideas regularly arise over the course of time. Those that follow do not represent a compilation of all such considerations, let alone a prediction of future ones. Furthermore, this list is intended to serve merely as an introduction to each of these developments rather than an exhaustive treatment of each.

2. Other Technology Considerations

Many new capabilities and increased efficiencies in the entire electric power system – from generation through end-uses – are being driven by the application of advanced digital and communications technologies. Others are emerging from enhanced data capture and analysis, better imaging and research capabilities, and new scientific discoveries and their application. Several of these technologically driven developments are covered in this chapter. Note that their order does not represent any kind of prioritization in terms of commercialization likelihood, time frame, or importance.

2.1. Energy Storage

Recent improvements in energy storage and power electronics technologies coupled with changes in the electricity marketplace are expanding opportunities for electricity storage as a cost-effective electric energy resource. Some analysts suggest, in fact, that we are nearing an inflection point in battery storage, with the economics of lithium-ion batteries unlocking new business opportunities that were unavailable just a few years ago. These in turn drive development efforts to, among other things, evaluate storage solutions as alternatives to future peaking needs. In conjunction with improving component costs, declining costs of capital, and the potential for utilities to rate-base the investment, factors are ripe for continued growth in storage as the market nears a tipping point on storage deployment.[2] Figures 26-1 and 26-2 illustrate the breadth

1 For example, the interval necessary for revising a National Ambient Air Quality Standard (NAAQS), adopting regulations to attain it, implementing and enforcing those regulations, and conducting the research necessary for the next periodic NAAQS review regularly exceeds ten years.

2 Dumoulin-Smith, J. (2014, December 8). *US Electric Utilities & IPPs: The Storage Inflection Point?* UBS.

Figure 26-1

New Storage Opportunities Are Beginning to Proliferate in Front of the Meter[3]

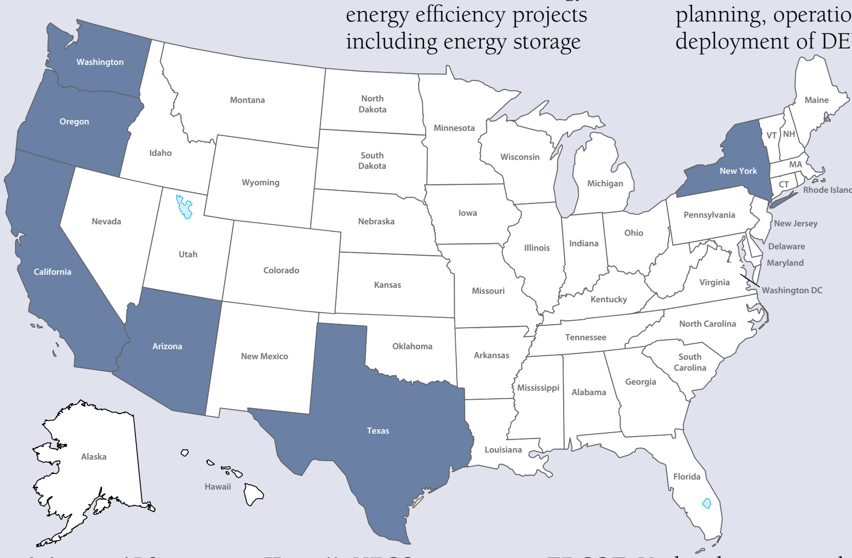
Oregon: Department of Energy sought comments to assist with development of storage demonstration RFP

Washington: Department of Energy awarded $15 million to three utilities for storage demonstration projects

US: DOE announced a $2.5 million solicitation (with additional funding up to $4 billion) in loan guarantees toward renewable energy and energy efficiency projects including energy storage

New York: Con Edison and PSEG Long Island procuring storage for T&D deferral; NYSERDA providing funding for storage technology startups in addition to microgrid projects; New York PSC reforming regulation to facilitate planning, operations, and market-based deployment of DERs, including storage

California: CPUC mandating 1.3 GW of storage by 2020; SCE, PG&E and SDG&E issued relevant RFOs; SCE also procured 100.5 MW through LCR and SDG&E issued LCR RFOs (which count toward the mandate), capacity requirements driving more procurements than the mandate so far; PG&E and SCE issued RPS RFOs for utility-scale renewables paired with storage; CPUC proceeding to improve utility distribution resource planning in 2015



PJM: Seeing consistent deployments for ancillary services; developing new capacity performance requirements for resources including storage

Arizona: APS to procure upward of 10 MW of storage; TEP to procure up to 10 MW

Hawaii: HECO considering three battery storage projects of 60 MW to 200 MW

ERCOT: Undertaking comprehensive redesign of ancillary service market to allow participation in the market and appropriately value fast-acting resources such as storage within three years; Oncor sponsored study showing value of utility-controlled distributed energy storage in Texas

of storage opportunities now being explored both "in front of the meter" and "behind the meter."[3]

Energy storage incorporates a variety of technology types that deliver four broad categories of energy services:

1. *Bulk energy services* (e.g., supply capacity, utility-scale time-shifting);
2. *Ancillary services* (e.g., regulation, spinning, non-spinning, and supplemental reserves, voltage support, black start, and the like);
3. *Transmission and distribution infrastructure services* (e.g., transmission/distribution upgrade deferral, avoided investments, reduced congestion); and
4. *Customer energy management services* (e.g., enhanced quality and reliability, retail time-shifting, and so forth).[4]

In what is known as stacked services, a single storage system can provide a combination of services, allowing it to become economically viable by capturing multiple revenue streams. These stacked configurations can be designed on a case-by-case basis, depending on location within the grid and the specific technology capabilities.[5]

Energy storage could be a key component of a comprehensive strategy to reduce GHG emissions from the power sector. Storage can reduce GHG emissions directly by providing bulk energy and ancillary services to replace

3 GTM Research and Energy Storage Association. (2015, February 20). *US Energy Storage Monitor: 2014 Year In Review: Executive Summary.* Available at: http://www.greentechmedia.com/research/us-energy-storage-monitor

4 Eyer, J., & Corey, G. (2010, February). SAND2010-0815 *Energy Storage for the Electricity Grid: Benefits and Market Potential Assessment Guide: A Study for the DOE Energy Storage Systems Program.* Sandia National Laboratories. Available at: http://www.sandia.gov/ess/publications/SAND2010-0815.pdf

5 See: California Public Utilities Commission. R.10-12-007, *Rulemaking to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems.* Available at: http://www.cpuc.ca.gov/PUC/energy/electric/storage.htm

Figure 26-2

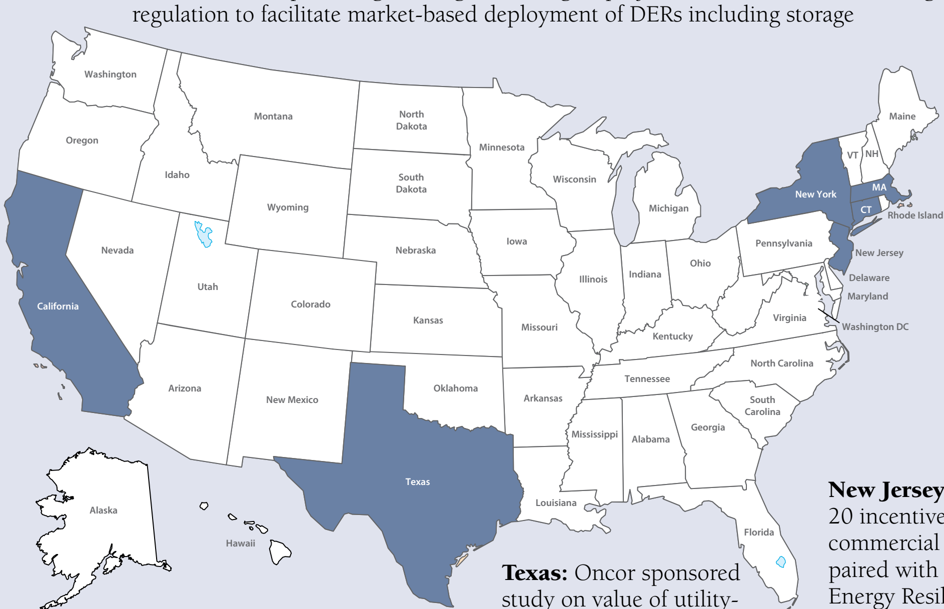
New Storage Opportunities Are Beginning to Proliferate Behind the Meter[6]

US: DOE reviewing applications for $15 million funding opportunity targeting behind-the-meter PV and solar integration

New York: Con Edison soliciting 85 MW of load management including battery and thermal storage across two programs; PSEG Long Island may issue similar RFP; NYSERDA providing funding for microgrid projects; New York PSC reforming regulation to facilitate market-based deployment of DERs including storage

Massachusetts: $25.8 million grant awarded to various microgrid projects, many including battery storage; MassCEC awarded $150,000 for demonstration of utility-controlled residential battery systems

California: CPUC's SGIP program to continue through 2020 on $83 million annual budget, 4 MW of non-residential and 0.15 MW of residential projects have received upfront incentive; SCE procured 160.6 MW of behind-the-meter storage (135 MW battery storage) through LCR



Connecticut: $2.9 million grant awarded to municipal microgrid project including 100 kW of battery storage

New Jersey: BPU reviewing 20 incentive applications for commercial storage systems paired with renewable generation; Energy Resiliency Bank accepting applications for backup power systems for critical facilities

Hawaii: HECO contracted with Stem for 1 MW of storage for C&I customers with PV

Texas: Oncor sponsored study on value of utility-controlled distributed (including behind-the-meter) energy storage in Texas

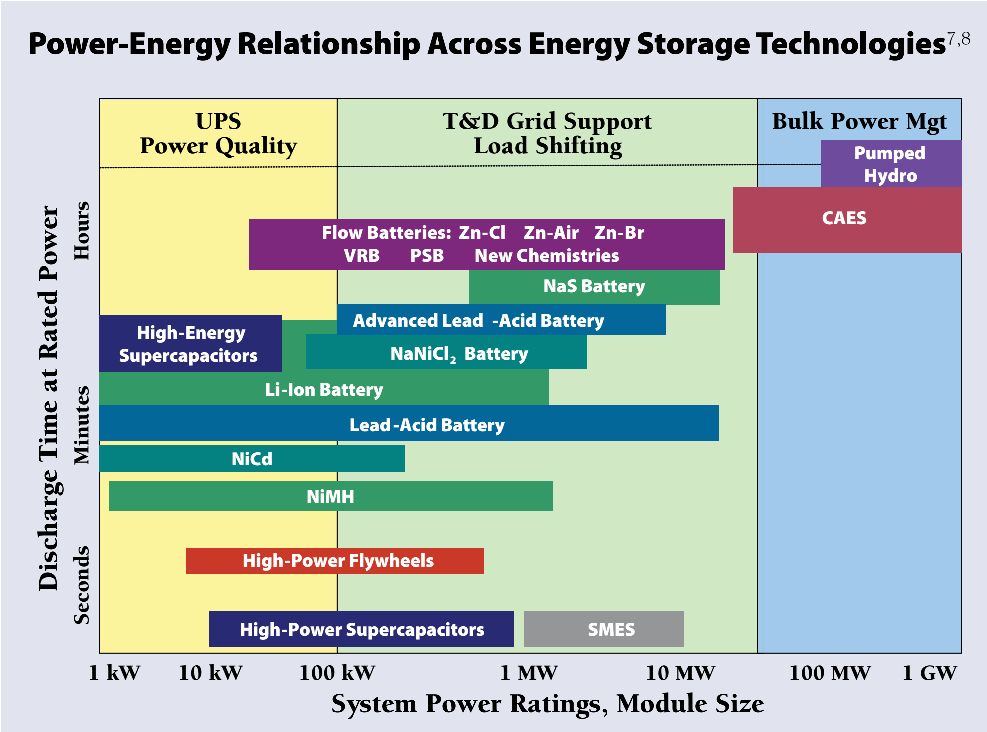
high-emitting resources, such as fossil fuel peaking units and conventional load-following/ramping units. Storage can also help mitigate emissions indirectly by providing ancillary services to help integrate variable renewable energy resources into the grid. Storage can provide time-shifting services by charging devices when electricity prices are low – including when renewables are producing excess energy that would otherwise be curtailed – and discharging from them when prices are high. This can help reconcile the discrepancy between peak demand and peak renewable output, which can become an issue for portfolio managers at high penetrations of variable renewable generation.

At present, viable storage opportunities have been primarily limited to pumped hydro and compressed air. Pumped hydro is a mature, utility-scale technology that takes advantage of off-peak electricity to pump water to a high elevation reservoir, from where it can be released and run through a hydroelectric turbine to generate electricity in peak hours. Compressed air energy storage (CAES) uses off-peak electricity to compress and store air, either belowground in manmade or natural caverns, or aboveground in tanks. When needed, the compressed air can be heated and expanded to generate electricity via an expansion turbine or in conjunction with a conventional gas turbine. To date, there are two existing commercial CAES plants, one in Germany and the second in Alabama. A number of second-generation facilities are currently planned or under development.

CAES and pumped hydro fit a similar profile of bulk storage services, capable of long discharge durations (>10 hours) at large sizes (15 to 1000 megawatts [MW]). Storage technologies can be classified according to this relationship between discharge time and power rating, as demonstrated conceptually in Figure 26-3, which shows that the majority of storage technologies (e.g., electrochemical batteries and flywheels) are better suited to shorter and rapid discharge times at lower power ratings.

6 Supra footnote 3.

Figure 26-3



Note that Figure 26-3 is intended as an illustration of this relationship and that many of the technology options shown can have broader applications than the figure characterizes.[9] Storage for utility-scale time-shifting (energy arbitrage) or storage tied to large variable power facilities (or groups of facilities) would fall in the upper right on Figure 26-3 at the higher end of the size and duration times. Alternatively, storage used for time-shifting smaller-scale wind farms or solar photovoltaic (PV) applications would fall on the left, at the lower end of size and duration times.

Bulk storage is especially complementary to solar generation. In a 2014 study examining strategies for integrating large amounts of variable energy resources, researchers at Lawrence Berkeley National Laboratory found that the value of PV and wind increase dramatically with availability of low-cost bulk power storage on the system.[10,11]

Discussion about "storage" often defaults to mean "storage of electricity," but electricity is used to provide energy services (heating, cooling, lighting, driving motors, and so on). Rather than storing electricity to provide such energy services

7 Sandia National Laboratories. (2013, July). *DOE/EPRI 2013 Electricity Storage Handbook in Collaboration with NRECA.* Available at: http://www.sandia.gov/ess/publications/SAND2013-5131.pdf

8 CAES = Compressed Air Energy storage; Li-Ion = Lithium Ion battery; NaNiCl2 = Sodium Tetrachloroaluminate battery; NaS = Sodium Sulfur battery; NiCd = Nickel Cadmium battery; NiMH = Nickel Metal Hydride battery; PSB = Polysulfide Bromide battery; SMES = Superconducting Magnetic Energy Storage; T&D = Transmission and Distribution; UPS = Uninterruptible Power Supply; VRB = Vanadium Redox Battery; Zn-Air = Zinc Air battery; ZnBr = Zinc Bromine battery; ZnCl = Zinc Chloride battery.

9 For greater technical detail on storage technology types, see full report: supra footnote 7. See also: State Utility Forecasting Group. (2013, June). *Utility Scale Energy Storage Systems: Benefits, Applications, and Technologies.* Available at: http://www.purdue.edu/discoverypark/energy/assets/pdfs/SUFG/publications/SUFG%20Energy%20Storage%20Report.pdf

10 Wiser, R., & Mills, A. (2014, March). *Strategies for Mitigating the Reduction in Economic Value of Variable Generation With Increasing Penetration Levels.* Lawrence Berkeley National Laboratory. Available at: http://eetd.lbl.gov/sites/all/files/lbnl-6590e.pdf

11 Among other strategies considered (e.g., flexible conventional generation, real-time pricing, and variable resource diversity), low-cost bulk power storage was found to increase marginal values of PV by 80 percent at a 30-percent penetration level. The bulk power storage analyzed – modeled on pumped hydro storage with ten hours of storage capacity – would be charging during times with PV generation and have the effect of driving up prices during those times. Results for wind were positive but less substantial than solar. Lawrence Berkeley National Laboratory modeling found an 11-percent increase in the value of wind at a 40-percent penetration level, in comparison to a scenario without low-cost storage. The low-cost bulk storage mitigation measure assumes that pumped-hydro storage with ten hours of storage capacity can be built with a much lower investment cost than was assumed in the reference scenario, $700/kilowatts-year, based on the cost of new pumped-hydro storage from the Energy Information Administration (2011).

at a later time, electricity can be converted to an alternative energy carrier and then stored in that form for direct use later. One of the most promising opportunities along these lines is thermal storage (e.g., water heating) in homes and businesses to shift electricity use from peak periods and/or to capture and store solar and wind generation when it is available. With water heating responsible for more than 17 percent of residential energy demand, the tens of millions of electric water heaters across the country represent a large opportunity for load control.[12] As is already being done by many rural cooperatives and other utilities, grid operators can shift water heating from morning and evening peak demand times to mid-day and overnight, when wind and solar may be underutilized. Using existing capacity, water can be "supercharged" to higher temperatures during off-peak times, and moderated through blending valves to achieve desired temperatures.[13] One million electric water heaters are roughly equivalent to 4000 MW of dispatchable load, yielding as much as 10,000 megawatt-hours (MWh) per day that could be shifted as needed.[14]

Another promising load-shifting strategy involves thermal storage associated with air conditioning units under grid operator control. Central air conditioners and large cooling systems can incorporate two hours of thermal storage in the form of chilled water and ice. Commercially available and being deployed today, these units allow ice-making during the hours of maximum solar output to meet demand for cooling later in the evening.[15]

Over a longer-term horizon, electrical batteries will offer opportunities for storage, but at the 2014 cost of $700 to $3000 per kilowatt-hour (kWh) of installed electricity storage, they remain expensive.[16] Some analysts predict 50-percent declines in cost over the next three years; other analysts forecast even larger cost reductions.[17] Initial market transformation is being driven by activities at the state level, including notably a 2013 energy storage mandate by the California Public Utility Commission requiring the state's three investor-owned utilities to add 1.3 gigawatts (GW) of cost-effective energy storage to their grids by 2020.[18] In the first competitive procurement process by Southern California Edison, storage proposals exceeded expectations, with 264 MW of storage capacity selected, including a 100-MW lithium-ion battery (with four-hour output duration) to replace older conventional peaking units.[19]

12 US Department of Energy. (2011). *Residential Energy Consumption Survey 2009.* Available at: http://www.eia.gov/consumption/residential/

13 Lazar, J. (2015, February 15). *Thermal Energy Storage: A Low-Cost Option for Electricity Storage.* Presentation at NARUC's 2015 Winter Committee Meetings. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.narucmeetings.org/Presentations/Winter2015%20Lazar.pdf

14 Lazar, J. (2014, January). *Teaching the "Duck" to Fly.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6977

15 In accordance with CPUC D.13-02-015, Southern California Edison selected 25.6 MW offered through 16 contracts in the West Los Angeles Basin for behind-the-meter thermal energy storage from Ice Energy Holdings, Inc. Gross, D. (2015, January 9). Long May You Run. *Slate.* Available at: http://www.slate.com/articles/business/the_juice/2015/01/battery_and_storage_infrastructure_is_the_next_growth_area_for_energy_here.html

16 UBS Global Research. (2014, October 2). *US Electric Utilities & IPPs: The Storage Opportunity.* Available at: https://neo.ubs.com/shared/d1vn32UwCm8eh; Supra footnote 7.

17 Byrd, S., Radcliff, T., Lee, S., Chada, B., Olszewski, D., Matayoshi, Y., Gupta, P., Rodrigues, M., Jonas, A., Mackey, P. J., Walsh, P. R., Curtis, M., Campbell, R., & Gosai, D. (2014, July 28). *Morgan Stanley Blue Paper – Solar Power & Energy Storage: Policy Factors vs. Improving Economics.* Available at http://energystorage.org/resources/morgan-stanley-blue-paper-solar-power-energy-storage-policy-factors-vs-improving-economics

18 California Public Utilities Commission. (2013, October 17). *Decision 13-10-040: Decision Adopting Energy Storage Procurement Framework and Design Program.* Available at: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M079/K533/79533378.PDF

19 Southern California Edison. *Pursuant to D. 13-02-015, Local Capacity Requirements Request for Offers, Selected Resource List.* Available at: https://www.sce.com/wps/portal/home/procurement/solicitation/lcr/!ut/p/b1/rVTBcpswEP0VXzzTHmQtSIB0JDVjw3jsJqSTwMU-jZJnQAsJA4rhfX0zcyfQQ43Ssk3bn6Wn37ZvFMX7Ec-SleslS0mS5Ffoxjex34U9eYUdNf3RgeuKHPpt7cg3Bld-4CoA8AHx4Vz778tbPyAYxzLsq3aJxw1Uq2lLltVtmtVjuF-0H4MqVZ0eRlWt5XOtij7X6DyTWdtX2owh11LkIykq-0SUPo1rtnrM3aDP6ksv66_GjSmYbHBFBqLmRCbISCxA-1JEOcbAniwhaUc5IYpnFq7EzlA8L0jQ0w9ACDzdy5H4I-PzoKDf_P9zuP3nDCHnAB8Bt48WIE_u78l4JNbWIauSwD-MpxRP8Bxmuukn2TklglhKY5rtVW1qidPumnx436_n6Rap-7maSF3gqOvb-bDqqYnDdyEdJoQSRoIgsQmiwCliDt0g-SR3TlnILlNhDhNa1CZ1PEwZDg-q0y37udrHbWfVoyddOtv_36vkGQvqPxBd5dYDQujah82nC4II9ckWJL1kHVfGjYOSAft3Nfy-2yyUSCQNi5S9FsX6LDvs_7AAmZw!!/dl4/d5/L2dBI-SEvZ0FBIS9nQSEh/#/accordionGrp2-4

Other developments in Texas bode well for the growing viability of battery storage. Building on the results of a study by the Brattle Group, which found broad benefits to Electric Reliability Council of Texas customers from grid-integrated distributed electricity storage,[20] Texas utility Oncor is seeking regulatory approval to invest in 5 GW of energy storage, including $2 billion in battery storage predicated on declining battery costs.[21] Another commercial project underway in Illinois uses two 19.8-MW batteries to provide real-time frequency regulation service to the PJM Interconnection ancillary services market.[22]

As greater segments of the transportation sector are electrified, electric vehicle (EV) batteries are another grid-integrated storage application that holds promise for low-cost grid support services.[23] With high ramping capabilities and the ability to shift loads over many hours, aggregated EV batteries can offer demand response and ancillary services to help accommodate variable energy resources and replace fossil fuel consumption in the transportation sector. Various pilot projects around the country, including those spearheaded by the Department of Defense (e.g., at Los Angeles Air Force Base, California; Joint Base Andrews, Maryland; Fort Hood Army Base, Texas; Joint Base McGuire-Dix-Lakehurst, New Jersey; and Fort Carson, Colorado) are exploring the benefits and costs of EV grid support across different utility and market environments.[24]

As the costs of many of these technologies steadily decline and storage becomes an increasingly important component of resource portfolios, market and regulatory frameworks also need to follow suit to allow the benefits of energy storage, both distributed and centralized, to be adequately evaluated and compensated. This may mean allowing utilities to include energy storage investments in their rate base, giving the right to own storage assets to transmission and distribution utilities, modifications to ancillary service markets, or other things in different utility market structures. These issues are explored in recent studies by the National Renewable Energy Laboratory (NREL), which provides more detail on valuing energy storage and overcoming related market and policy barriers.[25]

2.2. Smart Grid

The term "smart grid" refers to a vision of a future power grid in which new types of information technology and other technological improvements are integrated into the existing power delivery system to enable more visibility, control, coordination, and management of both the existing grid and new assets, such as increased levels of renewables, customer-sited resources, electricity storage, and others. This information technology is envisioned to be provided by high-speed, two-way communications networks between utilities and customers, improved sensing systems, advanced metering infrastructure, energy management and

20 Chang, J., Pfeifenberger, J., Spees, K., Davis, M., Karkatsouli, I., Regan, L., & Mashal, J. (2014, November). *The Value of Distributed Electricity Storage in Texas: Proposed Policy for Enabling Grid-Integrated Storage Investments.* The Brattle Group, Prepared for Oncor. Available at: http://www.brattle.com/system/news/pdfs/000/000/749/original/The_Value_of_Distributed_Electricity_Storage_in_Texas.pdf?1415631708

21 Klump, E. (2014, November 12). Texas Utility Sees Benefit in Potential $2B Battery Storage Rollout. *EnergyWire.* See: http://www.eenews.net/stories/1060008712

22 PV Magazine. (2014, November 11). *RES Americas to Build 40 MW of Energy Storage System in Illinois.* Available at: http://www.pv-magazine.com/news/details/beitrag/res-americas-to-build-40-mw-energy-storage-system-in-illinois-_100017126/#ixzz3SaInSmbS

23 Energy and Environmental Economics, Inc. (2014, October 23). *California Transportation Electrification Assessment, Phase 2: Grid Impacts.* Available at: http://www.caletc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf

24 Morse, S., & Glitman, K. (2014, April). *Electric Vehicles as Grid Resource in ISO-NE and Vermont.* Vermont Energy Investment Corporation. Available at: https://www.veic.org/documents/default-source/resources/reports/evt-rd-electric-vehicles-grid-resource-final-report.pdf; California Independent System Operator. (2014, February). *California Vehicle Grid Integration Roadmap: Enabling Vehicle-Based Grid Services.* Available at: http://www.caiso.com/Documents/Vehicle-GridIntegrationRoadmap.pdf

25 Denholm, P., Jorgenson, J., Hummon, M., Jenkin, T., & Palchak, D., Kirby, B., Ma, O., & O'Malley, M. (2013, May). *The Value of Energy Storage for Grid Applications.* NREL. Available at: http://www.nrel.gov/docs/fy13osti/58465.pdf; Cappers, P., MacDonald, J., & Goldman, C. (2013, March). *Market and Policy Barriers for Demand Response Providing Ancillary Services in the US Market.* Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/sites/all/files/lbnl-6155e.pdf; Ela, E., Milligan, M., Bloom, A., Botterud, A., Towsend, A., & Levin, T. (2014, September). *Evolution of Wholesale Electricity Market Design With Increasing Levels of Renewable Generation.* NREL. Available at: http://www.nrel.gov/docs/fy14osti/61765.pdf

control systems in buildings, and other technologies that will better coordinate all the pieces of the power delivery system. When fully operational, the technologies will increase the use of and enable the better integration and control of:

- Demand response on end-use devices and systems to reduce the demand for electricity at certain times (discussed in Chapter 23);
- Behavior responses of customers who change their electricity use in response to feedback they receive through smart technologies (discussed in Chapter 13);
- Distributed generation, such as small engine or turbine generator sets, wind turbines, and solar electric systems connected at the distribution level;
- Distributed storage, such as batteries, flywheels, superconducting magnetic storage, and other electric and thermal storage technologies (discussed earlier in this chapter);
- Distribution/feeder automation, such as expanded communications in substations and other parts of the distribution network with remotely actuated switches, dynamic capacitor bank controllers, better transformer-management systems, and so forth;
- Transmission control systems that rapidly sense and respond to disturbances;
- Microgrids, which can disconnect from the traditional grid when it is stressed and thus improve system resiliency; and
- Electric and plug-in electric hybrid vehicles that charge and discharge energy stored in the batteries of the vehicles at appropriate times (discussed elsewhere in this chapter).

Operators of the smart grid (and customers and devices themselves), through the technologically improved electricity delivery system, will be able to actively control and respond in real time to grid conditions by adjusting usage and improving efficiencies in order to meet one or more of several goals. Those goals are varied, but some of the most important are: energy savings and emissions reductions; integrating renewables and other distributed sources into the grid; managing peak load capacity; operating ancillary services; and improving costs, reliability, resiliency, and security.

The potential applications of the smart grid are varied and diverse. For example, a smart grid application could allow a utility to have better awareness and communication of outages, allowing for faster recovery. During capacity-constrained periods, a smart grid application could help deploy distributed energy resources to a greater extent or interrupt commercial and industrial customer loads. Large buildings could use whole-building control systems that would integrate all the energy-using devices within the building and allow building energy managers and utilities to control the devices in real time for optimal energy efficiency or other goals. Large customers that can't afford long outages, such as hospitals and some manufacturers, could use microgrids, increasing the resiliency and security of the grid. The smart grid also could make evaluation, measurement, and verification of energy efficiency and demand response programs easier, because smart meters and other technologies can more accurately record, track, and measure the energy savings impact of the programs.

In order to make the smart grid fully operational, several things need to occur: the improvement and modernization of the grid infrastructure; the addition of the digital communications layer onto the grid; and the business approaches and policy transformations necessary to capitalize on the investments and bring about the other goals of the smart grid. These many parts of the smart grid have been rolling out in pieces in different jurisdictions since the late 1990s and early 2000s. The rate of smart grid adoption varies across the United States, and depends on state policies, regulatory incentives, and technology experience within utilities.

Advanced metering infrastructure has been one of the most frequently deployed elements of the smart grid. Advanced metering infrastructure refers to three components: the smart meters at the point of energy end-use, the communications networks that transmit metered data, and the information management systems used to receive and process these data at utility offices. By 2015, an estimated 65 million smart meters will be installed across the country, representing more than one-third of the US meters of all types in use today.[26] Thirty of the largest utilities in the United States have fully deployed smart meters to their customers.[27] The smart meters so far are being used to produce operational savings for the

26 US Department of Energy. (2014, August). *2014 Smart Grid System Report: Report to Congress.* Available at: http://energy.gov/sites/prod/files/2014/08/f18/SmartGrid-SystemReport2014.pdf

27 Institute for Electric Innovation. (2014, September). *Utility-Scale Smart Meter Deployments: Building Block of the Evolving Power Grid.* Available at: http://www.edisonfoundation.net/iei/Documents/IEI_SmartMeterUpdate_0914.pdf

utilities; to roll out new services such as bill management tools, dynamic pricing, and energy use notifications; to improve outage management systems and restoration services; and to integrate new distributed resources. When combined with customer-based technologies such as programmable thermostats, in-home displays, and building energy management systems, smart meters have the potential to produce higher levels of energy savings. For example, at Oklahoma Gas and Electric, advanced metering infrastructure, time-based rates, and in-home displays are reducing peak demand by an amount that will potentially allow the utility to defer building a 170-MW peaking power plant.[28]

Grid modernization within the distribution system includes the use of smart sensor, communications, and control technologies that create highly responsive and efficient grid operations. These technologies allow operators to locate and isolate faults using automated feeder switches and reclosers, optimize voltage and reactive power levels, and monitor the health of the system. Investments in distribution automation technology are now exceeding investments in smart metering, according to industry analysts.[29]

An important piece of the smart grid is a modernized transmission grid. Investor-owned utilities have substantially increased their transmission investments in the past 15 years. In 2000, annual investment in the transmission infrastructure was less than $4 billion; in 2013, annual investment had jumped to a record $16.9 billion.[30] Although much of this investment was targeted at new transmission infrastructure and replacement of old infrastructure, some of it was targeted at advanced technologies and other grid modernization projects. For example, synchrophasors[31] are an important element in a future resilient smart grid and have received increased attention as a technology that can improve grid reliability and resilience. There were roughly 1700 synchrophasors connected to the US grid in 2014, up from only 200 in 2009.[32] There are a number of other emerging transmission-related technologies that will help monitor and control operations within high-voltage substations and wide-area operations across the transmission grid, including dynamic line ratings, grid-scale energy storage, volt-VAR optimization, high-voltage direct current transmission, high-temperature low-sag transmission lines, and smart solar inverters. Some of these technologies are described in more detail in Chapters 5, 10, and 18.

More smart grid applications are also being deployed and required as a result of the growth in distributed energy resources that has occurred during the past several years, including rooftop solar, combined heat and power, EVs, energy storage, and demand response practices. Two-way power flows are required to optimally use such assets. Interest in microgrids also has increased with growing resilience and sustainability concerns. North American microgrid capacity may reach almost 6 GW by 2020, up from 992 MW in 2013, according to industry analysts.[33]

Many smart grid projects have been deployed since 2010 as a result of the US Department of Energy's American Recovery and Reinvestment Act (ARRA) Smart Grid Program, which facilitated more than $9 billion in public and private investments for smart grid applications. In total, the electric industry spent an estimated $18 billion for smart grid technology deployed between 2010 and 2013 (ARRA and non-ARRA applications).[34] However, there is still a long way to go before the smart grid is fully built out. Estimates of the cost of full build-out vary, and range from $338 to $476 billion over a 20-year period (Electric Power Research Institute estimate) to nearly $900 billion (nominal) for the transmission and distribution investment

28 Supra footnote 26.

29 Ibid.

30 US Energy Information Administration. (2014, September 3). Electricity transmission investments vary by region. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=17811; Edison Electric Institute. (2015, January 8). *Actual and Planned Transmission Investment by Shareholder-Owned Utilities (2008-2017)*. Available at: http://www.eei.org/issuesandpolicy/transmission/Documents/bar_Transmission_Investment.pdf

31 A synchrophasor is a device that measures the electrical waves on an electricity grid, using a common time source for synchronization, allowing for real-time measurements of multiple remote measurement points on the grid. This provides grid operators with a better image of the grid in real time, helping to alert them to grid stress early on, potentially avoiding power outages and maintaining power quality.

32 Chaudhry, U. M. (2014, July). *Survey of Emerging Transmission Technologies*. Americans for a Clean Energy Grid. Available at: http://cleanenergytransmission.org/transmission-technology-series/

33 Supra footnote 26.

34 Ibid.

by 2030 (The Brattle Group estimate).[35]

Smart grid applications, when combined with smart policy and business decisions, have the potential to enable more energy and emissions savings than would otherwise be possible. A 2008 estimate that examined seven smart grid mechanisms found that the applications, if deployed across the United States, could potentially reduce annual energy use by 56 to 203 billion kWh and GHG emissions equivalent to 60 to 211 million metric tons of carbon dioxide (CO_2) by 2030.[36] A 2010 analysis that considered nine smart grid applications found that electricity use and CO_2 emissions in 2030 could be reduced by 12 percent directly through the implementation of smart grid applications, and by a further 6 percent indirectly if cost savings from energy and avoided capacity were further invested in energy efficiency.[37] The many smart grid applications that are now underway will be providing real-life assessments of their impacts during the upcoming years.

2.3. Electric Vehicles

Powering vehicles with electricity offers the chance to reduce or eliminate emissions coming from a vehicle's tailpipe. As a result, steps have been taken by governments and manufacturers to encourage growth in the market for plug-in hybrid EVs (PHEVs) and battery EVs. But the uptake of EVs has been slow, because high initial costs of the vehicles make them less attractive than conventional vehicles with internal combustion engines (ICEs). Moreover, current battery technology does not store enough energy to give EVs the same range as ICE vehicles without the help of an additional source of energy, such as an onboard gasoline-powered engine. In 2013, there were about 70,000 battery EVs and 104,000 PHEVs registered in the United States, a small number compared to the total of 226 million registered vehicles. Nevertheless, the market for EVs has expanded in recent years as manufacturers introduced new EVs and electric versions of existing models.[38] US sales of PHEVs represented about 0.7 percent of new vehicle sales in 2014, up from 0.6 percent in 2013 and 0.4 percent in 2012.[39]

Transportation accounts for 32 percent of total CO_2 emissions from all uses, and passenger vehicles represent the largest share of transportation CO_2 emissions.[40,41] Compared to ICE vehicles, which depend on the combustion efficiency and sophistication of onboard emissions control systems and fuel quality, the emissions attributable to an EV depend on the fuel source, efficiency, and emissions controls on the electric power sources used to charge them. An EV might be charged by solar panels on an adjacent rooftop, or electricity from a coal or nuclear plant hundreds of miles away.

As a result, emissions from EV electricity use vary widely based on the local grid mix, which varies by the time of day and, in certain cases, the time of year. Electricity from high-emitting generators reduces the comparative emissions benefits of EVs over ICE vehicles. EVs move emissions from the tailpipe to the power source (typically an EGU), reducing localized mobile-source emissions where vehicles are driven, but increasing the need to generate electricity elsewhere. Therefore, a robust understanding of the emissions implications of charging strategies is necessary to

35 Supra footnote 26.

36 Electric Power Research Institute. (2008, June). *The Green Grid: Energy Savings and Carbon Emissions Reductions Enabled by a Smart Grid.* Available at: http://www.smartgridnews.com/artman/uploads/1/SGNR_2009_EPRI_Green_Grid_June_2008.pdf

37 Pratt, R. G., Balducci, P. J., Gerkensmeyer, C., Katipamula, S., Kintner-Meyer, M. C. W., Sanquist, T. F., Schneider, K. P., & Secrest, T. J. (2010, January). *The Smart Grid: An Estimation of the Energy and CO_2 Benefits.* Pacific Northwest Laboratory for the US Department of Energy. Available at: https://www.smartgrid.gov/document/smart_grid_estimation_energy_and_co2_benefits

38 M. J. Bradley & Associates for The Regulatory Assistance Project and the International Council on Clean Transportation. (2013, June). *Electric Vehicle Grid Integration in the U.S., Europe, and China: Challenges and Choices for Electricity and Transportation Policy.* Available at: http://www.raponline.org/document/download/id/6645 June 2013.

39 EIA. (2014). *California Leads in the Adoption of Electric Vehicles.* Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=19131

40 US Environmental Protection Agency. (2014). *Overview of Greenhouse Gases, 2014.* Available at: http://www.epa.gov/climatechange/ghgemissions/gases/co2.html

41 E3/ICF. (2014, September). *California Transportation Electrification Assessment, Phase 1: Final Report.* Available at: http://www.caletc.com/wp-content/uploads/2014/09/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf

ensure net emissions reductions from EVs.[42,43]

A Texas EV study found that if vehicle charging is optimized, an EV fleet of up to 15 percent of light duty vehicles could actually decrease EGU nitrogen oxides (NO_X) emissions, even while increasing load. This is because selectively increasing system load allows EGUs to run more efficiently, and allows system operators to deploy more efficient units. The same study found that using the batteries in the EVs to provide "vehicle-to-grid" (V2G) services could also reduce the sulfur dioxide (SO_2) and CO_2 emissions impacts of increased load from charging EVs. V2G services include using EV batteries for spinning reserves, frequency regulation, and energy storage to address peak load.[44] The study did not compare EVs to conventional vehicles, however.[45,46]

EV charging strategies would typically seek to use off-peak electricity from the grid (i.e., nights and weekends). This would enhance the efficiency of the grid by shifting electricity use to off-peak nighttime hours, reducing the difference between off-peak and peak demand levels and allowing EGUs to operate more steadily and efficiently. As noted in Chapter 5, EVs can also be managed to help meet ancillary service needs on the grid as power supply market conditions change (e.g., by turning them off and on, drawing upon them as power "sources," or charging them as power "sinks"). Applying this V2G approach, a large number of EVs – plugged in and aggregated together as a single resource – could serve as a large battery for the grid, balancing variations in load and correcting for short-term changes in electricity use that might otherwise affect the stability of the power system.[47]

The wise application of EV charging strategies can provide benefits beyond peak shifting and the provision of ancillary services to the grid. Through their storage capabilities, EVs can also improve the ability of the grid to absorb higher levels of renewable generation.[48,49] EVs interfaced with the grid in a smart way can help meet balancing requirements associated with growing renewable energy deployment and maximize the amount of renewable energy that can be exploited without compromising grid robustness. Ultimately EVs and V2G could serve as twin pillars to boost renewables and simultaneously improve the overall performance of the grid.[50,51]

As also noted in Chapter 5, several questions associated with the Environmental Protection Agency's (EPA) proposed Clean Power Plan (CPP) must be addressed before EVs will contribute fully to grid optimization. States choosing a mass-based pathway for complying with the CPP, for example, could be discouraged from pursuing large-scale EV penetration because emissions from EGUs (which

42 Supra footnote 38.

43 US EPA. (2014). *Greenhouse Gas Emissions for Electric and Plug-In Hybrid Vehicles.* Available at: http://www.fueleconomy.gov/feg/Find.do?zipCode=82001&year=2014&vehicleId=34699&action=bt3

44 "Spinning reserves" are generation resources that are kept on standby and are able to provide capacity to the grid when called by the system operator. "Frequency regulation" is a service, typically provided by a power plant, which system operators use to maintain a target frequency on a power grid. Signaled, a frequency-regulating unit will either increase or decrease its output or load to rebalance system frequency.

45 Supra footnote 38.

46 Sioshansi, R., & Denholm, P. (2009, January). Emissions Impacts and Benefits of Plug-In Hybrid Electric Vehicles and Vehicle-to-Grid Services. *Environ Sci Technol* 43(4):1199–1204. Available at: http://pubs.acs.org/doi/abs/10.1021/es802324j

47 PJM Interconnection Fact Sheet. (2015, March 31). *Electric Vehicles and the Grid.* Available at: http://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/electric-vehicles-and-the-grid-fact-sheet.ashx

48 Keay-Bright, S. (2014). *EU Power Sector Market Rules and Policies to Accelerate Electric Vehicle Take-Up While Ensuring Power System Reliability.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7441

49 E3/ICF. (2014, October 23). *California Transportation Electrification Assessment, Phase 2: Grid Impacts.* Available at: http://www.caletc.com/wp-content/uploads/2014/10/CalETC_TEA_Phase_2_Final_10-23-14.pdf

50 Peças Lopes, J. A., Rocha Almeida, P. M., & Soares, F. J. (2009, June). *IEEE 2009 International Conference on Clean Electrical Power. Using Vehicle-to-Grid to Maximize the Integration of Intermittent Renewable Energy Resources in Islanded Electric Grids.* Available at: http://www.researchgate.net/profile/Joao_Abel_Lopes/publication/224581302_Using_vehicle-to-grid_to_maximize_the_integration_of_intermittent_renewable_energy_resources_in_islanded_electric_grids/links/53fc5c7c0cf22f21c2f3cc0a.pdf

51 Tuffner, F., & Kintner-Meyer, M. (2011, July). *Using Electric Vehicles to Meet Balancing Requirements Associated With Wind Power.* Pacific Northwest National Laboratory for the US Department of Energy. Available at: http://energyenvironment.pnnl.gov/pdf/PNNL-20501_Renewables_Integration_Report_Final_7_8_2011.pdf

are covered by the CPP) could rise owing to additional charging load, even though GHGs from motor vehicles (which the CPP does not cover) would decline.[52]

2.4. The Internet of Things

The *"Internet of Things"* (IoT) is a term used to describe an increasingly interconnected, responsive, and dynamic world in which many millions of new devices capable of two-way communication are being connected to the Internet every year. This interconnectedness offers convenience and comfort, but can also be designed to reduce costs and improve efficiency economy-wide.

In the industrial sector, smart manufacturing systems are connecting productivity on the factory floor with the business domain, permitting greater market responsiveness, reductions in lead times, and minimized material waste. In logistics, smart tagging of pallets and parcels is being deployed and piloted to enable a standardized, open transportation platform in global supply chains. These new models in transportation offer enormous potential improvements in freight utilization and associated reductions in GHG emissions.[53]

In the building sector, heating, ventilation, and air conditioning systems are being integrated with energy storage and distributed generation, such as ice storage, rooftop solar, and combined heat and power.[54,55] Networked locally, these systems can be optimized to incorporate renewable generation output and load forecasting. They can be controlled internally by building managers to respond to time-of-use (TOU) pricing and otherwise reduce energy costs. And they can be controlled remotely by grid operators to provide aggregated peak shaving and load-shifting benefits as well as ancillary services. Commercial and institutional buildings designed with this kind of interoperability are envisioned as key building blocks of a more resilient and distributed electric grid.[56]

In the residential sector, smart thermostats – notably the learning thermostat developed by Nest Labs and brought to media attention in 2014 after its acquisition by Google – are already gaining market share, reducing energy for heating and cooling by 10- to 15-percent, according to field studies.[57] Following smart thermostats, a new wave of lighting, water heating, and other smart appliances and automation platforms are making their way

52 Toor, W., & Nutting, M. (2014, November 30). *Southwest Energy Efficiency Project (SWEEP) and the Electric Vehicle Industry Coalition (EVIC), Comments on the Treatment of Electricity Used by Electric Vehicles in the EPA's Proposed Clean Power Plan Rule Docket ID No. EPA-HQ-OAR-2013-0602.* Available at: http://www.seealliance.org/wp-content/uploads/SWEEP-EVs.pdf

53 A National Science Foundation-supported analysis by the Center for Excellence in Logistics and Distribution estimated that smart-tagging enabled innovations in logistics (a vision for modern freight transport coined the physical Internet) applied to only a 25-percent subset of freight flows in the United States could reduce the total freight transportation emissions by 200 teragram (Tg), or 39 percent of a total of 517 Tg CO_2 per year. Meller, R. D., Ellis, K. P., & Loftis, B. (2012, September 24). *From Horizontal Collaboration to the Physical Internet: Quantifying the Effects on Sustainability and Profits When Shifting to Interconnected Logistics Systems.* Final Research Report of the CELDi Physical Internet Project, Phase 1. Available at: http://faculty.ineg.uark.edu/rmeller/web/CELDi-PI/Final%20Report%20for%20Phase%20I.pdf

54 US Department of Energy & Pacific Northwest National Laboratory. (2015). *Transactional Network and Rooftop Units Project Overview.* Available at: http://transactionalnetwork.pnnl.gov/overview.stm

55 Such integration can build on and be coupled with direct improvements to building energy use through benchmarking and annual disclosure of energy use, also called transparency. Benchmarking measures a building's energy use and compares it to the average for similar buildings, allowing owners and occupants to understand their building's relative energy performance and helping to identify opportunities to cut energy waste. More information is available at: http://www.imt.org/policy/building-energy-performance-policy

56 US Department of Energy, Building Technologies Office. *Sustainable and Holistic Integration of Energy Storage and Solar PV (SHINES).* Available at: http://energy.gov/eere/buildings/building-technologies-office-load-control-strategies

57 Three studies of the Nest Learning Thermostat have been conducted, one by Nest Labs and the other two by independent groups. Results generally agree, suggesting heating savings of about 10 percent to 12 percent and electric savings of about 15 percent of cooling use in homes with central air conditioning. Apex Analytics. (2014, October 10). *Energy Trust of Oregon Nest Learning Thermostat Heat Pump Control Pilot Evaluation.* Available at: http://energytrust.org/library/reports/Nest_Pilot_Study_Evaluation_wSR.pdf; Aarish, C., Perussi, M., Rietz, A., & Korn, D. (2015). *Evaluation of the 2013–2014 Programmable and Smart Thermostat Program.* Prepared by Cadmus for Vectren Corporation; Nest Labs. (2015, February). *Energy Savings from the Nest Learning Thermostat: Energy Bill Analysis Results* (white paper). Available at: https://nest.com/downloads/press/documents/energy-savings-white-paper.pdf

to consumers and promising further interoperability.[58] The future of demand response–enabled homes will rely on the proliferation of interconnected hardware and compatible software tools, but also – and probably more importantly for energy saving – it will rely on dynamic or TOU pricing plans being offered to residential utility customers.

In the power sector, IoT applications will increasingly combine greater situational awareness on the grid, and at the point of final energy use, with the interoperability of distributed energy resources. The influence of communicating and computing technologies going forward will represent a quantum change. It will enable complex interactions that integrate millions of customers with grid operations to manage end-use load and maximize the performance of variable resources like wind and solar and storage resources. This interconnectivity can bring about emissions reductions through overall reductions in demand, as well as improved system efficiency in matching demand with cleaner, more cost-effective supply through load shifting, peak shaving, and the provision of regulation services – all of which are required for the integration of large shares of intermittent renewable energy.

Although product developers are at the cusp of envisioning, testing, and piloting these IoT developments today, how market forces, enabling regulation, and consumer demand will interact to realize the potential for greater efficiency and cost savings – and precisely how large that potential is – remains to be determined.

2.5. The Water-Energy Nexus

Large amounts of power are used in managing water resources, including pumping, treatment, distribution, and increasingly desalination; and likewise, large amounts of water are used in energy production, especially for boiler feedwater and cooling purposes at thermal power stations, as well as in extractive activities such as hydraulic fracturing of oil and natural gas wells. These linkages mean that water efficiency saves energy, and energy efficiency saves water.

With parts of the country facing growing water stress, as in California and other western states, the linkages between water and energy have attracted attention in recent years. However, these interconnections deserve consideration across the country, where nationwide, water pumping, treatment, and distribution account for a substantial portion of total electricity consumption – between 4 and 13 percent, according to various estimates.[59,60] For GHG mitigation planning, water efficiency – whether in the form of water conservation or improved energy efficiency in water systems – represents an important opportunity that can be factored into state compliance plans for the EPA's CPP rule.

Opportunities are especially ripe at the municipal level, where drinking water and wastewater treatment facilities are often the largest energy consumers. They account for 30 to 40 percent of energy consumed by municipal governments, according to the EPA.[61] Because energy comprises the lion's share of water system costs – for drinking water and wastewater utilities, energy is typically

58 For examples, see GE: http://www.geappliances.com/connected-home-smart-appliances/; Belkin Home Automation: http://www.belkin.com/us/Products/home-automation/c/wemo-home-automation/; Philips: http://www2.meethue.com/en-us/; Whirlpool 6th sense appliances and my smart appliances app: http://www.whirlpool.com/smart-appliances/; https://www.mysmartappliances.com/

59 Estimates vary widely. An EPRI study from 2002 estimated that drinking water and wastewater systems accounted for four percent of national electricity demand. A 2009 study by the River Network, which includes commercial and residential water heating, places it closer to 13 percent. Another investigation by researchers at the University of Texas Austin in 2011 found energy use associated with public water supply to be 6.1 percent of national electricity consumption. Regional differences can be significant. For example, in California, as much as 19 percent of the electricity is consumed in pumping, treating, collecting, and discharging water and wastewater. See: Electric Power Research Institute. (2002, March). *Water & Sustainability (Volume 4): US Electricity Consumption for Water Supply & Treatment.* Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001006787; Griffiths-Sattenspiel, B., & Wilson, W. (2009, May). *The Carbon Footprint of Water. River Network.* Available at: http://www.rivernetwork.org/resource-library/carbon-footprint-water; Twomey, K., & Webber, M. (2011, August). *Evaluating the Energy Intensity of the US Public Water System.* Proceedings of the ASME 2011 5th International Conference on Energy Sustainability. Available at: http://proceedings.asmedigitalcollection.asme.org/proceeding.aspx?articleid=1636857

60 A survey of current estimates is included in: Copeland, C. (2014, January 3). *Energy-Water Nexus: The Water Sector's Energy Use.* Congressional Research Service. Available at: http://fas.org/sgp/crs/misc/R43200.pdf

61 US EPA. *Energy Efficiency for Water and Wastewater Utilities.* Available at: http://water.epa.gov/infrastructure/sustain/energyefficiency.cfm

the second-largest expense after labor[62] – improvements in water efficiency can yield substantial economic returns for local government.

Utilities and jurisdictions around the country have existing water conservation policies and programs. Program evaluation in many cases already involves quantification of associated energy savings,[63] allowing the programs to be readily incorporated as a mitigation strategy in GHG reductions plans.[64] Take, for example, an energy-management pilot project targeting drinking water and wastewater facilities in Massachusetts that was framed around a 20-percent GHG mitigation goal.[65] The state of Massachusetts also provides guidance on emissions calculations for water and wastewater treatment facilities on the basis of an average energy cost per volume of treated water (e.g., within the territory of Massachusetts Water Resources Authority: 1.3 kWh/1000 gallons treated for wastewater treatment; 0.2 kWh/1000 gallons treated for water treatment).[66]

As in the case of the Massachusetts project, efficiency investments in the water sector are often designed to improve performance of motors and pumps in the treatment and distribution systems, or to produce onsite electric generation from methane biogas or other renewable energy sources.[67] Another inquiry by researchers at The Analysis Group and American Water Works Association examined the carbon emissions associated with lost water recovery and found significant energy and emissions benefits associated with infrastructure upgrades to reduce leaks.[68] Their findings suggest that general infrastructure spending in the water sector could also be tied to GHG reduction strategies. The authors recommend further consideration of using generalized versions of ratepayer-funded energy efficiency cost-effectiveness tests to compare water infrastructure investments with other carbon reduction options.

3. Other Policy Considerations

Advancing technology has led and is leading to profound changes in the entire electric power system. At the same time, new technologies often create new policy issues and opportunities as well. Technology often makes possible, for instance, the measurement, management, and control of system processes where it was previously infeasible to do so. Resources can be identified and enlisted in ways that were previously inconceivable. Several of the most basic and traditional policy considerations for public utility regulators may need to be re-examined in light of these new developments. These include the core issues of reliability, rate design and pricing, and utility business models.

3.1. Reliability

No attribute of the electric power system garners more attention from public utility regulators than reliability. Many regulators consider "keeping the lights on" to be their most important job, if not a near-sacred duty. When the lights go out, utility employees and utility regulators endure harsh criticism and enormous political pressure, and may even fear for their jobs. Enormous economic

62 Supra footnote 60.

63 American Council for an Energy Efficient Economy. *Local Technical Assistance Toolkit: Energy Efficiency Opportunities in Municipal in Water and Wastewater Treatment Facilities.* Available at: http://aceee.org/sector/local-policy/toolkit/water

64 Tierney, S. (2014, July 21). Analysis Group's Tierney Says States Ready to Comply With Carbon Rule. *OnPoint: E&ETV Interview.* Available at: http://www.eenews.net/tv/videos/1856/transcript

65 US EPA. (2009, December). *Massachusetts Energy Management Pilot Program for Drinking Water and Wastewater Case Study.* Available at: http://water.epa.gov/aboutow/eparecovery/upload/2010_01_26_eparecovery_ARRA_Mass_EnergyCasyStudy_low-res_10-28-09.pdf

66 Massachusetts Energy and Environmental Affairs. *Greenhouse Gas Emissions Policy and Protocol. Guidance for GHG Emissions Calculations for Water and Wastewater Treatment.* Available at: http://www.mass.gov/eea/agencies/mepa/greenhouse-gas-emissions-policy-and-protocol-generic.html

67 US EPA. (2010). *Evaluation of Energy Conservation Measures for Wastewater Treatment Facilities.* Available at: http://water.epa.gov/scitech/wastetech/upload/Evaluation-of-Energy-Conservation-Measures-for-Wastewater-Treatment-Facilities.pdf; California Energy Commission. Process Energy – Water/Wastewater Efficiency. Available at: http://www.energy.ca.gov/process/water/index.html

68 Aubuchon, C., & Roberson, J. (2013). *Embodied Energy of Lost Water: Evaluating the Energy Efficiency of Infrastructure Investments.* The Analysis Group and American Water Works Association. Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/2013_Aubuchon_EconomicsOfWater.pdf

losses to businesses and individuals may occur from lost or spoiled production, as well as losses in service and Internet connectivity. Very real public health and environmental problems can also occur – for example, if water treatment or wastewater operations are interrupted, power to hospitals is lost, and so on. Simply stated, when reliability is raised as a concern against a particular regulation or compliance strategy, it must be taken seriously.

Reliability is a function of generation, transmission, distribution, and load interactions, and it may be measured on the local or regional level. Changes in one state or utility may impact the reliability or deliverability of power in another state or utility. As a result, generation and transmission projects must be assessed through regional processes to determine whether other upgrades are necessary and whether the benefits outweigh the costs overall. Resource adequacy and reserve margins are key elements of reliability, but they must also be supplemented with power flow studies. Reliability is maintained by a complex web of responsibilities at the utility, the balancing area, and authorities at the state, regional, and national levels. There are established procedures to assess reliability, to choose preferred solutions, and then to get solutions engineered, permitted, built, and operational. These processes can take several years, and they often involve significant tradeoffs for decision-makers.

Ensuring reliability is a fundamental constraint in reducing carbon emissions in the power sector, and it is a central concern of the EPA in developing the Carbon Pollution Emission Guidelines for Existing Stationary Power Sources (i.e., the proposed CPP). Accompanying the proposed rule, the EPA's Regulatory Impact Analysis used the Integrated Planning Model framework to assess impacts on the power sector, including reliability impacts.[69,70] The Integrated Planning Model is constrained by the need to maintain resource adequacy and meet reserve margin requirements in each of the 64 modeling regions.[71] It does this through existing sources or new construction, and limits interregional energy and capacity transfers such that the reliability of the bulk transmission system is ensured and the specific regional reserve requirements are met first.

Considering a policy scenario with state-specific goals (as opposed to goals associated with potential regional, multistate efforts), the EPA's modeling indicates that 49 GW of coal and 16 GW of oil-gas steam capacity would be uneconomic by 2020 as a result of its proposed CPP regulations. Where needed for reserves, the EPA's modeling assumes these retirements are replaced by 35 GW of new capacity, consisting of 23 GW of natural gas combined-cycle, 2 GW of combustion turbine capacity, and 10 GW of wind, and the equivalent of four percent of current reserve capacity. Retirements are also offset by energy efficiency, which reduces total operational capacity requirements by 35 GW, further reducing the capacity required to meet reserve margins and the burden on transmission infrastructure.[72] Given these results, the EPA concludes that the rule will not pose regional reliability risks that cannot be mitigated through standard planning processes within the timeline allowed.

The North American Electric Reliability Corporation (NERC) is an international regulatory authority responsible for assuring the reliability of the bulk power system in North America. In the United States, NERC acts under the oversight of the Federal Energy Regulatory Commission (FERC). In its *Initial Reliability Review*[73] of the proposed

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

70 US EPA. (2014, June). *EPA Analysis of the Proposed Clean Power Plan: Supplemental Documentation and IPM (v5.13) Run Files.* Available at: http://www.epa.gov/airmarkets/programs/ipm/cleanpowerplan.html

71 Reserve margins are based on reliability assessments of NERC or state requirements, where they may be more stringent. For more on IPM, see: US EPA. (2013, November 27). *EPA's Power Sector Modeling Platform v.5.13: Documentation.* Available at: http://www.epa.gov/airmarkets/programs/ipm/psmodel.html

72 Greater detail on the resource adequacy analysis, including a regional breakdown of results, is provided in the Regulatory Impact Analysis and supplemental documents on resource adequacy. See: US EPA. (2014, June). *Technical Support Document: Resource Adequacy and Reliability Analysis.* Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-resource-adequacy-reliability.pdf

73 NERC. (2014, November). *Potential Reliability Impacts of EPA's Proposed Clean Power Plan: Initial Reliability Review.* Available at: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Potential_Reliability_Impacts_of_EPA_Proposed_CPP_Final.pdf

CPP, NERC questioned some of the EPA's assumptions and emphasized the importance of additional research and analysis to better understand how the CPP may affect reliability. Several independent system operators (ISOs) and regional transmission organizations (RTOs) published analyses of the impacts of the proposed rule on their systems as well.[74,75] Concerns raised by these groups generally focus on the following potential risks to reliability:

1. Insufficient reserve margins owing to retirements of fossil-fueled generators;
2. Inadequate *Essential Reliability Services,* for example, ramping flexibility, load following, reactive power, voltage control, frequency response, and so on, to accommodate increased supply of both utility-scale and distributed non-hydro renewable energy;
3. Insufficient planning time for expansions and enhancement to transmission infrastructure; and
4. Strained natural gas infrastructure owing to increased gas-fired generation.

NERC's preliminary assessment also questions specific assumptions in the EPA's CPP Regulatory Impact Analysis, namely that the EPA may have overstated the reductions achievable through heat rate improvements at fossil-fueled generators, increased natural gas generation, and reductions in demand through energy efficiency (i.e., what the EPA refers to as Building Blocks 1, 2, and 4 of its assessment of the Best System of Emission Reduction for existing fossil fuel-fired EGUs).

A study released in February 2015 by the Brattle Group reached very different conclusions. It found that, although the EPA may have moderately overestimated potential reductions in some areas, it underestimated, or altogether excluded, potential reductions in other areas.[76] For example, Brattle noted that the EPA did not explicitly consider the emissions reductions that could be achieved by states through non-utility energy efficiency programs, appliance standards, or building codes (as explained in Chapters 12, 14, and 15, respectively). The potential for demand response programs to reduce emissions and maintain reliability was also not considered by the EPA or NERC (demand response is considered in detail in Chapter 23). The Brattle Group also evaluated several ideas that could potentially alleviate reliability problems. For example, higher-emitting facilities are expected to scale down hours of operation, but they may not need to retire, or not immediately. Some of these EGUs could perhaps be maintained on an emergency-capacity–only basis for two to three years to meet reserve margin requirements until other capacity resources such as combustion turbines, demand response, and energy efficiency can be built. The Brattle study also found that regional solutions to fuel switching, versus state-by-state solutions, could help offset short-term constraints in natural gas infrastructure. On balance the study found the CPP would not create major risks to reliability.[77]

74 Midcontinent Independent System Operator. (2014, November 23). *MISO Comments on Docket ID No. EPA-HQ-OAR-2013-0602.* Available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/EPA%20Regulations/MISO%20Comments%20to%20EPA%20on%20Proposed%20CPP%2011-25-14.pdf; New York ISO. (2014, December 19). *Comments of the NYISO on the Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.* Available at: http://www.nyiso.com/public/webdocs/markets_operations/documents/Legal_and_Regulatory/Other_Filings/Other_Filings/20141201_IRC_Cmmnts_CLEAN_POWER_PLAN.pdf; SPP. (2014, October 8). *SPP's Reliability Impact Assessment of the EPA's Proposed Clean Power Plan.* Available at: http://www.spp.org/publications/CPP%20Reliability%20Analysis%20Results%20Final%20Version.pdf; ERCOT. (2014, November 17). *ERCOT Analysis of the Impacts of the Clean Power Plan.* Available at: http://www.ercot.com/content/news/presentations/2014/ERCOTAnalysis-ImpactsCleanPowerPlan.pdf

75 Comments submitted to the EPA from many ISOs and RTOs have requested that the final rule include a reliability safety valve to provide a process for undertaking reliability assessments and through which to be granted leniency to implement any requisite reliability solutions. ISO/RTO Council. (2014). *EPA CO_2 Rule – ISO/RTO Council Reliability Safety Value and Regional Compliance Measurements and Proposals.* Available at: http://www.isorto.org/Documents/Report/20140128_IRCProposal-ReliabilitySafetyValve-RegionalComplianceMeasurement_EPA-C02Rule.pdf

76 The Brattle Group. (2015, February). *EPA's Clean Power Plant and Reliability: Assessing NERC's Initial Reliability Review.* Available at: http://info.aee.net/hs-fs/hub/211732/file-2486162659-pdf/PDF/EPAs-Clean-Power-Plan--Reliability-Brattle.pdf

77 EGUs are also subject to new Maximum Achievable Control Technology (MACT) standards for mercury, Clean Water Act Section 316(b) cooling water regulations, and possible additional regulations associated with the Cross-State Air Pollution Rule (CSAPR). Some analysts have suggested that these requirements and other issues may create a greater impact on bulk or local electric grid reliability – at least in terms of coal shutdowns – than the CPP. See, for instance: Dumoulin-Smith, J. (2015, March 16). *U.S. IPP Power Shock: The Next Capex Cycle?* UBS.

A May 2014 report from the Analysis Group also considered the reliability impacts of GHG reduction strategies, and enumerated a number of approaches that can be applied in different market structures to balance reliability requirements with environmental compliance.[78] Restricting the operating permits of specific high-emitting facilities or using multiyear compliance periods are two mechanisms that would allow a fossil fuel-fired EGU to continue to serve reliability purposes. The Analysis Group study presents a range of emissions trading schemes that could be instituted, from bubbling of emissions across units at a single station, to interstate trading across various power plant owners. Inter-facility averaging, for instance, would allow a utility holding multiple plants to determine the best set of actions through which to maintain reliability while bringing its fleet into overall compliance (e.g., by limiting operations of certain high-polluting units, increasing capacity factors at underutilized natural gas combined-cycle units, investing in renewables, and reducing demand through energy efficiency programs).[79] Further modeling of the power system would be needed to properly understand reliability impacts, but these examples show how states could tailor their implementation plans to help manage those impacts.

A common finding of the Brattle Group and Analysis Group studies is that the flexibility afforded through Section 111(d) of the Clean Air Act allows states to use a broad range of options, both inside and outside the fenceline, to develop compliance strategies that can account for the unique factors affecting system reliability in a particular state or region. Both organizations conclude that existing institutions, operational tools, procedures, and planning processes are likely sufficient for regulators, market participants, and system operators to work together to resolve any reliability challenges that compliance strategies may present, and in some cases these efforts are already underway. In addition, the industry has a demonstrated track record of effectively responding to environmental regulations – where most regulations have been less flexible than the current ones – without sacrificing reliability.

If the EPA has overestimated potential carbon reductions from heat rate improvements, coal-to-gas fuel switching, and energy efficiency, as NERC asserts, greater reliance would fall on renewable energy (in the CPP, Building Block 3) to achieve compliance. This raises the question of what risks there are to regional reliability from integrating variable energy resources at levels comparable to those established by the Best System of Emission Reduction. NERC expressed concern that variable energy resources significantly impact reliability, require build-out of transmission, and require additional ancillary services. However, the EPA's targets for 2020 are based on levels of renewable energy deployment that many states are already expecting and planning to accommodate. Of the 34 states that have already adopted renewable portfolio standards, only three have set levels that would be exceeded by the assumptions the EPA used in setting state targets for 2020.

In fact, the EPA's analysis suggests only a minor incremental increase in average renewable generation by states over its base-case scenario – from seven percent of generation from renewables in 2020 without policy intervention, to eight percent with policy intervention. The Brattle Group study concluded that this minor incremental increase is unlikely to disrupt reliability, even if renewables need to provide a greater share of total emissions reductions than the EPA assumes (as would be the case for states planning Renewable Portfolio Standard goals that exceed the EPA's targets).

The EPA sets renewable penetration levels below 20 percent by 2020 for all but two states, with a maximum penetration of 25 percent in Maine (a rate that state already exceeds, according to the EPA).[80] With Germany at 27 percent, Denmark at 39 percent (wind only), and California

78 The Analysis Group. (2014, May). *Greenhouse Gas Emission Reductions from Existing Power Plants: Options to Ensure Electric System Reliability.* Available at: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Tierney_Report_Electric_Reliability_and_GHG_Emissions.pdf

79 Inter-facility averaging, if conducted across facilities in multiple states operated by a multistate utility holding company, may require the relevant states to enter into a specific understanding that would enable each state's CPP compliance plan to appropriately account for the fleet-wide controls established for the multistate holding company.

80 US EPA. (2014, June). *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units.* Docket ID No. EPA-HQ-OAR-2013-0602. Available at: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-ghg-abatement-measures.pdf

on track to meet 33 percent of electricity from renewables by 2020,[81] experiences from around the world demonstrate that comparable rates of renewables do not inherently compromise reliability.

A number of operational practices have been proven to facilitate cost-effective integration of intermittent resources.[82] These include conventional techniques such as re-dispatch, curtailment, and adding additional flexible reserve capacity, as well as incorporating newer resources such as storage and demand response. Impacts of intermittency can also be mitigated by improving forecasting and scheduling, expanding balancing areas, and – where available and cost-effective – capturing a diversified portfolio of renewables, including resources with varying intermittency profiles and dispatchable resources such as geothermal, biomass, and biogas. These topics are addressed in more detail in Chapters 18 and 20 of this document.

Taking integration techniques like these into account, a number of recent analyses suggest that intermittent resources at higher levels than those set by the EPA in the CPP could be reliably accommodated. A study commissioned by Minnesota in collaboration with the Midcontinent Independent System Operator concluded that the state's electric power system could accommodate 40 percent variable renewable-energy resources without risking reliability.[83] Another study found that 30 percent of generation from wind and solar across the PJM Interconnection's territory would not have significant effects on reliability.[84] An additional study for California found levels of penetration of up to 50 percent were possible.[85] NREL has also conducted significant renewables integration work, including multiple phases of its Eastern Wind Integration and Transmission Study, Western Wind and Solar Integration Study, and Eastern Renewable Generation Integration Study.[86]

NERC's preliminary assessment and the other comments and studies discussed earlier agree that as states and regions develop implementation plans to comply with the EPA's CPP, additional modeling and analysis will be needed to ensure reliability. Some parties have suggested that some form of "reliability safety valve" should be built into the CPP or the state plan approval process, whereby detailed modeling could be conducted to ensure that state compliance strategies do not jeopardize reliability. In the CPP technical conferences that FERC held in early 2015, parties raised several possible iterations of such a safety valve, including broad-brush studies conducted using the EPA Building Blocks as a whole, followed by more detailed modeling after state plans are submitted. Actual power flow studies cannot be completed until regional groups have a clearer understanding of what individual states might propose in their compliance plans. These studies may indicate a need for more detailed regional assessment and possible adjustments to the timelines or to preferred methods in order to maximize benefits. Other parties recommend that the EPA build a step into the compliance process only if and when reliability issues arise and plan adjustments become necessary. Because reliability impacts cross state lines, no individual state is in a position to address this issue on a standalone basis. Safety valve studies, if conducted, must be transparent and include stakeholder participation, review periods, and opportunity for debate.

81 California Public Utilities Commission. (2014). *Renewables Portfolio Standard Quarterly Report: 3rd Quarter 2014.* Available at: http://www.cpuc.ca.gov/NR/rdonlyres/CA15A2A8-234D-4FB4-BE41-05409E8F6316/0/2014Q3RPSReportFinal.pdf

82 For discussion of costs of ancillary services, see: (1) NREL. (2013, September). *The Western Wind and Solar Integration Study Phase 2: Executive Summary, Technical Report, NREL/TP-5500-58798.* Available at: http://www.nrel.gov/docs/fy13osti/58798.pdf; (2) ERCOT. (2013, November 1). *Future Ancillary Services in ERCOT, Concept Paper, Draft Version 1.1.* Available at: http://www.ercot.com/committees/other/fast; (3) Porter, K , Mudd, C., Fink, S., Rogers, J., Bird, L., Schwartz, L., Hogan, M., Lamont, D., & Kirby, B. (2012, June 10). *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge.* Western Governors' Association. Available at: http://www.uwig.org/variable2012.pdf

83 GE Energy Consulting and MISO for Minnesota Department of Commerce. (2014, October 31). *Minnesota Renewable Energy Integration and Transmission Study: Final Report.* Available at: http://www.minnelectrans.com/documents/MRITS-report.pdf

84 GE Energy Consulting for PJM Interconnection, LLC. (2014, March 31). *PJM Renewable Integration Study: Executive Summary Report.* Available at: http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx

85 Energy and Environmental Economics. (2014, January). *Investigating a Higher Renewables Portfolio Standard in California.* Available at: https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

86 Additional information on these projects is available at: www.nrel.gov

The flexibility of Section 111(d) of the Clean Air Act gives states the opportunity to draw on a wide range of options – including operational practices, technological applications, pricing strategies, and market-based policies, among other approaches – which they can use to help mitigate potential reliability impacts while achieving compliance.

3.2. Rate Design and Pricing

The rate structure that electric utilities apply to residential, commercial, and industrial customers has a direct impact on the *amount* of electricity that customers consume and *when* they consume it. The impact occurs in at least five different ways:

- **Conservation.** Customers who face a higher price per kWh will be more likely to participate in energy efficiency programs or acquire more efficient appliances and equipment to save money;
- **Time-Shifting.** Customers who face time-varying rates may choose to schedule energy use, such as laundry and dishwashing (for residential customers), business activities or production processes (for commercial or industrial customers), or EV charging (for both) into lower-cost time periods;
- **Fuel-Switching.** Customers who face a higher price per kWh may be more likely to choose fuels other than electricity to meet needs, including natural gas for space heat and water heat, and natural gas or a clothesline for clothes drying;
- **Economic Curtailment.** Customers who face a higher price per kWh may choose to change their thermostat settings, be more attentive to turning off lights and appliances when not in use, or wash clothes in cold water; and
- **Onsite Generation.** Customers who face a higher price per kWh may be more likely to choose to install a solar PV system or other onsite generating facility.[87]

Although it is difficult to measure exactly which of these impacts causes the reduction in usage in response to a higher price (or an increase in response to a lower price), it is generally accepted that there is a price elasticity for electricity. Elasticity measures the change in the quantity demanded with respect to a change in price. That elasticity is generally recognized to be small in the short-run (one to three years) and higher in the long-run (over a period when appliances, lighting, and other energy-consuming equipment are replaced).

Although the techniques used to set prices are complex, the result is not. Customers deal with price-driven decisions every day. For example, an ice cream parlor entices customers to eat more ice cream with simple pricing tools, making additional scoops cheaper than the initial scoop. In electricity, this is known as a "declining block" rate design.

Residential rates are the best-understood rate designs, and they can have a dramatic impact on residential electricity consumption. Across the country, higher-cost utilities have lower usage per customer than lower-cost utilities. And there is plentiful evidence that the design of rates, within the constraint of the utility revenue requirement, also affects usage.

Residential prices generally include:

- **Customer Charge.** A fixed monthly charge, usually to cover billing and collection costs, but sometimes including distribution system costs as well.
- **Energy Charge.** A price per kWh for all usage; this may be in multiple blocks, differentiated by season, or differentiated by time of day.
- **Tariff Riders.** These are adjustments applied to rates that operate between general rate cases. The most common are for fuel and purchased-power recovery, but some regulators have allowed multiple riders that amount to one-third of the total bill or more.

Impact of Price Level on Usage

In general, the higher the per-kWh charge, the more incentive there is for customers to find alternatives to consumption. Economists use a concept known as "price elasticity" to estimate the change in usage in response to a change in price. An elasticity factor of –0.1 means that a one-percent increase in price is expected to produce a 0.1-percent decrease in the quantity demanded. Most estimates of the elasticity of demand for electricity are in the range of -0.2 to -0.7, with the expected price response greater over the long-term. For illustrative purposes below,

87 Rate designs may increasingly impact customers who face *low* kWh prices as well, as when an excess of low-cost renewable power exists. Such situations present an opportunity to specifically target electricity use for some industrial production, water pumping or heating, car charging, and so on. For instance, a standby desalinization facility could be operated when an excess of solar or wind generation might otherwise cause their use to be curtailed.

Table 26-1

Illustrative Residential Rate Design

	Flat Rate	Inclining Block Rate	High Customer Charge
Customer Charge	$ -	$ -	$25.00
First 250 kWh	$0.15	$0.1160	$0.1025
Over 250 kWh	$0.15	$0.1740	$0.1025
Usage Change With Elasticity of -0.2		-2.6%	+6.3%

Table 26-2

Illustrative Commercial Rate Design With Demand Charge

Rate Element	Price
Monthly Customer Charge	$20.00
Demand Charge *($/kW/month)*	$10.00
Energy Charge	$0.08/kWh

we use an elasticity of -0.2.[88]

Table 26-1 shows three alternative residential rate designs, all designed to produce the same total revenue from a given mix of customer usage. The first is a simple rate, with only a per-kWh charge that applies to all usage. The second divides these into two blocks, usage before 250 kWh, and a higher price for usage above that level. The third collects $25 per month in a customer charge, independent of usage, and the balance in a uniform price per kWh. Because the overwhelming majority of usage is by customers whose monthly usage exceeds 250 kWh per month, this "end block" price is the primary determinant upon which elasticity is measured; only a few customers using a very small percentage of power face the initial block rate for their marginal consumption. Therefore, a reduction in the price for the first 250 kWh has a very small effect increasing consumption, whereas a higher price for usage above 250 kWh affects a much larger percentage of total usage.

By applying the economic concept of elasticity, we estimate that, compared to the flat rate, the inclining block rate would result in about 2.6 percent *less* consumption, whereas the high customer charge (and lower per-kWh price) would result in 6.3 percent *more* consumption. This shows that the type of residential rate design *to produce the same revenue* can cause a swing of nine percent in total customer usage. This does not inform us as to whether the reduced usage is the result of conservation, curtailment, fuel switching, or other options the customer may choose.

Commercial and Industrial Prices

Prices for commercial and industrial customers are generally more complex. They often include a "demand charge" that is based on the customer's peak demand, usually measured as the highest hour (or even the highest 15 minutes) of the billing period. Although demand charges can be designed to fairly price the cost of providing adequate capacity for peak periods, they generally result in lower per-kWh prices, and can thus result in higher consumption. An illustrative commercial rate is shown in Table 26-2.

Because the typical commercial customer has usage of about 300 kWh per peak kW of demand, this rate design collects about $0.03 per kWh of the total revenue requirement through the demand charge.[89] Without the demand charge, the energy charge would have to be about $0.11 per kWh. The principal adverse impact of a demand charge is that once the customer had "hit their peak" for the month, they no longer see the demand charge as an incremental cost, and make consumption decisions based solely on the $0.08 per kWh energy price.

An alternative to imposing a commercial demand charge is to convert this into a TOU rate design. For example, if the $10.00 per kW demand charge were applied only to the 100 highest-use hours of the month (3:00 PM to 8:00 PM, Monday to Friday, for example), it would add about $0.06 per kWh to the energy price in those hours (the

88 For a detailed discussion of price elasticity, see: Lazar, J. (2013, April). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed,* Appendix A. Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516

89 A typical commercial customer using 300 kWh per peak kW means that its normal operations may reflect electricity use of about 40 percent of its peak, not surprising for a retail or office environment or a one-shift, light-manufacturing operation. The $10.00 per-kW demand charge, if amortized over these 300 kWh, would equate to about $0.03 per kWh. Meeting the utility's revenue requirements without the demand charge would require the energy charge to be the $0.08 per kWh plus this $0.03 per kWh, or about $0.11 per kWh.

Table 26-3

Illustrative Commercial Rate Design Without Demand Charge	
Rate Element	**Price**
Monthly Customer Charge	$20.00
On-Peak Energy *(3:00 PM to 8:00 PM Monday to Friday)*	$0.18/kWh
Off-Peak Energy *(other hours)*	$0.09/kWh

actual calculation requires dividing the demand charge revenue by the expected kWh consumed during that period). The resultant rate design is shown in Table 26-3.

This TOU rate would provide a strong incentive to conserve during the on-peak hours, whereas a higher energy rate for off-peak usage would encourage somewhat more conservation during the off-peak hours as well. But it could result in a higher customer peak demand during some normally off-peak hours of the month.

Another alternative would be to confine the demand charge to the few hours of the month when peak demands are expected to occur, in order to constrain usage during those particular hours. An example of this is shown in Table 26-4. This is known as a "coincident peak" demand charge, because it applies only when the *system* peak is likely to occur, rather than applying to the *customer's* individual demand, whenever it occurs. This would serve to constrain demands on the utility system during peak periods. Because it would apply to a lower total number of kW (because some customers have their individual peaks outside of these hours), the energy charge would need to be a little higher, leading to more incentive to conserve energy at all hours. Note that with a demand charge of this type, there would be no on-peak versus off-peak energy charge differential.

Table 26-4

Illustrative Coincident Peak Demand Charge Rate Design	
Rate Element	**Price**
Customer Charge $/month	$20.00
Demand Charge *(4:00 PM to 8:00 PM, Monday to Friday)*	$10.00/kW
Energy Charge	$0.09/kWh

There are a few electric utilities that impose residential demand charges. Most of these are based on the customer's non-coincident peak (highest usage, whenever it occurs during the month). These tend to increase usage (because of the correspondingly lower energy charge) without having a meaningful impact on peak demand. If narrowly focused on the highest hours of the day (for example, 4:00 PM to 7:00 PM), they may result in load-shifting out of those hours, similar to the effect of a TOU rate design, but with a lower level of customer understanding, and thus less impact.

Rate design concepts that result in lower usage include:

- **Inclining Block Rates.** Prices that apply higher per-kWh charges to usage over a baseline that generally reflects what is deemed to be essential-needs level of usage.
- **Low or Zero Customer Charges.** If the fixed charge per month is lower, then the per-kWh price must be higher to produce the utility's allowed revenue. A low customer charge thus results in lower expected usage.

Rate design concepts that generally result in higher usage include:

- **High Fixed Charges.** If a utility recovers a greater portion of its revenue requirement in a fixed charge or customer charge, the price per-kWh will be lower, and usage will increase.
- **Demand Charges.** If a separate charge is imposed based on the customer's highest usage for a short period during the month (15 minutes or 1 hour, typically), the price per kWh will be lower, and usage during hours other than those when the customer's highest demand occurs will increase.

Rate design concepts that may increase or decrease usage include:

- **Time-Varying Rates.** Prices that are higher during peak periods will reduce usage during those periods, but will be offset by lower prices at off-peak times, increasing usage during these periods. If time-varying rates are used to reduce or eliminate demand charges, they will likely result in reduced usage.[90]

90 For more discussion of time-varying pricing, see: Faruqui, A., Hledik, R., & Palmer, J. (2012, July). *Time Varying and Dynamic Rate Design.* The Regulatory Assistance Project and the Brattle Group. Available at: http://www.raponline.org/document/download/id/5131

- **Critical Peak Pricing.** Many utilities have implemented what is known as critical peak pricing, where in the highest 50 to 100 hours of the year, a much higher price is implemented, with customers notified by text, email, or telephone. These result in higher collection during the highest hours, and slightly lower rates in all other hours, and the overall impact on usage varies from circumstance to circumstance.
- **Peak-Time Rebates.** Many utilities have implemented a different form of peak load pricing that provides a rebate when usage is curtailed during the highest-cost hours. Although not shown separately, these require a slightly higher base rate in order to fund the rebates.

Clarity and Transparency

Many electric bills are either impossibly complex or hopelessly opaque. They have become more of a litigator's scorecard or an accountant's worksheet than a price that consumers can respond to. Improving clarity enables customers to take appropriate actions to save energy and money, based on an informed perspective on the benefits.

In addition, the more clarity there is in the electric bill, the more likely consumers are to understand the price and to respond to it. Table 26-5 provides an example of how one electric bill is calculated – and Table 26-6 shows what that rate design really means.

Table 26-5

Illustrative Elements of an Electric Bill With Multiple Tariff Riders

	Your Usage: 1,266 kWh		
Base Rate	**Rate**	**Usage**	**Amount**
First 500 kWh	$0.04000	500	$20.00
Next 500 kWh	$0.06000	500	$30.00
Over 1,000 kWh	$0.08000	266	$21.28
Fuel Adjustment Charge	$0.03456	1,266	$43.75
Infrastructure Tracker	$0.00789	1,266	$9.99
Decoupling Adjustment	$(0.00057)	1,266	$(0.72)
Conservation Program Charge	$.00123	1,266	$1.56
Nuclear Decommissioning	$.00037	1,266	$0.47
Subtotal			$126.33
State Tax	5%		$6.32
City Tax	6%		$7.96
Total Due			$140.60

Table 26-6

Distillation of an Electric Bill With Multiple Tariff Riders

	Effective Rate Including All Adjustments		
Base Rate	**Rate**	**Usage**	**Amount**
First 500 kWh	$0.09291	500	$46.46
Next 500 kWh	$0.11517	500	$57.59
Over 1,000 kWh	$0.13743	266	$36.56
Total Due:			$140.60

Table 26-6 distills these multiple elements into a more understandable inclining-block structure.

Consumers do not generally value the additional information provided in the example shown in Table 26-5. This can be seen in gasoline pricing, for example. Gasoline prices also include numerous components, from crude oil and refining to tankers and retailers. But consumers respond to a single per-gallon price in choosing where to buy gasoline. They aren't asked or expected to consider the fixed and variable costs of each component.

Encouraging utility regulators to simplify, condense, and improve the presentation of the effective prices that customers will incur or save with changed usage is important. There is no problem providing detailed information in a tariff published on the utility website, or even printed on the reverse side of the bill. But what consumers really need to know to make rational decisions is how much their bill will increase or decrease in response to a change in usage.

Load Shifting

Most time-varying pricing is designed to shift load from on-peak periods to lower-use periods, in order to improve the use of transmission and distribution system capacity, and to avoid the high costs of securing resources to meet short durations of high demand. The impact of this pricing structure on total usage, and on emissions, is a complex calculation.

Sometimes it will increase usage; for example, if a commercial building is pre-cooled in the early afternoon to a lower temperature, in order to be able to comfortably "ride through" a higher rate in the late afternoon, there may be a net increase in kWh usage. Conversely, if a residential customer chooses to raise the thermostat to reduce cooling costs during an on-peak period, the customer is unlikely to make this up by lowering the thermostat below a comfortable level at night.

There is an environmental issue with load shifting as well. If the effect of load shifting is to shift load from hours when natural gas is the marginal resource to hours when coal is the marginal resource, then criteria and CO_2 emissions may increase. If the effect of load shifting is to increase usage of natural gas power plants with better heat rates, and decrease usage of less-efficient natural gas power plants, then emissions will decrease. This topic is covered in detail in Chapter 23.

However, load shifting also affects transmission and distribution line losses. As noted in Chapter 10, line losses are highest during peak hours. Shifting loads to lower-use periods will reduce line losses, and thus reduce the total number of kWh that are needed.[91]

3.3. Utility Business Models

The traditional electric utility business model is based on "cost of service" regulation. The essence of this model is that the rates utilities charge to customers are designed to recover the utility's costs of serving those customers. In the case of investor-owned utilities, rates also allow utilities the opportunity to replenish their capital stock and to earn a reasonable rate of return on capital invested by shareholders. Implicit in this model is the fact that investor-owned utilities earn profits by making capital investments in generation, transmission, and distribution system assets. Where a third party or a customer invests in similar assets, the utility's shareholders lose the opportunity to enjoy that return. Finally, as noted in the preceding section, rates have typically been designed in such a way that utilities collect most of their revenue based on volumetric sales (i.e., per-kWh and per-kW). Absent any mitigating policies, this gives utilities an inherent interest in maximizing their sales volume.

It is widely agreed that the US electric industry is at the cusp of a fundamental transformation, which is both challenging the traditional utility business model and offering significant opportunities to reduce the carbon intensity of the power sector. The transformation at hand is from a twentieth century model of central power generation and unidirectional delivery, toward a decentralized model in which the provision and management of electric services are distributed across end-users, for which the grid serves as a transactive platform.

This shift is being driven by a number of factors, notably the improved performance and availability of distributed energy resources. Distributed energy resources incorporate both demand- and supply-side resources deployed across the grid, including, for example, small-scale generation, combined heat and power, energy storage, microgrids, sensors, smart inverters, and load control technologies. Siting generation at the point of consumption, be it residential solar PV or commercial combined heat and power, cuts into retail sales of electricity, and therefore bypasses traditional cost recovery mechanisms for the regulated utility. Reducing demand, whether through demand response or energy efficiency programs, similarly cuts into utility sales. Therefore, even though distributed energy resources have been demonstrated to provide a broad variety of system benefits, such as resilience, electric reliability, congestion relief, and other ancillary services, many of which directly enhance the grid, utility incentives still typically discourage customer-owned assets.

The more recent technological advances in distributed energy resources are occurring against a backdrop of steadily declining growth in electricity demand, another factor driving industry transformation. Growth in electricity consumption has dropped from 9.8 percent per year in the 1950s to 0.7 percent per year since 2000,[92] and demand has begun to level off over the last decade, with sales having declined in six out of the last seven years (2007 to 2014).[93] Reduced demand further undermines

91 See: Lazar, J., & Baldwin, X. (2011, August). *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements.* Available at: http://www.raponline.org/document/download/id/4537

92 US Energy Information Administration. (2014, May 7). *Annual Energy Outlook 2014. Market Trends: Electricity Demand.* Available at: http://www.eia.gov/forecasts/aeo/MT_electric.cfm

93 US Energy Information Administration. (2015, February). *Electric Power Monthly With Data for December 2014.* Available at: http://www.eia.gov/electricity/monthly/pdf/epm.pdf; US Energy Information Administration. (2015, February). *Monthly Energy Review. Table 7.6 Electricity End Use.* Available at: http://www.eia.gov/totalenergy/data/monthly/pdf/sec7.pdf; US Energy Information Administration. (2014, April 30). *Implications for Low Electricity Demand Growth.* Available at: http://www.eia.gov/forecasts/aeo/elec_demand.cfm

utility revenue and is contributing to the upward pressure on rates seen across the country.[94] The traditional utility model may have been well suited for planning investment in large facilities and infrastructure projects at economies of scale, where continuous growth in demand was all but guaranteed. Today, not only are the economies of scale in power generation known to be limited,[95] but owing to structural economic changes and improvements in end-use efficiency, large capacity additions are no longer needed in the same way to meet planning requirements.

This evolution, from a natural monopoly to a participatory network that relies more on customer interaction, energy services, and information management, will require a redefinition of the utility profit regime. What exactly this will look like is the subject of debate. Numerous research efforts have investigated the issue, representing a broad array of perspectives, including those of regulators, consumer advocates, environmental advocates, as well as the utility industry[96] and investors.[97]

The Electricity Markets and Policy Group at Lawrence Berkeley National Laboratory has been working in this space since the 1990s, analyzing business models, quantifying financial impacts of distributed energy resources on shareholders and ratepayers, and providing technical assistance to utilities across the country. A library of related resources is available online.[98] With funding from the US Department of Energy, Lawrence Berkeley National Laboratory began convening a high-level advisory group of regulators, utilities, experts, and other stakeholders in late 2014, with the objective of exploring a vision for utility models that can enable distributed energy resources. The initial round of issue papers is scheduled for release in 2015.[99]

One of the forerunners on the subject was Peter Fox-Penner's *Smart Power,* a 2010 book widely praised for presenting a rigorous yet accessible account of the challenges to electric utilities posed by smart grid technologies, energy efficiency, and related policy goals of reducing carbon emissions.[100] Fox-Penner envisions the utility of the future as a "smart integrator" of upstream supply, local supply, and storage, whose chief role is one of network operator, rather than commodity retailer.

The first wave of changes to the traditional business model has been less visionary, consisting instead of incremental variations to cost-of-service regulation. The most common example of this kind of regulatory fix is *revenue decoupling,* an approach that originated in the 1980s and has been instituted for electric utilities in 16 states as of 2013 (22 states have decoupling for gas utilities).[101] Decoupling separates revenue from volumetric sales and allows utilities to recover fixed costs even when pursuing public policy objectives that may reduce sales.

Work by the Rocky Mountain Institute (RMI) through its eLab collaboration[102] outlines additional incremental steps that utilities and regulators can take to create the price signals needed to optimize the deployment and operation of distributed energy resources. RMI frames pricing reforms in terms of three objectives:

94 Satchwell, A. (2014, April 2). *Utility Business Models in a Low Load Growth/High DG Future.* Presentation to the California Municipal Utilities Association. Lawrence Berkeley National Laboratory. Available at: http://cmua.org/wpcmua/wp-content/uploads/2014/04/Utility-Bus-Mods-of-FutureCMUA_20140327_Andy.pptx

95 Burger, C., & Weinmann, J. (2013). *Small Is Beautiful: Decentralized Energy Revolution: Business Strategies for a New Paradigm.* Palgrave Macmillan.

96 Kind, P. (2013, January). *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.* Energy Infrastructure Advocates for Edison Electric Institute. Available at: http://www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf

97 Small, F., & Frantzis, L. (2010, July). *The 21st Century Electric Utility: Positioning for a Low-Carbon Future.* Navigant Consulting for Ceres. Available at: http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1

98 Lawrence Berkeley National Laboratory, Electricity Markets and Policy Group. *Utility Business Models, Research Area.* Available at: http://emp.lbl.gov/ubm

99 Lawrence Berkeley National Laboratory, Electricity Markets and Policy Group. (2015, forthcoming). *Future Electric Utility Regulation Series Reports.* Available at: http://emp.lbl.gov/future-electric-utility-regulation-series

100 Fox-Penner, P. (2010). *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities.* Island Press. Available at: http://www.smartpowerbook.com/

101 Natural Resources Defense Council. (2013, August). *Map of Gas and Electric Decoupling in the US.* Available at: http://www.nrdc.org/energy/decoupling/files/Gas-and-Electric-Decoupling-Maps.pdf

102 Rocky Mountain Institute eLab. Available at: http://www.rmi.org/elab

1. ***Attribute unbundling*** **—** shifting from fully bundled pricing to rate structures that break apart energy, capacity, ancillary services, environmental attributes, and other components;
2. ***Temporal granularity*** **—** shifting from flat or block rates to pricing structures that differentiate the time-based value of electricity generation and consumption (e.g., peak versus off-peak, hourly pricing); and
3. ***Locational granularity*** **—** shifting from pricing that treats all customers equally regardless of their location on the distribution system to pricing that provides geographically differentiated incentives for distributed energy resources.[103]

By unbundling attributes and increasing temporal and locational resolution, rate design monetizes the system benefits provided by specific applications of distributed energy resources. As a result, prices can more effectively steer investment toward the areas, hours, and technologies that offer the greatest public benefit.[104] To achieve these objectives, RMI lays out six specific options for rate design, as shown in Table 26-7.

Ultimately prices would be highly differentiated to fully incorporate a two-way exchange of value and services. But interim rate structures offer actionable options over the near-term, which can help optimize the investment flows that are already being made in distributed energy resources and set pricing on a trajectory toward greater sophistication in reflecting marginal costs and benefits over the load curve.

In addition to adequately valuing and incenting distributed energy resources, another looming challenge is how to organize multiple third-party service providers at the distribution level. In one model, an independently reviewed Integrated Resource Planning (IRP) process would be undertaken for the distribution network. The IRP would be used to identify least-cost procurement needs, for which proposals would be solicited from third-party service providers, aggregators, and consumer advocates. Utilities could provide financing or invest directly in owning and operating assets on the customer side. In another model, the distribution utility would offer customer outreach and on-bill financing for qualifying distributed energy resources, which would be installed and managed by approved third-party service providers. Rates could be designed to reflect the attributes and performance of specific assets.[106]

Table 26-7

Rate Design Reforms as Proposed by RMI[105]

Near-Term Option	Longer-Term Option
Energy + Capacity Pricing Unbundling energy and capacity (demand) values helps differentiate prices, but leaves many elements still bundled. Time- and location-based differentiation is still minimal.	**Attribute-Based Pricing** Attribute-based pricing more fully unbundles electricity prices, and doing so could also add time- and location-based sophistication.
Time-Of-Use Pricing Relatively basic TOU pricing (e.g., off-peak, peak, critical peak) begins to add time-based differentiation, but could still allow attributes to remain fully bundled with no location-based differentiation.	**Real-Time Pricing** Real-time pricing, with prices dynamically varying by one-hour or sub-hour increments, adds much time-based sophistication, but could still allow attributes to remain fully bundled with no location-based differentiation.
Distribution System Hot Spot Pricing Identifying distribution system "hot spots" begins to add location-based differentiation, but could still allow fully bundled attributes and little or no time-based differentiation.	**Distribution Locational Marginal Pricing** Distribution locational marginal pricing adds location-based sophistication, and in turn a high degree of temporal sophistication.

103 Rocky Mountain Institute. (2014, August). *Rate Design for the Distribution Edge: Electricity Pricing for the Distributed Resource Future.* Available at: http://www.rmi.org/elab_rate_design

104 Linvill, C., Lazar, J., & Shenot, J. (2013, November). *Designing Distributed Generation Tariffs Well: Ensuring Fair Compensation in a Time of Transition.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/press-release/designing-distributed-generation-tariffs-well-ensuring-fair-compensation-in-a-time-of

105 Supra footnote 103.

106 Rocky Mountain Institute. (2013, April). *New Business Models for the Distribution Edge: The Transition From Value China to Value Constellation.* Available at: http://www.rmi.org/New_Business_Models

These models are attractive on the one hand, because they could be implemented within the existing utility structure. However, utilities would still be subject to conflicts of interest, and ensuring oversight and transparency in acquisition and valuation would remain a challenge. To enable a fully transactive platform, the logical extension of these models would require the more disruptive intervention of separating the ownership and operational roles of the distribution utility.

Former Chairman of the FERC Jon Wellinghoff is among those who have come out in support of imposing reforms on the distribution utility that would transfer its operational authority to an independent distribution system operator, not unlike RTOs and ISOs in the bulk transmission system.[107,108] A 2014 article by James Tong and Jon Wellinghoff in *Public Utilities Fortnightly* makes the case that the separation of assets from operations would be the best way for distribution utilities to embrace new innovation in consumer-based energy resources and eliminate the conflict of interest with grid management. The new independent distribution system operator would be responsible for: "maintaining the safety and reliability of the distribution system; (2) providing fair and open access to the distribution grid and information from the system; (3) promoting appropriate market mechanisms; and (4) overseeing the optimal deployment and dispatching of distributed energy resources."[109] This opening at the distribution level to competitive forces would be designed to create greater customer choice, facilitate a broad deployment and integration of distributed resources, and ultimately "spur the development of the 'Transactive Energy Framework' in which independent energy agents in the distribution system can trade and combine their services to meet increasingly disparate customer needs."

Without the burden of operations, the distribution utilities would retain ownership of assets and continue to be compensated through rates for the value of service provided. Distribution utilities would also continue to be responsible for maintaining and upgrading the system, which could potentially include investment in distributed energy resources on the utility side of the meter to capture associated grid services and public benefits, where appropriate as subject to state laws.

This model of reform is similar to the course that is being set in New York's Reforming the Energy Vision proceedings.[110] In April 2014, the New York Public Service Commission launched an ambitious initiative to modernize the institutions and incentives that govern the electric utility industry to better promote energy efficiency, renewable energy, and distributed energy resources. Central to this effort is the task of redefining the distribution utility as a platform that serves as an interface between energy products, services, and market participants, including producer-consumers ("prosumers").[111] The commission envisions this as a Distributed System Platform (DSP) provider, defined as follows:

> *The DSP is an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity that monetizes system and social values, by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system.*[112]

On February 26, 2015, the New York Public Service

107 Wellinghoff, J., Hamilton, K., & Cramer, J. (2014, September 22). *Comments Submitted Before the State of New York Department of Public Service, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision Case No. 14-M-0101*.

108 Others have proposed this model of reform as well. See, for example: Rehimi, F., & Mokhtari, S. (2014, June). From ISO to DSO: Imagining a New Construct – An Independent System Operator for the Distribution Network. *Public Utilities Fortnightly.* Also see: Kristov, L., & De Martini, P. (2014, May). *21st Century Electric Distribution System Operations* [discussion paper]. Available at: http://resnick.caltech.edu/docs/21st.pdf

109 Tong, J., & Wellinghoff, J. (2014, August). Rooftop Parity: Solar for Everyone, Including Utilities. *Public Utilities Fortnightly 152,* 8:18. Available at: http://www.fortnightly.com/fortnightly/2014/08/rooftop-parity

110 New York Department of Public Service. *Case 14-M-0101. REV: Reforming the Energy Vision Proceedings.* Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument

111 New York Department of Public Service. (2014, April 24). *Case 14-M-0101. Reforming the Energy Vision: NYS Department of Public Service Staff Report and Proposal.* Available at: http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/26be8a93967e604785257cc40066b91a/$FILE/ATTK0J3L.pdf/Reforming%20The%20Energy%20Vision%20(REV)%20REPORT%204.25.%2014.pdf

112 New York Department of Public Service. (2014, August 22). *Case 14-M-0101. Developing the REV Market in New York: DPS Staff Straw Proposal on Track One Issues,* p. 12. Available at: http://energystorage.org/system/files/resources/nyrev_dpsstaffproposal_8_22_14.pdf

Commission issued its Reforming the Energy Vision order,[113] determining that the DSP function be filled by incumbent utilities, as opposed to an independent entity. The main reason for this is to avoid creating redundancy in system planning and operations.[114] The order put forward transitional steps, requiring each utility to undertake an IRP-like, least-cost planning exercise, called a Distributed System Implementation Plan (DSIP), which:

> *[S]hould present the utility's proposed investment plan for the next five years, and should reflect an integrated view of (transmission and distribution) investment needs and DER [distributed energy resources] resource alternatives. Beyond resource investments, the DSIP should include the utility's plan for implementing DSP platform and market components in the plan period. The actions proposed in the DSIP should be evaluated via a business plan that includes a benefit-cost assessment, a qualitative assessment of non-quantifiable benefits, and a risk assessment.*

Extending the transactive energy market into the retail domain, the DSP would need to be in an unbiased position in order to optimize across all available distributed energy resources. To eliminate the conflict of interest in using the existing utilities to host the DSP platforms, New York is proposing to move away from cost-of-service regulation toward an outcome-oriented, performance-based regulation.

In performance-based regulation, utility profits are tied to achieving specific goals determined by the regulator. These can be a composite framework of environmental targets, service quality metrics, price caps, reliability goals, or other goals based on related indices. If carefully designed, performance-based metrics can harness the utility profit motive to inspire innovation in targeted areas of public interest. The challenge lies in framing the goals, however, which may include a system of penalties and rewards for under- and over-achievement, respectively, and require extensive financial modeling.[115,116] New York will be looking to the United Kingdom, where performance-based regulation is the basis of the new "Revenues = Incentives plus Innovation plus Outputs" (RIIO) framework. RIIO is a major reform effort to align utility business models with the policy-driven investment required to transition the nation to a low-carbon economy.[117] One potential impact of RIIO of relevance to readers is that it intends over time to diminish and eliminate any bias favoring utility capital investments over operating expenses. This step is important if emissions-reducing demand-side investments by customers are motivated by utility expenses to support assets they will not own. A focus on total expenses assures attention to overall rate levels. New York is exploring this approach with Consolidated Edison's Brooklyn-Queens reliability project.[118]

Whether utility transformation is being advanced by consumer demand (as in Hawaii and Arizona, for instance), by utilities (as in the case of Duke Energy in North Carolina), or by regulators (as in New York and Minnesota),[119] different models will work in different regulatory environments. And although near-term

113 New York Department of Public Service. (2015, February 26). *Case 14-M-0101. Order Adopting Regulatory Policy Framework and Implementation Plan.* Available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b0B599D87-445B-4197-9815-24C27623A6A0%7d

114 Supra footnote 112.

115 Goldman, C. A., Satchwell, A., Cappers, P., & Hoffman, I. M. (2013, April 10). *Utility Business Models in a Low Load Growth/High DG Future: Gazing Into the Crystal Ball?* Presentation Before the Committee on Regional Electric Power Cooperation (CREPC)/State-Provincial Steering Committee (SPSC) Meeting. Lawrence Berkeley National Laboratory. Available at: http://emp.lbl.gov/publications/utility-business-models-low-load-growthhigh-dg-future-gazing-crystal-ball

116 Goldman, C. (2014, September 24). *Utility Regulatory Models: LBNL Technical Assistance Analysis and Tools. Presentation Before DOE OE Electricity Advisory Committee Meeting.* Available at: http://energy.gov/sites/prod/files/2014/10/f18/02d-CGoldman.pdf

117 Fox-Penner, P., Harris, D., & Hesmondhalgh, S. (2013, October). A Trip to RIIO in Your Future? *Public Utilities Fortnightly.* Available at: http://www.brattle.com/system/publications/pdfs/000/004/958/original/A_Trip_to_RIIO_in_Your_Future.pdf?1386706496

118 Whited, M., Woolf, T., & Napoleon, A. (2015, March 9). *Utility Performance Incentive Mechanisms: A Handbook for Regulators.* Synapse Energy Economics, Inc. Available at: http://synapse-energy.com/sites/default/files/Utility%20Performance%20Incentive%20Mechanisms%2014-098_0.pdf

119 GTM Research. (2015). *Evolution of the Grid Edge: Pathways to Transformation: A GTM Research Whitepaper.* Available at: http://www.greentechmedia.com/research/report/evolution-of-the-grid-edge-pathways-to-transformation

modifications to traditional cost-of-service regulation will be appropriate as interim solutions in many markets, thought leaders are converging on a vision of the future utility as a transactive energy platform that will eventually require dramatic changes to the role of the distribution utility.

3.4. Carbon Offsets

A carbon offset is a certificate or credit that is created to represent the reduction of a fixed amount of GHG emissions (generally, one metric ton of CO_2 or CO_2-equivalent) through an activity that is not directly regulated or is supplemental to regulatory requirements. These can be activities that reduce emissions, avoid emissions, or sequester carbon. Offsets are registered, tracked, traded, and retired in a manner similar to the renewable energy credits described in Chapter 16. Offsets can be used to assist in compliance with California's AB-32 requirements, in the European Union's Emissions Trading Scheme, in Clean Development Mechanism (CDM) and Joint Implementation (JI) projects under the United Nations Framework Convention on Climate Change, and in voluntary markets, among other purposes.

The carbon offset concept first arose more than a decade ago to serve the needs of individuals, businesses, and institutions that wanted to voluntarily reduce their contribution to climate change but found that the options to directly reduce their own emissions were limited in amount or unacceptably expensive. Recognizing that other parties often had more potential to reduce emissions and to do so at lower costs, but couldn't afford to or were not so inclined, some early entrepreneurs created carbon offsets as a means to put these two groups together. The buyers of offsets, in effect, finance the sellers' emissions reduction projects. For example, anaerobic digesters installed on dairy farms can capture methane from cow manure, burn it to generate electricity, and reduce GHG emissions. However, anaerobic digesters require a large upfront capital investment, and they can be complicated and expensive to maintain. As a result, few dairy farms in the United States have installed a digester. However, in recent years some farmers have financed digester projects by selling carbon offsets to willing buyers.

Today the market for carbon offsets is no longer limited only to voluntary buyers. Many of the established GHG cap-and-trade programs include provisions allowing for the use of carbon offsets as an alternative to emissions allowances. For example, under the current cap-and-trade rules adopted by the nine Northeast states participating in the Regional Greenhouse Gas Initiative (RGGI), regulated power plants are allowed to meet up to 3.3 percent of their compliance obligation for each control period using CO_2 offset allowances. The RGGI states have thus far limited eligibility for offset allowances to just five project categories, each of which represents a project-based GHG emissions reduction outside of the capped electric power generation sector:

- Landfill methane capture and destruction;
- Reduction in emissions of sulfur hexafluoride in the electric power sector;
- Carbon sequestration in US forests (through reforestation, improved forest management, avoided conversion, or afforestation);
- Reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion owing to end-use energy efficiency in the building sector; and
- Avoided methane emissions from agricultural manure management operations.

Additionality requirements apply to all RGGI offset allowances, which means in this specific case that projects are not eligible for offsets if they are funded with utility ratepayer dollars or required under any statute, regulation, or order. A rigorous procedure has been developed for registering and verifying offset allowances. It is notable that no offset allowances had been awarded to any projects as of the end of 2013, in part because the low price of emissions allowances has not encouraged alternative investments.[120]

The state of California has also opted to allow the use of registered and verified offsets for compliance with its GHG cap-and-trade program, but in its case more than 17 million offset credits have already been issued.[121] Regulated entities in California can use offsets to meet up to eight percent of their compliance obligation. Projects in five categories are currently eligible for offset credits if they meet all program requirements:

- US Forest Projects;
- Urban Forest Projects;
- Livestock Projects;

120 Potomac Economics for RGGI. (2014, May). *Annual Report on the Market for RGGI CO_2 Allowances:* 2013. Available at: http://www.rggi.org/docs/Market/MM_2013_Annual_Report.pdf

121 See: http://www.arb.ca.gov/cc/capandtrade/offsets/issuance/arb_offset_credit_issuance_table.pdf

- Ozone Depleting Substances Projects; and
- Mine Methane Capture Projects.

At the international level, the Kyoto Protocol to the United Nations Framework Convention on Climate Change includes two offset programs, the CDM and JI. Countries that committed to limiting GHG emissions under the Kyoto Protocol are allowed to meet some of their commitment by funding and implementing emissions reduction projects in other countries. These projects can earn offset credits representing one metric ton of GHG emissions reductions, which can be counted toward meeting Kyoto Protocol targets. The list of eligible projects is much broader than the five categories approved for use in RGGI.

A CDM or JI project has to meet additionality requirements (i.e., provide emissions reductions that are additional to what would otherwise occur, and not result in the diversion of normal international development assistance). Verification and approval requirements also apply. Since the beginning of 2006, thousands of projects have registered and produced almost 2.5 billion credits.[122] In Europe, where the European Union's Emissions Trading Scheme is used by most countries to comply with Kyoto Protocol commitments, CDM and JI credits can be used for Emissions Trading Scheme compliance purposes by regulated entities.

The voluntary offset market is now much smaller than the markets using offsets for compliance purposes. A recent report on the state of the voluntary market found that it encompassed 102.8 million metric tons of GHG emissions in 2012, and 76 million metric tons in 2013. Most of this decline is attributed to changes in California, where offset projects that had previously been registering credits for voluntary purposes instead began registering for the new, mandatory cap-and-trade program. Even so, the voluntary market in 2013 brought in $379 million for offset projects that reduce GHG emissions.[123] A common criticism of voluntary offsets is that they are not regulated and thus not subject to the same project eligibility, additionality, and verification standards as compliance market offsets. However, several voluntary standards administered by independent third-party verifiers have been introduced in recent years to bring more credibility to this market.

The EPA, in its 111(d) rulemaking, proposed that offsets from outside the US power sector could not be applied to demonstrate compliance by regulated sources. The rationale behind this decision appears to be based on the idea that out-of-sector offsets do not, by definition, reduce power sector emissions and may not be a legal option under the specific language of Section 111 of the Clean Air Act. However, the EPA tried to make clear that programs like the RGGI and California cap-and-trade programs, which allow for the use of offsets, will not run afoul of the regulations so long as the affected EGUs would not exceed their federal 111(d)-based emissions limits. Officials in some states feel that this does not go far enough, and have asked the EPA to afford states more flexibility to use offsets. For example, comments on the proposed rule that were submitted by officials in Kentucky and Georgia recommend that the EPA allow offsets from outside the power sector to be used for compliance.[124]

4. Multi-Pollutant Planning

Most US states require utilities to plan for meeting forecasted annual peak and energy demand, plus an established reserve margin, considering all available supply- and demand-side resource options over a specified future period. Called "integrated resource planning" (IRP) and discussed at length in Chapter 22, such planning is often time- and resource-intensive, but its benefits are great – particularly to consumers. State public utilities commissions typically review and approve IRP plans submitted by utilities.[125]

There is no similarly comprehensive consideration in air

122 Refer to: http://cdm.unfccc.int/index.html and http://ji.unfccc.int/statistics/2015/ERU_Issuance_2015_01_31_1200.pdf

123 Peters-Stanley, M., & Gonzalez, G. (2014). *Sharing the Stage: State of the Voluntary Carbon Markets 2014.* Forest Trends' Ecosystem Marketplace. Available at: http://www.forest-trends.org/documents/files/doc_4841.pdf

124 Refer to pp. 13–14 of the Kentucky cabinet's comments at http://eec.ky.gov/Documents/Ky%20EEC%20111(d)%20Comments%20Nov.%2026,%202014.pdf, and p. 7 of the comments submitted by the Georgia Public Service Commission at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-23535

125 Wilson, R., & Biewald, B. (2013, January). *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans.* Synapse Energy Economics, Inc. for The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6608

quality planning that takes into account the multiple public health and welfare threats of various air pollutant emissions and how collectively they might be addressed most cost-effectively and expeditiously. Instead, the Clean Air Act clearly delineates and separates different air pollutants and different ways in which they are to be regulated. This is unfortunate because sources often emit multiple pollutants, and control measures can often be selected that reduce emissions of multiple pollutants simultaneously.

The idea of addressing air quality from a holistic, multi-pollutant perspective is not new. Several papers and books have been written on this topic and several recommendations made for the EPA, state, and local air quality agencies to consider adopting multi-pollutant approaches. Economic models also conclude that reducing multiple air pollutants through root-of-pipe measures (e.g., at the beginning of industrial processes) is far more cost-effective than multiple pollutant-specific approaches focused only at the end of the pipe.[126]

Two influential bodies in fact have recommended that the EPA explicitly enable and encourage states to develop multi-pollutant plans. In 2004, the National Research Council of the National Academies of Science published "Air Quality Management in the United States." This comprehensive assessment identified five major recommendations for the EPA to consider and adopt. Among them were to "transform the [state implementation plan] SIP process into a more dynamic and collaborative performance-oriented, multi-pollutant air quality management planning (AQMP) process" and to "develop an integrated program for criteria pollutants and hazardous air pollutants."[127] In 2010, the Clean Air Act Advisory Committee (CAAAC) developed a framework for a multi-pollutant strategy. The CAAAC's objectives were to align four major Clean Air Act programs: National Emission Standards for Hazardous Air Pollutant Standards (NESHAPS), New Source Performance Standards (NSPS), National Ambient Air Quality Standard (NAAQS), and New Source Review (NSR), and to coordinate – for the affected sources of pollution – the timing and obligations associated with these programs. CAAAC noted, "The Clean Air Act – read according to its express terms and without much of the intervening interpretative gloss of the past four decades – provides sufficient flexibility to achieve these objectives."[128] These recommendations appear even more appropriate with the recent addition of proposed GHG emissions reduction requirements.

The National Academies of Science and CAAAC recommendations anticipate that, done correctly along the lines of an "air quality IRP," states could develop comprehensive plans that meet existing NAAQS, as well as anticipate future NAAQS, hazardous air pollutant standards, and GHG reduction requirements. This concept has been explored further by The Regulatory Assistance Project under the rubric of Integrated Multi-Pollutant Planning for Energy and Air Quality (IMPEAQ).[129] IMPEAQ would identify all measures needed to meet a state's long-term air quality goals. Each time a NAAQS, NSPS, or NESHAP is revised by the EPA, the state would identify, assign, and/or add appropriate elements from its IMPEAQ planning process and incorporate them into the required state implementation plan (SIP) or other compliance plan revision as needed for EPA approval. Unlike IRP as generally practiced in the power sector, IMPEAQ would seek to include "externalities" in air quality decisions (e.g., the societal benefits and costs associated with the adoption and implementation of air quality control measures).

Although the Clean Air Act generally applies a pollutant-by-pollutant approach, it does not restrict states to developing air quality plans that only address one pollutant or that only include measures to reduce a single pollutant. Economic models conclude that the costs to achieve a particular environmental end-point are lower when the selected control measures reduce several pollutants at the

126 James, C., & Colburn, K. (2013, March). *Integrated, Multi-Pollutant Planning for Energy and Air Quality (IMPEAQ)*. Montpelier, VT: The Regulatory Assistance Project. Available at: www.raponline.org/document/download/id/6440

127 National Research Council, Committee on Air Quality Management in the United States. (2004). *Air Quality Management in the United States*. Available at: http://www.nap.edu/catalog/10728/air-quality-management-in-the-united-states

128 Clean Air Act Advisory Committee, Economic Incentives and Regulatory Innovation Subcommittee. (2010, September). *A Conceptual Framework for a Source-Wide Multi-Pollutant Strategy*. Available at: http://www.eli.org/sites/default/files/docs/seminars/10.20.10dc/EPA-Attachment-4.pdf?q=pdf/seminars/10.20.10dc/EPA-Attachment-4.pdf. CAAAC formally advises the EPA on air quality programs and regulatory standards.

129 Supra footnote 126.

same time and when both demand-side measures and end-of-pipe measures are applied. For example, modeling completed by the Bay Area Air Quality Management District for its 2010 Clean Air Plan indicated that public health benefits and reduced damages from climate change in the range of $270 million to $1.5 billion per year could be achieved from a suite of 55 control measures that would jointly reduce criteria, toxic, and GHG pollutants.[130]

Similarly, work using the GAINS model demonstrates that the cost to reduce public health risk by 50 percent over 20 years can be reduced by one-third when the control measures include energy efficiency, combined heat and power, and end-of-pipe controls, as compared to only end-of-pipe controls.[131] The EPA's regulatory impact analysis for the Mercury and Air Toxics Standards also showed that the costs of meeting the mercury standard were $3 to $12 billion lower when energy efficiency was an integral part of the control strategy, and that emissions of SO_2, NO_X, and CO_2 were also lower.[132] Another EPA analysis performed for the cement industry indicated that compliance costs to meet NSPS and NESHAPs would be lower and provide greater environmental benefits if the various regulations were synchronized.[133]

Among US states, Maryland is a leader in advancing multi-pollutant approaches. Working with the Northeast States for Coordinated Air Use Management, the University of Maryland, and Towson University, the Maryland Department of the Environment has leveraged Maryland's 2015 ozone SIP requirements and state-legislated 2012 GHG reduction requirements to build a multi-pollutant analytical framework. The Maryland Department of the Environment's framework allows it to:

- Quantify the emissions reductions of multiple pollutants for a broad suite of energy efficiency and renewable energy efforts;
- Model the reductions in ozone, fine particulate, and other pollutants;
- Estimate the public health benefits associated with those reductions; and
- Quantify the economic benefits and costs.[134]

The Regulatory Assistance Project envisions IMPEAQ as an air quality planning process that builds upon the best components of utility IRP processes and also incorporates environmental, energy, and economic externalities that are not typically included in an IRP. Including externalities and their influence on the cost-effectiveness of control measures – and considering whether and how control measures may have unintended consequences – can help meet both air regulators' goals to attain and maintain compliance with NAAQS and other requirements of the Clean Air Act, and energy regulators' goals to assure reliable and affordable electric and gas service.

5. Conclusion

As noted in the introduction to this document, the EPA's proposed Clean Power Plan establishes state-specific CO_2 emissions standards using four building blocks. These building blocks are intended to reflect the degree of emissions limitation achievable through the application of the best system of emission reduction that the EPA believes has been adequately demonstrated, taking into account the cost of achieving such reductions and any non-air-quality health and environmental impacts and energy requirements.

The proposed CPP does not, however, compel states to use the same four building blocks to meet the state-specific emissions targets. Instead, states are free to identify other options to reduce CO_2 emissions and to submit compliance plans that incorporate any combination of measures in the

130 Bay Area Air Quality Managment District. (2010, September 15). *2010 Clean Air Plan.* Available at: http://www.baaqmd.gov/Divisions/Planning-and-Research/Plans/Clean-Air-Plans.aspx

131 Bollen, J. C., van der Zwaan, B., Corjan, B., & Eerens, H. (2009). Local Air Pollution and Global Climate Change: A Combined Cost-Benefit Analysis. *Resource and Energy Economics 31;* 161–181. Available at: https://ideas.repec.org/a/eee/resene/v31y2009i3p161-181.html

132 US EPA. (2011, March). *Regulatory Impact of the Proposed Toxics Rule, Final Report (Chapter 8).*

133 Witosky, M. (2010, May 26). *Sector-Based Multi-Pollutant Approaches for Stationary Sources.* Presentation to the Clean Air Act Advisory Committee. US EPA Office of Air Quality Planning and Standards. Available at: http://www.eli.org/sites/default/files/docs/seminars/10.20.10dc/EPA-Attachment-1.pdf?q=pdf/seminars/10.20.10dc/EPA-Attachment-1.pdf

134 Adburn, T. (2013, March 25). *Building Energy Efficiency and Renewable Energy Programs Into the Clean Air Planning Process: Taking Credit for Nontraditional Programs.* Presentation at ACEEE Market Transformation Symposium. Maryland Department of the Environment. Available at: aceee.org/files/pdf/conferences/mt/2013/Tad%20Aburn_D2.pdf

EPA's building blocks, as well as other options that in total reduce CO_2 emissions sufficiently to achieve compliance with the CPP's emissions targets. The broad variety of technology and policy options available for states to consider and incorporate in their CPP compliance plans is evident in the previous 25 chapters of this *Menu of Options* – a breadth that far exceeds the EPA's four building blocks.

This twenty-sixth chapter introduces a variety of rapidly emerging technologies and additional policy opportunities that regulators may wish to consider as they formulate plans to reduce future power sector GHG emissions. With the dramatic evolution underway in the power sector, additional options – some not even conceived today – are likely to become available. Illustration of this rapid evolution is evident in the fact that many of the technologies and policies covered in this *Menu of Options* have advanced significantly during the year of its development and publication.

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