Technical Support Document (TSD) for
Carbon Pollution Guidelines for Existing Power Plants:
Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources:
Electric Utility Generating Units

Docket ID No. EPA-HQ-OAR-2013-0602

GHG Abatement Measures

U.S. Environmental Protection Agency
Office of Air and Radiation

June 10, 2014

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This version of the GHG Abatement Measures TSD corrects minor typographical errors EPA found in the version posted on the web on June 2, 2014.

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Chapter 1: Introduction

CAA section 111(d) requires that state plans must establish standards of performance that reflect the degree of emission limitation achievable through the application of the *best system of emission reduction* (BSER) that, taking into account the cost of achieving such reductions and any non-air quality health and environmental impact and energy requirements, the Administrator determines has been adequately demonstrated. Under CAA section 111(a)(1) and (d), the EPA is authorized to determine the BSER and to calculate the amount of emission reduction achievable through applying the BSER.

As a first step towards determination of BSER, the EPA recognized that, in general, reductions in carbon dioxide (CO_2) emissions from individual existing electric generating units (EGUs) can be achieved by implementing either of two basic approaches: (1) making emission rate improvements at affected EGUs (e.g., by improving heat rates or switching to lower carbon fuels), and/or (2) reducing utilization of greenhouse gas (GHG)-emitting EGUs (e.g., by reducing the overall demand for electricity or by shifting dispatch from higher-GHG-emitting EGUs to lower-GHG-emitting and non-emitting units). Accordingly, to determine BSER for reducing GHG emissions at affected units, the EPA evaluated numerous GHG abatement measures that utilize the above approaches. In its evaluation, the EPA considered only those measures that have been adequately demonstrated to reduce CO_2 emissions from fossil fuel-fired EGUs. These measures included: heat rate improvements at individual EGUs, switching to lower carbon fuels at individual EGUs, carbon capture and sequestration at individual EGUs, shifting dispatch from higher-GHG-emitting EGUs to lower-GHG-emitting and non-emitting units, and reducing the overall demand for electricity via improvements in demand-side energy efficiency.

Based on its evaluation of the above GHG abatement measures, the EPA identified four categories of demonstrated measures, or “building blocks,” that are technically viable and broadly applicable, and can provide cost-effective reductions in CO_2 emissions from individual existing EGUs. These building blocks include:

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 NGCC 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; and,

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 believes that for purposes of CAA section 111(d), as applied to the power sector, the BSER encompasses all four building blocks. The application of all four building blocks as BSER is consistent with current trends in the electric power sector and with strategies that companies and states are already taking to reduce GHG emissions. Also, the application of all four building blocks as BSER supports achieving cost-effective, and technically feasible reductions of CO_2.

The subsequent chapters in this technical support document describe EPA's evaluation of all adequately demonstrated GHG abatement measures. While evaluating each measure, the EPA considered its technical feasibility, applicability and use, application level appropriate for BSER, and cost effectiveness associated with reducing GHG emissions at EGUs.

Chapter 2: Heat Rate Improvement at Existing Coal-fired EGUs

2.0 Introduction

Based on the range of operating efficiencies for existing coal-fired electric generating units (EGUs), it is evident that EGUs are generally less efficient at converting fuel into electricity than is technically and economically possible. For example, the difference in operating efficiency of EGUs with similar design characteristics and the year-to-year variability in individual EGU efficiency indicates that there is potential for broadly applicable efficiency improvements through cost-effective operational and maintenance practices. These improved efficiencies would result in corresponding reductions in greenhouse gas emissions.

This chapter presents an overview of existing coal-fired EGUs, design factors that influence efficiency, technologies to improve efficiency, previous studies estimating potential efficiency improvements, the proposed EPA approach to calculate efficiency improvements, and the estimated capital costs of those improvements.

2.1 Overview of U.S. Existing Coal-Fired Electric Generating Units

Coal in the United States is predominately used for electric power generation. Most coal-fired EGUs in the United States burn either bituminous or subbituminous coals. The largest sources of bituminous coals burned in coal-fired EGUs are mines in regions along the Appalachian Mountains and in southern Illinois, western Kentucky and Indiana. Additional bituminous coals are supplied from mines in Utah and Colorado. The vast majority of subbituminous coals are supplied from mines in Wyoming and Montana, with many coal-fired EGUs burning subbituminous coals from the Powder River Basin (PRB) region in Wyoming. In general, the burning of lignite by U.S. electric utilities is limited to coal-fired EGUs that are located near the mines that supply the lignite in Texas, Louisiana, Mississippi, Montana, and North Dakota. At a few power plant locations in the Eastern United States, recovered anthracite coal or coal refuse is burned in limited quantities.

Existing coal-fired EGUs in the U.S. electric utility fleet use one of five basic coal combustion configurations: (1) pulverized coal (PC) combustion, (2) fluidized-bed combustion (FBC), (3) gasified coal combustion, (4) cyclone furnace combustion, or (5) stoker-fired coal combustion. Table 2-1 presents a summary of the operating characteristics of each of these coal combustion configurations.

Table 2-1. Characteristics of coal-firing configurations used for U.S. EGUs

Coal-firing Configuration	Coal Combustion Process Description	Distinctive Design/Operating Characteristics	
Pulverized Coal (PC) Combustion	Coal is ground to a fine powder that is pneumatically fed to a burner where it is mixed with combustion air and then blown into the furnace. The pulverized-coal particles burn in suspension in the furnace. Unburned and partially burned coal particles are carried off with the flue gas.	Wall-fired	An array of burners fire into the furnace horizontally, and can be positioned on one wall or opposing walls depending on furnace design.
		Tangential-fired (Corner-fired)	Multiple burners are positioned in opposite corners of the furnace producing a fireball that moves in a cyclonic motion and expands to fill the furnace.
Fluidized-bed Combustion (FBC)	Coal is crushed into fine particles. The coal particles are suspended in a fluidized bed by upward-blowing jets of air creating a turbulent mixing of combustion air with the coal particles. Typically, the coal is mixed with a sorbent such as limestone (for SO_2 emission control). FBC have a greater fuel flexibility than PC EGUs and can be designed for combustion within the bed to occur at atmospheric or elevated pressures. FBC operating temperatures are in the range of 1,500 to 1,650°F (800 to 900°C).	Bubbling fluidized bed (BFB)	Operates at relatively low gas stream velocities and with coarse-bed size particles. Air in excess of that required to fluidize the bed passes through the bed in form of bubbles.
		Circulating fluidized bed (CFB)	Operates at higher gas stream velocities and with finer-bed size particles. No defined bed surface. Must use high-volume, hot cyclone separators to recirculate entrained solid particles in flue gas to maintain the bed and achieve high combustion efficiency.
Integrated Coal Gasification Combined Cycle (IGCC)	Synthetic combustible gas ("syngas") derived from an on-site coal gasification process is burned in a combustion turbine. The hot exhaust gases from the combustion turbine pass through a heat recovery steam generator to produce steam for driving a steam turbine/generator unit.	Coal gasification units are unique among coal-firing configurations because a gaseous fuel (synfuel or syngas) is burned instead of solid coal because the combustion and power generation process and combines the Rankine and Brayton thermodynamic cycles as is the case for a combined cycle power plant.	
Cyclone Furnace Combustion	Coal is crushed into small pieces and fed through a burner into the cyclone furnace. A portion of the combustion air enters the burner tangentially creating a whirling motion to the incoming coal.	Designed to burn coals with low-ash fusion temperatures that are difficult to burn in PC boilers. The majority of the ash is retained in the form of a molten slag.	
Stoker-fired Coal Combustion	Coal is crushed into large lumps and burned in a fuel bed on a moving, vibrating, or stationary grate. Coal is fed to the grate by a mechanical device called a "stoker."	One of three types of stoker mechanisms can be used that ether feed the coal by pushing, dropping, or flipping coal unto the grate.	

The three technologies currently used for new coal-fired power plants are pulverized coal, fluidized bed (FBC), and integrated coal gasification combined cycle (IGCC). Pulverized coal combustion is the coal-firing configuration predominately used at existing EGUs. The most recent coal technology combustion development involves the integration of coal gasification technologies with the combined cycle electric generation process. The efficiency of an IGCC power plant is comparable to the latest advanced PC-fired and FBC EGU designs using supercritical steam cycles. The advantages of using IGCC technology can include greater fuel flexibility (e.g., capability to use a wider variety of coal ranks), potential improved control of PM, SO_2 emissions, and other air pollutants, the need for fewer post-combustion control devices (e.g., almost all of the sulfur and ash in the coal can be removed once the fuel is gasified and prior to combustion), generation of less solid waste, reduced water consumption, and the chemical process that creates a concentrated CO_2 stream that is more amenable to carbon capture processes.

Older combustion technologies, namely cyclone furnaces and stoker-fired coal combustion, have been replaced at new coal-fired EGUs by more efficient methods that provide superior coal combustion efficiency and other advantages. However, a few remaining old stoker-fired EGUs and cyclone furnaces still remain in service for a small number of existing EGUs in the U.S. electric utility market.

2.2 Influence of Heat Rate on Coal-Fired EGU CO_2 Emission Rate

Heat rate is a common way to measure EGU efficiency. As the efficiency of a coal-fired EGU is increased, less coal is burned per kilowatt-hour (kWh) generated by the EGU resulting in a corresponding decrease in CO_2 and other air emissions. Heat rate is expressed as the number of British thermal units (Btu) or kilojoules (kJ) required to generate a kilowatt-hour (kWh) of electricity. Lower heat rates are associated with more efficient coal-fired EGUs.

The electric energy output for an EGU can be expressed as either as “gross output” or “net output.” The gross output of an EGU is the total amount of electricity generated at the generator terminal. The net output of an EGU is the gross output minus the total amount of auxiliary (or parasitic) electricity used to operate the EGU (e.g., electricity to power fuel handling equipment, pumps, fans, pollution control equipment, and other on-site electricity needs), and thus is a measure of the electricity delivered to the transmission grid for distribution and sale to customers. Some EGUs also produce part of their useful output in the form of useful thermal output (e.g., steam for heating purposes). These types of facilities are called combined heat and power, or CHP, facilities.

A variety of factors must be considered when comparing the effectiveness of heat rate improvement technologies to increase the efficiency of a given coal-fired EGU. The actual overall efficiency that a given coal-fired EGU achieves is determined by the interaction of a combination of site-specific factors that impact efficiency to varying degrees. Examples of the factors affecting EGU efficiency at a given facility include:

- *EGU thermodynamic cycle* – EGU efficiency can be significant improved by using a supercritical or ultra-supercritical steam cycle. Supercritical and ultra-supercritical boilers operate above the critical point of water (approximately 374°C (705°F) and 22.1 MPa (3,210 psia)). As a general guideline, the thermal design efficiencies for subcritical EGUs are in the range of 35% to 37%, supercritical EGUs are in the range of 39% to 40%, and ultra-supercritical EGUs in the range of 42% to 45%. However, actual operating efficiencies can be lower than design efficiencies.
- *EGU coal rank and quality* – EGUs burning higher quality coals (e.g., bituminous) tend to be more efficient than EGUs burning lower quality coals with higher moisture contents (e.g., lignite). Bituminous coals have higher heating values of greater than 10,500 British thermal units per pound and lignite coals have higher heating values of less than 8,300 British thermal units per pound.
- *EGU size* –EGU efficiency generally increases somewhat with size (e.g., from 200 MW to 800 MW) because: a) the boiler and steam turbine losses are lower for larger equipment compared to smaller equipment, b) larger units tend to be younger incorporating improvements from advanced technologies, and c) the economy of scale of larger units allows the use of higher cost improvements to be more economic.
- *EGU pollution control systems* – The electric power consumed by air pollution control equipment reduces the overall efficiency of the EGU.
- *EGU operating and maintenance practices* – The specific practices used by an individual electric utility company for combustion optimization, equipment maintenance, etc. can affect EGU efficiency.

- *EGU cooling system* – The temperature of the cooling water entering the condenser can have impacts on steam turbine performance. Once-through cooling systems can have an efficiency advantage over recirculating cooling systems (e.g., cooling towers). However, once-though cooling systems typically have larger water related ecological concerns than recirculating cooling systems.
- *EGU geographic location and ambient conditions* – The elevation and seasonal ambient temperatures at the facility site potentially may have an impact on EGU efficiency. At higher elevations, air pressure is lower and less oxygen is available for combustion per unit volume of ambient air than at lower elevations. Cooler ambient temperatures theoretically could increase the overall EGU efficiency by increasing the draft pressure of the boiler flue gases and the condenser vacuum, and by increasing the efficiency of the cooling system. Also, geographic location influences the type of cooling system that can be used (e.g., EGUs located in arid locations often cannot use once through cooling)
- *EGU load generation flexibility requirements* – Operating an EGU as a baseload unit is more efficient than operating an EGU as a load following unit to respond to fluctuations in customer electricity demand.
- *EGU plant components* – EGUs using the optimum number of feedwater heaters, high-efficiency electric motors, variable speed drives, better materials for heat exchangers, etc. tend to be more efficient.

2.3 Technologies to Improve Existing Coal-Fired EGU Heat Rate

A number of studies have been conducted involving literature reviews of published articles and technical papers identifying potential efficiency improvement techniques applicable to existing coal-fired EGUs.[1] For example, a summary of the findings from one study conducted by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) is presented in Table 2-2. The efficiency percentages were converted to a common basis so that all of the data can be compared. All of the improvement technologies presented in Table 2-2 cannot necessarily be implemented at every existing coal-fired EGU facility in the U.S. electric utility

[1] See HRI Partial Bibliography at the end of this chapter.

fleet. The existing EGU design configuration and other site-specific factors may prevent the technical feasibility of using a given technology.

Typically, these studies share as a common basis the estimated potential efficiency improvement percentages and costs from the engineering study originally completed by Sargent and Lundy in 2009 titled "Coal-Fired Power Plant Heat Rate Reductions." It describes numerous well-known and technically proven methods to improve efficiency of coal-fired EGUs. The study lists possible efficiency improvements in the boiler, turbine, flue gas system, air pollution control equipment and the water treatment system. Each of these main areas are expanded upon below.

2.3.1 Boiler

The systems to focus on for improving heat input within the boiler area include the materials handling, combustion system, boiler control system, sootblowers, and the air heaters.

2.3.1.1 Materials Handling[2]

The coal-handling portion of materials handling typically requires about 0.07% (7 Btu/kWh) of the gross electrical output of a power plant. Depending on the state of the motors and drives, replacing them with energy-efficient motors and variable frequency drives can reduce the auxiliary power requirements. The variable frequency drives also limit the stress and strain on the other equipment.

Coal pulverizers typically require about 0.6% (60 Btu/kWh) of the gross electrical output and can be upgraded to provide more consistent size and finer coal particles. The fine particles improve combustion efficiency, consequently reducing fuel cost and heat rate. The costs for changes to the pulverizer system are significant, and, historically, the projects have improved the heat rate justifiably only when the existing equipment has degraded.

The bottom ash handling system may be a candidate for heat rate improvement. Switching from a water-sluicing bottom ash system to a dry drag chain system can reduce the auxiliary requirements and reduce the amount of water to the water treatment plant. The typical power requirements are about 0.1% (10 Btu/kWh) of the plant's gross output.

2.3.1.2 Economizer

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[2] The Sargent and Lundy report did not provide potential savings for material handling operations. Energy use in Btu/kWh has been provided to compare the energy use of materials handling relative to the potential energy savings from other efficiency activities.

An economizer is a heat exchanger that improves the efficiency of an EGU by recovering energy from the exhaust gases to preheat the boiler feedwater. The replacement of the economizer can lead to substantial heat rate improvements around 50-100 Btu/kWh, but is large capital investment (~$2-8M). Due to this high cost, economizer upgrades are not generally performed unless the existing equipment has degraded or a replacement is necessary due to the installation of new control equipment.

2.3.1.3 Boiler Control System

The boiler control system has a large impact on the heat rate of the unit. The process control capabilities can control and evaluate many aspects of the plant's operations. Commonly referred to as Neural Network, computer models are able to control the plant's processes by predicting performance during static and dynamic changes. Many vendors offer Neural Network systems to improve the overall efficiency. Neural network systems are typically around $550,000-$750,000 and offer heat rate reductions up to 150 Btu/kWh.

2.3.1.4 Sootblowers

Intelligent sootblowers may be installed to improve system efficiency. The intelligent sootblowers system monitors the furnace exhaust gas temperatures and steam temperatures. Other readings may be incorporated into the intelligent sootblower system, which also communicates with the boiler control system. This system uses real-time data to identify which areas need sootblowing. Boiler efficiency improvements range from 30-150 Btu/kWh with capital costs around $300,000-$500,000 and $50,000/year for fixed operating and maintenance costs.

2.3.1.5 Air Heaters

Air heaters operate to transfer heat between the incoming pre-combustion air and the effluent flue gas. These systems are critical to maintain an efficient power plant. For these systems to operate most efficiently, air heater leakages must be maintained below 6% of incoming air flow. Most leakage is due to the pre-combustion air leaking across the rotating section and leaving with the flue gas. This increases the flue gas volume going through the forced draft and induced draft fans and avoids capturing the heat transferred between the flue gas and pre-combustion air. The increased volume requires more power to move more flue gas. Improvements to seals on the air heaters reduce the leakages. Improvements to reduce air heater and duct leakages generally reduce the heat rate by 10-40 Btu/kWh with capital costs between $0.3-1.2M.

A second method to improve the heat rate is to lower the air heater outlet temperature by controlling the acid dew point. Typically the air heater outlet is maintained at 20-30°F above the sulfuric acid dew point to prevent corrosion of cold-end baskets. Injection of sorbents such as Trona or hydrated lime can be used to lower the dew point. Depending on the sizing of the air heater, it may need to be modified in order to optimize the lower outlet temperature. The capital costs can range from $1.5-18M for heat rate reductions of 50-120 Btu/kWh.

2.3.2 Turbine

The systems within the turbine area on which to focus heat rate improvements are the turbine, the feedwater heaters, the condenser, and the turbine drive and motor-driven feed pumps.

2.3.2.1 Turbine

Replacement or overhaul of existing steam turbines with advanced turbine designs improves the efficiency of converting the energy in the steam to electrical energy. The capital costs for these projects ranges from $2-25M with heat rate reductions of 100-300 Btu/kWh.

2.3.2.2 Feedwater Heaters

The feedwater heaters are heat exchangers used to heat the boiler feedwater by extracting heat from the steam leaving the turbine section. The EGU efficiency can be increased by improving the heat transfer surface area. This entails adding heat exchange surfaces to the existing heaters or adding additional heaters. The costs relative to the heat rate improvement associated with these projects typically prohibit the advancement of the project unless the feedwater heaters are in need of repair.

2.3.2.3 Condenser

To obtain the most efficiency from the condenser section, the most effective operation would have the steam from the turbine to reach the lowest temperature possible before entering the condenser. This allows for the turbine to extract as much energy from the steam as possible. Condensers are subject to fouling and plugging, which directly impact the heat transfer rates and water quality. To improve water quality, closed cooling water systems can be used to provide better control over water quality and tube cleaning can be performed as needed. Heat rate reductions observed from condenser upgrades and maintenances are 30-70 Btu/kWh with annual fixed costs of $30,000-$80,000.

2.3.2.4 Boiler Feed Pumps

Boiler feed pumps require a large amount of auxiliary power to pump large amounts of boiler feedwater through the heaters and the boiler. Due to the high use of these pumps, maintenance is extremely important to ensure reliability and the most efficient operation. As the pumps wear and operate less efficiently, a pump overhaul may be required. The overhaul can reduce the heat rate by 25-50 Btu/kWh with capital costs around $250,000-$800,000.

2.3.3 Flue Gas System

Two aspects of the flue gas system that can contribute to improvements in the plant heat rate are: (1) improve the forced draft and induced draft fan efficiencies, and (2) implement variable frequency drives.

2.3.3.1 Induced Draft Fans

One of the most important features in the fans is being able to control the flue gas flow. Many fans have dampers, which are the least efficient option. There are many other methods, such as variable inlet vanes, variable frequency drives, and variable pitch blades, available to control the flue gas flow allowing highly efficient fan performance. These upgrades or replacements provide a heat rate reduction of 10-50 Btu/kWh and cost between $6-$16M.

2.3.3.2 Variable Frequency Drives

Variable frequency drives facilitate more efficient plant operation by reducing the auxiliary load significantly. The capital costs for upgrading all drives at an EGU can be $6-16M with heat rate reductions between 10-150 Btu/kWh.

2.3.4 Emission Control Technologies

With the passage of environmental regulations, additional emission control devices have been and must be implemented in the power plant. These systems typically require large amounts of auxiliary power with their benefit being improved air quality. Even small upgrades can sometimes decrease the power requirements significantly while maintaining the level of emissions reduction desired. The three technologies discussed below are the flue gas desulfurization, the electrostatic precipitator, and the selective catalytic reduction systems.

2.3.4.1 Flue Gas Desulfurization

Coal-fired power plants use many types of flue gas desulfurization systems. Older units typically contained a venturi throat that increased the velocity of the fluid, but resulted in a large pressure drop and greater power to operate the induced draft fans. To improve this operation, a co-current spray tower quencher may replace the unit. The capital cost is about $2.5M with heat rate reductions around 13 Btu/kWh.

Another technology upgrade affects the vanes and distribution plate in an absorber. The improvement of the gas flow coming into contact with the absorber sorbent increases SO_2 capture, reduces maintenance due to erosion, and reduces the amount of energy required for the induced draft fan. Turning vanes and a perforated gas distribution plate improve gas distribution. The cost of the vanes is around $250,000 with heat rate reductions of 1-2 Btu/kWh.

In a wet flue gas desulfurization system, multiple spray levels are installed to deliver the limestone slurry. If a power plant is operating with SO_2 levels below its permit limit, turning off one spray level will reduce the auxiliary power required. If this is possible, a unit heat rate reduction of 16 Btu/kWh may be available.

2.3.4.2 Electrostatic Precipitator

The best operation for an electrostatic precipitator involves maintaining the maximum applied voltage, but below the level at which spark-over occurs. Electrostatic precipitator energy management system upgrades often help improve the electrostatic precipitator performance by maintaining the optimal performance and lowering power consumption. The installation for this technology can be from minimal to $0.8M and can lower heat rate by 5 Btu/kWh.

2.3.4.3 Selective Catalytic Reduction

For the last 15 years, selective catalytic reduction systems have been in use to reduce NO_X emissions from power plants. Extensive modeling was performed to achieve the necessary reduction with minimum ammonia slip. The results showed that reducing pressure drop and using secondary air as dilution for the ammonia vaporizer can reduce the auxiliary power necessary. The heat rate reduction is 0-10 Btu/kWh and capital costs between $0.5-$2M with fixed and variable costs up to $100,000 each.

2.3.5 Water Treatment System

The boiler water is one of the most important aspects of the power plant. The quality of the water is a key factor affecting the scale buildup on the boiler tubes, which reduces the heat transfer in the tubes or can cause tube failures. Proper use of chemicals to maintain pure water is key. Also, high-quality water can reduce the blowdowns required, which allows for more steam in the turbine cycle. If the water is not properly maintained, heat transfer may be reduced by up to 10%.

Similar to the boiler water, the cooling towers are also affected by the water quality. Fouling and scaling remain issues for heat transfer and purity of the water. By maintaining the cooling water system efficiently, the overall water quality is improved, which branches into other aspects already mentioned.

Table 2-2. Existing coal-fired EGU efficiency improvements reported for actual efficiency improvement projects

Efficiency Improvement Technology	Description	Reported Efficiency Increase[a]
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, CO 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 thorough 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.	0.2 to 1%
Flue Gas Heat Recovery	Flue gas exit temperature from the air preheater can range from 250 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 FGD systems, the flue gas is further cooled to approximately 125°F as it is sprayed with the FGD reagent slurry. However, it may be possible to recover some of this lost energy in the flue gas to preheat boiler feedwater via use of a condensing heat exchanger.	0.3 to 1.5%
Low-rank Coal Drying	Subbituminous and lignite coals contain relatively large amounts of moisture (15 to 40%) compared to bituminous coal (less than 10%). A significant amount of the heat released during combustion of low-rank coals is used to evaporate this moisture, rather than generate steam for the turbine. As a result, boiler efficiency is typically lower for plants burning low-rank coal. The technologies include using waste heat from the flue gas and/or cooling water systems to dry low-rank coal prior to combustion.	0.1 to 1.7%
Sootblower Optimization	Sootblowers 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. Proper control of the timing and intensity of individual sootblowers is important to maintain steam temperature and boiler efficiency. The identified technologies include intelligent or neural-network sootblowing (i.e., sootblowing in response to real-time conditions in the boiler) and detonation sootblowing.	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).	0.84 to 2.6

Source: National Energy Technology Laboratory (NETL), 2008. *Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet*, DOE/NETL-2008/1329. U.S. Department of Energy, National Energy Technology Laboratory, Pittsburgh, PA. July 23, 2008. Available at: <http://www.netl.doe.gov/energy-analyses/pubs/CFPP%20Efficiency-FINAL.pdf>.

[a] Reported efficiency improvement metrics adjusted to common basis by conversion methodology assuming individual component efficiencies for a reference plant as follows: 87% boiler efficiency, 40% turbine efficiency, 98% generator efficiency, and 6% auxiliary load. Based on these assumptions, the reference power plant has an overall efficiency of 32% and a net heat rate of 10,600 Btu/kWh. As a result, if a particular efficiency improvement method was reported to achieve a 1% point increase in boiler efficiency, it would be converted to a 0.37 % point increase in overall efficiency. Likewise, a reported 100 Btu/kWh decrease in net heat rate would be converted to a 0.30% point increase in overall efficiency.

2.4 Previous Studies on Heat Rate Improvements

A number of studies using varying approaches have been performed to determine potential efficiency improvements and associated resulting CO_2 emission reductions. These approaches include characterizing the current U.S. coal-fired EGU fleet, identifying potential efficiency improvements, and applying improvement actions to existing EGUs. The approach taken within each study varies. Five studies are briefly summarized and compared in Table 2-3.

The NETL studies used a benchmarking approach that evaluated the design factors that are known to influence efficiency and grouped EGUs based on similar design characteristics. The studies categorized the industry based on fuel type, location, steam cycle, and age of the boilers. Potential efficiency improvements were calculated based on an assumption that the lower-performing EGUs in each group should to be able to do as well as the better performing EGUs in that group. Specifically, the goal for potential improvement: for each subcategory was that the bottom 90% of EGUs in each group improved their heat rate to the average performance of top 10% in that group. While the studies are different in the level of detail and assumptions, the results of these studies overall suggest that a U.S. coal-fired EGU fleet-wide improvement ranging from 9% to 15% is theoretically possible. The Lehigh study used a less detailed approach and evaluated technologies applicable to bituminous and subbituminous coals to estimate potential fleet wide reductions.

An alternative approach to evaluate heat rate improvement is used by Resources for the Future. This study focused on the operating efficiency (synonymous with heat rate) of the entire existing U.S. coal-fired EGU fleet. The authors evaluated decades of data from industrial responses to economic factors such as demand, coal price and energy policies. This approach sought to estimate overall changes in industry fleet efficiency in response to changes in fuel prices or carbon prices. In one specific example, the coal price was assumed to be a 10% increase and the CO_2 emissions tax at $1.64 per ton for heat rate reductions of 0.3 to 0.9%.

The National Resources Defense Council approach considered the fleet of coal-fired EGUs and assumes a target heat rate in order for the EGUs to comply with an inferred standard. As opposed to the above studies that determined by how much the efficiencies can improve, this approach estimated how the industry will meet any imposed standards and calculated the heat rates necessary to meet a standard. As it has not been determined with regard to how the CO_2 emissions limit will be averaged, the paper discusses many potential options that coal-fired

EGUs may have to meet new standards. These options include additional options such as adding renewable, natural gas, and combined-cycle sources.

The EPA observed that existing HRI studies using a benchmarking approach have relied on a single year annual average heat rate data, whereas many of the operational impacts on heat rate (diurnal temperatures, load following, etc) become more apparent in the variability of hourly performance data. We further recognized that an examination of heat rate data over a multiple year period, perhaps a decadal time frame might reveal patterns of performance that should also inform estimates of HRI potential. For these reasons, the EPA has developed in this TSD an additional assessment of HRI potential that draws on multiyear historical hourly data. While we understand that engineering judgment remains essential to a proper interpretation of the results, the EPA intends that this assessment be a more substantial basis for estimating the fleet-wide HRI potential for coal-fired EGUs.

Table 2-3. Summary comparison of previous studies on EGU heat rate improvements

Study ID	Study Title Author	Factors Used for Industry Grouping	Key Study Assumptions	Relevant HRI Results
1	"Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet" NETL	*Plant design:* age and steam cycle	Category improvement is the bottom 90% of EGUs in each group improving their heat rate to the average performance of top 10% in that category Units with capacity factors under 50% were removed from dataset	15% reduction in overall heat rate of coal-fired EGUs
2	"Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions" NETL	*Plant design:* coal type, steam cycle, and size	Category improvement is the bottom 90% of EGUs in each group improving their heat rate to the average performance of top 10% in that category • Units with anomalous data, capacity factors under 10%, using less than 97% coal, and gasification plants were removed from dataset Low pressure subcritical units and 0-200 MW subbituminous units assumed retired for goal Lost generation made up by more efficient coal-fired EGUs	8.7% reduction in overall heat rate of coal-fired EGUs
3	"Reducing Heat Rates of Coal-Fired Power Plants"		All possible heat rate improvements are made	• 10% improvement for bituminous coal-fired EGU

Study ID	Study Title Author	Factors Used for Industry Grouping	Key Study Assumptions	Relevant HRI Results
	Lehigh Energy Update		including drying of high moisture coal:	• 15% improvement for subbituminous coal-fired EGU
4	"Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act" Resources for the Future	Analyze the actual operating efficiency of the entire fleet of U.S. coal-fired EGUs Assess abatement opportunities and costs by observing how coal plants respond to market and regulatory incentives to improve energy efficiency	Overall efficiency improvements of 2 to 5%, from other literature studies	10% coal price increase, corresponding to a tax on CO_2 emissions of about $1.64 per ton, improving heat rates by 0.3 to 0.9 %
5	"Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters" NRDC	*Plant design:* coal type and steam cycle	Improvements are broken into 3 group • Top 10% for each subcategory, no change • Top 11% to 49%, improve heat rate by 50% of the difference between facility heat rate and performance of top 10% in class or 600 Btu/kWh, whichever is less • Bottom 50%, improve heat rate by 100% of the difference between facility heat rate and performance of top 10% in class or 600 Btu/kWh, whichever is less	Broader analysis not strictly focused on heat rate improvements. 11% reduction on overall fossil fuel-fired EGU emission rates; includes switching from coal to natural gas.

2.5 EPA's Heat Rate Improvement Assessment

This EPA assessment of fleet-wide HRI potential looks at historical data from coal-fired EGUs in the U.S. to identify changes to EGUs' heat rates – the amount of heat input required, on average, to generate 1 kWh of electricity – that can be attributed to operation and maintenance practices and equipment upgrades. These heat rate changes are analyzed to determine their applicability to the rest of the coal-fired EGU fleet and to determine the potential heat rate improvement that, on average, could be achieved by the fleet.

This data analysis portion of the study relies on unit-level heat input and gross generation data reported to the EPA by owners or operators of EGUs to assess in detail the changes in gross heat rates. Potential changes in net heat rates are then addressed later in this section. Unit-level evaluations allowed the EPA to recognize the significant heterogeneity of coal-fired EGUs; even ‘sister’ units, units built at the same time at a given facility, may display different operating profiles and may have different equipment, controls, fuel mixes or cooling systems.

Based on literature reviews; informal interviews with engineering experts, vendors, and plant operators; and historical information collected by the EPA, we believe EGUs achieve heat rate improvements by: 1) operating under recommended operation and maintenance conditions (best practices), and 2) installing and using equipment upgrades. Best practices include no-cost or low-cost methods such as the installation or more frequent tuning of control systems and the like-kind replacement of worn existing components. Upgrades often involve higher costs and greater downtime, such as, extensive overhaul or upgrade of major equipment (turbine or boiler) or replacing existing components with improved versions.

The EPA developed unit-level statistics from over 60 million rows of hourly data. We evaluate each unit on its individual performance using heat rate variability as an indicator of the application of best practices and potential for improvement. To estimate heat rate improvement through equipment upgrades we survey engineering studies, examine year-to-year trends, and research EGUs where such methods were applied.

2.5.1 Study Population and Data

The EGU study population consists of 884 coal- and petroleum coke-fired EGUs that reported both heat input[3] and electrical output to the EPA’s Clean Air Markets Division in 2012.[4] It includes a wide range of configurations, from 24 to 1,500 MW nameplate capacities, super and subcritical thermodynamic cycles, between 1 and 69 years old, and different coal ranks. It excludes any EGUs at any facility that reported cogeneration to the EPA or the EIA. These units are excluded because a portion of the heat input was used to generate electricity and/or steam heat. Therefore, it is difficult for the EPA, using available data, to make a meaningful comparison of these units’ heat rates.

The EPA performed this study using hourly heat input (Btu), and electricity output (MWh) data from the Clean Air Markets Division and meteorological data from NOAA’s National Climatic Data Center for the years 2002-2012. As described later in this section, these

[3] Sources calculate heat input using an ‘F factor’ for the carbon content of the fuel being combusted and the average hourly measurements of CO_2 flow and concentration.
[4] Information on the Clean Air Markets Division data is available at http://ampd.epa.gov/ampd/

meteorological data were used to account for temperature impacts on heat rates. The eleven year study period is representative of a wide range of conditions, including growth and recessionary economic conditions, changing electricity generation from renewable and natural gas, and different regulatory constraints.

The hourly heat input and generation data used in this study is collected under the authority of 40 CFR part 75 (hereafter, Part 75). The EPA designed Part 75 to encourage complete and accurate emission measurement and reporting to support emission trading programs, including the Acid Rain Program and Clean Air Interstate Rule (CAIR). However, the EPA recognized that there will be times when emission data are not available due to monitoring system malfunctions or maintenance, technical challenges, or missed quality assurance/quality control (QA/QC) tests. When data are not available or deemed invalid (e.g., when a QA/QC test was not performed as required), the EPA has specified data substitution methods that are designed to overestimate emissions. This conservative bias is intended to create an incentive for better emission measurement – the overestimate incurs an economic penalty because, at the end of the compliance period, an EGU must surrender allowances equal to total reported emissions. Because of this conservative bias and the impact it would have on the results of this study, the EPA excluded substitute data reported by EGUs from this study's dataset. These substitute data represent approximately 2% of all reported operating hours. In addition, we excluded partial hours of operation that occur during the first hour of startup and the last hour of shutdown.

We also excluded 40 unit-years (0.5% of records) with atypical annual heat rates less than 6,500 or greater than 15,000 Btu/kWh resulting from a variety of factors including firing of natural gas, very low operating time, or errors in reported gross load. Table 2-4 summarizes the heat input, electric generation, heat rate and unit counts by year for the study population used in this work. This population corresponds to 9,388 unit-years of data at 884 distinct EGUs. Figure 2-1 displays the study population average gross heat rate by year and the 11-year average.

Table 2-4. Study Population Annual Heat Input, Generation, Heat Rate and Unit Count 2002 - 2012 [5]

Year	Heat Input (million MMBtu)	Electric Generation (million MWh-gross)	Heat Rate (Btu/kWh-gross)	Unit Count
2002	18,601	1,874	9,924	839
2003	18,428	1,864	9,886	834
2004	18,405	1,875	9,819	836
2005	18,665	1,910	9,774	838
2006	18,644	1,914	9,743	848
2007	18,704	1,920	9,740	846
2008	18,459	1,914	9,643	852
2009	16,588	1,719	9,649	864
2010	17,693	1,831	9,662	869
2011	16,934	1,744	9,708	878
2012	14,947	1,536	9,732	884

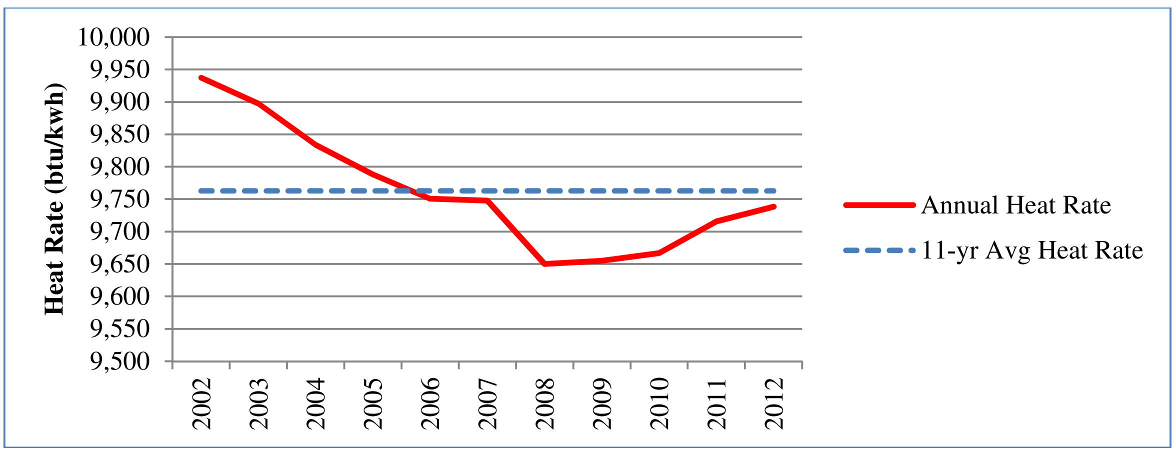

Figure 2-1. Study Population Average Gross Heat Rate by Year

NOAA's Integrated Surface Data (ISD) product provides hourly temperature for over 20,000 weather stations worldwide.[6] Since EGU heat rate performance is sensitive to air temperature and barometric pressure, which vary with elevation, we use meteorological data from stations that are reasonably close to the EGU's location and elevation to account for the

[5] The study population for each year includes those EGUs that reported both heat input and electric generation.
[6] Temperature data is from NOAA's Integrated Surface Data at http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/integrated-surface-database-isd.

impact of ambient conditions. For each of the plants in this study's database, we identified the nearest stations that reported a minimum of 8,400 hourly observations in the calendar year (i.e., greater than 95% of the hours in a year). Generally, each plant was associated with meteorological data from the two closest stations over the eleven-year study period. The average distance between the plant and the nearest station was 22 miles and the average difference in elevation was 366 feet. At nine plants we used data with as few as 7,000 observations in order to keep the maximum difference in elevation under 1,000 feet. The EPA believes that nearby weather station measurements are a good approximation of ambient meteorological conditions at each facility. Joining the trimmed heat rate and hourly temperature datasets resulted in 61,848,580 hourly records for the study population of EGUs (see Table 2-4).

The results of this study are based on analyses of data from the population of coal-fired EGUs shown in Table 2-4. These units emitted 1,605 million tons of CO_2 in 2012. In contrast, emissions of CO_2 from coal-fired EGUs in the entire U.S. electric power sector in 2012 were at 1,669 million tons according preliminary data from the EIA.[7] Since the study population of EGUs accounted for over 96% of CO_2 emissions from the fleet of U.S. coal-fired EGUs, the EPA considers the results of this study to be applicable to the coal-fired fleet at large.

2.5.2 Subcategorization

In this analysis, units are not categorized by unit specific design characteristics or fuel because: (1) EGU-specific detailed design information on all factors that influence heat rate is not available, and (2) certain design characteristics are not easily categorized (e.g., EGUs use a large range of steam conditions). Several other studies do categorize EGUs broadly by capacity, thermodynamic cycle, and/or fuel rank. Although the EPA believes grouping by categories can provide a useful way of understanding the operating profile of an EGU and the fleet, the range of heat rates for the broad categories has significant overlap (see box and whisker chart in Figure 2-2) and therefore makes it challenging to develop appropriate categorization. The figure below displays available information on coal-fired EGUs considered in this work for the years 2009-2011 in typical subcategories of capacity, fuel rank, and thermodynamic cycle. As the figure reflects, the means are clustered and the ranges of heat rates overlap.

[7] Preliminary 2012 results from http://www.eia.gov/tools/faqs/faq.cfm?id=77&t=3.

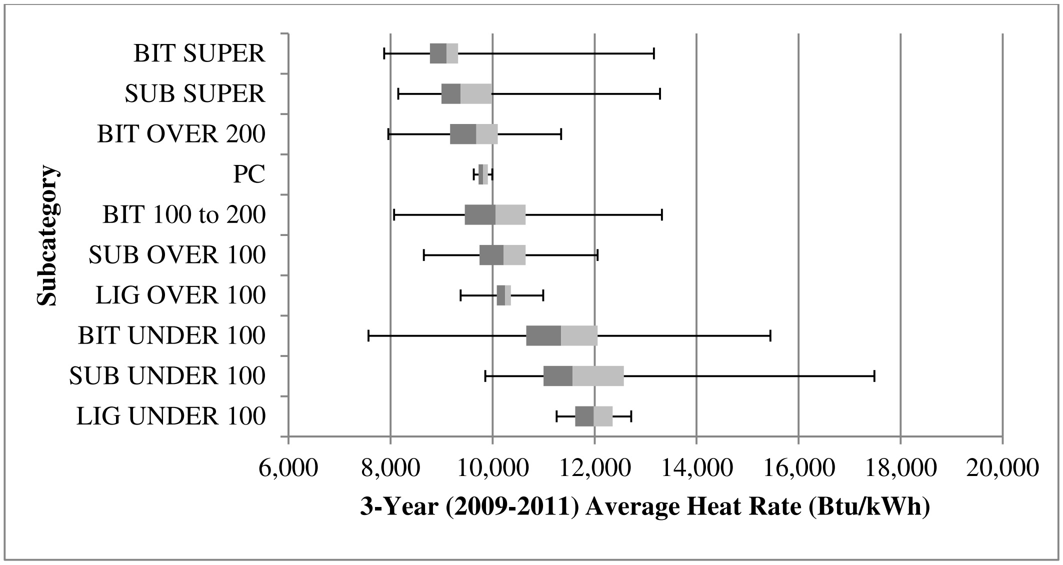

Figure 2-2. Three-Year Average Heat Rates by Subcategory[8]

2.5.3 Observed Trends in the Period 2002-2012

Three trends are notable for the study population during the period 2002-2012. Comparing the averages of the first three years (2002-2004) to the last three years (2010-2012), electric generation and gross heat rate declined by 9% and 2%, respectively. Capacity factor for the study population fell by 14% comparing the same time periods (see Table 2-5). The decrease in coal-fired generation and capacity factor may be because of reduced demand for electricity resulting from the recession starting in late 2008 and greater use of natural gas and renewables to generate electricity.

The 11-year average annual gross heat rate for the study population of coal-fired EGUs (see Table 2-4) was 9,754 (Btu/kWh). The decrease in study population annual heat rate between 2002 and 2012 may be due to several factors. Unit efficiency may have improved or units with lower heat rates may have taken up a larger share of generation. In addition, changes in reporting methodology described later in this chapter may be partly responsible. The minimum annual heat rate (9,643 (Btu/kWh)) occurred in 2008 and was approximately 1% below the 11-year average.

[8] Abbreviations in the figure: BIT means bituminous, SUB means subbituminous, PC means petroleum coke, LIG means lignite, SUPER means supercritical, OVER/UNDER means greater/less than indicated MW capacity. Unit counts (n) by category: BIT SUPER, n=80; SUB SUPER, n=30; BIT OVER, 200 n=196; PC, n=2; BIT 100 to 200 n=140; SUB OVER 100, n=299; LIG OVER 100, n=20; BIT UNDER 100, n=68; SUB UNDER 100, n=56; LIG UNDER 100, n=2. Total unit count is 893.

Table 2-5. Reported Annual Capacity Factor 2002-2012[9]

Year	Capacity Factor (%)
2002	68
2003	69
2004	70
2005	71
2006	70
2007	71
2008	70
2009	62
2010	65
2011	61
2012	53

2.5.4 Startups and Shutdowns - Impact On the Results of This Study

During periods of startup and shutdown, EGUs are known to operate at higher heat rates. Therefore, we evaluated the potential impact of such events in our study. A startup event, as defined here, occurs when an EGU begins combusting fossil fuel and generates some measurable amount of electricity. Table 2-6 summarizes the study population average, maximum and total starts by year. On average, coal-fired EGUs start combusting fuel and generating electricity 11 times per year. The total number (approximately 9,000) of starts for the study population of EGUs has remained stable over the study period. Our data reflects that some coal-fired units operate in a load following capacity and may report upwards of 200 starts in a single year, but these units tend to have low annual capacity factors. The subset of EGUs with more than 20 annual startup and shutdown events is responsible for less than 4% of total generation in any study year. Therefore while the number of starts is an important variable at a small number of EGUs, its impact on heat rate performance evaluated in this study is considered to be marginal.

[9] Table 2-5 shows data as reported to EPA as of May 8, 2014.

Table 2-6. EGU Start Count by Year

Year	Average	Maximum (at any single EGU)	Total
2002	11.1	209	9,363
2003	10.6	194	8,936
2004	10.7	134	9,081
2005	11.0	183	9,265
2006	10.5	139	8,859
2007	10.5	164	8,908
2008	10.4	134	8,880
2009	10.3	178	8,902
2010	10.5	211	9,110
2011	10.6	206	9,295
2012	9.9	119	8,805

To understand the potential for heat rate improvement available with existing coal-fired steam EGUs, the EPA conducted a number of quantitative analyses. These included: (1) regression analyses to understand the impact of capacity factor and ambient temperature; (2) using a bin model to determine the potential from best practices; and, (3) evaluating available data and information to assess the potential from equipment upgrades. These analyses are described in the following sections.

2.5.5 Impact of capacity factor and ambient temperature

Two important factors that affect heat rate at an EGU are hourly capacity factor and ambient temperature. In this section, we examine the impact of these two variables on heat rates of the EGUs in the study population. Power plant operators today typically use digital control systems to capture hundreds of data points in near real-time that are summarized in the unit heat rate statistic. EPA has access to a small fraction of that information. A key reason this study used capacity factor and ambient temperature as independent variables is that both were available as hourly data. Preliminary analyses of heat rate at higher time increments, such as month, were useful to describe aspects such as seasonality but we determined hourly data was necessary to understand how heat rate was responding to constantly changing operating conditions. We tested for collinearity between capacity factor and ambient temperature using a zero-order correlation matrix on the entire hourly data set. The correlation between the independent variables was -.048 – well below an indication of collinearity.

We also considered fixed unit characteristics such as unit type, fuel rank and age as independent variables. As noted above in the discussion on subcategorization, these factors can be helpful to understanding the heat rate performance of EGUs. The purpose of this study, however, is to find the potential for heat rate improvement across the fleet. We use heat rate variability as a key statistic to measure this potential. The correlation between the potential for heat rate improvement and fixed characteristics is typically low.[10]

Coal-fired units are designed to operate most efficiently at full capacity. As a unit drops below this level, in general, heat rate will increase. The average capacity factor over 11 years for the study population is 67%, but as noted above, has moved markedly over the study period. This study looks at utilization level at both hour and year time scales. The two are related but reveal different information about how an EGU is operating. For example, for a unit to achieve a high annual capacity factor (e.g., over 90%) it must operate at a high load for most hours in a year. At lower capacity factors interpreting the relationship between hourly and yearly utilization levels becomes more complex. For example, an EGU may run at an annual 60% capacity factor by operating 8 months at near full capacity and generating no electricity the rest of the year, or it may run at lower utilization levels for most hours of the year in response to weather, generation cost, and transmission constraints.

Ambient temperature can affect heat rate in two ways: 1) the efficiency of the thermodynamic steam cycle[11] and, 2) in many regions of the country, as temperatures increase electricity demand and capacity factor follow. Figure 2-3 shows the average monthly capacity factor in 2012 alongside the climate normal monthly temperature.[12] The lines intersect in the spring as temperatures begin to rise and the need for cooling drives electricity demand. Generally, peak capacity factor and generation in most parts of the U.S. occur on the hottest days of the year. Yet, the relationship between ambient temperature and capacity factor is complex. Each plant responds differently depending on design, meteorological conditions and electricity

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[10] For example, the correlation between annual unit heat rate variability (discussed below as relative standard deviation) and unit nameplate capacity (MW) is in the -0.1 range.

[11] The availability of a cold heat sink in the condenser is a key factor in that cycle. The design of the heat exchanger, type of cooling system and availability of water all have an impact on performance. An increase in ambient air temperature, and consequent increase in water temperature, typically lower the effectiveness of the cooling system, the condenser, and, therefore, overall plant efficiency.

[12] Climate normal is the average of temperature (or other measure) over a prescribed 30-year interval and location. The chart shows the 1981-2010 climate normal monthly temperature at Baltimore-Washington Airport, MD.

demand. For example, a base load plant may operate at a high capacity factor seven days a week regardless of temperature. As noted above, the collinearity between these two variables is low.

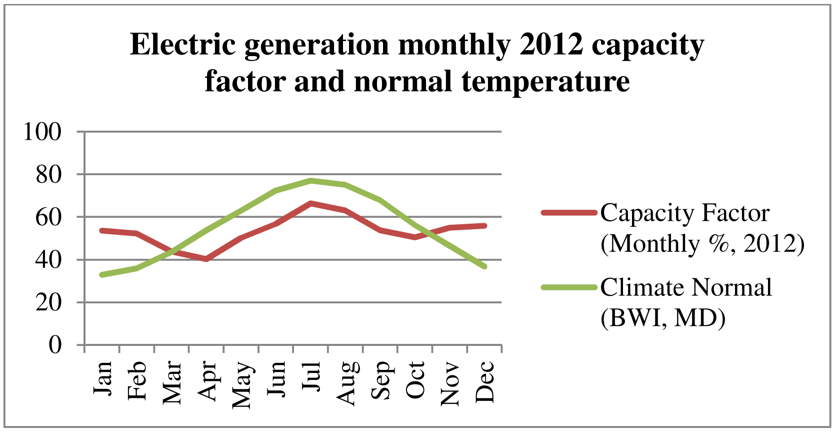

Figure 2-3. Monthly Capacity Factor, 2012.

2.5.5.1 Regression Analysis to Assess Impact of Capacity Factor and Ambient Temperature on Heat rate

Using the hourly data set, the EPA performed three regression analyses for each unit-year: heat rate onto capacity factor, heat rate onto ambient temperature and heat rate onto capacity factor and ambient temperature. Since this analysis seeks to evaluate heat rate under normal operating conditions, we removed records with hourly heat rate values outside of +/- 2.6 standard deviations (1.9% of records) before performing the regressions.[13] Similarly to partial operating hours, these outliers tend to occur during low load conditions. The records trimmed amount to one-fourth of a percent of the total study population generation. Regression results describe the goodness of fit for the model and are expressed as the coefficient of determination or 'r-squared'. To represent the relative contribution of varying unit capacities all results are generation-weighted.[14] The average study population r-squared for the multivariate regression is 26%. This means that hourly ambient temperature and capacity factor together explain 26% of the change in heat rate for the study population over the study period. The average study population r-squared from the single variable analysis of capacity factor is 16%; the

[13] The 2.6 standard deviation bound is used in other EPA regulatory analyses.

[14] In a weighted average, each component is multiplied by a factor reflecting its importance. In this case, generation-weighted r-squared is the sum of r-squared for each unit multiplied by its annual generation divided by the sum of generation for all units.

corresponding result for temperature is 10%. This means that approximately 16% of the change in hourly heat rate is attributable to capacity factor and 10% to ambient temperature. These results, however, conceal considerable variability. Some EGUs, typically load-following, have an 11-year average r-squared for capacity factor exceeding 50%. At those EGUs, the capacity factor is a key variable influencing changes in heat rate.

At approximately one-fourth of the study population the response to ambient temperature is larger than the response to capacity factor. At some individual EGUs, temperature may explain up to 30% of the change in heat rate. These are typically, but not exclusively, units with once-through, fresh water, cooling systems. Identifying temperature-responsive EGUs allows us to understand why heat rate may increase during periods of peak demand. These are the EGUs where the ambient temperature 'signal' is an important variable. At a typical EGU, summer month heat rates may increase by 2-4% compared to winter months, but at a temperature-responsive EGU that figure may be as high as 10%.

Our analysis indicates that as EGUs moved from base load to load following, capacity factor tended to have a larger effect on heat rate. Since 2008, the study population capacity factors moved from the top load bin into lower load bins. This can be seen from Figure 2-4, which compares the study population duty cycles in 2008 to 2012. A significant share of 2008 generation occurred at EGUs running at greater than 84% annual capacity factor. In 2012, little generation took place in that bin or above, and generation was reduced by about half in the next lower bin (78-83% capacity factor).

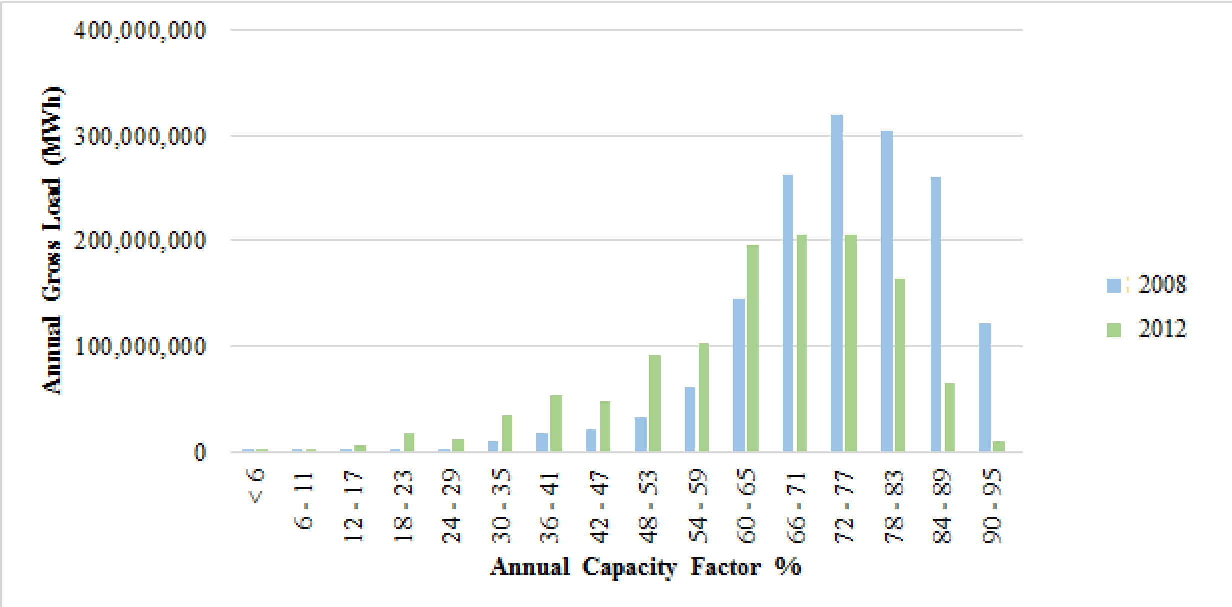

Figure 2-4. Change in Annual Duty-Cycle 2008 and 2012

2.5.6 Heat Rate Variability and Indication of Improvement Potential

This study examines heat rate variability from the standpoint of statistical process control, which is utilized throughout the power industry. Several years ago, the EPA introduced process control charts for auditing emissions data reported under Part 75. Sources and vendors adopted the EPA methodology to identify potential problems early, before they significantly affect emission measurements. Heat rate lends itself to process control since it is the principal indicator that defines the quality of the electric generation process.[15,16] Therefore, in general, high variability in heat rate values would reflect opportunities for process improvement.

We use the relative standard deviation (RSD) of the hourly heat rates to evaluate each unit against its past performance and to compare with the study population. Each unit has up to eleven RSD values, i.e., one for each operating year between 2002 and 2012. The generation-

[15] "The principal indicator that defines the quality of the process is heat rate." (Fredrick & Todd, 1993. Statistical Process Control Methods in Performance Monitoring. Available at famos.scientech.us/Papers/1993/1993section11.pdf)

[16] Since accurate measurement is essential to process control the introduction of increasingly sophisticated digital control systems (DCS) presents new opportunities for finding inefficiencies. Vendors (ABB, Siemens, Emerson) claim heat rate improvements of 2-5 percent can result from upgrading to a modern DCS and advanced control technologies. The improvement can be even higher if system-wide real-time optimization is included.

weighted mean RSD for the study population across 11 years is 5.4%. Table 2-8 summarizes eleven years of results for the study population by quartiles ordered by the 11-year generation-weighted RSD average (ascending).[17] The RSD of the top quartile (3.5%) is significantly lower than the study population generation-weighted mean RSD of 5.4%. Notably, the EGUs in the top quartile are not outliers; they report a third of all generation – the most of any segment. The results display a wide range of heat rate variability in the study population and thereby indicate the potential for heat rate improvement.

Table 2-8. RSD in reported heat rate (generation weighted)

Quartile	RSD Average	RSD Minimum	RSD Maximum	Share of Generation
1	3.5	1.6	4.2	33
2	4.8	4.2	5.3	26
3	6.1	5.3	7.0	24
4	9.8	7.1	25.2	16

The study also examined EGU heat rate variability using the residual heat rate. The residual in a regression analysis is the difference between the observed value of the dependent variable (heat rate) and the predicted value. The intercept is the value where the linear regression crosses the y-axis. For each EGU, we calculated the residual heat rate by summing the residual for each hour to the intercept value. The standard deviation of the residual heat rate statistic is used to understand the amount of variability that is not explained by capacity factor and temperature.

The average RSD corresponding to residual heat rate variability for each EGU is the generation-weighted average of up to eleven annual values. The study population generation-weighted mean RSD over the study period is 4.5%. This percentage represents the total variability across the study population that our analysis could not explain by hourly capacity factor or ambient temperature. Possible causes of this variability include changes in plant equipment, operating procedures and maintenance, fuels (particularly coal rank), reporting methodology, and unexplained factors. There is no temporal trend evident in the RSD. Table 2-9

[17] Nine EGU RSD values exceeded 2.6 standard deviations above the mean and were removed from the results in the table.

summarizes the study population generation-weighted average RSD of residual heat rate over the study period in quartiles ordered by the 11-year generation-weighted RSD average (ascending).

Table 2-9. RSD of residual heat rate (generation weighted)[18]

Quartile	RSD average	RSD Minimum	RSD Maximum
1	2.7	0.0	3.2
2	3.6	3.2	4.1
3	4.7	4.1	5.3
4	6.9	5.3	10.4

The weighted average RSD of the top quartile is 2.7% – well below the study population average of 4.5 %. This means that the residual hourly heat rates of these units generally stay in a narrow range within a given year. The maximum RSD in the top quartile is 3.2%. From the statistical process control point of view, these units appear to have low variability.

The weighted average RSD of the bottom quartile is 6.9%, which is over twice that of the top quartile. This spread indicates that there is likely room for improvement in study population operation to reduce variability and heat rate.

2.5.6.1 Heat rate variability and performance

To examine the association between heat rate variability and heat rate performance this study examined the RSD for unit-year heat rates calculated from reported data. The study population generation-weighted annual RSD ranges between 5% and 6% during the study period. Figure 2-5 below summarizes the results of regressing RSD of heat rate onto annual heat rate.[19] The r-squared result is 57%. These results indicate that, other factors held equal, if an EGU reduces heat rate variability, generally heat rate performance will improve.

[18] This table excludes nine units where RSD exceeded 2.6 standard deviations from the mean.

[19] The regression analysis was performed on 9,388 unit-years of study data which were trimmed to remove values outside 2.6 standard deviations.

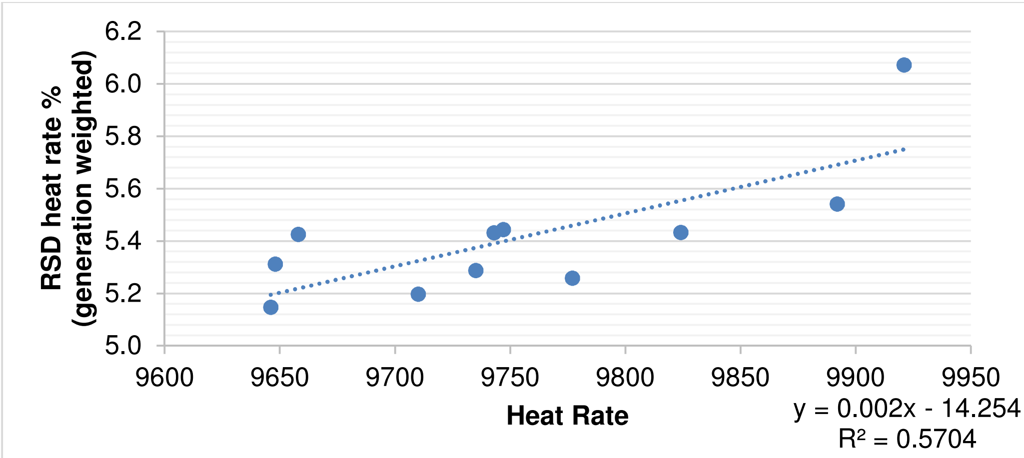

Figure 2-5. Regression analysis of reported heat rate RSD onto annual heat rate

2.5.7 Units with large heat rate changes

Over one third of the study population (355 units) reported at least one year-to-year change in heat rate greater than +/- 8.5%.[20] We consider this magnitude to be in the upper range of what would be expected due to changes in fuel rank, operations and maintenance, or plant equipment. Table 2-10 presents the counts by three categories: EGUs with at least one year-to-year decrease in heat rate > 8.5%; units with at least one year-to-year increase in heat rate > 8.5%; and, units with both. We examined whether the large heat rate changes were due to `year-to-year changes in capacity factor and found no correlation between the year-to-year changes in heat rate and capacity factor for any of the three groups in Table 2-10.[21] This would indicate that other factors account for these large changes to heat rate. The EPA's research found that approximately two-thirds of the large decreases in heat rate can be associated with changes in reporting method implemented to provide more accurate heat input data.[22] The large changes noted at the remaining one-third could not be explained by changes in reporting methodology. Moreover, we found no correlation between changes in reporting method and heat rate RSD.

[20] After removing unit-years where annual capacity factor fell under 50 percent the count is 313 EGUs.
[21] The correlation remains weak even when limited to cases where capacity factor changed more than 30 percent.
[22] EPA Reference method 2 specifies the normal procedure for measuring stack gas volumetric flow rate during a relative accuracy test audit. Methods 2F, 2G, 2H and CTM-041 are approved alternatives. Methods 2F and 2G correct measured flow rates for angular (non-axial) flow, Method 2H (for circular stacks) and conditional test method CTM-041 (method J, for rectangular stacks and ducts) are used to correct measured flow rates for velocity decay near the stack wall, using a "wall effects adjustment factor". These alternative methodologies are optional. Therefore, given the additional complexity and cost of using these alternatives a source is likely to use them only if the results are significantly lower volumetric stack gas flow. The EPA was unable to draw conclusions about the effect of changes in flow reporting methods on fleet heat rate performance.

Table 2-10. Year-to-Year Heat Rate Change

Description	Count	Correlation of heat rate to capacity factor
Units with only year-to-year heat rate decrease > 8.5%	166	.1
Units with only year-to-year heat rate increase > 8.5%	80	.1
Units with both year-to-year heat rate decrease and increase > 8.5%	355	.1

The breakdown of the 'large decrease' EGUs by quartile, in Table 2-11 below, is consistent with the study population results shown in Table 2-8. This does not imply that the changes associated with a large year-to-year decrease, which may include operations and maintenance, more accurate reporting methods, or new equipment, do not affect heat rate variability. If they occur as part of an engineering effort to improve efficiency, heat rate variability may also be reduced.

Table 2-11. RSD in reported heat rate of 166 'large decrease' EGUs (generation weighted)

Quartile	RSD Average	RSD Minimum	RSD Maximum
1	4.0	2.3	4.8
2	5.3	4.8	5.9
3	6.6	5.9	7.5
4	10.5	7.6	26.5

2.5.8 Assessment of heat rate improvement potential via best practices

As mentioned before, across the study period, the effects of hourly capacity factor and ambient temperature explain a generation-weighted average of 26% of the change in study population heat rate.[23] This means that on average 74% of the change remains unexplained after controlling for those factors. The residual heat rate analysis determined there is significant variation in the operation of EGUs. Since lower heat rate variability is associated with lower heat rate, other factors held equal, the range of variation indicates that significant potential for heat rate improvement is available through the application of best practices.

To control for known factors, the EPA constructed a model that groups each EGU's hourly heat rate data into 14 temperature bins and 12 capacity factor bins, resulting in a 12 by 14

[23] The 26% result is the generation weighted average of r-squared values from the multivariate regression analysis.

matrix of 168 bins.[24] For a given EGU, a temperature and capacity factor bin will have all the relevant hourly values over the eleven-year study period. For each bin with 15 or more values the model finds the reported hourly heat input value corresponding to the 10th percentile (p10).[25] This means that approximately 90% of the heat input values in that bin exceed p10. For each unit, the model reduces the reported hourly heat input greater than p10 by a percentage of the distance between the reported value and p10 (e.g., 50% of the difference). The same statistical procedure is applied to every hour of heat input data in each bin. These reduced hourly heat input values are then used to calculate a reduced 11-year average heat rate for each unit. The percent difference between a unit's reported 11-year average heat rate and the heat rate that corresponds to reduced heat inputs is the potential heat rate improvement for that unit.[26] Using this approach, those units with the lowest variability (e.g., in the top quartile of residual heat rate variability) take proportionally smaller reductions.

Table 2-12 below shows the model results with options of 10% to 50% stringency. For example, reducing reported heat input 10 % of the distance to the p10 value achieves a 1.3% study population wide reduction. Alternatively, a 50% reduction will result in a 6.7% study population wide improvement in heat rate. In effect, the model proportionately reduces heat rate variability and improves performance for each unit while controlling for temperature and capacity factor. The heat rate improvement for the study population is derived from the performance of each individual EGU as compared to its own record.

[24] The matrix provides up to 168 bins but only 164 contained hourly values. Temperature bins ranged from -20 to greater than 110 with 10 degrees F in each. Capacity factor bins ranged from 0% to greater than 110% with 10% in each.
[25] Performing the calculation with a minimum of 30 values in each bin has a modest effect on the results in Table 2-12. For example, a 30% reduction obtains a 3.9% fleet wide improvement in heat rate (rather than 4.0%).
[26] Heat rate is calculated as the sum of heat input (Btu, reported or reduced) divided by the sum of generation (kWh) for the given population and time period.

Table 2-12. Assessment of heat rate improvement potential via best practices

% Reduction from reported heat input to p10	Study population heat rate (Btu(kWh-gross)[27]	Reduced study population heat rate (Btu/kWh-gross)	Study population heat rate improvement (%)
10	9,753	9,623	1.3
20		9,493	2.7
30		9,363	4.0
40		9,233	5.3
50		9,103	6.7

2.5.9 Assessment of potential heat rate improvement via equipment upgrades

The EPA inspected the study population to find examples of EGUs that made significant year-to-year improvements in heat rate. After filtering out those cases that may have been the result of changes in capacity factor, reporting method, or other events, we identified 16 EGUs that reported a single year-to-year heat rate improvement of 3-8%. In two of these cases we were able to identify equipment upgrades responsible for 2-3% heat rate improvement using the applicable estimates from the Sargent & Lundy 2009 study. Similarly, in the other cases, while our research was unable to confirm specific equipment upgrades, based on the elimination of other possible explanations we believe that equipment upgrades were the most likely cause of some of the observed heat rate improvements.

Two other sources provide information about heat rate improvements after equipment upgrades at existing plants. EPA Region 7 provided data for seven coal-fired units at three anonymous plants with details on specific equipment modifications. These included turbine efficiency and condenser performance upgrades, installation of variable frequency drive fans, reducing boiler air in-leakage and others. Together, these measures achieved from 0.25% to 3.5% heat rate improvement at the seven EGUs.

An EPA study (SRA, 2001) describes WEPCO's two-phase efficiency program at four coal-fired plants over a ten-year period. In the first phase, 1990 – 1994, WEPCO installed equipment upgrades that included retractable turbine packing, variable speed drives on the forced and induced draft fans, feed water heater replacements and new performance monitoring instrumentation. The four units reported heat rate improvements ranging from 2.3% – 4.1% as a

[27] Fleet heat rate for study population as described in Table 2-4 is 9,753; the 9,753 value is derived from the dataset that includes hourly temperature values.

result of the equipment upgrades. In the second phase, 1995-2000, WEPCO implemented changes that would generally fall into the best practices category: equipment control and metering upgrades, boiler cleaning, feed water heater improvements and reduced condenser air in-leakage and thermal losses. These gained an additional 0.5% per year heat rate improvement (for a total of 2.5%).

The EPA also reviewed the engineering studies available in the literature and selected the Sargent & Lundy 2009 study as the basis for our assessment of heat rate improvement potentials from equipment and system upgrades. We focused on some thirteen heat rate improvement methods discussed by Sargent & Lundy, seen in Table 2-13. We used the average of the estimated $/kW costs for each method to develop the cost-ranked list of heat rate improvement methods (lowest cost at the top, highest at the bottom) shown in Table 2-13. The first nine items in Table 2-13 contribute about 15 percent of the total average $/kW cost for all items. We believe it is reasonable to consider those nine no-cost and low-cost heat rate improvement methods as belonging in the category of what has been described above as best practices. The remaining four methods are higher cost heat rate improvement items that we believe properly fall into the category discussed here as upgrades. Using an average of the ranges of potential Btu improvements estimated by Sargent & Lundy for the four upgrade methods, upgrades, as defined here, could provide a 4% heat rate improvement if all were applied on an EGU that has not already made these upgrades.

Table 2-13. Sargent & Lundy Heat Rate Improvement Methods

No-Cost and Low-Cost Options
Condenser Cleaning
Intelligent Soot Blowers
ESP Modification
Boiler Feed Pump Rebuild
Air Heater and Duct Leakage Control
Neural Network
SCR System Modification
FGD System Modification
Cooling Tower Advanced Packing
Higher Cost Options
Economizer Replacement
Acid Dew Point Control
Combined VFD and Fan
Turbine Overhaul

We also examined the annual heat rate trend line for each unit developed using the method of least squares. Using the slope of the trend line, 2002-2012, as an indicator of the heat rate performance of an EGU, a negative slope would indicate that the heat rate has improved. The annual trend line incorporates performance due to operating conditions (capacity factor, temperature), coal rank, maintenance, reporting method changes, equipment upgrades, and other factors. Over 40% of units have a positive slope. This would imply that equipment maintenance and upgrades at a significant fraction of the study population have not been sufficient even to maintain the status quo.

2.5.10 Combined study population results

The EPA's analysis finds that a total of 6% heat rate improvements for the coal study population can be achieved through two types of changes: best practices that have the potential to improve heat rate by 4% and equipment upgrades that have the potential to improve heat rate by 2%.

The best practices results are supported by the variability analysis using 11 years of hourly data applied to each unit. This analysis found that the top quartile of EGUs reported significantly lower heat rate variability than the study population average. Reducing heat rate variability will generally also improve heat rate performance, other factors held equal. We found that a 4% improvement is determined by conservatively reducing heat input by 30% of the difference between the reported value and p10 in each unit's capacity factor and ambient temperature bins. The 30% approach is in the middle of the range of options shown in Table 2-12 and is comparable to other approaches for measuring potential fleet heat rate improvement. For example, if each unit achieved heat rate performance equal to its best three-year moving average, the study population as a whole would post a 3.9% heat rate improvement. The best two-year moving average would achieve nearly a 5% improvement and the best single year over 6%. EPA believes that the minimum three-year moving average heat rate is a reasonable target for the improvement potential from applying best practices. Single year results could be due to unusual conditions, such as, an extended outage or weather. Using three consecutive years tends to smooth out the effect of equipment maintenance cycles and unusual meteorological patterns.

The equipment upgrades results are supported by numerous studies[28] and by the EPA's analysis of the costs and associated improvements in heat rate that can be attributed to equipment and system upgrades. We considered that a 4% reduction in heat rate might be achieved on a coal-steam unit by applying the four higher cost upgrade actions described in Table 2-13 above. However, because details of current actual unit configurations are unknown, and some units may have applied at least some of the upgrades, we conservatively estimate the heat rate improvement potential for upgrades at 2%. The EPA considers the results of this study to be applicable to the U.S. coal-fired fleet at large since the study population of EGUs accounted for over 96% of 2012 electric sector CO_2 emissions from coal.

2.5.11 Sensitivity Analysis Removing Planned or Announced EGU Retirements

The EPA's research found 233 coal-fired, non-cogeneration EGUs that have announced they will retire before 2016.[29] A sensitivity analysis was applied to the EGUs in the study population that plan to operate through 2015. The results are identical to the full population – both achieve a heat rate reduction of 4% under the 30 percent difference option described in best practices.

2.6 Heat Rate Improvement – Economics

Most of the methods that can be applied to achieve a sustained Heat Rate Improvement (HRI) on a coal-steam EGU will entail a capital cost. These HRI capital costs can be economic to incur if they yield sufficient reductions in other current or potential costs, particularly reductions in coal fuel cost and any cost related to CO_2 emissions. For the purpose of this TSD analysis, it is assumed that HRI can be economic if the annualized net savings (coal cost savings plus CO_2 emission cost savings minus capital cost) is positive:

Annual Net HRI Savings = Coal Cost Savings + CO_2 Emission Cost Savings – Capital Cost[30]

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[28] See discussion in Table 2-3 above, and the HRI Partial Bibliography at the end of this section

29 IPM documentation includes a list of the announced retirements. See Table 4-36 of IPM Documentation: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_4.pdf and http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/NEEDS_v513.xlsx

[30] This TSD analysis assesses a *broadly combined* application of multiple HRI methods. As estimated in the 2009 Sargent & Lundy study most HRI-related O&M costs are sufficiently small relative to the associated annualized capital costs, such that they do not materially affect the economics of broadly combined HRI methods. The analysis therefore does not consider the small economic impact of HRI-related O&M costs.

2.6.1 Heat Rate Improvement Capital Cost Assumption

The 2009 Sargent & Lundy study describes numerous well known and technically proven HRI methods for coal-steam EGUs. The study includes an estimated min-max range of heat rate improvement, and the min-max range of associated capital cost for each HRI method, for units ranging in size from 200 MW to 900 MW. If these methods and unit sizes are combined, as though they were all applied on a single EGU, the following range of Sargent & Lundy estimated Btu reductions and associated range of capital costs are obtained:

Combined Min-Max HRI Btu Reduction:	415-1205 Btu
Combined Min-Max HRI Capital Cost:	$40-150/kW[31]
EPA Assumed Combined HRI Capital Cost:	$100/kW

The wide ranges of estimated HRI Btu and costs are indicative of the wide range of real differences in the many details of site specific EGU designs, fuel types, age, size, ambient conditions, current physical condition, etc. This TSD analysis therefore assumes $100/kW as a representative combined HRI capital cost to achieve whatever HRI Btu reduction is possible at an average site. The effect of a lower HRI cost is also examined.

2.6.2 Heat Rate Reduction Assumption

The weighted average annual net heat rate of the U.S. coal-steam EGU fleet in 2020 is projected at 10,450 Btu/kWh in the EPA's IPMv5.13 Base Case modeling. As indicated by the Sargent & Lundy estimates given above, HRI methods could possibly reduce this average coal fleet heat rate by about 400 to 1200 Btu/kWh, or by about 4% to 12% of the projected 2020 average, provided that all units were able to apply all of the combined HRI methods. The proviso is important to this analysis because the EPA expects that a significant fraction of the coal fleet has already applied some or many of the available HRI methods.[32]

The EPA does not have sufficient site specific information to accurately estimate what percentage of the fleet has adopted various HRI methods, nor how effectively, and is not aware of any other investigator having sufficient information. HRI potential can therefore not be

[31] Note that highest cost does not necessarily align with greatest heat rate improvement. A low cost HRI method can have a large HRI potential (e.g., upgraded digital control system, neural network). Also, economy of scale causes most HRI methods to be more costly ($/kW) on smaller unit sizes.

[32] Based on the EPA informal discussions with Sargent & Lundy and other power sector engineering firms. The EPA has found no comprehensive data set on the extent to which specific HRI methods have already been applied at individual EGUs. The EPA believes that many EGU owners consider such information to be confidential.

estimated at this time through analysis of the current equipment configurations of the coal steam-EGU fleet. The EPA therefore analyzed 11 years of historical heat rate data and the literature on HRI methods, as discussed earlier in this TSD, to estimate that the U.S. coal-steam EGU fleet might reasonably be expected to reduce its annual average gross heat rate by about 6%.

The EPA understands that any HRI method that reduces gross heat rate will also reduce net heat rate, and that some HRI methods reduce net heat rate without reducing gross heat rate. We expect that the HRI potential on a net output basis is somewhat greater than on a gross output basis, primarily through upgrades that result in reductions in auxiliary loads. For purposes of this TSD the EPA conservatively assumes that the coal fleet average net heat rate can be reduced by 6%.

2.6.3 Heat Rate Improvement Breakeven Economic Analysis

Figure 2-6 presents a simple breakeven economic analysis for combined HRI methods using the assumptions described above, also assuming there is no CO_2 emission cost that is reduced via HRI.

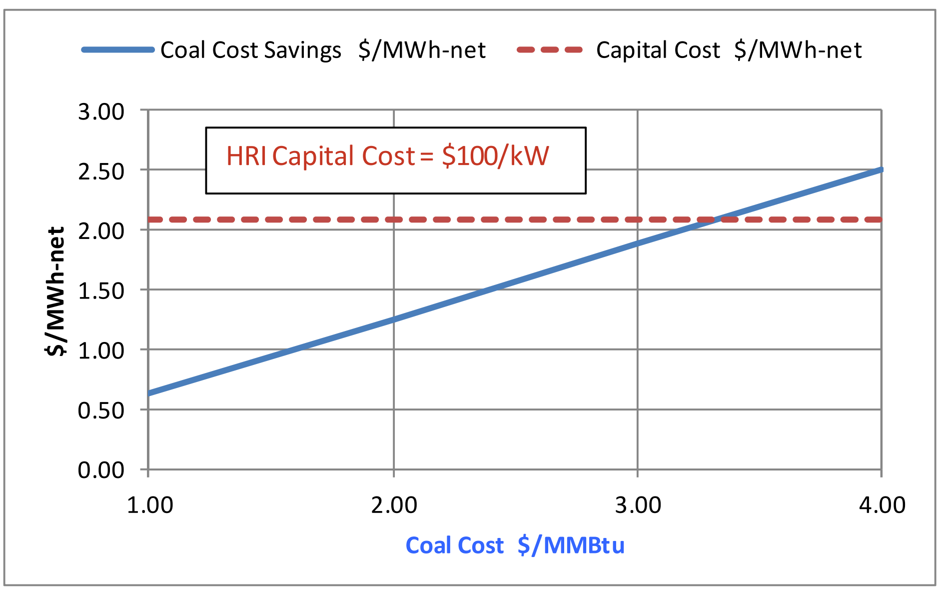

Figure 2-6. HRI Breakeven Economics

Notes:

1. Capital cost S/MWh assumes the following: HRI capital cost = $100/kW; capital charge rate = 14.3%; IPM projected 2020 annual capacity factor = 78%
2. Coal fleet average 2020 net heat rate = 10,450 Btu/kWh; heat rate reduction = 6%

Figure 2-6 shows that the average fleet-wide savings in coal cost would become greater than the annualized capital cost of an average 6% reduction in heat rate when the average fleet-wide coal cost exceeds about $3.25/MMBtu. For comparison, the average U.S. power sector delivered cost of coal in 2020 is projected in EPA's IPMv5.13 Base Case modeling at $2.62/MMBtu. For different assumptions, the HRI economic breakeven point would change directionally as follows:

- If the HRI capital cost were on average less than the assumed $100/kW, 6% HRI would then become economic at lower coal costs. For example, if the average capital cost were actually $75/kW, a fleet-wide 6% HRI would become economic at an average coal cost of about $2.50/MMBtu, which is comparable to the U.S. power sector average costs of $2.38/MMBtu for all coal ranks and $2.89/MMBtu for bituminous coals in 2012.[33] This sensitivity indicates that fuel cost savings alone would make it economic for some of those EGUs currently using high cost bituminous coals to make HRI investments.
- At an EGU net heat rate that is higher than the IPM projected 2020 average value of 10,450 Btu/kWh, 6% HRI could be economic at coal costs lower than the values mentioned above.
- If the average heat rate reduction were only 4% instead of the assumed 6%, at a cost of $100/kW, average coal costs would have to exceed $4/MMBtu for 4% HRI to be economic fleet wide,
- But, if the average heat rate reduction were 4% at a cost of $50/kW, HRI could become economic at an average coal cost of about $2.50/MMBtu.
- If there were additional HRI savings due to avoided future CO_2 emission costs, HRI could become economic at lower coal costs, or at higher capital costs, or at lower heat rate reduction percentages.

2.6.4 U.S. Coal-steam EGUs – Estimated Fleet-wide CO_2 Reduction and Cost via HRI

It is possible to make an order-of-magnitude estimate of the fleet-wide extent and cost-effectiveness of HRI using reasonable assumptions as in the following example:

Fleet-wide 2020 Assumptions (basis: similar to IPMv5.13 Base Case):

[33] EIA, Electricity DataTable 7.4, Average Weighted Cost of Fossil Fuels for the Electric Power Industry 2002-2012, http://www.eia.gov/electricity/annual/html/epa_07_04.html

- Coal fleet capacity applying combined HRI methods = 244,000 MW
- Average CO_2 emission rate = 0.976 tonne/MWh net
- Average net heat rate = 10,450 Btu/kWh net
- Average capacity factor = 78%
- Pre-HRI CO_2 emissions = 1.62 billion tonne/yr (calculated)
- HRI Btu and CO_2 reduction = 6%
- HRI capital cost = $100/kW
- Annual capital charge rate = 14.3%
- Average coal cost = $2.62/MMBtu

Estimated Fleet-wide Results:

- Fleet-wide CO_2 reduction via HRI = 97 million tonne/yr
- Total HRI capital cost = $24 billion
- Annualized HRI capital cost = $3.5 billion
- Annual coal cost savings (cost) = $2.7 billion
- Annual net savings (cost) = ($0.8 billion)
- Annual net savings (cost) of CO_2 reduction = ($7.7/tonne)

2.6.5 Conclusion - HRI Economics

This necessarily simplified HRI economic analysis supports the following summary conclusions:

- Some degree of HRI is already economic for high heat rate – high coal cost EGUs
- If a fleet-wide average 6% HRI is technically feasible, it would also be economic on the basis of fuel savings alone, before consideration of the value of the associated CO_2 emission reductions, on a fleet-wide basis at today's coal prices if the associated average capital cost is about $75/kW or less.
- If a fleet-wide average 6% HRI is technically feasible, and the associated average capital cost is as much as $100/kW, 6% HRI could become economic on the basis of fuel savings alone, before consideration of the value of the associated CO_2 emission

reductions, if/when average coal prices rise to about $3.25/MMBtu (IPM projects coal at $2.62/MMBtu in 2020).

- Even at a capital cost of $100/kW and an IPM projected 2020 coal price of $2.62/MMBtu, the fleet-wide cost of CO_2 reduction via 6% HRI would be a relatively low $7.7/tonne.

Thus, although there is currently some uncertainty associated with the costs of achieving a particular fleet-wide amount of HRI, it is clear that HRI is an available low-cost approach to CO_2 reduction for existing coal-fired EGUs

Definitions/Abbreviations	
Btu	British thermal unit
capacity factor	electricity generation expressed as a percentage of maximum electricity generation (i.e., actual generation / maximum potential generation)
CO_2	carbon dioxide
EGU	electric generating unit
EIA	Energy Information Administration
EPA	Environmental Protection Agency
heat input	amount of energy consumed in a combustion unit (e.g., boiler) expressed in Btu
heat rate improvement	decrease in the amount of heat input required to generate 1 kWh of electricity
heat rate	gross heat input required to generate 1 kWh of electricity, expressed in gross Btu/kWh.
MMBtu	million Btu
MW	megawatt
PC	pulverized coal (boiler)
RSD	Relative standard deviation
S & L report	Sargent & Lundy engineering study on the potential heat rate improvement from equipment upgrades (EPA 2009 version) [Available at: http://www.epa.gov/airmarket/resource/docs/coalfired.pdf]
start	a startup event in which an EGU begins combusting fossil fuel and generates some measurable amount of electricity before ceasing fossil fuel combustion
unit-year	data for one EGU over a one year period

Docket Datasets

Name	Description
hour_QA_data.txt	2002-2012 hourly dataset
hour_QA_regression_data.txt	2002-2012 hourly dataset for regression analysis
units_885.txt	List of study units and characteristics
year_bin_10_50_data.txt	2002-2012 unit-year binned results at 10 – 50% difference options

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Chapter 3: CO2 Reduction Potential from Re-Dispatch of Existing Units

Overview

This chapter explores the dynamics of power sector dispatch and the cost-effectiveness of lowering the carbon dioxide (CO_2) emissions intensity of the power sector by substituting generation from the most carbon-intensive existing EGUs and increasing utilization, to the extent possible, of less carbon-intensive existing fossil fuel-fired EGUs. More specifically, the examination focuses on opportunities to improve emissions intensity by increasing the utilization of existing natural gas combined cycle units. The TSD provides background on existing power plants, power system operation, and the economics of electricity production and delivery in the context of cost-effective CO_2 emission reduction opportunities.

Introduction

Electric system dispatch is typically defined as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[34] Electricity demand varies across geography and time in response to numerous conditions, such that electricity generators are constantly responding to changes in demand and "re-dispatching" to meet demand in the most reliable and cost-effective manner possible.

The nation's EGUs are connected by transmission grids that extend over large regions. Through these interconnections, EGU balancing authorities treat the product (i.e., electricity) of EGUs as fungible, calling for electricity generation supply to meet demand usually by deploying the least expensive power source first.[35]

EGU operators and balancing authorities must take into account several constraints in dispatch, including transmission constraints as well as emission control programs and other environmental requirements. Such programs and requirements can change the relative cost of generating electricity among plants and/or limit the number of hours that a plant can run. For

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[34] Energy Policy Act of 2005

[35] A balancing authority is the responsible entity that integrates resource plans ahead of time, maintains the balance between supply, demand, and generation within a balancing authority area, and supports interconnection frequency in real-time. http://www.nerc.com/files/glossary_of_terms.pdf

many years, EGU operators throughout the country have considered the emissions implications for pollutants such as SO_2 and NO_x when scheduling unit dispatch, in response to costs and regulatory requirements. For example, EGU operators in 10 states participating in the Regional Greenhouse Gas Initiative have several years of experience with factoring CO_2 emissions limits directly into bids for economic dispatch. The electric system's carbon intensity can be lowered through re-dispatch among existing EGUs, particularly by shifting generation from coal-fired units to natural gas combined cycle (NGCC) units.

Power Sector Background

Electric Dispatch

Electricity generation conforms to the principle of least-cost economic dispatch, which is "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[36] The cost of operating electric generators varies based on a number of factors, such as fuel used and generator efficiency. Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) help coordinate economic dispatch over larger areas to help keep the cost of meeting electricity demand as low as possible, subject to operational constraints.

The decision by balancing authorities to call upon, or dispatch, any particular generating unit is driven by the relative operating cost, or marginal cost, of generating electricity to meet the last increment of electric demand. These costs change over time depending upon a variety of factors like fuel prices, weather conditions, and overall demand levels. Since the fixed cost of power plants is a sunk cost, plant operators bid into electricity markets such that their variable costs are covered. For fossil fuel-fired electric generating units, variable costs are dominated by the cost of the fuel, although coal-fired units often also have considerable variable costs associated with running pollution controls.[37] Other generating technologies, like renewables, hydroelectric, and nuclear, have little or no variable costs and are generally dispatched to the extent possible. In order to maintain least-cost dispatch, the units with the lowest variable costs

[36] Federal Energy Regulatory Commission, 2005. Economic Dispatch: Concepts, Practices, and Issues

[37] In addition to fuel costs, variable costs also include costs associated operating and maintenance, and costs of operating a pollution control and/or emission allowance charges.

will be called upon first, then other units (with higher variable costs) will be called upon sequentially, such that total system demand is met. The economic order in which units are dispatched to meet demand, at any particular point in time, is commonly called a dispatch "curve."[38]

Balancing Authorities

In states with cost-of-service regulation of vertically-integrated utilities who own generation, transmission, and distribution infrastructure, the utilities themselves often form the balancing authorities who determine unit dispatch. Such utilities are presumed to dispatch their units in a cost-minimizing fashion (seeking the lowest marginal cost), and they can arrange to buy and sell power with other balancing authorities.

In states that have restructured regulation to allow for competition between generators, RTOs and ISOs are generally responsible for moving electricity across larger areas in the most efficient and least-cost manner possible.[39] They coordinate, control, and monitor electricity transmission systems to ensure cost-effective and reliable delivery of power, and they are independent from market participants. ISOs grew out of the Federal Energy Regulatory Commission (FERC) requirements for existing power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, FERC encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis throughout North America (including Canada).

RTOs and ISOs administer wholesale power markets, which match the generation of electricity with the purchase of electricity (and ancillary services) prior to delivery to end-users. Companies that provide retail electricity (e.g., utilities and energy service companies) procure power through these wholesale electricity markets.

State Public Utility Commissions (PUCs)[40]

Each state has a governing body that is tasked with regulating retail electricity rates and electric services to protect the public interest, ensure efficient and reliable delivery of electricity,

[38] http://www.eia.gov/todayinenergy/detail.cfm?id=7590
[39] http://www.ferc.gov/industries/electric/indus-act/rto.asp
[40] These entities are sometimes called Utilities Commissions, Utility Regulatory Commissions, or Public Service Commissions.

and plan appropriately for the short and long term energy needs of the state and consumers. Depending on market structure, PUCs also allocate costs among customers, design price structures and set price levels, set service quality standards, approve capital expenditure by utilities, and arbitrate disputes among relevant parties and stakeholders. In restructured markets, the PUC's authority is generally applicable to the transmission and distribution system, since the generation and dispatch component is governed by RTOs and ISOs. In cost-of-service states, the PUC also has oversight of the generation and capacity planning components.

Spot and Day-Ahead Markets

RTOs and ISOs operate spot markets for wholesale power supply and demand for their designated area, including both day ahead and real-time (hourly, or shorter time periods). These markets are based on bids for supply and demand and operate according to rules established by FERC. The RTOs and ISOs use these markets for balancing power supply and load in their area and typically serve as the balancing authority for the same area.

For areas not administered by RTOs and ISOs, dispatch is scheduled both day ahead and hourly, but is typically driven by the power supply costs and schedules of traditional utilities. This dispatch will depend, to a certain degree, on spot markets for power, since utilities will dispatch purchased power from other suppliers when that power can be obtained at a cost savings. There is an active wholesale market for this power in the spot market, from individual sales and from exchanges. These markets typically sell power day-ahead but not hourly, and also sell power for longer periods, such as weekly or monthly. However, the actual dispatch and balancing of power is conducted by the utility based on its own scheduling and purchasing protocols and varies considerably from one utility to the next.

As a balancing authority, the RTO or utility will balance demand, generation, and imports/exports in real time while maintaining system frequency and ensuring that the next hour's demand, or load, is met. In addition, the transmission system is constantly monitored to ensure reliability limits are met, voltage levels are appropriate, and appropriate corrective action is taken when needed.

Reliability

As reliability coordinators, balancing authorities are responsible for the reliable operation of the bulk electric system. The bulk electric system refers to a large interconnected electrical system made up of generation and transmission facilities and their control systems. To ensure reliability, system operators continuously analyze real-time and forecasted load and transmission conditions to ensure that scheduled generation dispatch can meet load without adverse impacts. If the scheduled dispatch is not feasible within the limits of the transmission system, it must be adjusted by the system operator. The North American Electric Reliability Corporation (NERC) develops and enforces the procedures to ensure reliability, in accordance with Federal laws and regulations, and with FERC oversight.[41]

Historical Context

In 2012, average CO_2 emission rates[42] across all the following technology categories on a net generation basis were:

- Coal Steam - 2,220 lbs/MWh
- Oil/Gas (O/G) Steam - 1,463 lbs/MWh
- NGCC – 907 lbs/MWh

Coal- and oil/gas-fired boilers are considerably higher-emitting sources than NGCCs, on average. Therefore, the replacement, or re-dispatch, of each megawatt-hour (MWh) from the average fossil fuel-fired boiler with each MWh from an average NGCC will result in notable CO_2 emission reductions.

The lower emission rate of NGCC conveys the potential of re-dispatch to reduce GHG emissions. However, the actual potential to realize emission reductions through this technology depends on the availability and capacity factors of the existing NGCC fleet. In order to re-dispatch from existing fossil fuel-fired boilers to existing NGCC, there needs to be some existing unused generation potential in the current NGCC fleet that could displace generation from more CO_2 intensive generating resources. The term "availability" is a common engineering term used in the power sector, which reflects the *percentage* of period hours that a plant is available to produce electricity (a period being 1 year, or 8,784 hours in 2012 since that year included a leap day). The unavailable period is generally attributed to scheduled maintenance, unplanned

[41] http://www.nerc.com/
[42] Emission rates in this document are shown on a net generation basis and reflect Hawaii and Alaska sources. See "2012 unit-level data using the eGrid methodology" file provided in the docket

maintenance, and unplanned outages. The EPA assumes that NGCC has an availability of 87%.[43] Other reports suggest that NGCC availability factors may reach as high as 92%.[44]

If the existing NGCC fleet was already operating at a level of 87% to 92%, there would not be any additional generation potential in the existing generating system for re-dispatch to those units. To evaluate re-dispatch opportunities to unused NGCC generation potential in the system, the EPA reviewed recent NGCC fleet operating data to determine capacity factors. Redispatch for GHG abatement purposes would require one <u>net</u> MWh of a lower emitting technology displacing one <u>net</u> MWh of generation from higher emitting technology. Therefore, when the EPA was assessing capacity factor it used the <u>net</u> generation of a given NGCC unit as the numerator. The EPA was interested in the relationship of a unit's total net generation relative to its net generating capacity (i.e., capacity factor). Net generating capacity is a function of weather/temperature conditions at the site, which varies throughout the year. While some units may model actual weather adjusted capacity by the hour/minute, these data are not reported for the fleet. Therefore, the EPA used the nameplate capacity reported for units. The net generation was divided into the nameplate generation capacity of a unit multiplied by the number of hours in a year. This calculation of capacity factor provides an indication of how much net generation a unit is providing as a percent of its total generating capacity. Whereas availability refers to the maximum amount of generation that could be expected from a given source, the capacity factor refers to the actual utilization of that source on an annual basis. The EPA surveyed 2012 data for over 1800 NGCC units and observed that the NGCC fleet had an average capacity factor in the 44% to 46% range for 2012.[45] Since the fleet-wide capacity factor in 2012 was less than the availability assumed for the technology, the historical data suggests that there is a significant potential for re-dispatch from higher CO_2 emitting resources to lower emitting NGCC generation.

Availability for NGCC fleet…………………………..87% to 92%

2012 Capacity Factor for NGCC fleet………………..44% -46%

[43] See Chapter 3, Table 3-18 at http://www.epa.gov/powersectormodeling/BaseCasev513.html

[44] http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html

[45] See "2012 unit-level data using the eGrid methodology" file provided in the docket for 44% figure. See EIA 860 and 923 for 46% value.

To quantify the GHG reduction potential from re-dispatch, the EPA considered alternative capacity factor levels at which the NGCC fleet could be dispatched. Although the availability for NGCC units is assumed to be in the mid to high 80s, the EPA did not assume that each state's NGCC fleet could collectively operate at this level on an annual basis. To determine reasonable average capacity factor ceilings for a state's NGCC fleet as part of BSER, the EPA considered historical data and modeling projections describing NGCC characteristics and operating behavior.

As seen in Table 3-1, the existing NGCC fleet is relatively young. More than 80% of the capacity has come online in the last 15 years.[46] Of this capacity, almost all are a highly efficient class of NGCCs that are able to achieve high availability factors.

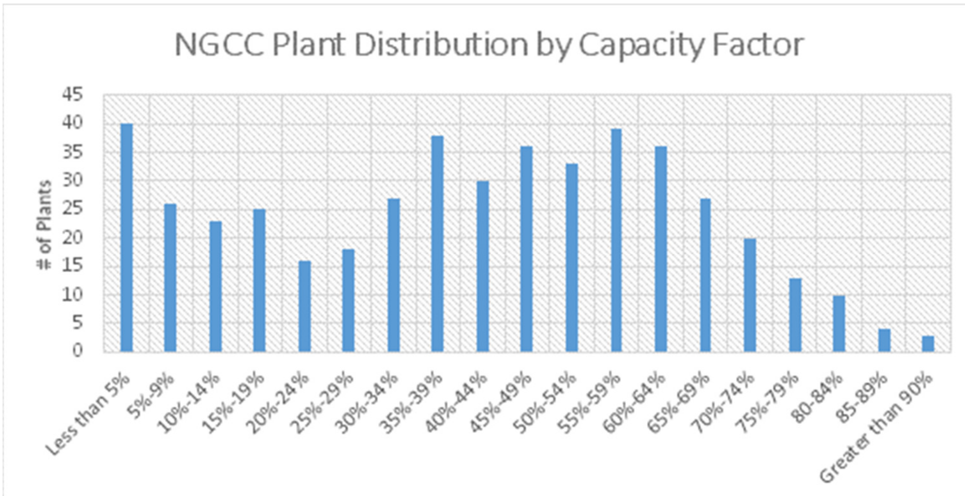
Table 3-1: Existing NGCC Capacity, by Age[47]

Online Year	Capacity (Name Plate Capacity – MW)	Percentage of Total Existing NGCC Fleet
Pre 1950	103	0%
1950-1959	1,769	0.7%
1960-1969	3,087	1.3%
1970-1979	6,909	2.8%
1980-1989	7,658	3.1%
1990-1999	28,467	11.7%
2000-2009	174,947	71.7%
2010+	21,068	8.6%
Total	**244,008**	**100%**

[46] See the National Electricity Energy Data Systems (NEEDS) file at http://www.epa.gov/powersectormodeling/BaseCasev513.html
[47] See "Operable" worksheet in "GeneratorY2012" Workbook in 2012 Zip file at http://www.eia.gov/electricity/data/eia860/

Of 464 NGCC plants generating in 2012 and greater than 25 MW, the EPA observed that 50 plants (more than 10% of NGCC plants) had a net generation value that was greater than or equal to its nameplate capacity x 8784 hours * 70%. That is, a capacity factor that was 70% or greater (see Figures 3-1 and 3-2).[48]

Figure 3-1: NGCC Plant Distribution by Capacity Factors (2012)



[49]

Table 3-2: Plant Distribution of Existing NGCCs (2012)

Capacity Factor	# of NGCC plants	% of NGCC Plants
Less than 5%	40	8.62%
5%-9%	26	5.60%
10%-14%	23	4.96%
15%-19%	25	5.39%
20%-24%	16	3.45%
25%-29%	18	3.88%
30%-34%	27	5.82%
35%-39%	38	8.19%
40%-44%	30	6.47%
45%-49%	36	7.76%
50%-54%	33	7.11%
55%-59%	39	8.41%

[48] See “2012 unit-level data using the eGrid methodology” file provided in the docket
[49] EIA Forms 860 and 923. CA and CT Prime Mover categories

60%-64%	36	7.76%
65%-69%	27	5.82%
70%-74%	20	4.31%
75%-79%	13	2.80%
80-84%	10	2.16%
85-89%	4	0.86%
Greater than 90%	3	0.65%

In 2012, more than 10% of NGCC plants operated at an annual capacity factor of 70% or higher. This subset of NGCCs was largely dispatched to provide base load power. While only 10% of plants operated at 70% or higher capacity factor on an annual basis, the fleet of NGCC units was relied upon heavily during certain periods of time, in response to higher demand. On a seasonal basis, a significant number of units achieved capacity factors greater than 50%, and even up to 80%. Using data reported to the EPA,[50] and looking more closely at data during the summer and winter peak electricity demand timeframes nationwide, *more* than 10% of NGCCs were operated at a capacity factor greater than 70%.[51] In fact, 19% of NGCCs achieved 70% capacity factor during the winter of 2011/2012 and 20% hit that level or higher during the summer.[52] During periods where demand levels are typically lower, some NGCCs were idled or operated at lower capacity factors. Nonetheless, a notable number of existing NGCCs have demonstrated the ability to achieve a 70% capacity factor for extended periods of time. These units achieved high capacity factors without adverse effects on the electric system. While many units demonstrated an ability to deliver net generation that was more than 70% of their nameplate capacity, the EPA assumed that 70% was a reasonable fleet-wide ceiling for each state. It should also be noted, roughly 6% of units (107 units) operated at a 75% capacity factor, or higher, in 2012. In addition, 16% of units (291 units) operated at 65%, or higher.

Over the last several years, advances in the production of natural gas have helped reduce natural gas prices and improved the competitive position of gas-fired units relative to coal-fired units. As a result, operators have shifted significant quantities of generation from coal units to

[50] Air Markets Program Data (at http://ampd.epa.gov/ampd/).
[51] Summer defined as June, July and August. Winter defined as December, January, and February. Estimates are for units for which data was provided to EPA. See file titled "NGCC capacity factors for summer months".
[52] Air Markets Program Data (http://ampd.epa.gov/ampd/). Winter includes December of 2011, January and February of 2012. Summer includes June, July, and August.

NGCCs, absent any federal CO_2 requirements. 2012 net generation from NGCC units grew to 981 TWh, up from 796 TWh in 2011 (22% growth in one year). The extent of this capability varies by region, based on factors such as the mix of EGU types and the amount of available NGCC capacity.

An analysis of historical dispatch across the generating fleet of coal and NGCC units for 2011 and 2012 provides some implicit measures of the cost dynamics between the two technologies. For example, one is able to look at the change in the prices of coal and gas to gauge the relative costs of generating, or dispatch, for each technology. While there are wide-ranging costs at the unit level, an aggregated assessment of the relative economics is informative and can provide a metric for assessing the implications of dispatch as it relates to emissions of CO_2.

The potential for redispatch from CO_2 intensive sources to less CO_2 intensive sources is evidenced in historical data. EIA form 860 and 923 data demonstrate an increase in NGCC generation and fuel use between 2011 and 2012 of more than 20% (even though the NGCC fleet capacity rose by just 3%). As NGCC generation rose by approximately 185 TWh, coal generation fell by approximately 216 TWh. The significant redispatch from coal to gas over just a one year period demonstrates the ability for the quick re-dispatch in response to market or economic drivers.

The increase in the NGCC utilization was in large part driven by the decrease in natural gas prices to historic lows (see Table 3-3). Henry Hub natural gas prices averaged $4.00/mmBtu in 2011 and $2.76/mmBtu in 2012. This $1.24/mmBtu creates an additional incentive for redispatch from coal generation to NGCC relative to 2011 dispatch economics. The fuel advantage is similar to the incentive that a $15/metric ton of CO_2 price signal would create.[53] This historical data also shows a sharp increase in the NGCC fleet's capacity factor from the high 30s to the mid 40s. During that same period, net coal generation dropped by an amount similar to the increase observed in NGCC net generation. Furthermore, natural gas supply is

[53] Assumes 11,000 Btu/KWh heat rate and 2354 lb/MWh emision rate for coal, 8000 Btu/KWh and 926 lbs/MWh for NGCC (based of "2012 eGrid file")

expected to grow more than 20% by 2020 relative to its 2012 levels, creating more fuel resources to foster the potential continued and increasing redispatch to NGCC generating technology.[54]

Table 3-3: 2011 and 2012 Gas and Coal Generation[55]

Year	NGCC Name Plate Capacity (GW)	NGCC Heat Input for Electricity (TBtu)	NGCC Net Generation (TWh)	NGCC Capacity Factor	Henry Hub Natural Gas Price ($/mmBtu	Coal Net Generation (TWh)
2011	239	5,912	796	38%	$4.00	1,719
2012	244	7,224	981	46%	$2.76	1,503

The demonstrated ability of the NGCC plants to consistently operate at levels greater than 70% of their nameplate capacity (e.g., this was the utilization level of the ~ 90th percentile plant), the historic evidence supporting quick and significant redispatch to NGCC, and the cost-effectiveness of high NGCC utilization demonstrated later in this TSD all supported the notion of a NGCC fleet capacity factor of 70% as a reasonable ceiling in the EPA's BSER approach.

For purposes of establishing state goals, historical electric generation data (2012) was used to apply each building block and develop each state's goal (expressed as an emissions rate, lbs/MWh). In 2012, electric generation from existing NGCC units likely subject to the 111(d) applicability criteria was 959 TWh.[56] After the application of NGCC re-dispatch to the 70% level,[57] these same existing sources were calculated to collectively generate 1,390 TWh. Adding in the existing sources that were not yet online in 2012 (under construction) increases total NGCC generation calculated in the goal setting to 1,444 TWh.

Although, states may choose to comply with state goals through other abatement measures, the EPA believes that upwards of 1,400 TWh from existing and under construction NGCCs is achievable. As a reference point, NGCC generation increased by approximately 430 TWh (an 81% increase) between 2005 and 2012. EPA is calculating that NGCC generation in

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[54] http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2014ER&subject=0-AEO2014ER&table=13-AEO2014ER&region=0-0&cases=ref2014er-d102413a
[55] EIA form 860 and EIA form 923
[56] For covered sources.
[57] This dispatch level is a ceiling dependent upon available existing steam generation that can be decreased. As a result, not all states achieve the assumed 70% re-dispatch for purposes of goal setting (see Goal Setting chapter).

2020 could increase by approximately 47% form today's levels. This reflects a smaller ramp rate in NGCC generation than has been observed from 2005 to 2012.

Table 3-4: Historic and Assumed Generation Patterns for State Goal Setting

	NGCC Name Plate Capacity (GW)	NGCC Net Generation (TWh)	Growth in NGCC Generation from 2005 to 2012	Growth in NGCC Generation from 2012 to 2020	Nationwide NGCC Capacity Factor
2005	199	551	NA	NA	32%
2012	244	981	81%	NA	46%
2020 State Goal Calculation	256	1,444		47%	64%

Natural Gas Supply

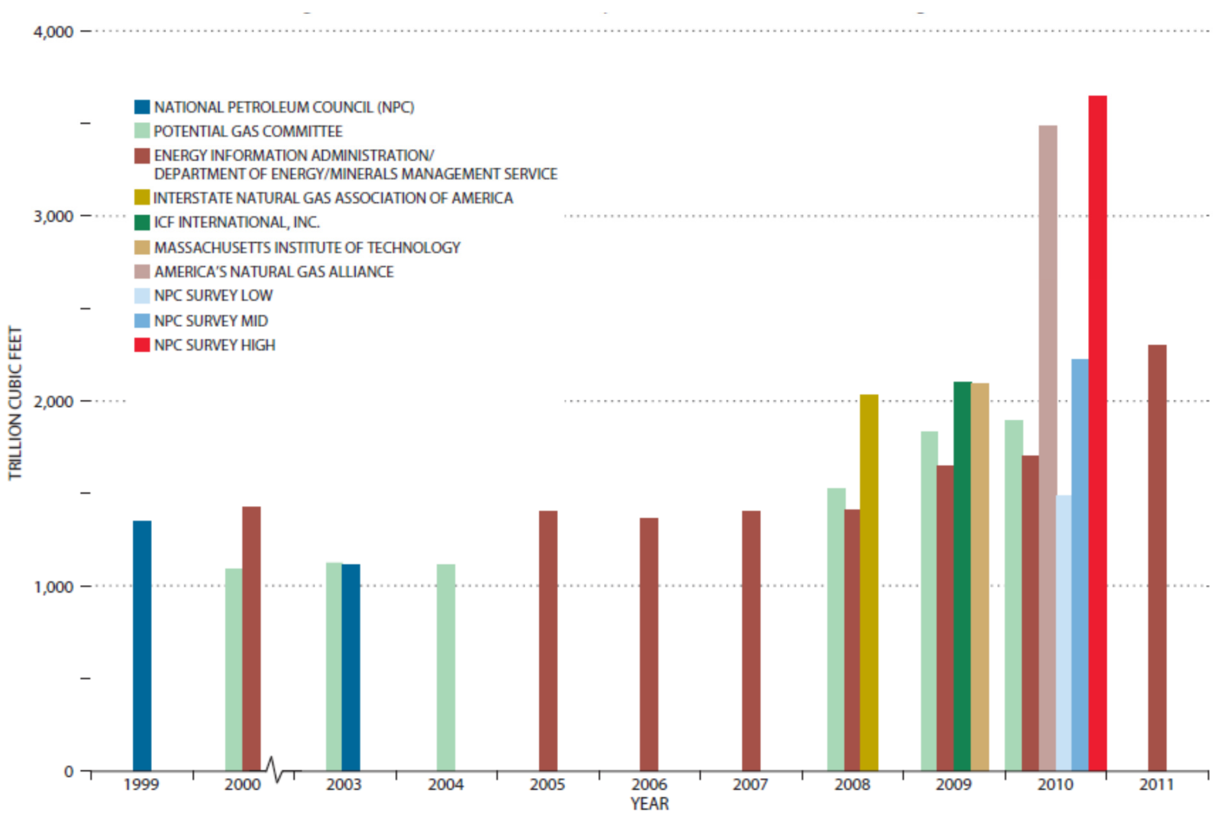
The EPA expects the growth in NGCC generation assumed in goal setting to be feasible and consistent with domestic natural supplies. Increases in the natural gas resource base have led to fundamental changes in the outlook for natural gas. There is general agreement that recoverable natural gas resources will be substantially higher for the foreseeable future than previously anticipated, exerting downward pressure on natural gas prices.[58]

According to EIA, natural gas proved reserves have doubled between 2000 and 2012.[59] Domestic production has increased by 32% over that same timeframe (from 19.2 TCF to 25.3 TCF). EIA's Annual Energy Outlook for 2014 projects that production will further increase to 29.1 TCF, due to increased supplies and favorable market conditions. For comparison, NGCC generation growth of 450 TWh (calculated in goal setting) would result in increased gas consumption of roughly 3.5 TCF for the electricity sector.[60]

[58] National Petroleum Council. 2011. Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources. http://www.npc.org/reports/rd.html (see Figure 1.2 on p. 47).
[59] http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=3&aid=6
[60] Assuming 1,024 Btu/cubic foot and 10,000 Btu/KWh

The National Petroleum Council (NPC), a privately funded advisory committee established by the Secretary of Energy, recently updated a major resource study and concluded that "the potential supply of North American natural gas is far bigger than was thought even a few years ago," *after* large increases in shale resource estimates.[61]

Figure 3-2: U.S. Natural Gas Technically Recoverable Resources (from NPC, 2011)[62]



Technical Considerations

Emission reductions through re-dispatch are largely determined by the ability to change the utilization of existing generating units, relative to current utilization levels. Other influences include physical limitations of the electric transmission system and considerations for reliability, timing, and cost.

NGCC Availability

[61] National Petroleum Council, 2012 (http://www.npc.org/PD_update-80112.pdf)
[62] http://www.npc.org/reports/rd.html

For purposes of economic dispatch, most NGCCs have historically been operated to serve base load or intermediate demand due to their high efficiency and flexibility of operation, with national average annual capacity factors in the range of 40-50%.[63,64] However, NGCCs are designed for, and are demonstrably capable of, reliable and efficient operation at much higher annual capacity factors, as shown in observed historical data for particular units and their design and engineering specifications.

The capability of NGCCs to operate at capacity factors of 70% and greater is indicated, in part, by statistics on the average availability factor of NGCCs.[65] Annual availability is the ratio of annual hours that an EGU is operating or considered able to operate (not in a forced or maintenance outage) to the hours in a year. The average availability factor for NGCCs in the U.S. generally exceeds 85%, and can exceed 90% for selected groups, as reported to NERC.[66,67] Advanced NGCCs being built today have availability factors of over 95%. According to one NGCC manufacturer, these highly efficient units already represent over 15 percent of total installed capacity nationwide, including all electric generating sources (as of 2010).[68]

These high-efficiency and high-availability NGCC units were first introduced around 1995 and have consistently reported availability factors of 90 to 92 percent to NERC (compared to 95 percent or greater availabilities reported by current vintage F class and H class turbines from General Electric Power Systems).[69] Data reported to NERC from NGCC units greater than 50 MW in 1994 through 1998 shows similar availability factors (generally exceeding 89 percent).

Natural Gas Pipeline and Electricity Transmission

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[63] EIA, Today In Energy, January 15, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=14611 (for recent data)
[64] EIA, Electric Power Annual 2009, http://www.eia.gov/electricity/annual/archive/03482009.pdf (Table 5-2 for 2009 and earlier data)
[65] NERC, 2008-2012 Generating Unit Statistical Brochure – All Units Reporting, http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx
[66] Power Engineering, Negotiating Availability Guarantees for Gas Turbine Plants, 03/01/2001, http://www.power-eng.com/articles/print/volume-105/issue-3/features/negotiating-availability-guarantees-for-gas-turbine-plants.html
[67] Power Engineering, Higher Availability of Gas Turbine Combined Cycle 02/01/2011, http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html
[68] http://site.ge-energy.com/corporate/network/downloads/7FA_Evolution.pdf
[69] GE Power Systems submitted to U.S. Department of Energy, 2000. Utility Advanced Turbine Systems Technology Readiness Testing Phase 3 Restructured. DOE Cooperative Agreement No. DE-FC21-95MC31176—30.

The EPA believes that the natural gas pipeline and electricity transmission networks can support aggregate operation of the NGCC fleet at up to a 70% capacity factor on average, either as they currently exist or with modifications that can be reasonably expected in the time frame for compliance with this rule. Existing NGCCs are already connected to both the power and natural gas networks and, while constraints to specific unit operations can occur in either or both networks during peak pipeline flow or electricity use, the rule allows for emission rate averaging across multiple units and across time for compliance. As a consequence of this averaging flexibility, constraints that occur at peak times are unlikely to be a barrier to achieving compliance with the rule, because these peak times are only a small percentage of the year and will constrain only a limited percentage of the state-wide NGCC fleet. The ability for the current fleet to ramp up significantly to meet changes in demand can be seen from the increased use of natural gas that occurred in 2012 in response to historically low natural gas prices. Power plant use of natural gas use in 2012 increased by 20% over 2011[70] and resulted in a national average capacity factor for NGCC of 45.8% on average, and higher in some states.[71]

During the peak hours of the day (which vary by region and season), NGCC capacity factors are typically well above average capacity factors.[72] The pattern of capacity utilization by hour for 2005 to 2010 is shown in Figure 3-3. In this figure, capacity factors in 2010 are approximately 50% from the Hour 11 to Hour 21.[73] The persistence of this hourly pattern across years shows the pattern to be stable. Since the average capacity factor for combined cycle units in 2010 from the same information source was 39%[74], this indicates that the current system can support levels of approximately 11% above the average capacity factor. These peak hours are the period when there are most likely to be constraints on the pipeline or electricity transmission networks; during other hours of the day, continued NGCC operation at equal, or higher levels, are technically feasible but may be limited by economic considerations (e.g., whether NGCCs can offer least-cost electricity compared to other sources at those times). As a result, the current system is already able to support national average capacity factors in the mid to high 50's for

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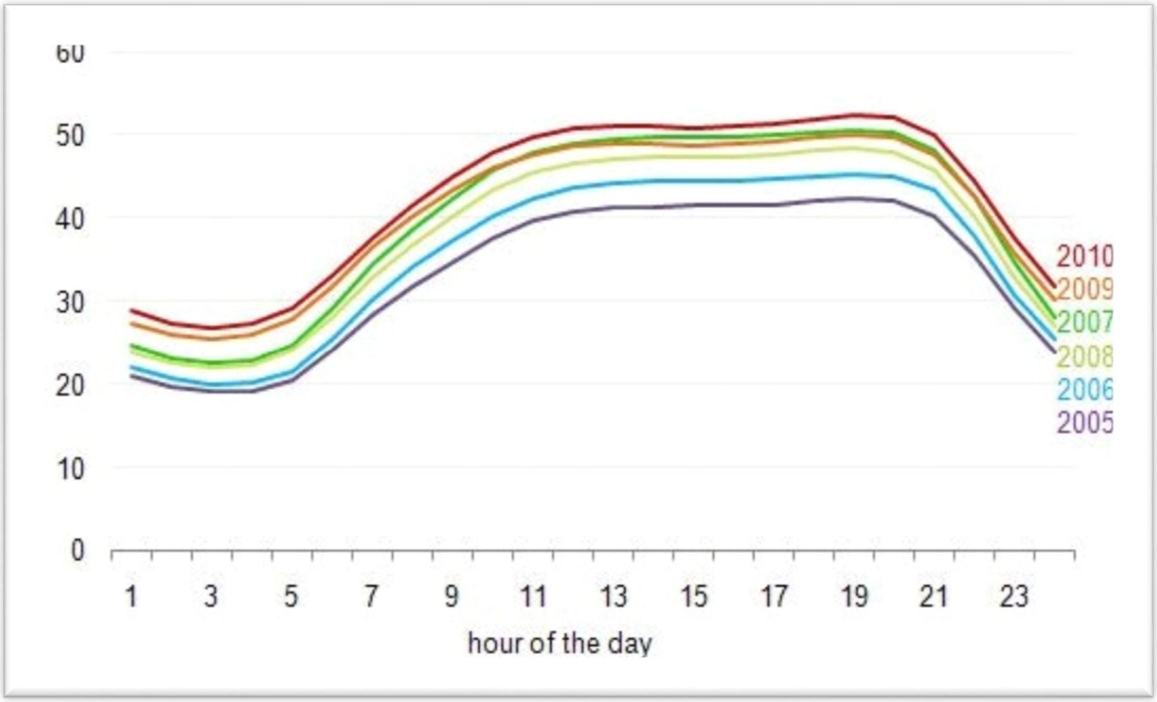
[70] Energy Information Administration, U.S. Natural Gas Consumption by End Use, http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm.
[71] Source: Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2014
[72] Energy Information Administration, Today in Energy, July 9, 2011. Average utilization of the nation's natural gas combined-cycle power plant fleet is rising. http://www.eia.gov/todayinenergy/detail.cfm?id=1730#
[73] In this figure, hour 11 is the hour ending at 11 AM, and similarly for other hours.
[74] Air Markets Program Data (AMPD), ampd.epa.gov, EPA, 2014

NGCC for peak. It is reasonable to expect that average capacity factors could be extended to higher levels at all hours without experiencing technical feasibility barriers from either pipeline supplies or electricity transmission.

Figure 3-3. Average Utilization of Natural Gas Combined Cycle Power Plant Fleet



Although there can be site-specific constraints on utilization at some NGCC facilities, several factors support the ability of the power and natural gas pipeline systems to respond effectively with increases in infrastructure when needed to alleviate these barriers. For example, in recent years, the power transmission system has responded with increased transmission infrastructure when needed to allow the retirement of uneconomic coal plants.[75] This rule provides for flexible implementation that will permit efficient scheduling of infrastructure upgrades as needed. Upgrades to pipeline and transmission infrastructure potentially needed to

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[75] See http://www.pjm.com/~/media/about-pjm/newsroom/2013-releases/20131211-pjm-board-authorizes-4.6-billion-in-chnages-to-regional-electric-grid.ashx for an example of short term transmission upgrades performed to facilitate environmental compliance. For technical description of these upgrades, see: http://www.pjm.com/~/media/committees-groups/committees/teac/20131211/20131211-december-2013-pjm-board-approval-of-rtep-whitepaper.ashx.

meet additional use of existing facilities will generally be less extensive than upgrades of that infrastructure potentially needed for siting of new capacity. In addition, this proposed rule is expected to result in significantly higher levels of end-use energy efficiency, which will reduce the load on the electricity transmission and natural gas pipeline infrastructure, while also providing other system wide benefits, such as decreased need for new generating units and reduced peak demands.

In addition, natural gas pipeline capacity is regularly added in response to increased gas demand and supply, such as the addition of large amounts of new NGCC capacity in 2001 to 2003, or the delivery to market of unconventional gas supplies since 2008.[76] These pipeline capacity increases have added significant deliverability to the natural gas pipeline network to meet the potential demands from increased use of existing NGCCs. Over a longer time period, much more significant pipeline expansion is possible. In previous studies, when the pipeline system was expected to face very large demands for natural gas use by electric utilities about 10 years ago, increases of up to 30% in <u>total</u> deliverability out of the pipeline system were judged to be possible by the pipeline industry.[77] There have also been notable capacity expansions over the past five years, in response to increased natural gas supply estimates and advances in drilling techniques.[78]

To examine the potential for increases in pipeline deliverability, the EPA analyzed the pipeline flow data from the Energy Information Administration. These data provide pipeline capacity for inflows and outflows by state. However, since the natural gas pipeline system is a network for flows into, across, and out of states and broader area, the level of gas supply that can be firmly delivered to a particular region depends on the amount of natural gas the will be required to be delivered out of the region to other regions. Consequently, it is important to focus on the net capacity – the difference between inflow capacity and outflow capacity -- in the relevant areas. The regions used by EIA for measuring regional natural gas deliverability are shown in Figure 3-4. Of these regions, the key regions for the analysis of the potential impact of the proposed rule are those natural gas consuming areas where there could be increases in natural

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[76] Energy Information Administration, Today in Energy, Natural Gas Pipeline Additions in 2011. Additions averaged around 20Bcf per day from 2008 to 2011.
[77] Pipeline and Storage Infrastructure Requirements for a 30 Tcf Market, INGAA Foundation, 1999 (Updated July, 2004); U.S. gas groups confident of 30-tcf market, Oil and Gas Journal, 1999.
[78] http://www.eia.gov/naturalgas/data.cfm#pipelines

gas consumption as a result of re-dispatch to comply with the proposed rule. These are the Northeast, Southeast, Midwest and Western regions in Figure 35. The net pipeline capacity for these regions from 2005 to 2011 is shown in Table 3-5 below.

Table 3-5. Natural Gas Pipeline Net Capacity by Region, 2005 - 2011 by Gas Consuming Area[79]

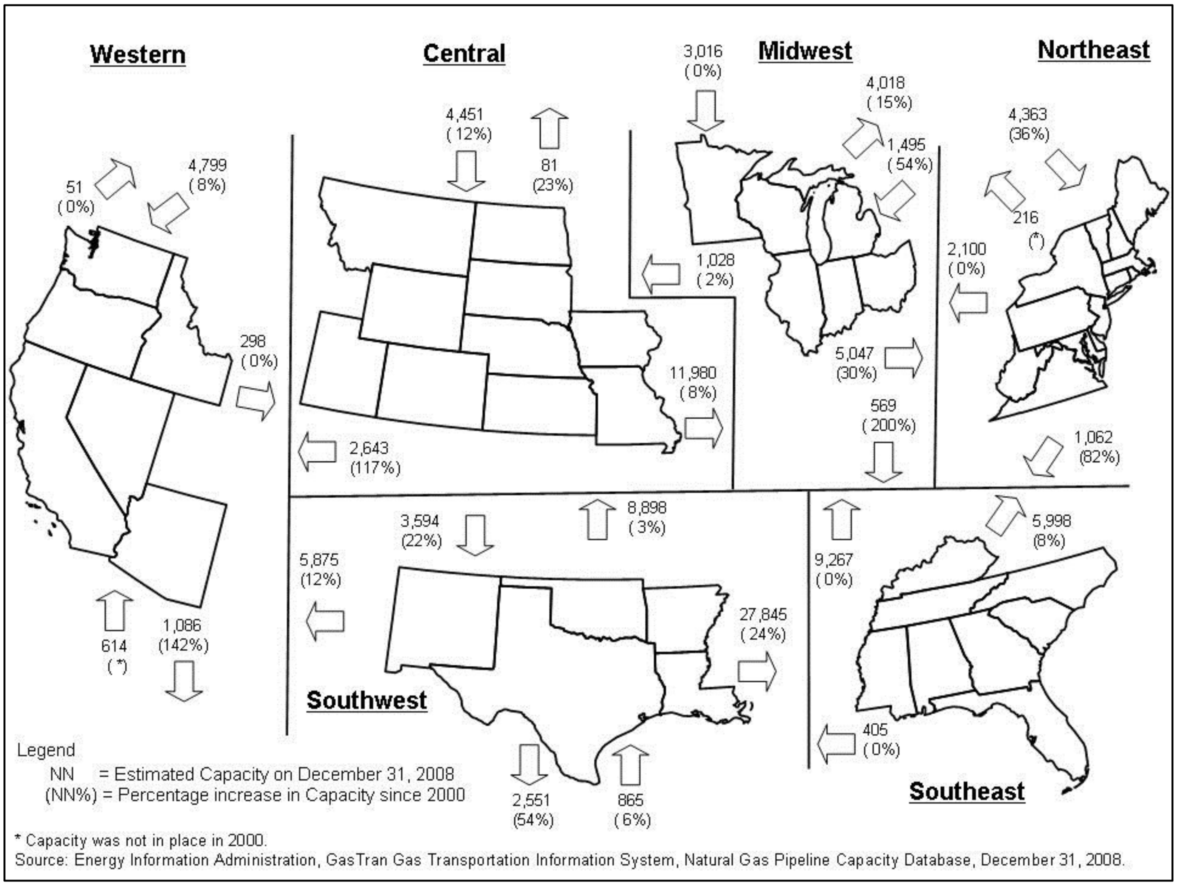
Region	2005	2006	2007	2008	2009	2010	2011
Capacity in MMCF/day							
Midwest	17,102	17,232	17,452	17,302	18,714	18,564	18,414
Northeast	11,199	11,219	11,384	11,929	12,079	12,229	12,379
Southeast	12,921	12,901	12,736	15,741	18,241	20,797	20,797
Western	11,882	11,882	12,496	12,496	12,496	12,641	14,407
All Areas	53,104	53,234	54,068	57,468	61,530	64,231	65,997
Percent Change from 2005							
Midwest	0.0%	0.8%	2.0%	1.2%	9.4%	8.5%	7.7%
Northeast	0.0%	0.2%	1.7%	6.5%	7.9%	9.2%	10.5%
Southeast	0.0%	-0.2%	-1.4%	21.8%	41.2%	61.0%	61.0%
Western	0.0%	0.0%	5.2%	5.2%	5.2%	6.4%	21.3%
All Areas	0.0%	0.2%	1.8%	8.2%	15.9%	21.0%	24.3%

As a conservative assumption, the increase from the period 2005 to 2010 can be used as an estimator of the potential increase in pipeline capacity to accommodate compliance with the rule between 2015 and 2020. This is an extremely conservative assumption, since compliance is measured over a longer period and is not limited to re-dispatch approaches. Moreover, increased use of natural gas in existing facilities can be largely met with expansions to existing pipeline facilities and corridors, so that the types of capacity expansion required will be less expensive and take less time than new pipelines. Over 2005-2010, the total gas deliverability in gas consuming areas increased by 21%. Since the power sector currently uses approximately 30% of the total national natural gas consumption, and gas usage in other sectors is expected to be

[79] Source: Energy Information Administration, http://www.eia.gov/naturalgas/data.cfm

essentially flat through 2020, this historical increase indicates that pipeline capacity will be adequate to support any compliance changes in re-dispatch of natural gas power plants.

Figure 3-4. Energy Information Administration Natural Gas Pipeline Regions



Source: Energy Information Administration.

Recent pipeline construction has continued to support the increasing need for natural gas. According to information released in April, 2014 by the EIA,[80] 118 pipeline projects were completed and placed into service from 2010 to 2014, totaling 4,699 miles of pipe, and 44,107 MMcf per day of additional pipeline capacity.

For projects expected to be in service from April, 2014 through 2016, EIA reports 47 projects, with planned capacity additions of 20,505 MMcf per day and 1,567 miles of pipe. These projects cover all major gas consuming areas of the US, and include both new pipeline

[80] See www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xls.

construction, such as the Spectra Energy's NEXUS Gas Transmission project in the Upper Midwest and pipeline expansions such as the Tennessee Gas Pipeline Project in Connecticut.

The electric transmission system has also been expanded over the past few years, and continued investment is expected. As of 2012, The EIA reports 187 thousand circuit miles of high voltage transmission in the US at 100 kV. There are 8 thousand miles of planned expansion in 2013, with a total 26 thousand miles proposed from 2013 to 2018.[81]

According to the Edison Electric Institute,[82] member companies are planning over 170 projects through 2024, totaling approximately $60.6 billion (this is only a portion of the total transmission investment anticipated). Approximately 75 percent of the reported projects are high voltage (345 kV and higher), representing over 13,000 line miles.

Analysis of Cost-Effectiveness

To further evaluate the technical capability of the natural gas supply and delivery system to provide increased quantities of natural gas and the capability of the electricity transmission system to accommodate shifting generation patterns, EPA employed the Integrated Planning Model (IPM), a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that the EPA has used for over two decades to evaluate the economic and emission 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 projections) while meeting fuel supply, transmission, dispatch, and reliability constraints.

Natural gas supply, demand, transportation, storage, and related costs are modeled directly in IPM through the incorporation of a natural gas module. The module includes a detail rich representation of the natural gas pipeline network inclusive of discount curves that represent the marginal value of gas transmission as a function of the pipeline's load factor. IPM's natural gas module has the capability to expand pipeline capacity on an economic basis.

At the unit level, IPM contains a detailed representation of new and existing resource options, inclusive of key operational limitations. For example, turn down constraints are

[81] http://www.eia.gov/electricity/annual/
[82] http://www.eei.org/issuesandpolicy/transmission/Documents/Trans_Project_lowres_bookmarked.pdf

designed to account for the cycling capabilities of EGUs to ensure that the model properly reflects the distinct operating characteristics of peaking, cycling, and base load units. EPA believes IPM represents a powerful tool to evaluate the technical feasibility of requiring increasing levels of re-dispatch from higher to lower-emitting EGUs.

The EPA has conducted extensive analysis to quantify the opportunity to reduce CO_2 emissions through re-dispatch. As part of this effort, the EPA conducted an initial set of analyses utilizing the Integrated Planning Model (IPM) to provide a framework for understanding the broader economic and emissions implications of shifting generation from coal-fired steam EGUs to NGCC units within defined areas.[83] In the most restrictive scenarios, re-dispatch was simulated only between EGUs located in the same state. These scenarios were designed to consider, even under a restrictive interpretation of the degree of re-dispatch that might constitute a component of BSER under CAA section 111(d),[84] to what extent existing NGCC units could increase their dispatch cost-effectively taking into account the impact of that behavior on prices of natural gas and electricity. To evaluate how EGU operators and balancing authorities could respond to a state's goal by incentivizing re-dispatch from more carbon-intensive to less carbon-intensive EGUs, the EPA introduced two additional elements to the IPM framework:

1. The application of a CO_2 charge to the variable cost of dispatch for all existing coal steam boilers, IGCC units, and oil/gas steam boilers greater than 25 MW and with a CO_2 emissions rate greater than 1,100 lbs/MWh.[85]

[83] IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. Full documentation of the IPM model can be found at http://www.epa.gov/powersectormodeling

[84] In practice, unit dispatch does not respect state boundaries because least-cost supply must be balanced with demand in real time over grid interconnects which span multiple states (with the exception of the Electric Reliability Council of Texas interconnect). The design of this modeling scenario assumes artificial constraints on re-dispatch to force such behavior to respect state boundaries, given the context of this rulemaking's quantification of individual state goals. These state boundary constraints necessarily forgo cost-effective opportunities to re-dispatch units in different states; as a result, costs and prices in this analysis are overstated.

[85] The addition of CO_2 costs represents a simple analytic approach to estimating the cost-effective CO_2 reductions under this building block and acts as a proxy for some existing state policies that shift dispatch. In actual plan implementation, states would be free to select any policy approach that has the net effect of reducing the carbon intensity of generation and/or reducing overall emissions from affected sources.

2. Generation constraints that maintain the sum of state-level generation in the Base Case[86] from existing NGCC of any size, plus existing coal steam, IGCC and oil/gas steam boilers greater than 25 MW and with a CO_2 emissions rate >1,100 lbs/MWh.

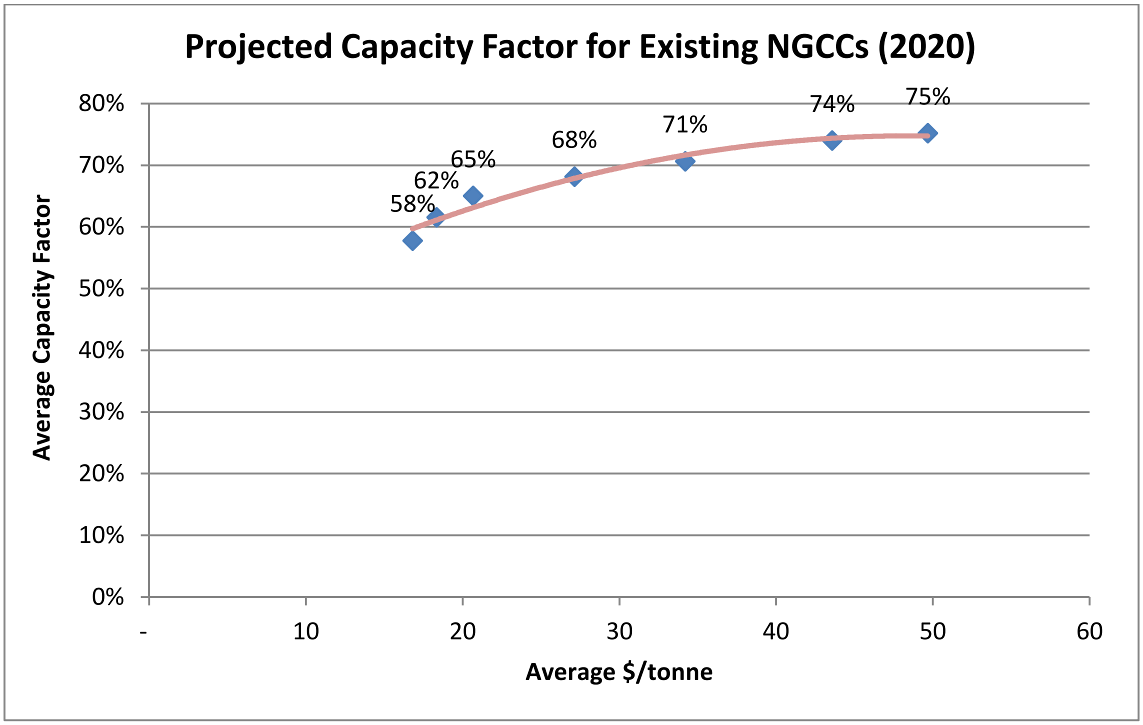
These elements test the economic and technical potential for re-dispatch by: (1) increasing dispatch costs for affected coal steam, IGCC, and O/G steam EGUs within each state, and (2) requiring that any reduction in output from those sources be offset in its entirety by an increase in output from that state's existing NGCC capacity. Utilizing IPM to conduct this analysis ensures an integrated, least-cost, technically feasible solution subject to power sector system reliability constraints, fuel market impacts, natural gas transmission and distribution networks, electric power transmission constraints, and unit-specific characteristics (e.g., operating and maintenance costs, heat rate, turndown/cycling behavior).

Cost and Availability of Economic Re-Dispatch Opportunities

In executing this analysis, the EPA conducted a number of scenarios to quantify the relationship between the amount and cost of re-dispatch. Figure 3-5 below presents the projected national average capacity factor for NGCCs in 2020 (the first year of the assumed re-dispatch incentive) and the associated average $/tonne of CO_2 reduced by comparing emissions and costs against the EPA's Base Case (the difference in total system cost divided by the difference in power sector emissions). While the charge is applied exogenously in IPM, the average $/tonne shown below is calculated from the modeling results and projections by dividing the increase in total system costs (compared to the base case) by the total change in CO_2 emissions (compared to the base case).

[86] http://epa.gov/powersectormodeling/BaseCasev513.html

Figure 3-5: NGCC National Capacity Factor, 2020 Initial Analyses



The EPA believes average $/tonne – which is distinct from the $/tonne CO_2 cost imposed in these analytic scenarios on affected coal steam, IGCC, and O/G steam EGUs – to be the most relevant metric in evaluating cost-effectiveness. System cost changes necessarily encompass all elements of cost across power, transmission, and fuel markets and therefore provide the most comprehensive perspective regarding cost-effectiveness.

Table 3-6: Power Sector Emission Reductions Due to Re-Dispatch

CO_2 Cost Level Imposed	National Average NGCC Capacity Factor	Average Cost ($/tonne)	2020 Power Sector CO_2 Emissions (MMT / % Change from 2020)
Base Case	52%	N/A	2,161
$10/tonne	58%	$17	2,038 / -6%
$15/tonne	62%	$18	1,997 / -8%
$20/tonne	65%	$21	1,961 / -9%
$25/tonne	68%	$27	1,928 / -11%
$30/tonne	71%	$34	1,901 / -12%
$40/tonne	74%	$44	1,866 / -14%
$50/tonne	75%	$50	1,852 / -14%

Although the EPA views this estimated range of average $/tonne costs as reasonable, we expect the costs of implementing this requirement in a compliance[87] setting will be considerably lower for several reasons:

- *Analytic construct used to simulate re-dispatch incentive:* As described earlier in this chapter, the EPA's initial analyses utilized CO_2 charges on the variable cost of dispatch for existing coal steam, IGCC, and O/G steam with emission rates greater than 1,100 lbs/MWh and a capacity greater than 25 MW, as an analytic construct to induce re-dispatch behavior in the model to existing NGCC facilities. The CO_2 charge was applied uniformly to all states in order to quantify the ultimate amount of in-state re-dispatch opportunities available as that charge is increased across scenarios. In the initial analyses, low levels of CO_2 charges produce cost-effective re-dispatch opportunities relative to the Base Case in almost all states. However, as the CO_2 costs are increased to higher levels, economic re-dispatch, opportunities within some states may eventually plateau – a point clearly illustrated in the declining slope of the best-fit line in Figure 3-5. A uniform

[87] The Regulatory Impact Analysis supporting the proposal examines, in an illustrative manner, how the power sector could respond to the state goals that are calculated from all of the building blocks in a cost effective manner.

application of the same rising CO_2 charge in all states produces an outcome for many states where the additional CO_2 costs imposed on affected coal steam, IGCC, and O/G steam are not able to produce incremental economic re-dispatch at units within that state; therefore, the additional costs imposed by these higher CO2 charges overstate the actual $/tonne necessary to induce achievable re-dispatch in each state.

- *Potential for multi-state compliance:* The EPA also analyzed scenarios where shifting of generation among EGUs was not limited by state boundaries. In one set of analyses, re-dispatch was allowed to occur across the multi-state regions defined by NERC assessment areas (subject to other real-world constraints specified in the model, including transmission limits). In these scenarios with greater re-dispatch flexibility, the system was able to achieve 8% greater CO_2 emission reductions at an identical CO_2 charge (relative to a scenario where it was limited on a state basis), demonstrating that the main analysis's imposition of artificial re-dispatch boundaries on state borders overstates the cost-effectiveness of re-dispatch potential.

To evaluate how EGU owners and grid operators could respond to a state plan's possible requirements, signals, or incentives to re-dispatch from more carbon-intensive to less carbon-intensive EGUs, the EPA also analyzed an additional series of scenarios in which the fleet of NGCC units nationwide was required, on average, to achieve a specified annual utilization rate. Specifically, the scenarios required average NGCC unit utilization rates of 65, 70, and 75 percent. For each scenario, dispatch decisions are allowed such that electricity demand is met at the lowest total cost, subject to all other specified operating and reliability constraints for the scenario, including the aforementioned state-by-state generation levels from the base case. This constraint effectively requires states that decrease coal generation to offset, in equal amounts, NGCC generation. Collectively, states must achieve the required capacity factor for NGCCs.

The costs and economic impacts of the various scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from a business-as-usual scenario. For the scenarios reflecting a 65, 70, and 75 percent NGCC utilization rate, comparison to the business-as-usual case indicates that the average cost of the CO_2 reductions achieved over the 2020-2029 period was $21, $30, and $40 per metric ton of CO_2, respectively. However, we also note that the costs just described are higher than we would expect to actually occur in real-world compliance with this proposal's goals. This is because only 29 state goals are premised on the existing NGCC fleet achieving an average capacity factor of 70 percent. Consequently, a 70 percent utilization rate target for the existing NGCC fleet requires an average national capacity factor of 63 percent.

The EPA also analyzed dispatch-only scenarios where shifting of generation among EGUs was limited by state boundaries. In these scenarios with less re-dispatch flexibility, the cost of achieving the quantity of CO_2 reductions corresponding to a nationwide average NGCC unit utilization of 70% was $33 per ton.

Table 3-7: IPM Results from Re-Dispatch Scenarios

Existing NGCC Average National Capacity Factor	Re-Dispatch Constraint	Average Cost ($/tonne, 2020-2029)	Average CO_2 Emissions (MMT, 2020-2029)	Reductions from Base Case (%, 2020-2029)
Base Case	NA	NA	2,215	NA
65%	Regional	$21	2,022	9%
70%	Regional	$30	1,969	11%
75%	Regional	$40	1,915	14%
65%	State	$22	2,024	9%
70%	State	$33	1,971	11%

Natural Gas Price Impacts

The extent of re-dispatch estimated in this building block can be achieved without causing significant economic impacts. For example, in neither of the 70 percent NGCC unit utilization rate scenarios – re-dispatch limited to regional or state boundaries – did delivered natural gas price projections increase by more than 10 percent in the 2020-2029 period, which is well within the range of historical natural gas price volatility. For example, the year-to-year percentage difference in Henry Hub prices reported by the Energy Information Administration averaged 18.5% over the period from 1981 to 2012.[88] Projected wholesale electricity price increases over the same period were less than 7 percent in both cases, which similarly is well

[88] http://www.eia.gov/dnav/ng/hist/rngwhhdA.htm

within the range of historic electric price variability. For example, the average year-to-year price change for the PJM region was 19.5 percent over the period from 2000 to 2013. For all the ISOs in the East, the variation is virtually unchanged from the PJM example (at 19.6%).[89]

However, for the reasons previously discussed with respect to estimated costs per ton of CO_2, the actual implementation is expected to result in notably lower economic impacts, including natural gas price impacts, and are considerably larger than would actually occur in real-world compliance with this rule's proposed goals.

Table 3-8: National Average Delivered Natural Gas Price, Power Sector (Average 2020-2029)

Existing NGCC Average National Capacity Factor	Re-Dispatch Constraint	Price ($/mmBtu)	% Change
Base Case	NA	$5.94	
65%	Regional	$6.36	7%
70%	Regional	$6.53	10%
75%	Regional	$6.69	13%
65%	State	$6.37	7%
70%	State	$6.52	10%

[89] ISO Real-Time data for all hours, from Ventx Velocity Suite data across Eastern ISOs (PJM, NYISO,ISO-NE and Midcontinent ISO).

Chapter 4: Cleaner Generation Sources

4.1. Introduction

Renewable energy is a cost-effective approach for reducing carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating units (EGUs) through the substitution of electricity generated from renewable resources, referred to in this document as renewable energy (RE). The portfolio of available RE sources encompasses a wide variety of technologies from utility-scale RE plants to smaller-scale distributed generation sited at residential, commercial, or industrial facilities. RE technologies are fueled by the sun, wind, water, organic matter, and other resources regularly replenished by physical and biological cycles. To integrate the rapidly increasing and evolving portfolio of RE into the Best System of Emission Reductions (BSER), the EPA has developed a proposed approach that builds upon current state policy encouraging increased production of RE taking into account renewable potential in particular regions of the country.

Additionally, the EPA believes that the planned expansion of new nuclear generating capacity and the preservation of existing nuclear generating capacity represent a cost-effective means to reduce CO_2 emissions at fossil fuel-fired EGUs by providing carbon-free generation that can replace generation at those EGUs. Increasing the amount of nuclear capacity relative to the amount that would otherwise be available to operate is a technically viable and economically efficient approach for reducing CO_2 emissions from affected fossil fuel-fired EGUs.

This TSD is intended to support discussion of cleaner generation sources (RE and nuclear) as a component of BSER in the preamble (most extensively in these sections: Building Blocks for Setting State Goals and Considerations, State Goals, State Plans, and Impacts of the Proposed Rule) and its representation within the RIA. Results from this chapter feed into the technical support document (TSD) on state goal setting. Cleaner generation is also addressed in TSDs on Survey of Existing State Actions, State Plan Considerations, Projecting EGU CO_2 Emission Performance, and Legal Memorandum.

4.2. Proposed Approach

To estimate the potential RE available for inclusion as part of BSER, EPA developed an RE generation scenario that provides a target for how much of each state's generation can be produced by RE based upon the current goals of leading states in the same region, and allows each state to grow RE generation over time towards that target, based upon that state's current level of RE. The method can be summarized as follows. First, the country is divided into regions. Second, an RE generation target is calculated for each region, based upon averaging all 2020 RPS requirements in that region. Third, an annual growth factor is calculated that would allow the region as a whole to reach the regional RE target in 2029 assuming that RE generation would increase from 2012 levels beginning in 2017. Fourth, the annual growth factor for a given region is applied to individual states' 2012 RE generation to calculate future RE generation in that state from 2017 through 2029, not to exceed a maximum RE generation level equivalent to the regional RE target. Finally, these annual RE generation levels for each state are used to calculate interim and final RE targets for that state.

The proposed approach is derived from state experience with policies that drive investment in RE and the generation that results from those efforts. The EPA focused on state-level RE policy for several reasons. Every state in the union is producing electricity from renewable resources, and some states have achieved significant levels of renewable generation, surpassing a quarter of in-state generation. State-level RE requirements have been implemented in 29 states plus Washington, DC, representing all regions of the country. Nine states have voluntary goals.[90,91] These 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.

The proposed approach focuses on RE requirements established through Renewable Portfolio Standards (RPS), which provide specific quantifiable RE generation requirements over time. The EPA used these RPS-mandated quantities as the basis for deriving regional targets to be applied to states as part of BSER, using the RPS-based targets as a reasonable benchmark of regionally cost-effective RE generation which states could grow towards over time. While EPA's proposed approach is derived from RPS data, states may also consider a broad variety of other RE policies to increase generation, such as performance-based incentives, financial assistance

[90] Database of State Incentives for Renewables and Efficiency, last modified March 2013, accessed at http://www.dsireusa.org/rpsdata/index.cfm.
[91] Alaska House Bill 306, Signed by Governor Sean Parnell June 16, 2010, http://www.legis.state.ak.us/basis/get_bill_text.asp?hsid=HB0306Z&session=26.

programs, regulatory changes to facilitate the development of renewable sources and their interconnection to the grid and "lead by example" strategies integrating RE generation into state properties.[92] Because the EPA did not quantify potential that could be tapped through any of those 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.

While future RPS requirements will necessitate more RE generation and capacity beyond current levels, the EPA does not expect the anticipated rate of growth required to meet those requirements to exceed the historical rate of RE deployment. Full compliance with current RPS requirements through 2035 would necessitate the deployment of approximately 3 to 5 GW of new renewable capacity per year through 2020 and 2 to 3 GW through 2035. Average deployment of RPS-supported renewable capacity from 2007-2012 has exceeded 6 GW per year.[93] In addition, recent improvements in RPS compliance rates indicate to the EPA the reasonableness of current RPS growth trajectories. Weighted average compliance rates among all states have improved in each of the past three reported years (2008 - 2011) from 92.1 percent to 95.2 percent despite a 40 percent increase in RPS obligations during this period.[94] As the Lawrence Berkeley National Laboratory (LBNL) RPS Status Update found, in the period 1998-2012, 67% of all non-hydro U.S. RE capacity additions, totaling roughly 46,000 MW, was built in states with RPS requirements.[95]

This scenario provides an estimate of an achievable level of total RE generation within states. It does not represent an EPA forecast of business-as-usual impacts of state policies or an

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[92] See State Plan Considerations TSD for a discussion of how states can incorporate such RE policies into their state plans for this rule.
[93] Barbose, Galen, "Renewables Portfolio Standards in the United States: A Status Update," Lawrence Berkeley National Lab, November 2013. Also, Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K., and Wiser, R., "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards," NREL Report No. 6A20-61042, LBNL Report No. 6589E, http://www.nrel.gov/docs/fy14osti/61042.pdf.
[94] Barbose, Galen, "RPS Compliance Summary Data," Lawrence Berkeley National Lab, May 2013, accessed March 2014 at http://emp.lbl.gov/rps. The RPS compliance measure cited is inclusive of credit multipliers and banked RECs utilized for compliance, but excludes alternative compliance payments, borrowed RECs, deferred obligations, and excess compliance. This estimate does not represent official compliance statistics, which vary in methodology by state.
[95] Barbose, Galen, "Renewables Portfolio Standards in the United States: A Status Update," Lawrence Berkeley National Lab, November 2013. Slide 8. Also, Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K., and Wiser, R., "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards." NREL Report No. 6A20-61042, LBNL Report No. 6589E, http://www.nrel.gov/docs/fy14osti/61042.pdf.

EPA estimate of the full potential of RE available to the power system; rather, it is intended to represent a feasible development scenario that enables reductions of CO_2 emissions from fossil fuel-fired EGUs in all states and that is generally consistent with ongoing trends in RE development. The scenario uses a level of performance that has already been demonstrated or required by policies of leading states, while considering each state's unique existing level of RE performance and allowing appropriate time for each state to increase from their current level of performance to the identified target level. In the context of this rulemaking, RE "performance" and RE targets are measured as the share of total generation represented by renewables as explained further below.

The following steps were taken to establish the inputs for development of the proposed approach for each state. The implementation of each step is illustrated in the table below its description, using the state of Illinois as an example.

4.2.1 *Determine current level of performance*
4.2.2 *Determine target level of performance*
4.2.3 *Determine start year for state efforts*
4.2.4 *Determine pace at which states improve from start year to target level of performance*
4.2.5 *Calculate RE targets for interim and final state targets*

Note that an accompanying excel file that contains the aggregate state level data, calculations, and proposed state RE targets is also available in the Docket for this rulemaking. The title of this document is "Proposed RE Approach Data File."

4.2.1 Determine current level of performance

The type and extent of current RE capacity varies significantly across states, and is influenced by the renewable resources available, the economics of the power sector to date in different regions, and the state policies that affect renewable sources specifically and energy production generally. The extent of that generation has also changed rapidly in the past few years, and states with RE policies have significantly increased their renewable capacity. To characterize the current level of RE generation and total generation[96], we have used the most current state-level data on generation: 2012 net generation data by state. [97]

For the purposes of calculating a baseline level of RE generation in each state, the EPA adopted a broad interpretation of RE generation to include any non-fossil renewable fuel type, with the exception of generation from existing hydroelectric power facilities. Large existing hydroelectric facilities provide a large percentage of RE generation in a few states (hydropower is America's largest existing source of RE, for which generating capacity has remained relative constant over the last 20 years), and inclusion of this generation in current and projected levels of performance would distort the proposed approach by presuming future development potential of large hydroelectric capacity in other states. Because RPS policies were implemented to stimulate the development of new RE generation, existing hydroelectric facilities are often excluded from RPS accounting. No states are expected to develop any new large facilities. [98] The RE target-setting method presented in the body of this chapter includes only non-hydropower RE in the target-setting calculations and in the RE generation levels used to inform the state goals calculated in this proposal. In Appendix 4-1, we provide a different version of the RE generation targets that includes existing hydropower generation from 2012 for each state in the state RE targets. These targets that include existing hydropower generation as of 2012 reflect the potential incorporation of existing hydropower in the state RE targets that could inform the calculation of state goals if such generation were included in the quantification of BSER-related RE generation. The analysis informing regional RE targets does not explicitly account for the potential of building new hydroelectric facilities as a source under RPS policies; however, states may choose to encourage such development, and generation from such facilities would not be excluded from compliance with a state's goal under this rule. The most recent 2012 performance data for all states is shown in Table 4-1. Consistent with the design of a number RPS policies, RE "performance" is measured here as the share of total generation represented by non-hydro RE.

[96] EIA state-level total generation has been adjusted to remove utility-scale fossil generation located in Indian Country.

[97] U.S. EIA state level data available at http://www.eia.gov/electricity/data/state/.

[98] U.S. EIA, Annual Energy Outlook 2014, p. 121, http://www.eia.gov/forecasts/archive/aeo13/index.cfm.

Table 4-1. 2012 RE Performance by State (MWh)

State	RE Generation	Total Generation	Performance Level
Alabama	2,776,554	152,878,688	2%
Alaska	39,958	6,946,419	1%
Arizona	1,697,652	95,016,925	2%
Arkansas	1,660,370	65,005,678	3%
California	29,966,846	199,518,567	15%
Colorado	6,192,082	52,556,701	12%
Connecticut	666,525	36,117,544	2%
Delaware	131,051	8,633,694	2%
District of Columbia[99]	-	71,787	0%
Florida	4,523,798	221,096,136	2%
Georgia	3,278,536	122,306,364	3%
Hawaii	924,815	10,469,269	9%
Idaho	2,514,502	15,499,089	16%
Illinois	8,372,660	197,565,363	4%
Indiana	3,546,367	114,695,729	3%
Iowa	14,183,424	56,675,404	25%
Kansas	5,252,653	44,424,691	12%
Kentucky	332,879	89,949,689	0%
Louisiana	2,430,042	103,407,706	2%
Maine	4,098,795	14,428,596	28%
Maryland	898,152	37,809,744	2%
Massachusetts	1,843,419	36,198,121	5%
Michigan	3,785,439	108,166,078	3%
Minnesota	9,453,871	52,193,624	18%
Mississippi	1,509,190	54,584,295	3%
Missouri	1,298,579	91,804,321	1%
Montana	1,261,752	27,804,784	5%
Nebraska	1,346,762	34,217,293	4%
Nevada	2,968,630	35,173,263	8%
New Hampshire	1,381,285	19,264,435	7%
New Jersey	1,280,715	65,263,408	2%
New Mexico	2,573,851	2,289,4524	11%
New York	5,192,427	135,768,251	4%

[99] The District of Columbia has no utility-scale RE generation, but the District does have distributed RE resources contributing to the electrical grid.

North Carolina	2,703,919	116,681,763	2%
North Dakota	5,280,052	36,125,159	15%
Ohio	1,738,622	129,745,731	1%
Oklahoma	8,520,724	77,896,588	11%
Oregon	7,207,229	60,932,715	12%
Pennsylvania	4,459,118	223,419,715	2%
Rhode Island	101,895	8,309,036	1%
South Carolina	2,143,473	96,755,682	2%
South Dakota	2,914,666	12,034,206	24%
Tennessee	836,458	77,724,264	1%
Texas	34,016,697	429,812,510	8%
Utah	1,099,724	36,312,527	3%
Vermont	465,169	6,569,670	7%
Virginia	2,358,444	70,739,235	3%
Washington	8,214,350	116,835,474	7%
West Virginia	1,296,563	73,413,405	2%
Wisconsin	3,223,178	63,742,910	5%
Wyoming	4,369,107	49,588,606	9%

<u>4.2.2 Determine target level of performance</u>

Achievable RE potential exists at significant and comparable levels in all regions of the country. While varied regional characteristics (e.g., the extent of renewable resources available, cost of competing sources of power, and level of past RE development) affect estimates of achievable potential, ongoing improvements in technologies and practices, and continually improving strategies for RE development are increasing the extent of economically utilized renewable resources across all regions of the United States. RE has been capturing a growing percentage of new capacity additions in the past few years. In 2012, RE accounted for more than 56% of all new electrical capacity installations in the U.S. – a major increase from 2004 when renewable installations captured only 2% of new capacity additions.[100] The economics of the fastest growing RE technologies – on-shore wind and solar photovoltaics (PV) – are improving and are competitive in many regions. In 2012, cumulative installed wind capacity increased by nearly 28% and cumulative installed solar PV capacity grew more than 83% from the previous

[100] U.S. Department of Energy. 2012 Renewable Energy Data Book. DOE/GO-102013-4291.October 2013, p. 3.

year.[101] In the United States, installed wind electricity capacity increased more than 23 fold between 2000 and 2012.[102] Solar electricity generating capacity grew by a factor of over 21 between 2000 and 2012 and currently accounts for 0.3% of annual U.S. electricity generation.[103] In 2013, 4.8 GW of solar PV capacity was installed, bringing total solar U.S. solar capacity to 12.1 GW.[104] The National Renewable Energy Laboratory (NREL) has also found that the continental U.S. has solar potential that exceeds high solar generating countries like Germany, which is now generating over 6% of their electricity from solar.[105] Looking forward, the U.S. Department of Energy has found that 46 states would have substantial wind development by 2030 under a scenario in which 20% of national generation is provided by wind. The distribution of that deployment is shown in Figure 4.1.[106]

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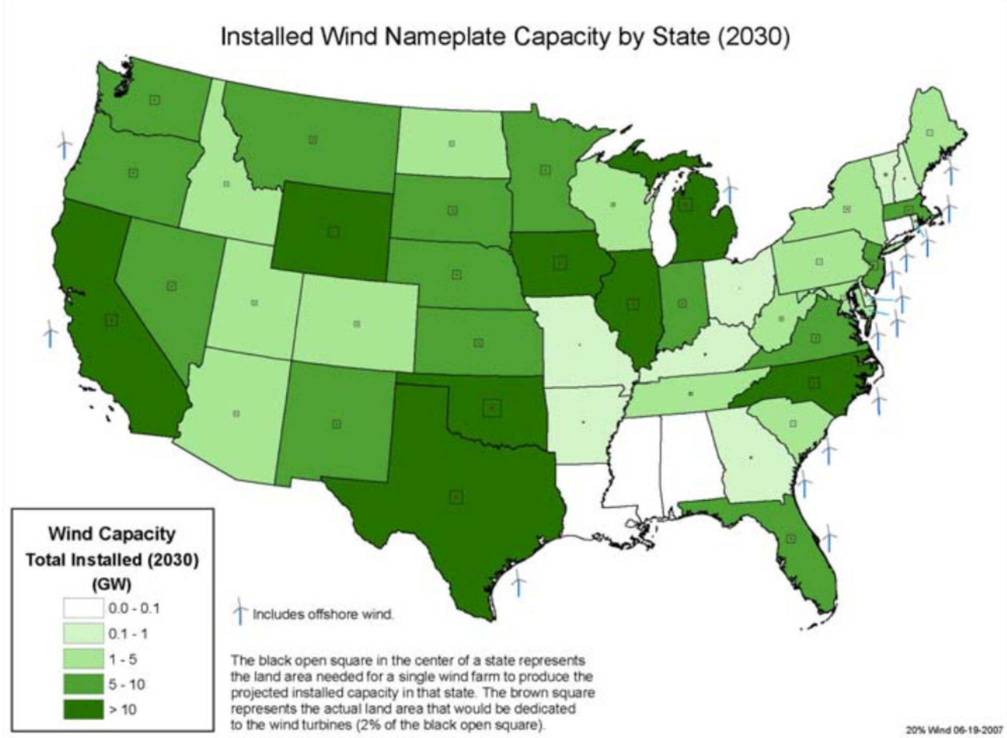
[101] Ibid. p. 18.
[102] Ibid. p. 53.
[103] Ibid. p. 63.
[104] GTM Research and the Solar Energy Industries Association (SEIA), "SEIA Solar Market Insight Report 2013: Year in Review", 2014, http://www.seia.org/research-resources/solar-market-insight-report-2013-year-review.
[105] NREL. Photovoltaic Solar Resource: The United States, Spain and Germany. 2009, http://www.nrel.gov/gis/images/us_germany_spain/pvmap_usgermanyspain%20poster-01.jpg. Also IEA, PVPS Snapshot of Global PV 1992-2013. Report IEA-PVPS T1-24:2014, March 31, 2014, http://www.iea-pvps.org/fileadmin/dam/public/report/statistics/PVPS_report_-_A_Snapshot_of_Global_PV_-_1992-2013_-_final_3.pdf.
[106] U.S. Department of Energy, 20% Wind Energy by 2030: Increasing Wind Energy's Contribution to U.S. Electricity Supply – Executive Summary, December 2008, http://www.nrel.gov/docs/fy09osti/42864.pdf.

Figure 4.1. DOE Projected Installed Wind Capacity by State under 20% National Generation Scenario



4.2.2.1. Quantification of Effective RE Levels from State-Level RPS Requirements

The proposed approach is also based upon an analysis of renewable portfolio standards, a policy that facilitates the quantification of RE targets. By only examining the impact of one type of policy, the analysis is inherently conservative, as many other policy options are also available to states in addition to RPS.

In order to apply the various RPS policies to the development of a target level of performance, the EPA used publicly-available quantitative information about mandatory state RPS requirements from the Database for State Incentives for Renewables and Efficiency (DSIRE).[107] This information enabled the EPA to determine the effective RE levels in 2020 for states with mandatory RPS requirements.[108]

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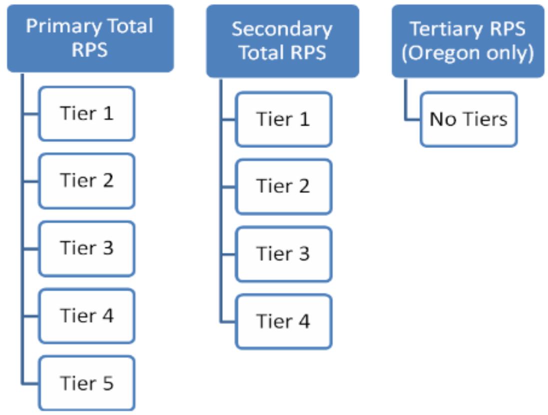
[107] Database of State Incentives for Renewables & Efficiency (DSIRE) is a very comprehensive source of information on incentives and policies that support renewables and energy efficiency in the United States. DSIRE is currently operated by the N.C. Solar Center at N.C. State University, with support from the Interstate Renewable Energy Council, Inc. DSIRE is funded by the U.S. Department of Energy. http://www.dsireusa.org/.
[108] EPA did not include targets that were capacity-based.

DSIRE provides regularly-updated RPS Data Spreadsheets that detail state RPS requirements by year, resources, and other key component parts.[109] The RPS compliance schedules are broken down into the specific annual percentages requirements for the years 2000 to 2030. Many states have multiple compliance requirements, including the main percentage requirements for eligible resources and additional resource-specific percentage requirements that states are increasingly using to promote the development of a particular set of resources or technologies (e.g., solar PV). DSIRE called each of these sets of resource requirements "tiers" and applied a standardized approach to them, "in order to compare RPS policies on equal footing."[110] The benefit of this approach is that state resource requirements become additive and facilitate a process of selection and exclusion. The EPA added together each state's tiers, as standardized by DSIRE, to determine states' effective RE levels for 2020, but excluded tiers, other than main tiers, that include energy efficiency or any fossil fuel.

In addition, six states have established more than one set of RPS requirements for in-state utilities, including "secondary" and "tertiary" RPS requirements for smaller utilities, municipal utilities, or cooperative utilities. The EPA only included the primary RPS requirements to simplify the analysis of primary and secondary RPS requirements in determining states' effective RE levels for 2020. By only considering primary requirements, there is additional inherent conservatism in the RPS estimates, as additional state-level RPS obligations are not included in the calculated targets.

[109] DSIRE, RPS Data Spreadsheet. April 2013, http://www.dsireusa.org/rpsdata/index.cfm.
[110] DSIRE, DSIRE RPS Field Definitions, April 2011. http://www.dsireusa.org/rpsdata/RPSFieldDefinitionsApril2011.pdf, p. 1.

Figure 4.2 RPS Data Structure[111]



The RPS compliance schedules in six states implement maximum requirements prior to 2020; their effective RE levels for 2020 are set to those maximum levels. In fact, most states maintain their percentage requirements indefinitely.

TABLE 4.2. Effective RE Levels Derived from RPS Requirements

RPS States	Primary Target	Target Year	2020 Effective RE Levels	Exclusions
AZ	15%	2025	10%	
CA	33%	2020	33%	
CO	30%	2020	30%	Secondary RPS requirement
CT	23%	2020	23%	Class 3 includes non-RE
DC	20%	2023	20%	
DE	25%	2027	19%	
HI	40%	2030	25%	
IL	25%	2025	16%	Secondary RPS requirement
KS	20%	2020	20%	
MA	33%	2030	22%	
MD	20%	2022	18%	
ME	40%	2017	40%	
MI	10%	2015	10%	

[111] Ibid.

MN	30%	2020	30%	Secondary RPS requirement
MO	15%	2021	10%	
MT	15%	2015	15%	
NC	13%	2021	10%	Secondary RPS requirement
NH	25%	2025	20%	
NJ	24%	2021	22%	
NM	20%	2020	20%	Secondary RPS requirement
NV	25%	2025	22%	
NY	29%	2015	29%	
OH	13%	2024	9%	
OR	25%	2025	20%	Secondary & tertiary RPS requirements
PA	8%	2021	8%	Class 2 includes non-RE
RI	16%	2019	16%	
WA	15%	2020	15%	
WI	10%	2015	10%	

4.2.2.2. Development of Regional RE Generation Targets from State-level Effective RE Levels

To take into account the varied availability of different renewable resources across regions of the United States, the EPA uses the state-level effective RE levels derived from RPS requirements to quantify regional RE targets consistent with states' reasonable level of increased RE development. This methodology helps us to quantify RE potential in states which do not have an RPS policy from which the renewable resource potential can be inferred. Specifically, the scenario estimates each region's RE potential by assuming all states in each region can achieve by 2030 the average of the 2020 requirements of RPS states in that region.

The regions assigned to states to quantify their RE generation target are based upon North American Electric Reliability Corporation (NERC) regions and Regional Transmission Organizations (RTOs) and are the same as the regions used in the modeling of the "regional" compliance scenarios as outlined in the proposal RIA (see Figure 4-3).[112] States within each region exhibit similar profiles of RE potential or have similar levels of renewable resources. The regional similarities can be inferred from the state-level technical potential reported in an NREL

[112] For more information on the structure of these regions, please refer to the Regulatory Impact Analysis Chapter 3.

GIS-based analysis.[113] The results show clear trends for the regions used to create the proposed approach, with portfolios of particular technologies showing clear dominance in specific regions. North Central and South Central regions have strong on-shore wind resource potential. The East Central and Southeast regions show moderate to strong resources in both biopower and rooftop PV potential. The West has notable potential in geothermal (hydrothermal) power and concentrating solar power, in addition to potential for increased hydropower generation. The Northeast has strong resources in off-shore wind and moderate biopower and solar resources available. It should be noted that high technical potential in a particular renewable resource is not necessarily needed to reach the generation levels quantified under this approach. For example, Maine produced 28% of its electricity generation in 2012 from biopower and onshore wind, while it is estimated in this report to have relatively moderate technical potential for biopower and relatively low levels of onshore wind capacity. Overall, results from the NREL GIS-based analysis show that the regional RE targets included in this proposed approach assume development of only 0.5% to 4.5% of the RE resources in those regions. See Figure 4.3.1 for a graph showing the state RE targets in each region represented as a percentage of the renewable resources available in the state.

[113] NREL. U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. NREL/TP-A20-51946. July 2012. http://www.nrel.gov/docs/fy12osti/51946.pdf.

Figure 4.3. Proposed Approach Regions

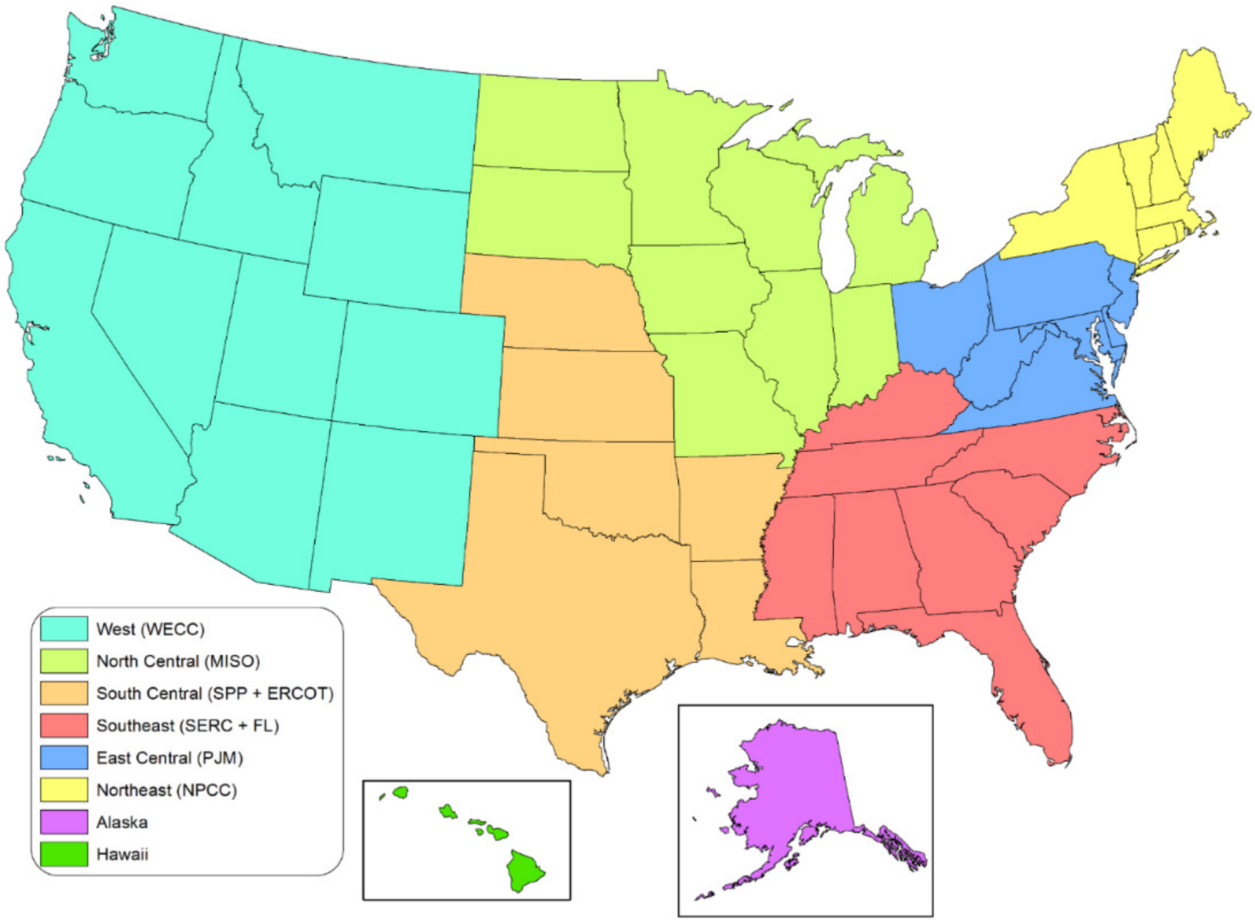
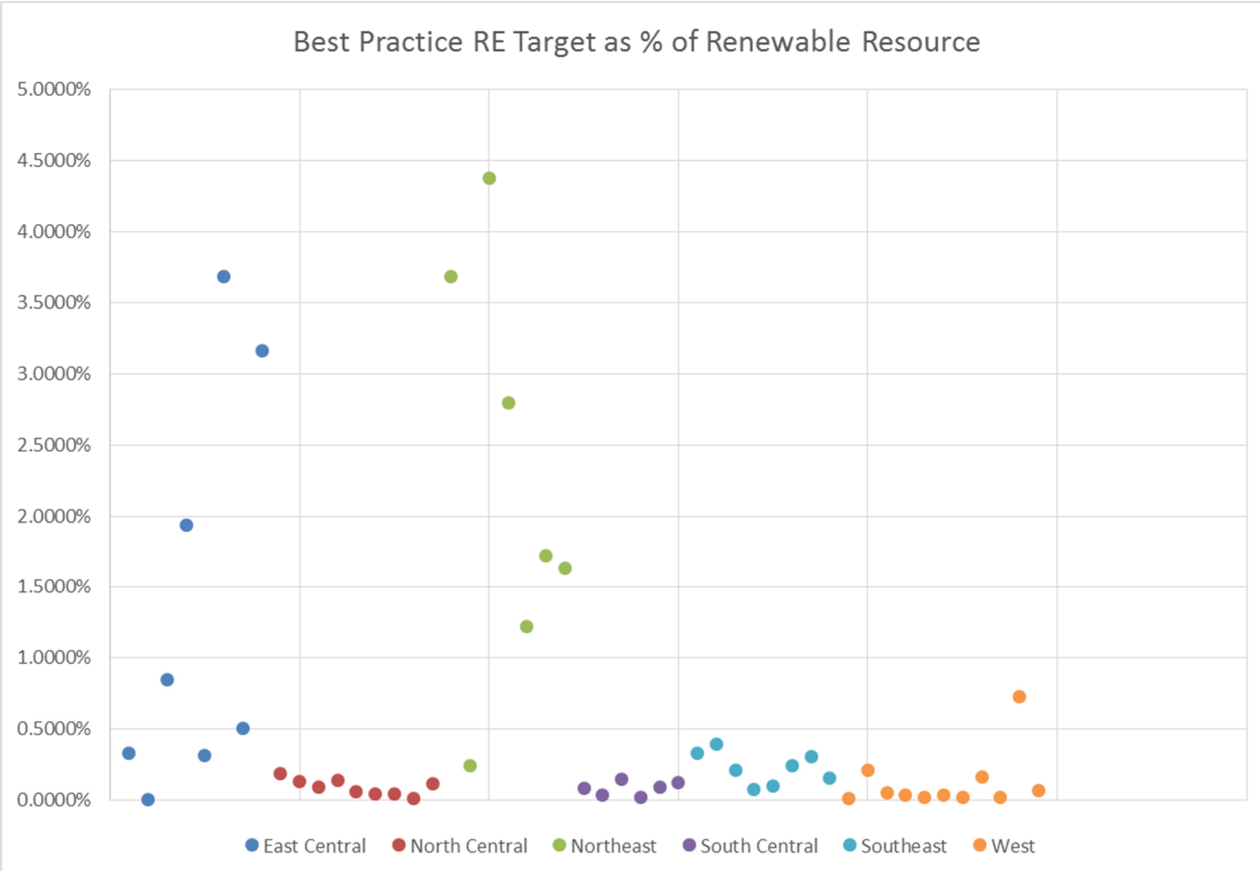


Table 4.3. List of States Included in Proposed Approach Regions[114]

Region	States
East Central	Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia
North Central	Illinois, Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, Wisconsin
Northeast	Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont
South Central	Arkansas, Kansas, Louisiana, Nebraska, Oklahoma, Texas
Southeast	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee
West	Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming

[114] Alaska and Hawaii are not grouped with other states into regions.

Figure 4.3.1. Regional RE Targets of each State as a Percentage of the State's Renewable Resources



The EPA compiled the state-level effective RE levels derived above, organized them by region, and determined an average percent generation target for that region. This average did not include any values for states in which there is no binding RPS requirement. For example, the RE target for the North Central region is calculated as the average of 2020 RPS requirements in Illinois (16%), Michigan (10%), Minnesota (30%), Missouri (10%), and Wisconsin (10%), which is equivalent to 15%. This average regional RE generation target offers a basis for the determination of state-level RE targets for informing state goals, as described below. Given their unique locations, Alaska and Hawaii are not grouped with other states into these regions. As a conservative approach to estimating cost-effective RE generation potential in Alaska and Hawaii, the EPA developed RE generation targets for each of those states based on the lowest values for the six regions evaluated here, equivalent to the regional target for the Southeast region. The calculated regional RE targets are shown in Table 4.4.

Table 4.4. Regional RE Generation Targets

Region	Regional RE Generation Targets
Alaska	10%
East Central	16%
Hawaii	10%
North Central	15%
Northeast	25%
South Central	20%
Southeast	10%
West	21%

4.2.3 Determine start year for state efforts

The proposed approach assumes that RE generation will begin increasing in 2017, the year following the initial state plan submission deadline[115], and continues through 2029, by which time the EPA assumes the regions can achieve the identified regional RE target level of performance. The EPA has set each state's level of performance prior to the start year of the scenario (2017) to be equal to its current level of performance (as shown above using 2012 generation data). This approach assumes neither improvement nor decline in performance between 2012 and 2017.

4.2.4 Determine pace at which states improve from start year to target level of performance

In order to account for the time needed to plan and construct the required additional amounts of renewable capacity, the proposed approach assumes an increasing trend over time of annual levels of RE generation that can carry the performance level of each region in the start year (in 2017, assumed to be equivalent to its 2012 observed performance level) to that region's RE generation target by 2029. This 2017-2029 trend yields an annual growth factor that is unique to each region and based upon each region's current renewable generation level and its RE target level identified above.

[115] See Preamble Section 8.E – Process for State Plan Submittal and Review for further discussion of timing requirements for state plan submittals.

To derive the annual growth factor, the EPA determined the amount of additional renewable generation (in megawatt-hours) that would be required beyond each region's historic (2012) generation to reach that region's RE target. The EPA then determined the constant rate at which each region would need to increase its generation each year to reach the regional RPS target, if these rates are applied in the period 2017-2029. The constant rate of annual RE generation increase calculated from this approach is called the growth factor. For example, the North Central region had 52,058,236 MWh of RE generation in 2012, while the North Central regional RE target of 15% applied to total 2012 generation across states in that region would yield an RE generation level of 110,786,042 MWh. This approach assumes that the North Central region would begin to increase its RE generation, starting at its 2012 level, from the year 2017 onward and would achieve its RE target level by 2029. Under those conditions, an annual growth rate of 6% per year for RE generation would occur in the North Central region. Due to their unique location, the EPA used a different method to calculate growth factors for Alaska and Hawaii, calculating an annual growth factor based on the growth between each states' individual historical 2002 and 2012 RE generation. Similar to the method for other states, EPA calculated the constant rate of growth that would have been required to take each of these two states from their 2002 RE generation to their 2012 RE generation levels, assuming that the growth over that time had been constant in each year. This resulted in an 8% growth factor for Hawaii, and an 11% growth factor for Alaska.

Table 4.5. Regional Annual RE Growth Factors

Region	Growth Factor
Alaska	11%
East Central	17%
Hawaii	9%
North Central	6%
Northeast	13%
South Central	8%
Southeast	13%
West	6%

Then, for all states in a given region, that region's annual growth factor was applied to each state's historic (2012) RE generation level to calculate a new level of RE generation for that state in the initial year (2017). This calculation is then repeated for each year in the 2017-2029 time period. If, as the growth factor is applied annually, a state reaches an RE generation level that equals or exceeds the regional RE percent generation target, their RE generation target is made equal to the RE percent generation target as applied to that state's 2012 generation and is kept at that level for the remainder of the time period. If a state's RE generation in 2012 has already exceeded the regional RE target, their annual RE generation levels are held to the regional RE target for all years in the 2017-2029 time period. For all other states, the annual growth factor is applied through 2029. These annual RE generation estimates represent the realization of the proposed approach for each state. These RE generation levels are provided in absolute and percentage (share of total generation) terms in Table 4.6 and Table 4.7.

This approach imposes the same regional RE target in percentage (share of total generation) terms to all states in a given region; therefore, the absolute megawatt-hour target will be smaller for states starting with a lower absolute amount of RE generation and larger for a state starting with a higher absolute amount of RE generation.

This approach applies the calculated growth factors and regional RE targets to state-level generation, whereas the state-level RPS requirements upon which they are based are not necessarily applied in practice to generation that is produced within the relevant state. However, the EPA notes that state-level RPS policies are often established with the aim of developing in-state renewables generation.[116] This intention is evident in RPS policies that include minimum requirements for specific types of renewable resources whose development is desired in that state. Regional analysis by NREL has also shown that many states in the west are satisfying RPS requirements with in-state generation.[117] Furthermore, the regional RE target is not applied directly as an immediate requirement of each state but is instead used to calculate a regional growth factor that is then applied to each state's pre-existing RE generation, such that historic RE performance acts as a limiting factor on the extent to which a state is assumed to reach the regional target. Over the program period, several states do not reach the RE percentage target in the proposed approach, such as Kentucky in the Southeast and Nevada in the West. Thus, this

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[116] Wiser, Ryan H., and Galen L. Barbose. 2008. *Renewable Portfolio Standards in the United States: A Status Report with Data Through 2007*, LBNL-154E, Berkeley, CA: Lawrence Berkeley National Laboratory, p. 7.
[117] Hurlbut, David, Joyce McLaren, and Rachel Gelman, Beyond Renewable Portfolio Standards: An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West, NREL/TP-6A20-57830, Golden, CO: NREL, August 2013.

approach is designed to respect each state's ability to improve toward the RE targets developed above.

An illustrative calculation for Illinois's target RE generation level is provided below. Generation levels for all states, in gigawatt-hours and percentage terms, are provided in Tables 4.6 and 4.7. Under this approach, Illinois grows its own historic RE generation level by the 6% growth factor calculated for the North Central region, but it does not reach the North Central regional RE target generation level of 15% (which would be 29,860 GWh for Illinois) between 2017 and 2029.

State	2012 RE (MWh) (source: EIA)	Assigned Region	Regional RE Generation Targets (%)	Annual Regional Growth Factor (%)
Illinois	8,373	North Central	15%	6%

Illinois RE Generation Targets		
Year	GWh	% of 2012 generation
2017	8,873	4.50%
2018	9,404	4.80%
2019	9,967	5.00%
2020	10,563	5.30%
2021	11,195	5.70%
2022	11,864	6.00%
2023	12,574	6.40%
2024	13,326	6.70%
2025	14,123	7.10%
2026	14,968	7.60%
2027	15,863	8.00%
2028	16,812	8.50%
2029	17,818	9.00%

Calculation for 2017 Generation Target = 8,372 x 1.06 = 8,873
Calculation for 2018 Generation Target = 8,873 x 1.06 = 9,404
Similar calculations are performed for all years from 2017 through 2029, with quantified RE targets in any year not to exceed the regional RE target level (e.g., 15% for states in the North Central region).

An illustrative calculation for Minnesota's target RE generation level is provided here, as an example of a state which has already reached its RE target, with 9,454 GWh of RE generation in 2012, and thus its obligation under the target is capped at its share of the 15% regional RE target, 7,889 GWh of RE generation.

State	2012 RE (MWh) (source: EIA)	Assigned Region	Regional RE Generation Targets (%)	Annual Regional Growth Factor (%)
Minnesota	9,453	North Central	15%	6%

Minnesota RE Generation Targets		
Year	GWh	% of 2012 generation
2017	7,889	15%
2018	7,889	15%
2019	7,889	15%
2020	7,889	15%
2021	7,889	15%
2022	7,889	15%
2023	7,889	15%
2024	7,889	15%
2025	7,889	15%
2026	7,889	15%
2027	7,889	15%
2028	7,889	15%
2029	7,889	15%

Table 4.6. State Target RE Generation Levels (Gigawatt-hours)

	Historic RE	RE Generation Targets (GWh)												
State	2012	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AK	40	45	50	55	62	69	76	85	95	106	118	131	146	163
AL	2,777	3,150	3,573	4,053	4,597	5,214	5,915	6,709	7,611	8,633	9,793	11,108	12,600	14,293
AR	1,660	1,799	1,949	2,112	2,288	2,479	2,686	2,911	3,154	3,417	3,702	4,011	4,346	4,709
AZ	1,698	1,801	1,911	2,027	2,151	2,282	2,421	2,569	2,725	2,891	3,068	3,255	3,453	3,663
CA	29,967	31,793	33,731	35,787	37,968	40,282	41,151	41,151	41,151	41,151	41,151	41,151	41,151	41,151
CO	6,192	6,569	6,970	7,395	7,845	8,324	8,831	9,369	9,940	10,546	10,840	10,840	10,840	10,840
CT	667	750	845	951	1,071	1,206	1,358	1,529	1,721	1,938	2,182	2,457	2,766	3,114
DE	131	154	180	211	248	291	341	399	468	549	644	755	886	1,038
FL	4,524	5,131	5,821	6,603	7,490	8,496	9,637	10,931	12,400	14,066	15,955	18,098	20,529	22,110
GA	3,279	3,719	4,219	4,785	5,428	6,157	6,984	7,922	8,987	10,194	11,563	12,231	12,231	12,231
HI	925	1005	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047	1,047
IA	14,183	8,566	8,566	8,566	8,566	8,566	8,566	8,566	8,566	8,566	8,566	8,566	8,566	8,566
ID	2,515	2,668	2,830	3,003	3,186	3,197	3,197	3,197	3,197	3,197	3,197	3,197	3,197	3,197
IL	8,373	8,873	9,404	9,967	10,563	11,195	11,864	12,574	13,326	14,123	14,968	15,863	16,812	17,818
IN	3,546	3,758	3,983	4,222	4,474	4,742	5,025	5,326	5,645	5,982	6,340	6,719	7,121	7,547
KS	5,253	5,691	6,166	6,681	7,239	7,843	8,498	8,885	8,885	8,885	8,885	8,885	8,885	8,885
KY	333	378	428	486	551	625	709	804	912	1,035	1,174	1,332	1,511	1,714
LA	2,430	2,633	2,853	3,091	3,349	3,629	3,931	4,260	4,615	5,001	5,418	5,870	6,361	6,892
MA	1,843	2,076	2,337	2,631	2,962	3,335	3,755	4,228	4,761	5,360	6,035	6,795	7,650	8,613
MD	898	1,053	1,235	1,448	1,698	1,991	2,335	2,738	3,210	3,764	4,414	5,176	5,982	5,982
ME	4,099	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612	3,612
MI	3,785	4,012	4,252	4,506	4,776	5,061	5,364	5,685	6,025	6,385	6,767	7,172	7,601	8,056
MN	9,454	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889	7,889
MO	1,299	1,376	1,459	1,546	1,638	1,736	1,840	1,950	2,067	2,190	2,322	2,460	2,608	2,764
MS	1,509	1,712	1,942	2,203	2,499	2,834	3,215	3,647	4,137	4,692	5,323	5,458	5,458	5,458
MT	1,262	1,343	1,430	1,523	1,621	1,726	1,837	1,956	2,082	2,217	2,360	2,513	2,675	2,848
NC	2,704	3,067	3,479	3,946	4,477	5,078	5,760	6,534	7,412	8,407	9,536	10,817	11,668	11,668
ND	5,280	5,460	5,460	5,460	5,460	5,460	5,460	5,460	5,460	5,460	5,460	5,460	5,460	5,460
NE	1,347	1,459	1,581	1,713	1,856	2,011	2,179	2,361	2,558	2,771	3,003	3,254	3,525	3,819
NH	1,381	1,555	1,751	1,971	2,220	2,499	2,814	3,168	3,567	4,016	4,522	4,822	4,822	4,822

State	Historic RE	RE Generation Targets (GWh)												
	2012	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
NJ	1,281	1,502	1,761	2,065	2,421	2,839	3,329	3,904	4,577	5,367	6,294	7,380	8,654	10,147
NM	2,574	2,731	2,897	3,074	3,261	3,460	3,671	3,894	4,132	4,384	4,651	4,722	4,722	4,722
NV	2,969	3,150	3,342	3,545	3,761	3,991	4,234	4,492	4,766	5,056	5,364	5,691	6,038	6,406
NY	5,192	5,846	6,582	7,411	8,344	9,395	10,578	11,910	13,409	15,098	16,999	19,139	21,549	24,262
OH	1,739	2,039	2,391	2,803	3,287	3,854	4,519	5,299	6,214	7,287	8,544	10,019	11,748	13,776
OK	8,521	9,232	10,003	10,838	11,743	12,723	13,785	14,936	15,579	15,579	15,579	15,579	15,579	15,579
OR	7,207	7,647	8,113	8,607	9,132	9,688	10,279	10,905	11,570	12,275	12,567	12,567	12,567	12,567
PA	4,459	5,229	6,131	7,189	8,430	9,885	11,591	13,592	15,938	18,688	21,914	25,696	30,131	35,331
RI	102	115	129	145	164	184	208	234	263	296	334	376	423	476
SC	2,143	2,431	2,758	3,128	3,549	4,025	4,566	5,180	5,875	6,665	7,560	8,575	9,676	9,676
SD	2,915	1,819	1,819	1,819	1,819	1,819	1,819	1,819	1,819	1,819	1,819	1,819	1,819	1,819
TN	836	949	1,076	1,221	1,385	1,571	1,782	2,021	2,293	2,601	2,950	3,346	3,796	4,306
TX	34,017	36,857	39,934	43,268	46,880	50,794	55,034	59,629	64,607	70,001	75,845	82,177	85,963	85,963
UT	1,100	1,167	1,238	1,313	1,393	1,478	1,568	1,664	1,765	1,873	1,987	2,108	2,237	2,373
VA	2,358	2,765	3,243	3,802	4,459	5,228	6,131	7,189	8,429	9,884	11,192	11,192	11,192	11,192
VT	465	524	590	664	748	842	948	1,067	1,201	1,353	1,523	1,645	1,645	1,645
WA	8,214	8,715	9,246	9,810	10,408	11,042	11,715	12,429	13,186	13,990	14,843	15,747	16,707	17,726
WI	3,223	3,416	3,620	3,837	4,066	4,310	4,567	4,841	5,130	5,437	5,762	6,107	6,472	6,859
WV	1,297	1,520	1,783	2,090	2,451	2,874	3,370	3,952	4,634	5,434	6,372	7,471	8,761	10,273
WY	4,369	4,635	4,918	5,218	5,536	5,873	6,231	6,611	7,014	7,441	7,895	8,376	8,886	9,428

Table 4.7. State Target RE Generation Levels (% of Total Generation)

	Historic RE	RE Generation Targets (GWh)												
State	2012	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
AK	0.6%	0.6%	0.7%	0.8%	0.9%	1.0%	1.1%	1.2%	1.4%	1.5%	1.7%	1.9%	2.1%	2.3%
AL	2%	2.1%	2.3%	2.7%	3.0%	3.4%	3.9%	4.4%	5.0%	5.6%	6.4%	7.3%	8.2%	9.3%
AR	3%	2.8%	3.0%	3.2%	3.5%	3.8%	4.1%	4.5%	4.9%	5.3%	5.7%	6.2%	6.7%	7.2%
AZ	2%	1.9%	2.0%	2.1%	2.3%	2.4%	2.5%	2.7%	2.9%	3.0%	3.2%	3.4%	3.6%	3.9%
CA	15%	16.0%	17.0%	18.1%	19.3%	20.5%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%
CO	12%	12.5%	13.4%	14.2%	15.1%	16.1%	17.2%	18.3%	19.4%	20.6%	20.6%	20.6%	20.6%	20.6%
CT	2%	2.1%	2.3%	2.6%	3.0%	3.3%	3.8%	4.2%	4.8%	5.4%	6.0%	6.8%	7.7%	8.6%
DE	2%	1.8%	2.1%	2.4%	2.9%	3.4%	3.9%	4.6%	5.4%	6.4%	7.5%	8.7%	10.3%	12.0%
FL	2%	2.3%	2.6%	3.0%	3.4%	3.8%	4.4%	4.9%	5.6%	6.4%	7.2%	8.2%	9.3%	10.0%
GA	3%	3.0%	3.4%	3.9%	4.4%	5.0%	5.7%	6.5%	7.3%	8.3%	9.5%	10.0%	10.0%	10.0%
HI	9%	9.6%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
IA	25%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%
ID	16%	17.3%	18.4%	19.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%	20.6%
IL	4%	4.5%	4.8%	5.0%	5.3%	5.7%	6.0%	6.4%	6.7%	7.1%	7.6%	8.0%	8.5%	9.0%
IN	3%	3.3%	3.5%	3.7%	3.9%	4.1%	4.4%	4.6%	4.9%	5.2%	5.5%	5.9%	6.2%	6.6%
KS	12%	12.8%	13.9%	15.0%	16.3%	17.7%	19.1%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
KY	0%	0.4%	0.5%	0.5%	0.6%	0.7%	0.8%	0.9%	1.0%	1.2%	1.3%	1.5%	1.7%	1.9%
LA	2%	2.5%	2.8%	3.0%	3.2%	3.5%	3.8%	4.1%	4.5%	4.8%	5.2%	5.7%	6.2%	6.7%
MA	5%	5.7%	6.5%	7.3%	8.2%	9.2%	10.4%	11.7%	13.2%	14.8%	16.7%	18.8%	21.1%	23.8%
MD	2%	2.8%	3.3%	3.8%	4.5%	5.3%	6.2%	7.2%	8.5%	10.0%	11.7%	13.7%	15.8%	15.8%
ME	28%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
MI	3%	3.7%	3.9%	4.2%	4.4%	4.7%	5.0%	5.3%	5.6%	5.9%	6.3%	6.6%	7.0%	7.4%
MN	18%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%
MO	1%	1.5%	1.6%	1.7%	1.8%	1.9%	2.0%	2.1%	2.3%	2.4%	2.5%	2.7%	2.8%	3.0%
MS	3%	3.1%	3.6%	4.0%	4.6%	5.2%	5.9%	6.7%	7.6%	8.6%	9.8%	10.0%	10.0%	10.0%
MT	5%	4.8%	5.1%	5.5%	5.8%	6.2%	6.6%	7.0%	7.5%	8.0%	8.5%	9.0%	9.6%	10.2%
NC	2%	2.6%	3.0%	3.4%	3.8%	4.4%	4.9%	5.6%	6.4%	7.2%	8.2%	9.3%	10.0%	10.0%
ND	15%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%
NE	4%	4.3%	4.6%	5.0%	5.4%	5.9%	6.4%	6.9%	7.5%	8.1%	8.8%	9.5%	10.3%	11.2%
NH	7%	8.1%	9.1%	10.2%	11.5%	13.0%	14.6%	16.4%	18.5%	20.8%	23.5%	25.0%	25.0%	25.0%
NJ	2%	2.3%	2.7%	3.2%	3.7%	4.4%	5.1%	6.0%	7.0%	8.2%	9.6%	11.3%	13.3%	15.5%
NM	11%	11.9%	12.7%	13.4%	14.2%	15.1%	16.0%	17.0%	18.0%	19.1%	20.3%	20.6%	20.6%	20.6%
NV	8%	9.0%	9.6%	10.2%	10.8%	11.5%	12.3%	13.1%	13.9%	14.8%	15.8%	16.8%	17.9%	19.0%
NY	4%	4.3%	4.8%	5.5%	6.1%	6.9%	7.8%	8.8%	9.9%	11.1%	12.5%	14.1%	15.9%	17.9%
OH	1%	1.6%	1.8%	2.2%	2.5%	3.0%	3.5%	4.1%	4.8%	5.6%	6.6%	7.7%	9.1%	10.6%
OK	11%	11.9%	12.8%	13.9%	15.1%	16.3%	17.7%	19.2%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
OR	12%	12.6%	13.4%	14.3%	15.2%	16.2%	17.2%	18.3%	19.5%	20.6%	20.6%	20.6%	20.6%	20.6%

State	Historic RE 2012	RE Generation Targets (GWh) 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
PA	2%	2.3%	2.7%	3.2%	3.8%	4.4%	5.2%	6.1%	7.1%	8.4%	9.8%	11.5%	13.5%	15.8%
RI	1%	1.4%	1.6%	1.8%	2.0%	2.2%	2.5%	2.8%	3.2%	3.6%	4.0%	4.5%	5.1%	5.7%
SC	2%	2.5%	2.9%	3.2%	3.7%	4.2%	4.7%	5.4%	6.1%	6.9%	7.8%	8.9%	10.0%	10.0%
SD	24%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%	15.1%
TN	1%	1.2%	1.4%	1.6%	1.8%	2.0%	2.3%	2.6%	2.9%	3.3%	3.8%	4.3%	4.9%	5.5%
TX	8%	8.6%	9.3%	10.1%	10.9%	11.8%	12.8%	13.9%	15.0%	16.3%	17.6%	19.1%	20.0%	20.0%
UT	3%	3.2%	3.4%	3.6%	3.8%	4.1%	4.3%	4.6%	4.9%	5.2%	5.5%	5.8%	6.2%	6.5%
VA	3%	3.9%	4.6%	5.4%	6.3%	7.4%	8.7%	10.2%	11.9%	14.0%	15.8%	15.8%	15.8%	15.8%
VT	7%	8.0%	9.0%	10.1%	11.4%	12.8%	14.4%	16.2%	18.3%	20.6%	23.2%	25.0%	25.0%	25.0%
WA	7%	7.5%	8.0%	8.5%	9.0%	9.6%	10.2%	10.9%	11.6%	12.4%	13.2%	14.0%	14.9%	15.9%
WI	5%	5.4%	5.7%	6.0%	6.4%	6.8%	7.2%	7.6%	8.0%	8.5%	9.0%	9.6%	10.2%	10.8%
WV	2%	2.1%	2.4%	2.8%	3.3%	3.9%	4.6%	5.4%	6.3%	7.4%	8.7%	10.2%	11.9%	14.0%
WY	9%	9.4%	10.0%	10.6%	11.3%	12.0%	12.8%	13.7%	14.5%	15.5%	16.5%	17.5%	18.7%	19.9%

4.2.5. Calculate RE targets for interim and final state goals

The agency then translated the annual RE target performance levels for each state into state-level interim and final RE targets for informing this rule's quantification of state goals. Separate interim and final RE targets were calculated for the proposed state goals and the alternate state goals in this proposed rulemaking. For the proposed state goals, the interim RE target for each state was calculated as the average of that state's RE target performance level from 2020-2029, and the final target is equivalent to that state's RE target performance level in the year 2029. For the alternate state goals, the interim RE target for each state was calculated as the average of that state's RE target performance level from 2020-2024, and the final target is equivalent to that state's RE target performance level in the year 2024.

A sample calculation for Illinois is provided below. State-level RE targets, expressed in absolute (megawatt-hour) terms and as a percentage level of each state's RE generation as a share of its total generation, along with 2012 RE levels for each state, are provided in Table 4.8. For an explanation of how these state-level RE targets informed the calculations of state goals in this rule, please refer to the Goal Computation TSD.

Illinois RE Generation Targets		
Year	GWh	% of 2012 generation
2017	8,873	4.50%
2018	9,404	4.80%
2019	9,967	5.00%
2020	10,563	5.30%
2021	11,195	5.70%
2022	11,864	6.00%
2023	12,574	6.40%
2024	13,326	6.70%
2025	14,123	7.10%
2026	14,968	7.60%
2027	15,863	8.00%
2028	16,812	8.50%
2029	17,818	9.00%

Interim & Final Target Calculation			
Proposed		Alternate	
Interim (2020-2029)	Final (2030)	Interim (2020-2024)	Final (2025)
13,910,775	17,818,004	11,904,488	13,326,217
7.00%	9.00%	6.00%	6.70%

Option 1 Interim = average of 2020-2029 values
Option 1 Final = 2029 value
Option 2 Interim = average of 2020-2024 values
Option 2 Final = 2024 value

Table 4.8. Proposed and Alternate State Targets for RE Generation as a Percentage of Total Generation, with 2012 Historical RE Generation

State	2012	Proposed Targets		Alternate Targets	
		Interim Level	Final Level	Interim Level	Final Level
Alabama	2%	6%	9%	4%	5%
Alaska	1%	2%	2%	1%	1%
Arizona	2%	3%	4%	3%	3%
Arkansas	3%	5%	7%	4%	5%
California	15%	20%	21%	20%	21%
Colorado	12%	19%	21%	17%	19%
Connecticut	2%	5%	9%	4%	5%
Delaware	2%	7%	12%	4%	5%
Florida	2%	6%	10%	4%	6%
Georgia	3%	8%	10%	6%	7%
Hawaii	9%	10%	10%	10%	10%
Idaho	16%	21%	21%	21%	21%
Illinois	4%	7%	9%	6%	7%
Indiana	3%	5%	7%	4%	5%
Iowa	25%	15%	15%	15%	15%
Kansas	12%	19%	20%	19%	20%
Kentucky	0%	1%	2%	1%	1%
Louisiana	2%	5%	7%	4%	4%
Maine	28%	25%	25%	25%	25%
Maryland	2%	10%	16%	6%	8%
Massachusetts	5%	15%	24%	11%	13%
Michigan	3%	6%	7%	5%	6%
Minnesota	18%	15%	15%	15%	15%
Mississippi	3%	8%	10%	6%	8%
Missouri	1%	2%	3%	2%	2%
Montana	5%	8%	10%	7%	7%
Nebraska	4%	8%	11%	6%	7%
Nevada	8%	14%	18%	12%	14%
New Hampshire	7%	19%	25%	15%	19%
New Jersey	2%	8%	16%	5%	7%

State	2012	Proposed Targets		Alternate Targets	
		Interim Level	Final Level	Interim Level	Final Level
New Mexico	11%	18%	21%	16%	18%
New York	4%	11%	18%	8%	10%
North Carolina	2%	7%	10%	5%	6%
North Dakota	15%	15%	15%	15%	15%
Ohio	1%	6%	11%	4%	5%
Oklahoma	11%	19%	20%	18%	20%
Oregon	12%	19%	21%	17%	19%
Pennsylvania	2%	9%	16%	5%	7%
Rhode Island	1%	4%	6%	3%	3%
South Carolina	2%	7%	10%	5%	6%
South Dakota	24%	15%	15%	15%	15%
Tennessee	1%	3%	6%	2%	3%
Texas	8%	16%	20%	13%	15%
Utah	3%	5%	7%	4%	5%
Virginia	3%	12%	16%	9%	12%
Washington	7%	12%	15%	10%	11%
West Virginia	2%	8%	14%	5%	6%
Wisconsin	5%	8%	11%	7%	8%
Wyoming	9%	15%	19%	13%	14%

Table 4.9. Proposed and Alternate State Targets for RE Generation in Megawatt-hours, with 2012 Historical RE Generation

State	2012	Proposed Targets		Alternate Targets	
		Interim Level	Final Level	Interim Level	Final Level
Alabama	2,776,554	8,647,278	14,292,801	6,009,218	7,610,632
Alaska	39,958	105,136	163,089	77,373	94,950
Arizona	1,697,652	2,847,759	3,663,325	2,429,595	2,725,233
Arkansas	1,660,370	3,370,253	4,708,823	2,703,555	3,153,509
California	29,966,846	40,745,587	41,150,704	40,340,469	41,150,704
Colorado	6,192,082	9,821,423	10,839,820	8,861,798	9,940,119
Connecticut	666,525	1,934,220	3,114,375	1,376,991	1,721,274
Delaware	131,051	561,909	1,038,351	349,356	468,394
Florida	4,523,798	13,971,137	22,109,614	9,790,728	12,399,889
Georgia	3,278,536	9,392,695	12,230,636	7,095,644	8,986,583
Hawaii	924,815	1,046,927	1,046,927	1,046,927	1,046,927
Idaho	2,514,502	3,195,606	3,196,687	3,194,526	3,196,687
Illinois	8,372,660	13,910,775	17,818,004	11,904,488	13,326,217
Indiana	3,546,367	5,892,120	7,547,086	5,042,327	5,644,522
Iowa	14,183,424	8,565,921	8,565,921	8,565,921	8,565,921
Kansas	5,252,653	8,577,482	8,884,938	8,270,026	8,884,938
Kentucky	332,879	1,036,717	1,713,556	720,442	912,434
Louisiana	2,430,042	4,932,549	6,891,619	3,956,800	4,615,333
Maine	4,098,795	3,611,728	3,611,728	3,611,728	3,611,728
Maryland	898,152	3,728,926	5,982,069	2,394,301	3,210,129
Massachusetts	1,843,419	5,349,504	8,613,477	3,808,366	4,760,555
Michigan	3,785,439	6,289,326	8,055,859	5,382,246	6,025,037
Minnesota	9,453,871	7,888,544	7,888,544	7,888,544	7,888,544
Mississippi	1,509,190	4,272,197	5,458,430	3,266,297	4,136,743
Missouri	1,298,579	2,157,527	2,763,528	1,846,357	2,066,863
Montana	1,261,752	2,116,550	2,722,706	1,805,757	2,025,485
Nebraska	1,346,762	2,733,684	3,819,427	2,192,912	2,557,879
Nevada	2,968,630	4,979,784	6,405,939	4,248,556	4,765,528
New Hampshire	1,381,285	3,727,303	4,822,223	2,853,632	3,567,113
New Jersey	1,280,715	5,491,354	10,147,466	3,414,138	4,577,463
New Mexico	2,573,851	4,161,824	4,721,996	3,683,568	4,131,791

State	2012	Proposed Targets		Alternate Targets	
		Final Level	Interim Level	Final Level	Interim Level
New York	5,192,427	15,068,148	24,261,905	10,727,168	13,409,233
North Carolina	2,703,919	8,135,750	11,668,176	5,852,016	7,411,538
North Dakota	5,280,052	5,459,957	5,459,957	5,459,957	5,459,957
Ohio	1,738,622	7,454,735	13,775,594	4,634,830	6,214,090
Oklahoma	8,520,724	14,666,348	15,579,318	13,753,378	15,579,318
Oregon	7,207,229	11,411,751	12,567,372	10,314,627	11,569,730
Pennsylvania	4,459,118	19,119,477	35,330,855	11,887,147	15,937,543
Rhode Island	101,895	295,694	476,110	210,507	263,140
South Carolina	2,143,473	6,534,613	9,675,568	4,639,057	5,875,334
South Dakota	2,914,666	1,818,850	1,818,850	1,818,850	1,818,850
Tennessee	836,458	2,605,058	4,305,814	1,810,322	2,292,760
Texas	34,016,697	67,689,311	85,962,502	55,388,864	64,607,260
Utah	1,099,724	1,844,752	2,373,069	1,573,870	1,765,381
Virginia	2,358,444	8,608,808	11,192,008	6,287,155	8,429,425
Washington	8,214,350	13,779,314	17,725,558	11,755,968	13,186,456
West Virginia	1,296,563	5,559,307	10,273,036	3,456,386	4,634,107
Wisconsin	3,223,178	5,355,156	6,859,301	4,582,807	5,130,122
Wyoming	4,369,107	7,329,040	9,427,996	6,252,848	7,013,706

The annual rates used to set state RE targets under the proposed approach are comparable to rates that leader states have been able to approach in the past. Eleven states across four regions have already achieved over 10% of total generation from RE, surpassing the lowest regional target applied in the Southeast. Two states, Maine and Iowa, have already equaled or surpassed the highest regional target of 25% of generation, with South Dakota close behind at 24%. Finally, five states have already reached their region's required target.

4.3 Cost Effectiveness of RE

The costs of building new RE capacity and generating more RE have changed significantly in the past decade, particularly for wind and solar. The economics of the fastest growing RE technologies – on-shore wind and solar PV – are improving. According to recent analyses of wind and solar project costs and pricing trends by U.S. Department of Energy, levelized long-term power purchase agreement (PPA) prices have been declining. PPA prices, in general, reflect actual agreements to pay for power from wind or solar projects over a long-term and cover the cost of installing, operating, and maintaining a wind or solar project, along with a profit margin.[118] For utility-scale solar PV, those levelized PPA prices have fallen by more than two-thirds in the past five years "driven primarily by lower installed PV project prices (which, in turn, have been driven primarily by declining module prices), as well as expectations for further cost reductions in future years."[119] More recent PPAs in the West are reporting levelized PPA prices in the range of $50-60/MWh (in 2012 dollars).[120] For wind, PPA prices have fallen since 2009 despite a trend within the wind industry to build projects at lower-quality wind resource sites.[121] "The average levelized long-term price from wind PAs signed in 2011/2012—many of which were for projects built in 2012—fell to around $40/MWh nationwide."[122]

Examining RE resource availability regionally, several recent studies have found cost-effective or economic RE resources are available to serve future needs. The National Renewable Energy Laboratory (NREL) examined the future availability of RE in the West after Western state RPS requirements level off in 2025.[123] The study compares the cost of RE generation from the West's most productive RE resource areas—including any needed transmission and integration costs—with the cost of energy from a new natural gas-fired generator built near the customers it serves. The report indicates that by 2025 wind and solar PV generation could become cost-competitive, if new RE development occurs in the most productive locations.[124] It also has shown that a cost decrease of 10% in 2025 would bring solar power to cost parity with NGCC in the West, with similar possibilities for utility scale geothermal. In 2010, the Southeast

[118] Mark Bolinger and Samantha Weaver, Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, Lawrence Berkeley National Laboratory, LBNL-6408E. September 2013, p. 19.
[119] Mark Bolinger and Samantha Weaver, Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States, Lawrence Berkeley National Laboratory, LBNL-6408E. September 2013, p. ii.
[120] Ibid.
[121] Ryan H. Wiser and Mark Bolinger, 2012 Wind Technologies Market Report, Lawrence Berkeley National Laboratory, August 2013, p. viii.
[122] Ibid.
[123] David Hurlbut, Joyce McLaren, and Rachel Gelman, Beyond Renewable Portfolio Standards: An Assessment of Regional Supply and Demand Conditions Affecting the Future of Renewable Energy in the West. NREL/TP-6A20-57830, Golden, CO: NREL, August 2013.
[124] Ibid. p. xvi.

Energy Efficiency Alliance published a report by Marilyn Brown et al. titled Renewable Energy in the South.[125] In addition to highlighting significant RE resources in different parts of the region, it stated, "Under realistic renewable expansion and policy scenarios, the region could economically supply a large proportion of its future electricity needs from both utility-scale and customer-owned RE sources."[126] This study suggested that increased RE utilization should not necessarily lead to significant rate increases in part because RE resources may moderate forecasted rate increases in the next decade or two.[127]

Several studies have found the cost of RPS-driven RE deployment to be modest. One comparative analysis that "synthesize[d] and analyze[d] the results and methodologies of 28 distinct state or utility-level RPS cost impact analyses" found the median change in retail electricity price to be $0.0004 per kilowatt-hour (only a 0.7 percent increase), the median monthly bill impact to be between $0.13 and $0.82, and the median CO_2 reduction cost to be $3 per metric ton.[128] This finding has been confirmed with more recent RPS cost data, including a report that determined 2010-2012 retail electricity price impacts due to state RPS policies to be less than two percent, with only two states experiencing price impacts of greater than three percent.[129]

4.4. Nuclear Energy

Nuclear generating capacity facilitates CO_2 emission reductions at fossil fuel-fired EGUs by providing carbon-free generation that can replace generation at those EGUs. Increasing the amount of nuclear capacity relative to the amount that would otherwise be available to operate is

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[125] Marilyn A. Brown, Etan Gumerman, Youngsun Baek, Joy Wang, Cullen Morris, and Yu Wang, 2010, Renewable Energy in the South. Atlanta, GA: Southeast Energy Efficiency Alliance, December 2010. Also Marilyn A. Brown, Etan Gumerman, Xiaojing Sun, Kenneth Sercy, and Gyungwon Kim, 2012, "Myths and Facts about Clean Electricity in the U.S. South," Energy Policy, 40: 231-241.
[126] Ibid. p. xxii.
[127] Ibid. p. 109.
[128] Chen et al., "Weighing the Costs and Benefits of State Renewable Portfolio Standards: A Comparative Analysis of State-Level Policy Impact Projections," Lawrence Berkeley National Laboratory, March 2007, http://emp.lbl.gov/publications/weighing-costs-and-benefits-state-renewables-portfolio-standards-comparative-analysis-s.
[129] Galen Barbose, "Renewables Portfolio Standards in the United States: A Status Update," Lawrence Berkeley National Lab, November 2013. Also, Heeter, J., Barbose, G., Bird, L., Weaver, S., Flores-Espino, F., Kuskova-Burns, K., and Wiser, R., "A Survey of State-Level Cost and Benefit Estimates of Renewable Portfolio Standards." NREL Report No. 6A20-61042, LBNL Report No. 6589E, http://www.nrel.gov/docs/fy14osti/61042.pdf.

therefore a technically viable approach that states may consider in the development of state plans for reducing CO2 emissions from affected fossil fuel-fired EGUs.

One way to increase the amount of available nuclear capacity is to build new nuclear EGUs. However, nuclear generating capacity is relatively expensive to build compared to other types of generating capacity, and little new nuclear capacity has been constructed in the U.S. in recent years. Five new nuclear EGUs at three plants are currently under construction: Watts Bar 2 in Tennessee, Vogtle 3-4 in Georgia, and Summer 2-3 in South Carolina. The EPA believes that since the decisions to construct these units were made prior to this proposal, it is reasonable to view the incremental cost associated with the CO_2 emission reductions available from completion of these units as zero for purposes of setting states' CO_2 reduction goals. Completion of these units therefore represents a highly cost-effective opportunity to reduce CO_2 emissions from affected fossil fuel-fired EGUs. For this reason, we are proposing that the emission reductions achievable at affected sources due to the generation provided at the identified new nuclear units should be factored into the state goals for the respective states where these new units are located.

Another way to increase the amount of available nuclear capacity is to preserve existing nuclear EGUs that would otherwise be retired. While each retirement decision is based on the unique circumstances of that individual unit, the EPA recognizes that a host of factors – increasing fixed operation and maintenance costs, relatively low wholesale electricity prices, and additional capital investment associated with ensuring plant security and emergency preparedness – have altered the outlook for the U.S. nuclear fleet in recent years. Reflecting similar concern for these challenges, EIA in its most recent Annual Energy Outlook has projected an additional 5.7 GW of capacity reductions to the nuclear fleet. EIA describes the projected capacity reductions – which are not tied to the retirement of any specific unit – as necessary to recognize the "continued economic challenges" faced by the higher-cost nuclear units.[130] Likewise, without making any judgment about the likelihood that any individual EGU will retire, we view this 5.7 GW, which comprises an approximately six percent share of nuclear capacity, as a reasonable proxy for the amount of nuclear capacity at risk of retirement.

[130] Jeffrey Jones and Michael Leff, "Implications of accelerated power plant retirements," EIA, April 2014.

We believe that, based on available information regarding the cost and performance of the nuclear fleet, preserving the operation of at-risk nuclear capacity is likely to be a relatively cost-effective approach to achieving CO2 reductions from affected EGUs. According to a recent report, nuclear units may be experiencing up to a $6/MWh shortfall in covering their operating costs with electricity sales.[131] Assuming that such a revenue shortfall is representative of the incentive to retire at-risk nuclear capacity, one can estimate the value of offsetting the revenue loss at these at-risk nuclear units to be about $12 to $17 per metric ton. [132] The EPA views this cost as reasonable. We therefore propose that the emission reductions achievable by retaining in operation approximately six percent of each state's historical nuclear capacity should be factored into the state goals for the respective states. [133]

The amount of at-risk nuclear generation quantified for each state is displayed in Table 4.10:

Table 4.10. Nuclear At-Risk Generation by State

State	2012 Nuclear Fleet (MW)*	At-Risk Nuclear Capacity (MW)	At-Risk Nuclear Generation (GWh)
Alabama	5,043	295	2,330
Arizona	3,937	230	1,818
Arkansas	1,823	107	842
California	2,240	131	1,035
Connecticut	2,103	123	971
Florida	3,514	205	1,623
Georgia	4,061	237	1,876
Illinois	11,486	671	5,305

[131] Eggers, et al., "Nuclear… The Middle Age Dilemma?" Credit Suisse, February 2013.
[132] The derivation of $12 to $17 per metric ton assumes that replacement power for at-risk nuclear capacity is sourced either from new NGCC capacity at 800 lbs CO_2/MWh or from the projected average 2020 emissions intensity across the U.S. power system at 1,127 lbs CO_2/MWh(from EPA's IPM Base Case).
[133] Historical nuclear fleet excludes Watts Bar 2, Vogtle 3-4, and Summer 2-3, as well as all units that have retired or are committed to retire (as of May 2014).

Iowa	601	35	278
Kansas	1,175	69	543
Louisiana	2,133	125	985
Maryland	1,705	100	788
Massachusetts	685	40	316
Michigan	3,957	231	1,828
Minnesota	1,819	106	840
Mississippi	1,368	80	632
Missouri	1,190	70	550
Nebraska	1,245	73	575
New Hampshire	1,246	73	576
New Jersey	3,499	204	1,616
New York	5,219	305	2,411
North Carolina	4,970	290	2,296
Ohio	2,150	126	993
Pennsylvania	9,700	567	4,480
South Carolina	6,486	379	2,996
Tennessee	3,401	199	1,571
Texas	4,960	290	2,291
Virginia	3,562	208	1,645
Washington	1,097	64	507
Wisconsin	1,184	69	547
Total	**97,559**	**5,700**	**45,062**

Appendix 4-1. RE Generation Targets Including Existing

Table 4-1.1. State RE Generation Targets including 2012 Existing Hydropower Generation (Gigawatt-hours)

State	2012 Existing Hydro	2012 Non-hydro RE (GWh)	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alabama	7,435	2,777	10,585	11,008	11,488	12,032	12,650	13,350	14,145	15,046	16,068	17,228	18,543	20,035	21,728
Alaska	1,575	40	1,620	1,625	1,630	1,637	1,644	1,652	1,660	1,670	1,681	1,693	1,706	1,721	1,738
Arizona	6,717	1,698	8,518	8,628	8,744	8,868	8,999	9,138	9,286	9,442	9,608	9,784	9,971	10,170	10,380
Arkansas	2,198	1,660	3,997	4,148	4,310	4,487	4,678	4,885	5,109	5,352	5,615	5,901	6,210	6,544	6,907
California	26,837	29,967	58,631	60,568	62,624	64,805	67,120	67,988	67,988	67,988	67,988	67,988	67,988	67,988	67,988
Colorado	1,497	6,192	8,067	8,467	8,892	9,343	9,821	10,328	10,866	11,437	12,043	12,337	12,337	12,337	12,337
Connecticut	312	667	1,063	1,157	1,263	1,383	1,518	1,670	1,841	2,033	2,250	2,494	2,769	3,078	3,427
Delaware	-	131	154	180	211	248	291	341	399	468	549	644	755	886	1,038
Florida	151	4,524	5,282	5,971	6,753	7,640	8,646	9,787	11,082	12,550	14,216	16,105	18,249	20,680	22,260
Georgia	2,236	3,279	5,955	6,455	7,021	7,664	8,393	9,220	10,159	11,223	12,430	13,799	14,467	14,467	14,467
Hawaii	115	925	1,119	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162	1,162
Idaho	10,940	2,515	13,608	13,771	13,943	14,126	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137	14,137
Illinois	111	8,373	8,985	9,515	10,078	10,674	11,306	11,976	12,685	13,437	14,235	15,079	15,975	16,924	17,929
Indiana	434	3,546	4,192	4,417	4,655	4,908	5,175	5,459	5,759	6,078	6,416	6,773	7,153	7,555	7,981
Iowa	766	14,183	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332	9,332
Kansas	10	5,253	5,702	6,177	6,692	7,249	7,854	8,508	8,895	8,895	8,895	8,895	8,895	8,895	8,895
Kentucky	2,362	333	2,739	2,790	2,848	2,913	2,987	3,071	3,166	3,274	3,397	3,536	3,694	3,872	4,075
Louisiana	680	2,430	3,313	3,533	3,771	4,029	4,308	4,611	4,940	5,295	5,681	6,098	6,550	7,041	7,572
Maine	3,733	4,099	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344	7,344
Maryland	1,657	898	2,710	2,891	3,105	3,355	3,648	3,991	4,394	4,867	5,421	6,070	6,832	7,639	7,639
Massachusetts	912	1,843	2,988	3,249	3,544	3,875	4,248	4,668	5,141	5,673	6,272	6,947	7,707	8,563	9,526
Michigan	1,215	3,785	5,227	5,467	5,721	5,991	6,276	6,579	6,900	7,240	7,600	7,982	8,387	8,816	9,271
Minnesota	561	9,454	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450
Mississippi	-	1,509	1,712	1,942	2,203	2,499	2,834	3,215	3,647	4,137	4,692	5,323	5,458	5,458	5,458
Missouri	714	1,299	2,091	2,173	2,260	2,353	2,451	2,554	2,664	2,781	2,905	3,036	3,175	3,322	3,478
Montana	11,283	1,262	12,622	12,704	12,790	12,882	12,980	13,083	13,193	13,309	13,432	13,563	13,702	13,850	14,006
Nebraska	1,257	1,347	2,716	2,838	2,970	3,113	3,268	3,436	3,618	3,815	4,028	4,260	4,511	4,782	5,076
Nevada	2,440	2,969	5,590	5,782	5,986	6,202	6,431	6,674	6,932	7,206	7,496	7,805	8,131	8,478	8,846
New Hampshire	1,289	1,381	2,845	3,040	3,261	3,509	3,789	4,103	4,458	4,856	5,306	5,811	6,112	6,112	6,112
New Jersey	11	1,281	1,513	1,772	2,076	2,432	2,850	3,340	3,914	4,588	5,378	6,305	7,391	8,665	10,158
New Mexico	223	2,574	2,954	3,120	3,297	3,484	3,683	3,894	4,117	4,355	4,606	4,874	4,945	4,945	4,945

| State | 2012 Existing Hydro | 2012 Non-hydro RE (GWh) | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |

New York	24,652	5,192	30,499	31,235	32,064	32,997	34,047	35,230	36,562	38,062	39,750	41,651	43,791	46,201	48,914
North Carolina	3,728	2,704	6,795	7,207	7,674	8,205	8,806	9,488	10,262	11,139	12,135	13,264	14,545	15,396	15,396
North Dakota	2,477	5,280	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937	7,937
Ohio	414	1,739	2,453	2,805	3,217	3,701	4,268	4,934	5,714	6,628	7,701	8,958	10,433	12,162	14,190
Oklahoma	1,146	8,521	10,378	11,148	11,983	12,888	13,869	14,931	16,082	16,725	16,725	16,725	16,725	16,725	16,725
Oregon	39,410	7,207	47,057	47,523	48,017	48,542	49,098	49,689	50,315	50,980	51,685	51,978	51,978	51,978	51,978
Pennsylvania	2,242	4,459	7,471	8,373	9,431	10,672	12,127	13,833	15,834	18,179	20,930	24,156	27,938	32,373	37,573
Rhode Island	4	102	119	133	150	168	189	212	238	267	301	338	380	427	480
South Carolina	1,420	2,143	3,852	4,178	4,549	4,969	5,446	5,986	6,600	7,296	8,085	8,980	9,996	11,096	11,096
South Dakota	5,981	2,915	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800	7,800
Tennessee	8,296	836	9,244	9,372	9,517	9,681	9,867	10,078	10,317	10,588	10,896	11,246	11,642	12,092	12,601
Texas	584	34,017	37,441	40,518	43,852	47,464	51,378	55,619	60,213	65,192	70,586	76,430	82,762	86,547	86,547
Utah	748	1,100	1,915	1,986	2,061	2,141	2,226	2,316	2,412	2,513	2,621	2,735	2,856	2,985	3,121
Virginia	1,044	2,358	3,809	4,287	4,846	5,503	6,272	7,174	8,232	9,473	10,928	12,236	12,236	12,236	12,236
Washington	89,464	8,214	98,179	98,711	99,274	99,872	100,506	101,179	101,893	102,651	103,455	104,307	105,212	106,172	107,190
West Virginia	1,431	1,297	2,952	3,214	3,522	3,883	4,306	4,802	5,383	6,066	6,865	7,803	8,903	10,192	11,704
Wisconsin	1,522	3,223	4,938	5,143	5,359	5,589	5,832	6,090	6,363	6,652	6,959	7,284	7,629	7,994	8,382
Wyoming	893	4,369	5,529	5,811	6,111	6,429	6,767	7,124	7,504	7,907	8,335	8,788	9,269	9,780	10,321

Table 4-1.2. State RE Generation Targets (% of Total Generation) including 2012 Existing Hydropower Generation

State	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Alabama	6.9%	7.2%	7.5%	7.9%	8.3%	8.7%	9.3%	9.8%	10.5%	11.3%	12.1%	13.1%	14.2%
Alaska	23.3%	23.4%	23.5%	23.6%	23.7%	23.8%	23.9%	24.0%	24.2%	24.4%	24.6%	24.8%	25.0%
Arizona	9.0%	9.1%	9.2%	9.3%	9.5%	9.6%	9.8%	9.9%	10.1%	10.3%	10.5%	10.7%	10.9%
Arkansas	6.1%	6.4%	6.6%	6.9%	7.2%	7.5%	7.9%	8.2%	8.6%	9.1%	9.6%	10.1%	10.6%
California	29.4%	30.4%	31.4%	32.5%	33.6%	34.1%	34.1%	34.1%	34.1%	34.1%	34.1%	34.1%	34.1%
Colorado	15.3%	16.1%	16.9%	17.8%	18.7%	19.7%	20.7%	21.8%	22.9%	23.5%	23.5%	23.5%	23.5%
Connecticut	2.9%	3.2%	3.5%	3.8%	4.2%	4.6%	5.1%	5.6%	6.2%	6.9%	7.7%	8.5%	9.5%
Delaware	1.8%	2.1%	2.4%	2.9%	3.4%	3.9%	4.6%	5.4%	6.4%	7.5%	8.7%	10.3%	12.0%
Florida	2.4%	2.7%	3.1%	3.5%	3.9%	4.4%	5.0%	5.7%	6.4%	7.3%	8.3%	9.4%	10.1%
Georgia	4.9%	5.3%	5.7%	6.3%	6.9%	7.5%	8.3%	9.2%	10.2%	11.3%	11.8%	11.8%	11.8%
Hawaii	10.6%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%	11.1%
Idaho	87.8%	88.8%	90.0%	91.1%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%	91.2%
Illinois	4.5%	4.8%	5.1%	5.4%	5.7%	6.1%	6.4%	6.8%	7.2%	7.6%	8.1%	8.6%	9.1%
State	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Indiana	3.7%	3.9%	4.1%	4.3%	4.5%	4.8%	5.0%	5.3%	5.6%	5.9%	6.2%	6.6%	7.0%
Iowa	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%	16.5%

Kansas	12.8%	13.9%	15.1%	16.3%	17.7%	19.2%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Kentucky	3.0%	3.1%	3.2%	3.2%	3.3%	3.4%	3.5%	3.6%	3.8%	3.9%	4.1%	4.3%	4.5%
Louisiana	3.2%	3.4%	3.6%	3.9%	4.2%	4.5%	4.8%	5.1%	5.5%	5.9%	6.3%	6.8%	7.3%
Maine	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%	50.9%
Maryland	7.2%	7.6%	8.2%	8.9%	9.6%	10.6%	11.6%	12.9%	14.3%	16.1%	18.1%	20.2%	20.2%
Massachusetts	8.3%	9.0%	9.8%	10.7%	11.7%	12.9%	14.2%	15.7%	17.3%	19.2%	21.3%	23.7%	26.3%
Michigan	4.8%	5.1%	5.3%	5.5%	5.8%	6.1%	6.4%	6.7%	7.0%	7.4%	7.8%	8.2%	8.6%
Minnesota	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%	16.2%
Mississippi	3.1%	3.6%	4.0%	4.6%	5.2%	5.9%	6.7%	7.6%	8.6%	9.8%	10.0%	10.0%	10.0%
Missouri	2.3%	2.4%	2.5%	2.6%	2.7%	2.8%	2.9%	3.0%	3.2%	3.3%	3.5%	3.6%	3.8%
Montana	45.4%	45.7%	46.0%	46.3%	46.7%	47.1%	47.4%	47.9%	48.3%	48.8%	49.3%	49.8%	50.4%
Nebraska	7.9%	8.3%	8.7%	9.1%	9.6%	10.0%	10.6%	11.1%	11.8%	12.4%	13.2%	14.0%	14.8%
Nevada	15.9%	16.4%	17.0%	17.6%	18.3%	19.0%	19.7%	20.5%	21.3%	22.2%	23.1%	24.1%	25.2%
New Hampshire	14.8%	15.8%	16.9%	18.2%	19.7%	21.3%	23.1%	25.2%	27.5%	30.2%	31.7%	31.7%	31.7%
New Jersey	2.3%	2.7%	3.2%	3.7%	4.4%	5.1%	6.0%	7.0%	8.2%	9.7%	11.3%	13.3%	15.6%
New Mexico	12.9%	13.6%	14.4%	15.2%	16.1%	17.0%	18.0%	19.0%	20.1%	21.3%	21.6%	21.6%	21.6%
New York	22.5%	23.0%	23.6%	24.3%	25.1%	25.9%	26.9%	28.0%	29.3%	30.7%	32.3%	34.0%	36.0%
North Carolina	5.8%	6.2%	6.6%	7.0%	7.5%	8.1%	8.8%	9.5%	10.4%	11.4%	12.5%	13.2%	13.2%
North Dakota	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%	22.0%
Ohio	1.9%	2.2%	2.5%	2.9%	3.3%	3.8%	4.4%	5.1%	5.9%	6.9%	8.0%	9.4%	10.9%
Oklahoma	13.3%	14.3%	15.4%	16.5%	17.8%	19.2%	20.6%	21.5%	21.5%	21.5%	21.5%	21.5%	21.5%
Oregon	77.2%	78.0%	78.8%	79.7%	80.6%	81.5%	82.6%	83.7%	84.8%	85.3%	85.3%	85.3%	85.3%
Pennsylvania	3.3%	3.7%	4.2%	4.8%	5.4%	6.2%	7.1%	8.1%	9.4%	10.8%	12.5%	14.5%	16.8%
Rhode Island	1.4%	1.6%	1.8%	2.0%	2.3%	2.5%	2.9%	3.2%	3.6%	4.1%	4.6%	5.1%	5.8%
South Carolina	4.0%	4.3%	4.7%	5.1%	5.6%	6.2%	6.8%	7.5%	8.4%	9.3%	10.3%	11.5%	11.5%
South Dakota	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%	64.8%
Tennessee	11.9%	12.1%	12.2%	12.5%	12.7%	13.0%	13.3%	13.6%	14.0%	14.5%	15.0%	15.6%	16.2%
Texas	8.7%	9.4%	10.2%	11.0%	12.0%	12.9%	14.0%	15.2%	16.4%	17.8%	19.3%	20.1%	20.1%
Utah	5.3%	5.5%	5.7%	5.9%	6.1%	6.4%	6.6%	6.9%	7.2%	7.5%	7.9%	8.2%	8.6%
Virginia	5.4%	6.1%	6.9%	7.8%	8.9%	10.1%	11.6%	13.4%	15.4%	17.3%	17.3%	17.3%	17.3%
Washington	84.0%	84.5%	85.0%	85.5%	86.0%	86.6%	87.2%	87.9%	88.5%	89.3%	90.1%	90.9%	91.7%
West Virginia	4.0%	4.4%	4.8%	5.3%	5.9%	6.5%	7.3%	8.3%	9.4%	10.6%	12.1%	13.9%	15.9%
Wisconsin	7.7%	8.1%	8.4%	8.8%	9.1%	9.6%	10.0%	10.4%	10.9%	11.4%	12.0%	12.5%	13.1%
Wyoming	11.1%	11.7%	12.3%	13.0%	13.6%	14.4%	15.1%	15.9%	16.8%	17.7%	18.7%	19.7%	20.8%

Table 4-1.3. Proposed and Alternate State Targets for RE Generation as a Percentage of Total Generation, with 2012 Historical RE Generation

State	2012	Proposed Targets		Alternate Targets	
		Interim Level	Final Level	Interim Level	Final Level
Alabama	7%	11%	14%	9%	10%
Alaska	23%	24%	25%	24%	24%
Arizona	9%	10%	11%	10%	10%
Arkansas	6%	9%	11%	8%	8%
California	28%	34%	34%	34%	34%
Colorado	15%	22%	23%	20%	22%
Connecticut	3%	6%	9%	5%	6%
Delaware	2%	7%	12%	4%	5%
Florida	2%	6%	10%	4%	6%
Georgia	5%	10%	12%	8%	9%
Hawaii	10%	11%	11%	11%	11%
Idaho	87%	91%	91%	91%	91%
Illinois	4%	7%	9%	6%	7%
Indiana	3%	6%	7%	5%	5%
Iowa	26%	16%	16%	16%	16%
Kansas	12%	19%	20%	19%	20%
Kentucky	3%	4%	5%	3%	4%
Louisiana	3%	5%	7%	4%	5%
Maine	54%	51%	51%	51%	51%
Maryland	7%	14%	20%	11%	13%
Massachusetts	8%	17%	26%	13%	16%
Michigan	5%	7%	9%	6%	7%
Minnesota	19%	16%	16%	16%	16%
Mississippi	3%	8%	10%	6%	8%
Missouri	2%	3%	4%	3%	3%
Montana	45%	48%	50%	47%	48%
Nebraska	8%	12%	15%	10%	11%
Nevada	15%	21%	25%	19%	20%
New Hampshire	14%	26%	32%	22%	25%
New Jersey	2%	8%	16%	5%	7%
New Mexico	12%	19%	22%	17%	19%
New York	22%	29%	36%	26%	28%
North Carolina	6%	10%	13%	8%	10%
North Dakota	21%	22%	22%	22%	22%

Ohio	2%	6%	11%	4%	5%
State	**2012**	**Proposed Targets**		**Alternate Targets**	
		Interim Level	**Final Level**	**Interim Level**	**Final Level**
Oklahoma	12%	20%	21%	19%	21%
Oregon	77%	83%	85%	82%	84%
Pennsylvania	3%	10%	17%	6%	8%
Rhode Island	1%	4%	6%	3%	3%
South Carolina	4%	8%	11%	6%	8%
South Dakota	74%	65%	65%	65%	65%
Tennessee	12%	14%	16%	13%	14%
Texas	8%	16%	20%	13%	15%
Utah	5%	7%	9%	6%	7%
Virginia	5%	14%	17%	10%	13%
Washington	84%	88%	92%	87%	88%
West Virginia	4%	10%	16%	7%	8%
Wisconsin	7%	11%	13%	10%	10%
Wyoming	11%	17%	21%	14%	16%

Table 4-1.4. Proposed and Alternate State Targets for RE Generation in Megawatt-hours, with 2012 Historical RE Generation

State	2012	Proposed Targets		Alternate Targets	
		Interim Level	Final Level	Interim Level	Final Level
Alabama	10,211,777	16,082,501	21,728,024	13,444,441	15,045,855
Alaska	1,615,003	1,680,181	1,738,134	1,652,418	1,669,995
Arizona	8,414,586	9,564,693	10,380,259	9,146,529	9,442,167
Arkansas	3,858,842	5,568,725	6,907,295	4,902,027	5,351,981
California	56,804,216	67,582,957	67,988,075	67,177,840	67,988,075
Colorado	7,689,291	11,318,632	12,337,029	10,359,007	11,437,328
Connecticut	978,666	2,246,361	3,426,516	1,689,132	2,033,415
Delaware	131,051	561,909	1,038,351	349,356	468,394
Florida	4,674,309	14,121,648	22,260,125	9,941,239	12,550,400
Georgia	5,514,836	11,628,995	14,466,936	9,331,944	11,222,883
Hawaii	1,039,396	1,161,508	1,161,508	1,161,508	1,161,508
Idaho	13,454,907	14,136,011	14,137,092	14,134,931	14,137,092
Illinois	8,483,868	14,021,983	17,929,212	12,015,696	13,437,425
Indiana	3,979,872	6,325,625	7,980,591	5,475,832	6,078,027
Iowa	14,949,615	9,332,112	9,332,112	9,332,112	9,332,112
Kansas	5,263,052	8,587,881	8,895,337	8,280,425	8,895,337
Kentucky	2,694,661	3,398,499	4,075,338	3,082,224	3,274,216
Louisiana	3,109,986	5,612,493	7,571,563	4,636,744	5,295,277
Maine	7,831,400	7,344,333	7,344,333	7,344,333	7,344,333
Maryland	2,554,691	5,385,465	7,638,608	4,050,840	4,866,668
Massachusetts	2,755,901	6,261,986	9,525,959	4,720,848	5,673,037
Michigan	5,000,293	7,504,180	9,270,713	6,597,100	7,239,891
Minnesota	10,014,892	8,449,566	8,449,566	8,449,566	8,449,566
Mississippi	1,509,190	4,272,197	5,458,430	3,266,297	4,136,743
Missouri	2,012,848	2,871,796	3,477,797	2,560,626	2,781,132
Montana	12,545,217	13,400,015	14,006,171	13,089,222	13,308,950
Nebraska	2,603,816	3,990,738	5,076,481	3,449,966	3,814,933
Nevada	5,409,045	7,420,199	8,846,354	6,688,971	7,205,943
New Hampshire	2,670,671	5,016,689	6,111,609	4,143,018	4,856,499
New Jersey	1,291,470	5,502,109	10,158,221	3,424,893	4,588,218
New Mexico	2,796,670	4,384,643	4,944,815	3,906,387	4,354,610
New York	29,844,923	39,720,644	48,914,401	35,379,664	38,061,729
North Carolina	6,431,857	11,863,688	15,396,114	9,579,954	11,139,476
North Dakota	7,757,282	7,937,187	7,937,187	7,937,187	7,937,187
Ohio	2,152,783	7,868,896	14,189,755	5,048,991	6,628,251

State	2012	Proposed Targets		Alternate Targets	
		Interim Level	Final Level	Interim Level	Final Level
Oklahoma	9,666,238	15,811,862	16,724,832	14,898,892	16,724,832
Oregon	46,617,408	50,821,930	51,977,551	49,724,805	50,979,909
Pennsylvania	6,701,038	21,361,397	37,572,775	14,129,067	18,179,463
Rhode Island	106,161	299,960	480,376	214,773	267,406
South Carolina	3,563,745	7,954,885	11,095,840	6,059,329	7,295,606
South Dakota	8,895,631	7,799,815	7,799,815	7,799,815	7,799,815
Tennessee	9,132,118	10,900,718	12,601,474	10,105,982	10,588,420
Texas	34,601,171	68,273,785	86,546,976	55,973,339	65,191,734
Utah	1,847,510	2,592,538	3,120,855	2,321,656	2,513,167
Virginia	3,402,218	9,652,582	12,235,782	7,330,929	9,473,199
Washington	97,678,705	103,243,669	107,189,913	101,220,323	102,650,811
West Virginia	2,728,003	6,990,747	11,704,476	4,887,826	6,065,547
Wisconsin	4,745,413	6,877,391	8,381,536	6,105,042	6,652,357
Wyoming	5,262,577	8,222,510	10,321,466	7,146,318	7,907,176

Chapter 5: Demand-side Energy Efficiency (EE)

Introduction

This chapter provides information on demand-side energy efficiency (EE) as an abatement measure for reducing carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating units (EGUs). Specifically, this chapter addresses EE as a component of both the "best system of emission reduction" (BSER) and state goals, and the inclusion of EE within the impacts assessment. Support is provided in this chapter for the discussion of the EE abatement measure throughout the preamble (most extensively in these sections: Building Blocks for Setting State Goals and Considerations, State Goals, State Plans, and Impacts of the Proposed Rule) and its representation within the Regulatory Impact Analysis (RIA). Results from this chapter feed into the technical support document (TSD) on Goal Computation. EE is also addressed in TSDs on state plan considerations and projecting emissions performance.

This chapter is organized as follows:

1) Background
   - EE Technologies and Practices
   - Barriers to EE Investment
   - EE Policies
   - EE Programs
2) The EE Opportunity
   - Rapid Growth in EE
   - EE Program Impacts
   - EE Potential
   - Costs and Cost-Effectiveness of State EE Policies
   - EE as an Abatement Measure
3) State Goal Setting
   - Approach
   - Inputs
   - Calculations
   - Results
4) Impacts Assessment

- Approach
- Inputs
- Calculations
- Results

5) Analysis Considerations
6) Appendices
7) References

Background

As discussed in the State Plan Considerations TSD (Appendix: "Survey of Existing State Policies and Programs that Reduce Power Sector CO_2 Emissions"), demand-side energy efficiency policies and programmatic efforts have existed for decades and are now used in all 50 states. These strategies are intended to help states achieve energy savings goals, reduce the environmental impacts (including CO_2 emissions) of meeting energy service needs, save energy and money for consumers, and provide a significant resource for meeting power system capacity requirements. EE policies currently in place are considered by states to be cost-effective strategies for contributing to these policy objectives.[134] Moreover, states – through their utilities, primarily – have been rapidly increasing their funding of EE programs in recent years, more than tripling budgets in the five years from 2006 to 2011, from $1.6 billion to $5.9 billion.[135] In 2012, the cumulative impacts of these programs represented a 3.7% reduction in national electricity demand.[136] And, EE spending is projected to continue to grow at a substantial rate. A recent study by Lawrence Berkeley National Laboratory (LBNL) projects EE program spending to reach $8.1 billion to $12.2 billion ("Medium Case" and "High Case," respectively) in 2025 even

[134] See below for discussion of cost-effectiveness and related cost tests used by states to evaluate EE programs.
[135] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.
[136] U.S. Energy Information Administration Form EIA-861 data files. 2012. Available at http://www.eia.gov/electricity/data/eia861/.

"without considering possible major new policy developments," such as requirements under Clean Air Act, Section 111(d).[137,138]

This section provides relevant background for the subsequent sections that address the EE opportunity, EE as a component of BSER, EE within state goal setting, and the integration of EE within the benefit, cost, and impacts assessments as reported in the RIA and elsewhere. This section begins with a discussion of EE technologies and practices, and then describes the market failures that limit cost-effective EE investments. We then summarize EE policy objectives and discuss policy types, their relative impacts, and discuss in more detail the key strategy of employing EE programs.

EE Technologies and Practices

Energy efficiency is using less energy to provide the same or greater level of service. Demand-side energy efficiency refers to an extensive array of technologies, practices and measures that are applied throughout all sectors of the economy to reduce energy demand while providing the same, and sometimes better, level and quality of service. Utilities employ a large array of strategies in implementing energy efficiency programs, these include financial incentives such as rebates and loans, technical services such as audits and retrofits, and educational campaigns about the benefits of energy efficiency improvements. The purpose of these EE programs is to induce EE investments and practices that would not otherwise occur in the presence of market failures and behavioral impediments. In the residential sector, examples of EE activities include the purchase of more efficient products and equipment (e.g., ENERGY STAR labeled), the upgrading of insulation in attics and walls, sealing of air leaks, and undertaking home energy audits leading to customized whole home retrofits. Opportunities for cost-effective EE in commercial buildings include optimization of heating, ventilation, and air conditioning (HVAC) systems, upgrades of windows, and use of more efficient office equipment

[137] Specifically, the LBNL study states: "By virtue of limiting the analysis to current energy efficiency policies, we do not consider the potential impact of major new federal (or state) policy initiatives (e.g., a national energy efficiency resource standard, clean energy standard, or carbon policy) that could result in customer-funded energy efficiency program spending and savings that exceed the values in our High Case."

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

at replacement. In the industrial sector key EE strategies include motor upgrades and maintenance programs, recovery of waste heat streams, and optimization of processes through modern instrumentation and controls systems.

The opportunity presented for economic investment in EE is dynamic, growing over time as technologies and practices advance, as populations grow, and as investment occurs in the construction of new homes, buildings, and industrial facilities. As new policies are enacted, leading to the acceleration of investment in EE, an additional portion of the expanding opportunity is realized. After decades of experience implementing policies to accelerate investment in cost-effective energy efficiency, states are finding renewed opportunities as they develop more sophisticated and effective strategies, evolving from a focus on individual end-uses and products to whole-building and systems-based strategies that account for the interactions between the many energy end-uses in buildings and industry.[139] As will be discussed, the experience in the U.S. has been that on balance, a persistent and large potential for achievable and cost-effective EE has remained even as the impact of past and ongoing efforts have accumulated.

Barriers to EE Investment

Despite the persistent and large potential for electricity savings through investment in EE technologies and practices, market failures, as well as non-market failures, limit the realization of the many benefits of these investments. Several market failures that lead to inefficiencies in energy use are well recognized by analysts and practitioners, and are discussed extensively in the economic literature.[140] Some of the most common examples of these market failures include:

- *Pollution externalities.* Energy consumption is associated with negative externalities, such as emissions of CO_2, SO_2, and NO_x that cause human health and environmental damages. Energy prices that do not correctly reflect these externalities lead to investments in energy efficiency below the socially optimal levels.

[139] Seth Nowak, Martin Kushler, Patti Witte, and Dan York. Leaders of the Pack: ACEEE's Third National Review of Exemplary Energy Efficiency Programs. American Council for an Energy-Efficient Economy (ACEEE). Research Report U132. Available at http://www.aceee.org/research-report/u132.

[140] See reviews of market failures and barriers related to energy efficiency in Gillingham, K, R Newell, and K Palmer. 2009. Energy Efficiency Economics and Policy. Annual Review of Resource Economics. Annual Review of Resource Economics 1: 597-619 and Gillingham and Palmer (2013). "Bridging the Energy Efficiency Gap: insights for policy from economic theory and empirical analysis," Resources for the Future DP 13-02.

- *Imperfect information.* Energy users often lack accurate information about energy savings and other attributes of energy efficient products or practices to understand the costs and benefits of EE investments. Market failure due to information imperfection leads to underinvestment in energy efficiency by consumers.
- *Split incentives (or the "principal-agent problem").* Incentives of individuals who make EE investment decisions are not always aligned with incentives of those who use and pay for energy. Examples include misalignment between landlords and tenants, and between builders and homeowners. Split incentives also persist within organizations and institutions that lead to underinvestment in EE in both public and the private entities.[141]
- *Credit constraints*. Limited access to credit may prevent some consumers, especially low-income consumers, from making cost-effective EE improvement decisions due to the higher upfront cost of energy efficient products or practices.
- *Under-provision of research and development (R&D).* Because of the public good nature of knowledge, technology innovation invested by one firm likely spills over to other firms. As a result, firms involved in technology development may be less willing to invest in R&D, leading to sub-optimal levels of EE investments from a social perspective.[142]
- *Supply market imperfections.* Market for energy efficient products is incomplete. Manufacturers do not have perfect information about consumer preferences and may supply limited menu of products to consumers. High start-up costs and the existence of patents may create barriers to entry in markets and result in oligopolistic or monopolistic behavior. Supply chains of EE products is fragmented, leading to underinvestment in innovation and energy efficiency by suppliers. In addition, supply chain fragmentation may also add complexity to the purchase and installation of otherwise economically rational investments, thereby slowing the adoption of EE technologies.

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[141] For example, see DeCanio, S. 1998. The efficiency paradox: bureaucratic and organizational barriers to profitable energy-saving investments. Energy Policy 26(5): 441-458; McKinsey & Co and The Conference Board. 2007. Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost? pp. (52-53).

[142] See discussion in Jaffe, A.B., R.G. Newell, and R.N. Stavins. 2003. Technological Change and the Environment. Chapter 11 in the Handbook of Environmental Economics. Volume 1, Edited by K.-G. Maler and J.R. Vincent. Elsevier Science B.V. 461-516.

- *Behavioral impediments*. Behavioral economics and psychology have identified potential behavioral phenomena that lead to consumers to deviate from the standard theory of welfare maximizing in consumption and other decisions, including energy efficiency investments. Behavioral economics posits possible explanations, including bounded rationality, heuristic decision-making, and non-standard preference and belief.[143]

In the presence of market failures, users of electricity, or those making energy efficiency investments, face prices or incentives that prevent them from weighing the social benefits and costs of their investments and thus under-invest in approaches to reduce electricity consumption. The behavioral impediments discussed above explain why individuals do not always make energy efficiency investments that are seemingly in their own best interest to reduce their total expenditure, given prevailing electricity prices.

In addition to market failures and behavioral impediments, other factors, such as hidden costs, risk and uncertainty experienced by both consumers and suppliers of energy efficient products, and heterogeneity among consumers, producers and markets, also influence EE investment decisions.[144] Examples of such factors include:

- *Risk and uncertainty*. Adopting an unfamiliar, typically more expensive EE technology can be an uncertain undertaking given the lack of credible information on product performance and future energy prices, and the irreversibility of the investment. Imperfect or asymmetric information can exacerbate the perceived risk of energy efficiency investments and help explain why consumers and firms do not always invest in EE measures. Suppliers also face risk and uncertainty, without perfect information of consumer preferences for energy efficiency. In the presence of risk and uncertainties, consumers and suppliers alike will underinvest in EE.

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[143] See discussion in Gillingham, K and K Palmer. 2014. Bridging the Energy Efficiency Gap: Policy Insights from Economic Theory and Empirical Analysis. Review of Environmental Economics & Policy, 8(1): 18-38.

[144] It has been recognized that there is a difference between cost-effective energy efficiency investment levels, based on cost-minimizing consideration, and observed levels of energy efficiency. This phenomenon, also termed ‘energy paradox,’ or ‘energy efficiency gap,’ has been studied extensively in the literature. See, for example, Jaffe, AB, and RN Stavins. 1994. “The Energy Paradox and the Diffusion of Conservation Technology.” *Resource and Energy Economics* 16(2): 91–122; Sanstad, A. H. and R. B. Howarth. 1994. ‘Normal’ markets, market imperfections and energy efficiency, *Energy Policy*, 22: 811-818; DeCanio 1998; DeCanio, SJ and WE Watkins. 2008. Investment in Energy Efficiency: Do the Characteristics of Firms Matter? *The Review of Economics and Statistics*, 80: 95-107; Allcott, H, and M. Greenstone. 2012. Is There an Energy Efficiency Gap? *Journal of Economic Perspectives* 26 (1):3-28.

- *Transaction costs*. Consumers face transaction costs in searching, assessing and acquiring energy efficient technologies and services. It can be time-consuming and difficult for consumers to estimate lifetime operating costs of a product. The complexity of the search process puts many efficient products at a disadvantage relative to less-efficient products with lower upfront costs.
- *Capital market barriers*. Consumers sometimes face higher interest rates to finance EE investments compared to other investments. Lenders can be reluctant to invest in EE loan portfolios in part because energy efficiency loans may lack standardization and financial markets have difficulty ascertaining the likely payoff from such investments.

EE policies and programs can play an important role in correcting market failures and addressing the barriers to the investment and adoption of socially beneficial energy efficiency opportunities. Examples of effective EE policies and programs include public funding of R&D, information programs (such as energy labeling, the voluntary ENERGY STAR Program, and consumer education), rebates for high-efficiency products, product energy performance standards, financing and loan programs, and technical assistance.

EE Policies[145]

Objectives and Role in Reducing CO_2 Emissions from the Power Sector

EE policies are implemented by states to meet a number of closely related policy goals[146], including:

- Reducing costs to electricity customers,
- Providing a significant resource for meeting power system capacity needs,
- Meeting energy savings goals,
- Stimulating local economic development and new jobs, and
- Reducing the environmental impacts of meeting electricity service needs.

EE policies currently in place are considered by states to be cost-effective strategies for contributing to each of these policy objectives.[147] While each of these objectives, and others,

[145] Existing state EE policies are described extensively in the State Plan Considerations TSD.
[146] U.S. EPA and U.S. DOE. July 2006. National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf.
[147] U.S. EPA and U.S. DOE. July 2006. National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf.

contribute to the motivation of state policymakers to pursue EE policies, reducing energy costs over the long term is the leading objective in pursuing these policies. In addition, EE policies are central to meeting state objectives for reducing CO_2 emissions from the power sector. As noted in the State Plan Considerations TSD, EE policies are a leading tool for achieving CO_2 reductions from power plants, accounting for 35% to 70% of reductions of sector emissions in ten states[148] with statutory requirements for greenhouse gas reductions.

Economy-wide studies of climate mitigation scenarios confirm that energy efficiency plays a critical role in reducing the costs and enhancing the flexibility of meeting long-term climate stabilization targets.[149] Analysis by the International Energy Agency (IEA) suggested that in order to stabilize carbon concentration in the atmosphere at 450 ppm, as much as 44% of the estimated global abatement potential in 2035 derives from greater energy efficiency in the world economy.[150] Several recent Energy Modeling Forum (EMF) studies have investigated the role of technology in achieving climate policy objectives in the U.S. ("EMF 24" and "EMF 25" studies) and globally ("EMF 27" study).[151] These studies concluded that compared to business-as-usual energy efficiency, improvements in energy efficiency in various economic sectors would slow the increases of GHG emissions in the short run, substantially reduce the costs of GHG mitigation (on average, by about 50%[152]), and ease the technology transformation pathways to achieve long-term carbon reduction goals.[153]

Several economic studies (including EMF25 studies) examined the role of energy efficiency policies (such as energy efficiency standards and subsidies) in relation to other climate

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[148] States with GHG reduction laws include: California, Connecticut, Hawaii, Maine, Maryland, Massachusetts, Minnesota, New Jersey, Oregon, and Washington.

[149] Kriegler, E., J. P. Weyant, G. J. Blanford et al. 2014. The role of technology for achieving climate policy objectives: overview of the EMF 27 study on global technology and climate policy strategies. *Climatic Change*. January 2014; Clarke, L, A Fawcett, J Weyant et al. Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise. [forthcoming]

[150] International Energy Agency (IEA). 2012. World Energy Outlook 2012. Paris.

[151] Energy Modeling Forum (EMF) is a consortium of energy economists and energy economic modeling teams that was established in 1976. Through ad hoc working groups, the EMF has focused on a series of energy and environmental topics that are of interest to policy decisions. In recent years, the EMF is recognized for its contribution to the advancement of economics of climate change and the reports of the Intergovernmental Panel on Climate Change (IPCC).

[152] It should be noted that these energy-economy modeling studies do not typically include the costs of implementing energy efficiency measures or would treat such costs as exogenous.

[153] E.g., Kriegler et al. (2014) cited above and Kyle P., L. Clarke, S. Smith et al. 2011. The Value of Advanced End-Use Energy Technologies in Meeting U.S. Climate Policy Goals. The Energy Journal, 32: 61-87.

policy instruments (such as carbon taxes). These studies found that when energy efficiency policies address market failures, they are welfare improving and can complement climate policy.[154] In addition, EE policies are recognized to be an appropriate response to demonstrated market failures and behavioral impediments, particularly in contexts where these failures have broader societal implications such as environmental externalities.[155]

In addition to providing cost-effective opportunities for reducing GHG emissions, energy efficiency is recognized to provide other co-benefits, including air quality and public health benefits, waste reduction from energy generation, energy security, energy system reliability, community economic and social development, and consumer amenities.[156] Energy efficiency investments and policies are also found to spur productivity growth, technology learning and innovation.[157, 158] Recently, more attention has been paid to developing methods for recognizing these co-benefits and integrating them into the cost-benefit analysis framework used by state utility commissions and administrators of EE programs. These co-benefits have not been fully accounted for in the EPA analysis.

Policy Types

EE policies come in many forms. The most prominent and impactful EE policies in most states include those that drive development and funding of EE programs[159], and building energy codes. Other policies that are leading to significant impacts include state appliance and equipment standards, building energy disclosure requirements, innovative financing strategies

[154] See, for example, Comstock, O, and E Boedecker. 2011. Energy and Emissions in the Building Sector: A Comparison of Three Policies and Their Combinations. *The Energy Journal*, 32: 23-41; Fischer, C. (2005) "On the importance of the supply side in demand side management." in *Energy Economics*, 27: 165-180; Fischer, C. 2010. Imperfect Competition, Consumer Behavior, and the Provision of Fuel Efficiency in Light-Duty Vehicles. Resources for the Future DP 10-60. Washington, DC.
[155] E.g., Gillingham, K, R Newell, and K Palmer. 2009. Energy Efficiency Economics and Policy. Annual Review of Resource Economics. *Annual Review of Resource Economics* 1: 597-619.
[156] Woolf, T. W. Steinhurst, E. Malone, K. Takahashi. 2012. "Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for 'Other Program Impacts' and Environmental Compliance Costs," Report prepared by RAP and Synapse Energy Economics.
[157] Boyd, GA and JX Pang (2000). "Estimating the linkage between energy efficiency and productivity," *Energy Policy*, 28: 289-296; Worrell, E. (2011). "Productivity benefits of industrial energy efficiency measures." Lawrence Berkeley National Laboratory Paper LBNL-52727.
[158] Van Buskirk, R, C. Kantner, B. Gerke et al. The benefits of energy efficiency standards and how policies may accelerate declines in appliance costs. Proceeding of National Academy of Sciences. [forthcoming]
[159] EE programs are described in more detail in the following section of this chapter and in the State Plan Considerations TSD.

(e.g., Property Assessed Clean Energy or "PACE"), state tax policies, and "lead by example" strategies targeting energy use in state operations. Comparing the relative impact (achieved or potential) of the different policy types is challenging, particularly to do so comprehensively, across all states, and at the national level. EE programs are the only state EE approach that has comprehensive and detailed reporting of impacts, costs, and other characteristics from all 50 states.[160] This information is generally based upon measurement and verification studies submitted annually, most commonly to state utility commissions, and reported to the Energy Information Administration (EIA) for all program administrator types (all utility types, third-parties, and government agencies). EE program data reported to EIA includes incremental and cumulative energy and peak demand savings, program costs broken down by component, and composition by end-use sector (residential, commercial, industrial). In 2012, utilities and other program administrators in 48 states reported savings from EE programs to EIA through form EIA-861. At a national level, the EPA is not aware of a comprehensive dataset reported by states of the achieved impacts of strategies other than those that lead to investment in EE programs. However, state and regional-level information does exist. For example, the Northwest Power and Conservation Council (NPCC) has been compiling the impacts of EE policies (including utility and third-party EE programs, state building energy codes, and federal appliance standards) across their member states (ID, MT, OR, WA) for more than three decades. For the past decade, EE programs have accounted for more than 75% of the cumulative energy savings from state EE policies for NPCC, with building energy codes accounting for the remaining savings.[161]

Another representation of the relative opportunity provided by different state EE strategies is presented by evaluations of EE achievable potential or projections of the impacts of EE policies. The results from two recent evaluations at a national level are presented in Table 5-

[160] In 2011, EIA began collecting data from third-party administrators of programs. Prior to 2011, this was a significant shortcoming in the breadth of the data collected. The breadth and quality of information collected through Form EIA-861 has improved over time, however, outside entities (e.g., ACEEE) have found that the data can be improved through expert review and supplementation with other data sources. While now fairly comprehensive, the EIA data can be improved further with regards to data quality and consistency. See "Analysis Limitations" section for further discussion.

[161] Sixth Northwest Electric Power and Conservation Plan, Northwest Power and Conservation Council. February 2010. Council Document 2010-09. http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf

1. EE programs account for 77% and 82% of achievable savings in ACEEE[162] and Georgia Tech[163] studies, respectively. These studies indicate that the substantial majority of potential savings from state EE efforts are available through EE programs, and that state and local building energy codes can make a significant additional contribution. Massachusetts provides a state example of the impacts of EE programs relative to other state EE policies. The Massachusetts Global Warming Solutions Act of 2008 established statewide limits on greenhouse gas (GHG) emissions of 25 percent below 1990 levels by 2020. To achieve this target, Massachusetts is relying upon an integrated portfolio of clean energy policies. State EE policies are expected to provide the largest contribution to meeting the 25 percent target with utility sponsored EE programs and state building energy codes accounting for 76% and 17%, respectively, of those policies.[164] In their 2013 progress report, Massachusetts indicates that they are generally on track for meeting or exceeding these projections.[165]

TABLE 5-1

Relative Opportunities Provided by Key EE Programs and Building Codes

Study	Year	EE Programs	Building Codes	Other
ACEEE	2030	77%	13%	10%
Georgia Tech	2035	82%	18%	0%

The full range of EE policies are addressed in greater detail (including designs, authority, obligated parties, measurement and verification (M&V), penalties for non-compliance, and implementation status) in the State Plan Considerations TSD. Because EE programs have provided the majority of state EE-policy electricity savings to-date and offer the majority of potential savings going forward, we next summarize key characteristics of this strategy.

[162] Hayes, S., et. al. American Council for an Energy-Efficient Economy (ACEEE). April 2014. Change is in the Air: How States Can Harness Energy Efficiency to Strengthen the Economy and Reduce Pollution. Report Number E1401. Available at http://www.aceee.org/research-report/E1401.
[163] Yu Wang and Marilyn A. Brown. February 2013. Policy Drivers for Improving Electricity End-Use Efficiency in the U.S.: An Economic-Engineering Analysis. Energy Efficiency.
[164] Ian A. Bowles. December 29, 2010. Massachusetts Clean Energy and Climate Plan for 2020. Available at http://www.mass.gov/eea/waste-mgnt-recycling/air-quality/green-house-gas-and-climate-change/climate-change-adaptation/mass-clean-energy-and-climate-plan.html.
[165] Commonwealth of Massachusetts. Global Warming Solutions Act: 5-Year Progress Report. December 2013. Available at http://www.mass.gov/eea/docs/eea/gwsa/ma-gwsa-5yr-progress-report-1-6-14.pdf.

EE Programs

EE programs (actually portfolios of programs) are comprised of numerous measures and measure types that are applied across all sectors of electricity end-users. Figure 5-1[166] illustrates the multi-level composition and breadth of EE program portfolios. The diversity represented by a typical portfolio of EE programs implemented by a utility (or other program administrator) is an important characteristic relevant to analysis of EE policies. Every detailed program type (as illustrated in the lower half of the figure) represents a unique set of characteristics including costs of energy saved, ratio of program to participant costs, investment life, scale, M&V approach, etc.[167]

Administrators

EE programs are administered by a variety of entities ("program administrators") including utilities of all ownership types (investor-owned, municipals, and cooperatives), non-profit and for-profit third-parties (e.g., Vermont Energy Investment Corporation), and state and local government agencies (e.g., NYSERDA). Most EE programs (including all investor-owned utilities which account for more than 75% of reported savings[168]) are overseen by state utility commissions, which review and approve program plans, projected impacts, and associated budgets; and establish annual reporting and M&V requirements.

Policy Drivers

EE programs result from a number of different policy approaches or "drivers."[169] These include energy efficiency resource standards (EERS) (26 states)[170], system benefit charges (14 states), integrated resource planning (IRP) requirements (34 states), demand-side management

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[166] Ian M. Hoffman, Megan A. Billingsley, Steven R. Schiller, Charles A. Goldman and Elizabeth Stuart. Lawrence Berkeley National Laboratory. August 28, 2013. Energy Efficiency Program Typology and Data Metrics: Enabling Multi-State Analyses Through the Use of Common Terminology. LBNL-6370E. Available at http://eetd.lbl.gov/news/article/56865/new-policy-brief-energy-efficie.

[167] See following sections for discussion of these factors.

[168] U.S. Energy Information Administration Form EIA-861 data files (2012). Available at http://www.eia.gov/electricity/data/eia861/.

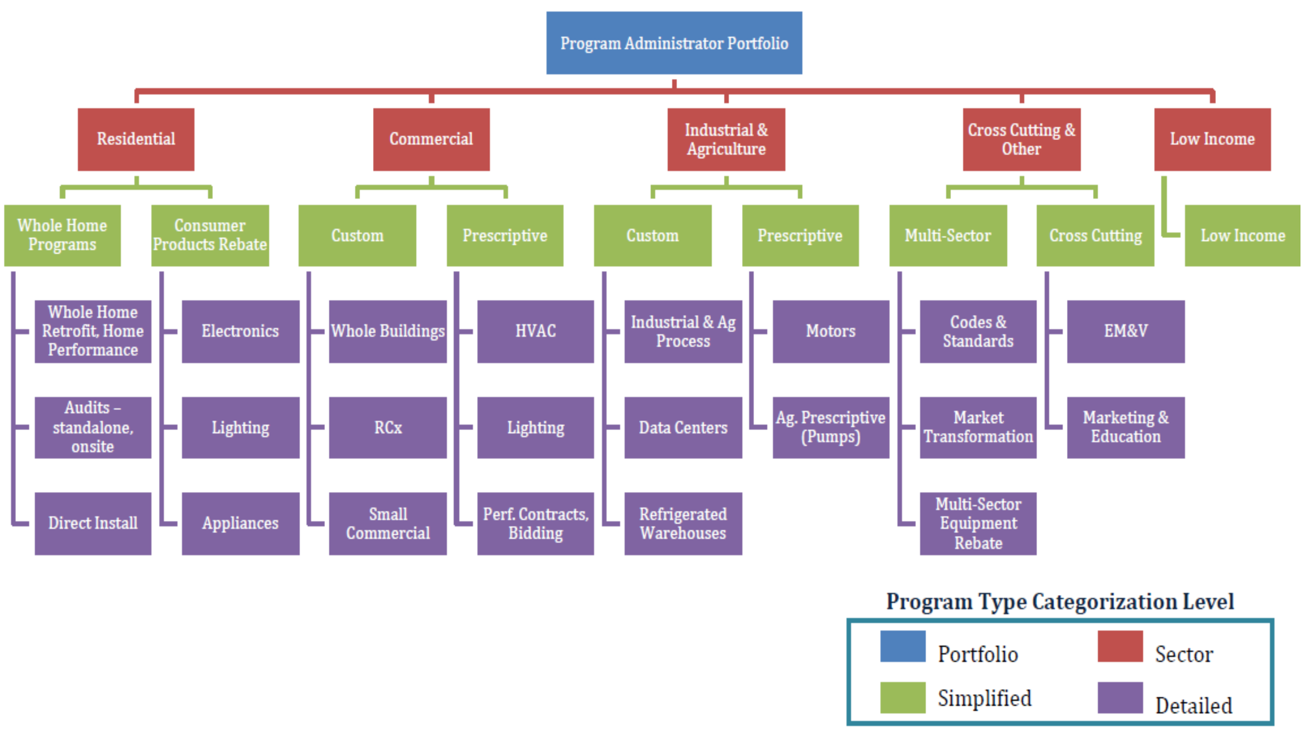
[169] These policies are discussed in depth in State Plan Considerations TSD.

[170] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.

plan or multi-year energy efficiency budget (28 states), and statutory requirement to acquire "all-cost-effective EE" (6 states).[171,172] EERS is a more recently developed strategy and has quickly become the leading driver of the rapid growth in EE programs due to their clear goals and proven success as a policy tool.[173] These policy drivers lead to the evaluation, planning, and adoption of EE programs and associated budgets, which are supported through different funding mechanisms.

FIGURE 5-1[174]

Energy Efficiency Program Portfolio



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

[172] The number of EERS states is from ACEEE (see endnote) and includes states with explicit EERS, those with long-term energy savings targets for individual program administrators, and those with EE incorporated as an eligible resource in a renewable portfolio standard. The numbers for the other policy approaches are from LBNL (see endnote).

[173] Sciortino, M., et. al. American Council for an Energy-Efficient Economy (ACEEE). June 2011. Energy Efficiency Resources Standards: A Progress Report on State Experience. Report Number U112. Available at http://www.aceee.org/research-report/u112.

[174] The "EM&V" box is not comparable to the other program types and is not relevant to this discussion. It was included in the referenced source to indicate that EM&V is a key activity within a program portfolio.

Funding Sources

Funding sources for EE programs are varied but for most states are dominated by revenues collected from ratepayers through electricity surcharges, typically ranging from $1 to $4 per megawatt-hour.[175] More recently adopted funding sources include proceeds from the auction of allowances in the Regional Greenhouse Gas Initiative (RGGI) states and from EE resources bid into the forward capacity market operated by the New England Independent System Operator (NE-ISO). Ratepayer-funding accounts for more than 90% of total EE program support nationally.

The EE Opportunity

As discussed, states are employing a number of EE strategies with EE programs yielding the most significant impacts both historically as well as in terms of future potential. Furthermore, EE programs are unique among state EE strategies in the comprehensiveness and transparency of their reported impacts, funding, and other characteristics. In this section we address the rapid growth in EE programs, estimated impacts of EE programs to-date and projections of the impacts of existing EE programs and trends, and the electricity savings potential achievable through expanded use of EE policies and programs. Finally, we will discuss the costs and cost-effectiveness of EE programs, specifically.

Rapid Growth in EE

Funding for EE programs has increased rapidly in recent years driven by recent policy innovations and increasing evidence of the effectiveness of these new strategies. Table 5-2 presents levels of EE program funding in the U.S. since 2006.[176] In the previous five years, funding increased by more than 250%, from $1.6 billion in 2006 to $5.9 billion in 2011.

[175] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.
[176] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.

TABLE 5-2

U.S. Electric Utility EE Program Funding (2006-2011)

	Year						
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Electric Efficiency Program Budgets (billions of $s, nominal)	1.6	2.2	2.6	3.4	4.6	5.9	5.9

Key new state policies that have helped to drive these rapid increases in EE program funding include EERS, electricity savings goals, and "all cost-effective energy efficiency" requirements. The adoption of EERS, in particular, increased through this period and clearly has been the primary driving force behind the increasing success of and investment in EE programs. Table 5-3 shows the number of states adopting EERS by year.[177]

TABLE 5-3

U.S. State Adoption of Energy Efficiency Resource Standards

Year	**States Adopting an EERS**	**Total**
1997-2004	California, Hawaii, Texas, Vermont	4
2005	Nevada, Pennsylvania	2
2006	Rhode Island, Washington	2
2007	Colorado, Connecticut, Illinois, Minnesota, North Carolina	5
2008	Maryland, Michigan, New Mexico, New Year, Ohio	5
2009	Arizona, Indiana, Iowa, Maine, Massachusetts	5
2010	Arkansas, Oregon	2
2011	Wisconsin	1
1997-2011		26

Source: ACEEE, 2014.

[177] American Council for an Energy-Efficient Economy (ACEEE). February 24, 2014. State Energy Efficiency Resource Standard (EERS) Activity Policy Brief. Available at www.aceee.org/files/pdf/policy-brief/eers-02-2014.pdf.

EE Program Impacts

Impacts to-date

The primary sources for EE program information (including costs and impacts) are annual EE program reports required by utility commissions, or cooperative or municipal utility boards of directors. These reports are based on M&V studies of individual EE programs within the program portfolio. The EIA has been collecting data on EE programs through Form 861, "Annual Electric Power Industry Report," for more than three decades.[178] The data collection reflects an increasing degree of breadth and detail over time. For example, third-party-administered programs were not initially required to report but were added beginning in 2011. Data fields have been added over the years to reflect industry trends (e.g., EE programs are now reported separately from load management programs). Outside organizations have taken the EIA data, supplemented it with additional sources including surveys of utility commissions and program administrators, and published their own annual reports that capture EE program impacts.[179, 180]

The EPA has relied on the EIA Form 861 dataset for identifying historic impacts of EE programs by state. Specifically, the reported sales data, and incremental and cumulative electricity savings in the 2012 EIA 861 dataset are used to estimate electricity EE impacts by state.[181] EIA data is reported by program administrator (e.g., utility, third-party, or state agency) and requires the disaggregation of reported data by state for administrators with programs in multiple states (e.g., multi-state investor-owned utilities). Program administrators in 48 states reported savings in 2012. The EPA has compiled this information and aggregated key data to the state level. Table 5-4 provides a summary of this data by state for the 2012 reporting year, the

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[178] More information on EIA Form 861 can be found at http://www.eia.gov/electricity/data/eia861/.

[179] Consortium for Energy Efficiency. March 28, 2013. 2012 State of the Efficiency Program Industry. Available at http://library.cee1.org/content/2012-state-efficiency-program-industry-report/.

[180] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.

[181] EPA recognizes concerns associated with consistency and quality of 861 data that different reporting entities may have used different methodologies to estimate savings and the EIA 861 data are self-reported. Over time, there has been increased standardization in data reporting. We believe his dataset remains to be the most comprehensive publically available dataset. See "Analysis Limitations" section below for further discussion.

most recent available. At the national level, incremental electricity savings[182] in 2012 was 0.58% of retail sales with individual state values ranging from 0.00% to 2.19%. Cumulative electricity savings[183] (representing the remaining impacts of programs from all prior years) reported at the national level for 2012 represent 3.74% of retail sales with individual state values ranging from 0.0% to 15.44%.

TABLE 5-4

2012 Reported Electricity Savings by State

State	Incremental Savings as a % of Retail Sales (2012)	Cumulative Savings as a % of Retail Sales (2012)
Alabama	0.07%	0.78%
Arizona	1.61%	5.39%
Arkansas	0.11%	0.39%
California	1.24%	13.67%
Colorado	0.84%	4.67%
Connecticut	1.05%	13.37%
Delaware	0.00%	0.00%
District of Columbia	0.00%	0.57%
Florida	0.27%	3.60%
Georgia	0.18%	0.67%
Idaho	0.79%	6.20%
Iowa	1.05%	7.80%
Illinois	0.93%	2.15%
Indiana	0.58%	1.72%
Kansas	0.02%	0.24%
Kentucky	0.23%	1.04%
Louisiana	0.00%	0.00%

[182] Incremental savings (also known as first-year savings) represent the reduction in electricity use in a given year associated with new EE activities in that same year, either new participants in DSM programs that already existed in the previous years, or new DSM programs that existed for the first time in the current year.
[183] Cumulative savings (also known as annual savings) represent the reduction in electricity use in a given year from EE activities in that year and all preceding years, taking into account the lifetimes of installed measures.

Maine	1.96%	5.42%
Maryland	0.89%	2.47%
Massachusetts	0.94%	6.27%
Michigan	1.01%	2.77%
Minnesota	1.12%	13.10%
Mississippi	0.08%	0.50%
Missouri	0.12%	0.55%
Montana	0.66%	5.85%
Nebraska	0.30%	0.99%
Nevada	0.54%	6.19%
New Hampshire	0.48%	4.90%
New Jersey	0.03%	1.04%
New Mexico	0.60%	1.86%
New York	0.93%	6.89%
North Carolina	0.37%	1.26%
North Dakota	0.07%	0.22%
Ohio	0.87%	3.20%
Oklahoma	0.21%	0.70%
Oregon	1.09%	7.72%
Pennsylvania	1.06%	3.08%
Rhode Island	0.78%	11.22%
South Carolina	0.35%	1.12%
South Dakota	0.13%	0.33%
Tennessee	0.31%	1.76%
Texas	0.19%	1.54%
Utah	0.74%	6.59%
Vermont	2.19%	15.44%
Virginia	0.03%	0.30%
Washington	0.93%	7.37%
West Virginia	0.18%	0.20%

Wisconsin	1.05%	6.61%
Wyoming	0.14%	0.71%
Continental U.S. Total	0.58%	3.75%
Alaska	0.02%	0.10%
Hawaii	0.04%	0.25%
U.S. Total	0.58%	3.74%

Source: EPA calculation based on 2012 EIA Form 861 data.

Projected Spending and Savings from EE Programs

In 2013, Lawrence Berkeley National Laboratory (LBNL) published an update to a 2009 analysis and projected future spending levels and savings through 2025 from energy efficiency programs funded by electric and gas utility customers in the United States under three scenarios (high, medium, and low cases).[184] The scenarios represent "a range of potential outcomes under the current policy environment" and were based on detailed, bottom-up analysis of existing state energy efficiency policies. Significantly, the study presumes no new major policy developments such as a "national energy efficiency standard, clean energy standard, or carbon policy" and specifies that such policy changes could "result in customer-funded energy efficiency program spending and savings that exceed the values in our High Case."

The study concludes that efficiency programs are "poised for dramatic growth over the course of the next 10 to 15 years" with the most significant increases occurring in regions with lower levels of program spending, historically, including the Midwest and South. For example, under the medium scenario total U.S. spending on electric efficiency programs increase by 40% to $8.1 billion in 2025 from 2012 levels. Under the high scenario, spending more than doubles from 2012 levels to $12.2 billion in 2025. Incremental savings levels grow commensurately, to 0.8% and 1.1% of sales under the medium and high scenarios, respectively. The study results indicate that under the high scenario 20 states would be achieving 1.5% or higher levels of

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

incremental savings, with 11 of those reaching or exceeding 2.0%.[185] Table 5-5 summarizes the results of the LBNL analysis.

Table 5-5

Summary of Impacts:

Scenarios of Future Utility Customer-Funded Electric Energy Efficiency Programs

Case	2025		
	Incremental Savings (% of Sales)	Program Costs (billions of $, nominal)	Programs Costs (% of Revenues)
Low	0.5%	5.5	1.1%
Medium	0.8%	8.1	1.7%
High	1.1%	12.2	2.7%

EE Potential

Evaluations of EE Potential

Energy efficiency potential studies are a common tool for informing the development of EE program plans and budgets, as well as supporting the development of electricity savings targets, required savings levels under an EERS, or "all cost-effective" EE requirement. In conducting these studies, states and utilities have developed a methodology that is often described as a "bottom-up, engineering-based" approach.[186] EE potential studies are conducted at various geographic scopes (national, regional, state, and utility service territory level) and at different degrees of aggregation (e.g., economy-wide, sectoral, and program), and can be broadly grouped into a few types: technical, economic, market, and program.[187]

- **Technical potential** represents the theoretical maximum amount of energy use that could be displaced by efficiency, without regard to non-engineering constraints such as costs and the willingness of energy consumers to adopt the efficiency measures. It often

[185] LBNL provided these unpublished results from their analysis.
[186] U.S. EPA and U.S. DOE. November 2007. Guide for Conducting Energy Efficiency Potential Studies: a Resource of the National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.
[187] The definitions discussed below largely follow that outlined in the *Guide for Conducting Energy Efficiency Potential Studies* (NAPEE 2007) but the variations in definition are also discussed (e.g., Sathaye and Murtishaw 2004; Huntington 2011).

assumes immediate implementation of all technologically feasible energy saving measures, with additional efficiency opportunities assumed as they arise.

- **Economic potential** refers to the subset of the technical potential that is economically cost-effective. Definition of "economic potential" can vary to some degree by study. Some estimate economic potential by evaluating technology upfront cost, operating costs that considers energy prices, product lifetime and discount rate, compared to a conventional alternative or the supply-side energy resources. Others incorporate consideration of consumer preferences in addition to consumers' out-of-pocket expenditure when evaluating the economic potential. Both technical and economic potential estimates assume immediate implementation of efficiency measures without regard to technology adoption process or real-life program implementation. In addition, these estimates do not always reflect market failures or barriers that impede energy efficiency and often fail to capture transaction costs (e.g., administration, marketing, analysis, etc.) beyond the costs of efficiency measures.
- **Market potential (or "achievable" potential**) refers to the subset of economic potential that reflects the estimated amount of energy savings that can realistically be achieved, taking into account factors such as technology adoption process, market failures or barriers that inhibit technology adoption, transaction costs, consumer preferences, social and institutional constraints, and possibly the capability of programs and administrators to ramp up program activity over time.
- **Program potential** refers to the subset of market potential that can be realized given specific program funding levels and designs. Program potential studies can consider scenarios ranging from a single program to a full portfolio of programs.[188]

As mentioned, the EE industry standard for potential studies is the bottom-up, engineering evaluation of energy efficiency potential of individual end-use technologies and measures.[189] Bottom-up analyses all employ a similar methodology but can vary significantly in

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[188] Each subsequent potential estimate described above is a subset of the previous potential estimate, e.g., the market potential is a subset of the economic potential, and the economic potential is a subset of the technical potential.
[189] U.S. EPA and U.S. DOE. November 2007. Guide for Conducting Energy Efficiency Potential Studies: a Resource of the National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.

key assumptions (e.g., breadth of sectors and end-uses considered, study period, discount rate, pattern of technology penetration, whether economically justified early replacement of technologies is allowed for, and whether continued improvement in efficiency of technology is provided for). As a result, estimated efficiency potential can vary significantly among studies.[190]

Overview of Results

Studies of energy efficiency potential are numerous. In recent years, dozens of studies have been conducted at regional, state, and utility levels. This section reviews recent studies and presents a summary of findings. We first address meta-analyses that summarize results from multiple utility, state, and regional studies, and then we address the few national studies that have been conducted. To normalize results of analyses addressing different study periods, we present average annual achievable potential by dividing cumulative percentage savings in the last year of the study by the duration (in years) of the study period. This is a common method of normalization for energy efficiency potential studies.

At the regional and state level, two meta-analyses, Sreedharan (2013)[191] and Eldridge et al. (2008)[192], captured numerous studies conducted between 2001 and 2009. The meta-analysis conducted by Sreedharan (2013) presents average annual values of 4.1% per year in technical potential, 2.7% per year in economic potential, and 1.2% per year in maximum achievable potential. In comparison, Eldridge et al. (2008) estimated average annual values of 2.3% per year in technical potential, 1.8% per year in economic potential, and 1.5% per year in achievable potential. To supplement these studies with more recent data, the EPA has conducted a meta-analysis of twelve studies conducted between 2010 and 2014 at the utility, state or regional level (see Appendix 5-1). The EPA review indicates an average annual achievable potential of 1.5% per year across the reviewed studies. See Appendix 5-2 (Summary of Recent (2010-2014)

[190] Because of the complex consumer behavior, energy market and macroeconomic drivers of energy use and energy efficiency, and in some cases due to the lack of consistent data, quantifying energy efficiency potential and energy savings from policies and programs remains a challenging analytical task. Assumptions about consumer technology adoption behavior, market barriers and failures, and how technology diffusion occurs can also affect estimated potential.

[191] Sreedharan, P. 2013. Recent estimates of energy efficiency potential in the USA. Energy Efficiency.

[192] Eldridge et. al. 2008. State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned. 2008 ACEEE Summer Study on Energy Efficiency in Buildings.

Electric Energy Efficiency Potential Studies) for complete results from the EPA research. Table 5-6 presents a summary of these three meta-analyses of EE potential.

TABLE 5-6

Summary of Meta-Analyses of EE Potential at Utility, State, and Regional Levels

Study	Dates of Studies	Number of Studies	Average Annual Achievable Potential
Sreedharan (2013)	2001-2009	10	1.2%/year
Eldridge (2008)	2001-2007	20	1.5%/year
EPA (2014)	2010-2014	12	1.5%/year

In addition to the numerous studies conducted at the utility, state, or regional levels since 2001, a number of studies have evaluated efficiency potential at the national level, applying a generally consistent methodology and employing a common data set, across all regions of the country. Sreedharan (2013) evaluated four major energy efficiency potential studies at the national level, namely, McKinsey and Co. (2007), McKinsey and Co. (2009), EPRI (2009), and AEO (2008) Energy Efficiency Side Case. All four studies used the AEO 2008 reference case as the baseline but differed in other key respects (e.g., breadth of end-uses, assumed technology improvement over time, and definition of cost test for economic potential screening). These studies suggest technical electricity savings potential in the range of 25-40% and economic potential in the range of 10-25%, as a percentage of total demand in 2020. Of these studies, only EPRI provided an estimate of achievable potential. On a normalized basis, the EPRI 2009 study provides an achievable annualized potential range of 0.2-0.4% per year (realistically achievable and maximum achievable potential, respectively) through 2030 at the national level.

Two more recent studies also provide national estimates of achievable EE potential: EPRI (2014)[193] updates their 2009 analysis, using a conventional bottom-up engineering approach, and ACEEE (2014)[194], using a top-down, policy-based approach derived from state experience and their evaluated results. EPRI (2014) results show an average annual achievable

[193] Electric Power Research Institute (EPRI). April 2014. U.S. Energy Efficiency Potential Analysis through 2035. [forthcoming]
[194] American Council for an Energy-Efficient Economy (ACEEE). April 2014. Select State-Level Energy Efficiency Policy Opportunities 2016-2035. [forthcoming]

potential range of 0.5% to 0.6% per year (achievable and high achievable potential, respectively). ACEEE found average annual achievable potential of 1.5% per year. The results of the EPRI and ACEEE studies are summarized in Table 5-7.

TABLE 5-7

Summary of National EE Potential Studies

Study	Study Type	Average Annual Achievable Potential
EPRI (2009)	Bottom-up, engineering	0.2%-0.4%/year (realistic to maximum achievable)
EPRI (2014)	Bottom-up, engineering	0.5%-0.6%/year (achievable to high achievable)
ACEEE (2014)	Top-down, policy-based	1.5%/year

Notably, each of these national potential studies show significant potential in every region of the country including regions with lower electricity prices like the southeast, regions with historically high levels of EE program budgets like the northeast and west coast, and across regions with varied sectoral composition (e.g., higher manufacturing regions like the midwest and south, as well as higher service industry regions like the northeast and California). Both EPRI studies illustrate the substantial and similar scale opportunity across all regions. For instance, EPRI (2014) shows achievable potential ranging from 8% to 14% relative to baseline in 2035 across the thirteen regions of their analysis as well as significant opportunity in the residential, commercial and industrial sectors in every region. The ACEEE (2014) study also shows consistently large potential across all states and regions through 2030, with an average potential of 24% and a range of 20% to 36% across 50 states.

<u>**Costs and Cost-Effectiveness of State EE Policies**</u>

EE Cost-Effectiveness

States enact EE policies to meet multiple policy objectives including reduction of customer electricity bills, lower costs of meeting electricity supply needs, energy reduction, environment and health benefits, and local economic development benefits.[195] Most states evaluate their EE policy options through the application of cost tests, weighing the projected benefits with the costs of the energy efficiency technologies and practices.[196] [197] Each state determines their own policies for the specific costs and benefits to include in these tests. The costs and benefits are compared on an equal footing by using present value analysis. This is necessary because EE typically requires primarily upfront expenditures (e.g., a whole home retrofit) while the economic benefits (e.g., electricity bill savings) accrue over the life of the investment ("measure life") which can range from a few to twenty or more years. As such, the choice of discount rate and the estimation of measure life are significant determinants of the cost-effectiveness results. Most states employ multiple tests, adjusting cost and benefit categories depending upon the economic perspective of interest (e.g., utility, ratepayer, program participant, society), and consider the results from each one, usually with an identified primary test type. Policies that are selected are those that are found to be cost-effective, with benefits greater than costs, as determined by the utility applying methods defined by their state utility commission.

There are five primary cost-effective tests used in the U.S.:

(1) *Participant cost test* from the perspective of the customer installing the measure. Costs may include incremental equipment and installation costs; benefits include incentive payments, bill savings, and applicable tax credits or incentives.

(2) *Utility/program administrator cost test* from the perspective of utility, government agency or third-party implementing the program. Costs may include program incentive, installation, and overhead costs; benefits may include avoided energy and capacity costs - including generation, transmission and distribution - by the utility.

(3) *Ratepayer impact measure test* from the perspective of utility ratepayers not participating in available energy efficiency programs. This text includes the costs and benefits that will affect utility rates, including program and administration costs, as well as "lost revenues" to the utility; benefits include avoided energy and capacity costs, and additional resource savings.

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[195] U.S. EPA and U.S. DOE. July 2006. National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/napee_report.pdf.

[196] U.S. EPA and U.S. DOE. November 2008. Understanding Cost-Effectiveness of Energy Efficiency Programs (Best Practices, Technical Methods, and Emerging Issues for Policy-Makers): a Resource of the National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/cost-effectiveness.pdf.

[197] Woolf, T., et. al. November 2012. Regulatory Assistance Project, "Energy Efficiency Cost-Effectiveness Screening. Available at http://ww.raponline.org/document/download/id/6149.

(4) *Total resource cost test* from the perspective of all utility customers in the service area. Costs may include the full incremental cost of the measure, program installation and overhead costs; benefits may include avoided energy and capacity costs, and additional resource savings.

(5*) Societal cost test* from the social perspective. In addition to benefits considered in total resource cost test, may also include non-monetized benefits such as environmental and health benefits.

While many states consider more than one cost test in evaluating EE programs, the most commonly used (29 states) primary test is the total resources cost test. This test is considered to be the best measure of the interests of all utility customers. The utility and societal cost tests are the next most commonly used primary tests, used by five states each. The utility cost test is considered to be the most comparable metric to compare with supply-side resource investments from a utility resource planning perspective.

Economic and modeling analyses of climate change policy suggests that energy efficiency presents a large potential in reducing greenhouse gas emissions and plays a critical role in offsetting the costs and enhancing the flexibility to achieve long-term GHG reduction targets.[198] Consistently, evaluations of the economic potential for carbon dioxide reductions from the United States' power sector identify demand-side energy efficiency as the lowest cost strategy (typically, as noted above, with positive net present value) as well as the strategy having the greatest reduction potential.[199] For example, McKinsey (2007) found that EE accounted for more than 60% of their mid-range potential for greenhouse gas reductions from the U.S. power sector and that it was available at positive net present value if "persistent barriers to market efficiency" could be addressed. [200]

[198] See, for instance, Kriegler, E., J. P. Weyant, G. J. Blanford et al. 2014. The role of technology for achieving climate policy objectives: overview of the EMF 27 study on global technology and climate policy strategies. Climatic Change, January 2014; Kyle P., L. Clarke, S. Smith et al. 2011. The Value of Advanced End-Use Energy Technologies in Meeting U.S. Climate Policy Goals. The Energy Journal, 32: 61-87.

[199] U.S. EPA and U.S. DOE. September 2009. Energy Efficiency as a Low-Cost Resource for Achieving Carbon Emissions Reductions: a Resource of the National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/ee_and_carbon.pdf.

[200] McKinsey & Company. December 2007. Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost? Available at http://www.mckinsey.com/client_service/sustainability/latest_thinking/reducing_us_greenhouse_gas_emissions.

Costs of Saved Energy

A common metric for comparing alternative electricity resource options within utility resource plans is the levelized cost of energy (LCOE) or, for EE resources, the levelized cost of saved energy (LCSE).[201] LCSE EE is often compared favorably with LCOE of alternative new generation sources such as fossil-fueled or nuclear power plants, or renewable energy resources like wind or solar-power generation. In these comparisons, typically only utility (or program) costs are considered, not the total costs of saved energy that are discussed later in this chapter. The energy efficiency analysis literature reports average LCSE in the range of 1-6 cents/kWh based on program administrator cost.[202] A recent review by ACEEE (2014) examined studies across 20 states between 2009 and 2012, and estimated LCSE for electricity energy efficiency programs in the range of 1.3-5.6 cents/kWh, with a mean value of 2.8 cents/kWh.[203] Earlier reviews of utility EE programs identified a similar range of LCSE. Friedrich et al. (2009) reviewed 14 utility studies of LCSE and found a range from 1.6 to 3.3 cents/kWh, with a mean value of 2.5 cents/kWh.[204] An earlier ACEEE study (2004) reviewed cost-effectiveness analysis results in nine states and suggested that reported utility LCSE ranged between 2.3-4.4 cents/kWh, with a mean value of 3 cents/kWh.[205]

The economic literature also evaluates the LCSE from EE measures using other techniques (e.g., econometrics, top-down modeling), although this body of studies is much smaller compared to the bottom-up, engineering-based analysis. The economic literature has varying treatment of the free ridership, EE program endogeneity, and the rebound effect. The different assumptions used in these analyses make direct comparison challenging, but overall

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[201] U.S. EPA and U.S. DOE. November 2007. Guide for Resource Planning with Energy Efficiency: a Resource of the National Action Plan for Energy Efficiency. Available at http://www.epa.gov/cleanenergy/documents/suca/resource_planning.pdf.

[202] Unless otherwise noted, estimates of LCSE discussed in this section refer to program administrator cost (also known as utility cost). The discount rates, average measure lives, and other assumptions affecting the calculation of LCSE were not always consistent or reported in all studies.

[203] Molina, M. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE Report No. U1402. Washington, DC. Available at http://www.aceee.org/research-report/u1402.

[204] Friedrich, K., M. Eldridge, D. York et al. 2009. Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs," ACEEE Report No. U092. Available at http://www.aceee.org/research-report/u092.

[205] Kushler, M., D. York, and P. Witte. American Council for an Energy-Efficient Economy (ACEEE). 2004. Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies.

these empirical analyses present a wider range of estimates of cost of saved energy. For example, a recent study by Auffhammer et al. (2008) examining utility DSM programs estimated the average utility cost of saved energy in the range of 5.1 to 14.6 cents per kWh.[206] Some other studies in the economic literature suggest estimated LCSE in a similar range as from the bottom-up analyses. Gillingham et al. (2004) estimated an average cost of 3.4 cents per kWh saved from utility EE programs.[207] In a recent econometric analysis of utility rate-payer funded demand-side management and energy efficiency programs between 1992 and 2006, Arimura et al. (2009) found that the estimated energy savings in electricity consumption were achieved at an expected average cost to utilities of approximately 5 cents/kWh.[208] Using a top-down approach that evaluates the savings potential of EE investments using state- and region-specific price elasticity, Paul et al. (2011) estimated that electricity savings of 1 to 3 percent were available at a marginal cost of 5 cents/kWh and a corresponding average cost of 2.5-3.5 cents/kWh.[209]

A number of analytical and data considerations related to LCSE estimation are also discussed in the literature, including the issue of "free riders" in EE programs[210], and the accuracy of utility reported costs and energy savings.[211] Energy efficiency practitioners also recognize the need to consider "free rider" and "spillover" effects in program evaluation. A slight majority of states adjust for free ridership in energy savings estimates, leading to higher LCSE values than otherwise would be the case. A smaller number of states adjust for spillover effects which reduce LCSE values when addressed.[212]

Another consideration related to LCSE estimation is the rebound effect. The economic literature has extensive discussion of the potential rebound effect, market interactions and

[206] Auffhammer M., C. Blumstein, M. Fowlie. 2008. Demand Side Management and Energy Efficiency Revisited. *Energy Journal* 29(3): 91-104.
[207] Gillingham, K., R. Newell, K. Palmer. 2004. Retrospective Examination of Demand-Side Energy Efficiency Policies. Resources for the Future Working Paper DP 04-19 REV. Washington, DC.
[208] Arimura, T. S. Li, R. Newell, and K. Palmer, 2012. Cost-Effectiveness of Electricity Energy Efficiency Programs, *The Energy Journal* Vol 33(2).
[209] Paul, A., K. Palmer and M. Woerman. 2011. Supply Curves for Conserved Electricity. Resources for the Future Discussion Paper 11-11. Washington, DC.
[210] Trains, K. 1994. Estimation of Net Savings from Energy-Conservation Programs. *Energy* 19 (4):423-441.
[211] Joskow, P., and D. Marron. 1992. What Does a Negawatt Really Cost? Evidence from Utility Conservation Programs. The Energy Journal 13 (4):41-74.
[212] Kushler, M., S. Nowak, and P. Witte. February 2012. A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs. ACEEE Report No. U122. Available at http://www.aceee.org/research-report/u122.

economy-wide response of energy efficiency policies and investments. An improvement in energy efficiency would effectively reduce the cost of a service or production input, potentially boosting its demand or production output thus increasing energy use ("direct" rebound). In addition, money saved from energy efficiency can be used for consumption or investment that can increase energy consumption in other markets of the economy and lower energy prices as a result of energy efficiency improvement may increase energy consumption (two forms of "indirect" rebound). Reviews suggest that both direct and indirect rebound effects exist and the size of such effects varies among different studies, technologies, sectors and income groups.[213] Overall, however, rebound effects are found to be relatively modest compared to the importance of energy efficiency as an effective way of reducing energy consumption and carbon emissions (Greening et al. 2000[214]; Sorrell 2007[215]; Davis 2008[216]; Gillingham et al. 2013[217]).

EE as an Abatement Measure

Demand-side energy efficiency is a technically viable and broadly applicable measure for achieving significant reductions in the amount of generation required and associated emissions from affected EGUs. Moreover, this measure has been adopted by every state and most utilities across the country, typically through multiple policy approaches. Increased use of, and impacts from, state energy efficiency policies is a leading industry trend over recent years and the trend of increasing investment in EE programs is projected to continue for the next decade, at least. These findings support the inclusion of demand-side energy efficiency as an abatement measure for reducing CO_2 emissions from fossil fuel-fired EGUs. In the next section, we address the setting of state-specific goals for electricity savings levels resulting from state demand-side

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[213] Sorrell, S. 2007. "The Rebound Effect: an assessment of the evidence for economy-wide energy savings from improved energy efficiency." A report produced by the Sussex Energy Group for the Technology and Policy Assessment function of the UK Energy Research Centre. ISBN 1-903144-0-35.
[214] Greening, LA, DL Greene, and C Difiglio. 2000. Energy efficiency and consumption — the rebound effect — a survey, *Energy Policy*, 28: 389-401.
[215] Sorrell, S. 2007. "The Rebound Effect: an assessment of the evidence for economy-wide energy savings from improved energy efficiency." A report produced by the Sussex Energy Group for the Technology and Policy Assessment function of the UK Energy Research Centre. ISBN 1-903144-0-35
[216] Davis, LW 2008. Durable goods and residential demand for energy and water: evidence from a field trial. *The RAND Journal of Economics*, 39: 530–546.
[217] Gillingham K, MJ Kotchen, DS Rapson, G Wagner. 2013. Energy policy: the rebound effect is overplayed. *Nature* 493: 475-476.

energy efficiency efforts. In the final section, the integration of these goals into the impacts assessment is presented and we consider the reasonableness of the costs of this building block.

State Goal Setting

Approach

To estimate the potential CO_2 reductions at affected EGUs that could be achieved through implementation of demand-side energy efficiency policies as a part of state goals, the EPA developed a "best practices" demand-side energy efficiency scenario. This scenario provides an estimate of the potential for states to implement policies that increase investment in cost-effective demand-side energy efficiency technologies and practices, and projects the annual impacts of the scenario for each state. The scenario does not distinguish between policies that are currently in place and additional policies that in most states would be required to be implemented to realize the goals established. It does not represent an EPA forecast of business-as-usual impacts of state energy efficiency policies or an EPA estimate of the full potential of end-use energy efficiency available to the power system, but rather is intended to represent a feasible policy scenario showing the reductions of CO_2 emissions from fossil fuel-fired EGUs resulting from accelerated use of energy efficiency policies in all states, generally consistent with ongoing industry trends. The scenario uses: 1) a level of performance that has already been demonstrated or required by policies (e.g., energy efficiency resource standards) of many leading states; 2) considers each state's unique existing level of performance; and 3) allows appropriate time for each state to increase from their current level of performance to the identified best practices level.

The best practices scenario is derived from state experience with, and reliance on, policies that drive investment in energy efficiency programs, and the energy savings that result from those efforts. We focus on energy efficiency programs for several reasons:

- EE programs have achieved significant levels of savings and are being used in almost every state,
- EE program spending and savings levels are reported by utility or other program administrator, by state, and compiled nationally, using standardized elements and definitions, and

- EE program savings are projected and evaluated under requirements established and overseen by state utility commissions, and by municipal and cooperative utility boards of directors.

While the approach is derived from information about energy efficiency programs overseen by state utility commissions, other state energy efficiency policies are available to realize a state's goals[218] such as building energy codes, appliance standards, and building energy benchmarking requirements. All policies included in a state plan will need to meet established requirements or guidance for EM&V.[219]

The following steps were taken to establish the inputs for development of the best practices scenario for each state:

- *Step 1: Determine current level of performance*
- *Step 2: Determine best practices level of performance*
- *Step 3: Determine start year for state efforts*
- *Step 4: Determine start year level of performance*
- *Step 5: Determine pace at which states improve from start year to best practices level of performance*
- *Step 6: Determine average portfolio measure life and distribution of measure lives*
- *Step 7: Determine sustainability of best practices level of performance*

<u>Inputs</u>

Step 1: Determine Current Level of Performance

A fundamental indicator of the level of energy efficiency program performance is incremental annual savings as a percent of retail sales. This is a common metric defining savings levels for energy efficiency resource standards and is readily calculated from EIA Form 861 data for each state. Incremental annual savings are also more directly estimated and evaluated than are cumulative savings.[220] For the best practices scenario, we aggregated the most recent year of

[218] See State Plan Considerations TSD.
[219] See State Plan Considerations TSD.
[220] Estimates of cumulative savings impacts in a given year are derived from incremental savings values and information on measure lives. Information on measure lives is less consistently gathered than is information on incremental savings values.

EIA Form 861 data to the state level to establish each state's current level of performance. These results were presented previously in Table 5-4.

Step 2: Determine Best Practices Level of Performance

As discussed previously, achievable demand-side energy efficiency potential exists at significant and comparable levels (on the basis of total cumulative potential over a period of ten to twenty years) in all regions of the country. While varied regional characteristics (e.g., avoided power system costs, economic growth, sectoral mix, climate, and level of past energy efficiency efforts) affect estimates of achievable potential, ongoing improvements in energy-efficient technologies and practices, economic growth, population increases, and continually improving strategies for program delivery have resulted in persistent and substantial levels of achievable potential regardless of specific regional characteristics.

A direct indicator of the achievable incremental levels of energy savings performance is provided by past performance at the state and utility levels, and by requirements states have put in place for levels of savings to be achieved by 2020. As discussed, these requirements are typically in the form of energy efficiency resource standards or similar savings goals that are applied to utilities in the state.[221]

Table 5-8 summarizes incremental savings levels as a percentage of retail sales from EIA Form 861 (2012) data, aggregated to the state level, and categorized into four ranges of savings levels (< 0.5%, 0.5% to 0.99%, 1.0% to 1.49%, and >= 1.5%). As shown, three states achieved the highest level of performance (> 1.5%) and an additional eight states achieved the second highest level of performance (1.0% to 1.49%).

Table 5-9 summarizes incremental savings levels required by state policy on or before 2020 and categorized into the same four ranges.[222] Eleven states are required to achieve the highest level of performance (> 1.5%) and an additional five states are required to achieve the next highest level of performance (1.0% to 1.49%).

[221] See State Plan Considerations TSD for more information.
[222] American Council Energy-Efficient Economy (ACEEE). February 24, 2014. State Energy Efficiency Resource Standard (EERS) Activity Policy Brief. Available at www.aceee.org/files/pdf/policy-brief/eers-02-2014.pdf.

TABLE 5-8

2012 Reported State Levels of Incremental Annual Savings

Incremental Savings as % of Retail Sales	# of States	States
>= 1.5%	3	AZ, ME, VT
1.0% to 1.49%	8	CA, CT, IA, MI, MN, OR, PA, WI
0.5% to 0.99%	14	
< 0.5%	25	

Source: EPA calculation based on EIA Form 861.

TABLE 5-9

Levels of Incremental Savings Required by State Policy on or before 2020

Incremental Savings as % of Retail Sales	# of States	States
>= 1.5%	11	AZ, CO, IL, IN, MA, MN, NY, OH, RI, VT, WA
1.0% to 1.49%	5	HI, IA, ME, MI, OR
0.5% to 0.99%	3	AR, CA, WI
< 0.5%	1	TX

Source: ACEEE, 2014.

For the best practices level of performance for Option 1[223], the EPA has chosen 1.5% incremental savings as a percentage of retail sales. This level was achieved by three states (AZ, ME, and VT) in 2012 and an additional nine states (CO, IL, IN, MA, MN, NY, OH, RI, and WA), accounting for overlap, are expected to achieve this level by 2020. Thus, twelve states have either achieved or are required to achieve this level of performance by 2020.

For Option 2[224], the EPA has chosen 1.0% incremental savings as a percentage of retail sales as the best practices level of performance for this alternate approach. This level was achieved by eleven states in 2012 and an additional twelve states are expected to achieve this

[223] See Preamble and Goal Computation TSD for description of Option 1.
[224] See Preamble and Goal Computation TSD for description of Option 2.

level by 2020. In total, twenty states (accounting for duplication between the two sets of states) have either achieved or are required to achieve this level of performance by 2020.

Step 3: Determine Start Year for State Efforts

For construction of the best practices scenario, the EPA has used 2017, the year following the required state plan submittal[225], as the first year for state efforts.

Step 4: Determine Start Year Level of Performance

For construction of the best practices scenario, the EPA has set each state's level of performance (incremental savings) in the start year (2017) to its current level of performance (aggregated to the state-level from reported EIA Form 861 data). This approach reflects neither improvement nor decline in performance between 2012 and 2017. Any improvement in EE savings performance between 2012 and 2017 will benefit a state in meeting its state EE goals for the 2020-2029 interim compliance period.[226]

Step 5: Determine Pace at Which States Improve from Start Year to Best Practices Level of Performance

To determine a trajectory of incremental savings levels from the 2017 level to the best practices level, the EPA considered past performance of individual program administrators[227] as well as requirements of existing state energy efficiency resource standards. For the past performance of individual program administrators, we first screened the data and divided them into moderate and high performing sub-groups. The moderate group (47 entities) was defined as programs that achieved from 0.8% to 1.5% maximum incremental savings levels and the high group (26 entities) was defined as programs that achieved greater than 1.5% maximum incremental savings levels. We then calculated the rate at which each entity had increased savings over time and calculated average values for each sub-group. For the moderate group, the average rate of improvement of incremental annual savings rate was 0.30% per year. For the

[225] See Preamble and State Plan Considerations TSD for descriptions of the schedule for state plan submittals.
[226] See Preamble for description of interim and final compliance periods.
[227] EIA 861 was the primary data source; however, we supplemented EIA 861 data with data for third-party program administrators because prior to 2011 EIA did not collect data from third-party program administrators.

high group, the average rate of improvement of incremental annual savings rate was 0.38% per year. See Appendix 5-3 for supporting data and analysis.

The EPA also considered requirements of existing state EERS and evaluated the rate at which their incremental savings levels increase over time. For several EERS, we were unable to clearly identify ramp-up schedules. We identified ten states with clear schedules and calculated the average rate of improvement for each. The average rate of improvement of incremental annual savings rate required for these ten states is 0.21% per year. See Appendix 5-3 for supporting data and analysis.

Based on these results, for the best practices rate of improvement the EPA has chosen 0.2% per year and 0.15% per year for Options 1 and 2, respectively. These values are conservative by comparison with our analysis of past state performance and future state requirements.

Step 6: Determine Average Portfolio Measure Life and Distribution of Measure Lives

The next step in defining the best practices scenario requires projecting the cumulative future impacts of the annual incremental savings levels for each state. The incremental savings impacts reflect the savings from EE measures put in place in that year, driven by EE program activities in that year. The cumulative annual savings represent the total impacts of all EE measures put in place in that year and all prior years, due to EE program activities. The cumulative savings account for the continuing impacts of energy efficiency measures that remain in place for a period of time (the "measure life") before being replaced. For example, the purchase of a high-efficiency refrigerator may lead to savings for twelve years, before being replaced with a new model. To estimate cumulative impacts of a series of years of incremental savings, the industry uses the concept of an average measure life for the entire portfolio of EE programs. Rather than use a single, average measure life to represent a diverse portfolio of programs, that range in measure lives from as little as a few years (e.g., certain lighting technologies and applications) to as long as fifteen or twenty years (e.g., adding insulation to an attic), the EPA is assuming a distribution of measure lives around the average to account for future impacts of incremental savings levels.

In 2014, ACEEE updated their 2004 and 2009 national reviews of EE program costs and related program characteristics, including measure lives.[228] They reviewed electricity EE program data from 20 states and summarized average measure lifetimes by state and customer class. Table 5-10 summarizes the results from the ACEEE study and shows an average across all sectors for these states of 10.6 years.

TABLE 5-10

Average Electricity Measure lifetimes by state and customer class

	Sector			All Sectors
	Residential	**Commercial/Business**	**Industrial**	
Average	8.1	12.5	9.5	10.6

Source: ACEEE 2014.

Other studies have found slightly higher values for average measure life for EE portfolios, ranging from 10 to 13 years.[229] Our assumption of 10 years is conservative by comparison and leads to lower cumulative impacts over time and correspondingly lower state goals.

To approximate a distribution of measure lives across an EE portfolio, consistent with an average measure life of ten years, we have assumed an even distribution from one year in length to two times the average measure life (twenty years) in length. Our approach is generally supported by the substantial range in measure lives reviewed and summarized in a 2014 study by LBNL which shows an interquartile range from five to 25 years across twelve program categories (e.g., low income, residential new construction, commercial/industrial custom, etc.). Our approach represents a first-order approximation of the distribution of measure lives across a diverse portfolio of programs. The more common approach in other studies is to assume a portfolio with no diversity of measure lives whatsoever, with the entirety of incremental savings being realized in each year from the first through the full average measure life and then dropping to zero in the following year. Our approach is a conservative one, leading to the same quantity of

[228] Molina, M. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE Report No. U1402. Available at http://www.aceee.org/research-report/u1402.
[229] Billingsley, Megan A., I. M. Hoffman, E. Stuart, S. R. Schiller, C. A. Goldman, K. LaCommare, Lawrence Berkeley National Laboratory. March 2014. The Program Administrator Cost of Saved Energy for Utility Customer-Funded energy Efficiency Programs. http://emp.lbl.gov/sites/all/files/cost-of-saved-energy-for-ee-programs.pdf.

total energy savings, but with a greater portion of the savings occurring in later years than occurs with the more common, and simpler, approach. This results in lower cumulative impacts in earlier years and correspondingly lower state goals through 2030.

Step 7: Determine Sustainability of Best Practices Level of Performance

For construction of the best practices scenario, once a state achieves the best practices level of performance, the EPA has kept the level of performance constant through 2030. For states with lower levels of current performance (and, hence, later achievement of the best practices level of performance – as late as 2025 in some instances), this requires sustaining the target level for as little as five years. For states currently at or above the best practices level of performance, this reflects an ability to sustain the target level for thirteen years (2017 through 2030).

Limited empirical data suggests the reasonableness of this approach; however, comprehensive data, across all regions and states, does not exist because these levels of performance have not been achieved and sustained nationwide previously. The Northwest Power Conservation Council (NPCC) provides one such example. NPCC has been conducting the most consistent and long-running series of evaluations of achievable cost-effective potential in the country, updated every five years, as part of their five-state[230] regional energy resource plans[231]. These analyses have become more detailed, reliable, and purposeful over time. Since 1998, NPCC's estimates of achievable potential have more than tripled even as evaluated electricity savings from energy efficiency programs have increased rapidly, more than quadrupling between 1998 and 2010 (while levelized costs of saved energy achieved have remained flat), and exceeding plan targets every year since 2005. A study of the NPCC results concludes: "our research shows that when programs invest in higher levels of efficiency, this helps drive measurement improvements and technical innovation, resulting in larger and more reliable

[230] NPCC's resource plans cover Idaho, Oregon, and Washington in their entirety, and western regions of Montana and Wyoming.
[231] Northwest Power & Conservation Council (NPCC). February 1, 2010. "Sixth Northwest Conservation and Electric Power Plan," Council Document 2010-09. Available at www.nwcouncil.org/energy/powerplan/6/plan/.

conservation supply estimates."[232] Table 5-11 summarizes the NPCC's achievable potential estimates and evaluated savings since 1998.[233]

TABLE 5-11

NPCC Achievable EE Potential and Achieved Incremental Savings (1998-2010)

	Year		
	1998	**2005**	**2010**
Achievable Potential over 20 Years (GWh)	13,447	24,651	51,684
Achieved Incremental Savings from EE Programs (GWh)	547	1,184	2,248

Additional substantiation of this approach is provided by average annual achievable rates from reviewed studies, as discussed previously, and comparison of those with the rates resulting from the best practices scenario. We address this in a later section, ***Results in Context***, after presenting those results.

Summary of Best Practices Scenarios Construction

Table 5-12 provides a summary of inputs for the best practices scenarios for Options 1 and 2. The pace of improvements, average measure life, and distribution of measure lives are each conservative and, therefore, contribute lower state goals than would otherwise result. Similarly, the best practices level of performance, being based solely on results from and requirements of EE programs, is less stringent than a level would be that accounted for potential impacts of other state EE policies such as building energy codes, building energy benchmarking requirements, and state appliance standards. The use of 2012 level of performance for the 2017

[232] Gordon, Fred, Lakin Garth, Tom Eckman, and Charles Grist, "Beyond Supply Curves," Proceedings of 2008 ACEEE Summer Study on Energy Efficiency in Buildings, August 17, 2008 available at: http://aceee.org/files/proceedings/2008/data/papers/8_419.pdf.
[233] Northwest Power & Conservation Council (NPCC). February 1, 2010. "Sixth Northwest Conservation and Electric Power Plan," Council Document 2010-09. Available at www.nwcouncil.org/energy/powerplan/6/plan/.

start year, allows states that increase their use of effective EE policies prior to submitting their implementation plan to benefit.

Table 5-12

Summary of EE Best Practices Scenario Inputs

Input	Option 1	Option 2
Current Level of Performance (incremental savings as % of retail sales)	Data from 2012 EIA 861 (2012)	Data from 2012 EIA 861 (2012)
Best Practices Level of Performance (incremental savings as % of retails sales)	1.5%	1.0%
Start Year	2017	2017
Start Year Level of Performance	Data from 2012 EIA 861 (2012)	Data from 2012 EIA 861 (2012)
Pace of Improvement (increase in incremental savings rate per year)	0.20% per year	0.15% per year
Average Measure Life and Distribution of Measure Lives	10 years; evenly distributed across 20 years	10 years; evenly distributed across 20 years
Continued Performance	Once achieved, best practices level sustained through 2030	Once achieved, best practices level sustained through 2025

Calculations

This section addresses the calculations for determining cumulative savings levels (cumulative savings as a percentage of baseline sales) for each state, for each year of the interim and final compliance periods for Options 1 and 2. The cumulative savings levels are derived based upon the key inputs summarized in Table 5-12. These levels represent the demand-side EE component of the state goals for each state. See the Goal Computation TSD for a detailed description of how the demand-side EE component is used as one of several inputs to the calculation of interim and final state emission rate goals.

Calculating the net cumulative savings as a percent of electricity sales for each state involves six steps. For each state, for each year (2017-2030 for Option 1 and 2017-2025 for Option 2) the following steps are taken:

1. Determine annual business as usual (BAU) sales
2. Determine annual incremental EE savings as a percentage of sales
3. Determine annual incremental EE savings (GWh) and sales after net EE (GWh)
4. Determine annual expiring EE savings (GWh)
5. Determine net cumulative EE savings (GWh)
6. Determine net cumulative EE savings as a percentage of BAU sales

To illustrate these calculations, each step is described and results provided for one state (using South Carolina as an example) for 2017 through 2025 for Option 1. We truncate the results at 2025 for simplicity, but full results are presented for all states in the section.

Step 1: Determine the Annual Business as Usual (BAU) Sales

BAU sales are derived by taking 2012 sales from EIA Form 861 data for the state and increasing them for each subsequent year by the average annual growth rate from the AEO 2013 Reference Case for the region corresponding to the state. For South Carolina the corresponding region is SERC and the average annual growth rate from 2012 to 2040 is 1.10% per year. The resulting values are summarized in Table 5-13 for South Carolina.

TABLE 5-13

BAU Sales for South Carolina

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
BAU Sales (GWh)	82,451	83,359	84,278	85,206	86,145	87,094	88,054	89,024	90,005

Step 2: Determine Annual Incremental EE Savings as a Percentage of Sales

As discussed, the 2017 value for annual incremental EE savings as a percentage of sales is set at the 2012 value based upon EIA-861 reported data. For South Carolina that value is 0.34%. This value is then increased by the pace of improvement of 0.2% per year (for Option 1) until the goal level of 1.50% (for Option 1) is reached and then held constant. The resulting values are summarized in Table 5-14 for South Carolina.

TABLE 5-14

Annual Incremental EE Savings as a Percentage of Sales for South Carolina

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Annual Incremental EE Savings (% sales)	0.34%	0.54%	0.74%	0.94%	1.14%	1.34%	1.50%	1.50%	1.50%

Step 3: Determine Annual Incremental EE Savings (GWh) and Sales after net EE

Annual incremental EE savings are calculated by multiplying the annual incremental savings as a percentage of sales times the prior year sales after net EE. Sales after net EE are calculated by subtracting net cumulative savings from BAU sales. The resulting values are summarized in Table 5-15 for South Carolina.

Step 4: Determine Annual Expiring EE Savings (GWh)

Expiring EE savings are calculated as the sum of all expired savings in a given year from all prior years' incremental (first-year) savings based upon an average measure life of 10 years and a linear decline in first-year savings over twenty years. As an example, Figure 2 illustrates the decline in first-year savings from EE measures installed in 2017. The resulting values for expiring EE savings are summarized in Table 5-16 for South Carolina.

TABLE 5-15

Annual Incremental EE Savings and Sales after Net EE Savings for South Carolina

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Annual Incremental EE Savings (GWh)	274	440	608	777	945	1,113	1,250	1,249	1,249
Sales after Net EE (GWh)	82,177	82,660	83,008	83,229	83,333	83,329	83,258	83,264	83,346

FIGURE 1

Generalized Distribution of First-Year Savings over Time.

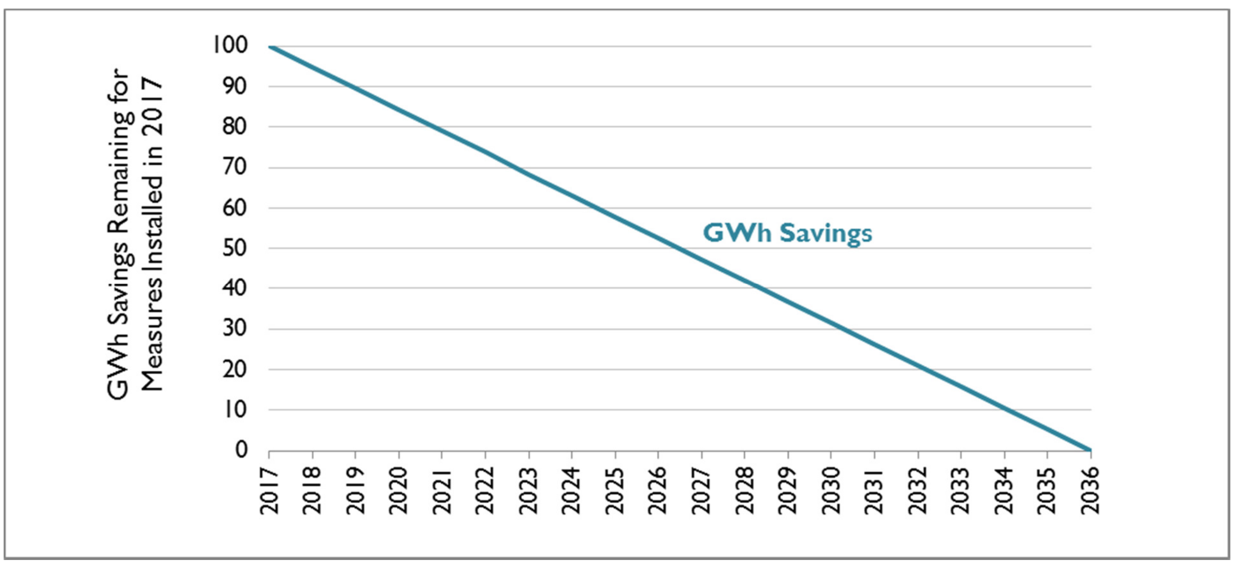

TABLE 5-16

Expiring EE Savings for South Carolina

	Year								
	2017	2018	2019	2020	2021	2022	2023	2024	2025
Expiring EE Savings (GWh)	0	14	38	70	110	160	219	285	350

Step 5: Determine the Net Cumulative EE Savings (GWh)

Net cumulative EE savings in a given year are equal to annual incremental savings for that year minus total expiring savings for that year plus net cumulative savings for the prior year. The resulting values are summarized for South Carolina in Table 5-17.

TABLE 5-17

Net Cumulative EE Savings for South Carolina

	Year								
	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Cumulative EE Savings (GWh)	274	700	1,270	1,977	2,812	3,765	4,796	5,760	6,659

Step 6: Determine the Net Cumulative EE Savings as a Percentage of BAU Sales

Net cumulative EE savings as a percentage of BAU sales are equal to net cumulative savings divided by BAU sales. The resulting values are summarized for South Carolina in Table 5-18.

TABLE 5-18

Net Cumulative EE Savings as a Percentage of BAU Sales for South Carolina

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Net Cumulative EE Savings as % of BAU Sales	0.33%	0.84%	1.51%	2.32%	3.26%	4.32%	5.45%	6.47%	7.40%

Summary of General Formulas and Results by Step for South Carolina

Tables 5-19 and 5-20 provide summaries of the generic formulas and results for South Carolina for each step.

TABLE 5-19

Summary of Calculation Formulas by Step

Step	Result	Formula
1	**BAU Sales (GWh)**	BAU Sales $_{year\ i}$ = BAU Sale $_{year\ i-1}$ * Annual Average Sales Growth Rate
2	**Annual Incremental EE Savings (% of Sales)**	Annual Incremental EE Savings $_{2017}$ = Annual Incremental EE Savings $_{2012}$; Annual Incremental EE Savings $_{year\ i}$ = Annual Incremental EE Savings $_{year\ i-1}$ + annual pace of improvement (until goal level is reached)
3	**Annual Incremental EE Savings (GWh)**	Annual Incremental Savings $_{year\ i}$ = Annual Incremental Savings as a Percent of Sales $_{year\ i}$ * Sales After Net EE $_{year\ i-1}$
3	**Sales after Net EE (GWh)**	Sales After Net EE $_{year\ i}$ = BAU Sales $_{year\ i}$ – Net Cumulative Savings $_{year\ i}$
4	**Expiring EE Savings (GWh)**	Expiring Savings $_{year\ i}$ = Σ Expiring measures from all prior program years (10-year average measure life with linearly decline over 20 years)

5	**Net Cumulative Savings (GWh)**	Net Cumulative Savings $_{\text{year i}}$ = Σ Annual Incremental Savings $_{\text{YTD}}$ – Expiring Savings $_{\text{year i}}$
6	**Net Cumulative Savings (% of Sales)**	Net Cumulative Savings $_{\text{year i}}$ = Net Cumulative Savings $_{\text{year i}}$ / BAU Sales $_{\text{year i}}$

TABLE 5-20

Summary of Results by Step for South Carolina.

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
BAU Sales (GWh)	82,451	83,359	84,278	85,206	86,145	87,094	88,054	89,024	90,005
Annual Incremental EE Savings (% sales)	0.34%	0.54%	0.74%	0.94%	1.14%	1.34%	1.50%	1.50%	1.50%
Annual Incremental EE Savings (GWh)	274	440	608	777	945	1,113	1,250	1,249	1,249
Sales after Net EE (GWh)	82,177	82,660	83,008	83,229	83,333	83,329	83,258	83,264	83,346
Expiring EE Savings (GWh)	0	14	38	70	110	160	219	285	350
Net Cumulative EE Savings (GWh)	274	700	1,270	1,977	2,812	3,765	4,796	5,760	6,659

Net Cumulative EE Savings as % of BAU Sales	0.33%	0.84%	1.51%	2.32%	3.26%	4.32%	5.45%	6.47%	7.40%

<u>Results</u>

Summary of Results

As discussed, the EE goals for each state are represented as cumulative savings as a percentage of retail sales by year for each option. Table 5-21 summarizes these values for the first and last year of the interim compliance period for Options 1 and 2. See Appendix 5-4 for comprehensive results by state, for each year, including both annual incremental and cumulative savings as a percentage of retail sales, for each options, as well as cumulative energy savings (MWh).

TABLE 5-21

Summary of State EE Goals for Options 1 and 2

State	EE State Goal Cumulative Savings as a % of Retail Sales			
	Option 1		Option 2	
	2020	2029	2020	2024
Alabama	1.36%	9.48%	1.07%	3.86%
Arizona	5.24%	11.42%	3.52%	5.98%
Arkansas	1.52%	9.71%	1.24%	4.10%
California	4.95%	11.56%	3.55%	6.08%
Colorado	3.92%	11.01%	3.32%	5.87%
Connecticut	4.71%	11.88%	3.61%	6.25%
Delaware	1.14%	9.47%	0.86%	3.59%

District of Columbia	1.14%	9.47%	0.86%	3.59%
Florida	2.03%	9.98%	1.75%	4.65%
Georgia	1.76%	9.83%	1.48%	4.36%
Idaho	3.80%	11.10%	3.28%	5.88%
Illinois	4.36%	11.63%	3.52%	6.15%
Indiana	3.20%	11.11%	2.89%	5.70%
Iowa	4.65%	11.66%	3.58%	6.17%
Kansas	1.22%	9.52%	0.94%	3.70%
Kentucky	1.91%	10.02%	1.63%	4.55%
Louisiana	1.14%	9.33%	0.85%	3.56%
Maine	5.37%	12.13%	3.61%	6.25%
Maryland	4.21%	11.51%	3.47%	6.10%
Massachusetts	4.43%	11.77%	3.55%	6.21%
Michigan	4.59%	11.77%	3.59%	6.22%
Minnesota	4.80%	11.72%	3.58%	6.17%
Mississippi	1.40%	9.59%	1.12%	3.93%
Missouri	1.58%	9.92%	1.29%	4.20%
Montana	3.36%	10.90%	3.01%	5.69%
Nebraska	2.20%	10.40%	1.91%	4.89%
Nevada	2.95%	10.69%	2.67%	5.45%
New Hampshire	2.84%	11.00%	2.56%	5.49%
New Jersey	1.25%	9.58%	0.96%	3.74%
New Mexico	3.10%	10.60%	2.81%	5.50%
New York	4.42%	11.76%	3.54%	6.20%
North Carolina	2.37%	10.26%	2.09%	4.98%
North Dakota	1.39%	9.71%	1.11%	3.95%
Ohio	4.17%	11.56%	3.47%	6.12%
Oklahoma	1.86%	9.97%	1.57%	4.49%
Oregon	4.66%	11.41%	3.55%	6.06%
Pennsylvania	4.67%	11.69%	3.58%	6.18%

Rhode Island	3.90%	11.56%	3.35%	6.06%
South Carolina	2.32%	10.23%	2.04%	4.94%
South Dakota	1.60%	9.91%	1.32%	4.22%
Tennessee	2.21%	10.26%	1.93%	4.86%
Texas	1.78%	9.91%	1.50%	4.40%
Utah	3.62%	11.03%	3.19%	5.82%
Vermont	5.37%	12.13%	3.61%	6.25%
Virginia	1.23%	9.33%	0.95%	3.67%
Washington	4.24%	11.26%	3.45%	6.00%
West Virginia	1.77%	10.11%	1.49%	4.44%
Wisconsin	4.68%	11.79%	3.60%	6.22%
Wyoming	1.61%	9.73%	1.33%	4.19%
Continental U.S.	3.05%	10.66%	2.44%	5.18%
Alaska	1.22%	9.45%	0.94%	3.69%
Hawaii	1.29%	9.52%	1.01%	3.79%
U.S. Total	3.04%	10.65%	2.43%	5.17%

Results in Context

To provide context for state cumulative savings results presented in Table 5-21 and Appendix 5-4, the average annual savings were calculated for each state through 2025 and 2030, starting from 2017. Table 5-22 summarizes the results.

TABLE 5-22

Summary of Average Annual Savings Rates of Best Practices Scenario

Option	**Years**	**Number of Years**	**Range of Cumulative Savings (% of Sales) across States in Last Year (2025/2030)**	**Range of Average Annual Savings Rates across States**	**National Average Annual Savings Rate**
1	2017-2030	13	9.9% to 12.5%	0.76%/year to 0.96%/year	0.86% per year

2	2017-2025	8	4.3% to 6.8%	0.54%/year to 0.85%/year	0.72% per year

The state range and national values for the average annual savings rate represented in the EE best practices scenario are below the range of values found in recent utility, state, and regional studies (1.2% to 1.5% per year) as summarized in Table 5-6, and within the range of values found in the 2014 national studies from EPRI and ACEEE (0.5%/0.6% to 1.6% per year) as summarized in Table 5-7. These results provide additional support for the feasibility of the EE best practices scenario and associated state-specific EE goals.

Impacts Assessment

<u>Approach</u>

In the Goal Computation TSD, state-specific EE goals from the previous section are integrated with the other building blocks and used to set state-specific emission rate goals for the interim and final compliance periods. These state emission rate goals are then represented as requirements within the power sector modeling for the RIA. In addition, the EE state goals, resulting from the EE best practices scenario, are used to adjust electricity demand levels used as exogenous inputs to power sector modeling for the illustrative compliance scenarios. In other words, the degree to which EE is employed as an abatement resource is not determined endogenously within the power sector modeling based upon optimization of costs but, rather, "hard wired" into the illustrative compliance scenarios. This approach is taken because the EPA has determined, as discussed previously, that EE is cost-effective at the established EE goal levels. The EE goal levels were constrained by practical considerations of state EE policy implementation, specifically, the current levels of EE performance and the pace at which states can feasibly improve their levels of performance over time.

The EE goals represented in the illustrative compliance scenarios lead to substantial reductions in power system costs due to the reductions in specified electricity demand. Since EE is not represented endogenously as an abatement measure within the power sector modeling, the costs associated with the EE best practice scenario must be estimated outside of the power sector modeling and integrated with the results from that modeling. These EE cost estimates, their basis, and calculations are addressed in the following sections.

Inputs

The following steps were taken to establish the inputs for development of the EE cost estimates for each state.

- Step 1: Determine state-specific electricity savings by year
- Step 2: Determine first-year program costs of saved energy
- Step 3: Determine the ratio of program to participant costs
- Step 4: Determine the escalation rate of EE costs

Step 1: Determine State-Specific Electricity Savings by Year

Results from the previous section, State Goal Setting, provide the starting point for estimation of EE costs. From those results, state-specific annual incremental savings (MWh) and yearly distribution of associated continuing savings (MWh) in future years are used as inputs to the cost estimation calculations.

Step 2: Determine First-Year Program Costs of Saved Energy

First-year program costs refer to the full costs (e.g., administration, incentive payments, marketing, information to consumers, etc.) incurred by a utility or other administrator of EE programs in a given year that lead to EE measures (technologies and practices) put in place in that year and resulting in reductions in electricity demand in that and future years (driven by the mix of measure lives across the portfolio of EE programs employed). Unlike participant costs, program costs are readily known by the administrator of EE programs and are, therefore, an appropriate starting point for EE program cost analysis. In 2009, ACEEE conducted a national review of data on EE program costs from program annual reports, evaluation reports, and information compiled from contacts at program administers in 14 states. Compiled data was sourced from multiple EE program administrators in each state and over multiple years of data for each administrator. ACEEE found average first-year net[234] costs of $275/MWh (2011$). The EPA has used this value for our analysis.

[234] "Net costs" refers to costs per electricity saved after accounting for effects of free-ridership on those savings. Depending upon the state, spillover effects may also be accounted for in net costs.

Two recent national analyses have found lower program costs than the 2009 ACEEE study. In 2014, ACEEE updated their analysis from 2009, expanding the number of states to 20, and including a greater number of program administrators and years. In this analysis ACEEE found average first-year net costs of $230/MWh (2011$). In 2014, an LBNL study presented results from a uniquely comprehensive study of EE program costs. The LBNL analysis reviewed program-level data from over 100 program administrators in 31 states. Data were collected from over 1,700 individual programs for up to three years (2009-2011), covering more than 4,000 individual program years of data points. Because of the broad scope of their study and the lack of net savings information for many programs, LBNL focused on gross[235], rather than net, savings values. LBNL found national average first-year cost of gross savings of $162/MWh (2012$). Applying an average net-to-gross ratio of 0.9 and deflating costs at 3%, results in an estimated national average first-year cost of net savings of $175 (2011$). The up-to-date, more comprehensive results from the ACEEE and LBNL studies, indicate that the value of $275/MWh used for this analysis is conservative, resulting in comparatively higher total costs than would be the case based upon the newer studies.

Step 3: Determine the Ratio of Program to Participant Costs

As noted above, while program costs are readily known and consistently reported by the program administrator, participant costs require significant effort to estimate, and are less consistently estimated and reported. The ratio between program and participant costs will vary significantly from one program to the next within a utility's portfolio. The EPA has used a generic approach to estimate the ratio of program to participant costs across an entire portfolio, thus providing for the estimation of total costs once program costs are determined. To derive the ratio, the EPA reviewed 2012 EE annual reports from program administrators in 22 states identified as leaders in EE programs[236] based upon their magnitude of savings or their savings as a percentage of retail sales. Complete information on full portfolio participant costs were available for nine of the 22 states. Across the nine states, the average program and participant costs as a percentage of total costs were 53% and 47%, respectively. See Appendix 5-3 for the

[235] "Gross savings" refers to electricity savings before any accounting for effects of free-ridership or spillover.
[236] Leaders were identified using results from the 2013 ACEEE State Energy Efficiency Scorecard based on energy savings as a percentage of retail sales or total savings.

data and analysis documenting this review. Based on this review, the EPA has taken a slightly conservative approach[237] and used a ratio of 1:1 between program and participant costs. We use this ratio to derive participant and total costs based upon program costs. Starting from program CSE of $275/MWh and applying the 1:1 ratio, we estimate participant CSE of $275/MWh and total CSE of $550/MWh (all values 2011$).

Step 4: Determine the escalation rate of EE costs

The level of EE program impacts represented in the state EE goals are substantial and represent a scenario that has not previously been achieved and sustained at a national level in the U.S. Thus, even though the EPA has taken a conservative approach (i.e., leading to higher estimates of costs) to the development of the EE state goals as well as to other factors that affect the EE cost estimates, we have also chosen to take a cautious approach to the escalation of EE costs at higher levels of performance (i.e., as states improve from their historic levels of incremental savings to the best practices level of 1.5% of retails sales). Economic theory suggests two mechanisms that would change EE costs as higher levels of performance are achieved. Economies of scale in the operation of larger EE programs and larger portfolios of EE programs, and learning and expertise gained over time from the continued implementation of programs, are two factors that would lower costs as programs scale up and expand to realize higher levels of performance. However, the limited supply of EE abatement measures and the need to employ higher cost measures, over time, to reach higher levels of performance, and to sustain high levels of performance, are factors that would increase costs as higher levels of performance are achieved. Analysis based upon limited empirical data does provide support for significant economies of scale and/or cost reductions over time as learning and expertise are gained.[238] "Supply curves" of EE as an energy resource, as well as EE as a measure represented within a GHG abatement curve, provide support for escalating costs as higher levels of savings

[237] If we had used the 53% and 47% values, starting from program costs, total costs would have been slightly lower than calculated with the 1:1 split used.

[238] Kenji Takahashi and David Nichols, Synapse Energy Economics, Inc. 2008. The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date. ACEEE Summer Study on Energy Efficiency in Buildings. http://www.aceee.org/files/proceedings/2008/data/papers/8_434.pdf.

are realized.[239] In a recent analysis, Lawrence Berkeley National Laboratory (LBNL) adopted an approach that generically represented both effects discussed above.[240] LBNL changed EE costs (first-year program costs) as a function of EE savings levels, decreasing costs at savings levels up to 0.5%, leaving costs constant at the base level at savings levels from 0.5% to 1.5%, and increasing costs at savings levels above 1.5%. Another recent analysis, by ACEEE, provides weak statistical support for a cost increase of 20% when going from 0.5% to 1.0% savings rate and an additional cost increase of 20% when going from 1.0% to 1.5% savings rate.[241]

In consideration of the above discussion, the EPA has chosen to escalate EE costs over three steps as a function of incremental savings (as a percentage of electricity sales) at the state level. Until a state reaches a 0.5% savings level, their costs are set at the base level; for savings levels between 0.5% and 1.0%, state costs are escalated to 120% of the base level; and for savings levels over 1.0%, state costs are escalated to 140% of the base level. This approach leads to higher costs relative to the one used by LBNL when applied to EPA's EE best practices scenario.

Summary of Inputs for EE Cost Analysis

Table 5-23 provides a summary of inputs for the EE cost analysis including first-year costs of saved energy, ratio of program to participant costs, and escalation of costs as a function of the rate of incremental savings. Each of these factors incorporates some level of conservatism, leading to higher costs than would otherwise result.

[239] For example: Northwest Power & Conservation Council (NPCC). February 1, 2010. "Sixth Northwest Conservation and Electric Power Plan," Council Document 2010-09. Available at www.nwcouncil.org/energy/powerplan/6/plan/; and McKinsey & Company. December 2007. Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost? Available at http://www.mckinsey.com/client_service/sustainability/latest_thinking/reducing_us_greenhouse_gas_emissions.
[240] Barbose, G. L., C.A. Goldman, I. M. Hoffman, M. A. Billingsley. 2013. The Future of Utility Customer-Funded Energy Efficiency Programs in the United States: Projected Spending and Savings to 2025. January 2013. LBNL-5803E. Available at http://emp.lbl.gov/publications/future-utility-customer-funded-energy-efficiency-programs-united-states-projected-spend.
[241] Molina, M. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE Report No. U1402. Available at http://www.aceee.org/research-report/u1402.

Table 5-23

Summary of EE Cost Analysis Inputs

Input	Source or Assumption	
State-Specific Electricity Savings by Year	Results from state goal setting	
First-Year Program Cost of Saved Energy	\$275/MWh (2011\$)	
Ratio of Program to Participant Costs	1:1	
First-Year Participant Cost of Saved Energy	\$275/MWh (2011\$)	
First-Year Total Cost of Saved Energy	\$550/MWh (2011\$)	
Escalation of Costs	Incremental savings rate	
	0.5% - 1.0%	> 1.0%
	120% of base costs: \$660/MWh (2011\$)	140% of base costs: \$770/MWh (2011\$)

<u>**Calculations**</u>

This section addresses the calculations for estimating the costs associated with the state-specific EE goals discussed above. The results of these calculations are then used within the RIA and preamble. Specifically, three values are calculated (annual first-year costs, levelized cost of saved energy (LCSE), and annualized costs); for each, program and participant components are then calculated using the 1:1 ratio (i.e., 50% of total for each) derived above. Specific results from prior sections on state goal setting and impacts assessment inputs are used as inputs for these calculations. For each state, the following steps are taken for each year (2017-2030) and for each option. Calculations for steps 2 and 3 are done using real discount rates of 3% and 7%.

The steps are:

1. Calculate annual first-year costs
2. Calculate levelized cost of saved energy (LCSE)
3. Calculate annualized costs

To illustrate these calculations, each step is described and results are provided for one state (using South Carolina as an example) for 2017 through 2025 for Option 1. The results are truncated at 2025 for simplicity, but full national results (through 2030) are presented below.

Step 1: Calculate Annual First-Year Costs

Annual total first-year costs are calculated by multiplying annual total incremental savings (MWh) (from Table 5-15) by the first-year total CSE (from Table 5-23 with escalation based upon results from Table 5-14). Program and participant portions of the first-year costs are then calculated as 50% of total first-year costs for each per Table 5-23.

The resulting values are summarized for South Carolina in Table 5-24.

TABLE 5-24

Calculation of Annual First-Year Costs for South Carolina

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Annual Incremental Savings (GWh)	274	440	608	777	945	1,113	1,250	1,249	1,249
First-Year Total Cost of Saved Energy (2011$/MWh)	$550	$660	$660	$660	$770	$770	$770	$770	$770
First-Year Total Cost (millions 2011$)	151.6	290.5	401.4	512.6	727.8	857.1	962.5	961.6	961.7
First-Year Program (millions of 2011$)	75.3	145.3	200.7	256.3	363.9	428.5	481.2	480.8	480.9
First-Year Participant (millions of 2011$)	75.3	145.3	200.7	256.3	363.9	428.5	481.2	480.8	480.9

Step 2: Calculate Levelized Cost of Saved Energy

Levelized costs of saved energy (LCSE) are based on levelization of all savings (first and future years) resulting from EE activities in a given year. The levelization algorithm is based on the 2002 California Standard Practice Manual.[242] The net present value of all savings from a single year's EE activities (i.e., over the entire distribution of program lifetimes) is calculated using the real discount rate. The levelized cost of saved energy is then calculated by dividing the annual first-year costs (from Table 5-24) by the levelized savings. The resulting values are summarized for South Carolina in Table 5-25.

TABLE 5-25

Levelized Cost of Saved Energy for South Carolina (at 3% discount rate)

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Levelized Savings (GWh)	2,313	3,720	5,139	6,563	7,987	9,405	10,562	10,553	10,554
First-Year Total Cost (millions 2011$)	151.6	290.5	401.4	512.6	727.8	857.1	962.5	961.6	961.7
Total LCSE (cents/kWh)	6.51	7.81	7.81	7.81	9.11	9.11	9.11	9.11	9.11
Program LCSE (cents/kWh)	3.25	3.91	3.91	3.91	4.56	4.56	4.56	4.56	4.56

[242] State of California Governor's Office of Planning and Research. July 2002. California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects. Available at http://www.calmac.org/events/SPM_9_20_02.pdf.

Participant LCSE (cents/kWh)	3.25	3.91	3.91	3.91	4.56	4.56	4.56	4.56	4.56

Step 3: Calculate Annualized Costs

The costs of the EE program can also be represented as annualized costs in a given year. Annualized costs are calculated by multiplying the LCSE for each year by the estimated savings in each year through the full distribution of measure lifetimes. For each year in the analysis, the annualized costs resulting from all current and past investments are summed to calculate the total annualized costs in that year. The resulting values are summarized for South Carolina in Table 5-26.

TABLE 5-26

Annualized Costs for South Carolina

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Annualized Total Costs (millions 2011$)	17.8	51.3	96.0	151.4	229.1	317.6	413.2	502.7	586.2
Annualized Program Costs (millions 2011$)	8.9	25.6	48.0	75.7	114.6	158.8	206.6	251.3	293.1
Annualized Participant Costs (millions of 2011$)	8.9	25.6	48.0	75.7	114.6	158.8	206.6	251.3	293.1

Summary of General Formulas and Results by Step for South Carolina

Tables 5-27 and 5-28 provide summaries of the generic formulas and results for South Carolina for each step.

TABLE 5-27

Summary of Calculation Formulas by Step

Step	Result	Formula
1	**Annual First-Year Costs (2011$)**	Annual First-Year Costs $_{\text{year } i}$ = Annual Incremental Savings $_{\text{year } i}$ x First-Year CSE $_{\text{year } i}$ First-Year CSE $_{\text{year } i}$ = f(incremental savings rate) per Table 5-23
2	**Levelized Savings (GWh)**	Levelized Savings $_{year\ i} = \sum_{i=0}^{T} \frac{Annual\ Incremental\ Savings_{\ year\ i}}{(1+r)^i}$, where T = measure life, r = discount rate.
2	**LCSE (2011$/MWh)**	Levelized Cost of Saved Energy $_{\text{year } i}$ = Annual First-Year Cost $_{\text{year } i}$ / Levelized Savings $_{\text{year } i}$
3	**Annualized Costs (2011$)**	Annualized Cost of Saved Energy $_{year\ i} = \sum_{t=0}^{T}(LCSE_{year\ i-t} \times$ $annual\ incremental\ savings\ in\ year\ i_{\ year\ i-t})$, where $LCSE_{\ year\ i\text{-}t}$ is the LCSE of EE programs implemented in year i-t, $annual\ incremental\ savings\ in\ year\ i_{\ year\ i-t}$ represents estimated incremental savings in year i from EE programs implemented in year i-t.

TABLE 5-28

Summary of Results by Step for South Carolina.

	Year								
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Total First-Year Costs (millions 2011$)	151.6	290.5	401.4	512.6	727.8	857.1	962.5	961.6	961.7
Total LCSE (2011$/MWh)	65.1	78.1	78.1	78.1	91.1	91.1	91.1	91.1	91.1
Annualized Total Costs (millions 2011$)	17.8	51.3	96.0	151.4	229.1	317.6	413.2	502.7	586.2

Results

Summary of National Results

Tables 5-29 and 5-31 summarize the national first-year and annualized EE costs for Option 1 for 2018, 2020, 2025, and 2030. Table 5-30 summarizes national LCSE for Option 1 for the same years. Each of the three tables includes values for program, participant, and total costs.

TABLE 5-29

First-Year EE Costs (billions 2011$)

(Continental U.S.)

	Year			
	2018	**2020**	**2025**	**2030**
Program	10.2	15.4	21.8	21.8
Participant	10.2	15.4	21.8	21.8
Total	20.5	30.7	43.6	43.5

TABLE 5-30

Levelized Cost of Saved Energy (3% discount rate, 2011$/MWh)

(Continental U.S.)

	Year			
	2018	**2020**	**2025**	**2030**
Program	42	43	45	45
Participant	42	43	45	45
Total	83	85	89	90

TABLE 5-31
Annualized EE Costs (3% discount rate, billions 2011$)

(Continental U.S.)

	Year			
	2018	**2020**	**2025**	**2030**
Program	2.0	5.1	14.4	21.4
Participant	2.0	5.1	14.4	21.4
Total	4.1	10.2	28.9	42.7

See Appendix 5-4 for comprehensive data sheets of EE cost results at the national level by year for Options 1 and 2, and at discount rates of 3% and 7%. These data sheets provide results of LCSE (total, program and participant), first-year costs (total, program and participant), and annualized costs (total, program and participant).

Results in Context

To provide context for the pace of increase in EE program spending levels represented by Option 1, we consider the compound annual growth rate (CAGR) of the recent rapid increase in historic investment (2006 to 2011) and the CAGR from 2011 through 2018, 2020, and 2025 represented by Option 1 program costs. Historic data is from Table 5-2 and Option 1 data is from Table 5-29. Table 5-32 provides a summary of the results. The CAGRs represented by Option 1 through 2018, 2020, and 2025 vary from 8% to 11%. The historic growth rate reflecting the rapid recent growth in EE program spending is 30%, roughly three times the Option 1 values.

TABLE 5-32

Historic and Projected (Option 1) Annual Growth Rates of EE Program Spending

Time Period (Years)	Compound Average Growth Rate
Historic (2006-2011)	29.8%
Option 1 (2011-2018)	8.1%
Option 1 (2011-2020)	11.3%
Option 1 (2011-2025)	9.8%

Costs per Tonne CO_2 Reduced

To estimate the reductions in power system costs and CO_2 emissions associated with this building block, EPA analyzed a scenario incorporating the resulting reduction in electricity demand (the “energy efficiency scenario”) and compared the results with the base case scenario. Both analyses were conducted using the Integrated Planning Model (IPM) described in earlier chapters. Combining the resulting power system cost reductions with the energy efficiency cost estimates associated with the energy efficiency scenario, EPA derived net cost impacts for 2020, 2025, and 2030. Dividing these net cost impacts by the associated CO_2 reductions for each year, EPA found that the average cost of the CO_2 reductions achieved ranged from $16 to $24 per metric tonne of CO_2. Although EPA considers this estimated range of average $/tonne to be reasonable, we expect the $/tonne would be lower in combination with the other building blocks because, in that context, power system costs would be somewhat higher and, thus, avoided power system costs due to this building block would be higher as well, leading to lower $/tonne CO_2 avoided.

Analysis Considerations

Two considerations are worth noting in regards to the analysis described in the previous two sections, “Goal Setting” and “Impacts Assessment:” 1) state energy efficiency policies implicitly represented in the baseline electricity demand and 2) Form EIA-861 as a data source.

State Energy Efficiency Policies in the Baseline Electricity Demand

The baseline electricity demand forecast used for the state goal setting approach represented in this chapter, as well as for the power sector modeling discussed in the RIA, is based upon the AEO 2013 reference case scenario. AEO 2013 does not explicitly represent existing utility energy efficiency programs or future requirements (e.g., EERS) to achieve savings goals through such programs. For example, existing state EERS are not evaluated and represented in the AEO 2013 reference case. However, to some degree, AEO 2013 does implicitly reflect a continuation of the effects of existing state energy efficiency programs in the electricity demand projections represented in the reference case. This implicit representation is captured in part through a calibration process that is affected by several historic factors including reported electricity sales and sectoral energy consumption surveys.

As noted, EPA's state goal setting approach for demand-side energy efficiency is built upon the AEO 2013 forecast of electricity demand. However, because the goal setting approach uses percentage incremental savings by year to derive percentage cumulative savings by year (for each state), the resulting state goals (expressed in percentage cumulative savings by year, by state) are not affected by the underlying electricity demand forecast. The impacts assessment of the demand-side energy efficiency building block is affected, to some degree, by the implicit representation of a continuation of existing energy efficiency programs because the assessment is built partly from absolute energy savings values that are partly derived from the business-as-usual (BAU) demand forecast. If the BAU forecast did not implicitly represent a continuation of existing energy efficiency programs, the forecast would indicate higher electricity demand, at least in the near term. However, the direction (higher or lower) of the net cost impacts (energy efficiency program costs as well as power system cost reductions) is not clear as it is possible that program costs could increase while avoided power system costs also increase.

Energy Information Administration Form EIA-861 as Data Source

Comprehensive data on energy efficiency programs' spending and energy savings are limited for evaluating and comparing energy efficiency programs and their effectiveness at the utility, state, and national scale. Issues related to the lack of standardized definitions and reporting, and data quality are noted to limit evaluation of energy efficiency programs.[243] The EIA Form 861, "Annual Electric Power Industry Report," remains the most comprehensive effort that collects data annually on utility demand-side management (DSM) programs, including their spending and energy savings impacts, nationally.[244] The form is requested for electric utilities, electric power producers, energy service providers, wholesale power marketers, and all DSM program managers and entities responsible to estimate the DSM activity for the reporting year using their best available data, including costs and incremental and cumulative energy savings from energy efficiency programs and load management programs.

This analysis uses only two EIA-861 data variables. Specifically, we use the 2012 sales data and reported incremental annual energy savings of energy efficiency programs to estimate the current performance of energy efficiency programs to inform setting best practices performance level for the state EE goal setting.

EPA notes potential concerns associated with consistency and quality of reported DSM program data in Form EIA-861. Specifically, the data are self-reported by utilities and DSM program administrators. The definition and data categories may not be consistently applied across utility, state, and data year. Over time, however, the data quality has improved significantly and there is increased standardization in data reporting and more detailed data categories are being reported. For instance, in 2011, EIA began collecting data from third-party administrators of programs. While now comprehensive, outside entities have found that the EIA-861 data can be improved through supplementation with publicly available annual energy efficiency program reports.[245]

[243] MJ Bradley & Associates, LLC. 2011. Benchmarking Electric Utility Energy Efficiency Portfolios in the U.S.
[244] More information on EIA Form 861 can be found at http://www.eia.gov/electricity/data/eia861/
[245] See, for example, American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.

Appendices

Appendix 5-1: Summary of Recent (2010-2014) Electric Energy Efficiency Potential Studies

Appendix 5-2: Incremental Electricity Savings Pace of Improvement Analysis

Appendix 5-3: Review of the Ratio of Program to Participant Costs

Appendix 5-4: Comprehensive Results: State Goal Setting and Impacts Assessment

Appendix 5-1

Summary of Recent (2010-2014) Electric Energy Efficiency Potential Studies

The following table summarizes estimates of economic and achievable energy efficiency potential from a number of recent studies (2010-2014) for states, utilities, and other agencies across the U.S. Study periods ranged from five to twenty-one years in length. As Table 1 shows, across the eleven studies that reported achievable potential, results for average annual achievable potential range from 0.8% per year to 2.9% per year (of baseline sales) with an average of 1.5% per year.

TABLE 1

Summary of Recent (2010-2014) Electric Energy Efficiency Potential Studies

State	Client	Analyst	Study Year	Study Period	End-year Projected Potential as % of Baseline Sales		Average Annual Projected Potential as % of Baseline Sales	
					Economic	Achievable	Economic	Achievable
Arizona	Salt River Project	Cadmus Group	2010	2012-2020	29%	20%	3.2%	2.2%
California	California Energy Commission	California Energy Commission	2013	2014-2024	Not reported	9.6%	N/A	0.9%
Colorado	Xcel Energy	Kema, Inc.	2010	2010-2020	20%	15%	1.8%	1.4%
Delaware	Delaware DNR/DEC	Optimal Energy, Inc.	2013	2014-2025	26.3%	Not reported	2.2%	N/A
Illinois	ComEd	ICF International	2013	2013-2018	32%	10%	5.3%	1.7%

Michigan	Michigan PSC	GDS Associates	2013	2013-2023	33.8%	15%	3.1%	1.4%
New Jersey	Rutgers University	EnerNOC Utility Solutions	2012	2010-2016	12.8%	5.90%	1.8%	0.8%
New Mexico	State of New Mexico	Global Energy Partners	2011	2012-2025	14.7%	11.1%	1.1%	0.8%
New York	ConEd	Global Energy Partners	2010	2010-2018	26%	15%	2.9%	1.7%
Pacific Northwest (Idaho, Montana, Oregon, Washington)	US Department of Energy	Lawrence Berkeley National Laboratory	2014	2011-2021	11%	Not reported	1.9%	Not reported
Pennsylvania	Pennsylvania PUC	GDS Associates and Nexant	2012	2013-2018	27.2%	17.3%	4.5%	2.9%
Tennessee	Tennessee Valley Authority	Global Energy Partners	2011	2009-2030	24.8%	19.8%	1.1%	0.9%
			Range					**0.8% - 2.9% per year**
			Average					**1.5% Per year**

References

Arizona: The Cadmus Group, Inc. 2010. Salt River Project 2012-2017 Energy Efficiency Plan – Final Report. Prepared for Salt River Project, April 16.

Colorado: Kema, Inc. 2010. Colorado DSM Market Potential Assessment – Final Report. Prepared for Xcel Energy, March 12.

Delaware: Optimal Energy, Inc. 2013. Delaware Economic Energy Efficiency Potential. Prepared for the Delaware Department of Natural Resources and Environmental Control, May 24.

Illinois: ICF International. 2013. ComEd Energy Efficiency Potential Study Report, 2013-2018. August 20.

Michigan: GDS Associates, Inc. 2013. Michigan Electric and Natural Gas Energy Efficiency Potential Study – Final Report. Prepared for the Michigan Public Service Commission, November 1.

New Jersey: EnerNOC Utility Solutions Consulting. 2012. New Jersey Energy Efficiency Market Potential Assessment, Volume 1: Executive Summary. Report Number 1401, Prepared for Rutgers, The State University of New Jersey, October 17, 2012.

New Mexico: Global Energy Partners. 2011. Energy Efficiency Potential Study for the State of New Mexico, Volume 2: Electric Energy Efficiency Analysis. June 30.

New York: Global Energy Partners, LLC. 2010. Energy Efficiency Potential Study for Consolidated Edison Company of New York, Inc., Volume 2: Electric Potential Report. March.

Pacific Northwest states (combined): Barbose, Galen, and Alan Sanstad, Charles Goldman, Stuart McMenamin, Andy Sukenik. 2014. Incorporating Energy Efficiency into Western Interconnection Transmission Planning. Draft report, Lawrence Berkeley National Laboratory, January.

Pennsylvania: GDS Associates, Inc., and Nexant. 2012. Electric Energy Efficiency Potential for Pennsylvania – Final Report. Prepared for the Pennsylvania Public Utilities Commission, May 10.

Tennessee: Global Energy Partners. 2011. Tennessee Valley Authority Potential Study, Final Report, Volume 1: Executive Summary. Report Number 1360, December 21.

Appendix 5-2

Incremental Electricity Savings Pace of Improvement Analysis

This appendix summarizes and analyzes data to characterize the pace of improvement of incremental (or first-year) savings as a percentage of retail sales for electricity energy efficiency (EE) programs. We considered two different perspectives: 1) historical data reflecting achieved savings of EE programs and 2) requirements of existing state energy efficiency resource standards (EERS). For the historical perspective, we reviewed data from the Energy Information Administration's Form EIA-861 on EE program electricity savings (supplemented as needed with program administrator reports) and identified the pace at which entities reaching higher savings levels have historically increased energy savings over time.[246] Specifically, we reviewed the historical savings data in the following two groups of energy efficiency program administrators.

1. Top saver 1% - a group with 47 entities that achieved a maximum first-year savings level of 0.8% to 1.5%.
2. Top saver 2% - a group with 26 entities that achieved a maximum first-year savings level of 1.5% to 3.0%.[247]

For the existing state requirements perspective, we reviewed energy savings ramp-up schedules established under EERS for states that provide clear ramp-up schedules. According to ACEEE's 2013 State Energy Efficiency Scorecard[248], there are a total of 26 states that have

[246] The EIA 861 was the main data source. However, we have supplemented the EIA 861 with third-party program administrator data because the EIA 861 just started to collect third-party administrator data in 2011. The third-party entities included in our analysis are Efficiency Vermont, Energy Trust of Oregon, Efficiency Maine Trust, and Cape Light Compact. In addition, we supplemented the EIA 861 database with additional data for two utilities that we found achieved high energy savings, but did not report savings data in the EIA 861 data for one or two years. These entities are Burlington Electric and Massachusetts Electric Company (now part of National Grid).

[247] In addition to these maximum first-year savings thresholds, we screened program administrators for the following conditions: (a) the maximum savings levels occurs after the minimum savings levels; (b) sufficient amounts of increase in first-year savings are provided to evaluate reasonable ramp-up schedules to gain an incremental 1% first-year savings; and (c) savings data series are continuous between the years for the minimum and maximum savings levels.

[248] American Council for an Energy-Efficient Economy (ACEEE). November 2013. The 2013 State Energy Efficiency Scorecard. Available at http://www.aceee.org/state-policy/scorecard.

mandatory EERS policies.[249] Our analysis contains 10 states for which clear ramp-up schedules were identifiable.

Our research findings on historical savings performance are:

- The "Top Saver 1%" group (savings between 0.8% and 1.5%) exhibits a trend that these entities took or would take about 3.4 years on average to increase first-year savings by 1% (with a range of 1.6 years to 10 years) (see Table 1). The entities in this group have increased the level of first-year savings by 0.30% per year on average from their minimum to their maximum first-year savings levels (with a range of 0.10% per year to 0.63% per year).[250]
- The "Top Saver 2%" group (savings between 1.5% and 3%) exhibits a trend that took or would take about 2.6 years on average to increase savings by 1% (with a range of 0.8 years to 7.3 years) (see Table 1). The entities in this group have increased the level of first-year savings by 0.38% per year on average from the minimum to the maximum first-year savings levels (with a range of 0.14% per year to 1.28% per year).[251]

Table 1. Energy savings ramp-up trends in first-year savings for "Top Saver 1%" and "Top Saver 2%" groups[252]

	Top Saver 1%		Top Saver 2%	
	Average Annual First-Year Savings Increase	Estimated Years to Gain Incremental 1%	Average Annual First-Year Savings Increase	Estimated Years to Gain Incremental 1%
Average	**0.30%**	**3.4**	**0.38%**	**2.6**

249 ACEEE, 2013 State Energy Efficiency Scorecard, Appendix B, November 2013,
250 This is a simple average estimate of the annual average increase in first-year savings from each entity in this group.
251 This is the simple average estimate of the annual average increase in first-year savings from each entity in this group.
252 Data sources: The EIA 861 was the main data source. However, we have supplemented the EIA 861 with third-party program administrator data because the EIA 861 just started to collect third-party administrator data in 2011. The third-party entities included in our analysis are Efficiency Vermont, Energy Trust of Oregon, Efficiency Maine Trust, and Cape Light Compact. In addition, we supplemented the EIA 861 database with additional data for two utilities that we found achieved high energy savings, but did not report savings data in the EIA 861 data for one or two years. These entities are Burlington Electric and Massachusetts Electric Company (now part of National Grid).

Median	**0.29%**	**3.4**	**0.34%**	**3.0**
Max	0.63%	1.6	1.28%	0.8
Min	0.10%	10	0.14%	7.3
# of sample entities	47		26	

Our research findings on incremental electricity savings ramp-up based on existing state EERS policies are:

- The states with EERS policies which exhibit savings ramp-up schedules are requiring increases in first-year energy savings at a pace that ranges from 0.11% (Colorado and Oregon) to 0.40% (Rhode Island) as shown in Table 2.
- The first-year savings pace of increase averages 0.21% per year across the 10 states. This savings level translates to about 4.7 years to achieve an incremental 1% first-year savings increase.

Table 2. First-Year Energy Savings Ramp-up Review of State EERS Policies[253]

State	Minimum Target		Maximum Target		Climb Time (years)	Annual Average % Increase	Years to Achieve 1% Increase
	Min	**Year**	**Max**	**Year**			
	a	b	c	d	e=d-b	f=(c-a)/e	g=1/f
Arizona	1.25%	2011	2.5%	2016	5	0.25%	4.0
Arkansas	0.25%	2011	0.9%	2015	4	0.16%	6.2
Colorado	0.80%	2011	1.7%	2019	8	0.11%	9.3
Illinois	0.20%	2008	2.0%	2015	7	0.26%	3.9
Indiana	0.30%	2010	2.0%	2019	9	0.19%	5.3
Massachusetts	1.4%	2010	2.6%	2015	5	0.24%	4.2
Michigan	0.3%	2009	1.0%	2012	3	0.23%	4.3
Ohio	0.3%	2009	1.2%	2019	10	0.17%	5.9
Oregon	0.8%	2010	1.0%	2013	3	0.07%	15.0
Rhode Island	1.7%	2011	2.5%	2013	2	0.40%	2.5

253 Data sources: ACEEE, 2013 State Energy Efficiency Scorecard, Appendix B, November 2013, Arkansas Public Service Commission, Docket Nos. 13-002-U. Order No. 7, September 9, 2013.

Average						**0.21%**	4.8

Appendix 5-3

Review of the Ratio of Program to Participant Costs

Introduction and Summary

This appendix summarizes and analyzes data on EE costs (program and participant) to develop a ratio to enable the estimation of participant costs from known program costs. We reviewed cost data from leading EE program administrators in 22 states. Our research findings are as follows:

- A 1:1 ratio between program and participant costs is a reasonable and slightly conservative (i.e., slightly higher total costs) basis for estimating participant costs from known program costs.
- Reported data was reviewed from 22 states; however, program administrator reports from only nine states contained sufficient information (participant costs across entire portfolio of EE programs) to inform the analysis.
- Participant cost data from ten program administrators in nine states indicate that the weighted average and simple average participant costs were 47 percent of total costs.

Participant Cost Analysis

We first identified states having high incremental electricity savings rates or high absolute savings levels based upon 2013 ACEEE State Energy Efficiency Scorecard.[254] These states represent a large portion of total EE savings in the U.S. We identified 22 states meeting these criteria and collected publicly available EE program reports for major program administrators within each state. From these program reports we identified 10 program administrators across nine states where we were able to identify both program administrator and participant costs across their full portfolio of EE programs. The table below provides the 2012 portfolio-level program administrator and participant costs for the nine states. Program

[254] For the purpose of this research, we have defined leading or high impact states as the top 15 states in the 2013 ACEEE State Energy Efficiency Scorecard in terms of incremental savings as a percentage of retail sales or absolute annual energy savings in terms of total annual MWh savings. These criteria resulted in a total of 22 states which include Arizona, California, Connecticut, Florida, Hawaii, Illinois, Indiana, Iowa, Maine, Massachusetts, Michigan, Minnesota, New Jersey, New York, North Carolina, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, Vermont, and Washington.

administrator costs represent the program administrator's program development and implementation costs, and the participant costs represent the customer costs to partake in the program. Total program costs are the sum of both costs. Each state's program administrator and participant costs are presented as a percentage of total program costs in Table 3. The weighted and simple average program and participant costs across all nine states are presented as a percentage of total program costs. The weighted average cost shares were based on each program's spending by administrator and participants.

Table 1
2012 Participant and Program Cost Information from Reported Entities

2012 Portfolio Costs						
State	**Program Administrator**	**Program Costs (Million $s)**	**Participant Costs (Million $s)**	**Total Costs (Million $s)**	**Program Costs as Percent of Total Cost (%)**	**Participant Costs as Percent of Total Cost (%)**
		A	**b**	**c = a + b**	**a / c**	**b / c**
California	Southern California Edison	$ 316	$ 269	$ 585	54.0%	46.0%
Hawaii	Hawaii Energy	$ 31	$ 37	$ 68	45.6%	54.4%
Iowa	MidAmerican Energy Company	$ 50	$ 70	$ 120	41.5%	58.5%
Maine	Efficiency Maine Trust	$ 24	$ 36	$ 60	39.8%	60.2%
Massachusetts	National Grid	$ 173	$ 54	$ 227	76.3%	23.7%
Minnesota	Xcel Energy	$ 53	$ 98	$ 151	35.1%	64.9%
Pennsylvania	PECO	$ 68	$ 109	$ 178	38.5%	61.5%
Rhode Island	National Grid	$ 63	$ 13	$ 75	83.2%	16.8%
Vermont	Efficiency Vermont; Burlington Electric Department	$ 34	$ 23	$ 57	59.3%	40.7%
		Weighted Average			**53.4%**	**46.6%**
		Simple Average			**52.6%**	**47.4%**

In our analysis, the weighted average program and participant costs are 53.4% and 46.6%, respectively, of total costs. On a simple average basis, program and participant costs are

52.6% and 47.4%, respectively, of total costs. Participant cost results range from a low of 17% of total costs (National Grid in Rhode Island) to a high of 65% (Xcel Energy in Minnesota). When deriving participant costs from program costs, using a ratio of 1:1 is consistent with these results and slightly conservative, leading to slightly higher total costs than the precise average values would provide.

References

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Appendix 5-4

Comprehensive Results: State Goal Setting and Impacts Assessment

See attached file, "Abatement Measures TSD Appendix 5-5.xlsx," containing the following:

Goal Setting Sheets

- Option 1 – Incremental Savings as % of Sales by State (2017-2030)
- Option 1 – Cumulative Savings as % of Sales by State (2017-2030)
- Option 1 – Cumulative Savings (GWh) by State (2017-2030)
- Option 2 – Incremental Savings as % of Sales by State (2017-2025)
- Option 2 – Cumulative Savings as % of Sales by State (2017-2025)
- Option 2 – Cumulative Savings (GWh) by State (2017-2025)

Impacts Assessment Sheets

- Option 1 – National Costs at 3% Discount Rate (2017-2030)
    - Levelized Cost of Saved Energy, First-year Costs, and Annualized Costs
- Option 1 – National Costs at 7% Discount Rate (2017-2030)
    - Levelized Cost of Saved Energy, First-year Costs, and Annualized Costs
- Option 2 – National Costs at 3% Discount Rate (2017-2025)
    - Levelized Cost of Saved Energy, First-year Costs, and Annualized Costs
- Option 2 – National Costs at 7% Discount Rate (2017-2025)
    - Levelized Cost of Saved Energy, First-year Costs, and Annualized Costs

Chapter 6: Fuel Switching

Coal-to-Natural Gas Switching

Introduction

Firing natural gas in a boiler designed for coal-fired generation is one approach to reducing the output-based CO_2 emissions rate (lbs/MWh) in these boilers. The CO_2 emission rate is reduced when natural gas is substituted for coal because the gas has a much higher percentage of hydrogen and a lower percentage of carbon than the coal it replaces. When quantities of gas and coal are burned with oxygen from air to produce the same amounts of heat, the higher hydrogen content of natural gas produces more water vapor (H_2O) than coal, but far less CO_2.

The discussion below focuses solely on the conversion of an existing coal-fired boiler to burn natural gas instead of, or along with, coal. There are other technical options for gas substitution in an existing coal-steam EGU that are not examined in any detail here. They include:

- Repowering an existing coal EGU by providing heat input to the boiler from the exhaust of a newly installed gas turbine generator; and,
- Gasification of coal, producing substitute natural gas (SNG) that provides heat input to the existing coal-fired boiler.

These other options have higher capital cost and thus would not be as economic as the direct substitution of natural gas in an existing coal boiler, for reasons that will become apparent in this analysis.

This chapter evaluates the cost-effectiveness of widespread adoption of coal-to-gas switching at a national level for the purpose of setting CO_2 emissions goals consistently in each state.

Description of Technology

Engineering Considerations

Most existing coal-fired EGU boilers can be modified to switch to 100% gas input, or to co-fire gas with coal in any desired proportion. This transition typically requires at least some plant modifications and might have some negative impact on the efficiency of the unit as described later in this chapter.

A conversion from coal to gas firing first requires either an existing natural gas delivery system to the boiler or the installation of a new gas pipeline to serve the boiler. While it is sometimes assumed that a need to install a new gas pipeline would render the conversion uneconomic, this analysis will show that the cost of a new gas pipeline is not likely to be the determining factor for the project's economic merit, given the significance of the change to the cost of fuel for generation from the converted boiler.

Conversion to natural gas firing in a coal-fired boiler typically involves installation of new gas burners and supply piping, modifications to combustion air ducts and control dampers, and possibly modifications to the boiler's steam superheater, reheater, and economizer heating surfaces that transfer heat from the hot flue gas exiting the boiler furnace. The conversion may also involve some modification and possible deactivation of some downstream air pollution emission control equipment. Engineering studies are performed to assess changes in furnace heat absorption and exit gas temperature; material changes affecting heat transfer surfaces; the need for sizing of flue gas recirculation fans; and operational changes to sootblowers, spray flows, air heaters, and emission controls.

Whether co-firing with coal or switching completely to natural gas, boilers will become less efficient due to the high hydrogen content of natural gas. When combusted, the additional hydrogen yields increased moisture content (water vapor) in the flue gas. The increased moisture content, in turn, results in additional heat lost up the stack instead of being directed towards electricity generation. Additionally, depending on the design of the boiler and extent of modifications, some boilers may incur some derate (reduction in generating capacity) in order to maintain steam temperatures at or within design limits, or for other technical reasons.
Even with a decrease in boiler efficiency, the overall net output efficiency of a coal-steam boiler EGU that switches from coal to natural gas firing may change only slightly, depending on how much auxiliary load is converted to net output by avoiding the need to run coal pulverizers, conveyors, ash sluice pumps, and relevant air pollution control equipment (e.g., PM and SO_2 controls).

Fuel Considerations

Delivery of natural gas via pipeline is critical for conversion of a coal-fired boiler to a gas-fired boiler. Some coal boilers are connected to the natural gas pipeline network for purposes of using gas as a startup fuel, or are located at facilities with onsite gas-fired generators. These boilers are likely able to co-fire to some degree with gas (at least 10% total output[255]) without constructing additional gas pipeline capacity. For purposes of this analysis, the EPA conservatively assumed that gas use of 10% or greater at these boilers, or any gas use at boilers without an existing gas pipeline, would require construction of additional pipeline capacity. Unlike coal, natural gas cannot be stored in quantities sufficient for sustained utilization on site. To the extent that firm (uninterruptible) gas supply is contractually unavailable or cost-prohibitive, any potential interruption in gas supply could impact the ability of the unit to continue operating without increasing its CO_2 emissions rate (since it would likely need to substitute more CO_2-intensive fuel for the unavailable natural gas). Additionally, for boilers that switch to 100% gas, interruption in gas impacts the ability of the unit to continue generating at all if gas is unavailable. For these reasons, an EGU switching to a large percentage of gas use may elect to install more than one new gas supply pipeline from separate sources. Although the EPA assumes the addition of one gas pipeline in the simplified cost analysis presented below, it will be seen that pipeline cost will generally not be the main driver of economic feasibility.

Cost and Performance Impacts of Coal-to-Gas Switching

The analysis described in this section presents a hypothetical conversion of a boiler from burning 100% coal to burning varying proportions of gas (10%, 50%, and 100%). The capital cost of modifying a coal boiler to switch to natural gas includes the new gas burners and piping, combustion air ductwork and control damper modifications, air heater upgrades, gas recirculating fans, control systems modifications, and other site-specific modifications, as well as any pipeline installation costs that would be necessary to supply the unit's assumed level of gas combustion following the conversion.

[255] Based on assumed use of Class 1 igniters (10% of burner capacity) as defined in NFPA 85 Boiler and Combustion Systems Hazards Code.

For this analysis, the EPA assumes capital costs for pulverized coal (PC) and cyclone boiler modifications are as follows[256]:

$$\$/\text{kW} = 267*(75/\text{MW})^{0.35} \text{ (pulverized coal)}$$

$$\$/\text{kW} = 374*(75/\text{MW})^{0.35} \text{ (cyclone)}$$

Based on the above formula, a 500 MW pulverized coal unit would have a capital cost of $137/kW to convert the boiler such that it could burn any proportion of natural gas. For this illustrative example, to support 100% gas combustion we assume that a 50-mile gas pipeline[257] at $50 million, [258] or $100/kW for a 500 MW unit, is also required, which raises the unit's total capital cost for conversion to $237/kW. Black & Veatch also used a similar cost level in a recent case study.[259] At a 14.3% capital charge rate[260] and 75% annual capacity factor, the total capital cost in this example equates to an annualized capital cost of about $5/MWh. This $/MWh capital cost is relatively insignificant compared to the increase in fuel cost discussed later.

Due to a reduced need for operators, maintenance materials, and maintenance staff, EPA engineering staff assumed that fixed O&M costs are reduced by 33% as a result of switching from coal to 100% gas. Similarly, variable O&M costs are assumed to be reduced by 25% due to reduced waste disposal, reduced auxiliary power requirement, and miscellaneous other costs. EPA engineering staff also assumed for this analysis that there would be no derate in the net EGU output, and estimated that the impact on net heat rate for an average unit would be a 3% increase for a switch from coal to 100% natural gas firing. The assumed 3% increase in net heat rate is conservative compared to the 2% assumption used by Black & Veatch in their previously mentioned case study.

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[256] EPA assumptions on costing and performance associated with coal-to-gas conversion and pipeline additions in this analysis are generally consistent with assumptions presented and discussed in EPA's power sector modeling documentation, Chapter 5.7, at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_5.pdf

[257] Based on EPA analysis, the majority of existing coal units would require less than 50 miles of new gas pipelines to switch fuels from coal to 100% natural gas. See Chapter 5 and Table 5-22 of Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

[258] For those plants that require additional pipeline capacity, the average capital cost of constructing new pipelines is assumed to be approximately $1 million per mile of pipeline built, which is consistent with assumptions used in EPA's IPM modeling.

[259] A Case Study on Coal to Natural Gas Fuel Switch, Black & Veatch, Power-Gen International, December 2012, available at http://bv.com/redirects .

[260] Capital charge rate at 14.3% is the average of the regulated utility and unregulated merchant rates as used in IPMv5.13 for environmental retrofits having a 15 year book life.

Cost of Fuel

For this analysis, the EPA uses base case projections for delivered gas prices that are about double projected delivered coal prices on average ($2.62/MMBTU for coal, $5.36/MMBTU for gas).[261] As a result, the fuel cost for a typical converted boiler burning 100% gas is expected to be at least double its prior fuel cost on an output basis as well ($27/MWh for coal, $57/MWh for gas).[262,263] Compared to the estimated $5/MWh capital cost impact presented above, a $30/MWh increase in fuel cost would make the difference in fuel costs the most significant driver of project economics when switching from coal to gas in a coal boiler.[264] This difference would increase with higher gas prices, which would be projected to result from an increase in overall gas demand caused by widespread adoption of gas co-firing.

Emission Reduction Potential

The CO_2 reduction potential is directly related to the amount of gas co-fired, and is due largely to the different carbon intensities of each fuel. More reductions in CO_2 rate are achieved at higher levels of gas co-firing as shown in Table 6-1. At 10% gas co-firing, the net emissions rate (lbs/MWh net) of a typical unit would decrease by approximately 4%. At 100% gas co-firing, the net emissions rate (lbs/MWh net) of a typical unit would decrease by approximately 40%.

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[261] EPA Base Case 5.13, projections for 2020

[262] This estimated fuel cost also accounts for the decrease in efficiency that results from switching from coal to gas in a boiler, as well as the decrease in parasitic power consumption.

[263] Combusting natural gas using combined-cycle turbine technology can remain economically attractive notwithstanding these types of fuel price differentials because combined cycle turbine technology converts a substantially higher share of the fuel's heat input into electricity output as compared to boiler technology. The $/MWh impact of a higher gas price in that instance is significantly mitigated by higher MWh output produced for a given amount of heat input from the fuel purchased.

[264] This demonstration assumes that the converting boiler in question remains a "price taker" in the fuel marketplace, such that the projected gas and coal prices would be unaffected by this hypothetical unit's potential decision to convert. However, if enough other units might be expected to make similar conversions, the aggregate increased demand for natural gas would be likely to further increase the price differential between coal and gas, making fuel costs an even more influential factor in the evaluation of such a project's economic merit.

Table 6-1. CO_2 Rates at Various Levels of Natural Gas Co-Firing

Case	Heat Rate (Btu/kWh)	CO_2 Rate (lbs/MWh net)	Reduction in CO_2 Rate from 100% Coal (lbs/MWh net)
100% Coal	10,340	2,108	N/A
10% Gas	10,370	2,021	4%
50% Gas	10,490	1,673	21%
100% Gas	10,640	1,239	41%

In addition to reducing CO_2 emissions, natural gas co-firing at a coal-fired steam EGU will generally also reduce criteria air pollution. Reducing CO_2 and criteria air pollution will result in climate benefits and human health co-benefits. The impacts of these pollutants on the environment and health are discussed in detail in Chapter 5 of the RIA for this proposed rule. For this analysis, EPA estimated the $PM_{2.5}$-related human health co-benefits of SO_2, NO_X, and direct-$PM_{2.5}$ emission reductions attributable to a range of natural gas co-firing levels at an illustrative coal steam unit burning bituminous coal in 2020.[265] The estimated monetized co-benefits do not include climate benefits or health effects from direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment. Only the unit-level emissions of SO_2, NO_X and direct-$PM_{2.5}$ are considered in this illustrative exercise. Additionally, emissions from the extraction and transport of the fuels used by these technologies are not considered. Furthermore, there may be differences in upstream greenhouse gas emissions (in particular, methane) from different technologies but those were not quantified for this assessment. The estimated avoided emissions under 10% gas co-firing and a 100% switch to gas are presented Table 6-2.

Table 6-2. Avoided Emissions at Various Levels of Co-Firing, based on Illustrative Unit (lbs/MWh net)

	10% Gas	100% Gas
SO_2	0.3	3.1
NO_X	0.2	2.04
$PM_{2.5}$	0.02	0.2

[265] The illustrative unit in this analysis was assumed to be a 500 MW coal-steam unit burning bituminous coal with a heat rate of 10,339 btu/kWh (net) operating at 75% capacity factor. Furthermore, this unit was assumed to operate a wet scrubber, cold-side ESP, and SNCR.

To estimate human health co-benefits for this illustrative coal steam unit, the EPA used $PM_{2.5}$-related benefit-per-ton estimates for SO_2, NO_X, and direct-$PM_{2.5}$ emission reductions described in detail in Chapter 5 of the RIA for this proposal. To estimate the benefits associated with co-firing, we determine the emission reductions for co-firing in Table 6-2 and apply the 2020 social benefit values discussed in Chapter 5 of the RIA for this proposal. Specifically, we multiply the reduction in SO_2, NO_X, and direct-$PM_{2.5}$ emissions by the $PM_{2.5}$-related benefit per-ton estimates, and add those values to get a measure of 2020 benefits. Table 6-3 shows the $PM_{2.5}$-related benefits expected based on the estimated emission reductions that would occur in this illustrative example. These estimates are purely illustrative as the EPA does not assert a specific location for the illustrative electricity generation technologies and is therefore unable to specifically determine the population that would be affected by their emissions. Therefore, the benefits for any specific unit can be different than the estimates shown here.

Table 6-3. Rounded PM2.5-related Co-benefits ($/MWh net) of Gas Co-firing (2011$)

	Health Co-benefit Discount Rate					
	3% Discount Rate			7% Discount Rate		
Gas Co-firing 10%	$6.5	to	$15	$5.9	to	$13
Gas Co-firing 100%	$67	to	$150	$61	to	$140

Note: All estimates are rounded to two significant figures. Co-benefits are based on national benefit-per-ton estimates for directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors, SO_2 and NO_X. It is important to note that the monetized health co-benefits do not include reduced health effects from ozone or direct exposure to NO_2, SO_2, and HAP; ecosystem effects; or visibility impairment. Emissions of directly emitted particles are disaggregated into EC+OC or crustal components using the method discussed in Appendix.[266] 5A of the RIA for this proposal. The health co-benefits reflect the sum of the PM2.5 co-benefits and reflect the range based on adult mortality functions (e.g., from Krewski et al. (2009) to Lepeule et al. (2012)).

The precise incremental health co-benefits associated with lower emissions would depend primarily on the location of the co-firing unit, the specific types of coals that natural gas would replace, and the pollution controls installed on that unit. This illustrative assessment is unable to

[266] Krewski D.; M. Jerrett; R.T. Burnett; R. Ma; E. Hughes; Y. Shi, et al. 2009. Extended Follow-Up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality. HEI Research Report, 140, Health Effects Institute, Boston, MA.
Lepeule, J.; F. Laden; D. Dockery; J. Schwartz. 2012. “Chronic Exposure to Fine Particles and Mortality: An Extended Follow-Up of the Harvard Six Cities Study from 1974 to 2009.” Environmental Health Perspectives, July, 120(7):965-70.

account for these characteristics. However, these factors will not change the qualitative conclusion. There will always be incremental human health co-benefits associated with co-firing natural gas in an existing coal steam boiler, independent of the location, coal type, and operating pollution controls.

A related beneficial use of natural gas in existing coal boilers can be via gas reburning, a NOx reduction technology.[267] Gas reburning involves firing natural gas (between 10 and 25% of total heat input) above the primary combustion zone in the boiler furnace. This upper-level firing creates a slightly fuel-rich zone. NOx produced in the primary zone of the furnace is "reburned" in this zone and converted to molecular nitrogen and other reduced nitrogenous species. Overfire air is injected downstream of the reburn zone to burn out the remaining combustibles and convert the reduced nitrogenous species to molecular nitrogen. The heat input from gas would approximately substitute for a similar heat input from coal, thus reducing CO_2 and other coal emissions in a manner similar to gas co-firing as discussed above.

<u>Cost of Reductions and Cost Effectiveness</u>

This analysis examines the average $/tonne[268] cost of avoided CO_2 that results from applying a range of natural gas co-firing levels to a typical baseload coal boiler. We capture the capital costs of boiler modifications and new pipeline construction (assuming 50 miles of new pipeline),[269] decreased FOM and VOM costs, and incremental fuel costs (based on IPMv5.13 Base Case average delivered fuel price projections for coal and gas in 2020). For a typical coal boiler at current base case fuel prices, the average cost of avoided CO_2 ranges from $83/tonne for 100% gas switch to $150/tonne for co-firing at 10% (see Table 6-4).

[267] DOE/NETL 2001, Evaluation of Gas Reburning and Low-NOx Burners on a Wall-Fired Boiler, DOE/NETL-2001/1143, February 2001, available at http://www.netl.doe.gov/File%20Library/Research/Coal/major%20demonstrations/cctdp/Round3/GRLNBPPA.pdf

[268] This document uses "tonne" to refer to a metric tonne. All control costs in this analysis are presented in dollars per metric tonne, or "$/tonne."

[269] Based on EPA analysis, the majority of existing coal units would require less than 50 miles of new gas pipelines to switch fuels from coal to 100% natural gas. See Chapter 5 and Table 5-22 of Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Table 6-4. Average Cost of Avoided CO_2 and CO_2 Emission Rate Reductions from 100% Coal at Various Levels of Natural Gas Co-Firing at Base Case Projected Gas Price ($5.36/MMBtu)

Case	Average Cost of Avoided CO_2 ($/tonne)	Change in CO_2 Rate from 100% Coal (lbs/MWh net)
100% Coal	N/A	N/A
10% Gas	150	4%
50% Gas	91	21%
100% Gas	83	41%

Note: Based on a typical 500 MW bituminous coal steam unit operating at 75% capacity factor. Assumes construction of new 50-mile pipeline. EPA estimated reduced total capital costs for the 50% and 10% gas cases; for example, total capital cost for 10% gas was estimated to be about one-half of the capital costs for the 100% gas case.

However, widespread adoption of gas co-firing would increase overall gas demand and place upward pressure on the natural gas price, which would consequently increase the average cost of avoided CO_2 of a potential boiler conversion.

Conclusion

Switching from coal to gas is a relatively costly approach to CO_2 reductions at existing coal steam boilers when compared to other measures such as heat rate improvements and re-dispatch of generation supply to other existing capacity with lower CO_2 emission rates. Moreover, this analysis shows that coal-to-gas conversion of an existing boiler is less efficient than constructing a new natural gas combined cycle (NGCC) turbine in its place. For example, EPA analysis indicates that replacing the coal steam plant discussed above with a new NGCC facility would reduce the net CO_2 emission rate of the generating capacity by 62% at a cost of about $50/tonne of avoided CO_2 under the base case projected gas price and about $81/tonne of avoided CO_2 at a future gas price 50% higher than the base case projection. See preamble section VI.C.3.c.

The EPA is considering cost-effectiveness at a national level for the purpose of setting emissions goals consistently in each state. While this analysis suggests that cost-effective reductions of CO_2 are not available on a national basis from widespread adoption of natural gas co-firing, it does not preclude the potential for individual EGUs to utilize co-firing as a way to reduce CO_2 and other emissions, nor does it preclude states from factoring in that unit-level potential into the design of state plans for compliance with the 111(d) standard. EPA notes that there are utilities that see merit in converting some existing coal units to burn 100% gas, and several are currently doing so.[270,271]

[270] Reuters 2014, "Southern to repower three Alabama coal power plants with natgas," Reuters U.S. Edition, January 16, 2014 , available at http://www.reuters.com/article/2014/01/16/utilities-southern-alabama-idUSL2N0KP1WA20140116

271 Dominion 2012, "Dominion Virginia Power Proposes To Convert Bremo Power Station From Coal To Natural Gas," Dominion News, September 5, 2012, available at http://dom.mediaroom.com/2012-09-05-Dominion-Virginia-Power-Proposes-To-Convert-Bremo-Power-Station-From-Coal-To-Natural-Gas

Biomass Co-firing

<u>Introduction</u>

Co-firing biomass in existing boilers designed for coal-fired generation, or converting those boilers to consume entirely biomass, is another approach to potentially reduce the output-based CO_2 emissions rate (lbs/MWh) of these boilers. In the analysis presented in this technical support document, the physical CO_2 emissions rate at the boiler stack could increase or decrease, depending on the amount of coal energy replaced by biomass energy and differences in the properties of a selected biomass and the coal it replaces.[272]

There are many possible combinations of coals and biomass types that could be co-fired. Site-specific economics and accessibility would determine which combinations might actually be feasible. This TSD analysis does not attempt to estimate an economically feasible national average increase or decrease in CO_2 emission rate via biomass co-firing. Instead, this analysis simply employs one reasonably representative case to evaluate the cost effectiveness of biomass energy substitution in reducing the physical CO_2 emission rate based only on the CO_2 coming from coal. This analysis indicates that while the co-firing of biomass with coal is technically feasible as a means of reducing the coal-based CO_2 emission rate due to the substitution of biomass for coal, it generally has limited economic feasibility due to the generally higher cost of energy from biomass as compared to coal. This general finding largely explains the very limited amount of biomass co-firing currently practiced in the U.S. It is also consistent with recent findings by others[273] , including an earlier study by the State of Maryland[274] that concluded as follows:

"Due to the higher cost of biomass fuels when compared to coal, cofiring with biomass will lead to an increase in fuel costs. Without consideration for any environmental benefits, it is unlikely that any Maryland coal-fired facility would make the investments required to cofire with a more expensive and less efficient fuel."

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[272] Fuel properties particularly affecting relative CO_2 emission rates are: higher heating value, carbon and hydrogen contents, and as-fired moisture content.
[273] Nowling, Una, Black & Veatch, "Utility Biomass Use: Turning Over a New Leaf?, *Power*, May 2014, available at http://accessintelligence.imirus.com/Mpowered/book/vpow14/i5/p52
[274] The Potential for Biomass Cofiring in Maryland, Maryland Department of Natural Resources, March 2006, (pg 53) http://esm.versar.com/pprp/bibliography/PPES_06_02/PPES_06_02.pdf

Based on the basic analysis of the cost effectiveness of biomass energy substitution in reducing the physical CO_2 emission rate based only on the CO_2 coming from coal presented below, the EPA concludes in this TSD that biomass co-firing would not be a cost-effective measure on which to base state goals. [275]

Description of Technology

Engineering/Economic Considerations

The technical feasibility of biomass co-firing in existing coal-fired boilers has been thoroughly investigated in many research and engineering studies, as well as in test burns at coal power plants in the U.S. and globally.[276] It has been demonstrated that the boiler and related systems of almost any existing coal-fired EGU can accept or be modified to support co-firing of at least some small percentage of biomass. In some cases, major modifications can be made to support a switch to 100% biomass.[277]

A decision to actually modify an existing coal-fired boiler for biomass co-firing at any percentage level depends on numerous technical and economic factors, including reliable availability of suitable biomass at an economic cost; adequate onsite space for biomass receiving, storage, preparation, and handling systems; potential corrosive effects of biomass ash in the boiler furnace; potential impacts of co-firing on boiler efficiency even at low biomass percentages, and the likely reduction (derate) in unit generating output at very high biomass percentages.

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[275] This analysis does not include evaluation of stack biogenic CO_2 emissions relative to the net landscape and process-related carbon fluxes associated with the production and use of the biogenic feedstocks combusted. Issues related to methods for assessing biogenic CO_2 emissions from stationary sources are currently being evaluated by the EPA. In general, the overall net atmospheric contribution of CO_2 resulting from the use of a biogenic feedstock by a stationary source, such as an EGU, will ultimately depend on the stationary source process and the type of feedstock used, as well as the conditions under which that feedstock is grown and harvested. In September 2011, the EPA submitted a draft Accounting Framework to the Science Advisory Board (SAB) Biogenic Carbon Emissions (BCE) Panel for peer review. The SAB BCE Panel delivered its Peer Review Advisory to the EPA on September 28, 2012. In its Advisory, the SAB recommended revisions to the EPA's proposed accounting approach, and also noted that biomass cannot be considered carbon neutral *a priori,* without an evaluation of the carbon cycle effects related to the use of the type of biomass being considered.

[276] See Partial Bibliography – Biomass Co-firing at end of this section.

[277] For example, one unit at Schiller Station (NH) was converted in 2006 to burn biomass exclusively. See: https://www.psnh.com/PlantsTerritory/Schiller-Station.aspx

There are considerable physical differences between coal and biomass that will generally limit the extent to which biomass can be reasonably used to replace coal in a boiler. For example, compared to most coals, many solid biomass fuels have both a significantly higher as-fired moisture content and a significantly lower heating value per unit of weight. Most solid biomass fuels are also significantly less dense than most coals. For example, a typical biomass might have twice the moisture, half the heating value, and less than half the density of coal.[278] Important consequences of these physical differences are that the weight of biomass needed to provide a given amount of heat energy could be twice the weight of the coal it replaces, and the volume (cubic feet) of biomass needed could be four-to-eight times the volume of coal replaced. Biomass requires space for storage after delivery to a facility, and the length of time that the biogenic material would remain on site prior to use can differ. For example, wood chips could be delivered year-round while crop residue delivery would follow specific seasons in which the crop was grown. As noted above, the four-fold or greater increase in volume occupied by biomass relative to coal means that the necessary additional storage space could be large. However, if pre-prepared or condensed biomass fuels such as pelletized or torrefied biomass is used, some of these concerns may be lessened, recognizing that such pre-preparations of the feedstock will entail additional costs. Stored biomass can be at even greater risk of spontaneous combustion than stored coal; this may limit the safe height of biomass piles and further increase storage area requirements.[279]

The volumetric differences alone can have other unexpected consequences. For this analysis, experienced EPA engineering staff estimated that a 500 MW baseload coal plant co-firing 10% biomass and receiving biomass deliveries 10 hours per day and 5 days per week would require a 20-ton truck delivery to the plant every 10 minutes, in addition to the ongoing coal deliveries. Limiting traffic issues may arise in some situations. Also, because of the low energy density of biomass and its relatively higher transportation cost per unit of delivered energy, it may only be economically viable to transport biomass a limited distance from where it is grown. This could limit the both the percentage of biomass co-firing in a single boiler and the maximum MW output from biomass at a single site. New technologies under development, such

[278] Biomass Energy Data Book- Edition 4, October 2012, DOE-EERE-ORNL, http://cta.ornl.gov/bedb/index.shtml
[279] Properties of Wood Waste Stored for Energy Production, Purdue University, 2011, http://www.extension.purdue.edu/extmedia/ID/ID-421-W.pdf

as torrefaction of biomass, could mitigate some of these transportation, storage and energy content concerns, but are not yet commercially available.

The relatively higher moisture content and lower heat content of biomass reduces boiler efficiency, and typically requires a derating in unit generation at very high co-firing percentages as furnace volume and boiler fan capacities become inadequate.

For all of the above reasons, the EPA assumed for this analysis that coal-steam EGU boilers will generally only co-fire with biomass to a limited degree. While the actual level at which any plant can co-fire with biomass is highly site-specific, this analysis adopts the assumption used in EPA's fleet wide IPM modeling of the electric power sector: a reasonable average limit on biomass co-firing is up to 10% on any single boiler, not to exceed 50 MW total biomass powered output at an individual plant site (which aligns with the magnitude of some of the larger such entities currently in the U.S.). This amount of co-firing has been used as representative practical limit in other studies as well.[280]

Costs and Performance Impacts of Retrofitted Biomass Co-firing

For this analysis the EPA adopted capital and O&M costs, and performance impacts for retrofitted biomass co-firing capability that are approximately representative of EPA assumptions used in its IPM modeling and discussed in the documentation for IPM v.5.13.[281]
EPA estimated that the capital cost to install 50 MW of biomass co-firing capability would be at least $10 million.[282] As applied to a 500 MW coal unit, the minimum cost of this 10% co-firing capability would then be $20/kW. Fixed O&M cost was estimated by EPA engineering staff to be 10% greater than with coal alone, and variable O&M cost was estimated to remain unchanged.

The heat rate impact (Btu/kWh) of 10% biomass co-firing as estimated by EPA engineering staff for this analysis was an increase of slightly more than 1% compared to coal

[280] The Potential for Biomass Cofiring in Maryland, Maryland Department of Natural Resources, March 2006, http://esm.versar.com/pprp/bibliography/PPES_06_02/PPES_06_02.pdf
[281] See Sec 5.3, pg 5-19 at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v513/Chapter_5.pdf
[282] Generally consistent with EPA assumptions in IPM modeling; also see the following source using the same retrofit capital cost assumption: Cofiring Biomass and Coal for Fossil Fuel Reduction and Other Benefits – Status of North American Facilities in 2010, USDA, August 2012, http://www.fs.fed.us/pnw/pubs/pnw_gtr867.pdf

alone. At low biomass cofiring rates, this factor slightly affects calculated biomass fuel consumption and any associated CO_2 emission from biomass.

Cost of Fuel

For this analysis, the EPA uses a delivered biomass cost of $4/MMBtu, representative of delivered woody crops grown specifically for energy-generating combustion,[283] and roughly 50% greater than IPM projected 2020 average delivered coal costs.[284] This analysis also considers a sensitivity scenario assuming a higher $6/MMBtu biomass price.

The EPA recognizes that the cost of biomass is highly site-specific, and in some cases could be largely comprised of collection and transportation cost (as is the case for opportunity fuels with little to no other market value). The transportation component depends primarily on the distance that biomass needs to be transported. For example, the EPA engineering staff estimate that for a one-way distance of 50 miles with a 20-ton semi-trailer truck, transportation costs could be $10-20/ton. For biomass at a total delivered price of $4/MMBtu with an indicative heating value of 5,000 Btu/lb (higher heating value (HHV) basis), transportation cost in this example case could account for 25-50 percent of the total delivered biomass cost. In any case, it is the total delivered price of biomass on a $/MMBtu basis that will primarily determine the economic feasibility of biomass co-firing.

Emission Reduction Potential

The CO_2 reduction potential of biomass co-firing is directly related to the amount and type of biomass co-fired and is due to the difference in heating value, moisture content and hydrogen/carbon ratios[285] for a selected biomass fuel compared to the particular coal it replaces. The types of biomass typically available to EGUs in the United States include woody-based feedstocks such as wood chips, forest industry byproducts, and to a lesser degree agricultural crop residues, as well as emerging dedicated energy crops such as switchgrass and short-rotation

[283] Average biomass price as projected by EPA modeling in IPMv5.13 Base Case
[284] EIA, Electric Power Annual 2012 – Electricity (Table 7.4)
http://www.eia.gov/electricity/annual/html/epa_07_04.html
[285] IFRF Combustion Handbook, Combustion File No. 23, What is Biomass? (Van Krevelen Diagram), http://www.handbook.ifrf.net/handbook/cf.html?id=23

woody crops.[286] In general, when comparing coal-only versus co-firing coal with biomass, co-firing may result in either an increase or decrease in the stack CO_2 emission rate. The extent to which the use of biomass contributes to net emissions to the atmosphere is being considered in EPA's current study on biogenic emissions accounting. See preamble Section VIII.G.

Cost of Reductions and Cost Effectiveness

In order to evaluate cost-effectiveness of potential reductions, the EPA first estimated the cost of avoided coal CO_2 emissions in a hypothetical scenario where biomass CO_2 emissions are not included in total stack CO_2 emissions (in effect, biogenic CO_2 emissions are subtracted from total CO_2 emissions measured at the stack). The estimated results presented below are based on a reasonably representative case using a baseload bituminous coal-fired boiler with a net heat rate of 10,340 btu/kWh that shifts from 100% bituminous coal to 90% coal and 10% biomass (assuming fuel prices of $2.62/MMBtu for coal in 2020 as projected in IPMv5.13 Base Case and $4/MMBtu for biomass as explained above). When biogenic stack emissions are not counted as part of total emissions, the cost of avoided CO_2 for a "typical" baseload coal boiler co-firing 10% biomass is $30/tonne. At higher delivered fuel price differentials, the cost of avoided coal CO_2 emissions would increase (for example, at a biomass price of $6/MMBtu, cost of avoided CO_2 is $80/tonne if CO_2 emissions from biomass are not counted).[287] This estimated cost of avoided coal CO_2 emissions, which ranges for $30 to $80/tonne, would increase if any portion of the biogenic CO_2 emissions from the co-fired biomass were included.

Conclusion

Replacing some coal with low levels of biomass co-firing may result in stack CO_2 emission increases.[288] Even if biogenic CO_2 emissions are not counted as part of stack emissions, biomass co-firing is a relatively costly approach to CO_2 reductions at existing coal steam boilers when compared to other measures such as heat rate improvements and re-dispatch of generation supply to other existing capacity with lower CO_2 emission rates.

[286] Biomass Combined Heat and Power Catalog of Technologies, U.S. EPA, September 2007, http://www.epa.gov/chp/documents/biomass_chp_catalog.pdf
[287] Similarly, the costs of avoided CO2 emissions would decrease at lower fuel price differentials.
[288] Depending on biogenic feedstocks used and whether or not an assessment system is applied that evaluates biogenic CO_2 emissions from the stack in relation to the terrestrial carbon cycling associated with the production and use of that biogenic feedstock.

The EPA is considering cost-effectiveness at a national level for the purpose of setting emissions goals consistently in each state. While this analysis concludes that cost-effective reductions of CO_2 are not available on a national basis from widespread adoption of biomass co-firing, it does not preclude the potential for individual EGUs to utilize co-firing as a way to reduce overall CO_2 emissions, nor does it preclude states from factoring in that unit-level potential into the design of state plans for compliance with the 111(d) standard.[289]

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[289] EPA notes that states will need to consider any future EPA finding regarding an assessment framework that considers carbon fluxes on the biogenic feedstock production landscape applied when evaluating net stack CO_2 emissions from biomass co-firing.

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Chapter 7: Carbon Capture & Storage

Introduction

Another possible approach for reducing CO_2 emissions from existing fossil fuel-fired EGUs is through the application of carbon capture and storage technology (CCS; sometimes also referred to as carbon capture and sequestration). In the recently proposed standards of performance for new fossil fuel-fired EGUs (79 FR 1430), the EPA proposed to find that the best system of emission reduction for new fossil fuel-fired boilers and IGCC units is partial application of CCS. In that proposal, the EPA found that, for new units, partial CCS has been adequately demonstrated; it is technically feasible; it can be implemented at reasonable costs; it provides meaningful emission reductions; and its implementation will serve to promote further development and deployment of the technology. This chapter examines the potential for implementation of CCS technology at existing fossil fuel-fired utility boilers and IGCC units.

Carbon Capture Options for Existing Fossil Fuel-fired EGUs

In general, CO_2 capture technologies applicable to existing fossil fuel-fired power generation can be categorized into three approaches – (1) post-combustion capture; (2) pre-combustion capture; and (3) oxy-combustion. Each of these is described and discussed in more detail below.

<u>Post-combustion Capture</u>

Post-combustion CO_2 capture refers to removal of CO_2 from a combustion flue gas prior to discharging to the atmosphere. Separating CO_2 from such a gas stream can be challenging for a number of reasons. Because CO_2 is a dilute fraction of the combustion flue gas – typically 13-15 % in coal-fired systems and 3-4 % in natural gas-fired systems – a large volume of flue gas must be treated. The flue gas from typical combustion systems is usually at near atmospheric pressure. Therefore, most of the available capture systems rely on chemical absorption (chemisorption) options (e.g., amines) that require added energy to release the captured CO_2 and regenerate the solvent. Many of the chemical solvents require a flue gas stream that is free of or has very low quantities of components – such as SO_2, NO_X, and HCl – that can degrade the solvent. The captured CO_2 must then be compressed from near atmospheric pressure to much higher pipeline pressures (about 2,000 psia).

Pre-combustion Capture

Pre-combustion capture systems are applicable to fossil fuel gasification power plants (i.e., IGCC units) where coal or other solid fossil fuel (e.g., pet coke) is converted into a synthesis gas (or "syngas") by applying heat under pressure in the presence of steam and limited O_2. The product syngas contains primarily H_2 and CO – and, depending on the fuel and gasification system – some lesser amount of CO_2. The amount of CO_2 in the resulting syngas stream can be increased by "shifting" the composition via the catalytic water-gas shift (WGS) reaction. This process involves the catalytic reaction of steam ("water") with CO ("gas") to form H_2 and CO_2. The resulting CO_2 contained in the syngas is then captured before combustion of the H_2-enriched syngas for power generation in a combined cycle system. Contrary to the post-combustion capture flue gas, the IGCC syngas can contain a high volume of CO_2 and is pressurized. This allows the use of physical absorbents (e.g., Selexol™, Rectisol®) that require much less added energy to release the captured CO_2 and require less compression to get to pipeline standards.

Oxy-combustion

Oxy-combustion systems for CO_2 capture rely on combusting coal or other fuels with relatively pure O_2 diluted with recycled CO_2 or CO_2/steam mixtures. Under these conditions, the primary products of combustion are water and CO_2, with the CO_2 purified by condensing the water. Challenges associated with oxy-combustion include the capital cost and energy consumption for a cryogenic air separation unit (ASU) to produce oxygen, introduction of N_2 via boiler air infiltration, and excess O_2 in the CO_2 product stream.

CO_2 Transportation and Storage

CO_2 Pipeline Infrastructure

Carbon dioxide has been transported via pipelines in the U.S. for nearly 40 years. Approximately 50 million metric tons of CO_2 are transported each year through 3,600 miles of pipelines. Moreover, a review of the 500 largest CO_2 point sources in the U.S. shows that 95 percent are within 50 miles of a possible geologic sequestration site, which would lower transportation costs. There are multiple factors that contribute to the cost of CO_2 transportation via pipelines including but not limited to: availability and acquisition of rights-of-way for new pipelines, capital costs, operating costs, length and diameter of pipeline, terrain, flow rate of CO_2, and the number of sources utilizing the pipeline.

Geologic Storage

Existing project and regulatory experience, research, and analogs (e.g. naturally existing CO_2 sinks, natural gas storage, and acid gas injection), indicate that geologic sequestration is a viable long term CO_2 storage option. The viability of geologic sequestration of CO_2 is based on a demonstrated understanding of the fate of CO_2 in the subsurface. Geologic storage potential for CO_2 is widespread and available throughout the U.S. and Canada. Nearly every state in the U.S. has or is in close proximity to formations with carbon storage potential including vast areas offshore. Estimates based on DOE studies indicate that areas of the U.S. with appropriate geology have a storage potential of 2,300 billion to more than 20,000 billion metric tons of CO_2 in deep saline formations, oil and gas reservoirs and un-mineable coal seams.[290] Other types of geologic formations such as organic rich shale and basalt may also have the ability to store CO_2; and the DOE is currently evaluating their potential storage capacity.

Further evidence of the widespread availability of CO_2 storage reserves in the U.S. comes from the Department of Interior's U.S. Geological Survey (USGS) which has recently completed a comprehensive evaluation of the technically accessible storage resource for carbon storage for 36 sedimentary basins in the onshore areas and State waters of the United States.[291] The USGS assessment estimates a mean of 3,000 billion metric tons of subsurface CO_2 storage potential across the United States. For comparison, this amount is 500 times the 2011 annual U.S. energy-related CO_2 emissions of 5.5 Gigatons (Gt).[292]

Enhanced Oil Recovery (EOR)

Geologic storage options also include use of CO_2 in EOR, which is the injection of fluids into a reservoir to increase oil production efficiency. EOR is typically conducted at a reservoir

[290] The United States 2012 Carbon Utilization and Storage Atlas, Fourth Edition, U.S Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory (NETL).
[291] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources – Results: U.S. Geological Survey Circular 1386, 41 p., http://pubs.usgs.gov/fs/2013/1386/.
[292] U.S. Geological Survey Geologic Carbon Dioxide Storage Resources Assessment Team, 2013, National assessment of geologic carbon dioxide storage resources – Summary: U.S. Geological Survey Factsheet 2013-3020, 6p.http://pubs.usgs.gov/fs/2013/3020/.

after production yields have decreased from primary production. EOR using CO_2, sometimes referred to as 'CO_2 flooding' or CO_2-EOR, involves injecting CO_2 into an oil reservoir to help mobilize the remaining oil and make it available for recovery. The crude oil and CO_2 mixture is produced, and sent to a separator where the crude oil is separated from the gaseous hydrocarbons and CO_2. The gaseous CO_2-rich stream then is typically dehydrated, purified to remove hydrocarbons, recompressed, and re-injected into the oil or natural gas reservoir to further enhance recovery.

CO_2-EOR has been successfully used at many production fields throughout the U.S. to increase oil recovery. The oil and natural gas industry in the United States has over 40 years of experience of injection and monitoring of CO_2 in the deep subsurface for the purposes of enhancing oil and natural gas production. This experience provides a strong foundation for the injection and monitoring technologies that will be needed for successful deployment of CCS.

Evaluation of Retrofit CCS as BSER for Existing Fossil Fuel-fired EGUs

<u>Technical Feasibility</u>

In evaluating partial CCS as the BSER for new fossil fuel-fired boilers and IGCC units, the EPA determined that the technology is feasible and adequately demonstrated for new units because the major components of CCS – the capture, the transportation, and the storage – are all proven technologies that have been demonstrated at large 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 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.

Partial CCS has been demonstrated at existing EGUs. It has been demonstrated at a pilot-scale at Southern Company's Plant Barry; it is being installed for large-scale demonstration at NRG's WA Parish facility; and it will very soon be applied at commercial-scale as a retrofit at SaskPower's Boundary Dam coal-fired EGU in Canada. However, all of these facilities are located in areas that are either near an existing oil field or in an area that is geologically favorable for CO_2 storage. Thus, at some existing facilities, the implementation of partial CCS may be a viable GHG mitigation option and some utilities may choose to pursue that option. However, the EPA does not believe that it can serve as the best system of emission reduction for a broadly applicable GHG mitigation program. Therefore, the EPA does not propose to find that CCS is a component of the best system of emission reduction for CO_2 emissions from existing fossil fuel-fired EGUs.

Reasonableness of Cost

In the proposed standard of performance for new fossil fuel-fired EGUs (79 FR 1430), the EPA found that the costs to implement partial CCS (to a level to meet the proposed emission standard of 1,100 lb/MWh-gross) were consistent with costs for other non-natural gas-fired generating technologies – such as nuclear, biomass and geothermal – that utilities are considering for new intermediate and base load generating capacity. The EPA also noted in the proposal, that most of the relatively few new projects that are in the development phase are already planning to implement CCS; and, as a result, the standard would not have a significant impact on nationwide energy prices.

In contrast, the EPA did not identify full or partial CCS as BSER for new natural gas-fired stationary combustion turbines noting technical challenges to implementation of CCS at NGCC units as compared to implementation at new solid fossil fuel-fired sources. The EPA also noted that, because virtually all new fossil fuel-fired power is projected to use NGCC technology, requiring full or partial CCS would have more of an impact on the price of electricity than the few projected coal plants with CCS and the number of projects would make it difficult to implement in the short term.

An emission standard for existing units based on CCS (or even partial CCS) would most certainly have an even more significant effect on nationwide electricity prices and could affect the reliability of the supply of electricity. Therefore, we do not find that the cost to implement existing source emission standards to be reasonable, which further supports the determination that CCS is not an appropriate component of the best system of emission reduction for CO_2 emissions from existing fossil fuel-fired EGUs.

Emission Reductions and Promotion of Advanced Technology

An emission standard for existing units based on CCS (or even partial CCS) would clearly result in significant emission reductions and would certainly serve to promote further deployment, development and improvement in the most advanced technology. However, the EPA has determined that such an emission standard may not be technically or logistically feasible in a number of cases and cannot be broadly implemented at a reasonable cost at this time.

APPENDIX

Technical Memorandum

Consideration of Heat Rate Improvement (HRI) Potential at Existing Oil/Gas-fired Steam, Natural Gas Combined Cycle, and Combustion Turbine EGUs for Inclusion in Building Block 1

As described in the GHG Abatement Measures TSD, the EPA identified four categories of demonstrated measures, or "building blocks," that are technically viable and broadly applicable, and can provide cost-effective reductions in CO_2 emissions from individual existing EGUs. These building blocks include:

Building Block 1 - Reducing the carbon intensity of generation at individual affected EGUs through heat rate improvements;

Building Block 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 NGCC units under construction);

Building Block 3 - Reducing emissions from affected EGUs in the amount that results from substituting generation at those EGUs with expanded low- or zero-carbon generation; and,

Building Block 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.

Coal-fired Steam EGUs

For Building Block 1, the EPA evaluated the fleet-wide potential for lowering the carbon intensity of generation at individual affected coal-fired steam EGUs by improving heat rates at these EGUs (see the GHG Abatement Measures TSD). The EPA analyzed 11 years of historical heat rate data and the literature on HRI methods to estimate that the U.S. coal-steam EGU fleet might reasonably be expected to reduce its annual average gross heat rate by about 6%. Furthermore, the EPA understood that any HRI method that reduces gross heat rate will also reduce net heat rate, and that some HRI methods reduce net heat rate without reducing gross heat rate. As such, the EPA expects that the HRI potential on a net output basis is somewhat greater than on a gross output basis, primarily through upgrades that result in reductions in auxiliary loads. Therefore, the EPA conservatively assumed that the coal-steam fleet average net heat rate can be reduced by 6% and included this finding in its Building Block 1.

As discussed in the preamble, for purposes of developing the alternate set of goals on which we are taking comment, the EPA used an estimate of a 4% HRI from affected coal-fired steam EGUs on average. The EPA views the 4% estimate as a reasonable minimum estimate of the technical potential for HRI on average across affected coal-fired EGUs.

<u>Oil/Gas Steam EGUs</u>

As summarized above, the EPA made a detailed assessment of the fleet-wide potential for HRI at existing affected coal-fired steam EGUs in Building Block 1. However, we did not make a detailed assessment of this potential for existing affected oil and gas steam units at this time, for the three main reasons described below.

First, oil and gas contain significantly less carbon per unit of heating value than coal. Oil and gas therefore produce significantly less CO_2 than coal for the same amount of heat. (This is discussed further under NGCCs, below.)

Second, coal-fired steam EGUs are utilized at much higher levels compared to oil/gas steam EGUs. Therefore the amount of CO2 reduction that can be achieved via HRI at oil/gas EGUs is significantly smaller. For example, EPA modeling[293] projects that in 2020 coal-steam units will provide 59% of all fossil-fired electrical generation, while oil/gas steam units will provide only 2%. Even if CO_2 emissions from all oil/gas steam units could be reduced by 6% on average using HRI methods (as assumed on coal-steam units) that reduction would amount to only a fraction of 1% of the HRI reduction that might be obtained from coal-steam units. [294]

[293] IPM Base Case v5.13 modeling results as presented in RIA Chapter 3.
[294] The EPA is not suggesting that CO_2 reductions from fossil-fired sources other than coal-steam EGUs are never important. Such reduction might be significant in a few situations, and states are free to make use of these reductions in meeting their goals.

Third, oil/gas steam EGUs employ less extensive systems and equipment compared to coal steam EGUs and therefore, in general, have a lesser range of opportunities for implementing HRI. For example, oil/gas steam units do not typically use flue gas SO_2 scrubbers, particulate collection devices, coal mills, coal conveyors, ash handling systems, sootblowers, etc. Consequently, some of the HRI methods discussed in the GHG Abatement Measures TSD are not applicable for oil/gas steam EGUs.

The above factors taken together explain why the potential for CO_2 reduction achieved via HRI at oil and gas steam EGUs would be quite small compared to that from the existing fleet of coal-fired EGUs. Therefore the EPA conservatively decided to not separately itemize and include this potential in Building Block 1.

Natural Gas Combined Cycle (NGCC) EGUs

EPA modeling also projects that in 2020 natural gas-fired NGCCs will provide about 39% of the U.S. electrical generation from fossil fuels, compared to 59% from coal-steam EGUs. Also, as explained below, NGCCs in 2020 would emit only about 20% of the total CO_2 emissions from fossil fuels used in electrical generation.

The significantly lower amount of CO_2 produced by combustion of natural gas compared to coal (about 40% less for the same amount of heat input) is due primarily to the higher hydrogen content and lower carbon content in natural gas compared to coal. Also, because a NGCC is typically more efficient than a coal-steam EGU, thus using less heat input from fuel to make an equal electrical output, a very efficient NGCC can further reduce the CO_2 emission rate per MWh to about 60% less than that from coal-steam EGUs. Thus, natural gas, particularly as used in NGCCs, inherently reduces CO_2 emissions by more than one-half. Existing NGCC EGUs are therefore already significantly reducing CO_2 emissions compared to existing coal EGUs, per MWh of output, before considering whether NGCCs might be able to further reduce their CO2 emissions via HRI methods.

The EPA has preliminarily considered that there may be some potential for a further reduction in the CO_2 emissions of NGCC EGUs via HRI. However, as with coal-steam EGUs, we do not have the unit-specific detailed design information on existing individual NGCCs that would be needed to make a detailed assessment of the HRI potential via best practices and upgrades for each NGCC unit. While it would be possible for EPA to make a "variability analysis" of NGCC historical hourly heat rate data (as was done for coal-steam EGUs), we are aware that the various NGCC configurations in use and the historically lower capacity factors of the NGCC fleet (less run time per start, and more part load operation) would require a NGCC analysis that includes more complexity and likely more uncertainty than in the coal-steam analysis. In addition, the analysis would be limited by the fact that only one-third of the NGCC fleet has historically reported complete (combustion turbine and steam turbine generator) load data to EPA.

To preliminarily gauge the HRI potential for NGCCs, EPA engineering staff familiar with NGCC design and operation informally discussed the NGCC HRI potential with power sector engineering firms and NGCC suppliers. Our preliminary conclusion is that the fleet-wide HRI potential for existing NGCC EGUs may be only about 2-3% at most, on a sustained basis, for the following two reasons.

First, as a "combined" combustion turbine and steam turbine power cycle, some of the available HRI methods would be applicable only to the steam turbine portion of the power cycle: the HRSG (heat recovery steam generator), the steam turbine-generator, and the heat rejection system (water or air-cooled condenser systems). The HRI potential associated with the steam portion of the NGCC is significantly less than in a coal-steam unit because the NGCC steam system is much simpler (gaseous fuel, no back-end scrubbers, less parasitic power, no air heater leakage, no feedwater heaters, etc) and its flue gas exit temperature is typically already much lower than in a coal-steam unit.

Second, the HRI methods applicable to the combustion turbine portion of the NGCC relate primarily to critical components in the hot expansion side of the unit - components that are exposed to the products of combustion of fuel and air that contain small amounts of corrosive/erosive contaminants at very high temperatures. These critical components (combustors, nozzles/vanes, seals, rotating blades) therefore require regular periodic removal and refurbishment or replacement to maintain high NGCC efficiency levels, and indeed to avoid potentially catastrophic mechanical failures. The greatest loss in the performance (increased heat rate) of a NGCC is this physical degradation that occurs in proportion to its hours of operation and number of starts. Consequently, it has long been an accepted practice by NGCC owners to closely follow the NGCC manufacturer's maintenance recommendations, a practice that regularly restores the NGCCs efficiency and reliability. This close adherence to manufacturer recommendations is financially motivated in part by the fact that many NGCC owners have long-term maintenance contracts with the manufacturers, wherein the manufacturer guarantees the service life and replacement costs of expensive critical components - provided that the regular preventive/restorative maintenance schedule is followed. Regularly scheduled maintenance practices are the most effective HRI methods that can be applied on NGCCs, and the EPA concludes that they are likely already being applied across most of the NGCC fleet.

With NGCCs projected to produce 20% of fossil CO_2 emissions in 2020, and with a max sustained HRI potential for existing NGCCs of 2-3%, as mentioned earlier, the CO_2 reduction potential for NGCCs would amount to only a fraction of 1% of total fossil emissions in 2020, which would be only about 10% of the potential CO_2 reductions expected from coal-steam EGUs via HRI. Because of this limited potential and the uncertainty associated with it, EPA conservatively decided to not separately itemize and include this NGCC potential in Building Block 1.

Simple-cycle Combustion Turbine (CT) EGUs

Natural gas-fired CTs provide peaking generation, typically operating at very low capacity factors. This is primarily because of their relatively low efficiency, which is economically only partially offset by their relatively low capital cost. As peaking capacity, any CT may have many starts/shutdowns in the course of a year. It may also "load follow," with an average electric power output that may be well below its most efficient load point. CTs have an operational flexibility well suited to their role as peakers, but this role requires them to be inherently less efficient than they could be if it were economic to operate them at higher capacity factors.

EPA modeling projects that the power sector CT capacity in 2020 (Base Case) will be about 21% of total fossil-fired capacity (GW), and that it will provide only about 1% of total fossil-fired electrical generation (GWh). Whether gas or oil-fired, CT capacity can therefore only contribute CO_2 emissions amounting about 1% of total fossil CO_2 emissions, or perhaps 2% of total coal-steam CO_2 emissions. Any single-digit percentage reduction in CT heat rates, can therefore only provide much less than a 1% reduction in total fossil-fired CO_2 emissions.

Most CTs likely benefit from the same regular preventive/restorative maintenance as the combustion turbine portion of a NGCC, as discussed above, and for the same reasons, Thus, the heat rates of most CTs are already periodically (even if not regularly, depending on their irregular operating hours and starts) restored to a level that allows them to be both reliable and as efficient as reasonably possible. Therefore the EPA decided to not include HRI for CTs as an additional potential in Building Block 1.

Conclusion

This technical memorandum outlines the EPA's reasons for not including CO_2 reduction potentials via HRI on oil/gas steam, NGCC, and CT EGUs as part of the CO_2 reduction target of Building Block 1 at this time. For each non-coal technology the EPA concludes that the total additional potential reduction is small compared to the potential coal-steam CO_2 reduction. Furthermore, we do not have the detailed site-specific information that would be needed to make a more precise engineering evaluation of the HRI potential for any individual EGU, including coal-steam units; only the owners/operators of these EGUs would have that information.

The EPA notes, however, that although we did not include an HRI potential for these non-coal classes of existing fossil-fired EGUs in Building Block 1, we do expect that some amount of CO_2 reduction via HRI is available from these EGUs. States and sources would be free to use HRI at these EGUs to help reach the state CO_2 reduction goals. Further, we note that there are geographic differences in the proportions of total generation produced from various EGU types, and that in certain geographically isolated jurisdictions, HRI from non-coal fossil fuel-fired EGUs could be a more important potential approach to reducing CO_2 emissions. For this reason, as noted in the preamble, we are taking comment on whether HRI from non-coal fossil fuel-fired EGUs should be included as part of the basis supporting the BSER.