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

Greenhouse Gas Mitigation Measures

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

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CHAPTER 1: INTRODUCTION

Under the authority of Clean Air Act (CAA) section 111(d), EPA is establishing final CO_2 emission guidelines for existing fossil fuel-fired electric generating units (EGUs) – the Clean Power Plan (CPP). More specifically, EPA is establishing: (1) carbon dioxide (CO_2) emission performance rates based on the best system of emission reduction (BSER) for two subcategories of existing fossil fuel-fired EGUs, fossil fuel-fired electric utility steam generating units and stationary combustion turbines, and (2) guidelines for the development, submittal and implementation of state plans that implement the CO_2 emission performance rates. The emission performance rates reflect the "best system of emission reductions … adequately demonstrated" for CO_2 emissions from the EGU source category. The guidelines also provide for the development, submittal and implementation of state plans that implement the CO_2 emission performance rates, either directly by means of source-specific requirements or through measures that achieve equivalent CO_2 reductions from the same group of EGUs. This technical support document (TSD) provides additional information, data, and analysis to support EPA's assessment and application of BSER.

In the June 2014 proposal, EPA proposed to determine that the best system of emission reduction adequately demonstrated for reducing CO_2 emissions from existing EGUs was a combination of measures: (1) increasing the operational efficiency of existing coal-fired steam EGUs, (2) substituting increased generation at existing NGCC units for generation at existing steam EGUs, (3) substituting generation from low- and zero-carbon generating capacity for generation at existing fossil fuel-fired EGUs, and (4) increasing demand-side energy efficiency to reduce the amount of fossil fuel-fired generation. These activities were categorized as four "building blocks."

The final rule BSER incorporates certain changes from the proposed rule, reflecting EPA's consideration of comments received and further analysis. The principal changes are the exclusion from the BSER of emission reductions achievable through demand-side energy efficiency (building block 4) and through nuclear generation; a revised approach to determination of emission reductions achievable through increased renewable energy generation; a consistent approach to determination of emission reductions achievable through all the building blocks that better reflects the regional nature of the electricity system; and a revised interim goal period of 2022 to 2029 (instead of the proposed interim period of 2020 to 2029). These changes to the BSER and the building blocks are discussed in more detail in the preamble for the CPP Final Rule. Further information can be found in the Legal Memorandum for the CPP Final Rule, the CO_2 Emission Performance Rate and Goal Computation TSD for the CPP Final Rule, and the Response to Comments document, all of which are available in the docket.

This TSD includes chapters with detailed information and EPA's evaluation of each building block included in BSER, and also includes a chapter on carbon capture and storage technology (CCS).[1] A separate TSD includes supplemental information on demand-side energy efficiency (Demand-side Energy Efficiency TSD for CPP Final Rule), which is not part of BSER, but supports the Regulatory Impact Analysis.

While evaluating each measure, EPA considered the technical feasibility, applicability and use, application level appropriate for BSER, and cost effectiveness associated with reducing GHG emissions at EGUs. The application of the 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. The application of the building blocks as BSER supports achieving cost-effective and technically feasible reductions of CO_2, consistent with the final CPP rule.

[1] The proposed rule GHG Mitigation Measures TSD (docket ID #EPA-HQ-OAR-2013-0602-0437) also included a chapter on fuel switching at affected EGUs. This mitigation strategy was not included as BSER in the proposal, nor is it included in the final rule.

CHAPTER 2: CO_2 INTENSITY REDUCTIONS THROUGH HEAT RATE IMPROVEMENTS AT EXISTING COAL FIRED ELECTRICITY GENERATING UNITS

This is Technical Support Document (TSD) incorporates by reference the materials found in the *Clarified Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units: GHG Abatement Measures* as well as the *Dataset related to Chapter 2 of the GHG Abatement Measures TSD*, including *inter alia* the description of the data and methodology, analytical results, illustrative equipment upgrades, costs, and datasets.[1]

2.0 Overview

The heat rate of coal-fired electricity generating units (EGUs) is the amount of energy required to generate each kilowatt-hour (kWh) of electricity. The more efficiently an EGU converts the energy embedded in coal into electricity, the lower the EGU's heat rate and, correspondingly, the lower its CO_2 intensity (CO_2 lb/kWh). Because heat rate improvements reduce fuel consumption, improving coal-fired EGUs' heat rates can be a cost-effective method of reducing the CO_2 intensity of the power system as a whole.[2] In addition, it can provide additional economic benefits from reduced fuel costs.

To assess the potential heat rate improvements of existing coal-fired EGUs, EPA analyzed historical gross heat rate data from 2002 to 2012 for 884 coal-fired EGUs that reported both heat input and gross electricity output to the agency in 2012. The agency grouped the EGUs by regional interconnections – Western, Texas, and Eastern – and analyzed potential heat rate improvements within each interconnection using three analytical approaches. The approaches compare EGUs' "best" or "benchmark" historical gross heat rates against EGUs' 2012 gross heat rate. By founding the methodology on comparisons between EGUs' historical and baseline performances, the analyses control for variations in EGU design and largely obviate the need for subcategorization. By using the 2012 gross heat rate as the baseline, the analyses account for actions that individual EGUs have already taken to improve and maintain gross heat rate. Accordingly, the results identify the overall heat rate improvements that will result if coal-fired EGUs simply returned to their demonstrated and achievable past performance.

[1] See Clarified Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units; GHG Abatement Measures, Docket No. EPA-HQ-OAR-2013-0602-17180 (Sept. 16, 2014), available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-17180; and Dataset related to Chapter 2 of the GHG Abatement Measures TSD, Docket No. EPA-HQ-OAR-2013-0602-0238 (June 8, 2014), available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-0238.

[2] Improving heat rate can result in a "rebound effect" that undermines the emissions reductions a coal-fired EGU would otherwise achieve. For a detailed discussion of the consequences of the rebound effect for building block 1 and the best system of emission reductions, see sections V.A and V.C of the final rule preamble of the CPP.

In the first approach, "best historical average performance," the agency selected each EGU's best (*i.e.*, lowest) 1- and moving 2-year gross heat rates, calculated the generation weighted average across all units, and compared that to the generation-weighted 2012 average gross heat rate across all units. For the second and third approach, the agency controlled for select conditions beyond the EGU operator's control – hourly capacity factor and hourly ambient air temperature. These two conditions account for approximately 26 percent of variation in gross heat rate for the 884 coal-fired EGUs between 2002 and 2012. To control for these conditions, the agency grouped, or "binned," data by hours with similar hourly capacity factors (using 10 percent increments) and hourly ambient air temperature conditions (using 10° F ranges). In the second approach, "best historical average performance under similar conditions," within each capacity-temperature bin for each coal-fired EGU, EPA calculated the bin-specific 1- and moving 2-year gross heat rates, selected the lowest 1- and moving 2-year gross heat rate within that capacity-temperature bin, calculated the generation weighted average across all bins and units, and compared that to the generation weighted 2012 average gross heat rate. For the third approach, "efficiency and consistency improvements under similar conditions," the agency identified "benchmarks" for each EGU equal to the EGU's lowest hourly gross heat rate (characterized as the 10th percentile value over 1- and 2-year periods) for each capacity-temperature bin.[3] Then the agency determined the heat rate that could be achieved if the EGU implemented measures to operate more consistently nearer the lowest "benchmark," and compared that to the actual gross heat rate.

The results of these three approaches indicate that there is significant potential for heat rate improvement ranging from 4.0 to 6.6 percent nationally if coal-fired EGUs return to their best past performance between 2002 to 2012. The most conservative approach that is supported by the weight of evidence yields average potential heat rate improvements of 2.1 percent in the Western Interconnection, 2.3 percent in the Texas Interconnection, and 4.3 percent in the Eastern Interconnection.

2.1 Introduction

Heat rate, a measure of efficiency for fossil fuel-fired EGUs, is commonly expressed as the amount of heat input in British thermal units (Btu) required to generate one kWh of electricity (Btu/kWh). As a coal-fired EGU's heat rate improves (*i.e.*, efficiency improves), less coal or other fuel is required to produce the same amount of electricity. Because less fuel is combusted, the amount of CO_2 and other emissions (*e.g.*, mercury, NO_X, PM, SO_2) released to the environment also declines. In addition to the clear environmental benefits of heat rate improvements, there are important

[3] The third approach uses hourly values to determine a heat rate benchmark for each EGU for periods with similar hourly capacity factor and hourly ambient temperature conditions. Therefore, the agency determined it was appropriate to select the 10th percentile value to (1) control for unusually low hourly values and (2) set a benchmark with sufficient hourly measurements at or below the benchmark. The first and second approaches use annual averages so the agency did not determine it necessary to remove unusually low or unusually high heat rate values as the low and high values will generally balance out.

economic co-benefits attributable to reduced fuel costs and coal combustion residue management and disposal costs.

Heat rates of existing coal-fired EGUs in the U.S. vary substantially. The variation in heat rates among EGUs with similar design characteristics (*e.g.,* boiler type, fuel type, size, cooling system) as well as year-to-year variation in heat rate at individual EGUs indicate that there is potential for efficiency improvements that can yield significant CO_2 emission reductions and fuel savings for the existing coal-fired EGU fleet as a whole. This chapter presents (1) the characteristics of existing coal-fired EGUs in the US, including heat rate performance over time, (2) the impact that design characteristics and other factors may have on EGU heat rates, (3) additional equipment upgrades and practices that can improve efficiency at existing coal-fired EGUs, (4) the potential heat rate improvements from existing coal-fired EGUs that, when realized, would reduce CO_2 emission intensity, and (5) responses to key comments about building block 1 of the proposed rule.

2.2 Coal-fired EGUs

Several different coal combustion configurations and technologies are used at existing coal-fired EGUs in the U.S. Nevertheless, they all commonly follow the same process for converting the energy stored within coal into electricity. Figure 2-1 depicts a pulverized coal-fired EGU, the most widely used configuration in the U.S.[4] In general, coal is ground into small pieces or a fine powder, and then fed into a furnace where it is burned. The heat from coal combustion boils preheated water creating high-pressure high-temperature steam that is transported to a steam turbine-generator where the steam passes through, forcing the blades of the steam turbine to rotate, which in turn drives a generator to generate electricity. The steam drops in pressure and expands in volume as its energy is transferred to the turbine. After the steam has expanded, the exhaust steam is cooled in a heat exchanger (*i.e.,* condenser). The water is then returned to the boiler to repeat the cycle. Coal combustion waste gases (*i.e.,* flue gas), including various air emissions (*e.g.,* CO_2, mercury, NO_X, PM, SO_2), are drawn downstream from the furnace by fans and pass through pollution control devices before they are released from the stack to the atmosphere.

[4] For information about coal combustion configurations at coal-fired EGUs, see *supra* note 1.

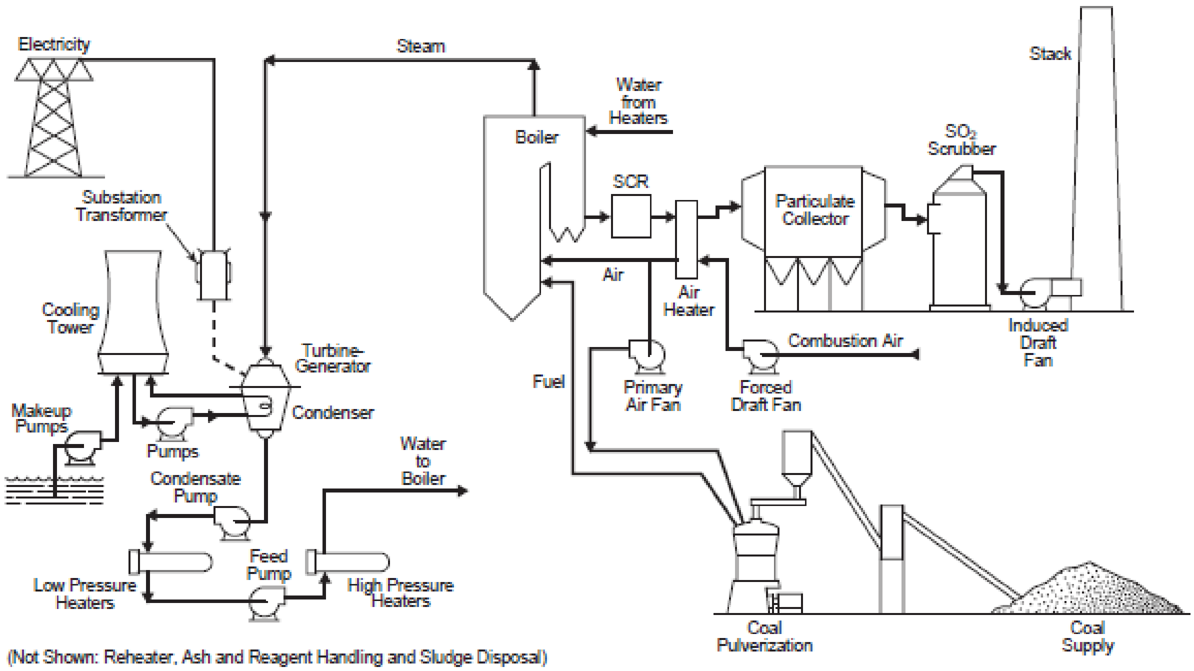

Figure 2-1 Coal-fired EGU schematic

Note: Used by permission. Courtesy of the Babcock & Wilcox Company.

2.2.1 Design characteristics and site-specific factors that affect heat rate

A variety of design characteristics, site-specific factors, and operating conditions can affect the heat rate of existing coal-fired EGUs. Some of these factors are influenced by or are under the direct control of the EGU operator, but other factors may be beyond the operator's control, such as:

Thermodynamic cycle. The thermodynamic steam cycle of a coal-fired EGU indicates the range of steam temperatures and pressures used in the boiler and steam turbine. There are two common steam cycles: subcritical and supercritical. In general, the higher the steam temperature and pressure, the higher the efficiency of the EGU and the lower the heat rate. Existing subcritical boilers that operate below the critical pressure of water (approximately 22.1 MPa or 3,206 psia) generally have higher heat rates with design thermal efficiencies of up to 35 percent while supercritical and ultrasupercritical EGUs that operate above the critical pressure of water may have design thermal efficiencies of 40 to 45 percent. In any case, actual thermal efficiencies in daily operation are usually lower than design values.

Boiler and steam turbine size. In general as the size of the boiler and the steam turbine increase, heat rate decreases. Larger coal-fired EGUs generally have lower heat rates for technical and economic reasons. Furthermore, relative to smaller EGUs, the larger EGUs typically have lower percentages of draft loss, heat loss, and seal leakage, and also tend to use more advanced technologies. They also have economies of scale for investment, operation, and maintenance, and have higher capacity factors because they are often dispatched before smaller, less-efficient units.

Cooling system. The design of the cooling system for existing coal-fired EGUs – once-through, recirculating (*i.e.*, evaporative), or dry – is largely dependent on an EGU's proximity to water resources, ecological concerns, and regulatory requirements. The cooling system design directly affects the steam turbine's ability to extract energy from the steam and affects overall efficiency. The amount of energy that the steam turbine can extract from the steam depends on the steam temperature and pressure as well as condenser pressure (affected by the cooling system design, condenser cleanliness, EGU load, and ambient cooling water or air temperature). At lower condenser pressures (within design limits), more energy can be extracted by the steam turbine, with a resulting lower EGU heat rate.

Auxiliary equipment. Auxiliary equipment, such as pumps, fans, pulverizers, and pollution control devices, require power to run, thereby consuming some of the electricity generation on-site and reducing the amount of electricity output available for use on the electricity grid. These systems vary in efficiency based on design, age, and usage.

Geographic location. Ambient conditions (*e.g.*, seasonal ambient temperatures, cooling water temperatures) at the power plant location affect an EGU's heat rate. Ambient air is mixed with the fuel prior to combustion, and a fraction of energy released during combustion heats the incoming air, increasing heat rate. Cooler water temperatures improve the efficiency of the cooling system, thereby reducing heat rate. Colder cooling water (or ambient air for dry cooling systems) in the condenser reduces the back pressure in the condenser, allowing for more energy to be extracted by the steam turbine.

Coal rank and quality. Higher rank coals (*e.g.*, bituminous) tend to have higher energy contents (*i.e.*, carbon content), burn more intensely, and have a lower moisture content than mid-rank (*e.g.*, subbituminous) and low-rank (*e.g.*, lignite) coals. In general, the lower the moisture content of coal, the less energy that is needed to evaporate the moisture and, therefore, the more energy that is available for producing steam, thus lowering heat rate. The ash content of the coal can also affect heat rate by accumulating on heat transfer surfaces (*i.e.*, metallic tubes) and impeding energy transfer to the steam. While systems are designed to remove this "soot," the quantity present between surface cleanings hinders energy transfer and results in higher heat rates.

2.2.2 Regional electricity interconnections

As discussed in sections V.A and V.C of the preamble for the final CPP rule and the associated *CO_2 Emission Performance Rate and Goal Computation Technical Support Document for CPP Final Rule*, EPA assessed the potential CO_2 reductions achievable through each of the building blocks that comprise the best system of emission reduction. The agency conducted assessments at the level of the three large regional electricity interconnections: Western, Texas, and Eastern (see

Figure 2-2). The Western Interconnection is a major power grid that comprises one North American Electric Reliability Corporation (NERC) region – the Western Electricity Coordinating Council (WECC). The Western Interconnection encompasses all or portions of 14 western states. The Texas Interconnection includes the portion of Texas managed by the Electric Reliability Council of Texas (ERCOT). The Eastern Interconnection is the other major regional power grid, comprising six NERC regions – Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), SERC Reliability Corporation (SERC), and Southwest Power Pool (SPP) – covering all or portions of 39 eastern and midwestern states.

Each interconnection is a highly-connected electricity grid in which, during normal conditions, power generated in one part of the interconnection can help balance power generation and load in all other parts of the system. Therefore, each interconnection must carefully manage electricity generation and load to ensure safe and reliable electricity service.

For the proposal, EPA analyzed the potential heat rate improvements from coal-fired EGUs at the national level. Some commenters suggested that EPA should adjust the analysis and develop state-specific estimates of potential heat rate improvements from coal-fired EGUs. While the agency carefully evaluated these comments, the agency determined that due to the highly interconnected nature of the electricity system, and as further discussed in section V.C.3 of the final rule preamble, it is more appropriate in this rule to assess potential for heat rate improvements from existing coal-fired EGUs at the regional interconnection level than at the national or state level.

2.2.3 Coal-fired EGUs in operation in 2012

In 2012, there were 884 coal-fired EGUs at 367 power plants in the contiguous U.S. (CONUS) that reported hourly heat input and gross electricity generation to EPA's Clean Air Markets Division.[5] These EGUs are spread across the CONUS (see Figure 2-2) in each of the three regional electricity interconnects. Of the 884 coal-fired EGUs, 93 (10.5 percent) are located in the Western Interconnection, 32 (3.5 percent) are located in the Texas Interconnection, and 759 (86 percent) are located in the Eastern Interconnection.

[5] Excludes cogeneration, integrated gasification and combined cycle (IGCC), retired, and non-operational EGUs. EGUs that reported steam co-generation to EPA or EIA are excluded because only a portion of heat input is used to generate electricity while the remainder is used to generate steam, making it difficult to meaningfully compare these EGUs' heat rates. IGCC units are excluded because they are not conventional steam boilers and may regularly use pipeline natural gas in lieu of syngas from coal gasification. EGUs retired prior to 2012 or EGUs that did not operate in 2012 are also excluded because they do not have 2012 operating data necessary to estimate potential heat rate improvement using the methodology described later in this document.

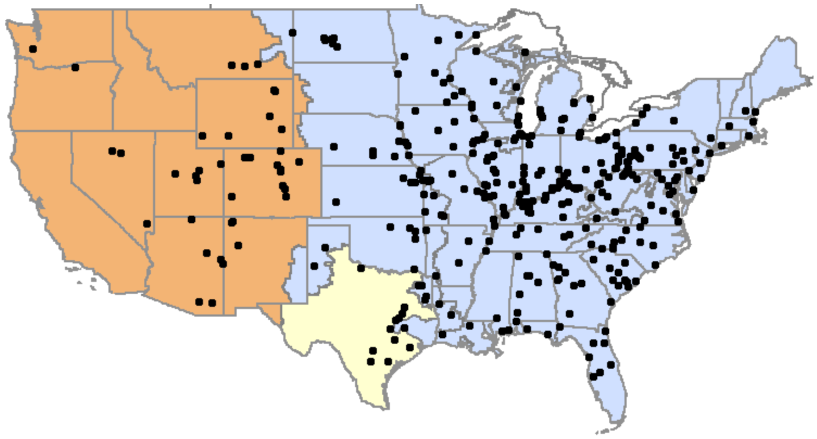

Figure 2-2 Power plants with coal-fired EGUs reporting heat input and gross electricity generation in 2012

The population of 884 coal-fired EGUs includes units with a variety of design configurations and operating characteristics that can affect an EGU's heat rate, such as thermodynamic steam cycle, coal rank and coal quality, boiler type, boiler size (*i.e.*, maximum hourly heat input), and generator power output capacity.

At the end of 2012, the age of the 884 coal-fired EGUs varied widely, ranging from less than 1 year to 68 years. Nationally, the average age was 42 years, but this differed among the interconnections. The Texas Interconnection had the lowest average age of existing coal-fired EGUs at 27 years followed by the Western Interconnection at 34 years. The average age of the coal-fired EGUs in the Eastern Interconnection was 44 years (see Figure 2-3).

Similarly, electricity generating capacity of the 884 coal-fired EGUs varied widely within and between the interconnections. In 2012, the capacity ranged from 25 MW to nearly 1,500 MW with a national average capacity of 385 MW.[6] In the Western Interconnection the average generator capacity of coal-fired EGUs was 390 MW, in the Texas Interconnection the average was 689 MW, and in the Eastern Interconnection the average was 372 MW (see Figure 2-4).

[6] EGU operators report maximum hourly load data to EPA/CAMD. This value may differ from the EGU's nameplate capacity and summer net capacity.

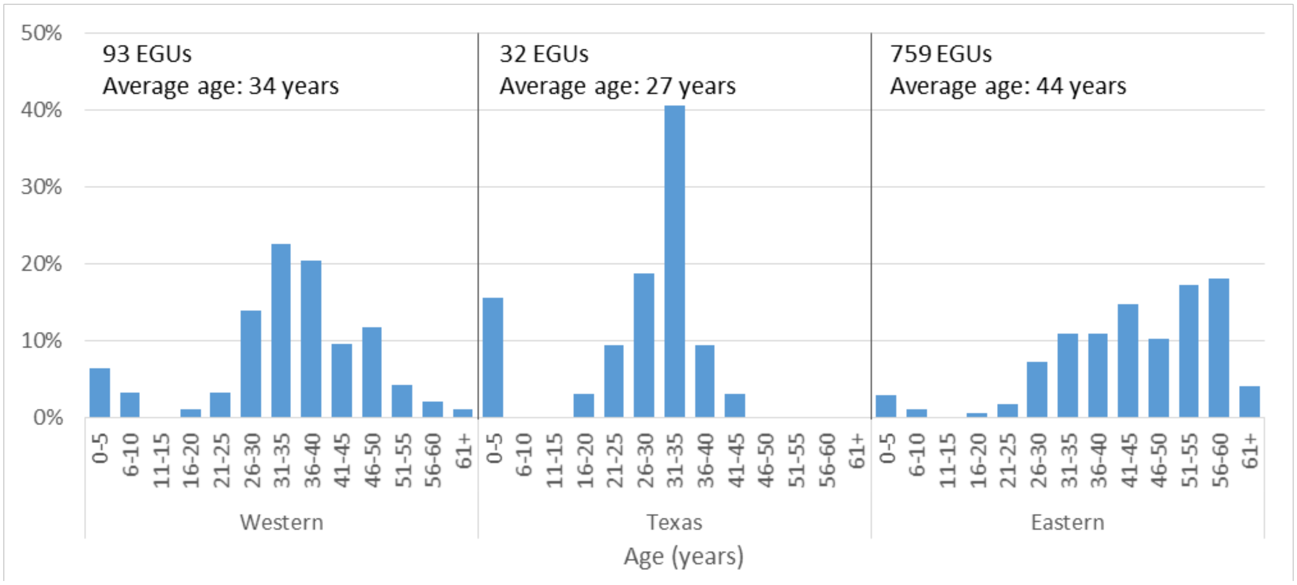

Figure 2-3 Age (years) distribution of coal-fired EGUs in 2012, by interconnection

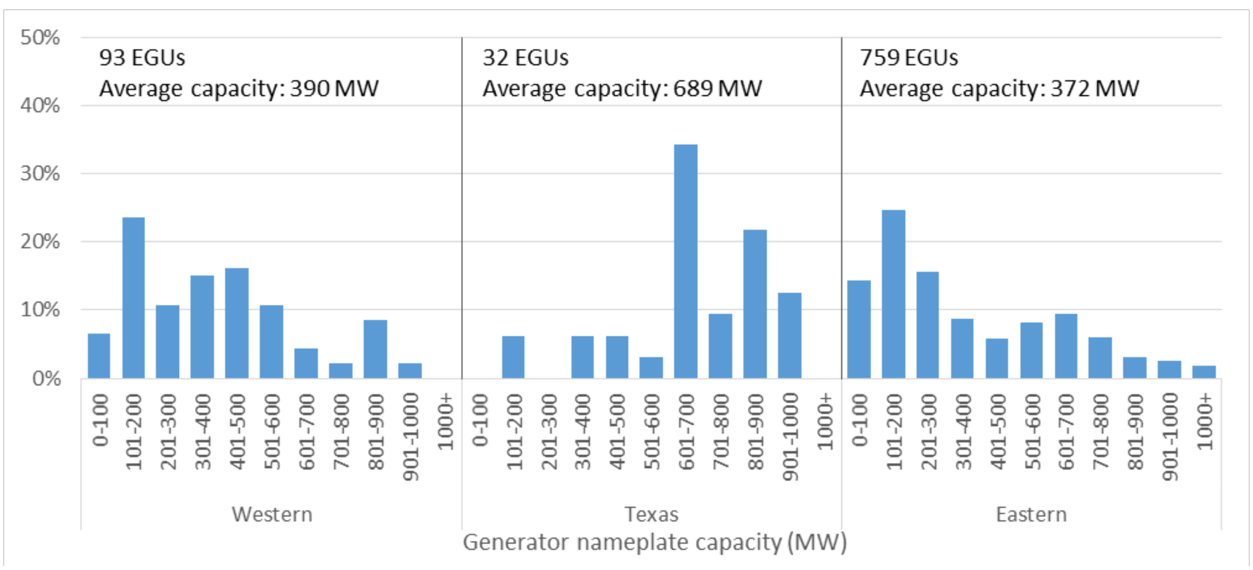

Figure 2-4 Generator capacity (MW) distribution of coal-fired EGUs in 2012, by interconnection

2.2.3.1 Historical gross heat rate trends of coal-fired EGUs

Between 2002 and 2012, the average gross heat rates of the 884 coal-fired EGUs have fluctuated from year to year. Nationally, the average gross heat rate[7] declined between 2002 and 2008 to a low of 9,645 Btu/kWh in 2008 and 2009 (see Figure 2-5). However, after 2009, the average annual gross heat rate of the 884 coal-fired EGUs began to deteriorate, climbing to 9,753 Btu/kWh in 2012.

The variation for each of the interconnection regions was more pronounced. The average annual gross heat rate of the 93 coal-fired EGUs in the Western Interconnection declined from nearly 10,458 Btu/kWh in 2002 to 9,888 Btu/kWh in 2012, just slightly higher than the lowest gross heat rate in 2010. The larger and relatively younger 32 coal-fired EGUs in the Texas Interconnection saw less change than those in the Western Interconnection. The lowest average gross heat rate for the Texas Interconnection occurred in 2009 and was only slightly higher in 2012 (9,760 Btu/kWh and 9,789 Btu/kWh in 2009 and 2012, respectively). In the Eastern Interconnection, where 86 percent of the coal-fired EGUs are located, gross heat rates have steadily increased since 2008, rising from 9,567 Btu/kWh to 9,700 Btu/kWh.

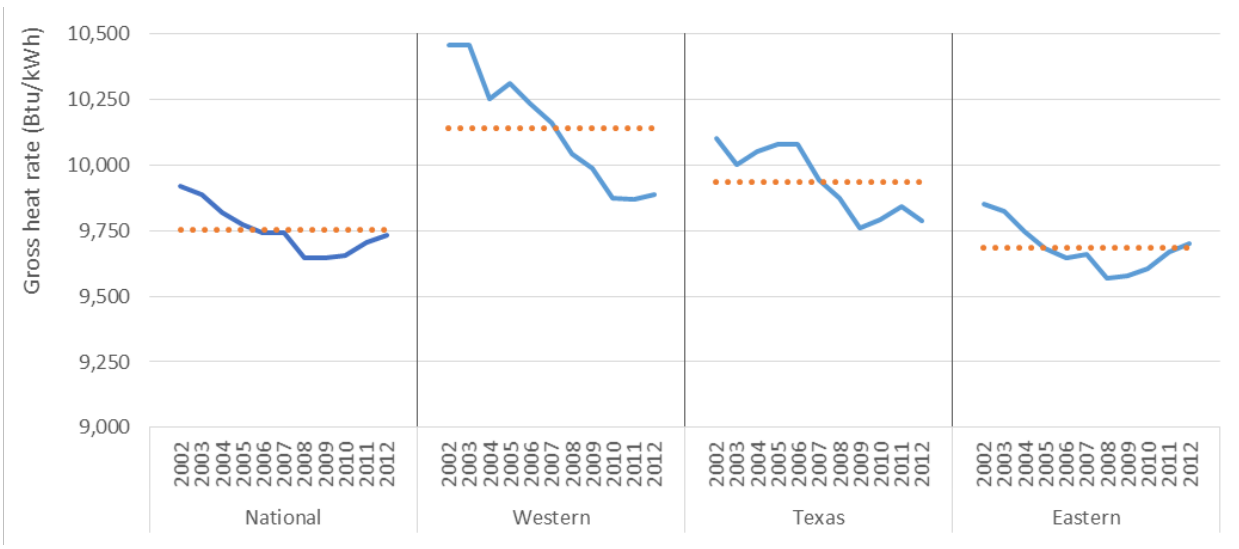

Figure 2-5 Gross heat rate trends of coal-fired EGUs, 2002-2012 by interconnection

Notes: red dotted line represents the 11-year arithmetic average;
axis does not start at zero to better illustrate trends in gross heat rate

Commenters have offered a variety of opinions in an attempt to explain these gross heat rate trends over time, such as shifts from low-moisture bituminous coals to higher-moisture subbituminous coals from the Powder River Basin, installation of air pollution control devices in response to

[7] EPA used hourly heat input (Btu) and hourly gross electricity generation (kWh) to calculate the hourly gross heat rate (Btu/kWh). As described later in this chapter, gross generation was the only complete and accurate hourly dataset available to EPA. Therefore, unless otherwise noted, references to heat rate in this chapter refer to gross heat rate.

federal and state regulations, retirements of less-efficient coal-fired EGUs, fluctuations in precipitation and weather conditions, deterioration of plant equipment or deferral of equipment maintenance, or changes in dispatch patterns and capacity factors. EPA acknowledges that there are many factors that can affect the heat rate of coal-fired EGUs, some of which are within the EGU operator's control and some that are not. In the analysis of potential heat rate improvements described below, the agency attempts to limit the influence of some of the factors outside the EGU operator's control.

2.3 Heat rate improvement practices and equipment upgrades at coal-fired EGUs

In the proposal TSD, EPA provided examples of best practices and equipment upgrades that may be available to existing coal-fired EGUs to improve heat rate and, as a result, reduce the EGU's CO_2 emissions intensity.[8] Several commenters also provided extensive information about additional best practices and equipment upgrades that may be available for coal-fired EGUs to improve heat rate. Commenters also noted that many coal-fired EGUs have already implemented heat rate improvement measures for economic reasons and requiring EGUs to implement the measures again might not yield substantial benefits or might not be feasible.

As explained in section 2.5 below and in preamble sections V.A and V.C, the agency has decided not to estimate a separate potential for heat rate improvements from equipment upgrades. As stated in the proposal TSD, the agency lacks reliable and complete information about the unit-level upgrades that coal-fired EGUs have already implemented and it is not practical for EPA to conduct engineering analyses at each coal-fired EGU for the purpose of answering the question about whether existing coal-fired EGUs are already taking advantage of all opportunities to improve heat rate. Nonetheless, the agency remains confident that there are additional opportunities for coal-fired EGUs to achieve heat rate improvements by implementing some combination of best practices and equipment upgrades, including the illustrative best practices and equipment upgrades shown below. The agency recognizes that the types and extent of capital improvements and operational and maintenance improvements available to individual coal-fired EGUs will vary. For this and other reasons stated below, the agency is therefore not basing the estimate of potential heat rate improvement on a specific proportion of best practices or equipment upgrades.

The lists below are intended to provide examples of equipment upgrades and best practices to improve heat rates. While the agency believes these equipment upgrades and best practices are highly cost-effective, the agency recognizes that some EGUs (*e.g.*, small EGUs) may not find each of the measures to be cost effective. In addition, the agency recognizes that not all measures are applicable to each and every EGU. Therefore, these lists are intended only to demonstrate the types of actions that EGUs might be able to implement to improve or maintain heat rate.

[8] See Clarified Technical Support Document, *supra* note 1.

2.3.1 Example equipment upgrades for heat rate improvement

- Install intelligent sootblowing system
- Replace feed water pump steam turbine seals
- Overhaul high pressure feed water pumps
- Upgrade main steam turbine seals
- Upgrade steam turbine internals
- Install variable frequency drives for motors
- Retube or expand the condenser
- Install sorbent injection system to reduce flue gas sulfuric acid to allow lower temperature exhaust gas
- Upgrade air heater baskets for lower temperature operation
- Upgrade and repair flue gas desulfurization systems
- Refurbish the economizer
- Upgrade ESP components to lower auxiliary power consumption
- Improve SCR and FGD system components to lower draft loss

2.3.2 Example best practices for heat rate improvement

- Adopt training for O&M staff on heat rate improvements
- Perform on-site appraisals to identify areas for improved heat rate performance
- Install neural network software for combustion/optimization with monitoring system for heat rate optimization
- Repair steam and water leaks – replace leaking valves and steam traps
- Replace / repair worn air heater seals
- Manage feed water quality
- Chemical clean boiler to remove scale build-up from water side
- Install and operate condenser tube cleaning system
- Repair boiler furnace and ductwork cracks to prevent boiler air in-leakage
- Clean air preheater coils to restore performance
- Adopt sliding pressure operation to reduce turbine throttling losses
- Reduce activation of attemperator which compensates for over-firing the unit
- Remove deposits on turbine blades

2.3.3 Heat rate improvement measures identified by external studies

There are a number of engineering studies that explore opportunities for improving the efficiency of existing coal-fired power plants, including studies by Sargent & Lundy and NETL that were referenced in the proposal TSD. Some of the practices and equipment upgrades have the potential to improve gross heat rate while others will not affect an EGU's gross heat rate, but they will reduce the auxiliary load from on-site equipment, thereby improving the net heat rate (*i.e.*, making more net electricity available for the same amount of fuel input). The following potential efficiency improvements in the boiler, turbine, flue gas system, air pollution control equipment, and the water treatment system are discussed below.[9]

2.3.3.1 Boiler systems

2.3.3.1.1 Materials handling

Materials handling includes the handling and transport of coal, the preparation of coal for combustion, and handling of combustion residues:

- Coal-handling equipment: Installation of energy-efficient motors and variable frequency drives can reduce auxiliary power requirements.
- Coal pulverizers: Upgrading the pulverizers to provide more consistent size and finer coal particles can improve the EGU's combustion efficiency, produce less unburned coal, and consequently reduce fuel cost and gross heat rate.
- Bottom ash handling equipment: Switching from a water-sluicing bottom ash system to a dry system can reduce the auxiliary requirements and reduce the amount of wastewater to the water treatment plant.

2.3.3.1.2 Boiler control system

The boiler control system has a large impact on the gross heat rate of the unit. Commonly referred to as the DCS (Distributed Control System), this computer controls and displays many parameters affecting boiler operation. A neural network is an advanced control system utilizing artificial intelligence and installed in addition to the plant DCS. The neural network evaluates many parameters of the EGU's operation and makes adaptive tuning based on statistical analysis to predict performance for increased efficiency. Many vendors offer neural network systems to improve the overall efficiency. These systems can offer gross heat rate improvements up to 150 Btu/kWh.

2.3.3.1.3 Steam turbine

The steam turbine extracts energy from the steam and rotates a generator to produce electricity. Modern developments allow the steam turbine to extract more energy from the same amount of steam than was possible with equipment from decades ago. Replacing existing steam turbines with advanced designs or, where practical, upgrading turbines with improved internals can reduce gross heat rate by 100-300 Btu/kWh. As one commenter pointed out, Leyzerovich explains that

[9] Chapter 2 of the proposal TSD provides a detailed description of numerous well-proven measures for improving heat rate at coal-fired EGUs. See *supra* note 1.

upgrading and retrofitting a turbine at a 20-year old 500 to 700 MW coal-fired EGU can reduce heat rate by a total of about 4 percent while also increasing output by approximately 5 percent.[10]

2.3.3.1.4 Feed water heaters

Boiler feed water heaters pre-heat the water going to the boiler. The hotter the water entering the boiler, the less energy it takes to convert it to steam. Like any heat exchanger, EGUs can improve efficiency by removing built-up scale or increasing heat transfer surface area. Chemical cleaning removes scale and restores heat transfer efficiency.

2.3.3.1.5 Condenser

Condensers are subject to fouling and plugging, which directly impact the heat transfer efficiency and water quality. Closed cooling water systems can be used to provide better control over water quality and tube cleaning can be performed as needed. Condenser upgrades and maintenance typically improve gross heat rate by 30-70 Btu/kWh.

2.3.3.1.6 Cooling tower

The temperature of cooling water affects condenser performance. Supplying cold water allows the condenser to operate at lower pressures, which allows the steam turbine to extract more energy for power generation. As the cooling towers foul, the water returned to the condenser becomes warmer and negatively affects steam turbine performance and reduces gross electricity generated. Routine maintenance on the cooling towers might include discarding accumulated debris, removing biologic growth, replacing defective fill material, ensuring uniform water distribution, correcting for uneven air distribution, verifying water flow rates, and replacing missing louvers

2.3.3.1.7 Boiler feed water pumps

Boiler feed pumps require a large amount of auxiliary power to pump large amounts of boiler feed water through the heaters and the boiler. Due to their continuous operation, the pumps wear over time, lose efficiency, and require more energy to move the same volume of water. A pump overhaul restores efficiency, ensures reliability, and can reduce the net heat rate by 25-50 Btu/kWh.

2.3.3.1.8 Water Treatment System

The quality of boiler water affects the rate of scale build-up on boiler tubes. Scale inhibits heat transfer and the EGU operator typically compensates by increasing the firing-rate to overcome this effect. Scale can reduce heat transfer up to 10 percent in severe cases. However, the higher the quality of water used in the boiler, the slower the scale build-up and thus the higher the efficiency

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[10] See page 477 in AS Leyzerovich, 2007. Steam Turbines for Modern Fossil-Fuel Power Plants. CRC Press. ISBN 13: 978-1420061024.

of the EGU. Enhanced water treatment can reduce scale. In addition, scale can be removed through chemical cleaning to restore heat transfer and lower gross heat rate.

The cooling water system can also suffer from poor water quality for the same reason – scale build-up fouls the heat transfer surfaces in the condenser, causing higher condenser temperatures and reducing the capability of the turbine to extract energy from the steam. Chemical cleaning and better water quality can mitigate the issue.

2.3.3.1.9 Variable frequency drives

Replacing fixed speed electric motors with variable frequency drives reduces auxiliary power requirements by reducing the drives' speed (*i.e.*, rpm) when maximum speed is not required. The net heat rate improvements can be 10-150 Btu/kWh.

2.3.3.2 Flue gas and emission control technologies

Equipment to move flue gases and control air pollution typically require large amounts of auxiliary power to properly operate equipment. Even small upgrades to the equipment can decrease auxiliary power requirements while maintaining emission reduction levels.

2.3.3.2.1 Economizer

The economizer extracts energy from the combustion gases as they exit the furnace. This energy is used to preheat the water returning to the boiler. This heat exchanger improves EGU efficiency by reducing the amount of fuel required to convert water into steam. The replacement or refurbishment of the economizer can lead to gross heat rate improvements of around 50-100 Btu/kWh.

2.3.3.2.2 Sootblowers

Coal combustion produces ash that builds up on tubing surfaces, reducing heat transfer for steam generation and resulting in higher gross heat rates. Sootblowers remove built-up coal ash to restore performance of the heat transfer surfaces. Intelligent sootblowers monitor system conditions and activate when boiler operation indicates the need to remove ash rather than activating at arbitrary time intervals set by operators. These systems use real-time furnace data to identify specific areas requiring ash removal. They can improve gross heat rates 30-150 Btu/kWh.

2.3.3.2.3 Air heaters

Air heaters transfer heat between the incoming pre-combustion air and the exiting flue gas. By preheating the combustion air, less fuel is required to convert pre-heated water to steam. Due to their design, leakage can occur and, as a result, reduce the pre-combustion air temperature, requiring greater coal consumption. Leakage also increases auxiliary power requirements since equipment must now handle the increased volume of air from the in-leakage. Properly maintained air heaters limit leakage to below 6 percent. Reducing leakage can reduce the auxiliary power requirements and, therefore, the net heat rate by 10-40 Btu/kWh.

Another method to improve heat rate is to extract more energy across the air heater to raise pre-combustion air temperature. Typically, the air heater outlet is maintained at 20-30°F above the sulfuric acid dew point to prevent corrosion. Depending on the air heater's size, major modifications may be required to capture more energy, but the modifications might reduce gross heat rate by 50-120 Btu/kWh.

2.3.3.2.4 Induced draft fans and forced draft fans

Induced draft fans and forced draft fans typically operate at constant speed with dampers to control flue gas flow rate. Using dampers is the conventional choice to control flow while the fan motor runs at constant speed. However, newer methods are available to control flow for more efficient operation while reducing auxiliary load (*e.g.*, variable frequency drives, variable pitch blades). These upgrades or replacements provide net heat rate improvements of 10-50 Btu/kWh.

2.3.3.2.5 Flue gas desulfurization

A variety of flue gas desulfurization systems are used at existing coal-fired EGUs. Some EGUs still employ outdated venturi-type designs that create large pressure drops and require greater auxiliary power to operate the induced draft fans. Upgraded designs, such as co-current spray tower quenchers, can replace the outdated designs and enhance net heat rate.

A more common flue gas desulfurization technology installed throughout the fleet is a spray tower absorber, also known as a wet scrubber. Technology upgrades, including installing turning vanes to reduce pressure drop and improve gas flow, can reduces induced fan auxiliary power requirements and enhance net heat rate.

2.3.3.2.6 Electrostatic precipitator

Efficient electrostatic precipitator operation involves maintaining the maximum applied voltage, without arcing. Arcing represents lost energy unusable for particulate removal and requires the field be re-energized, consuming additional auxiliary power. Electrostatic precipitator upgrades can improve performance by eliminating arcing and reducing auxiliary power consumption.

2.3.3.2.7 Selective catalytic reduction

Innovations in selective catalytic reduction systems have reduced auxiliary energy requirements, such as the use of hot secondary air or auxiliary steam for heating system equipment (instead of electrically heating ambient air). Catalyst design can lower pressure drop across the reactor and reduce induced fan auxiliary power requirements.

2.4 External studies of heat rate improvement potential at existing coal-fired EGUs

There are a number of technical and statistical studies that explore opportunities to improve heat rate at existing coal-fired EGUs in the U.S. In the proposal TSD, EPA summarized five studies that found potential heat rate improvements of between 8.7 and 15 percent from existing coal-fired EGUs. Commenters provided information on additional studies, including government and independent research reports that assess potential heat rate improvements from a large study population of coal-fired EGUs. In general, the concepts for improving heat rate or reducing CO_2 emissions presented in these studies focus on: reducing heat losses, extracting more energy from the steam cycle, replacing worn or degraded equipment, installing equipment upgrades, increasing data measurement and tracking to enhance operation and efficiency, conducting routine maintenance to sustain peak performance, hiring staff dedicated to heat rate improvement and management, and instituting a corporate culture that places emphasis on efficiency improvements.

The studies use a variety of approaches to estimate potential heat rate improvement and CO_2 emission reductions. For example, some studies used engineering assessments, some subcategorized EGUs by specific design characteristics or operating conditions and then compared EGUs in each subcategory against one another, and others compared each EGU's heat rate performance or CO_2 emission rate over time. Summaries of several of the studies referenced in the proposal TSD are presented below.

NETL produced a number of reports and workshop summaries about improving efficiency at existing coal-fired EGUs. In a 2009 workshop to "explore opportunities to improve the thermal efficiency of existing and future coal-fired power plants," NETL brought together 18 leading industry experts representing EGU operators, equipment vendors, energy consultants, and industry associations to analyze the technical and non-technical issues affecting power plant efficiency.[11] The analysis identified a wide variation in efficiency levels across the EGU fleet, but found numerous opportunities to improve efficiency exist, such as: (1) decreasing excess oxygen to the boiler, (2) installing variable speed motors, (3) utilizing waste heat for coal drying, and (4) employing solar systems to heat feed water. The report identifies several barriers that limit the adoption of measures to improve heat rate, including: (1) lack of economic incentives to improve efficiency because of fuel adjustment clauses that enable electricity generating companies to "pass through" changes in fuel costs directly to customers, (2) lack of management commitment for efficiency programs, (3) focus on optimizing profitability and ensuring EGU availability over efficiency, and (4) lack of on-site performance engineers dedicated to heat rate improvement. In general, the report found that while heat rate improvements and efficiency are important, potential

[11] See J Eisenhauer and R Scheer, 2009. Opportunities to Improve the Efficiency of Existing Coal-fired Power Plants. NETL Workshop Report. 2009 July 15-16 in Rosemont, IL. Available at http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/OpportImproveEfficExistCFPP-ReportFinal.pdf.

fuel cost savings represent only a small portion of total costs and are "of secondary concern when compared to needs for maintaining system reliability."

A second NETL workshop was conducted with 53 leading industry experts to explore technical opportunities to improve efficiency, identify barriers, and identify initiatives to enhance efficiency across the fleet.[12] The workshop participants developed a list of more than 50 distinct opportunities to improve efficiency, many of which are broadly applicable "across most of the fleet of coal-fired [EGUs]," including better sensing, measurement, and control; better and more frequent maintenance; improved fuel handling; and capital upgrades and improvements.

In 2010, NETL published a report that estimated existing coal-fired EGUs could enhance efficiency from a fleet wide generation-weighted efficiency of 32.5 percent in 2008 to 35.2 percent, equivalent to a heat rate improvement of about 9 percent.[13] To develop the estimate, NETL segmented coal-fired EGUs into 13 groups based on steam cycle, coal type, and capacity. Using data from 1998 to 2008, the researchers identified the 90th percentile EGU,[14] ranked by efficiency, within each of the 13 segments and calculated the potential efficiency improvements if all EGUs below the 90th percentile improved their average efficiency to the level of the 90th percentile EGU in the segment. Aside from the impact of steam cycle, coal type, and capacity, the NETL study found that other design characteristics, location, and emission air pollution controls did not account for variations in plant efficiency. NETL also conducted an alternate analysis that evaluated existing coal-fired EGUs' past performance between 1998 and 2008 and found that if each EGU returned to its own best historical heat rate, overall fleet wide heat rate would improve more than 6 percent.

Lehigh University's Energy Research Center (ERC) compiled techniques for improving heat rate, and a 2009 update stated improvements in net heat rate of up to 15 percent for existing coal-fired EGUs burning Powder River Basin subbituminous coal and lignite coal, and 10 percent for bituminous coal were possible if improvements could be made "in all possible areas."[15] However, the authors note that it would not be possible to take full advantage of all opportunities at all EGUs, but the information demonstrates that there are substantial opportunities to improve heat rate. The

[12] See R Brindle, J Eisenhauer, A Greene, M Justiniano, L Kishter, M Munderville, R Scheer, 2010. Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States. Workshop Report. 2010 February 24-25 in Baltimore, MD. Available at http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/ThermalEfficCoalFiredPowerPlants-TechWorkshopRpt.pdf.

[13] See P DiPietro and K Krulla, 2010. Improving the Efficiency of Coal-Fired Power Plants for Near Term Greenhouse Gas Emissions Reductions. NETL Report DOE/NETL-2010/1411. Available at http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2010-1411-ImpEfficCFPPGHGRdctns-0410.pdf.

[14] NETL ranked heat rate in the opposite order of many of the other studies discussed below. Therefore, the 90th percentile in the NETL study is methodologically equivalent to the 10th percentile performer in the studies discussed below.

[15] See Lehigh University Energy Research Center, 2009. "Reducing Heat Rates of Coal-fired Power Plants," Lehigh Energy Update, 27(1). Available at http://www.lehigh.edu/~inenr/leu/leu_61.pdf.

research includes improvement opportunities from process optimization, more aggressive maintenance practice, and equipment design modifications.

The Congressional Research Service (CRS) published a report summarizing NETL and other analyses.[16] The report notes that as coal-fired EGUs age, the EGUs lose efficiency due to mechanical wear; minimizing energy losses presents the greatest opportunity for regaining efficiency through equipment refurbishment, improved operations, and dedicated maintenance programs. For example, the top 10 percent of EGU's operate on average 3.5 percentage points more efficiently than the remaining fleet. Consequently, there exists room for improvement.

Lashof et al. of the Natural Resources Defense Council (NRDC) analyzed the potential heat rate improvements from coal-fired EGUs from a suite of heat rate improvement measures at EGUs with the highest heat rates for their thermodynamic steam cycle category.[17] The study ranked coal-fired EGUs by their full-load gross heat rate. EGUs that ranked higher than the 10th percentile for their category, but lower than the median (*i.e.,* 50th percentile) were assumed to have potential heat rate improvements of 300 Btu/kWh and EGUs ranked greater than the median for their category were assumed to have potential heat rate improvements of 600 Btu/kWh. The 600 Btu/kWh heat rate improvement is based on measures outlined in the NRDC report (*e.g.,* combustion optimization software and controls, upgrading economizers, cleaning and tuning steam condensers).

Linn et al. examined annual heat rate data from approximately 1,000 coal-fired EGUs between 1985 and 2009, grouping plants by boiler type, age, size, and other characteristics.[18] The RFF study estimates that if coal-fired EGUs in each category improved heat rate to the level of the EGU with the 10th percentile heat rate in the category, overall gross heat rate would improve by 5.5 percent.

Sargent & Lundy, LLC (S&L) developed an engineering study for EPA of potentially applicable heat rate improvement methods for coal-steam EGUs. The S&L study, cited in the proposal TSD, presents technical descriptions of numerous well proven, commercially available heat rate improvement techniques. The study also includes indicative ranges of potential heat rate improvement (Btu/net kWh) with associated indicative ranges of capital and O&M costs at three unit sizes (200, 500, and 900 MW).

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[16] See RJ Campbell, 2013. Increasing the Efficiency of Existing Coal-Fired Power Plants. CRS Report R43343. Available at http://fas.org/sgp/crs/misc/R43343.pdf.

[17] See DA Lashof, S Yeh, D Doniger, S Carter, L Johnson, 2013. Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

[18] See J Linn, E Mastrangelo, and D Burtraw, 2014. "Regulating Greenhouse Gases from Coal Power Plants under the Clean Air Act," Journal of the Association of Environmental and Resource Economists. 1(1/2): 97-134. (DOI: 10.1086/676038). First published as 2013 working paper RFF-DP-13-05 available at http://www.rff.org/rff/Documents/RFF-DP-13-05.pdf.

Several leading energy sector engineering consultants produced conference papers and presentations that summarize real-world projects and/or the consultants' experience with heat rate improvement projects. In a conference paper, Storm indicated that there were at least 22 O&M heat rate factors that are controllable by the EGU operator, including (1) reducing air in-leakage into the boiler; (2) improving fineness of fuel by optimizing coal pulverizers; (3) reducing air heater leakage; (4) optimizing primary, overfire air, and secondary air flow measurement and control; and (5) balancing fuel and air distribution into the burner belt. The consultant estimates that the average large coal-fired EGU has about 300 to 500 Btu/kWh potential heat rate improvement (*i.e.,* about 3 to 5 percent for an EGU with a heat rate of 10,000 Btu/kWh). The consultant goes on to say that "exacerbating the challenge [to improve heat rate] is the fact that often major plant overhauls have been changed from 6 months between boiler scheduled outages to sometimes more than 2 years."[19]

Commenters submitted independent studies to inform EPA's analysis of potential heat rate improvement, including engineering analyses, statistical analyses, and case studies. The results of the commenters' studies provide similar results to EPA's potential heat rate improvement analyses described in the following section. The commenters' studies are summarized below.

Sierra Club and Earthjustice submitted an independent study comparing each coal-fired EGU's best rolling 365-day gross heat rate between 2001 and 2012 against the EGU's own average gross heat rate.[20] The study included 52 randomly selected coal-fired EGUs designed to represent the coal-fired EGU fleet as a whole (based on 2012 electricity generation). The study uses rolling 365-day averages of daily gross heat rates in order to minimize the influence of weather and electricity generation, and to represent long-term trends. For each EGU, the EGU's lowest and 95th percentile rolling 365-day average gross heat rate were compared to the EGU's 12-year average gross heat rate (2001-2012). The results of the analysis indicate that, on average, the coal-fired EGUs in the study achieved and maintained gross heat rates over a 365-day period that were 7.6 or 6.1 percent lower at the lowest and 95th percentile gross heat rate, respectively.

The General Electric Company (GE) submitted an assessment of technical, economic, and market potential for heat rate improvements at coal-fired EGUs.[21] The assessment identified equipment upgrades and best practices that, individually, could improve heat rate between 0 and 2.9 percent. The study estimated the average technical potential for gross heat rate improvements to be 5.8 for large coal-fired EGUs to 6.8 percent for smaller coal-fired EGUs. To calculate the economic

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[19] See D Storm, 2009. Applying the Fundamentals for Best Heat Rate Performance of Pulverized Coal Fueled Boilers. EPRI 2009 Heat Rate Conference Paper. 2009 February 3-5 in Albuquerque, NM. Available at http://www.stormeng.com/pdf/EPRI2009HeatRateConference%20FINAL.pdf.

[20] See Comments of Sierra Club and Earthjustice. Available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-24029. Also, see B Buckheit and N Spiegel, 2014. Sierra Club 52-Unit Study: Data Files. Available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-25475.

[21] See Comments of The General Electric Company. Available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-22971.

potential, GE estimated the penetration rate for equipment upgrades and best practices by establishing a "best in class" full load net heat rate benchmark (9,400 Btu/kWh), irrespective of EGU design characteristics, and compared each EGU's full-load net heat rate to the "best in class" benchmark to determine potential heat rate improvements. The study then constrained equipment upgrades and best practices to those with costs below the social cost of carbon, resulting in estimated heat rate improvement of 6.3 percent for large coal-fired EGUs to 5.3 percent for small coal-fired EGUs. Finally, the study includes an assessment of market potential based on results from the North American Electricity & Environmental Model (NEEM). For the modeling study, each state was constrained to the CO_2 emission rate from EPA's proposal; coal-fired EGUs for which the study assumed some heat rate improvement measures were implemented were only offered the option to use the most expensive heat rate improvements (on the assumption that the lower price options were already implemented at the EGU.) Using the least-cost electricity utility planning framework of NEEM, the modeling study estimates that only 1 percent heat rate improvement will be implemented and the remaining CO_2 reductions will come from other actions within each state.

In addition to the reports described above, POWER Magazine published an article on heat rate improvement opportunities at coal-fired EGUs.[22] Korellis summarized an Electric Power Research Institute (EPRI) report of heat rate improvement case studies at five large coal-fired EGUs with electricity generating capacities of 95 to 650 MW, combusting Powder River Basin subbituminous (3 EGUs) and bituminous (2 EGUs) coal, and utilizing different thermodynamic steam cycles (2 supercritical and 3 subcritical). Through a combination of best practices and equipment upgrades, four of the five EGUs were able to improve net heat rate by 3 to 5 percent (see Table 2-1). Common issues at the EGUs prior to the heat rate improvement projects included: (1) problems related to combustion and high air heater/stack gas temperatures, (2) shortage of heat rate data, (3) lack of training and understanding of controllable losses, (4) lack of performance testing, (5) problems with feed water heater train performance, and (6) buildup of soot on heat transfer surfaces. The article provides a list of general and EGU-specific heat rate improvement recommendations with estimated reductions in heat input. The article also provides a summary of a utility's "fleet wide" heat rate improvement assessment. The engineering study indicated that the 12 coal-fired EGUs in a member utility's fleet could improve net heat rate by approximately 5.3 percent at a cost of approximately $40 per ton of CO_2 reduced. The summary of the full report states, "[r]educing a power plant's heat rate can lower emissions, fuel consumption, and costs, thus contributing to the plant's bottom line. A significant improvement in heat rate can often be achieved with a re-

[22] See S Korellis, 2014. "Coal-Fired Power Plant Heat Rate Improvement Options, Part 2," Power Magazine. Available at http://www.powermag.com/coal-fired-power-plant-heat-rate-improvement-options-part-2. For the full report, see EPRI, 2014. Range and Applicability of Heat Rate Improvements. Technical Update 3002003457. Available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003457. This supplementary study expands upon and confirms the large quantities of similar information presented in this TSD.

commitment to best operating practices, which can minimize the need for capital expenditures on new technology."

Table 2-1 EPRI net heat rate improvement case study at five coal-fired EGUs

EGU	Project type	Net heat rate improvement
A	Implementing multi-level heat rate teams, training, managing excess air	279 Btu/kWh
B	Aligning cycles, reducing air inleakage, chemically cleaning turbine	557 Btu/kWh
C	Maintaining steam path and replacing feed water heater	400 Btu/kWh
D	Reducing air inleakage, replacing feed water heater, cleaning condenser and feed water tubes	500 Btu/kWh
E	[Not available]	Heat rate increased (350 Btu/kWh)

A report by the Energy Information Agency (EIA) used data from 1,027 coal-fired EGUs to estimate potential net heat rate improvements.[23] The coal-fired EGUs were grouped into quartiles based on the difference between reported and predicted net heat rates. Those EGUs with the least difference between the reported and predicted net heat rates (*i.e.*, 1st quartile) were assumed to have the least potential for net heat rate improvement while those with the largest difference (*i.e.*, 4th quartile) were assumed to have the most potential for net heat rate improvement. Using a matrix of 29 heat rate improvement measures (out of 56 identified in the study), the study determined that net heat rate for the 1,027 coal-fired EGUs could be improved, on average, by approximately 2.0 to 5.5 percent at capital costs of approximately $300/kW of capacity.

These studies provide technical information about potential heat rate improvement at existing coal-fired EGUs, including available best practices and equipment upgrades. As several commenters noted, these studies demonstrate that heat rate improvements are both readily available and achievable. The studies and commenters' suggestions informed EPA about the different

[23] See EIA, 2015. Analysis of Heat Rate Improvement Potential at Coal-Fired Power Plants. Available at http://www.eia.gov/analysis/studies/powerplants/heatrate/pdf/heatrate.pdf. This supplementary study expands upon and confirms the large quantities of similar information presented in this TSD.

approaches and analytical techniques that are available to assess potential heat rate improvements at existing coal-fired EGUs. The agency used the information to enhance the analytical approaches, but decided not to adopt any one of the studies described above. The agency believes its analyses, described in the next section, are more appropriate for the purpose of determining potential heat rate improvement for this final rule because the agency's approach: (1) uses more recent data on nearly all existing coal-fired EGUs in the CONUS; (2) compares EGUs' 2012 performance against the EGUs' best performance, largely obviating the need for subcategorization or a "one-size-fits-all" heat rate or CO_2 emission rate; and (3) controls for key ambient and operating conditions outside the EGU operators' control.

2.5 EPA study of heat rate improvement potential at existing coal-fired EGUs

To assess potential heat rate improvements at coal-fired EGUs, EPA began by looking at each coal-fired EGU's past gross heat rate performance. EPA used three analytical approaches to assess potential heat rate improvement for each interconnection by comparing the EGUs' best historical gross heat rates between 2002 and 2012 against the EGUs' own 2012 gross heat rate. The agency based this approach on the reasonable expectation that, in the general sense, if coal-fired EGUs in an interconnection were able to demonstrate and achieve specific heat rates in the past, the EGUs should be able to achieve similar heat rates again. The advantages of such an approach are (1) it compares each EGU against the EGU's own past performance, thereby controlling for many of the design characteristics that vary among EGUs but are constant or nearly constant over time at individual EGUs (*e.g.*, generator capacity, thermodynamic steam cycle, coal type, cooling system type); (2) it accounts for heat rate improvement measures employed during the study period by using 2012 as the baseline, (3) it is not significantly affected by the addition of pollution control devices during the study period because the auxiliary power consumption from these devices has negligible impact on gross electricity generation;[24] and (4) the historical unit-level gross heat rate is by definition demonstrated and achievable by the respective coal-fired EGU.

In the June 2014 proposal, EPA proposed a 6 percent potential heat rate improvement for the coal-fired EGU fleet for the purpose of establishing state emission goals. The potential heat rate improvement was based on two components: (1) a statistical analysis that determined 4 percent

[24] In addition to the parasitic load from add-on pollution controls, another effect of some add-on controls is worth mentioning here. The installation of wet flue gas desulfurization (*i.e.*, wet FGD or scrubber) technologies can affect heat rate because the chemical process of capturing SO_2 creates CO_2 that is measured in the continuous emission monitoring systems. This results in higher calculated heat input (see *infra* note 30). However, the typical increase in heat rate is less than 1 percent and may be offset by heat rate improvements resulting from switching to lower-moisture, higher-sulfur bituminous coal. Furthermore, the impact on calculated heat input is only relevant to EGUs that added WFGD during the study period because the analytical approaches described below evaluate the change in heat rates. Assuming consistent operation and fuel sulfur content, an EGU with a WFGD during the entire study period would not have a heat rate change due to the WFGD CO_2. Circulating fluidized bed (CFB) boilers also have higher CO_2 emissions from the chemical process of limestone injection to capture SO_2, thereby affecting the heat input calculations. However, because CFBs generally injected limestone at all times throughout the study period, the EGUs would not have heat rate changes due to limestone injection. See section 2.6.3 for more information about the impact of CO_2 emissions from SO_2 pollution control devices.

improvement in the fleet wide coal-fired EGU heat rate is possible through best practices (*e.g.*, improved operation and maintenance), and (2) an estimate that a 2 percent heat rate improvement is possible through additional equipment upgrades.

Several commenters suggested these values were too conservative, suggesting the agency should require greater heat rate improvements from the fleet on average or from each and every coal-fired EGU. Some of these commenters provided studies and analyses showing larger heat rate improvements are feasible for coal-fired EGUs (see summaries in section 2.4). EPA carefully reviewed the comments and supplemental materials before refining the potential heat rate improvement analysis. As explained below, the analysis for this final rule does not include a separate estimate of the potential from equipment upgrades.

Conversely, several commenters suggested EPA's proposed heat rate improvement was too optimistic, providing engineering studies and data describing heat rate improvement measures that had already been implemented at specific coal-fired EGUs. Commenters also expressed concern that EPA improperly characterized the potential heat rate improvements from equipment upgrades because: (1) the Sargent & Lundy (S&L) report cited in the proposal TSD is based on "conceptual" equipment upgrades, (2) plant operators indicate they have already implemented many of the heat rate improvement measures identified in the S&L report, (3) heat rate improvements from the list of equipment upgrades and best practices in the S&L report may not be additive (*i.e.,* cumulative), and (4) the costs of equipment upgrades are highly site specific. The EPA generally agrees with the four points noted above, and alluded to these considerations in the proposal TSD, section 2.6.1 Heat Rate Improvement Capital Cost Assumptions. The points are also discussed in more detail below.

The agency does not agree that the EPA improperly characterized or misused information from the S&L study.[25] The S&L study was prepared for EPA, and agency senior engineering staff with previous experience in fossil power plant engineering, operations, and management were involved in the scoping and review of the study report. The agency recognized the limits of the study and considered the S&L caveats/limitations when using information from the study, including the following statements from the S&L study:

1. The primary intent of the study was to focus on methods that have been successfully implemented by the utility industry.
2. This study identifies specific plant systems and equipment where efficiency improvements can be realized either through new installations or modifications, and provides estimates of the resulting net plant heat rate reductions and the order-of-magnitude costs for implementation. To conduct the study presented in this report, S&L

[25] See Sargent & Lundy, 2009. Coal-fired Power Plant Heat Rate Reductions. Available at http://www.epa.gov/airmarkets/documents/ipm/coalfired.pdf.

surveyed available literature, spoke with technology manufacturers, and used its engineering expertise as the basis.

3. This report discusses potential efficiency improvement concepts and the resulting heat rate reductions that can be implemented in various systems of a typical coal-fired power plant. All estimated capital and installation costs are referenced from work in progress and vendor quotes as of the year 2008.
4. S&L cautions that the costs presented herein are not indicative of those that may be expected for a specific facility due to variables such as equipment, material, and labor market conditions and site specifications. However, these cost estimates provide valuable information for comparative purposes when evaluating the advantages and disadvantages of the various concepts. The costs should not be used as a basis for project budgeting or financing purposes.

In consideration of these caveats/limitations, the agency used the average conceptual performance values from the S&L study to develop an estimated 4 percent potential heat rate improvement that the average coal-fired EGU could make from only a few of the higher-cost equipment upgrades. The agency then discounted that potential by 50 percent to obtain the 2 percent potential heat rate improvement estimate attributable to equipment upgrades that was included in the proposal. The 50 percent discount was applied to account for site-specific factors that could limit the potential heat rate improvement, including the fact that the cumulative effect of installing multiple measures can be less than the sum of their individual effects. The agency similarly used averages of S&L order-of-magnitude costs for thirteen of the fifteen S&L heat rate improvement measures[26] to develop an indicative conceptual cost estimate ($100/kW) for an overall 6 percent heat rate improvement. That estimate was conservative because 4 percent was projected to come from relatively inexpensive best practices while only 2 percent was projected to come from a small number of more expensive "new installations or modifications" described in the S&L study. The average $100/kW cost, derived from S&L estimates for unit sizes ranging from 200 to 900 MW inherently reflects the inverse relationship of $/kW cost to MW unit size, and was thus appropriately applied in the agency's estimate of the fleet-wide average cost of heat rate improvement. The agency was also mindful of the 2008 time frame of the S&L cost estimates. EPA considered the 2008 cost values to be applicable as 2011 values because, through a coincidence of timing, the 2008 study reflected the highest cost levels experienced by the power sector up to that point in time. The economic recession that commenced in late 2008 caused costs to decrease sharply before beginning a slow recovery. The agency therefore considered the S&L cost values to quite reasonably represent the costs in 2011.[27]

[26] Three mutually exclusive fan and fan drive modifications were discussed in the S&L study. Accordingly, EPA conservatively selected the fan-related measure that included both a fan upgrade and variable frequency drive for use in the cost estimate because the selected measure had the highest estimated capital cost.

[27] Cost estimates for implementation of the final rule are based on 2011 dollars.

In addition to the S&L report, EPA referred to several other studies in the proposal TSD that present similar information on equipment upgrades to the S&L report. As demonstrated by the materials provided by commenters expressing a preference for larger heat rate improvements, there are further analyses that show a greater than 6 percent heat rate improvement is achievable at coal-fired EGUs. One commenter also noted that many existing smaller coal-fired EGUs have recently retired or will be retiring over the next decade (see section 2.6.5 below for more information about retirements), leaving more of the larger, well-controlled coal-fired EGUs that are similar to the example EGUs used in the S&L report. Furthermore, the equipment upgrades and best practices identified in the proposal TSD and supporting reports are only intended to serve as illustrative lists of measures that coal-fired EGUs might employ to improve heat rate.

In the refined heat rate analyses for this final rule, the results are not based on heat rate improvements that would be achieved by implementation of specific measures. Instead, the heat rate analyses are based on each coal-fired EGU's best historical heat rate performance as well as its 2012 heat rate performance. It reflects the heat rate improvements that would occur if EGUs performed at heat rates that they have already demonstrated are achievable. As one commenter phrased it, EPA is simply basing building block 1 on a continuation of the types of good maintenance and operating practices that are necessary for EGUs overall to maintain the better heat rates they have previously achieved.

Some commenters noted that if a coal-fired EGU implemented equipment upgrades during the study period (2002–2012), improvements to gross heat rate would show up in the historical gross heat rate data and could result in double counting because the heat rate improvements would affect the statistical results and would still be expected from the equipment upgrade component. Similarly, many commenters provided lists of equipment upgrades undertaken at specific coal-fired EGUs, arguing that the equipment upgrade component of the agency's potential heat rate improvements does not account for upgrades that coal-fired EGUs have already implemented. EPA acknowledges that there could be overlap between the two components of the potential heat rate results, but notes that the agency was not requiring individual coal-fired EGUs to achieve specific heat rate improvements. However, for this analysis the agency no longer uses the two components to identify potential heat rate improvements. Instead, the agency conducts the statistical analyses described below to compare each EGU's best historical performance to its 2012 performance. The results reflect the overall heat rate improvement for coal-fired EGUs in each regional interconnection if those EGUs had returned to their demonstrated best historical gross heat rates from the baseline year of 2012. This backward-looking approach is inherently conservative because it does not reflect opportunities for heat rate improvements from additional best practices and equipment upgrades that could have been (and still can be) cost-effectively implemented at coal-fired EGUs.

In the proposal TSD, EPA's statistical analysis compared each EGU's best historical gross heat rate to the EGU's 11-year average gross heat rate. Commenters stated that some coal-fired EGUs made significant investments to improve heat rate during the 11-year study period and the use of an 11-year baseline fails to recognize those investments. These commenters suggested the agency could adjust the potential heat rate improvements to reflect any upgrades already implemented at coal-fired EGUs. In the revised analyses described below, in order to account for actions undertaken to improve gross heat rates at coal-fired EGUs, the agency refined the methodology to compare each EGU's best heat rate performance to its 2012 gross heat rate. Therefore, any actions an EGU implemented to improve gross heat rate during or before 2012 (and maintained in 2012) would be accounted for in the analysis and would result in a reduction in the estimated potential heat rate improvement. In addition, the selection of 2012 as a baseline is conservative because many commenters noted that coal-fired EGUs experienced greater cycling and lower capacity factors in the later years of the study period (2002-2012).

Several commenters suggested that EPA should replace the statistical analysis with unit-specific engineering studies to establish unit-level heat rate improvement goals. These commenters contended that such studies are the only method for accurately identifying what types of equipment upgrades and best practices (and therefore, potential heat rate improvements) are feasible and cost effective at each coal-fired EGU. As discussed in sections V.A and V.C of the preamble and the response to comments, conducting engineering studies to determine the potential for improving heat rate through best practices and equipment upgrades at every coal-fired EGU would be unnecessarily lengthy and expensive, and would not be consistent with the broader goal-setting purpose of this rulemaking. However, the agency does believe that EGU owners and operators that conduct such studies will discover additional cost-effective opportunities to improve heat rate at their EGUs. Commenters also suggested that as an alternative to unit-level engineering studies, EPA could identify unit-level heat rate improvement goals. EPA's methodology does assess the potential heat rate improvement for each interconnection by comparing an individual EGU's best demonstrated historical gross heat rate relative to the EGU's own 2012 gross heat rate. However, as several commenters note, and the agency explained in the proposal, this rule does not establish mandatory federal heat rate performance requirements for coal-fired EGUs or mandate heat rate improvement as a compliance strategy. The agency uses the results of the heat rate improvement analysis for each regional interconnection (*i.e.*, the electricity system) along with emission reductions from the other building blocks of the best system of emission reductions to establish state-level goals. Each state has the flexibility to identify measures in its state plan to achieve the state goals and, if the state chooses, it may develop unit-specific heat rate improvement targets – or entirely ignore potential heat rate improvement. Commenters also stated that the proposal expressly anticipates fleet wide averaging of CO_2 emission intensity improvements, thereby offering greater opportunities to achieve the state goals at lower cost relative to controlling emissions or heat rate at the plant or unit level. Therefore, the agency believes it is appropriate in this rulemaking to assess potential heat rate improvement at a scope broader than the unit-level.

Commenters also recommended that EPA subcategorize coal-fired EGUs and develop specific heat rate improvement goals for each subcategory to account for the influence of different design characteristics and fuel choices on an EGU's heat rate. However, as discussed above and noted in the proposal TSD, the agency is not establishing mandatory heat rate improvements that must be achieved at each and every coal-fired EGU. Instead, the agency is attempting to determine a reasonable heat rate improvement that, on average, the coal-fired electricity generating fleet can achieve, and to use the potential heat rate improvement to calculate state goals. In addition, the agency does not believe there is a need to subcategorize by design characteristics because the heat rate improvement potential is based on analyses of each EGU's past performance. Because heat rate improvement is assessed using each EGU's best historical and 2012 performance, the full analyses inherently account for design characteristics that do not change from year to year.

Commenters also highlighted the role of age and coal rank on an EGU's heat rate. The average age of coal-fired EGUs in the study population was approximately 42 years in 2012. To assess the impact of age, EPA grouped the 884 coal-fired EGUs by 10-year age increments (as of December 2012). While there is a difference in median and average annual gross heat rates between coal-fired EGUs less than 10 years of age and those greater than 10 years, there was no statistical difference in gross heat rates for the different groupings of coal-fired EGUs older than 10 years of age (*i.e.,* the range of performance of EGUs 10-19 years of age is approximately the same as EGUs 30-39 years of age). This indicates that operation and maintenance practices to manage degradation plays an important part in ensuring the efficiency of coal-fired EGUs. In addition, it is likely that the gross heat rate differences for younger units is due to other factors (*e.g.,* advanced technology, larger boiler and/or steam turbine size) that do not change as the EGU ages. Therefore, the influence of age is unlikely to play an important role for an individual coal-fired EGU.

An EGU's primary coal rank may change, but changing coal ranks at a coal-fired EGU requires significant effort. Generally, coal-fired EGUs – especially pulverized coal boilers and their corresponding fuel handling equipment, combustion systems, and pollution control devices – are designed for the characteristics of a specific type of coal. Significant deviations from those coal characteristics can affect the EGU's performance and reliability. Changes to coal type might require plant modifications to maintain maximum output and efficiency (*e.g.,* pulverizer capacity, fan capacity, heating surface). Commenters noted that changing coal rank is likely not practical at many EGUs because coal rank is determined by the design of the EGU and environmental control systems. Although it might be a significant engineering endeavor, some coal-fired EGUs have switched coal types or blended different coal types. Furthermore, some EGUs might have the option of changing coals in the future, potentially improving their heat rate. Commenters also discussed the impact that coal quality (*e.g.,* higher heating value, moisture content, ash content) can have on an EGU's heat rate. While EPA recognizes the impact that coal rank and quality can have on an EGU's heat rate, the agency also recognizes that EGU operators and coal suppliers typically set requirements for coal quality in purchase contracts, providing coal-fired EGUs with some level of control over the quality of fuel they purchase. Therefore, EPA did not control for coal rank or coal quality in the analysis.

In summary, the agency feels the analytical approaches described below, which are founded on each coal-fired EGU's historical performance and its 2012 performance, account for nearly all design characteristics because these characteristics do not vary for a particular EGU between years or are accounted for by the use of 2012 as the baseline. Other factors, (*i.e.*, ambient temperature and hourly capacity factor) that are beyond the EGU operator's control are explicitly accounted for in some of the agency's analyses presented below. Finally, for all of these analyses, by using long-term averages of heat rate (*i.e.*, at least a year) or grouping large numbers of hourly values and accounting for outliers, EPA implicitly accounts for some of the variation that might be beyond the EGU operator's control. Accordingly, subcategorization among affected coal-fired EGUs is not appropriate under building block 1.

EPA used three approaches to calculate the potential heat rate improvement: (1) best historical performance, (2) best historical performance under similar conditions, and (3) efficiency and consistency improvements under similar conditions. Each of these approaches is described in more detail below.

2.5.1 Heat rate, capacity factor, and temperature data

Under 40 CFR Part 75, most fossil fuel-fired EGUs report hourly emission and operation data to EPA's Clean Air Markets Division (EPA/CAMD). In 2012, 884 coal-fired EGUs reported heat input and gross electricity generation data to EPA.[28] These 884 EGUs account for approximately 1.61 billion tons of CO_2 emissions in 2012, 96 percent of the 1.67 billion tons of CO_2 emitted by the national coal-fired EGU fleet in 2012.[29] Therefore, EPA considers these 884 coal-fired EGUs representative of the coal-fired EGU fleet as a whole.

EPA's dataset includes the 884 coal-fired EGUs that reported heat input and gross electricity generation in 2012, including those EGUs that are near retirement. Some commenters suggested that the agency's inclusion of coal-fired EGUs near retirement inflates the results of the heat rate improvement analysis because the soon-to-retire EGUs may have more variability in gross heat rate and higher gross heat rates due to frequent cycling, deferred or canceled maintenance, and termination of good heat rate practices. While the agency recognizes the commenters' concern that soon-to-retire EGUs that operate with poor maintenance and operating practices can increase the potential heat rate improvements identified by the heat rate improvement analysis, the agency does not believe this artificially inflates the potential heat rate improvements. Any coal-fired EGU that stops implementing good maintenance and operations practices to maintain heat rates will have a similar type of impact on the results regardless of whether it is scheduled to retire to not. Also, the

[28] This population does not include coal-fired EGUs that did not operate in 2012, some of which retired before 2012 and others which may have resumed operation after 2012. See *supra* note 5 for a discussion about treatment of cogeneration EGUs.
[29] CO_2 emissions for the national coal-fired EGU fleet are taken from *Table 12.6 Carbon dioxide emissions from energy consumption: electric power sector*. EIA, 2015. Monthly Energy Review. Dated 2015 May 22 available at http://www.eia.gov/totalenergy/data/monthly/#environment.

agency believes that the inclusion of coal-fired EGUs that are near retirement is conservative for two reasons: (1) for states with mass-equivalent goals based on 2012 baseline levels, after soon-to-retire EGUs cease operation they cease emitting CO_2 contributing to attainment of the state goal, and (2) for states with CO_2 intensity goals based on 2012 baseline levels, the retirement of coal-fired EGUs with high heat rates in 2012 will contribute to achievement of the state goals.

The data used in the analysis include hourly gross heat rate values. 40 CFR Part 75 requires that most coal-fired EGUs continuously measure emissions of CO_2, NO_X, and SO_2, and report those hourly emissions along with hourly heat input[30] and gross electricity generation to EPA/CAMD at the end of each calendar quarter. The monitoring regulation requires regular quality assurance/quality control (QA/QC) of the monitoring systems, including daily calibrations and semi-annual or annual relative accuracy tests.[31] When EGU operators submit the hourly emission and operation data to EPA/CAMD, a responsible company official must certify that the data are true, accurate, and complete. In addition, the data undergo thousands of automated quality assurance tests as well as statistical analyses and EPA staff audits. Therefore, the agency believes these high-quality data are the best available information for assessing coal-fired EGUs' performance over time.

The monitoring regulation includes provisions to accommodate time periods when emission data are not available due to monitoring system malfunctions or maintenance, technical challenges, or missed QA/QC tests. When data are not available or deemed invalid (*e.g.*, when a QA/QC test was not performed as required), the EGU is required to use specified data substitution methods that are designed to be conservative (*i.e.*, 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 agency excluded substitute data reported by EGUs from the dataset. These substitute data represent approximately two percent of all reported operating hours for the 884 coal-fired EGUs during the study period. In addition, the agency excluded partial hours of operation that occur during the first hour of startup and the last hour of shutdown, and hourly gross heat rate values that were greater than or less than 2.6 standard deviations from an EGU's annual average gross heat rate.[32] Both of these conditions tend to occur during very low gross electricity generation. The hourly values ±2.6 standard deviations from the EGU's annual average gross heat

[30] Heat input is derived using CO_2 or O_2 concentration and calculations detailed in 40 CFR Part 75 Appendix F. As a result, heat rate (Btu/gross kWh) is proportional to CO_2 rate (CO_2/gross kWh).
[31] The quality assurance requirements for monitoring systems are described in 40 CFR Part 75 Appendix B.
[32] For datasets with a normal distribution, 99 percent of all values will be within 2.6 standard deviations of the mean.

rate may be due to unusual operating conditions or misreported gross electricity generation.[33] These outliers account for approximately 1.9 percent of hourly data records.

The monitoring provisions of 40 CFR Part 75 require regular QA/QC testing of the monitoring systems to ensure they are reading accurately. Commenters hypothesized that discrepancies between the monitoring system and the reference tests could explain much of the variation in heat rates. EPA assessed the monitoring systems' relative accuracy and the findings indicate that the relative accuracy does not significantly affect the results of the agency's analyses. In general, coal-fired EGU operators are required to perform relative accuracy test audits (RATA) once per year if the difference between the monitoring system and RATA results is less than or equal to 7.5 percent, and twice per year if the difference is greater than 7.5 percent but less than 10 percent.[34] If the flow monitoring system readings are statistically-significantly lower than the RATA results, the EGU operator must apply a bias adjustment factor (BAF) to all subsequent flow measurements to reduce potential underreporting of flow. There is no BAF applied for CO_2 measurements. To assess the relative accuracy of the monitoring systems during the study period, EPA reviewed the EGU-level RATA results for the study period and then calculated the average annual generation-weighted relative accuracy within each of the interconnection regions. As shown in Table 2-2, the average (*i.e.*, mean) relative accuracy[35] for both CO_2 and flow monitoring systems are reasonable – the difference between the reference tests and measured values is approximately 1.5 to 3.0 percent – and varies little from year to year within each interconnection.

Table 2-2 Generation-weighted relative accuracy of CO_2 and flow monitoring systems, by interconnection

	Western		Texas		Eastern	
	CO_2	Flow	CO_2	Flow	CO_2	Flow
2003	2.57	2.70	2.27	2.30	2.52	2.22
2004	3.17	2.51	2.63	1.64	2.51	2.11
2005	3.21	2.95	2.82	2.25	2.69	2.10

[33] 40 CFR Part 75 requires operators to apportion heat input to all EGUs sharing a common stack. For this reason, EGUs that are not generating electricity during startup or shutdown periods may report a small amount of gross electricity generation (*e.g.,* 1 MW) to avoid errors in the apportionment calculations. However, this can result in unusually large gross heat rates.

[34] More information about the quality assurance provisions, including RATAs, can be found in 40 CFR Part 75 Appendix B.

[35] Relative accuracy is expressed as the absolute value of the difference between the reference method measurements and the EGU's pollutant concentration or flow measurements. However, the averages at the interconnection level are overstated because the relative accuracy is expressed as an absolute value. As a simple example, if the difference between the measurements at one unit is -2 percent and at another unit the difference is 2 percent, the arithmetic average is 0 [(-2+2)/2] while the average of the absolute values is 2 [(|-2| + |2|)/2]. EPA's calculation is based on the absolute value.

	Western		Texas		Eastern	
	CO_2	**Flow**	**CO_2**	**Flow**	**CO_2**	**Flow**
2006	3.06	2.81	2.85	1.33	2.56	1.99
2007	3.15	2.59	2.25	1.50	2.61	2.06
2008	3.41	2.86	3.68	1.59	2.75	2.12
2009	2.95	2.97	2.47	1.76	2.55	1.97
2010	2.65	3.07	2.86	2.00	2.45	2.05
2011	2.40	2.59	2.56	1.69	2.63	2.02
2012	2.33	2.56	2.46	1.53	2.41	2.13

Notes: All values are generation weighted;
Due to data management and archive policies, 2002 data
were not available at the time of this analysis

While the average relative accuracy at the EGU-level varies from 1 to 3 percent, the uncertainty becomes significantly less when these differences are aggregated over many EGUs – the relevant scope of analysis for building block 1 as a whole. EPA evaluated the combined effect of CO_2 and flow measurement differences between the RATA and measurement systems at 685 coal-fired EGUs between 2009 and 2012.[36] The results show that the combined differences across the 685 EGUs over four years amount to a fleet wide standard "error" – an estimate of the uncertainty expected in fleet-wide emissions – of 0.08 percent.[37] Therefore the agency believes the impact of monitoring system relative accuracy does not significantly influence the results of the potential heat rate improvement analyses.

EPA also used data from NOAA's Integrated Surface Data (ISD) and the USGS's WaterQualityWatch (WQW). The NOAA dataset provides hourly ambient air temperature for over 20,000 weather stations worldwide.[38] Since coal-fired EGU heat rates can be sensitive to ambient air temperature and barometric pressure, the agency collected meteorological data from stations that are reasonably close to each coal-fired EGU's location and elevation to account for the impact of ambient conditions. For each of the 884 coal-fired EGUs, the agency identified the nearest

[36] Coal-fired EGUs with complex stacks (*i.e.*, common stacks or multiple stacks) were excluded from the analysis. Coal-fired EGUs that converted to or from complex stacks between 2009 and 2012 are included only for years during which the EGUs did not use complex stacks.

[37] The average combined difference between the RATA and monitoring system for flow and CO_2 measurements, using the directional difference (*e.g.*, positive and negative values), is 0.5 percent and the standard deviation is 3.4 percent. To calculate the standard error, EPA used the following equation: $\frac{Standard\ deviation}{\sqrt{n}}$ where n is 3 years × 685 EGUs.

[38] NOAA's Integrated Surface Data are available at http://www.ncdc.noaa.gov/data-access/land-based-station-data/land-based-datasets/integrated-surface-database-isd.

weather station[39] that reported a minimum of 8,400 hourly observations in the calendar year (*i.e.*, greater than 95 percent of the hours in a year). Because of the constraint that a station must report at least 8,400 measurements in a calendar year, most of the 884 EGUs were associated with meteorological data from the two closest stations over the study period (2002-2012). The average distance between the EGUs and the weather stations was 22 miles and the average difference in elevation was only 366 feet.[40] For at least one year of the study period (2002-2012), nine power plants did not have weather stations that met the three constraints described above. For these plants, the agency used its judgement and assigned nearby weather stations that were within 100 miles and 1,000 feet elevation, but had as few as 7,000 hourly observations. In response to commenters' concerns that EPA's analysis did not account for cooling water temperature, the agency added data from the USGS WaterQualityWatch (WQW).[41]

After excluding coal-fired EGUs that did not report heat input and gross electricity generation in 2012 and coal-fired cogeneration EGUs that reported steam generation in one or more years during the study period, and excluding the data described above, EPA developed a dataset of hourly heat input, gross electricity generation, gross heat rate,[42] capacity factor,[43] and ambient air temperature for the years 2002 through 2012 for all 884 coal-fired EGUs. This dataset, which was included in the proposal,[44] contained more than 61,848,500 hourly records.

Commenters also suggested that EPA should use fewer years of data in its analysis, noting that the power sector is very different today than it was in 2002. EPA recognizes that the power sector went through many changes between 2002 and 2012, and is likely to go through many more changes between 2012 and 2022 – the first year of the interim implementation period. Nevertheless, the agency believes it is appropriate and beneficial to use the full 11 years of data. First, this time period includes a variety of national and regional economic conditions, fuel prices, electricity resource mixes, weather conditions (*e.g.*, precipitation), and demand levels. As a result, it is more likely that future economic and weather conditions will be represented by data periods between 2002 and 2012. Second, commenters specifically expressed concern that many coal-fired retired during the study period and might bias the results. However, EGUs that retired prior to 2012 are not included in the dataset. Only coal-fired EGUs that reported both heat input and gross electricity generation in 2012 are included in the dataset. Third, the foundation of EPA's methodology uses

[39] EPA established two constraints on the locational differences of the weather station and the EGU: (1) less than 100 miles in distance, and (2) less than 1,000 feet in elevation.

[40] The NOAA dataset is the most complete and comprehensive ambient air temperature data available to EPA. The hourly ambient air temperature of the nearest weather station is used only for the purpose of grouping hourly heat rate into temperature bins by 10° F increments. Therefore, the agency believes conditions at the nearest weather station provide a reasonable approximation of temperature conditions at the coal-fired EGU.

[41] The USGS WQW dataset provides hourly surface water temperature from approximately 2,000 sites around the U.S. The data are available at http://waterwatch.usgs.gov/wqwatch.

[42] EPA calculated gross heat rate as heat input (Btu) / gross electricity output (kWh).

[43] EPA calculated capacity factor as gross electricity output (kWh) / hourly gross electricity generating capacity (kWh).

[44] See *supra* note 1.

each coal-fired EGU's best gross heat rate performance between 2002 and 2012 and the EGU's own 2012 gross heat rate. Therefore, if a coal-fired EGU employed better practices for maintenance and operation in the past than it did in 2012, as characterized by a lower gross heat rate, the agency believes it is reasonable to base the potential heat rate improvement for the population of EGUs in the interconnection region on their more efficient operations – whether for individual EGUs those operations were in 2012 or as early as 2002.[45] This longer time period better reflects various operating practices and investment priorities for the sector. As one power-sector trade magazine stated, "[R]elatively cheap coal and a focus on plant emissions controls has, unfortunately, taken the focus away from maintaining and improving plant heat rate."[46] EPA's analysis seeks to identify the potential for EGUs to re-achieve their better heat rates.

Commenters also noted that the state goals are based on CO_2 intensity using net electricity generation, but EPA based its potential heat rate improvement analysis on gross heat rate.[47] The commenters suggested that EPA should change the analysis to use net heat rate. While EPA acknowledges the discrepancy between the unit of measure for the state goals and the gross heat rate improvement analysis, the agency uses hourly gross heat rate for the analysis because it is the only comprehensive, quality assured hourly dataset available to the agency. The agency also believes the use of gross heat rate is inherently conservative for two reasons: (1) it does not reflect additional opportunities that coal-fired EGUs may have to reduce auxiliary energy use (*i.e.*, parasitic load),[48] and (2) gross electricity generation is not affected by auxiliary energy use required to power the significant capacity of air pollution control devices that were installed between 2002 and 2012. If net heat rate data were available and the agency used these data for the analytical approaches described below, the auxiliary energy use of air pollution control devices installed during the study period could possibly inflate the potential heat rate improvement.

2.5.2 Influence of ambient conditions and capacity factor on gross heat rate

Ambient conditions can affect a coal-fired EGU's gross heat rate. EPA evaluated three ambient conditions – hourly capacity factor, hourly air temperature, and, at the suggestion of commenters, hourly surface water temperature – to assess the influence these conditions can have on coal-fired EGU's gross heat rate. The assessment results indicate that each of the ambient conditions has

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[45] Beginning in reporting year 2002, the agency introduced numerous quality assurance checks on hourly emission data, enhancing the data quality. Therefore, for the purpose of the potential heat rate improvement analyses, the agency chose not to include data prior to 2002.

[46] See U Nowling, 2015. "Understanding coal power plant heat rate and efficiency," Power. Available at http://www.powermag.com/understanding-coal-power-plant-heat-rate-and-efficiency.

[47] For an explanation of why EPA used gross heat rate in this heat rate improvement analysis, section V.C.3 of the final rule preamble of the CPP.

[48] See EPRI, 2011. Opportunities to Enhance Electric Energy Efficiency in the Production and Delivery of Electricity. Technical Report 1024651. Available at http://www.pserc.wisc.edu/documents/publications/special_interest_publications/EPRI_Electricity_Use_Report_Final_1024651.pdf. The report explores the auxiliary electricity consumption at EGUs and finds that auxiliary energy use (and transmission and distribution losses) can be reduced by 15 percent through available technology options, including variable speed drives.

significant influence on the variation in hourly gross heat rate of the 884 coal-fired EGUs during the study period (2002–2012). The agency chose to control only for the influence of hourly capacity factor and hourly ambient air temperature in two of the three analyses described below because: (1) comprehensive water temperature data from monitoring locations nearby and upstream of each of the 884 coal-fired EGUs were not available, and (2) water temperature data are highly correlated with ambient air temperature data so, as described below, the additional influence of water temperature on heat rates is implicitly included.

2.5.2.1 Capacity factor

Coal-fired EGUs are designed to operate most efficiently near full capacity. In general, as an EGU's hourly capacity factor declines, the EGU's hourly gross heat rate increases. Across the full range of capacity factors, this trend is not linear. This relationship between hourly gross heat rate and capacity factor is illustrated in Figure 2-6. Each dot represents the average hourly gross heat rate for all measurements at a specific hourly capacity factor for four "sister units"[49] in 2012. The bottom chart shows the number of hourly measurements at each hourly capacity factor. The figure illustrates three effects that are broadly applicable to the 884 coal-fired EGUs: (1) average hourly gross heat rate is higher and shows more variation, or "scatter," from the average at lower hourly capacity factors, (2) the gross heat rate trend flattens at around 60 – 70 percent hourly capacity factor, and (3) the majority of operating hours are at higher hourly capacity factors.

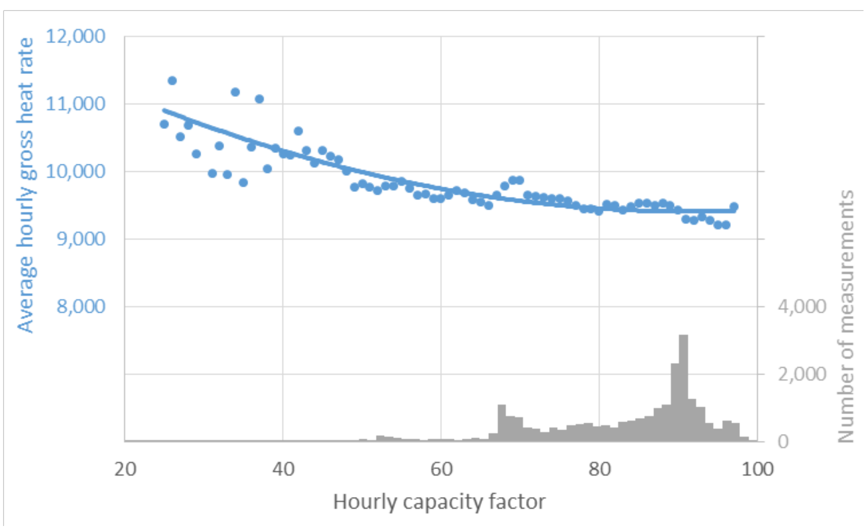

Figure 2-6 Average hourly gross heat rates at partial load levels

Notes: 2012 data are from four 650 MW coal-fired "sister units" at JM Stuart in Ohio; cumulative number of measurements exceeds 8,784 hours because it includes measurements from four EGUs; the trend line is a power function in the form of $y=c\times x^b$; average hourly gross heat rate axis does not start at zero to better illustrate changes in gross heat rate

[49] Four 650 MW cell burner coal-fired EGUs at J M Stuart Station in Ohio.

For each EGU, EPA used a least-squares linear regression to assess the relationship between hourly gross heat rates and hourly capacity factor.[50] The hourly capacity factor explained about 18 percent of the variation in gross heat rate for the 884 coal-fired EGUs between 2002 and 2012. These results, however, conceal considerable variability. At some coal-fired EGUs hourly capacity factor has a greater influence on hourly gross heat rate. For example, hourly capacity factor can explain nearly 50 percent of variation in gross heat rate at some load-following EGUs. The analysis indicates that as EGUs move from base load to load following (*i.e.,* cycling operation), hourly capacity factor tends to have a larger influence on gross heat rate.

Several commenters noted that the power sector saw dramatic changes during the 11-year study period, including significant declines in annual capacity factors at coal-fired EGUs. As discussed in the proposal TSD, it can be difficult to interpret the relationship between annual capacity factors and hourly capacity factors as used in the agency's analyses. EGUs with high annual capacity factors (*e.g.,* greater than 90 percent) must operate at high levels for most hours in a year. However, it is not possible to make such a generalization at lower annual capacity factors. For example, if a hypothetical coal-fired EGU operated at 90 percent capacity for six months and was offline for the remaining six months of the year, the EGU's annual capacity factor would be only 45 percent – equivalent to an EGU that might have operated below 50 percent capacity factor for the entire year. However, to assess the commenters' concerns, the agency reviewed two annual capacity factors for the 884 coal-fired EGUs – annual capacity factor and annual capacity factor during hours of operation. The latter represents the average annual capacity factor for the 884 coal-fired EGUs excluding hours in which the EGU did not operate, such as downtime for maintenance or due to low electricity demand. This latter capacity factor reflects the average capacity levels when EGUs are operating.

As shown in Table 2-3 and Figure 2-7, the annual average capacity factor of the 884 coal-fired EGUs declined by approximately 10 percent in 2009 and, after a small increase in 2010, continued to decline through 2012. However, the annual capacity factor during operating hours (*i.e.,* excluding non-operating hours) declined after 2010, but by a much smaller amount. This illustrates that during the 11-year study period, coal-fired EGUs operated fewer hours in later years, but maintained high hourly capacity factors, on average, during the hours they operated.

[50] For each EGU, the annual coefficient of determination (*i.e.,* the square of the correlation coefficient, or R^2) values were weighted using the EGU's total annual gross electricity generation resulting in an EGU-specific generation-weighted R^2. This approach controlled for any differences in average gross heat rates between years. The weighted R^2 values were averaged across all 884 coal-fired EGUs, resulting in an R^2 value of 0.179.

Table 2-3 Annual capacity factors for 884 coal-fired EGUs

Year	Annual capacity factor (%)	Operating hours capacity factor (%)
2002	68	77
2003	69	79
2004	70	79
2005	71	80
2006	70	80
2007	71	81
2008	70	80
2009	62	77
2010	65	78
2011	61	76
2012	53	72

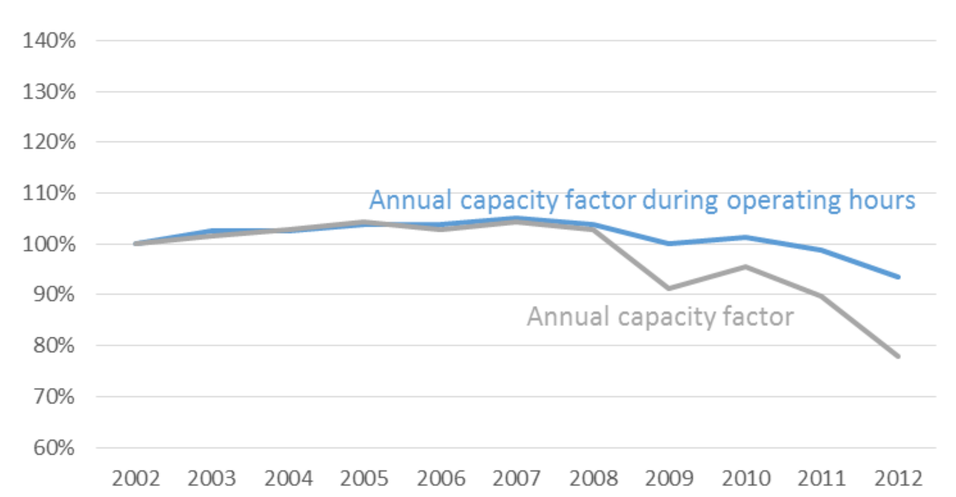

Figure 2-7 Change in annual capacity factors for 884 coal-fired EGUs relative to 2002

Note: capacity factors are relative to 2002 capacity factor, the first year of the study period

2.5.2.2 Ambient air temperature

Ambient air temperature can affect gross heat rate in three ways: (1) energy released during combustion heats the incoming air, (2) in many regions of the country temperature affects electricity demand and, as a result, some EGUs' hourly capacity factors may increase when ambient temperatures are high, and (3) ambient air temperature influences cooling water temperatures, affecting an EGU's efficiency. The relationship between hourly ambient air temperature and hourly capacity factor is complex. Generally, peak electricity demand in most parts of the U.S. occurs on the hottest days of the year. However, each EGU responds differently depending on design, duty cycle, meteorological conditions, electricity demand, and other factors. For example, a baseload plant may operate at high hourly capacity factors regardless of temperature. EPA assessed the correlation between hourly ambient air temperature and hourly capacity factor during the study period (2002–2012) to determine and found the correlation to be very low.[51]

For each EGU, EPA used a least-squares linear regression to assess the influence that hourly ambient air temperature has on the variability of hourly gross heat rates.[52] The hourly ambient air temperature explained about 8 percent of the variation in gross heat rate across the entire fleet. At approximately one-fourth of the 884 coal-fired EGUs ambient air temperature had a greater influence on hourly gross heat rate than the influence of hourly capacity factor. At some individual EGUs, ambient air temperature may explain up to 30 percent of the variation in hourly gross heat rate. These are typically, but not exclusively, units with freshwater once-through cooling systems. Identifying temperature-responsive coal-fired 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. Gross hourly heat rates at a temperature-responsive EGU may increase as much 10 percent during high temperature days in summer months.

2.5.2.3 Cooling water temperature

As discussed earlier in this chapter and noted by commenters, cooling water temperature can have a significant influence on a coal-fired EGU's heat rate. The availability of a cold heat sink in the condenser is important to maximize the EGU's efficiency. The design of the heat exchanger, type of cooling system, availability of water, and temperature of water all have an impact on performance. Higher water temperatures typically reduce the effectiveness of the cooling system and, therefore, overall plant efficiency.

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[51] The Pearson correlation coefficient for hourly ambient air temperature and hourly capacity factor from 2002–2012 is -0.048.

[52] For each EGU, the annual coefficient of determination (*i.e.*, the square of the correlation coefficient, or R^2) values were weighted using the EGU's total annual gross electricity generation resulting in an EGU-specific generation-weighted R^2. This approach controlled for any differences in average gross heat rates between years. The weighted R^2 values were averaged across all 884 coal-fired EGUs, resulting in an R^2 value of 0.083.

Commenters suggested EPA should account for the influence of cooling water temperature in addition to ambient air temperature. The agency did not have comprehensive cooling water temperature data to assess the influence on gross heat rate at the time of the proposal. However, in response to commenters' suggestions, the agency compiled hourly surface water temperature data for 45 coal-fired EGUs in the Eastern Interconnection. For each EGU and each year with available data, EPA used a least-squares linear regression to assess the influence that hourly water temperatures had on the variability of hourly gross heat rates.[53] The variation in hourly water temperature explained about 7 percent of the variation in gross heat rate.

When EPA applied the same approach for the 45 coal-fired EGUs over the same time period using hourly ambient air temperature instead of hourly water temperature, the air temperatures explained approximately 6 percent of the variation in gross heat rate.[54] The agency also examined the influence of several time-averaged temperatures (air and water temperatures) and found comparable results to the hourly ambient temperature values. For example, the rolling 24-hour water temperatures and rolling 24-hour ambient air temperatures explained 7 percent of the variation in hourly gross heat rate.[55] Not surprisingly, the air temperature and water temperature are strongly related.[56]

Although the surface water data in this analysis were from the Eastern Interconnection, where 86 percent of the 884 coal-fired EGUs are located, the agency has no reason to believe, nor have commenters suggested, that this correlation would not hold elsewhere in the country. Studies suggest that ambient air temperature is similarly correlated with surface water temperature elsewhere in the country. See, for example, a report by the New Mexico Environment Department notes that "based on data for approximately 300 New Mexico streams, air temperature is highly correlated with stream water temperature…"[57]; Kaushal et al. found "[l]ong-term increases in stream water temperatures were typically correlated with increases in air temperatures";[58] and Webb et al. found there is usually a strong correlation between ambient air temperatures above 0°

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[53] For each EGU, the annual coefficient of determination (*i.e.*, the square of the correlation coefficient, or R^2) values were weighted using each EGU's total annual gross electricity generation resulting in an EGU-specific generation-weighted R^2. This approach controlled for any differences in average gross heat rates between years. The weighted R^2 values were averaged across all 45 EGUs, resulting in an R^2 value of 0.072.

[54] For each EGU, the annual coefficient of determination (*i.e.*, the square of the correlation coefficient, or R^2) values were weighted using each EGU's total annual gross electricity generation resulting in an EGU-specific generation-weighted R^2. This approach controlled for any differences in average gross heat rates between years. The weighted R^2 values were averaged across all 45 EGUs, resulting in an R^2 value of 0.057.

[55] The R^2 value for rolling 24-hour water temperature and hourly gross heat rate was 0.071 and the R^2 for rolling 24-hour ambient temperature and hourly gross heat rate was 0.072.

[56] The Pearson correlation coefficient for hourly water temperature and 24-hour ambient air temperature is 0.74.

[57] See New Mexico Environment Department, 2011. Air-Water Temperature Correlation. Available at https://www.env.nm.gov/swqb/documents/swqbdocs/MAS/Protocols/Air-Water/Air-Water08-01-2011.pdf.

[58] See SS Kaushal, GE Likens, NA Jaworski, ML Pace, AM Sides, D Seekell, KT Belt, DH Secor, and RL Wingate, 2010. "Rising stream and river temperatures in the United States," Frontiers in Ecology and the Environment. 8:461-466. (DOI: 10.1890/090037).

C and stream water temperatures (although the relationship may be non-linear at higher temperatures).[59]

Based on these results, the agency believes that hourly ambient air temperature is the appropriate variable to use in the potential heat rate improvement analyses because: (1) available hourly water temperature data are limited to a portion of the fleet, (2) air and water temperatures are highly correlated (*i.e.,* simultaneously controlling for air temperature and water temperature appears highly redundant), and (3) the results from all of the agency's analyses described above demonstrate that ambient air temperature and water temperature explained similar amounts of the variability in hourly gross heat rate.

2.5.2.4 Capacity factor and ambient air temperature

In addition to the regression analyses discussed above, EPA conducted a least-squares linear regression analysis to assess the influence that the combination of hourly capacity factor and hourly ambient air temperature had on the variability of hourly gross heat rate.[60] For the 884 coal-fired EGUs, the combination of hourly capacity factor and hourly ambient air temperature explained about 26 percent of variation in gross heat rate between 2002 and 2012.

2.5.2.5 Accounting for the influence of factors outside coal-fired EGU operators' control

The objective of EPA's analysis is to identify the potential heat rate improvements at coal-fired EGUs for the purpose of calculating state goals. Therefore, the agency attempted to control for many of the factors that influence gross heat rate but are beyond the control of the coal-fired EGU operator. For example, as stated above, EPA's analysis controls for EGU design characteristics such as boiler type and size, generator size, coal type, and cooling system type because it compares each coal-fired EGU's historical performance against the EGU's own 2012 performance. Because these design characteristics are typically constant over time, they do not influence the results of the EGU-level analyses. As mentioned earlier, age does not appear to have a significant effect on gross heat rate. In addition, EPA controlled for the installation of air pollution control devices by analyzing gross heat rate – because the impact of air pollution control devices' auxiliary energy consumption does not affect gross electricity generation, the addition of controls does not influence the results of the gross heat rate analyses.

In two of the three analytical approaches discussed below, EPA also controlled for hourly capacity factor and hourly ambient air temperature because these two environmental and operating factors are considered to be beyond the EGU operators' control. To limit the influence of these two factors,

[59] See BW Webb, DM Hanna, RD Moore, LE Brown and F Nobilis, 2008. "Recent advances in stream and river temperature research," Hydrological Processes. 22: 902-918 (DOI: 10.1002/hyp.6994).

[60] For each EGU, the annual coefficient of determination (*i.e.,* the square of the correlation coefficient, or R^2) values were weighted using the EGU's total annual gross electricity generation resulting in an EGU-specific generation-weighted R^2. This approach controlled for any differences in average gross heat rates between years. The weighted R^2 values were averaged across all 884 coal-fired EGUs, resulting in an R^2 value of 0.255.

the agency grouped each EGU's hourly gross heat rate values into unit-specific "capacity-temperature bins" based on hourly capacity factor and hourly ambient air temperature. This enabled the agency to compare gross heat rate values for each coal-fired EGU during hours with similar capacity factor and ambient air temperature conditions, effectively controlling for a large influence on the variation in an EGU's hourly gross heat rates.

To create the capacity-temperature bins, the agency divided the range of hourly capacity factors into 12 groups, each separated by 10 percent of an EGU's electricity generating capacity (*i.e.*, 0-9, 10-19, 20-29, … , 90-99, 100-109, greater than or equal to 110 percent), and the ambient air temperatures into 14 groups, each separated by 10° F (*i.e.*, below $^{-}$10°, $^{-}$10-$^{-}$1°, 0-9°, … , 90-99°, 100-109°, greater than or equal to 110° F). The result is 168 capacity-temperature bins (12 X 14) for each of the 884 coal-fired EGUs. However, not all capacity-temperature bins for an individual EGU have data (*e.g.*, coal-fired EGUs in Florida are unlikely to experience hourly ambient temperatures below -10° F).

At least one commenter expressed concern that the hourly capacity factor ranges were too large. They pointed to information that showed heat rate can vary significantly at low hourly capacity factors, resulting in differences of as much as 4 percent from a 30 percent hourly capacity factor to a 40 percent hourly capacity factor. Figure 2-6 illustrates this concept. At higher hourly capacity factors the hourly gross heat rate declines. However, the trend is more pronounced at low capacity factors, as noted by the commenter, and less prominent at higher capacity factors. EPA chose to maintain the size of the hourly capacity factor ranges for three reasons: (1) approximately 70 percent of the hourly values are greater than 70 percent capacity factor in each of the three interconnection regions and nationally (see Figure 2-8), (2) the data are skewed toward the higher end of each range (*e.g.*, more hourly data points range from 75-79 percent range than from 70-74 percent), and (3) reducing the range of the hourly capacity factor groups would double the number of capacity-temperature bins, resulting in fewer measurements in each bin and more data excluded from the analysis.[61] EPA's assessment does not indicate that using a smaller range for capacity factor would have a significant impact on the results.

[61] As described below, in the efficiency and consistency analysis EPA excluded any capacity-temperature bins that had fewer than 15 hourly measurements for a single coal-fired EGU.

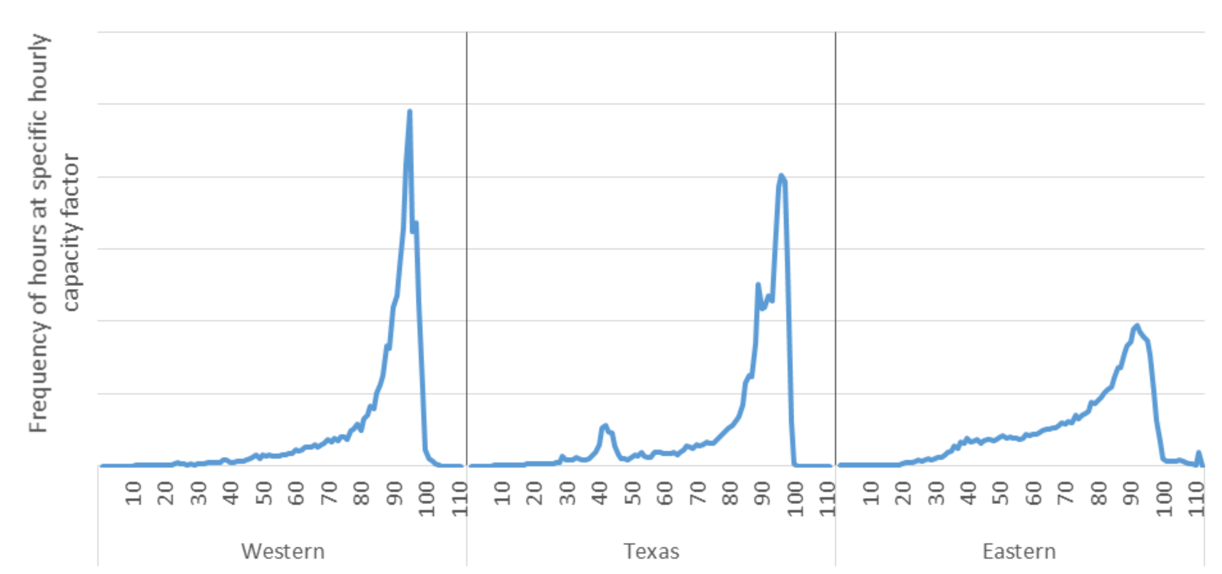

Figure 2-8 Distribution of hourly capacity factors by interconnection

Several commenters noted that EPA's analysis does not account for all the factors that affect a coal-fired EGU's heat rate. Specifically, these commenters mention the influence of geographic differences (*e.g.,* seasonality, altitude), coal rank and quality, equipment degradation, and operating conditions. As stated above, the agency made every effort to control for design characteristics and ambient conditions that the agency believes to be outside the EGU operator's control. The agency also controlled for capacity factor, which some commenters argued is partially under the operator's control. However, the agency lacks sufficient information to determine the portion of hourly capacity factor that is under the direct control of influence of the EGU owner or operator. Therefore, the agency chose to reasonably and conservatively control for the full effect of hourly capacity factor based on the results of the analysis described above. Regarding commenters' assertion about the role of a coal-fired EGU's location (*i.e.,* geography) on heat rate, the agency believes that the approaches described below do control for these conditions because coal-fired EGUs are not considered mobile sources so by comparing each EGU's performance from 2002 to 2012 against the EGU's performance in 2012 the agency controlled for both seasonal differences and location characteristics (*e.g.,* altitude). Commenters also noted that coal-fired EGUs that changed coal rank during the study period might have significantly different heat rates depending on the rank of coal burned. The agency recognizes that: (1) different coal ranks have different heating values and moisture content, and (2) coal-fired EGUs are generally designed for a specific coal rank and coal quality and deviations from that coal rank can adversely affect heat rate. However, the agency believes that for most coal-fired EGUs coal rank and coal quality are controlled by the EGU operator through purchase contracts with fuel suppliers. Therefore, the agency chose not to control for coal rank or coal quality. Commenters also stated that equipment degrades over time, increasing heat rate. As discussed further in section 2.6.8 below, EPA recognizes that all equipment will degrade over time. However, some of the best practices that can be employed to improve heat rate involve properly operating and maintaining equipment to minimize the degradation and, when necessary, replacing equipment to maintain efficient operation of the plant. Therefore, the agency did not control for the effect of equipment degradation in the analyses described below because EGU operators can limit equipment degradation through best practices for operation and maintenance.[62] Similarly, the agency believes operating conditions at each coal-fired EGU are largely under the control of the EGU operator so it is reasonable and appropriate for the agency to include variability due to operating conditions (with the exception of capacity factor.)

2.5.3 Heat rate improvement approach "best historical performance"

In the proposal TSD, EPA included an assessment of potential heat rate improvement based on the difference between each coal-fired EGU's best rolling annual gross heat rate and its 11-year (2002–2012) gross heat rate. Based on commenters' suggestions and heat rate improvement analyses provided by commenters, the agency refined the approach and calculated 1- and moving 2-year average gross heat rates for each of the 884 coal-fired EGUs in the study for the years 2002–2012. The agency removed the 3-year averaging period discussed in the proposal TSD because, as noted by commenters, the differences in temperature profiles and loads from one year to the next are relatively small and not large enough to justify a 3-year rolling average. Commenters suggested that 1 year is sufficient because the agency already controls for capacity factor and temperature in some of the analytical approaches. However, the agency chose to conservatively include a 2-year rolling average to account for atypical annual operations due to factors such as extended outages, equipment failures, cooling water availability, or unusual demand patterns. The advantage of using the moving 2-year average is that it can smooth out the peaks and troughs and reduce the influence of a single unusual year (*e.g.,* low utilization, unusual weather or climate conditions), while not diluting the results so much that it would obscure significant changes to annual gross heat rate.

The agency selected each EGU's best (*i.e.*, lowest) 1- and moving 2-year average gross heat rates, calculated the generation-weighted average across all EGUs in each interconnection, and compared the results to the interconnection's generation-weighted 2012 average gross heat rate. As described above, this approach controls for design characteristics that remain constant and is not affected by the installation and operation of air pollution control devices.

2.5.3.1 Methodology

The procedures for calculating the potential heat rate improvement are:

1. For each coal-fired EGU, calculate the 1- and moving 2-year average gross heat rate.
2. Identify each EGU's best 1- and moving 2-year gross heat rate.

[62] See section 2.6.8 for more information about equipment degradation and maintaining heat rate performance.

3. Calculate the generation-weighted average heat rate based on the lowest 1- and moving 2-year average gross heat rate and the generation over the time period within each interconnection region.
4. For each interconnection, calculate the 2012 average gross heat rate weighted by the 2012 generation.
5. For each interconnection, calculate the potential heat rate improvement – the percent difference between the best 1- and moving 2-year average gross heat rate from step 3 and the 2012 gross heat rate from step 4.

2.5.3.2 Results

This approach identifies the potential heat rate improvement by determining what would have been possible if each of the 884 coal-fired EGUs had reproduced its demonstrated best performance from 2002 to 2012. These results are conservative because they only account for a return to each EGU's historical best annual performance and do not account for the full extent of heat rate improvement available through additional equipment upgrades and best practices. The results of the analytical approach are presented in Table 2-4.

Table 2-4 Potential heat rate improvement based on best historical performance, by interconnection

Performance period	Western	Texas	Eastern	Nationally[63]
Best 1-year gross heat rate (%)	4.1	4.2	6.3	5.9
Best moving 2-year gross heat rate (%)	2.6	3.1	4.9	4.6

2.5.4 Heat rate improvement approach "best historical performance under similar conditions"

The second analytical approach – best historical performance under similar conditions – is an outgrowth of the first and third analytical approaches based on comments and analyses provided by commenters. The second approach is similar to the first approach described above, but in this approach EPA controlled for each EGU's hourly capacity factor and hourly ambient air temperature as described above. Within each capacity-temperature bin for each coal-fired EGU, EPA calculated the bin-specific 1-year and moving 2-year average gross heat rates, selected the lowest gross heat rate within that capacity-temperature bin, calculated the generation weighted average across all bins and units, and compared that to the generation weighted 2012 average gross

[63] EPA has provided nationwide results for purposes of comparison; they are not part of the methodology.

heat rate. One advantage of this approach is that it controls for factors that explain a significant portion of variation in EGUs' gross heat rate.

2.5.4.1 Methodology

The procedures for calculating the potential heat rate improvement using this approach are the same as those shown above with one exception: the agency partitioned the hourly data by hourly capacity factor and temperature as described in the following steps.

1. For each coal-fired EGU and capacity-temperature bin, calculate the 1- and moving 2-year average gross heat rate.
2. Identify each EGU's best 1- and moving 2-year gross heat rate in each temperature and capacity factor bin.
3. Calculate the generation-weighted average heat rate using the lowest 1- and moving 2-year average gross heat rates from step 2 and the generation over the time period for all the EGUs and temperature and capacity factor bins in each interconnection region
4. Within each interconnection, calculate the 2012 average gross heat rate weighted by the 2012 generation.
5. For each interconnection, calculate the potential heat rate improvement – the percent difference between the best 1- and moving 2-year average gross heat rate from step 3 and the 2012 gross heat rate from step 4.

2.5.4.2 Results

This approach identifies the potential heat rate improvement by determining what would have been possible if each of the 884 coal-fired EGUs had reproduced its demonstrated best performance from 2002 to 2012 while controlling for the influence of hourly capacity factor and hourly ambient temperatures. These results are conservative because they account only for potential heat rate improvements if each coal-fired EGU returned to its best performance; it does not account for the full extent of heat rate improvements available through additional equipment upgrades and best practices.

One reason this approach yields interconnection-level results that are higher than the first approach is that it relies on the lowest 1- and moving 2-year average gross heat rates within each capacity-temperature bin. Therefore, unlike the first approach where the "best" performance for each coal-fired EGU is from one or two years across all capacity factor and temperature conditions, this second approach may have different "best" years for the different capacity-temperature bins.

The results of this second analysis are shown in Table 2-5.

Table 2-5 Potential heat rate improvement based on best historical performance under similar conditions, by interconnection

Performance period	Western	Texas	Eastern	Nationally[64]
Best 1-year gross heat rate (%)	4.7	4.9	6.9	6.6
Best moving 2-year gross heat rate (%)	3.1	3.5	5.3	5.0

2.5.5 Heat rate improvement approach "efficiency and consistency under similar conditions"

The two approaches described above are based on the general principle that coal-fired EGUs are capable of returning to historically demonstrated heat rates (*e.g.*, best annual average over a 1- or moving 2-year period). The third approach, which was described extensively in the proposal TSD, uses a different approach to determine the potential heat rate improvement. This third approach is based on the principle that coal-fired EGUs are capable of operating more consistently with their historically demonstrated "best" hourly gross heat rates. For this approach, the agency grouped each coal-fired EGU's data by capacity-temperature bin and determined a 1- and moving 2-year gross heat rate "benchmark."[65] This benchmark was based on each coal-fired EGU's 10th percentile hourly gross heat rate during each 1- and moving 2-year period for each capacity-temperature bin. The 10th percentile value means 10 percent of all hourly values for the 1- or 2-year period were below the selected value (*i.e.*, the benchmark is demonstrated by 10 percent of all measurements in each capacity-temperature bin). The agency chose the 10th percentile because it represents a demonstrably achievable gross heat rate indicating efficient operation of the EGU, but ignores unusually low outlier values.[66] Furthermore, the 10th percentile is a commonly used statistical level for determining if particular values are unusually low relative to the average value.[67]

In this approach, EPA assumed that a coal-fired EGU could achieve the benchmark with the same frequency in the future as in the past while also assuming that for the remaining time it could achieve heat rates that were closer to the benchmark under similar hourly capacity factor and hourly ambient air temperature conditions. The agency calculated the potential heat rate

[64] EPA has provided nationwide results for purposes of comparison; they are not part of the methodology.
[65] EPA excluded capacity-temperature bins that had fewer than 15 hourly measurements for a single coal-fired EGU.
[66] During the development of the dataset the agency excluded extreme outliers – hourly gross heat rate values that were greater than ±2.6 standard deviations from the EGU's mean gross heat rate.
[67] Common statistical levels include the 10th and 90th percentiles, the 5th and 95th percentiles, and the 1st and 99th percentiles. EPA considered these other levels but selected the 10th percentile because it is a common statistical level, is conservative, and is substantially less likely to have been an outlying value than the 5th or 1st percentile. If EPA had selected the 5th percentile as the benchmark, each EGU would have half as many hours of historical operation at or below the benchmark and the overall resulting potential heat rate improvement would have been substantially larger.

improvements from greater consistency (*i.e.*, less variability of heat rate) such that each EGU's hourly gross heat rates that were greater than the benchmark for the capacity-temperature bin were adjusted downward by a specific percentage – a consistency factor – to represent more consistently efficient operation of the EGU. Using this approach, the hourly gross heat rate values that were adjusted most in absolute terms were the highest values (*i.e.*, less-efficient hours of operation) that indicate a relative failure to fully employ heat rate improvement measures. The result is that the post-adjustment distribution of hourly heat rate values has a smaller variability in heat rate, with the average value nearer the benchmark value, while the lowest heat rate values remain unchanged (see Figure 2-9). This is based on the principle that a coal-fired EGU following best practices should be able to consistently operate closer to the demonstrated and achievable benchmark heat rate.

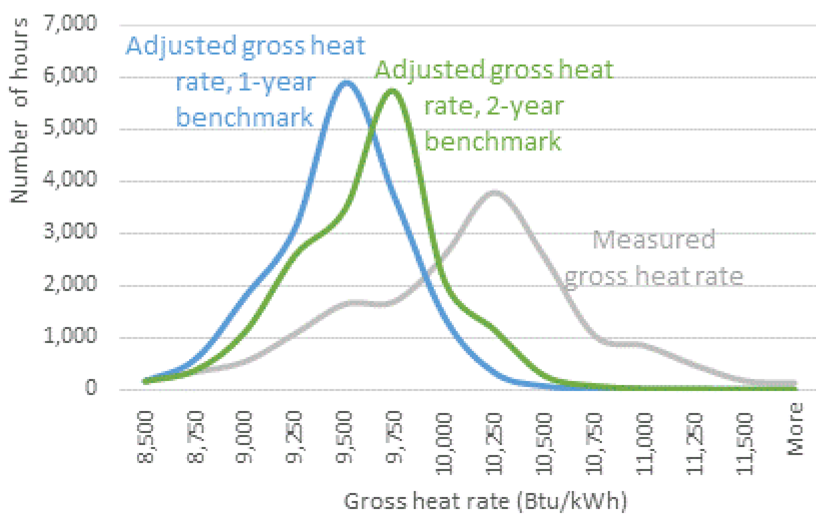

Figure 2-9 Frequency of hourly gross heat rates measured and adjusted, 2002–2012 for an example coal-fired EGU in a single capacity-temperature bin

In the proposal TSD, EPA assessed several different consistency factors ranging from 10 to 50 percent and proposed 30 percent because the results were similar to results achieved through other analytical approaches (*e.g.*, 3-year rolling averages relative to the 11-year average), accorded with EPA experts' engineering judgment, and because 30 percent was in the middle of the reasonable range evaluated by the agency. Several commenters suggested that this choice of values was arbitrary and could have easily been higher or lower had EPA selected the middle of a different range of values. To identify a consistency factor with more precision for this analytical approach, EPA analyzed EGUs' historically demonstrated level of consistency (*i.e.*, variability) for hourly gross heat rate over 1-year and moving 2-year periods between 2002 and 2012 for each capacity-temperature bin. The agency calculated the mean-centered standard deviation of hourly gross heat rate values for each 1- and 2-year period for the population of EGUs in each interconnection for all capacity-temperature bins.[68] The lowest standard deviations – a measure of variability – for the 1- and moving 2-year periods were then compared to the mean-centered standard deviation of 11-year gross heat rate data. The percent difference of the 1- and moving 2-year standard deviations and the 11-year standard deviation represent the potential consistency improvement at each interconnection. In other words, this approach compares the EGUs' most consistent performance (*i.e.*, least variability) for each capacity-temperature bin over a 1- or moving 2-year period to the EGUs' average consistency (*i.e.*, variability) over the study period (2002-2012).

As described above at the beginning of section 2.5, EPA replaced the 11-year baseline used in the proposal TSD with a 2012 baseline in this analysis. For the population of EGUs in each interconnection, the refined approach – compares the generation weighted average heat rate across all bins and units adjusted to be "efficient and consistent", with the generation weighted 2012 average gross heat rate.

Several commenters noted that reduced variability does not necessarily equate to improved heat rates. EPA agrees with commenters that reducing variability alone does not result in lower heat rates and, therefore, lower CO_2 emissions. For example, if an EGU were to operate more consistently at a higher heat rate (*i.e.*, less efficient), the variability would decrease, but the heat rate would increase. However, the agency is not simply asking for less variability in operation at existing coal-fired EGUs. Instead, the agency is assessing the average heat rate improvement that would result if coal-fired EGUs had operated more consistently nearer their gross heat rate benchmarks. Both the benchmark gross heat rates and reduced variability in heat rate were demonstrated by the EGUs from 2002–2012 during hours with similar hourly capacity factors and hourly ambient air temperatures.

[68] The mean-centered standard deviation shows the extent of variation relative to the mean and allows for meaningful comparison of variability from coal-fired EGUs that can have different average gross heat rates. The mean-centered standard deviation, also called the coefficient of variation, is calculated by dividing each coal-fired EGU's standard deviation for the capacity-temperature bin by the EGU's capacity-temperature bin's average gross heat rate. It is reasonable to use the standard deviation when evaluating the potential to reduce variability because standard deviation is the most common measure of the spread, or variation, of values within a dataset.

2.5.5.1 Methodology

The procedures for calculating the consistency factor are:

1. For each coal-fired EGU, calculate the 1-year average gross heat rate for each capacity-temperature bin.[69]
2. For each coal-fired EGU, calculate the difference, as a percentage, between every hourly gross heat rate value and the value from step 1 within each capacity-temperature bin.
3. Within each interconnection, calculate the mean-centered deviation of all the values derived from step 2 for each 1-, moving 2-, and 11-year period.[70]
4. Within each interconnection, calculate the consistency factor as the percent difference between the lowest 1- and 2-year standard deviations and the 11-year standard deviation from step 3.

The procedures for calculating the potential heat rate improvement are:

1. For each coal-fired EGU, determine the gross heat rate benchmarks – the 10th percentile hourly gross heat rate – for each 1- and moving 2-year period within each capacity-temperature bin.
2. Identify each EGU's best 1- and moving 2-year gross heat rate benchmark within each capacity-temperature bin.
3. For each hourly heat rate value, calculate the adjusted gross heat rate:
    a. For each hourly gross heat rate value greater than the 1- or moving 2-year benchmark calculate the difference between the hourly value and the relevant benchmark;
    b. Multiply the difference by the relevant 1- or moving 2-year interconnection-specific consistency factor; and
    c. Subtract the result from the hourly gross heat rate value.
4. Within each interconnection, calculate the 11-year generation-weighted adjusted average gross heat rate representing "efficient and consistent" operation using the adjusted gross heat rate values from step 3.
5. For each interconnection, calculate the 2012 average gross heat rate weighted by the 2012 generation.

[69] The agency did not calculate 2-year average gross heat rates because any change in average heat rate from one year to the next could lead to overestimates in the amount of variability. The method used here accounts for changes in average heat rate from one year to the next, so that only the relative variability is being evaluated.

[70] This approach identifies the variability of the best 1 or 2-year time period relative to the 11-year average variability. As described above, mean-centering the data accounts for changes in heat rate over the time period. Because the analysis accounts for changes in heat rate, the average variability is more-representative than the variability of any particular year (*e.g.*, 2012).

6. For each interconnection, calculate the generation-weighted potential heat rate improvement by calculating the percent difference between the 11-year adjusted heat rate average from step 4 and the 2012 generation-weighted gross heat rate from step 5.

One commenter noted that EPA's analysis in the proposal TSD used heat input instead of gross heat rate to assess potential heat rate improvements. The commenter noted that EPA's assumption of an equivalent level of gross electricity generation across the full range of the capacity factor bin skewed the results. EPA agrees with the commenter that using the gross heat rate for the analysis provides more accurate results. Therefore, the agency changed the approach to use hourly gross heat rate, calculated as heat input divided by gross electricity generation.

2.5.5.2 Results

This approach calculates the potential heat rate improvement by determining what would be possible if each of the 884 coal-fired EGUs had operated more efficiently and consistently nearer their historically demonstrated "best" gross heat rate from 2002 to 2012 while controlling for the influence of hourly capacity factor and hourly ambient temperatures. The consistency factors calculated for this analytical approach are presented in Table 2-6 and the potential heat rate improvement results are presented in Table 2-7.

Table 2-6 Consistency factors based on best historical performance under similar conditions, by interconnection

Performance period	Western	Texas	Eastern	Nationally[71]
Best 1-year consistency (%)	46.9	46.6	45.5	45.8
Best 2-year consistency (%)	38.4	37.1	38.1	38.2

Table 2-7 Potential heat rate improvement based on efficiency and consistency under similar conditions, by interconnection

Performance period	Western	Texas	Eastern	Nationally[72]
Best 1-year benchmark and consistency (%)	3.5	3.7	5.6	5.3
Best 2-year benchmark and consistency (%)	2.1	2.3	4.3	4.0

[71] EPA has provided nationwide results for purposes of comparison; they are not part of the methodology.
[72] EPA has provided nationwide results for purposes of comparison; they are not part of the methodology.

2.5.6 Summary of results

Each of the three analytical approaches described above constitutes a reasonable means of assessing the potential for heat rate improvements by affected coal-fired EGUs within the regional interconnections. Because the analyses are based on actual historical gross heat rate data for each of the 884 coal-fired EGUs in the study population, EPA is confident that the potential heat rate improvements identified on the regional basis through these approaches are feasible.

Although each of these three analytical approaches is a reasonable definition of heat rate improvement potential under building block 1, EPA's overall methodology adopts the most conservative value identified by any of the approaches. Under each of the three analytical approaches, EPA separately calculated potential heat rate improvements based on the best 1-year and moving 2-year performance for each EGU in each region. In order to further increase our confidence in the region-wide results, EPA's conservative methodology compared the six resulting values for each region and adopted the lowest value identified by any analytical approach. Because the results from the moving 2-year analyses will always be more conservative than those from the 1-year analyses,[73] and thus the 1-year analyses cannot provide the most conservative outcome as a whole, only the results of the moving 2-year analyses are presented in Table 2-8.[74]

Table 2-8 Potential heat rate improvement for best moving 2-year period, by interconnection

Analytical approach	Western	Texas	Eastern	Nationally[75]
Best historical performance (%)	2.6	3.1	4.9	4.6
Best historical performance under similar conditions (%)	3.1	3.5	5.3	5.0
Efficiency and consistency under similar conditions (%)	2.1	2.3	4.3	4.0

For the final rule, the "efficiency and consistency under similar conditions" approach provides the most conservative result for all three regions. Accordingly, the tripartite methodology adopts those results for purposes of calculating the relevant CO_2 emission performance rates and accompanying

[73] The "best" gross heat rate over a moving 2-year period will always be higher than the best gross heat rate over a 1-year period because the moving 2-year period includes at least one non-best year (*i.e.*, a year with higher average gross heat rate values).
[74] The results of EPA's inherently less conservative 1-year analyses can be found in section V.C.1.a of the final rule preamble of the CPP, as well as in the discussion above.
[75] EPA has provided nationwide results for purposes of comparison, they are not part of the methodology.

state goals.[76] Specifically, a well-supported and conservative estimate of the potential heat rate improvements (and accompanying reductions in CO_2 emission rates) that affected coal-fired EGUs in the Western interconnection is 2.1 percent, in the Texas interconnection is 2.3 percent, and in the Eastern interconnection is 4.3 percent. The agency believes these values are conservative and that EGUs have demonstrated these gross heat rates during the study period.

It is important to note that these potential heat rate improvements are based on the difference between coal-fired EGUs' past performance and their 2012 performance; they do not reflect additional opportunities for heat rate improvements from best practices and equipment upgrades that could have been (and still can be) cost-effectively implemented at coal-fired EGUs. The agency decided not to pursue a separate heat rate improvement target for specific equipment upgrades due to (1) insufficient information about the current deployment of the technologies specified in the proposal TSD, (2) the availability of data necessary to conduct the statistical analyses to identify potential heat rate improvement, and (3) potential impact of past deployments of heat rate improvement technology at some EGUs that might already be reflected in the results of the analyses described above.

2.6 Assessment of key comments

EPA received more than 1,500 comments on building block 1 of the best system of emission reductions, including comments on the methodology and assumptions for calculating potential heat rate improvements. Several of the comments are addressed above and below, and in the preamble with the remaining comments addressed in the response to comments (RTC). EPA appreciates the information and insights that commenters shared about the proposal. The information assists the agency in developing a stronger, more effective rule. Below are several key comments related to potential heat rate improvement and the additional analyses conducted by EPA to respond to those comments.

2.6.1 Effect of heat rate improvement implemented during study period

Several commenters expressed concern that measures implemented at specific EGUs to improve heat rate between 2002 and 2012 would result in greater variability of heat rate and, therefore, inflate the potential heat rate improvements. EPA acknowledges variability from heat rate improvements would affect the results of the approach used for the proposal. However, by changing the methodology to use a 2012 baseline for the analytical approaches described in this chapter, any heat rate improvements made during the study period and maintained through 2012 are accounted for and do not result in additional potential heat rate improvement.

[76] The "best historical performance" and "best historical performance under similar conditions" approaches identify greater potential heat rate improvement in each region. Accordingly, they inherently support the feasibility of the more conservative values identified by the "efficiency and consistency under similar conditions" approach.

2.6.2 Impact of air pollution controls installed during study period

Commenters described many of the air pollution control devices that were installed at coal-fired EGUs between 2002 and 2012, noting that these devices can have significant auxiliary energy requirements (*i.e.*, parasitic load) that reduce the amount of electricity available for distribution on the regional interconnection. As a result of lower net electricity generation, an EGU's net heat rate increases. Many commenters recommended that EPA consider the auxiliary energy requirements of these controls when assessing the potential heat rate improvement. EPA recognizes that air pollution control devices have auxiliary power requirements and a significant amount of coal-fired EGUs were retrofitted with air pollution controls during the study period (2002-2012). However, EPA rejects the recommendation to credit the auxiliary power requirements in the analysis because the agency's analysis is based on gross heat rate and, therefore, is not affected by auxiliary power requirements of air pollution controls.[77]

2.6.3 Impact of CO_2 emissions from SO_2 pollution control devices

Commenters noted that the addition of wet flue gas desulfurization (WFGD, or wet scrubber) technologies result in increased process CO_2 emissions because of the dissolution of limestone to capture SO_2.[78] Because heat input, the numerator for calculating heat rate, is based on an EGU's measured CO_2 emissions, the additional process CO_2 emissions result in artificial increases in calculated gross heat rate. Commenters suggest that process CO_2 emissions can be "several percentage points." To assess the range of potential impacts on EPA's analysis from process CO_2 emissions, the agency estimated the incremental CO_2 from the WFGD chemical reaction. The results indicate that retrofit WFGD installed on existing coal-fired EGUs between 2002 and 2012 increased 2012 CO_2 emissions (and calculated heat input) by an average of no more than 0.7 percent for those EGUs in 2012.

To calculate the CO_2 emissions, the agency first identified the 121 existing coal-fired EGUs that installed retrofit limestone WFGD between 2002 and 2012. Collectively these EGUs have approximately 59 GW of electricity generating capacity. Next, EPA reviewed monthly fuel transactions and calculated the weighted average sulfur content of fuel deliveries to the relevant power plants.[79] Finally, the agency calculated the process CO_2 emissions that could result at 85 and 95 percent removal efficiencies (see Table 2-9). Due to data limitations – EGU-level fuel consumption data are not available – the agency assumed that: (1) coal delivered to the power plant in 2012 was representative of coal burned in the WFGD-equipped coal-fired EGU, and (2) EGUs operated the WFGD to remove 85 to 95 percent of the sulfur. The resulting process CO_2 emission increase at coal-fired EGUs that installed retrofit limestone WFGD ranges from 0.2 percent (Texas)

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[77] See *supra* note 47.

[78] The reaction in the WFGD absorber is summarized by $SO_2+CaCO_3+½H_2O \rightarrow CaSO_3+½H_2O+CO_2$ (see RK Srivastava, 2000. Controlling SO_2 emissions: a review of technologies. EPA report EPA/600/R-00/093. Available at http://nepis.epa.gov/Adobe/PDF/P1007IQM.pdf.

[79] Monthly fuel transactions are reported at the plant level on form EIA-923.

to 1.0 percent (Eastern). It should be noted, however, that this is a conservative estimate for the following reasons: (1) some of the sulfur is bound in pyrites and well-maintained coal pulverizers/grinders should remove much of the pyritic-bound sulfur, (2) a small amount of the combustion CO_2 might be absorbed in the WFGD slurry, and (3) in 2012 some EGUs did not operate their WFGD at full capacity.

Table 2-9 Increase in 2012 CO_2 measurements due to retrofit limestone wet flue gas desulfurization

	Western	Texas	Eastern	Nationally
Number of retrofit limestone WFGD	6	6	109	121
Average sulfur content (%) of 2012 coal deliveries	0.55	0.43	1.82	1.63
Total quantity (1,000 tons) of 2012 coal deliveries	12,375	11,637	148,631	172,644
Potential process CO_2 increase (%) from WFGD	0.3	0.2	0.9-1.0	0.8-0.9

Note: Interconnection-level totals may not add up to national-level totals due to rounding; Potential process CO_2 emissions are based on 85 and 95 percent removal rates, Western and Texas values round to the same quantity for 85 and 95 percent removal rates; Retrofits are for limestone WFGD only and do not account for other WFGD that do not produce process CO_2 emissions

2.6.4 Impact of future retrofit air pollution controls to comply with EPA and state environmental requirements

This rule establishes CO_2 intensity goals based on net electricity generation for each state using the state's 2012 net electricity generation baseline. Many commenters noted that air pollution controls installed after 2012, many of which are required to comply with other federal and state environmental regulations, will require auxiliary power and therefore will increase EGUs' net heat rate and CO_2 intensity. These commenters suggested that EPA should account for the addition of future air pollution controls when calculating the state goals. EPA evaluated the potential impact of the additional pollution controls that are expected to be installed between 2013 and 2025 to comply with rules such as the Mercury and Air Toxics Standards (MATS), Clean Air Interstate Rule (CAIR), Cross-State Air Pollution Rule (CSAPR), Regional Haze Rule, as well as consent decrees and state policies. The agency's analysis, described below, indicates that the potential impact on national net heat rate and, therefore, CO_2 intensity is small – approximately 0.3 percent – in 2025.

To assess the anticipated impact of new retrofit air pollution controls on net heat rate, EPA used data and information from EPA's Power Sector Modeling Platform v.5.15.[80] The Base Case is a projection of power sector activity, taking into account existing federal and state air emission laws and regulations. The Base Case includes projected installations of air pollution controls and EGU-level net electricity generation in the years 2017, 2018, and 2025. The agency compared the Base Case 2025 installations of air pollution controls to the 2012 installations listed in the National Electric Energy Data System (NEEDS) v.5.15. Specifically, the agency identified predicted additions of WFGD, dry flue gas desulfurization (DFGD), selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR) (see Table 2-10).

Table 2-40 Predicted additional nameplate capacity (MW) with air pollution controls installed by 2025, by interconnection

Air pollution control	Western	Texas	Eastern
WFGD: wet flue gas desulfurization (MW)	283	0	18,214
DFGD: dry flue gas desulfurization (MW)	505	584	15,388
SCR: selective catalytic reduction (MW)	11,194	0	13,618
SNCR: selective non-catalytic reduction (MW)	0	391	4,014

To estimate the impact on heat rates, the agency used the heat rate penalties (*i.e.*, auxiliary power requirements) from EPA's Power Sector Modeling Platform v.5.13 (see Table 2-11).[81] Each EGU's 2012 net heat rate was adjusted for the assumed heat rate penalties and multiplied by the EGU's projected 2025 net electricity generation in the Base Case to estimate the incremental heat input required to operate the retrofit air pollution controls. The incremental heat input at EGUs with additional air pollution controls was aggregated to the interconnection region and then divided by the region's pre-control heat input.[82] The anticipated impacts of the retrofit air pollution controls on net heat rate in 2025 are 0.31 percent in the Western Interconnection, 0.06 percent in the Texas Interconnection, and 0.31 percent in the Eastern Interconnection.

[80] More information about the Power Sector Modeling Platform, including data, assumptions, and documentation is available at http://www.epa.gov/airmarkets/programs/ipm/psmodel515.html.

[81] Information on air pollution controls is taken from Chapter 5 available at http://www.epa.gov/airmarkets/documents/ipm/Chapter_5.pdf.

[82] The pre-control heat input is calculated as 2012 net heat rate (before additional air pollution controls) multiplied by 2025 net electricity generation.

Table 2-11 Assumed heat rate penalty for air pollution controls

Air pollution control	Heat rate penalty (%)
WFGD: wet flue gas desulfurization	1.70
DFGD: dry flue gas desulfurization	1.33
SCR: selective catalytic reduction	0.56
SNCR: selective non-catalytic reduction	0.78

This estimate is conservative for at least two reasons: (1) EPA's cost performance assumptions tend to overestimate the auxiliary energy requirements from individual retrofit controls, and (2) at some EGUs these newer pollution control devices will replace existing pollution control devices. Accordingly, for these EGUs, the increase in net heat rate due to auxiliary power requirements to operate new controls will be at least partially offset by the decrease in net heat rate caused by removal of current control devices. The retrofit of air pollution control devices also present opportunities to improve net heat rate by replacing some equipment (*e.g.*, fans, pumps, air heaters, economizers) with more efficient equipment.[83] In addition, future technological innovations or advances in emission control practices may reduce the need for retrofit emission controls.

Therefore, for the reasons described above, the agency has determined that when calculating overarching state goals, it is not necessary to account for the net heat rate impact of predicted installations of controls. However, EPA recognizes that states may choose to account for the installation of pollution controls at coal-fired EGUs after 2012 when developing their state plans.

2.6.5 Impact of cycling operations and lower capacity factors on heat rate

Several commenters expressed concern that the application of the other building blocks that make up the best system of emissions reductions will result in coal-fired EGUs operating at lower capacity factors and cycling more frequently during the interim and full compliance periods. Commenters noted that at lower hourly capacity factors, heat rate increases (*e.g.*, see Figure 2-6) making improving heat rate even more challenging. EPA disagrees that the application of the other building blocks from the best system of emission reductions necessarily results in more cycling at existing coal-fired EGUs for the following reasons: (1) many coal-fired EGUs are expected to retire between 2012 and 2020, reducing the remaining capacity of existing coal-fired EGUs during the interim and full compliance periods; (2) EPA modeling of electricity generation in 2030

[83] For example, see D Osowski, 2014. "Bagging Two Birds with One Economizer," Power Engineering. Available at http://www.power-eng.com/articles/print/volume-118/issue-11/departments/clearing-the-air/bagging-two-birds-with-one-economizer.html.

indicate that the remaining coal-fired EGUs will have higher annual capacity factors than the 884 coal-fired EGUs in 2012 – the baseline for the agency's heat rate improvement analyses; and (3) states have flexibility when developing their state plans and may choose policies that do not require heat rate improvements at specific EGUs.

A significant amount of coal-fired EGU capacity has retired since 2012 and even more is expected to retire by 2020. For the 884 coal-fired EGUs in the agency's analyses, more than 53,000 MW of capacity is expected to retire. This represents approximately 16 percent of the capacity from the 884 coal-fired EGUs across the nation. In the Western Interconnection, coal-fired EGU owners and operators have officially announced 6,000 MW of capacity, 16 percent of total capacity, will retire in 2020 or earlier (see Figure 2-10). The agency does not have information about any official planned retirements in the Texas Interconnection. In the Eastern Interconnection, EGU owners and operators have officially announced more than 47,000 MW of capacity, 17 percent of total capacity, will retire in 2020 or earlier (see Figure 2-11). Because less coal-fired electricity generating capacity will be available for dispatch, the remaining coal-fired EGUs are expected to operate at higher annual capacity factors.

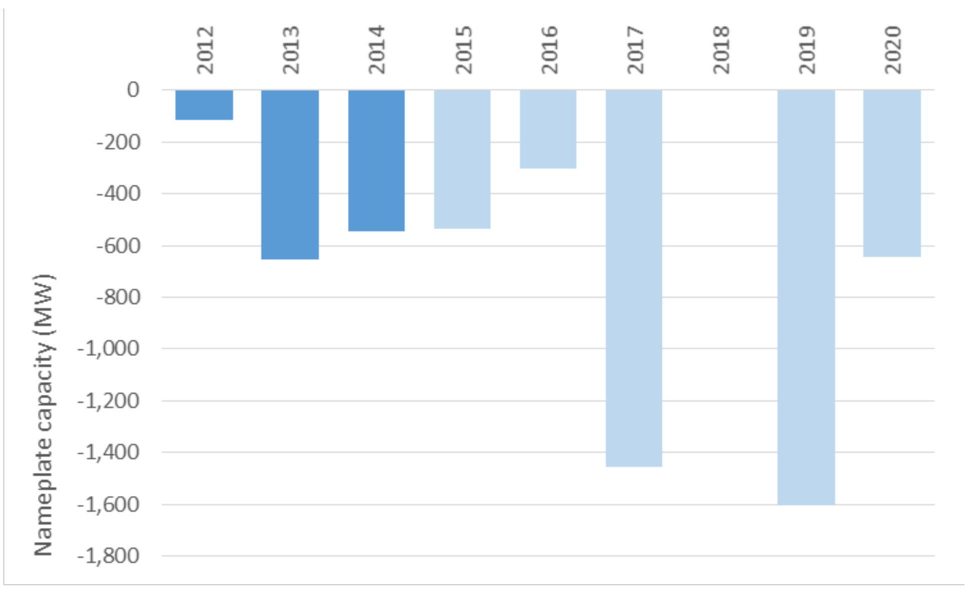

Figure 2-10 Official completed and planned retirements of coal-fired EGUs in Western Interconnection, 2012–2020

Note: Capacity scale is $^{1}/_{10}$ of scale in Eastern Interconnection (Figure 2-11)

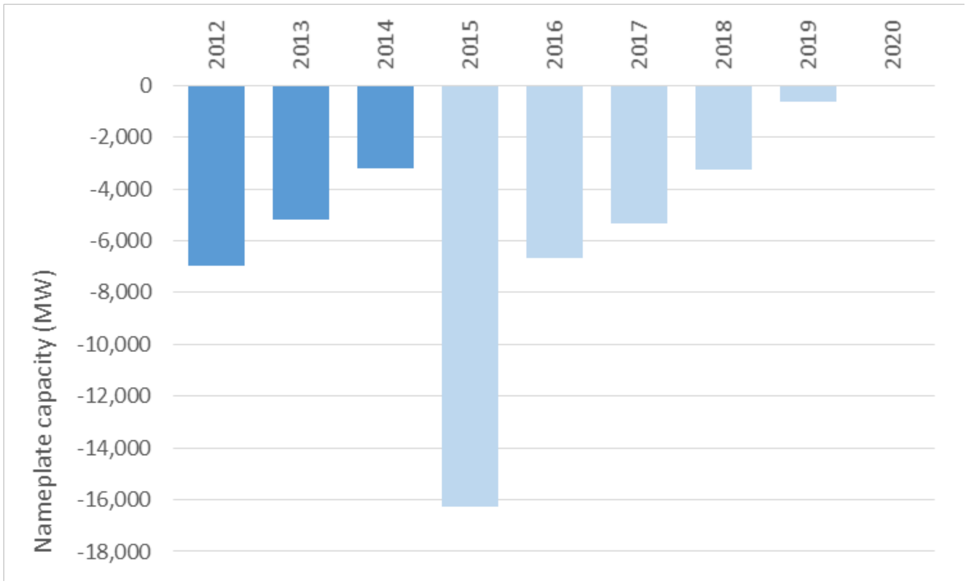

Figure 2-11 Official completed and planned retirements of coal-fired EGUs in Eastern Interconnection, 2012–2020

EPA's power sector modeling for this rule predicts that annual capacity factors for coal-fired EGUs in 2030, with the rule in full effect, will be higher than the EGUs' capacity factors in 2012. As noted above, the increased utilization of existing coal-fired EGUs that remain in operation is due in large part to significant retirements of coal-fired EGUs that have already occurred or are expected to occur as well as growth in electricity demand. Nationally, net annual capacity factors – net electricity generation divided by net summertime capacity – at coal-fired EGUs is predicted to be approximately 70 percent under a rate-based goal and 75 percent under a mass-based goal while the 2012 net annual capacity factor averaged 55 percent. [84] The values for the interconnections are shown in Table 2-12. While these values represent annual capacity factors and not hourly capacity factors, the substantial increase in annual capacity factors at existing coal-fired EGUs in all interconnections except Texas leads to a reasonable conclusion that the remaining coal-fired EGUs as a whole will operate at higher levels in 2030 than the coal-fired EGU fleet did in 2012, the baseline for this heat rate improvement study. For the Texas interconnection, the capacity factors are anticipated to be approximately the same under a mass-based policy approach and lower under a rate-based approach. The state of Texas has the flexibility to consider this projected change in annual capacity factors when designing the state plan.

[84] The 2012 net annual capacity factors were calculated from the 2012 baseline data using the eGRID methodology. For the 947 coal steam EGUs in the CONUS, the capacity factor was calculated as net electricity generation (MWh)/[8784 hours X net summertime capacity (MW)]. The difference between the values in Table 2-12 and the values in Table 2-3 are attributable to the metric – Table 2-12 lists net capacity factor while Table 2-3 lists gross capacity factors.

Table 2-52 Annual net capacity factors (percent) in 2012 and 2030, by interconnection

Interconnection	2012	2030 mass goal	2030 rate goal
Western	69.5	80.5	79.5
Texas	66.5	66.5	55.8
Eastern	52.8	74.9	69.5
CONUS	55.3	74.7	69.5

2.6.6 Influence of flow monitoring method on historical heat rate data

To calculate heat input at a coal-fired EGU, the operator must measure the flow rate of flue gases as they pass through the stack (or duct). Initially, all coal-fired fired EGUs used EPA Reference Method 2 to measure stack gas flow.[85] However, in 1999 EPA introduced new reference methods to address angular flow (Methods 2F and 2G) and the effect of the stack walls on gas flow (Method 2H). In general, these alternative measurement methods reduce or eliminate the over estimation of stack gas flow that results from the use of method 2 when the specific flow conditions (*e.g.*, angular flow) are present in the stack. Generally, the alternative methods lead to lower flow rates and as a result, lower heat input. After the introduction of these new methods, many coal-fired EGUs adopted the alternative methods to measure flow and calculate mass emissions.[86] However, coal-fired EGUs are not required to use the alternative measurement methods and they may change methods when conducting a RATA. Commenters have hypothesized that much of the variability in gross heat great is caused by coal-fired EGUs changing from one flow measurement method to another. EPA considered this possibility and discussed some of the issues in the proposed TSD. The agency evaluated the commenters' concerns and conducted additional analyses to explore the potential impact of flow method on heat rate variability.

.Evaluation of flow measurement methods is complex because coal-fired EGUs may have one or more stacks, including common stacks that are shared with other EGUs at the power plant, and might use different flow measurement methods for up to three different load levels in each stack. To assess the potential influence of flow measurement methods on heat rate variability, EPA reviewed the reported flow measurement methods for the 884 coal-fired EGUs between 2002 and 2012. Of the 884 EGUs, 531 EGUs modified one or more flow measurement method for at least

[85] For more information about Method 2, see 40 CFR Part 60 Appendix A.
[86] Coal-fired EGUs use continuous emission monitoring systems to measure pollutant concentrations and stack gas flow. The two measured values are used to calculate mass emissions.

one load level during the 11-year study period (2002–2012).[87] If, as commenters suggested, changes to flow measurement methods were responsible for much of the variability in EPA's data, the analytical results should show that EGUs with a change of flow measurement method have higher indicated potential heat rate improvements. To test this theory, the agency conducted the "efficiency and consistency" analysis using only the 531 EGUs that changed flow measurement methodology.[88] However, as shown in Table 2-13, the EGUs that changed flow method during the study period (2002–2012) have *lower* potential heat rate improvements in the Western and Texas interconnections than for the full group of coal-fired EGUs in the interconnections. In the Eastern interconnection, the results between the two groups – EGUs that changed flow measurement method(s) and all coal-fired EGUs – are nearly identical.[89] This demonstrates that although changes in flow measurement method might have implications for an individual EGU's reported heat rate, the changes do not adversely affect the overall interconnection-level results of EPA's potential heat rate improvement analyses.

Table 2-63 Potential heat rate improvement (percent) based on the 2-year efficiency and consistency under similar conditions analytical approach for all coal-fired EGUs and coal-fired EGUs that changed flow measurement method, by interconnection

Interconnection	884 coal-fired EGUs	Coal-fired EGUs with flow measurement method changes
Western	2.1	2.0
Texas	2.3	0.0
Eastern	4.3	4.3
CONUS	4.0	3.8

Because the potential heat rate improvement for the 884 coal-fired EGUs and the 531 coal-fired EGUs that changed one or more flow measurement methods are approximately the same in the Western and Eastern Interconnection, EPA disagrees with commenters' concern that changes to

[87] The flow measurement methods for these 531 coal-fired EGUs are available in the dataset titled *Supplemental data and analysis for potential heat rate improvement for the CPP final rule*.

[88] EPA did not reassess the other analyses of the tripartite approach for EGUs that changed flow measurement methodology because the "efficiency and consistency" approach was the most conservative approach (*i.e.*, resulted in the lowest potential heat rate improvement).

[89] This is particularly noteworthy given that the best system of emission reductions for the Eastern Interconnection sets the best system of emission reductions for the entire CONUS.

flow measurement methods were responsible for much of the variation in gross heat rates. In the Texas Interconnection, only six of 32 coal-fired EGUs reported changing flow measurement methodology during the study period (2002–2012). Collectively, the six EGUs in the Texas interconnection that changed flow measurement methods had performed better in 2012 and/or had lower variability than the population of Texas Interconnection coal-fired EGUs.

In the year 2012, 193 of the 884 coal-fired EGUs used Method 2 for all load levels, 663 coal-fired EGUs used alternative flow measurement methods for all load levels, and 28 coal-fired EGUs used a combination of methods.

For the reasons described above, changes in monitoring methodology at some coal-fired EGUs does not alter our confidence in the regional results that constitute the potential heat rate improvement under building block 1.

2.6.7 Inability of individual coal-fired EGUs to achieve the heat rate improvements and concerns about stranded assets

Several commenters stated that specific coal-fired EGUs are not able to achieve the heat rate improvements identified in the proposal TSD. They provide a variety of reasons, including: (1) the EGU's fuel type (*e.g.*, lignite has low energy value and high moisture content) makes it difficult to improve heat rate, (2) specific EGUs have already implemented efficiency measures and are not capable of improving heat rates beyond their current levels, and (3) small coal-fired EGUs do not have the same economies of scale as larger EGUs. Commenters also expressed concern that (1) soon-to-retire EGUs would be forced to make additional efficiency upgrades to improve heat rate, resulting in stranded assets, and (2) mandatory heat rate targets might force retirements, resulting in stranded assets.[90]

First, EPA disagrees with commenters that this rule establishes a mandatory "one-size-fits-all" heat rate improvement standard. Rather, the heat rate improvement is one part of the best system of emission reduction and must be viewed in the context of the full best system of emission reductions. As noted earlier, states have the flexibility to establish policies in the state plan that are reasonable and appropriate for that state; these policies may or may not include heat rate improvement goals. Second, EPA disagrees with the commenters' presumption that each coal-fired EGU must independently achieve the potential heat rate improvements identified in this analysis. The results of the analyses described above provide an estimate of potential heat rate improvements that, on average, are possible within each interconnection region based on each coal-fired EGU's best historical heat rate between 2002 and 2012 and the EGUs' 2012 heat rate. Because the results represent the average potential heat rate improvement for an interconnection,

[90] For more information about EPA's analysis of the stranded assets question, see preamble section VIII.G.1, the legal memorandum, and the July 2015 docket memo titled "Stranded assets analysis."

some coal-fired EGUs can make greater heat rate improvements while other EGUs might make less.[91] Third, the agency's analysis is based on coal-fired EGUs' historical heat rates and is therefore demonstrated. Commenters also noted that the interim and full compliance periods do not begin for several years and new or enhanced technologies and practices for improving heat rate might be available in the future if there is a stronger incentive to improve efficiency. With regard to soon-to-retire EGUs, the interim compliance period does not begin until 2022 so the agency does not expect there would be significant requirements of those EGUs to make additional investments in heat rate improvements if a state chose to pursue heat rate improvements in its state plan. However, if a soon-to-retire EGU did make such investments, those investments might serve to extend the useful life of the EGU.

2.6.8 Impact of equipment degradation

Several commenters stated that EPA's assessment of potential heat rate improvement from equipment upgrades was unrealistic because it did not account for degradation of the equipment over time. First, it is important to note that: (1) EPA is no longer basing potential heat rate improvements on specific upgrades and (2) the rule does not establish a federal requirement for coal-fired EGUs to meet specific heat rate improvement targets (see section 2.6.7). Second, the agency believes EGU operators can control the rate of degradation through proper maintenance and, when necessary, replacement or refurbishment of equipment. This is supported by information provided by a commenter referring to National Petroleum Council (NPC) and International Energy Agency (IEA) reports that discuss deterioration and enhanced maintenance practices at coal-fired EGUs. The NPC report stated:

Deterioration naturally occurs, and if left unchecked it can become substantial. Therefore, some amount of deterioration, normal deterioration, will always be present and non-controllable. Most of the normal deterioration can be recovered with regularly scheduled maintenance intervals… There is a gradual increase in the unrecoverable portion as the unit ages which would require a replacement rather than a refurbishment to eliminate. Poor maintenance practices regarding the timing of the intervals and the amount of refurbishment may result in excessive deterioration and is controllable [by the EGU operator].[92]

[91] The final CPP provides states the flexibility to develop emission standards for individual EGUs that more precisely take into account that EGU's potential heat rate improvement – should states desire to consider potential heat rate improvement at all in establishing emission standards. Furthermore, if an affected EGU cannot meet the particular emission standard solely because it has below-average potential to reduce emissions through heat rate improvements, then in instances where the EGU's state plan allows emissions trading, the EGU can acquire credits or allowances from affected EGUs that have above-average potential.

[92] See National Petroleum Council (NPC), 2007. Electricity Generation Efficiency. NPC Working Document; Topic Paper #4. Available at http://www.npc.org/Study_Topic_Papers/4-DTG-ElectricEfficiency.pdf.

The IEA report stated:

[I]mprovements can not only restore ageing plants to their original performance, but also can often improve them further by avoiding the limitations of the prevailing technology at the time of original plant design…Not all of these areas have been considered worthy of attention previously, and a conclusion from that is that there may be other unrecognized areas of losses in efficiency which could be worth identifying.[93]

2.6.9 Limited adoption of low- and zero-cost heat rate improvements

Commenters suggested that if there were low- or no-cost options to improve heat rate and, therefore, reduce fuel cost, coal-fired EGUs would have already implemented those measures because they have economic incentives to do so. However, research from NETL, RFF, and others show that there are a number of reasons that existing coal-fired EGUs might not implement low- and no-cost heat rate improvement practices, including: (1) concerns or uncertainties about New Source Review impacts; (2) lack of economic incentives to improve efficiency because of fuel adjustment clauses that enable electricity generating companies to "pass through" fuel costs directly to customers; (3) lack of management commitment for efficiency programs; (4) focus on optimizing profitability and ensuring availability; (5) lack of on-site performance engineers dedicated to heat rate improvement; (6) potential fuel cost savings represent only a small portion of total costs and are "of secondary concern when compared to needs for maintaining system reliability"; and (7) lack of regulatory certainty about future environmental regulations that lead to operators deferring significant upgrades on older coal-fired EGUs.[94]

2.7 Costs

2.7.1 Breakeven costs

In the proposal TSD, EPA used an estimated average cost of $100/kW for a potential national average 6 percent heat rate improvement by coal-fired EGUs. Four percentage points of that potential improvement was projected to come from relatively inexpensive low- or no-cost best practices. Thus, most of the estimated $100/kW average cost actually represented the cost of relatively more expensive equipment and system upgrades that EPA expected would provide the remaining 2 percent improvement.

For this final rule, as explained above, EPA has refined the estimate of potential national average net heat rate improvement by coal-fired EGUs to between 2.1 to 4.3 percent for each interconnection, or about 4 percent nationally, with potentially all of that improvement coming

[93] See C Henderson, 2013. Upgrading and efficiency improvement in coal-fired power plants. International Energy Agency (IEA) Clean Coal Centre Report. CCC/221. ISBN 978-92-9029-541-9. Available at http://bookshop.iea-coal.org/reports/ccc-221/83186.

[94] See *supra* notes 11 and 18. Also see Comments of Natural Resources Defense Council (NDRC). Available at http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2013-0602-26818.

from best practices. The agency no longer relies on an additional and distinct 2 percent improvement contribution from equipment upgrades. The agency expects, however, that some EGUs will in fact choose to make equipment upgrades for heat rate improvement, and that at least some small fraction of the overall heat rate improvement will come from equipment upgrades, and for at least a few EGUs most of the improvement may come from equipment upgrades. Overall, the agency expects the cost of heat rate improvement to be significantly less than $100/kW at the new level of heat rate improvement. However, because of the uncertainty associated with what fractions of a potential national average 4 percent heat rate improvement may come from no- or low-cost versus higher cost measures at individual EGUs, and considering commenter concerns that EPA's previous estimated cost was too optimistic, the agency assessed the economic effects of a heat rate improvement cost that might range from $50 to $100/kW.

The agency acknowledges here, as in the proposal TSD, that the technical applicability and efficacy of heat rate improvement measures, the cost of implementing them, and delivered coal cost, all depend upon site specific factors and can vary widely from site to site. Nonetheless, the agency finds it reasonable to expect that a fleet wide average cost for a national fleet wide average improvement of 4 percent, based primarily on low- and no-cost best practices, would be significantly less than $100/kW. However, as a conservative measure, and because the cost of heat rate improvement is one of the least costly and least impactful measures considered in the best system of emission reductions for this rule, the agency has decided to conservatively use the previously estimated $100/kW cost value for IPM modeling and the RIA estimates of the total cost of this final rule.

The brief assessment presented here is intended only to illustrate the approximate effects of coal cost and heat rate improvement capital cost on the economic breakeven point between coal cost savings and the capital cost of implementing heat rate improvement. The resulting order-of-magnitude cost range for CO_2 removal ($ per ton) is also discussed. EPA does not suggest in the proposal nor in this final rule that heat rate improvement measures should meet a particular economic criterion (*e.g.*, pay for themselves through reduced fuel costs) in order to be applied in state plans for compliance with this rule.

Figure 2-12 presents a simplified economic breakeven analysis for a 4 percent nationwide average heat rate improvement, assuming there is no CO_2 emission allowance cost involved. Additional assumptions used in the breakeven calculation include: capital charge rate of 14.3 percent, as used in the IPM Base Case modeling for this final rule; 2030 annual capacity factor of 78 percent, derived from IPM modeling; coal fleet generation-weighted average 2030 net heat rate of 10,250 Btu/kWh before heat rate improvement, also derived from IPM modeling.

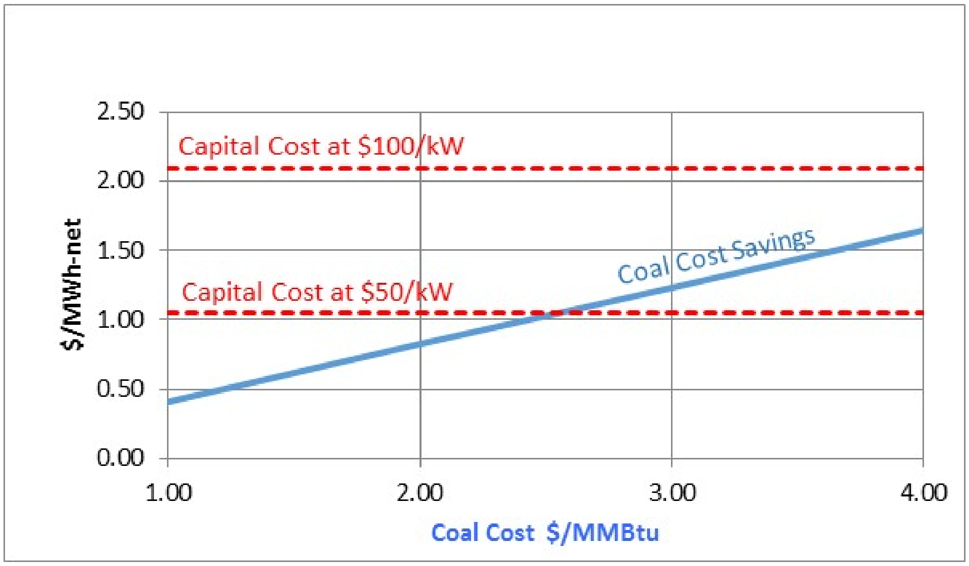

Figure 2-12 Breakeven economics of a 4 percent heat rate improvement

Figure 2-12 shows that at a capital cost of $50/kW, the average fleet wide 2030 savings in coal cost would become greater than the annualized capital cost of an average 4 percent reduction in net heat rate when the average fleet wide coal cost exceeds about $2.50/mmBtu. For comparison, the average U.S. power sector delivered cost of coal was $2.38/mmBtu in 2012,[95] and is projected to be about $2.70/mmBtu in 2030.[96] For different assumptions, the heat rate improvement economic breakeven point would change directionally as follows:

If the heat rate improvement capital cost were on average less than $50/kW, 4 percent heat rate improvement would then "become economic" (*i.e.*, pay for itself) at lower coal costs. For example, if the average capital cost were actually $25/kW, a fleet wide 4 percent heat rate improvement would become economic at an average coal cost of about $1.25/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.[97] This sensitivity indicates that fuel cost savings alone would make it economic for some of those EGUs currently using the higher cost bituminous coals to make heat rate improvement investments.

At an EGU net heat rate that is higher than the IPM projected 2030 average value of 10,250 Btu/kWh, 4 percent heat rate improvement could be economic at coal costs lower than the values mentioned above.

[95] EIA, Electricity Data Table 7.4, Average Weighted Cost of Fossil Fuels for the Electric Power Industry 2002–2012. Available at http://www.eia.gov/electricity/annual/html/epa_07_04.html.
[96] 2030 projected fuel costs are derived from IPM Base Case.
[97] See *supra* note 955.

If there were additional heat rate improvement savings due to avoided future CO_2 emission costs, heat rate improvement could become economic at lower coal costs, or at higher capital costs, or at lower heat rate reduction percentages.

2.7.2 Estimated fleet wide CO_2 reduction from and cost for heat rate improvements

EPA derived the following illustrative order-of-magnitude estimate of the fleet wide cost-effectiveness of a 4 percent heat rate improvement from the IPM Base Case modeling:

2.7.2.1 Fleet wide 2030 assumptions derived from IPM Base Case for this final rule

- Coal fleet capacity applying combined heat rate improvement methods: 213,000 MW
- Average net heat rate: 10,250 Btu/kWh net, before 4 percent heat rate improvement
- Average capacity factor: 78 percent
- Heat rate improvement Btu and CO_2 reduction: 4 percent
- Heat rate improvement capital cost: $50/kW (assumed)
- Annual capital charge rate: 14.3 percent
- Average coal cost: $2.70/mmBtu

2.7.2.2 Estimated fleet wide results

- Fleet wide CO_2 reduction via heat rate improvement: 62 million ton/year
- Total heat rate improvement capital cost: $10.7 billion
- Annualized heat rate improvement capital cost: $1.5 billion
- Annual coal cost savings: $1.6 billion
- Annual net savings: $0.09 billion
- Annual net savings for CO_2 reduction: $1.4/ton

2.7.3 Conclusion - heat rate improvement economics

This necessarily simplified analysis supports the following summary conclusions:

1. Some degree of heat rate improvement is very likely already economic (paying for itself) for high heat rate-high coal cost EGUs, and will remain so in 2030

2. If a fleet wide average 4 percent heat rate improvement were implemented, it would also pay for itself 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 projected 2030 coal prices if the associated average capital cost is about $50/kW or less.

3. If a fleet wide average 4 percent heat rate improvement were implemented, and the associated average capital cost is as much as $100/kW, 4 percent heat rate improvement would not likely pay for itself based on fuel cost savings alone.

4. Even at a capital cost of $100/kW and an IPM projected 2030 coal price of $2.70/mmBtu, the average fleet wide cost of CO_2 reduction via 4 percent heat rate improvement would be a still relatively low $23/ton.

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

CHAPTER 3: CO_2 REDUCTION POTENTIAL FROM GENERATION SHIFTS AMONG EXISTING UNITS

3.0 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.

3.1 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."[1] Electricity demand varies across geography and time in response to numerous conditions, such that electricity generators are constantly responding to changes 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, subject to the constraints of reliable system operation.[2]

EGU operators and balancing authorities must take into account several constraints in dispatch, including transmission and other operating 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 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 by

[1] Energy Policy Act of 2005

[2] 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

shifting generation among existing EGUs, particularly by shifting generation from coal-fired units to natural gas combined cycle (NGCC) units.

3.2 Power Sector Background

3.2.1 Electric Dispatch

The operation of electricity generation accords to the principle of security-constrained 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."[3] The cost of operating electric generators varies based on a number of factors, such as fuel used and generator efficiency. In many regions of the country, System Operators help coordinate economic dispatch over large 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 generally driven by the relative operating cost, or marginal cost, of generating electricity to meet the last increment of electricity 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 usually 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.[4] Other generating technologies, like renewables, hydroelectric, and nuclear, have little or no variable costs and are generally dispatched to the extent possible. Under economic dispatch, the units with the lowest variable costs 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 merit order in which units are dispatched to meet demand, at any particular point in time, is commonly called a dispatch or supply "curve."[5]

3.2.2 Balancing Authorities

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

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

[4] In addition to fuel costs, variable costs also include costs associated with operation and maintenance, and costs of operating a pollution control and/or the price of allowances to emit certain pollutants.

[5] http://www.eia.gov/todayinenergy/detail.cfm?id=7590

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 (least-cost) manner possible.[6] RTOs and ISOs coordinate, control, and monitor the operation of the electric power system 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.

3.2.3 State Public Utility Commissions (PUCs)[7]

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, 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 revenues from generation (and sometimes capacity) are earned through markets governed by RTOs and ISOs. In cost-of-service states, the PUC also has oversight of the generation and capacity planning components.

3.2.4 Wholesale Power Markets

RTOs and ISOs operate spot markets for wholesale power supply and demand for their designated area, including both day-ahead and real-time markets (using 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, serve as the reliability coordinator for their area and typically serve as the balancing authority for the same area.

For areas not administered by RTOs and ISOs, dispatch is scheduled on both a day-ahead and an hourly basis, but it 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

[6] http://www.ferc.gov/industries/electric/indus-act/rto.asp
[7] These entities are sometimes called Utilities Commissions, Utility Regulatory Commissions, or Public Service Commissions.

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 on a day-ahead basis rather than on an hourly basis, and they can also sell power for longer periods of time, 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.

3.2.5 Reliability

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

A reliability coordinator is responsible for the generation-demand balance within its reliability coordination area of the bulk power system, and may direct a balancing authority within its reliability coordinator area to take whatever action is necessary to ensure that this balance does not adversely impact reliability. The bulk power 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.[8]

3.3 Generation Shifting: Technical Potential

In 2012, national average CO_2 emission rates[9] across the following technology types on a net generation basis were:

- Coal Steam: 2,217 lbs/MWh
- Oil/Gas (O/G) Steam: 1,435 lbs/MWh
- NGCC: 905 lbs/MWh

[8] http://www.nerc.com/

[9] Emission rates in this document are shown on a net generation basis and reflect Hawaii and Alaska sources, as well as units that commenced construction in 2012. See "2012 unit-level data using the eGrid methodology" file provided in the docket

Coal- and oil/gas-fired boilers are considerably higher-emitting sources than NGCCs, on average. Therefore, shifting generation from the average existing fossil fuel-fired boiler to an average existing NGCC will result in notable CO_2 emission reductions.

The lower emission rate of NGCC conveys the potential of generation shifting 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 shift generation 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 replace generation from more CO_2-intensive generating resources.

Given their cost structure, for purposes of economic dispatch, most NGCCs have historically operated as base load or intermediate load[10] due to their high efficiency and flexibility of operation, with national average annual capacity factors in the range of 40-50%.[11,12] 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 is indicated, in part, by data on the average availability factor of NGCCs.[13] The term "availability" is a common engineering term used in the power sector that 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 attributable to scheduled maintenance, unplanned maintenance, and unplanned outages. For modeling purposes, EPA assumes that NGCC has an availability of 87%.[14] Other reports suggest that NGCC availability factors may reach as high as 92%.[15,16] Many modern NGCCs have demonstrated 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).[17] These high-efficiency and high-availability NGCC units were first introduced around 1995 and have consistently

[10] Unlike baseload power, intermediate load is cycled to follow the changing demand for electricity, but it is not cycled as often as peaking supply which operates on much shorter timescales.
[11] EIA, Today In Energy, January 15, 2014, http://www.eia.gov/todayinenergy/detail.cfm?id=14611 (for recent data)
[12] EIA, Electric Power Annual 2009, http://www.eia.gov/electricity/annual/archive/03482009.pdf (Table 5-2 for 2009 and earlier data)
[13] NERC, 2008-2012 Generating Unit Statistical Brochure – All Units Reporting, http://www.nerc.com/pa/RAPA/gads/Pages/Reports.aspx
[14] See Chapter 3, Table 3-18 at for Base Case v513 at http://www.epa.gov/airmarkets/powersectormodeling.html
[15] http://www.power-eng.com/articles/print/volume-115/issue-2/features/higher-availability-of-gas-turbine-combined-cycle.html
[16] 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
[17] http://site.ge-energy.com/corporate/network/downloads/7FA_Evolution.pdf

reported availability factors of 90 to 92 percent to NERC.[18] These availability factors are substantially above the 2012 NGCC generation level, indicating that there is a significant potential for increasing generation from unutilized existing NGCC capacity.

To evaluate potential opportunities for shifting generation to unused NGCC capacity, EPA reviewed recent operating data across all NGCCs to determine NGCC capacity factors in 2012. For GHG abatement purposes, generation shifting would require one net MWh of generation from a lower-emitting technology operating in place of one net MWh of generation from a higher-emitting technology. Therefore, EPA calculated capacity factors as the ratio of a unit's reported net generation to its potential net generation, the latter of which is determined by the unit's net generating capacity. Net generating capacity reflects a reduction from nameplate capacity due to on-site electricity use (e.g., station service or auxiliaries) and local temperature conditions. EPA used the net summer capacity reported for units in the EIA Form 860 because it controls for local conditions and is thus a consistent metric for evaluating dependable capacity nationwide. Potential net generation was calculated as the net summer generation capacity of a unit multiplied by the number of hours in a year. Therefore, the equation for calculating capacity factors is:

$$\frac{\text{Reported generation in 2012}}{(\text{Net summer capacity}) \text{ x } (\text{hours in 2012})}$$

This calculation of capacity factor provides an indication of how much net generation a unit is providing as a percent of its total net generating capacity. The capacity factor refers to the actual utilization of that source on an annual basis, while that source's availability refers to its potential maximum utilization level. EPA surveyed 2012 data for 439 NGCC plants and observed that the NGCC fleet had an average capacity factor of 46% in 2012.[19] Since the fleet-wide capacity factor in 2012 was less than the technical generation potential available for the technology, the historical data suggests that there is a significant potential for shifting generation from higher CO_2 emitting resources to lower CO_2 emitting NGCC generation.

Availability for NGCC fleet..87% to 92%

2012 Capacity Factor for NGCC fleet 46%

[18] 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.
[19] EIA 860 and 923.

To quantify the GHG reduction potential from generation shifting, EPA considered alternative capacity factor levels at which the NGCC fleet could be dispatched. Although the availability for NGCC units is assumed to be 87% to 92%, EPA did not assume that the NGCC fleet could collectively operate at this level on an annual basis. To determine a reasonable average capacity factor for the NGCC fleet as part of BSER, 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.[20] Of this capacity, almost all are highly efficient NGCCs that are able to achieve high availability factors.

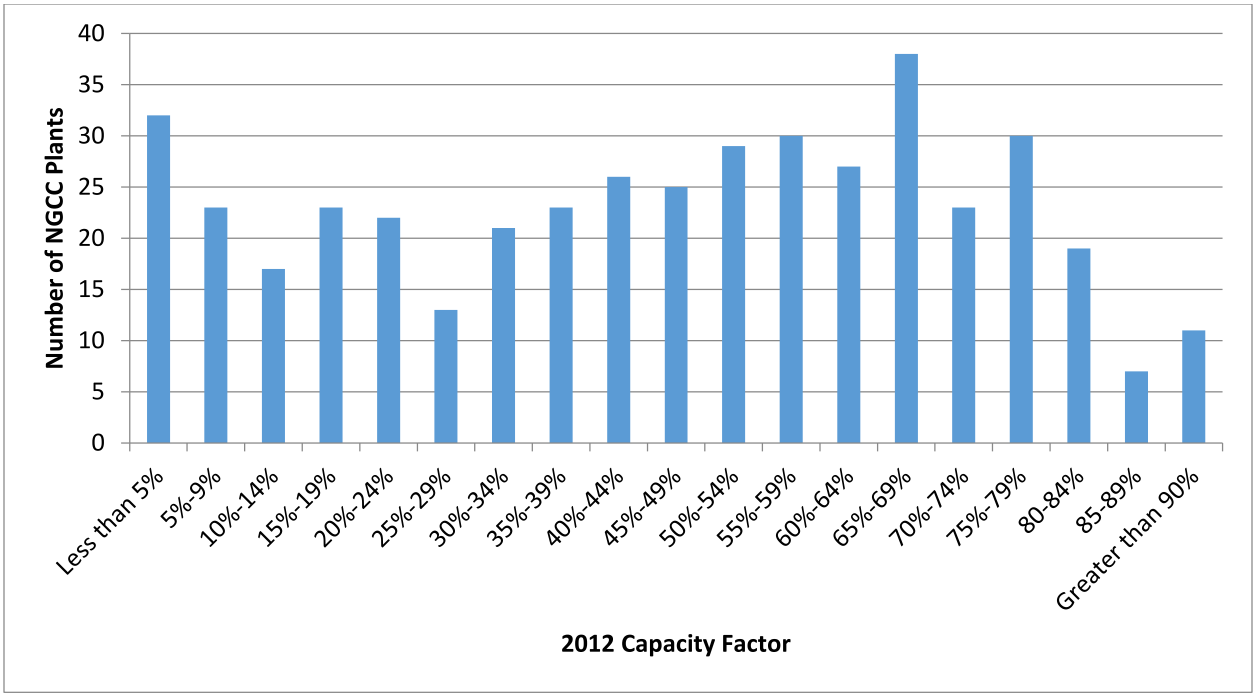
Table 3-1: Existing NGCC Capacity, by Age[21]

Online Year	Capacity (Name Plate Capacity – MW)	Percentage of Total Existing NGCC Fleet, by Capacity
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%**

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

Of 439 NGCC plants generating in 2012, EPA observed that 67 plants (more than 15% of NGCC plants) had a capacity factor of 75% or greater (see Figures 3-1 and 3-2).[22]

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



Source: EIA forms 860, 923 (2012), Combined Cycle Steam Part (CA) and Combined Cycle Combustion Turbine Part (CT) prime mover categories

[22] See "2012 unit-level data using the eGrid methodology" file provided in the docket

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

Capacity Factor (net summer)	# of NGCC plants	% of NGCC Plants
Less than 5%	32	7.3%
5%-9%	23	5.2%
10%-14%	17	3.9%
15%-19%	23	5.2%
20%-24%	22	5.0%
25%-29%	13	3.0%
30%-34%	21	4.8%
35%-39%	23	5.2%
40%-44%	26	5.9%
45%-49%	25	5.7%
50%-54%	29	6.6%
55%-59%	30	6.8%
60%-64%	27	6.2%
65%-69%	38	8.7%
70%-74%	23	5.2%
75%-79%	30	6.8%
80-84%	19	4.3%
85-89%	7	1.6%
Greater than 90%	11	2.5%

In 2012, more than 15% of NGCC plants operated at an annual capacity factor of 75% or higher on a net summer basis. This subset of NGCCs was largely dispatched to provide base load power. While only 15% of plants operated at 75% 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%. 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 75% or higher capacity factor for extended periods of time. These units achieved high capacity factors without adverse effects on the electric system.

Hourly data reported to EPA[23], particularly from the peak summer months of July and August, also show that most individual NGCC units can operate at high capacity factors. Capacity factors from the hourly unit level data reported to EPA are based on heat input and input capacity; these calculations correspond closely to the capacity factor calculations described above (that are based on data reported to EIA representing longer periods of time) and enable consideration of capacity factors at the unit and hourly level. Using EIA and EPA data from 2012 for the same facilities, capacity factor averages from EIA nameplate values and EPA unit level data from 2012 data are both 46%, while net summer capacity factors from EIA are 52%.[24] On average, then, net capacity factors are approximately 5% or more above nameplate capacity factors. Analysis of these hourly data demonstrates several important point about the feasibility of running NGCC units at capacity factors above 70% nameplate – or 75% net summer – levels. To examine historical potential capacity factors for NGCC units, EPA calculated nameplate capacity factors for daily peak operation from 7 AM to 7 PM during the months of July and August, a sustained period that demonstrates both the ability of individual units to operate at high capacity factors and of the power grid to support regional operation of the NGCC fleet at much higher levels than current averages. This analysis shows the following key points:

- Most individual units are capable of high levels of operation: 88% of NGCC units operated at a nameplate capacity factor of 70% or above for at least one day in July and August of 2012; 67% operated at 80% or above for at least one day.
- The interconnected power grids can support region-wide NGCC operation at much higher than average capacity factors. Each NERC region operated at a nameplate capacity 70% or above for at least one day, as shown below:
    - ERCOT 75%
    - WECC 74%
    - Eastern Interconnection Regions
        - RFC 75%
        - MRO 76%

[23] Air Markets Program Data (at http://ampd.epa.gov/ampd/).
[24] EPA Air Markets data is unit level data from 411 facilities; EIA data surveys are from 439 facilities.

- SERC 73%
- FRCC 75%
- SPP 71%
- NPCC 70%

These observations demonstrate the technical ability to operate existing NGCC capacity at or above a 70% nameplate capacity factor, and therefore at least at a 75% net summer capacity factor or higher. These observations also demonstrate the ability of the natural gas transmission system to support this level of generation.

3.4 Historical Trend

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 NGCCs, absent any federal CO_2 requirements. 2012 net generation from NGCC units grew to 966 TWh, up from 783 TWh in 2011 (23% growth in one year).[25]

An analysis of historical generation across the 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 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 this generation pattern as it relates to emissions of CO_2.

The potential for shifting generation 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 183 TWh, coal generation fell by approximately 217 TWh. The significant shift from coal to gas generation over just a one year period demonstrates the ability for a quick shift in generation patterns in response to market or economic drivers.

The increase in NGCC utilization was in large part driven by a decrease in natural gas prices (see Table 3-3). Electric power sector delivered natural gas prices averaged $4.89/Mcf in 2011 and $3.54/Mcf in 2012.[26] This price decline of $1.35/TCF created an additional incentive for decreasing coal generation and increasing NGCC generation relative to 2011 electricity production economics. This historical data also shows a sharp increase in the NGCC fleet's net summer

[25] EIA Form 860, 923 (2011)
[26] EIA Natural Gas Prices, http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

capacity factor from approximately 40% on average in 2011 to approximately 46% on average in 2012.

The historical trend of shifting generation to NGCC is expected to continue, as dry natural gas production is expected to grow as much as 23% by 2022 relative to its 2012 level.[27]

Table 3-3: 2011 and 2012 Gas and Coal Generation[28]

Year	NGCC Net Summer Capacity (GW)	NGCC Net Generation (TWh)	NGCC Capacity Factor	Electric Power Sector Natural Gas Price ($/TCF)	Coal Net Generation (TWh)
2011	204	783	40%	$4.89	1,718
2012	211	966	46%	$3.54	1,501

[27] AEO 2015

[28] EIA form 860 and EIA form 923 (NGCC), and EIA Monthly Energy Review, Table 7.2b (coal)

Table 3-4. Electric Power Sector Electricity Net Generation from Natural Gas, 1990-2012

Year	Net Generation: Natural Gas (million KWh)	Percent Increase from Previous Year
1990	309,486	
1991	317,773	3%
1992	334,274	5%
1993	342,222	2%
1994	385,689	13%
1995	419,179	9%
1996	378,757	-10%
1997	399,596	6%
1998	449,293	12%
1999	472,996	5%
2000	517,978	10%
2001	554,940	7%
2002	607,683	10%
2003	567,303	-7%
2004	627,172	11%
2005	683,829	9%
2006	734,417	7%
2007	814,752	11%
2008	802,372	-2%
2009	841,006	5%
2010	901,389	7%
2011	926,290	3%
2012	1,132,791	22%

Source: EIA Monthly Energy Review, Table 7.2b (multiple years)

3.5 Phase-In

The application of an increase in NGCC operation equivalent to a 75% net summer utilization to the baseline data from 2012 would yield an increase of about 55% in NGCC generation, from 966 TWh to 1,498 TWh. To allow time for potential infrastructure improvements to facilitate increased utilization of existing NGCC plants, EPA is finalizing a gradual phase over the interim period, consistent with the historical data presented above. The phase-in schedule is based on two parameters. The first parameter defines an amount of generation shift to existing NGCC capacity that is feasible by 2022. This parameter is conservatively defined as a percent increase from 2012 to 2022 that is equal to the largest single largest annual increase in power sector gas-fired generation since 1990. It is reasonable to assume that the same increase in NGCC utilization that occurred in one year could be implemented again by 2022.

The increase in NGCC utilization over the remaining years of the interim period is limited by the average annual growth in gas-fired generation in the power sector between 1990 and 2012, or approximately 5 percent per year. Since this is the average annual increase in gas utilization that has occurred over recent history, it is reasonable to assume that this increase could occur throughout the interim period, up to the full technical potential of 75% utilization on a net summer basis.

In the performance rate calculation methodology, these two parameters constrain the annual rate at which building block 2 shifts generation from fossil steam units to NGCC units. As discussed in the preamble, the interim performance rate is an average of annual rates calculated over the 2022-2029 period. The two parameters above limit the extent to which NGCC generation is assumed to increase and replace fossil steam generation in each year of the interim period. From historical data, we can observe that the single largest annual increase in power sector gas-fired generation since 1990 occurred between 2011 and 2012 and is equal to 22 percent. Therefore, in the first year of the interim period, NGCC generation is limited to a maximum of a 22 percent increase from 2012 levels in each region. In each subsequent year, regional NGCC generation is limited to a maximum of a 5 percent increase from the previous year. This phase-in continues in the performance rate-setting methodology until the BSER level of shifting from fossil steam generation to NGCC generation is completed. Under this approach, building block 2 is completely phased into the performance rates of all regions by the end of the interim period. Table 3-5 summarizes the quantity of NGCC generation that represents building block 2 potential as incorporated in the emission performance rate calculation in each region and year.

Table 3-5. BSER Maximum NGCC Generation by Region and Year (TWh).

Region	NGCC Generation (TWh)										
	Maximum Potential at 75%	2012 (adjusted)	BSER Maximum								
			2022	2023	2024	2025	2026	2027	2028	2029	2030
Limit	--	--	22%	5%	5%	5%	5%	5%	5%	5%	5%
Eastern Intercon-nection	988	735	896	941	988	988	988	988	988	988	988
Western Intercon-nection	306	198	242	254	267	280	294	306	306	306	306
Texas Intercon-nection	204	137	167	176	185	194	203	204	204	204	204

Source: Preamble, Section V.D.

3.6 Natural Gas Supply

EPA expects that the gradual increase in generation from existing NGCC as defined above to be feasible and consistent with domestic natural gas supplies in each year of the 2022-2029 phase-in. 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.[29]

According to EIA, natural gas proved reserves have doubled between 2000 and 2012.[30] Domestic dry gas production has increased by 25% over that same timeframe (from 19.2 TCF to 24.0 TCF). EIA's Annual Energy Outlook for 2015 projects that production will further increase to 29.5 TCF by 2022, due to increased supplies and favorable market conditions. For comparison, building

[29] 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).
[30] http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=3&pid=3&aid=6

block 2 assumes NGCC generation growth of 340 TWh from 2012 to reach the level assumed for 2022, and that NGCC generation growth would result in increased gas consumption of less than 2 TCF for the electricity sector, which is less than EIA's projected increase in natural gas production of 5.5 TCF from 2012 to 2022.[31]

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 had already been realized.[32]

Figure 3-2: U.S. Natural Gas Technically Recoverable Resources (from NPC, 2011)[33]

[31] Assuming 1,028 Btu/cubic foot and 7,615 Btu/KWh
[32] National Petroleum Council, 2012 (http://www.npc.org/PD_update-80112.pdf)
[33] http://www.npc.org/reports/rd.html

3.6.1 Natural Gas Deliverability

To examine the potential for increases in pipeline deliverability, EPA analyzed the pipeline flow data from the Energy Information Administration. These data provide pipeline capacity for inflows and outflows by region (see Figure 3-3). However, we cannot measure natural gas deliverability solely by considering a region's inflow capacity, since that region may need to allow some of that inflowing natural gas to become outflow to other regions (effectively passing that natural gas through the region to consumers in other regions). Consequently, net capacity – the difference between inflow capacity and outflow capacity -- is a better metric for a region's ability to increase deliverability of natural gas supply, because natural gas using such pipeline net capacity must be consumed within the region (as there would be no more outflow capacity for it to leave the region). The regions used by EIA for measuring regional natural gas deliverability are shown in Figure 3-3. Our assessment focuses on areas that would experience increases in natural gas consumption in line with building block 2's quantified potential for increased utilization of NGCC; in other words, these areas have most of the unutilized NGCC capacity. These are the Northeast, Southeast, Midwest and Western regions in Figure 3-3. The net pipeline capacity for these regions from 2005 to 2011 is shown in Table 3-6 below.

Table 3-6. Natural Gas Pipeline Net Capacity by Region, 2005 - 2011 by Gas Consuming Area[34]

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%

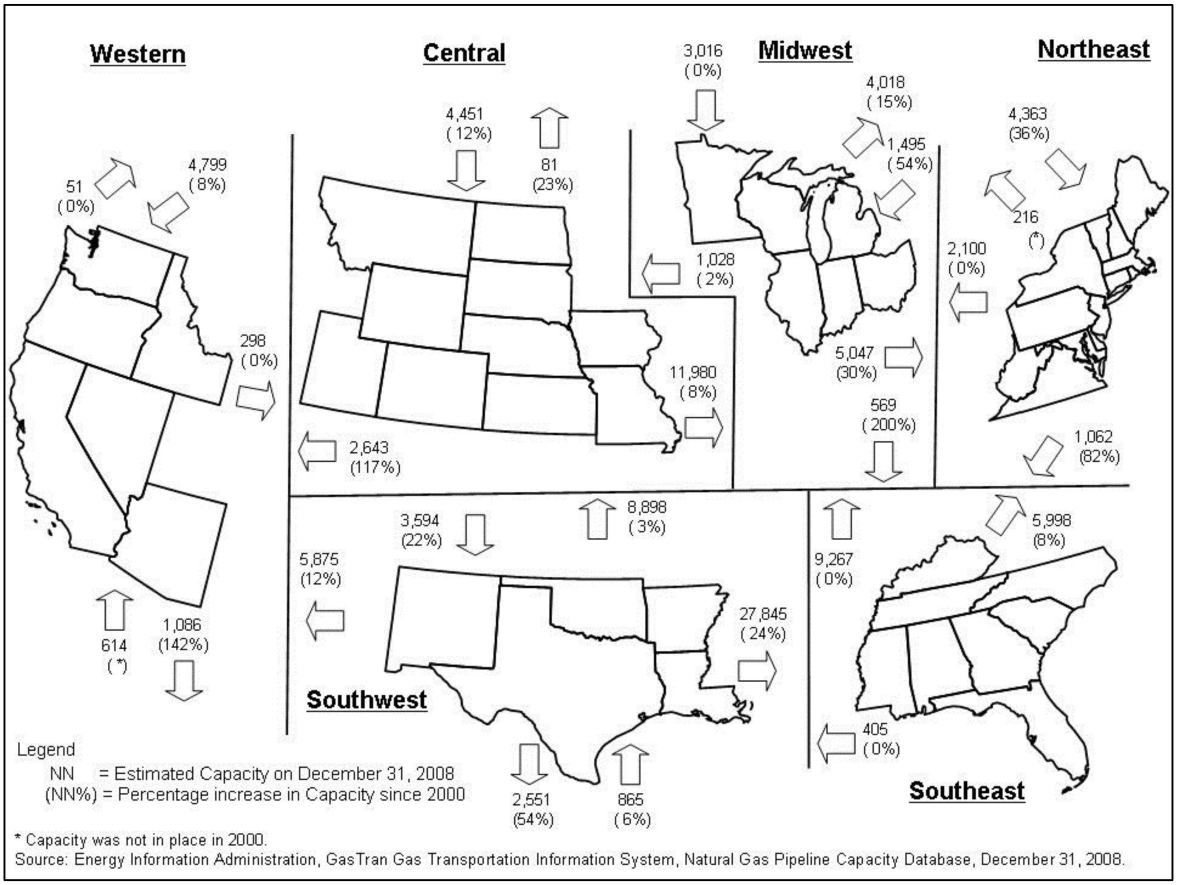
[34] Source: Energy Information Administration, http://www.eia.gov/naturalgas/data.cfm

As a conservative assumption, the increase from the period 2005 to 2011 can be compared with the longer period of the projected increase in pipeline capacity between 2016 and 2030 in the IPM projections for the BB2 BSER scenario where existing natural gas units were required to operate at the BSER capacity factor. Increased use of natural gas in existing units 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 2005-2011, the total gas deliverability in gas consuming areas increased by 24%. In the BB2 BSER scenario, power sector natural gas consumption increased 36% over the base case, and 35% over estimated 2016 consumption. However, pipeline deliverability increases apply to all sector consumptions, and the total consumption in the BSER scenario were projected to increase by 13% over the base case and 18% over 2016 consumption. Since this historical increase in pipeline capacity over the 2005 to 2011 period is 24.3%, the historical data indicate that pipeline capacity can expand sufficiently to support the potential increased utilization of natural gas power plants quantified for building block 2 in the BSER modeling.

Recent pipeline construction continued to demonstrate the pipeline network's ability to accommodate increasing demand for natural gas. According to information released in April, 2014 by the EIA,[35] 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 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.

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

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



Source: Energy Information Administration.

The ability of the pipeline system to accommodate the increased utilization of NGCC quantified for building block 2 is reinforced by a recent DOE study of pipeline system expansion.[36] This study examined two cases of pipeline expansion through 2030, one with a 25% increase in overall natural gas demand in 2030 and one with a 46% increase compared to a reference case projection. In a key finding, the study concluded that, in both scenarios, compared to historical pipeline infrastructure expansion, "Intermediate interstate natural gas pipeline infrastructure needs in [the assessed scenarios] are projected to be modest relative to the Reference Case".[37] The levels of increased natural gas demand assessed in that DOE study are substantially above the 15% increase in natural gas demand projected in EPA's power sector modeling of a scenario that would realize the building block 2 NGCC utilization level (described below).

[36] U.S. Department of Energy, Natural Gas Infrastructure Implications of Increased Demand from the Electric Power Sector, February 2015.
[37] Ibid. Page vi.

3.7 Cost-Effectiveness of Shifting Generation to NGCC

To evaluate the cost-effectiveness and technical capability of increasing utilization of existing NGCC as quantified for building block 2, EPA employed the Integrated Planning Model (IPM), a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector that 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 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.

EPA used IPM to model a series of scenarios representing replacement of fossil steam generation in each interconnection with increases of average NGCC net capacity factors in the same interconnection of up to 70, 75, and 80 percent. For example, in the 70 percent net capacity factor scenario, total fossil fuel-fired generation at existing sources across each interconnection is held constant with the level projected in the base case, while the model increases existing NGCC utilization in each interconnection either to a 70 percent capacity factor on average, or to a lower utilization level if such a level would deliver the same amount of fossil fuel-fired generation projected from existing sources in that interconnection in the base case.[38]

The costs and economic impacts of these scenarios were evaluated by comparing the total costs and emissions from each scenario to the costs and emissions from the base case. For the scenarios reflecting a 70, 75, and 80 percent NGCC utilization rate, comparison to the base case indicates that the average cost of CO_2 reductions was \$15, \$24, and \$33 per short ton of CO_2, respectively, over the 2022-2030 period.

[38] The existing source fossil fuel-fired generation described here includes generation from existing NGCC, coal steam, IGCC and oil/gas steam boilers greater than 25 MW.

Table 3-7: IPM Results

Existing NGCC Average Capacity Factor	Average Cost ($ per short ton, 2022-2030)
Base Case	N/A
70%	$15
75%	$24
80%	$33

3.8 Natural Gas Price Impacts

The extent of generation shifting estimated in this building block can be achieved without causing significant economic impacts, even without the gradual phase-in of this building block that was not represented in this analysis. For example, in the 75% scenario, delivered natural gas price projections increase by approximately 7 percent in the 2022-2030 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.[39] Projected wholesale electricity price increases over the same period were about 4 percent in the 75% case, which is similarly well within the range of historic electric price variability. For example, the average year-to-year price change for all of the ISOs and RTOs in the East was about 20 percent over the period from 2000 to 2013.[40]

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

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

Table 3-8: National Average Delivered Natural Gas Price, Power Sector (Average 2022-2030)

Existing NGCC Average Capacity Factor	Price ($/mmBtu)	% Change from Base Case
Base Case	$5.45	N/A
70%	$5.70	5%
75%	$5.85	7%
80%	$5.99	10%

CHAPTER 4: CLEANER GENERATION SOURCE

4.1 Introduction

Renewable energy is a cost-effective approach for reducing carbon dioxide (CO2) emissions from fossil fuel-fired electric generating units (EGUs) through the replacement of electricity generated from affected EGUs by renewable resources, referred to in this document as renewable energy (RE). The portfolio of available RE sources encompasses a wide variety of technologies 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), EPA has developed a methodology that is based on historical data.

This chapter serves to complement the description of incremental RE as a component of the BSER in section V.E of the preamble and is organized into several sections:

- Section 4.2 provides data and examples to support the seven steps described in the preamble to quantifying RE generation potential for the BSER
- Section 4.3 describes the interaction between the building block 3 generation levels and the goal-setting methodology
- Section 4.4 compares the final building block 3 generation level against the proposed levels
- Section 4.5 details the NREL's 2015 Annual Technology Baseline mid-case estimates
- Section 4.6 explores the technical feasibility and cost effectiveness of the building block 3 generation level

4.2 Approach to Quantifying RE Generation Potential for the BSER

The methodology used to quantify building block 3 generation for the BSER, as described in section V.E.6 of the preamble, contains seven steps:

1. Identify historical maximum capacity change and average capacity change from year to year over the past five years (2010 – 2014) for utility-scale solar photovoltaic (PV),[1] concentrating solar power (CSP), onshore wind, hydropower, and geothermal technologies.
2. Assign each RE technology an annual capacity factor that represents expected generation from each megawatt installed in the future.

[1] In their Solar Market Insight reports, Greentech Media and SEIA define utility-scale by offtake arrangement rather than by project size: any project owned by or that sells electricity directly to a utility (rather than consuming it on site) is considered a "utility-scale" project. This definition includes even relatively small projects (e.g., 100 kW) that sell electricity through a feed-in tariff ("FIT") or avoided cost contract."(See Bolinger, M.; Weaver, S.; "Utility Scale Solar 2013." *Defining "Utility-Scale,"* LBNL, Sept. 2014. Page 3. http://emp.lbl.gov/publications/utility-scale-solar-2013-empirical-analysis-project-cost-performance-and-pricing-trends)

3. Use the data from steps 1 and 2 to produce the annual generation change associated with the historical average and historical maximum RE capacity changes for each technology.
4. Establish an initial level of incremental generation from the building block 3 RE technologies that could be expected by 2022 even in the absence of the rule, using EPA's IPM Base Case.
5. Add the generation associated with the historical average capacity change to the initial level to obtain the building block 3 generation level for 2022. To that 2022 level, add the generation associated with the historical average capacity change to obtain the building block 3 generation level for 2023.
6. For each subsequent year, add the generation associated with the historical maximum capacity change to the building block 3 generation level calculated for the preceding year, in order to obtain the building block 3 generation level for each year from 2024 through 2030.
7. Apportion the national totals calculated in steps 5 and 6 to each of the three interconnections for inclusion in the BSER.[2]

4.2.1 Step 1

EPA relied on numerous data sources to compile the most recent five years of capacity deployment data for each of the RE technologies that contribute to building block 3 generation.[3] The totals in Table 4-1 represent the net change in capacity from year to year, inclusive of declines in operating capacity.

Table 4-1: Annual Capacity Change by RE Technology (MW)

RE Technology	2010	2011	2012	2013	2014	Average	Maximum
Solar PV[4]	267	784	1,803	2,847	3,934	1,927	3,934
CSP	78	0	0	410	767	251	767
Onshore Wind	5,112	6,816	13,131	1,087	4,854	6,200	13,131
Geothermal	15	138	147	407	4	142	407
Hydropower	294	-10	47	216	158	141	294

Note: All values are rounded to the nearest MW.

[2] Unless otherwise indicated, "national" in this chapter refers to the contiguous U.S.
[3] Energy Information Administration, Geothermal Energy Association, Lawrence Berkley National Laboratory, Solar Energy Industries Association/GTM Research, Interstate Renewable Energy Council, American Wind Energy Association (2014 onshore wind), and Federal Energy Regulatory Commission (2014 hydropower)
[4] Solar PV capacity totals are for utility-scale solar PV installations only and are expressed in terms of MW_{DC}

4.2.2 Step 2

The NREL Annual Technology Baseline (ATB) estimates serve as the basis for the expected future generation by MW of installed capacity for each RE technology:[5]

- **Solar PV –** Simple average of all three annual capacity factor values presented in the ATB (14%, 20%, and 28%).[6]
- **CSP –** Simple average of representative plant performance with six hours of thermal electric storage across Solar Class 1, 3, and 5 (28%, 37%, and 38%, respectively).
- **Onshore Wind –** Simple average of annual capacity factors for each of the five techno-resource groups (32.0%, 37.9%, 44.0%, 46.3%, and 49.0%).
- **Geothermal –** Simple average of annual capacity factors for both geothermal technology types (90% flash; 80% binary)
- **Hydropower –** Simple average of annual capacity factors for each technology (non-power dams and new stream-reach development) and resource combination (58% - 67%).

The capacity factors displayed in Table 4-2 below are assumed to be constant over time for the purposes of calculating building block 3 generation totals from 2022-2030.

Table 4-2: Annual Net Capacity Factor by Technology Type

RE Technology	Capacity Factor
Solar PV	20.7%
CSP	34.3%
Onshore Wind	41.8%
Geothermal	85.0%
Hydropower	63.8%

[5] http://www.nrel.gov/analysis/data_tech_baseline.html

[6] The capacity factor values presented for solar PV account for the range of latitude across the contiguous U.S. Solar PV capacity factors are influenced by hourly solar profile, technology type, axis type, inverter losses due to conversion from DC to AC power, and other factors.

4.2.3 Step 3

The change in generation, expressed in MWhs, associated with the average and maximum capacity changes are the result of multiplying the corresponding capacity values by 8,760 hours/year and the net annual capacity factor for each technology, as shown in Table 4-3.

Table 4-3: Annual Generation Change Associated with Average and Maximum RE Capacity Changes

	Average Capacity Change (MW)	**Capacity Factor**	**Generation (MWh, Average Capacity Change)**	**Maximum Capacity Change (MW)**	**Capacity Factor**	**Generation (MWh, Maximum Capacity Change)**
Solar PV[7]	1,927	20.7%	3,494,268	3,934	20.7%	7,133,601
CSP	251	34.3%	754,175	767	34.3%	2,304,590
Onshore Wind	6,200	41.8%	22,702,416	13,131	41.8%	48,081,520
Geothermal	142	85.0%	1,057,332	407	85.0%	3,030,522
Hydropower	141	63.8%	788,032	294	63.8%	1,643,131
Total Generation (MWh)			**28,796,222**			**62,193,363**

4.2.4 Step 4

Initial incremental RE generation totals for utility-scale solar PV, CSP, onshore wind, geothermal, and hydropower are taken from EPA IPM Base Case.[8] Initial incremental RE represents generation from existing projects currently in commercial operation with an online year of 2013 or later; projects that are not currently operating but are firmly anticipated to be operational in the future and have either initiated construction or secured financing; and capacity that is projected to deploy as an economic resource to meet load. All of this generation is represented in EPA IPM Base Case projections.

To quantify an initial generation value, EPA interpolated between EPA IPM Base Case's 2020 and 2025 projections, assuming each calendar year accounts for 20% of the difference in those projections (i.e., a linear interpolation between run years). Given that the projected incremental

[7] Solar PV capacity totals are for utility-scale solar PV installations only and are expressed in terms of MW_{DC}

[8] Documentation and modeling files are available in the docket for this rulemaking and online at http://www.epa.gov/airmarkets/powersectormodeling.html

RE generation across the contiguous U.S. in 2020 is 202,219,818 MWh, and the corresponding projected value in 2025 is 256,541,353 MWh, the initial generation value is calculated as:

$$\frac{256{,}541{,}353 - 202{,}219{,}818}{5} + 202{,}219{,}818 = 213{,}084{,}125$$

This initial level represents expected incremental RE generation before the assumed deployment of additional RE capacity in 2022 and beyond, as described in the following steps.

4.2.5 Step 5

The national building block 3 generation total in 2022 is the initial level (step 4) plus the generation associated with the historical average change in capacity (step 3):

- 2022 National Building Block 3 Generation = 213,084,125 MWh + 28,796,222 MWh = 241,880,347 MWh

The 2023 national building block 3 generation value is the sum of the 2022 value plus the generation associated with the historical average change in capacity:

- 2023 National Building Block 3 Generation = 241,880,347 MWh + 28,796,222 MWh = 270,676,570 MWh[9]

4.2.6 Step 6

The 2024 national building block 3 generation value is the sum of the 2023 value plus the generation associated with the historical maximum change in capacity (step 3):

2024 National Building Block 3 Generation =
270,676,570 MWh + 62,193,363 MWh = 332,869,933 MWh

For each subsequent year through 2030, the national building block 3 generation total is the previous year's value plus the generation associated with the historical maximum change in capacity (62,193,363 MWh). The annual values for all years are presented below in Table 4-4:

[9] Values may not sum due to rounding; refer to GHG Mitigation Measures spreadsheet for unrounded values.

Table 4-4: National Building Block 3 Generation Totals (MWh)

Year	Building Block 3 Generation
2022	241,880,347
2023	270,676,570
2024	332,869,933
2025	395,063,296
2026	457,256,659
2027	519,450,023
2028	581,643,386
2029	643,836,749
2030	706,030,112

4.2.7 Step 7

To apportion the national building block 3 generation totals calculated in steps 5 and 6, EPA considered the geographic pattern of RE deployment in an IPM modeling scenario projecting national-level incremental generation for 2025 and 2030 at levels similar to the building block 3 generation totals.[10] The scenario included a representation of utility-scale solar PV, CSP, onshore wind, geothermal, and hydropower generation. The geographic pattern by interconnection of incremental RE generation totals for 2020, 2025, and 2030 are displayed below:

Table 4-5: Incremental RE Generation by Interconnection from Building Block Assignment Analysis (MWh)

Interconnection	2020	2025	2030
Eastern	165,133,240	272,168,303	449,874,640
Western	53,558,376	76,325,304	165,543,643
Texas	20,146,141	63,283,451	109,380,771

The absolute generation levels in this projection do not substitute for the national building block 3 generation totals in Table 4-4; instead, this step is only assessing the most economic location by interconnection of this general level of incremental RE generation potential. To facilitate this geographic assignment of the building block 3 generation totals in Table 4-4, the modeled generation totals for each interconnection are converted into a percentage of the modeled national total such that these interconnection-specific percentage values, or "shares", can be applied to

[10] The IPM run 'Building Block 3 Generation Assignment' is available in the docket

apportion the building block 3 generation levels. The interconnection shares by model projection year are shown below in Table 4-6.

Table 4-6: Incremental RE Generation Shares by Interconnection from Building Block Assignment Analysis

Interconnection	2020	2025	2030
Eastern	69.2%[11]	66.1%	62.1%
Western	22.4%	18.5%	22.8%
Texas	8.4%	15.4%	15.1%

The model run-year values are then converted into values for each year from 2022 through 2030 using a linear interpolation of the model-projected 2020 and 2030 generation share values. The resulting shares by interconnection for each year are shown in Table 4-7 below.

Table 4-7: Building Block 3 Generation Shares by Interconnection

	Eastern	Western	Texas
2022	67.8%	22.5%	9.7%
2023	67.1%	22.5%	10.4%
2024	66.4%	22.6%	11.1%
2025	65.7%	22.6%	11.8%
2026	64.9%	22.6%	12.4%
2027	64.2%	22.7%	13.1%
2028	63.5%	22.7%	13.8%
2029	62.8%	22.8%	14.4%
2030	62.1%	22.8%	15.1%

Applying the generation shares in Table 4-7 to the national building block 3 generation totals in Table 4-4 produces an annual incremental generation value for each interconnection in each year, as shown in Table 4-8.

[11] Value rounded up to ensure all interconnections sum to 100%

Table 4-8: Annual Average Incremental Generation Values, Eastern Interconnection (MWh) [12]

	National Building Block 3 Generation Total	Eastern Interconnection Generation Share (%)	Eastern Interconnection Generation Share (MWh)	Annual Increase in Generation Values[13]	Multi-Year Average Annual Increase in Generation Values
2022	241,880,347	67.8%	163,946,499	12,983,007	15,289,641
2023	270,676,570	67.1%	181,542,775	17,596,276	
2024	332,869,933	66.4%	220,892,487	39,349,712	36,700,275
2025	395,063,296	65.7%	259,359,054	38,466,566	
2026	457,256,659	64.9%	296,942,475	37,583,421	
2027	519,450,023	64.2%	333,642,749	36,700,275	
2028	581,643,386	63.5%	369,459,879	35,817,129	
2029	643,836,749	62.8%	404,393,862	34,933,983	
2030	706,030,112	62.1%	438,444,700	34,050,838	

As shown in the steps above, this approach considers annual generation levels associated with the historical average RE capacity change to inform building block 3 levels in 2022 and 2023, and the historical maximum RE capacity change to inform building block 3 levels in 2024 through 2030. In keeping with that schedule, multi-year average annual incremental generation values are presented in Table 4-8 for 2022-2023 and for 2024-2030 to create an interconnection-specific analog to the national values presented above in step 3. For example, the 2022-2023 average annual incremental generation value for the Eastern Interconnection (using the values in Table 4-8) is 15,289,641 MWh, which is the Eastern Interconnection's share of the national annual incremental generation value of 28,796,222 MWh (based on the historical average RE capacity change) presented in step 3. Following the same process, the 2024-2030 average annual incremental generation value for the Eastern Interconnection is 36,700,275 MWh, which is the Eastern Interconnection's share of the national annual incremental generation value of 62,193,363 MWh (based on the historical maximum RE capacity change) presented in step 3.

The final step in calculating interconnection-level building block 3 generation totals is to apply each region's average incremental generation to its share of the initial generation level presented in step 4. To continue the Eastern Interconnection example:

[12] Table 4-8 displays the Eastern Interconnection; refer to the GHG Mitigation Measures spreadsheet for the Western and Texas Interconnections calculations:
[13] These amounts are in addition to the initial generation value for the Eastern Interconnection, which is 150,963,493 MWh.

- 2022 Building Block 3 Generation Level = Initial Generation Level + 2022-2023 Average Incremental Generation = 150,963,493 MWh + 15,289,641 MWh = 166,253,134 MWh
- 2023 Building Block 3 Generation Level = 2022 Building Block 3 Generation Level + 2022-2023 Average Incremental Generation = 166,253,134 MWh + 15,289,641 MWh = 181,542,775 MWh

For all subsequent years, 2024 through 2030, the building block generation level for the Eastern Interconnection is the previous year's generation level plus the 2024-2030 average incremental generation level of 36,700,275 MWh. The calculations for all years and interconnections are available in the GHG Mitigation Measures spreadsheet.

The building block 3 generation levels used in the BSER for each interconnection are displayed below in Table 4-9:

Table 4-9: Building Block 3 Generation Levels by Interconnection (MWh)

	Eastern Interconnection	Western Interconnection	Texas Interconnection	Total
2022	166,253,134	56,663,541	18,963,672	241,880,347
2023	181,542,775	60,956,363	28,177,431	270,676,570
2024	218,243,050	75,244,721	39,382,162	332,869,933
2025	254,943,325	89,533,078	50,586,893	395,063,296
2026	291,643,600	103,821,436	61,791,623	457,256,659
2027	328,343,875	118,109,793	72,996,354	519,450,023
2028	365,044,150	132,398,151	84,201,085	581,643,386
2029	401,744,425	146,686,508	95,405,816	643,836,749
2030	438,444,700	160,974,866	106,610,547	706,030,112

4.3 Building Block 3 Generation Required by the Goal-Setting

As discussed in section V.A.3.f and section VI of the preamble, the BSER reflects the degree of emission limitation achieved through application of the building blocks in the least stringent region. Therefore, by definition, there is an amount of building block 3 generation in each year that is not required to achieve the goal rates. Through the application of a minimization routine described in the CO_2 Emission Performance Rate and Goal Computation TSD, EPA has solved for the minimum amount of building block 3 generation necessary in each interconnection for affected EGUs to achieve the source category-specific emission performance rates.

Table 4-10: National Building Block 3 Generation Necessary to Achieve Source Category-Specific Emission Performance Rates (MWh)

Year	Building Block 3 Generation	Building Block 3 Generation Required to Achieve Goal Rates
2022	241,880,347	146,904,585
2023	270,676,570	179,963,324
2024	332,869,933	239,903,903
2025	395,063,296	292,428,842
2026	457,256,659	346,222,749
2027	519,450,023	405,981,689
2028	581,643,386	449,706,611
2029	643,836,749	493,669,241
2030	706,030,112	539,774,619

The building block 3 generation levels, both total and required to achieve the goal rates, are presented together with the projections of incremental RE from EPA's IPM Base Case:

Figure 4-1: Building Block 3 Generation Levels, Relative to Base Case Incremental RE (MWh)

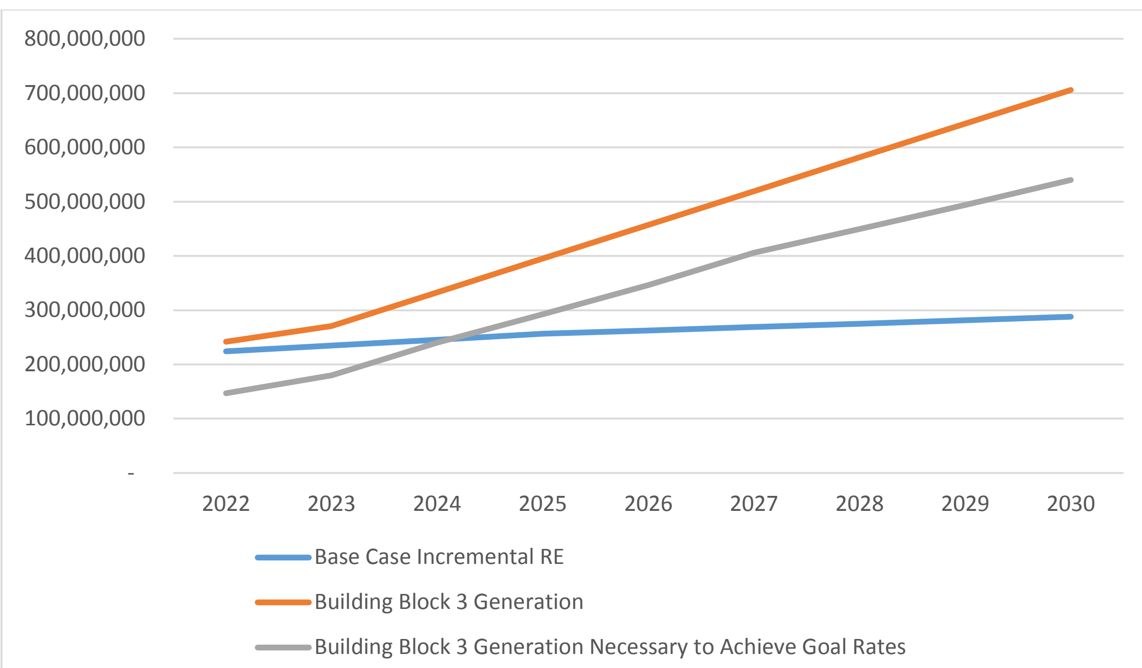
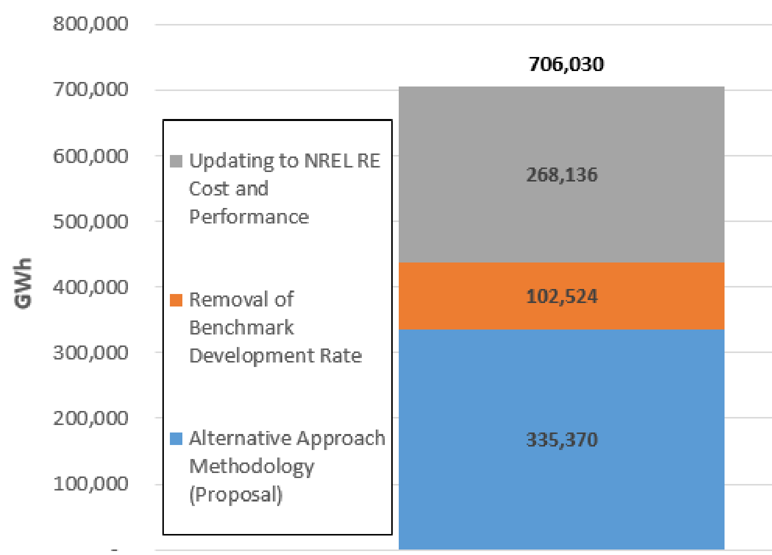


Figure 4-1 displays how the combination of building block 3 and the goal-setting methodology serve to significantly reduce compliance pressure on affected EGUs in the near-term, insulating near-term building block 3 generation levels against adjustments to RPS requirements and fluctuations in market conditions, while still establishing an historically-based deployment pathway that achieves significantly greater amounts of RE through 2030 than what is projected in the Base Case. The interaction between the building block 3 generation level, goal-setting methodology and the technical feasibility and cost-effectiveness of incremental RE is explored in greater detail in section 4.6.

4.4 Building Block 3 Generation Levels, Relative to Proposed Levels

The final methodology, which is adapted from the proposal's alternative approach, produces greater incremental RE generation than the proposed levels. For example, the 2030 building block 3 generation level of 706,030 GWh in the final rule is 370,660 GWh greater than the incremental RE contained in the proposal's alternative approach at a constant $/ton cost-effectiveness.[14] This difference is comprised primarily of two components – removal of the benchmark development rate[15] from the proposed approach and updating RE cost and performance data to the most recent NREL data. The magnitude of these components is shown below:

Figure 4-2: Proposed and Final Building Block 3 Generation Levels, by Component in 2030

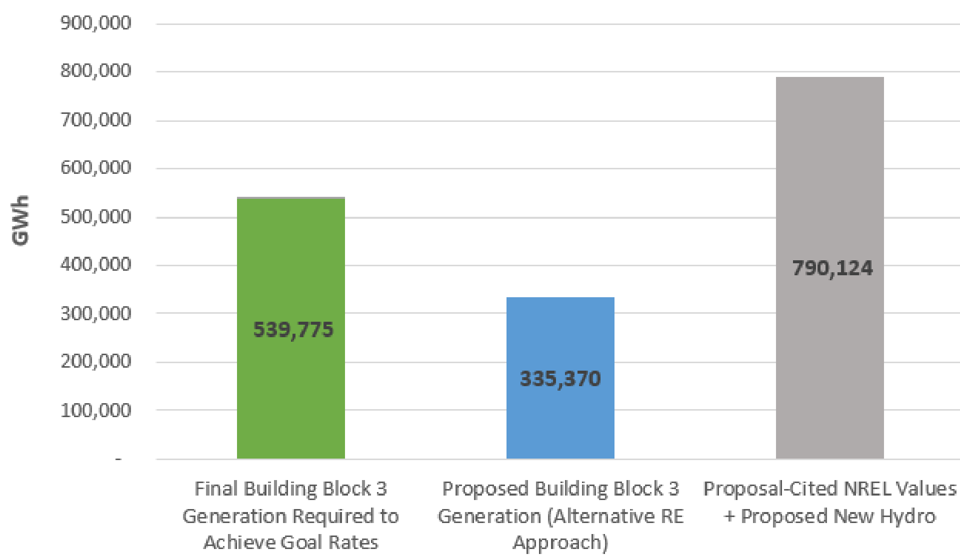


[14] The proposed RE levels were associated with a $36/ton cost; the final building block 3 generation levels produce an average cost of $37/ton (see section 4.6).
[15] The benchmark development rate set limits on the projected economic deployment of RE if a state had achieved deployment levels that met a benchmark deployment rate (total capacity/total resource) equal to the top-third of states. See the response to comment document for more detail.

EPA invited comment at proposal on RE levels in excess of the final building block 3 generation level. For example, the Alternative RE Approach TSD cited NREL values for incremental onshore wind, solar and geothermal technologies of 687,600 GWh.[16] When combined with the proposed levels of incremental hydropower (102,524 GWh), the resulting generation level of 790,124 GWh exceeds the building block 3 generation level in the final rule by more than 80 TWh in 2030.

Additionally, the goal-setting methodology in the final rule does not require all of the building block 3 generation level to achieve the goal rates (see Section 4.3). In evaluating the proposed and final levels of building block 3 generation, it is appropriate to compare the amount of building block 3 generation levels necessarily reflected in the final goal rates:

Figure 4-3: Block 3 Generation Levels Necessary to Achieve Goal Rates and Alternative NREL Values, in 2030



It should be noted that the building block 3 generation levels from the proposal and the final rule produce consistent estimates of cost-effectiveness - $36/ton at proposal versus $37/ton in the final rule. Preserving a consistent cost-effectiveness determination at increased levels of RE penetration reflects the final rule's adoption of updated cost and performance assumptions from the 2015 NREL Annual Technology Baseline (ATB). This update is described in detail in section 4.5 below.

4.5 NREL's 2015 Annual Technology Baseline Mid-Case Estimates

EPA's approach for determining the building block 3 component of the BSER is based in part on revised cost and performance estimates for onshore wind and solar technologies. As discussed in section V.E.6 of the preamble to final rule, commenters provided data demonstrating that the cost and performance estimates relied on in the proposed rule did not reflect the decline in cost and

[16] http://www2.epa.gov/cleanpowerplan/clean-power-plan-proposed-rule-alternative-renewable-energy-approach

increase in performance that have been demonstrated by current projects, particularly in regards to wind and solar. As a result, the agency revised its data for onshore wind and solar technologies in the final rule. The revision included the mid-case estimates from the National Renewable Energy Laboratory's (NREL) 2015 Annual Technology Baseline (ATB).

EPA selected the NREL 2015 ATB mid-case estimates based on the quality of its data and consistency with recent RE cost and performance trends. The ATB capital cost estimates cover the same scope of power plant envelope (equipment, installation, developer costs, etc.) as used for AEO inputs used in the proposal. The agency used the draft 2015 ATB version, which was available at the time of the analysis. Recently, the final 2015 version was posted.[17] It is particularly notable that the final 2015 version's cost estimates are either unchanged or lowered.[18] Despite the recent availability of the final 2015 version, the agency believes its data is well supported by the draft 2015 version's cost and performance data.

In comparing the AEO2013 data set used in the proposal to the NREL ATB data set used in the final rule, EPA found AEO2013 installation cost assumptions for onshore wind in 2014 are 30% higher than the ATB mid-case cost assumptions for the same year.[19] Moreover, the AEO2013 assumes onshore wind installation costs in 2030 at $2,100/kW, which is almost 30% higher than installation costs in the ATB mid-case in that year. Installation costs for solar PV in 2013 for the AEO2013 are 15% higher than those assumed in the ATB mid-case. [20] Similarly, installation cost assumptions for solar PV in 2030 are almost 75% higher in the AEO2013 cost assumptions when compared to the NREL ATB Mid RE Case.

[17] Available at http://www.nrel.gov/analysis/data_tech_baseline.html.
[18] NREL lowered current and projected overnight capital cost values for the ATB mid-case solar PV projection to reflect significant changes in solar market prices that has occurred over the last year. NREL, Annual Technology Baseline (ATB) Spreadsheet, July 2015, see "Solar – PV" worksheet, Available at: http://www.nrel.gov/docs/fy15osti/64077-DA.xlsm.
[19] EIA capital costs sourced from Assumptions to the Annual Energy Outlook 2013, Table 8.2 (pp 103), Available at: http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2013).pdf. Cost projections for future years were obtained from personal communications with EIA.
[20] The AEO2015 contains updated capital costs for wind and solar PV which are lower than the AEO2013, reflecting the decrease in costs over the previous two years. Despite the lower capital costs in AEO2015, the NREL 2015 ATB estimates were lower and more consistent with recent RE cost and performance trends.

Table 4-11: Comparison of Onshore Wind and Utility-Scale Solar PV Cost Estimates in AEO2013 and ATB Mid-Case

		Capital Costs (2013$/kW)					
Technology	**Report**	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
Onshore Wind	AEO 2013	$2,246	$2,274	$2,330	$2,293	$2,192	$2,106
	ATB - TRG 3 Mid	$1,758	$1,729	$1,721	$1,674	$1,643	$1,630
Utility Solar PV	AEO 2013 ($/kW-DC)	$3,144	$2,932	$2,881	$2,658	$2,501	$2,363
	ATB - Mid ($/kWDC)	$2,673	$2,522	$2,369	$1,603	$1,470	$1,337

Notes 1. The AEO2013 costs are in 2011$, whereas in ATB they are in 2013$. For the comparison, the AEO2013 costs were inflated using a net inflation of 3.28% to make them directly comparable.

2. The costs for solar PV in AEO are in $/kW-AC, whereas in ATB they are in $/kW-DC. For the comparison, AEO costs were expressed in $/kW-DC, using EIA's assumed 1.25:1 ratio, which was presented as a rounded value in EIA's Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (See p. 24-2), according to email communications with EIA staff.

In comparing the two data sets with current project costs, recent trends, and a reasonable expectation of the future, EPA found that the ATB mid-case estimates are more in line with current costs and recent market analysis and projections than the AEO2013 costs.

The rapid cost declines for wind and solar have been well documented. Lazard's recent Levelized Cost of Energy Analysis found that wind and solar PV became increasingly competitive over the last five years. During that time period, the average percentage decrease of high and low of the LCOE ranges for wind and utility-scale solar PV were 58 percent and 78 percent, respectively.[21] Lazard's capital costs for wind and utility-scale solar PV were $1,400-$1,800/kW and $1,500-$1,750/kW$_{DC}$, respectively.[22] These cost estimates were significantly lower than near term and longer term AEO forecasts.

EPA also observed solar PV costs from other data sources that are considerably lower than those reported in the AEO2013, and more consistent with those seen in ATB mid-case. For instance, the U.S. Solar Market Insight report published for Q1 2015 shows recent utility-scale solar installed costs below $2,000/kW$_{DC}$, whereas the AEO2013 assumes costs above $2,800/kW$_{DC}$ for the year 2015.[23] Similarly, a recent report by Lawrence Berkley National Lab (LBNL) shows that utility-scale solar PV projects were installed in 2013 at average costs of $3,000/kW$_{DC}$.[24] While these recent projects may have represented best-in-class installations for the years 2013-2014, it is

[21] Lazard, *Levelized Cost of Energy Analysis-Version 8.0*, September 2014, p. 9, Available at: http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.
[22] *Levelized Cost of Energy Analysis-Version 8.0*, Lazard, September 2014, pp. 16-17, Available at: http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.
[23] *U.S. Solar Market Insights Report*, Solar Energy Industries Association/GTM Research, Q1 2015, figure 2.4, Available at: http://www.seia.org/research-resources/solar-market-insight-report-2015-q1.
[24] *Is $50/MWh Solar for Real? Falling Project Prices and Rising Capacity Factors Drive Utility-Scale PV Toward Economic Competitiveness* (2015). LBNL. Available at: http://emp.lbl.gov/sites/all/files/lbnl-183129.pdf (referenced figure 4).

reasonable to assume that average costs by 2020 will generally reflect these best-in-class installations. In contrast, the AEO2013 assumes a more conservative cost decline, and is close to $2,600/kW$_{DC}$ by 2020, and about $2,300/kW$_{DC}$ by 2030.

Table 4-12: Comparison of Utility-Scale Solar PV Cost Estimates

		Capital Costs (2013$/kW)					
Technology	**Report**	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
Utility Solar PV	AEO 2013 ($/kWDC)	$3,144	$2,932	$2,881	$2,658	$2,501	$2,363
	ATB - Mid ($/kWDC)	$2,673	$2,522	$2,369	$1,603	$1,470	$1,337
	LBNL ($/kWDC)	$3,000					
	SEIA/GTM ($/kWDC)		$2,000				
	Lazard (2014$)	$1,500-$1,750					

Notes 1. The AEO2013 costs are in 2011$, whereas in ATB they are in 2013$. For the comparison, the AEO2013 costs were inflated using a net inflation of 3.28% to make them directly comparable.

2. The costs for solar PV in AEO are in $/kW-AC, whereas in ATB they are in $/kW-DC. For the comparison, AEO costs were expressed in $/kW-DC, using EIA's assumed 1.25:1 ratio, which was presented as a rounded value in EIA's Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (See p. 24-2), according to email communications with EIA staff.

3. While all sources are reported as '2013', there is a difference what each source defines as 'year'. For example, the LBNL report and the ATB represent the projects *completed installation* in 2013 while the AEO numbers are for projects that were *initiated* in 2013.

The ATB near-term capital cost estimates for CSP with storage are comparable with Lazard's. The ATB assumes a CSP trough with six and twelve hours of storage ($6,777-$8,532/kW) and Lazard examines a tower with ten to eighteen hours of storage ($7,000-$9,800/kW). While the configurations that serve as the basis for the estimates differ, they are close enough to validate the ATB cost estimates for CSP. Additionally, the projections were based on SunShot Vision study and vetted with solar industry participants.

Similarly, the recent wind costs estimates are also much lower than those assumed in the AEO2013. The LBNL 2013 Wind Technologies Report showed 2013 capacity-weighted average installed costs for onshore wind at $1,630/kW, whereas the AEO2013 assumes costs close to $2,250/kW (2013$) for the same year.[25] Furthermore, the AEO2013 wind cost in 2030, which assumes continued cost reductions, is about $2,100/kW. Yet, this wind cost in 2030 is almost 30 percent higher than observed wind costs in 2013.[26]

[25] *2013 Wind Technologies Market Report*, LBNL, August 2014, Available at: http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf (referenced Figure 39 on Page 49).

[26] Although the LBNL sample size is small for 2013, the decline in wind installed costs in 2013 from 2012 is in keeping with the decline in wind turbine prices, which is a leading indicator of installed cost trends. *2013 Wind Technologies Market Report*, LBNL, August 2014, Available at: http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.

Table 4-13: Comparison of Onshore Wind Capital Cost Estimates

		Capital Costs (2013$/kW)					
Technology	**Report**	**2013**	**2014**	**2015**	**2020**	**2025**	**2030**
Onshore Wind	AEO 2013	$2,246	$2,274	$2,330	$2,293	$2,192	$2,106
	ATB - TRG 3 Mid	$1,758	$1,729	$1,721	$1,674	$1,643	$1,630
	Lazard (2014$)	$1,400-$1,800					
	LBNL	$1,630					

Notes 1. The AEO2013 costs are in 2011$, whereas in ATB they are in 2013$. For the comparison, the AEO2013 costs were inflated using a net inflation of 3.28% to make them directly comparable.
2. While all sources are reported as ‘2013’, there is a difference what each source defines as ‘year’. For example, the LBNL report and the ATB represent the projects *completed installation* in 2013 while the AEO numbers are for projects that were *initiated* in 2013.

Commenters (see RTC Chapter 3.3.7, Cost Effectiveness of RE) said that the proposal did not capture the full potential of RE and that the final rule needs to reflect the dramatic cost reductions that have occurred in recent years. There was support for the principle of using conservative assumptions, but significant concern about the use of cost and performance assumptions that are more pessimistic than currently observable and accurate data on the cost of RE deployment. They also added that EPA's analysis for the proposed rule using AEO2013 did not account for the cost reductions that can reasonably be expected to continue. For projecting future economics and performance, commenters recommended reliance on credible projections available from the DOE and National Laboratories. They asserted that recent cost declines are also consistent with the projected declines expected as an industry experiences significant growth, which the RE industry has seen in the U.S. and abroad.

Commenters provided a number of references to data from a variety of sources (e.g., LBNL, NREL and Lazard) to support their arguments that the agency needs to change cost assumptions. A number of commenters noted NRDC’s recent analysis that used a number of these sources to show AEO2013's cost estimates for wind and solar energy are 46 percent above current average costs.[27] Commenters also contrasted Lazard’s current range of levelized costs of energy (LCOE) for onshore wind without subsidies of $37-$81/MWh with AEO2013's 2019 estimates of $70-90/MWh.[28] Regarding solar PV, commenters highlight DOE and national laboratory reports that have observed the cost of building utility-scale solar projects has declined by about 50 percent between 2010 and 2014. The commenters said these declines are consistent with NREL's modeled prices using its bottom-up modeling methodology - NREL estimates that the price of solar declined to $1800/kW$_{DC}$ in Q4 2013. Commenters also highlight forecasted solar PV cost estimates and found no reason to believe that the declines in cost will not continue. Referencing the SunShot

[27] NRDC, *Issue Brief: EPA's Clean Power Plan Could Save Up to $9 Billion in 2030*, November 2014, Available at: http://www.nrdc.org/air/pollution-standards/files/clean-power-plan-energy-savings-IB.pdf.
[28] Lazard, *Levelized Cost of Energy Analysis-Version 8.0*, September 2014, p. 15, Available at: http://www.lazard.com/media/1777/levelized_cost_of_energy_-_version_80.pdf.

Vision study's roadmap for continued cost declines in solar PV technologies, they observed that estimates of solar system costs dropping 75% between 2010 and 2020. They added that NREL recently predicted in its 2014 update on Solar PV pricing trends that solar PV costs are still on track to meet the SunShot Initiative goal of $1,000/kW$_{DC}$ by 2020 for utility-scale PV.

It should also be noted that the NREL ATB cost report was published in 2015, whereas the AEO costs were published in 2013, and that the most recent AEO2015 includes significant cost reductions of wind and solar PV as compared to AEO2013.[29] Commenters noted that the LBNL found that the AEO2013 assumptions were based on projects completed in 2012, and the installed price data for those projects may reflect contract terms agreed to a number of years prior to project completion.[30]

NREL's ATB and Standard Scenarios were developed with the objectives of creating consistent and normalized technology cost and performance assumptions as well as defining a conceptual and consistent scenario framework that can be used in future analyses.

In general, the ATB cost and performance estimates represents typical U.S. RE plants by reflecting a range of resources and groupings of RE technologies, such as wind technology resource groups or TRGs based on wind resource and turbine technologies. The future cost projections are compared with data in published literature and generally within the bounds of those perspectives. These literature estimates were normalized to a common starting point. Projections for each technology were developed independently using distinct methods, but the starting points were compared with available market data to provide consistent baseline methodology.[31]

The wind cost projections derived from literature reviews for onshore and offshore wind, including numerous projection scenarios from many independently published studies, and vetted with a consortium of National Laboratory, DOE and wind industry experts. The results are three different projections developed for scenario modeling as bounding levels, based generally on maximum, median, and minimal annual cost reductions based on literature. These are reflected as the low, mid, and high cost cases, respectively.[32]

The solar cost projections are based on SunShot Vision study (2012) and vetted broadly with solar industry participants. Similar to wind projections, three cost projections are developed for scenario modeling as bounding levels. These low, mid, and high cases for utility-scale solar PV are based changing cost reduction trajectories. The concentrating solar power (CSP) cases are based on

[29] http://www.eia.gov/forecasts/aeo/assumptions/pdf/table_8.2.pdf
[30] Barbose, et al., *Tracking the Sun VII*, LBNL, September 2014, Available at: http://emp.lbl.gov/publications/tracking-sun-vii-historical-summary-installed-price-photovoltaics-united-states-1998-20.
[31] ATB Summary Presentation, NREL, March 2015, Available at: http://www.nrel.gov/analysis/data_tech_baseline.html.
[32] ATB Summary Presentation, NREL, March 2015, Available at: http://www.nrel.gov/analysis/data_tech_baseline.html.

differing evolutionary paths for CSP design and deployment. These projections are compared to range of available analyst projections from BNEF, EIA, and EREC.[33]

4.6 Technical Feasibility and Cost-Effectiveness of the Building Block 3 Generation Levels

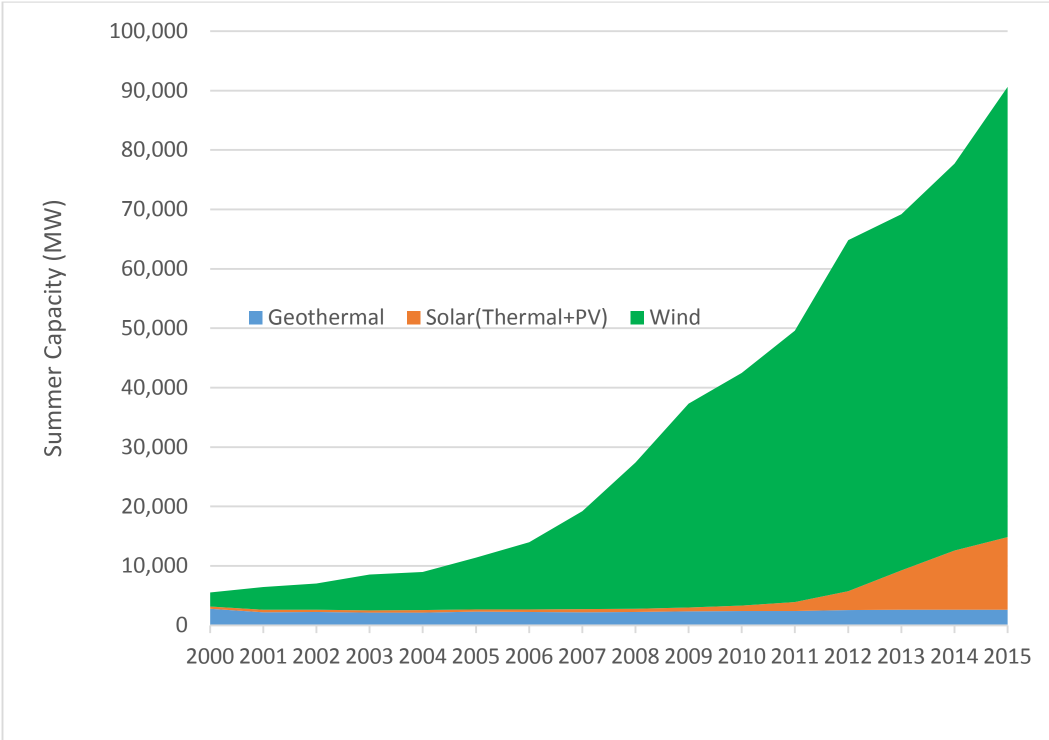
This section addresses the technical feasibility of the RE requirements described in the previous sections for this building block. The current deployment and operation of RE resources are discussed first, followed by analysis of the future deployment potential for RE and related needs such as available transmission capacity to deliver RE.

4.6.1 Historical Deployment

The major incremental additions to RE capacity over the past two decades have come from wind and solar, although there have also been some additions to hydro and geothermal resources. After constituting two or three percent of the total RE capacity in the 1990s, wind and solar capacity have increased dramatically to over 50 percent of total RE today, as shown in Figure 4-4:

[33] ATB Summary Presentation, NREL, March 2015, Available at: http://www.nrel.gov/analysis/data_tech_baseline.html. The cost projection references include: Greenpeace/EREC (2014). Energy [R]evolution: A Sustainable USA Energy Outlook. http://www.greenpeace.org/usa/Global/usa/planet3/PDFs/Solutions/Energy-Revolution-2014.pdf (utility-scale only); International Energy Agency. (2013). World Energy Outlook 2013. http://www.worldenergyoutlook.org/publications/weo-2013/. (New Policy & 450 Scenarios for utility-scale & commercial-scale); Bloomberg New Energy Finance (2014). Q2 PV Market Outlook; and, United States Energy Information Administration (EIA). (2014a). Annual Energy Outlook 2014 with Projections to 2040. DOE/EIA-0383(2014). Washington, D.C.: U.S. Department of Energy Office of Integrated and International Energy Analysis. http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf

Figure 4-4: Growth in Utility-Scale U.S. Renewable Resources[34]



Many states are already integrating significant levels of Variable Generation (VG) RE resources. For wind and solar, there were 21 states in 2014 where RE exceeded 5% of the total annual generation, and 10 states where RE exceeded 10%.[35] Several states were considerably higher: Iowa at 28.5% from wind and solar, Kansas 21.7% and South Dakota at 25.3% were all above 20 %, in 2014 with Idaho not far below at 18.6%. If Geothermal is included, California is also close with 18.3%.

The current grid can reliably integrate much higher levels of over short time intervals of an hour or a day. ERCOT met 40 percent of demand on 3/31/14 with wind power; SPP met 33 percent on 4/6/13, and Xcel Energy Colorado 60 percent on 5/2/13. Moreover, many states also demonstrate that high levels of wind and solar VG can be sustained for longer periods. Looking at the maximum monthly percentage of wind and solar in 2014, nine states are already above 20% and 18 are above 10% of total generation from wind and solar for at least one month in 2014. Percentages are as high as 42.3 in Iowa, 37.1 in South Dakota, and 33.7 in Kansas. These figures, along with many other studies[36] looking at the integration of variable generation RE, indicate that the current

[34] Source: http://www.eia.gov/electricity/data.cfm#generation
[35] EIA, Form EIA-923 and EIA-860 reports.
[36] References to include: Cochran, J., Denholm, P., Speer, B., and Miller, M. Grid Integration and the Carrying Capacity of the U.S. Grid to Incorporate Variable Renewable Energy. NREL/TP-6A20-62607, 2015. (http://www.nrel.gov/docs/fy15osti/62607.pdf); Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. (2012). Renewable Electricity Futures Study. NREL/TP-6A20-

configuration of the electric power system is already capable of integrating very high levels of renewable variable generation for sustained periods of time.

4.6.2 Deployment Projections

EPA believes the historically grounded Building Block 3 generation levels constitute moderate estimates of the future deployment of RE that can be achieved. The moderate nature of these levels is demonstrated by:

- EPA's analysis of building block 3 generation levels conducted using IPM
- A multitude of external studies and reports that demonstrate the feasibility of higher percentages of total generation than are associated with the building block 3 generation levels

The IPM scenarios support building block 3 generation levels in two ways - by apportioning the national-level generation totals calculated from national-level deployment, and validating the building block 3 generation levels as technically feasible and cost-effective.[37] It is important to note that the IPM model was not the basis for the overall setting of the Building Block 3 generation levels; as described above, those levels are based on historical additions that have actually been achieved. The IPM model, however, is a useful tool for analyzing the cost and impact of deploying these historically-based generation levels. IPM is a power sector planning model with a detailed representation of current and potential generating resources, a large number of regions, interregional transmission constraints based on current limits, and regional reserve margins based on current NERC standards. IPM does not attempt to perform a detailed power flow analysis, or to project new transmission additions; however, it captures key variables such as costs associated with connecting new renewable resource to the grid within a region and will include additional costs related to interregional transmission congestion from constraints in the current grid. For these reasons, IPM is an appropriate tool for analyzing the generation levels assumed for RE and for reviewing RE penetration levels and the impact on the overall generation mix.[38]

52409. Golden, CO. (http://www.nrel.gov/analysis/re_futures/); Bloom, A., Townsend, A., Palchak, D., King, J., Ibanez, E., Barrows, C., Hummon, M., Draxl, C., (2015). Eastern Renewable Generation Integration Study. NREL/TP-6A20-64472. Golden, CO. In press, http://www.nrel.gov/electricity/transmission/eastern_renewable.html; Lew, D., Brinkman, G., Ibanez, E., Florita, A., Heaney, M., Hodge, B.-M., Hummon, M., Stark, G., King, J., Lefton, S.A., Kumar, N., Agan, D., Jordan, G., Venkataraman, S., (2013). The Western Wind and Solar Integration Study Phase 2. NREL/TP-5500-55588. Golden, CO. (http://www.nrel.gov/docs/fy13osti/55588.pdf); Miller, N.W., Shao, M., Pajic, S., D'Aquila, R., (2014). Western Wind and Solar Integration Study Phase 3 – Frequency Response and Transient Stability. NREL/SR-5D00-62906. Golden; (http://www.nrel.gov/docs/fy15osti/62906.pdf); PJM Renewable Integration Study. 2014. (http://www.pjm.com/committees-and-groups/subcommittees/irs/pris.aspx)

[37] Supporting IPM analysis, including 'BB3: Generation Assignment' and 'BB3: Cost-Effectiveness' are available in the docket.

[38] For further documentation detail on the IPM model, visit http://www.epa.gov/airmarkets/powersectormodeling.html

To specifically assess the cost effectiveness and technical feasibility of building block 3, EPA imposed minimum generation constraints in IPM at levels consistent with the building block 3 generation levels. The only technologies made available to satisfy these constraints were the RE technologies associated with building block 3 – utility-scale solar PV, CSP, onshore wind, geothermal, and hydropower with an online year of 2013 or later. [39] To meet these levels in a manner that reflects the BSER, every incremental MWh of qualifying RE the model deployed necessitated that one MWh of affected EGU generation be reduced.[40] This requirement was necessary to reflect that building block 3 is premised on the replacement of affected EGU generation by incremental RE. The cost effectiveness of meeting this constraint, expressed as the average $/ton of CO_2 emissions reductions, is shown below in Table 4-14:[41]

Table 4-14: Cost Effectiveness of Building Block 3

	Average Annual Cost (Billion $)			Average CO2 Emissions (Million Short Tons)			Avoided Cost per Short Ton
Year	Base	Building Block 3	Incremental Cost	Base	Building Block 3	Reduced Emissions	
2022-2030[42]	184.7	193.7	9.1	2184.8	1940.9	243.9	$37

EPA believes the 2022-2030 average cost of $37/ton to be reasonable.[43]

[39] This same procedure was used to apportion the national-level building block 3 generation totals to each of the three interconnections. See the IPM analysis 'BB3: Generation Assignment' in the docket for further details.

[40] To model 1:1 replacement, incremental RE replaced affected EGU generation from levels projected by EPA IPM Base Case, rather than from historical levels. All other resources – non-building block 3 RE, other existing non-affected sources, and new sources - were available to meet projected demand growth in the analysis. In contrast, and to reflect the flexibilities inherent in compliance, the 'BB3: Generation Assignment' analysis did not include constraints necessitating 1:1 replacement of affected EGU generation.

[41] Refer to 'BB3: Cost-Effectiveness' IPM analysis, available in the docket, for further detail.

[42] The cost-effectiveness calculation is based on the 2022-2030 time period, reflecting the entirety of the interim compliance period through achievement of the final building block 3 generation level in 2030. The results presented reflect a weighted average of the 2020, 2025, and 2030 run years; specifically, one calendar year from IPM's 2020 run year (2022), five calendar years from IPM's 2025 run year (2023 – 2027), and three calendar years from IPM's 2030 run year (2028 – 2030).

[43] The wind and solar resource potential in IPM was developed with the assistance of NREL data and methodologies, which includes appropriate resource exclusions and constraints to recognize land uses that are incompatible with RE development. The level of RE deployment required by the building block 3 analyses represents a small amount of the total resource estimates, which, together with the regional nature of the BSER, effectively addresses the various examples of land use incompatibilities raised by commenters. For example, in 2030 the total onshore wind capacity projected to be developed is only 1.5% of potential capacity (153 GW out of a potential of 10,468 GW). Likewise, the total solar PV potential developed in the building block 3 analysis is only 0.1% of potential (154 GW out of a potential of 194,490 GW). Consequently, the level of RE deployment associated with achieving building block 3 remains technically feasible and cost-effective even under conservative land use assumptions.

The feasibility of these generation levels is further confirmed by the results of other industry projections of RE, as well as many industry studies of the technical feasibility of even higher levels of RE penetration. The percentage of total RE generation associated with building block 3 projected in 2025 and 2030 is shown in Table 4-15.[44] As the table shows, the highest national-level share of generation from renewables is 20 percent. Virtually all recent studies of achievable penetration level of RE in the power grid are above 20 percent, for the simple reason that 20 percent has been shown to be feasible – as indicated by the current RE levels discussed above – and studies are directed at assessing the impact of higher levels. A good review of the main integration studies is provided in a report by the National Renewable Energy Laboratory.[45] The summary table from this report is included as an Appendix to this TSD. The table summarizes a range of regional and national studies that analyze renewable penetration levels up to 50 percent.

Table 4-15: EPA IPM Analysis of Generation Mix

	2025 (TWh)			2030 (TWh)		
Scenario	Total	RE	RE%	Total	RE	RE
EPA IPM Base Case	4328	441	10	4467	472	11
Building Block 3 Analysis[46]	4326	582	13	4473	894	20

Another important reference point for understanding the Building Block 3 generation levels is found in projections of future renewables by independent industry evaluations. Two example of such evaluations have been recently conducted by IHS Energy and by UBS Securities LLC.[47] In each case, these projections are presented in terms of the additions of RE capacity that are expected to be deployed. Comparable levels of capacity for Building Block 3 are available from the IPM results for the base and Building Block 3 levels and are shown in Table 4-16 along with the projections from IHS Energy. This table shows Building Block 3 potential RE capacity additions are somewhat above a midpoint, but well within the range of industry expectations.

In the UBS projections cited, UBS estimates a solar market of 90GW. This compares closely with the Building Block 3 projection of 93GW of total solar capacity.[48] Together these comparisons

[44] For purposes of Table 4-15, RE is comprised new and existing wind, utility-scale solar, geothermal, and new hydropower.
[45] NREL, Relevant Studies for NERC's Analysis of EPA's Clean Power Plan 111(d) Compliance, Table ES-1, at http://www.nrel.gov/docs/fy15osti/63979.pdf.
[46] Available in the docket as IPM run 'BB3: Cost-Effectiveness.'
[47] HIS Energy, North American Renewables Outlook: The rise of solar and the uncertainty of policy, 2 June 2015; UBS Securities LLC, US Solar & Alternative Energy, Sizing Up the US Solar Market.
[48] UBS includes some distributed solar as well as utility scale.

show that the assumed generation levels are within the range of expected feasible future expectations of independent industry analysts. Moreover, it is important to realize that these results from the IPM model are not projections of any expected future scenario of compliance with the final rule, but rather results designed to show the potential impact in key variables of modeling a potential future based on demonstrated historical performance. In this context it is also important to note that compliance with the final rule may be achieved with far lower overall levels of RE generation. In the illustrative scenario for the rate-base compliance, for example, the total renewable capacity additions were 95 GW in 2030[49], only slightly above the 87 GW in the IHS Energy Low case.

Table 4-16: Total RE Capacity Additions from 2015 (GW)

Scenario	Through 2025	Through 2030
EPA Base Case	48	62
EPA Building Block 3[50]	121	233
IHS Energy -Low	64	87
IHS Energy -Mid	126	192
IHS Energy -High	222	352

4.6.3 Transmission

Compliance with the final rule is not expected to add significant transmission requirements. The RIA projects that the final rule will add only 20 GW of renewable generation capacity beyond the base case; this is a small increment that can be accommodated in the normal transmission planning process. Even the larger levels of new generation for Building Block 3 considered here should not raise concerns about the reasonableness of the costs associated with the full build out of renewables. There are several reasons for this:

- Although it is reasonable to assume that some proposed renewable scenarios will require specific patterns of new transmission requirements,[51] transmission will be required for any new generation under all future scenario, with or without significant additions of renewables. Although the location-specific nature of renewables will place different requirements that can add to some transmission needs, it will also mean that generation and flows on the grid will shift, resulting in reduced flows and constraints in some areas. Since the additional renewable capacity projected for Building Block three occurs over a

[49] See the RIA, Table 3-14.
[50] Available in the docket as IPM run 'BB3: Cost-Effectiveness.'
[51] An example of these requirements can be found in the Eastern Interconnection Planning Collaborative (EIPC) Phase 2 Report: Interregional Transmission Development and Analysis for Three Stateholder Selected Scenarios (December, 2012). These studies have been used to analyze the feasibility of a 30 percent wind and solar scenario by the Eastern Renewable Generation Integration Study (ERGIS).

15 year period, and rises to a level of only 20 percent renewables, these additions should be manageable in the normal planning and expenditure process for transmission.

- EEI members alone are expected to increase transmission expenditures substantially over the next five years to approximately 20 billion dollars per year, nearly doubling the historical investment over the average of the past five years. [52] By contrast, DOE's SunShot scenario, which increases utility-scale PV to 180 GW by 2030, anticipated spending of $60 billion through 2050. This level is approximately double the level of solar assumed in this building block and still amounts to less than $2 Billion per year.
- Using the Eastern Interconnection as an example, the additional costs required for transmission expansion are almost all either for generation interconnection or for constraint relief.[53] For renewable generation, many of these costs are already captured in the cost estimates from the IPM modeling. For example, the cost of connecting wind to the existing grid are reflected in the cost classes assigned to different categories of wind available for deployments. The IPM model considers the location of generating resources and the existing limits of interregional transfer of capacity in costs of developing new capacity and delivering it to load, so where increased interregional congestion arises from delivering power from new remote supply, the cost of from re-routing the flows to avoid congestion are captured in the total cost of modeled scenarios.

4.6.4 Ownership and Co-Location

The availability of co-owned RE that is proximate to affected EGUs allows owners and operators to increase RE and reduce CO2 emissions at their affected EGUs. In addition to the examples of owners and operators of affected EGUs that own RE in section V.E.4 of the preamble to the final rule, there are examples of owners and operators of RE and affected EGUs in which they are co-located or located close to each other (e.g., within power control areas or balancing authorities).

EPA has observed that companies, such as NRG, NextEra, Constellation, Sempra and Exelon, offer examples of co-owned RE and affected EGUs that are at least within the same power control area. NRG's asset map include examples, such as western Pennsylvania wind and coal plants, Texas wind, coal and natural gas plants and southern California solar and natural gas plants.[54] NextEra Energy Resources, a subsidiary of NextEra Energy, owns solar PV in Gloucester County, NJ a short distance from its two Marcus Hook NGCC plant in PA, across the Delaware River. They also own two NGCC facilities in Texas along with more than ten wind plants.[55] Constellation Energy has an ownership interest in a concentrating solar thermal plant in CA along with several

[52] Edison Electric Institute, Transmission Projects at a Glance, March 2015, Page v.
[53] The Eastern Interconnection is a key region, because it is the limiting region for purposes of setting final rule goals for 2030. See the EIPC study, Section 5.1, Table 5-9, where over 95 percent of the scenario costs for Transmission related costs arise from these two sources.
[54] NRG, Asset Map, Available at: http://maps.nrg.com/, accessed July 2015
[55] NextEra Energy Resources, Facilities Map, Available at: http://www.nexteraenergyresources.com/where/us_map.shtml?type=Hydro, Accessed July 2015

small coal plants.[56] Sempra Energy has neighboring natural gas and solar PV projects in both Boulder City, NV and Arlington, AZ.[57]

These owners and operators have a direct path to reducing higher-emitting generation with RE that is either in close proximity or within the same grid regions regardless of their organizational type and regardless of whether they operate in a cost-of-service framework or in a competitive, organized market.

[56] Constellation Energy, Generation Assets Portfolio, Available at: http://www.constellation.com/documents/constellation_energy_pdf_documents_corpcontent_1286210749525/asset-map.pdf, Accessed July 2015
[57] Sempra Energy, Our Energy Assets, Available at: http://www.sempra.com/about/our-companies/, Accessed July 2015

CHAPTER 5: CARBON CAPTURE & STORAGE

5.1 Introduction

Another possible approach for reducing CO_2 emissions from existing fossil fuel-fired steam generating EGUs is through the application of carbon capture and storage technology (CCS; sometimes also referred to as carbon capture and sequestration). In the final standards of performance for new fossil fuel-fired EGUs, EPA has determined that the best system of emission reduction (BSER) for new fossil fuel-fired steam generating units is implementation of partial CCS (i.e., capturing a portion of the CO_2 from the emission stream – in contrast to "full CCS" which would involve capturing > 90% of the CO_2 from the emissions). EPA has determined that that, for new steam generating EGUs (utility boilers and IGCC 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 steam generating EGUs.

5.2 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.

5.2.1 Post-combustion Capture

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., using 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 and HCl – that can degrade the solvent. The captured CO_2, if it is to be transported via pipeline for storage or use in enhanced oil recovery (EOR), must then be compressed from near atmospheric pressure to much higher pipeline pressures (about 2,000 psia).

5.2.2 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., petroleum 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.

5.2.3 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.

5.3 CO_2 Transportation and Storage

5.3.1 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.

5.3.2 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.[1] 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.[2] 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).[3]

5.3.3 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 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.

[1] 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).
[2] 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/.
[3] 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/.

5.4 Evaluation of Retrofit CCS as BSER for Existing Fossil Fuel-fired EGUs

5.4.1 Technical Feasibility

In evaluating partial CCS as the BSER for new fossil fuel-fired boilers and IGCC units, 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 EPA found that partial CCS is technically feasible for new fossil fuel-fired boilers and IGCC units, it is 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 can be more challenging. Some existing sources have a limited footprint and may not have the land or space available to add the equipment needed to implement CO_2 capture, compression, and transportation. 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 and it is being installed for large-scale demonstration at NRG's WA Parish facility. SaskPower's Boundary Dam Unit #3, a 110 MW coal-fired utility boiler in Saskatchewan, began operations in October 2014. The facility has retrofit post-combustion carbon capture technology that is capturing approximately 90 % of the CO_2 from flue gas stream. 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 preferred compliance option. However, for the reasons stated above, CCS as a system of emission reduction would be much more easily implemented at some existing plants relative to others, and for some would be precluded due to limited space. Therefore, identification of CCS as the best system of emission reduction for existing fossil fuel fired EGUs would require sub-categorization of EGUs based on such factors and EPA does not have adequate information to appropriately perform such a sub-categorization.

5.4.2 Reasonableness of Cost

In the proposed standard of performance for new fossil fuel-fired EGUs (79 FR 1430), EPA proposed that the costs to implement partial CCS (to a level to meet the proposed emission standard of 1,100 lb CO_2/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. 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 issuing the final NSPS for new fossil fuel-fired EGUs, EPA – in response to public comments and updated cost information – reevaluated the cost to implement partial CCS and adjusted the final emission limitation to a standard of 1,400 lb CO_2/MWh-gross.

In contrast, EPA did not propose to 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. EPA also noted that, because virtually all new fossil fuel-fired generating capacity 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. Importantly, the approach identified as the best system of emission reduction will achieve equivalent or greater emission reductions at a far lower cost and provide sources and states with greater flexibility to ensure reliability. Therefore, as stated earlier, EPA did not find partial CCS to be an appropriate component of the best system of emission reduction for CO_2 emissions from existing fossil fuel-fired EGUs.

5.4.3 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, EPA has determined that such an emission standard may not be feasible in a number of cases and would involve higher costs (and less flexibility) than the approach identified as the best system of emission reduction.

5.4.4 CCS and CCU in State Plans

Affected EGUs may utilize retrofit CCS technology to reduce reported stack CO_2 emissions from the EGU.[4] Affected EGUs that apply CCS under a state plan must meet the same monitoring, recordkeeping and reporting requirements for sequestered CO_2 as new units with CCS capability

[4] Addition of retrofit CCS technology should not trigger CAA section 111(b) applicability for modified or reconstructed sources. Pollution control projects do not trigger NSPS modifications and addition of CCS technology does not count toward the capital costs of reconstruction.

subject to the final CAA section 111(b) rule for new EGUs.[5] Specifically, the final CAA section 111(b) rule for new sources requires that, if a new affected EGU uses CCS to meet the applicable CO_2 emission limit, the EGU must report in accordance with 40 CFR part 98 subpart PP (Suppliers of Carbon Dioxide), and the captured CO_2 must be injected at a facility or facilities that report in accordance with 40 CFR part 98 subpart RR (Geologic Sequestration of Carbon Dioxide).[6,7] See 40 CFR part 60.46Da(h)(5) and part 60.5555(d). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting. As detailed in the preamble for the CAA section 111(b) standards for new EGUs, EPA is convinced that there is ample evidence that CCS is technically feasible and that partial CCS can be implemented at a new fossil fuel-fired steam generating EGU at a cost that is consistent with the cost of other dispatchable, non-NGCC generating options.

EPA received comments suggesting that carbon capture and utilization (CCU) technologies should also be allowed as a CO_2 emission rate adjustment measure for affected EGUs. Potential alternatives to storing CO_2 in geologic formations are emerging and these relatively new potential alternatives may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. For example, these carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine® project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products including sodium carbonate and sodium bicarbonate.[8] Other companies – including Calera[9] and New Sky[10] – also offer commercially available technology for the beneficial use of captured CO_2. These processes can be

[5] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.

[6] The final CAA section 111(b) rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) the electronic GHG Reporting Tool identification (e-GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e-GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR. As noted, the final 111(b) rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emissions limit must transfer the captured CO_2 to a facility that reports under 40 CFR part 98 subpart RR.

[7] Under final requirements in the CAA 111(b) NSPS, any well receiving CO_2 captured from an affected source, be it a Class VI or Class II well, must report under subpart RR. A UIC Class II well's regulatory status does not change because it receives such CO_2, nor does it change by virtue of reporting under subpart RR.

[8] http://skyonic.com/technologies/skymine.

[9] http://www.calera.com/beneficial-reuse-of-co2/process.html.

[10] http://www.newskyenergy.com/index.php/products/carboncycle.

utilized in a variety of industrial applications – including at fossil fuel-fired power plants.

However, consideration of how these emerging alternatives could be used to meet CO_2 emission performance rates or state CO_2 emission goals would require a better understanding of the ultimate fate of the captured CO_2 and the degree to which the method permanently isolates the captured CO_2 or displaces other CO_2 emissions from the atmosphere.

Several commenters also suggested that algae-based CCU (i.e., the use of algae to convert captured CO_2 to useful products – especially biofuels) should be recognized for its potential to reduce emissions from existing fossil-fueled EGUs.

Unlike geologic sequestration, there are currently no uniform monitoring and reporting mechanisms to demonstrate that these alternative end uses of captured CO_2 result in overall reductions of CO_2 emissions to the atmosphere. As these alternative technologies are developed, EPA is committed to work collaboratively with stakeholders to evaluate the efficacy of alternative utilization technologies, to address any regulatory hurdles, and to develop appropriate monitoring and reporting protocols to demonstrate CO_2 reductions.

In the meantime, EPA has specified that state plans may allow affected EGUs to use qualifying CCU technologies to reduce CO_2 emissions that are subject to an emission standard, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission. Approvable state plans must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation and provide monitoring, reporting, and verification requirements to demonstrate the reductions. EPA would then review the appropriateness and basis for the analysis and the verification requirements in the course of its review of the state plan.