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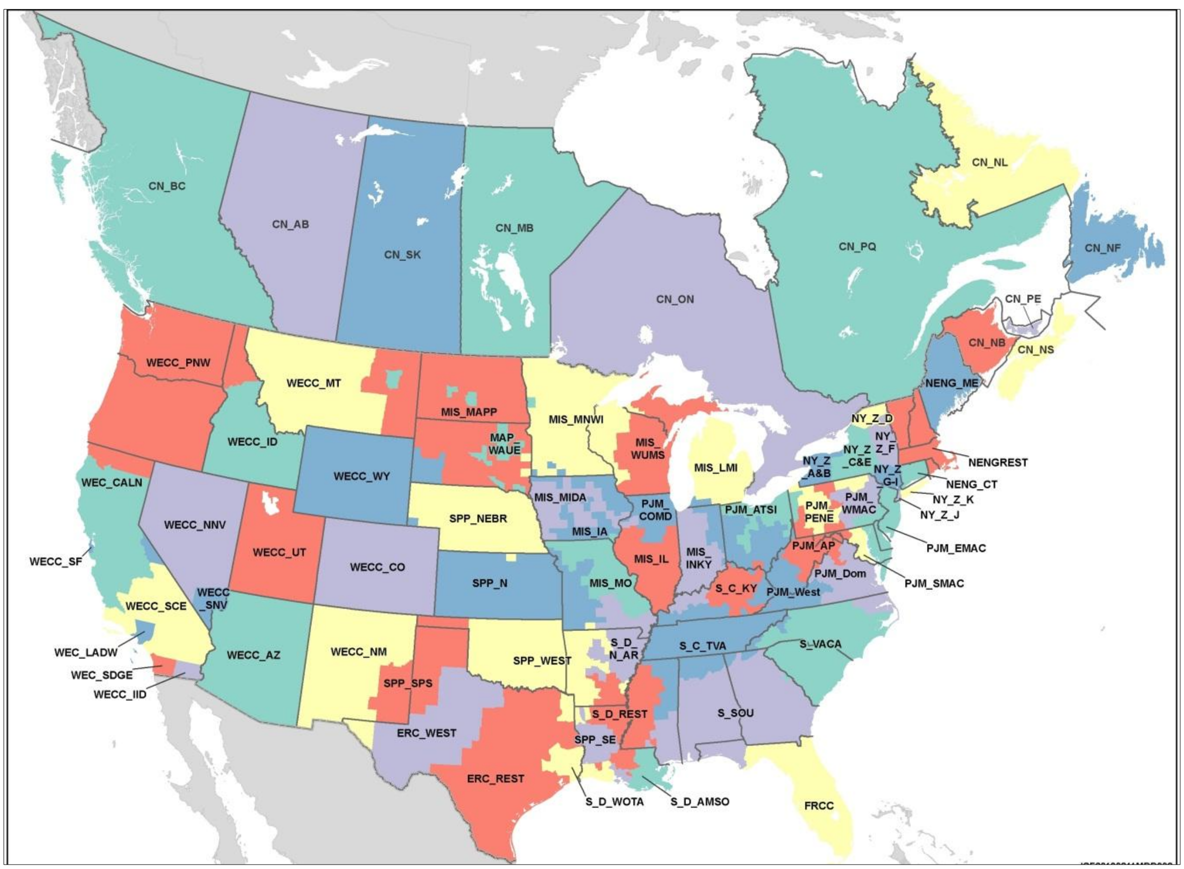
Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model



Cover: EPA Base Case v.5.13 and associated policy cases are used by the U.S. Environmental Protection Agency to project the impact of emissions policies on the electric power sector in the 48 contiguous states and the District of Columbia in the lower continental U.S. Representation of the electric power sector in Canada is also included for purposes of integrated projections. The map appearing on the cover shows the 64 model regions used to characterize the operation of the U.S. electric power system in the lower continental U.S. and 11 model regions in Canada. EPA Base Case v.5.13 was developed by EPA's Clean Air Markets Division with technical support from ICF International, Inc. The IPM modeling platform is a product of ICF Resources, LLC, an operating company of ICF International, Inc and is used in support of its public and private sector clients. IPM® is a registered trademark of ICF Resources, L.L.C.

Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model

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1. Introduction

This document describes the nature, structure, and capabilities of the Integrated Planning Model (IPM) and the assumptions underlying the base case (designated EPA Base Case v.5.13) that was developed by the U.S. Environmental Protection Agency (EPA) with technical support from ICF, Inc. (ICF). IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. It provides forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand and environmental, transmission, dispatch, and reliability constraints. IPM can be used to evaluate the cost and emissions impacts of proposed policies to limit emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon dioxide (CO_2), mercury (Hg), and HCl from the electric power sector.

This new base case (v.5.13) incorporates important structural improvements and data updates with respect to the previous version (v.4.10). A new version number (moving from v.4 to v.5) indicates a substantial change to Base Case architecture (such as this version's significant increase in the number of model regions). Changing the portion of the version name after the 'dot' (moving from .10 to .13) indicates the calibration of the model to more recent information (most importantly electricity demand projections) from a particular iteration of the Energy Information Agency's (EIA) Annual Energy Outlook (AEO) , in this case AEO 2013.

Base cases, like EPA Base Case v.5.13, serve as the starting point against which policy scenarios are compared. Base Case v.5.13 is a projection of electricity sector activity that takes into account only those Federal and state air emission laws and regulations whose provisions were either in effect or enacted and clearly delineated at the time the base case was finalized in August 2013 (prior to publication of this documentation). Section 3.9 contains a detailed discussion of the environmental regulations included in EPA Base Case v.5.13, which are summarized below.

- EPA Base Case v.5.13 includes the Clean Air Interstate Rule (CAIR), a Federal regulatory measure for achieving the 1997 National Ambient Air Quality Standards (NAAQS) for ozone (8-hour average of 0.08 ppm) and fine particles (24-hour average of 65 µg/m3 or less and annual average of 15 µg/m3 for particles of diameter 2.5 micrometers or less, i.e., PM 2.5). Originally issued on March 10, 2005, CAIR was remanded back to EPA by the U.S. Court of Appeals for the District of Columbia Circuit in December 2008 and EPA was required to correct legal flaws in the regulations that had been cited in a ruling by the Court in July 2008. CAIR remains in effect until replaced by EPA pursuant to the Court's ruling. CAIR's provisions were still in effect when EPA Base Case v.5.13 was released.
- EPA Base Case v.5.13 includes NAAQS to the extent that state regulations included in EPA Base Case v.5.13 contain measures to bring non-attainment areas into attainment. A summary of these state regulations can be found in Appendix 3-2. Apart from these state regulations, individual permits issued by states in response to NAAQS are captured (a) to the extent that they are reflected in the NO_x rates reported to EPA under CAIR, Title IV and the NO_x Budget Program which are incorporated in the base case and (b) to the extent that SO_2 permit limits are used in the base case to define the choice of coal sulfur grades that are available to specific power plants.
- EPA Base Case v.5.13 includes the Mercury and Air Toxics Rule (MATS), which was finalized in 2011. MATS establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the "electric utility steam generating unit" source category.
- EPA Base Case v.5.13 also reflects the final actions EPA has taken to implement the Regional Haze Rule. This regulation requires states to submit revised State Implementation Plans (SIPs) that include (1) goals for improving visibility in Class I areas on the 20% worst days and allowing no degradation on the 20% best days and (2) assessments and plans for achieving Best Available Retrofit Technology (BART) emission targets for sources placed in operation between 1962 and 1977. Since 2010, EPA has approved SIPs or, in a very few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of August 29, 2013) that will be in place for EGUs are represented in the EPA Base Case v.5.13.

Table 1-1 lists updates included in EPA Base Case v.5.13 listed in the order they appear in this documentation report. Updates that are highlighted in gray were “non-routine” in the sense that they constituted new modeling capabilities, notable extensions beyond the capabilities provided in previous EPA base cases, or significant reviews of important assumptions.

Table 1-1 Updates in the EPA Base Case v.5.13

Description	For More Information
Modeling Framework	
Expansion of US model regions from 32 to 64	Section 3.1
Incorporation of three stages of environmental retrofits	Section 7.2
Power System Operation	
Updated capacity deployment constraints (for new advanced coal with carbon capture, carbon capture retrofits, and new nuclear)	Section 3.10 and Attachment 3-1
Updated inventory of state emission regulations, including RGGI and AB32 (as of August 2013)	Table 3-12
Updated inventories of NSR, state, and citizen settlements (as of August 2013)	Table 3-13
Updated transmission TTC's (2012-2013 ISO/RTO and NERC reports)	Table 3-4 and Table 3-5
Updated regional reserve margins (NERC 2012)	Table 3-9
AEO NEMS region level electricity demand is disaggregated to IPM model region level	Table 3-2
Generating Resources	
Updates to NEEDS, the database of existing and planned-committed units and their emission control configurations (Primary Sources: 2010, 2011 EIA Form 860, ETS 2011, NERC ES&D 2011, AEO 2013)	Table 4-1
Updated cost and performance characteristics for potential (new) conventional, nuclear and renewable generating units (AEO 2013 and NETL)	Table 4-13 and Table 4-16
New renewable units including biomass, wind, solar, geothermal and landfill gas are modeled at a state level within each IPM region (Resource assumptions from NREL)	Section 4.4.5
Emission Control Technologies	
Complete update of cost and performance assumptions for SO_2, NO_x, Hg and HCl emission controls based on engineering studies by Sargent and Lundy	
Updated cost and performance assumptions for coal-to-gas and retrofit options	Section 5.7
Set-Up Parameters and Rules	
Modeling time horizon with seven model run years (2016, 2018, 2020, 2025, 2030, 2040, 2050)	Section 7.1
CAIR, MATS, and BART are part of Base Case	Section 7.3
All costs and prices are in 2011 dollars	
Financial assumptions	
Update of discount and capital charge rate assumptions based on a hybrid capital cost model of utility and merchant finance structures for new units	Section 8.2.2
Use of separate capital charge rates for retrofits based on utility and merchant finance structures	Section 8.3.2
Coal	
Complete update of coal supply curves and transportation matrix (Wood Mackenzie 2012-2013 and Hellerworx 2012-2013)	Table 9-23 and Table 9-24
Coal demand regions are now disaggregated to the coal facility (ORIS) level	Table 9-2
Natural Gas	
Update of unconventional gas resource base (ICF 2013)	Section 10.4
Other Fuels	
Update of price assumptions for fuel oil, nuclear fuel and waste fuel (AEO 2013)	Section 11.1
Incorporation of biomass supply curves at a state level (AEO 2013)	Section 11.2
Biomass storage costs are added to the agricultural residues component of the biomass supply curves	Section 11.2

Table 1-2 lists the types of plants included in the EPA Base Case v.5.13.

Table 1-2 Plant Types in EPA Base Case v.5.13

Fossil Fuel Fired
Coal Steam
Oil/Gas Steam
Combustion Turbine
Combined-Cycle Combustion Turbine
Integrated Gasification Combined-Cycle (IGCC) Coal
Advanced Coal with Carbon Capture
Fluidized Bed Combustion
Non-Fossil Fuel Fired
Nuclear
Renewables and Non-Conventional Technologies
Hydropower
Pumped Storage
Biomass
Onshore Wind
Offshore Shallow Wind
Offshore Deep Wind
Fuel Cells
Solar Photovoltaics
Solar Thermal
Geothermal
Landfill Gas
Other[a]

Note:
[a] Includes fossil and non-fossil waste plants.

Table 1-3 lists the emission control technologies available for meeting emission limits in EPA Base Case v.5.13.

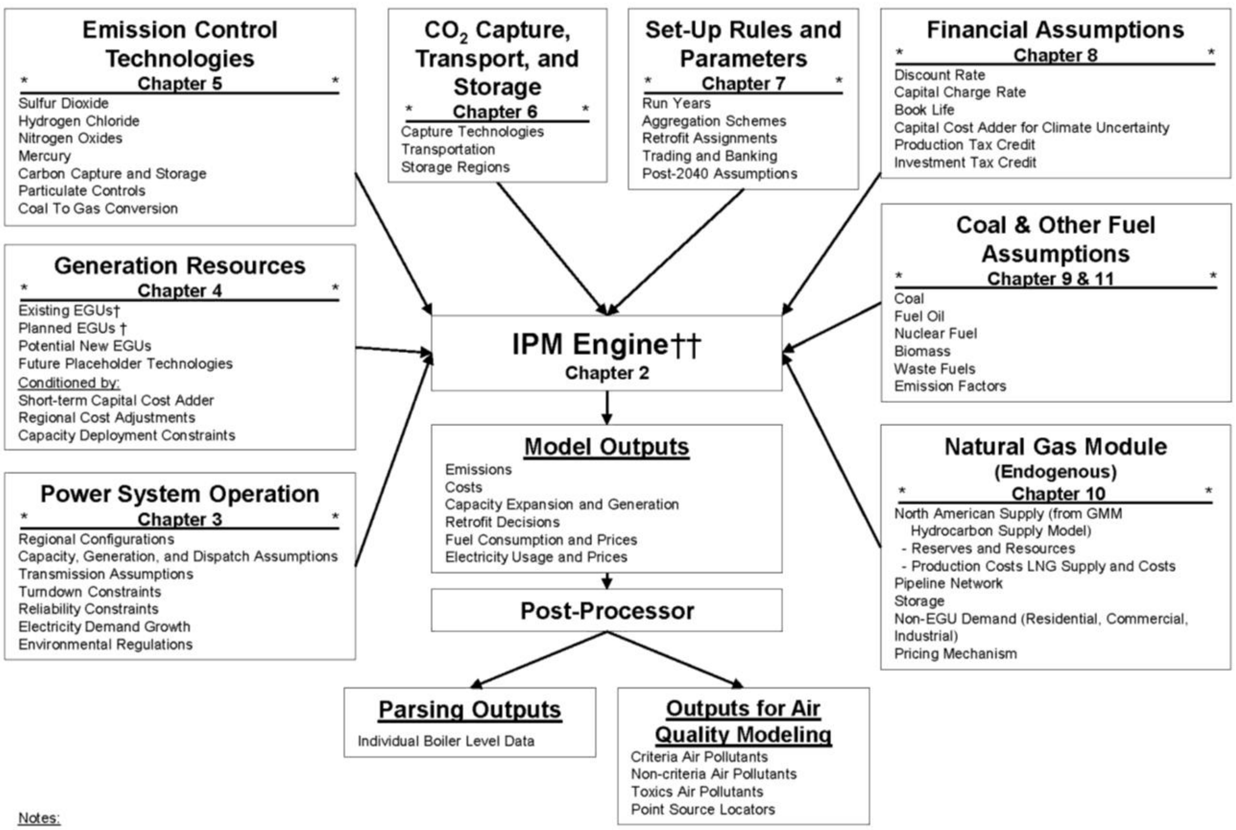
Table 1-3 Emission Control Technologies in EPA Base Case v.5.13

Sulfur Dioxide (SO_2) and Hydrochloric Acid (HCl)
Limestone Forced Oxidation (LSFO)
Lime Spray Dryer (LSD)
Dry Sorbent Injection (with milled Trona)
FGD Upgrade Adjustment
Nitrogen Oxides (NO_x)
Combustion controls
Selective catalytic reduction (SCR)
Selective non-catalytic reduction (SNCR)
Mercury (Hg)
Combinations of SO_2, NO_x, and particulate control technologies
Activated Carbon Injection
Particulate Matter (PM)
Pulse-Jet Fabric Filter (FF)
Electrostatic Precipitator (ESP) Upgrade Adjustment
Carbon Dioxide (CO_2)
Heat rate improvement
Coal-to-gas
Carbon Capture and Sequestration

Notes:
[a] Units may also select among different coal types to manage emissions in EPA Base Case v.5.13.

Figure 1-1 provides a schematic of the components of the modeling and data structure used for EPA Base Case v.5.13. This report devotes a separate chapter to all the key components shown in Figure 1-1. Chapter 2 provides an overview of IPM's modeling framework (sometimes referred to as the "IPM Engine"), highlighting the mathematical structure, notable features of the model, programming elements, and model inputs and outputs. The remaining chapters are devoted to different aspects of EPA Base Case v.5.13. Chapter 3 covers the power system operating characteristics captured in EPA Base Case v.5.13. Chapter 4 explores the characterization of electric generation resources. Emission control technologies (chapter 5) and carbon capture, transport and storage (chapter 6) are then presented. Chapter 7 describes certain set-up rules and parameters employed in EPA Base Case v.5.13. Chapter 8 summarizes the base case financial assumptions. The last three chapters discuss the representation and assumptions for fuels in the base case. Coal is covered in chapter 9, natural gas in chapter 10, and other fuels (i.e., fuel oil, biomass, nuclear fuel, and waste fuels) in chapter 11 (along with fuel emission factors).

Figure 1-1 Modeling and Data Structures in EPA Base Case v.5.13



Notes:

† Information on existing and planned electric generating units (EGUs) is contained in the National Electrical Energy Data System (NEEDS) data base maintained for EPA by ICF International. Planned EGUs are those which were under construction or had obtained financing at the time that the EPA Base Case was finalized.

††IPM Engine is the model structure described in Chapter 2

2. Modeling Framework

ICF developed the Integrated Planning Model (IPM) to support analysis of the electric sector. The EPA, in addition to other state air regulatory agencies, utilities, and public and private sector clients, has used IPM extensively for various air regulatory analyses, market studies, strategy planning, and economic impact assessments.

The first section of this chapter provides a brief overview of the model's purpose, capabilities, and applications. The following sections are devoted to describing the IPM model's structure and formulation, key methodological characteristics, and programming features, including its handling of model inputs and outputs. Readers may find some overlap between sections. For example, transmission decision variables and constraints are covered in the discussion of model structure and formulation in section 2.2', and transmission modeling is covered as a key methodological feature in section 2.3.8. The different perspectives of each section are designed to provide readers with information that is complementary rather than repetitive.

2.1 IPM Overview

IPM is a well-established model of the electric power sector designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets – fuel markets, emission markets, and electricity markets. Since the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.

2.1.1 Purpose and Capabilities

IPM is a dynamic linear programming model that generates optimal decisions under the assumption of perfect foresight. It determines the least-cost method of meeting energy and peak demand requirements over a specified period. In its solution, the model considers a number of key operating or regulatory constraints (e.g. emission limits, transmission capabilities, renewable generation requirements, fuel market constraints) that are placed on the power, emissions, and fuel markets. In particular, the model is well-suited to consider complex treatment of emission regulations involving trading, banking, and special provisions affecting emission allowances (like bonus allowances and progressive flow control), as well as traditional command-and-control emission policies.

IPM represents power markets through model regions that are geographical entities with distinct characteristics. While they are more numerous (for purposes of respecting smaller-scale transmission limitations where adequate information was available), the model regions representing the U.S. power market in EPA Base Case v.5.13 are largely consistent with the North American Electric Reliability Council (NERC) assessment regions and with the organizational structures of the Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs), which handle dispatch on most of the U.S. grid. IPM represents the least-cost arrangement of electricity supply (capacity and generation) within each model region to meet assumed future load (electricity demand) while constrained by a transmission network of bulk transfer limitations on interregional power flows. All existing utility power generation units, including renewable resources, are modeled, as well as independent power producers and cogeneration facilities that sell electricity to the grid.

IPM provides a detailed representation of new and existing resource options, including fossil generating options (coal steam, gas-fired simple cycle combustion turbines, combined cycles, and oil/gas steam), nuclear generating options, and renewable and non-conventional (e.g., fuel cells) resources. Renewable resource options include wind, landfill gas, geothermal, solar thermal, solar photovoltaic and biomass.

IPM can incorporate a detailed representation of fuel markets and can endogenously forecast fuel prices for coal, natural gas, and biomass by balancing fuel demand and supply for electric generation. The model also includes detailed fuel quality parameters to estimate emissions from electric generation.

IPM provides estimates of air emission changes, regional wholesale energy and capacity prices, incremental electric power system costs, changes in fuel use, and capacity and dispatch projections.

2.1.2 Applications

IPM's structure, formulation and set-up make it very adaptable and flexible. The necessary level of data, modeling capabilities exercised, and computational requirements can be tailored to the particular strategies and policy options being analyzed. This adaptability has made IPM suitable for a variety of applications. These include:

Air Regulatory Assessment: Since IPM contains extensive air regulatory modeling features, state and federal air regulatory agencies have used the model extensively in support of air regulatory assessment.

Integrated Resource Planning: IPM can be used to perform least-cost planning studies that simultaneously optimize demand-side options (load management and efficiency), renewable options and traditional supply-side options.

Strategic Planning: IPM can be used to assess the costs and risks associated with alternative utility and consumer resource planning strategies as characterized by the portfolio of options included in the input data base.

Options Assessment: IPM allows industry and regulatory planners to "screen" alternative resource options and option combinations based upon their relative costs and contributions to meeting customer demands.

Cost and Price Estimation: IPM produces realistic estimates of energy prices, capacity prices, fuel prices, and allowance prices. Industry and regulatory agencies have used these cost reports for due diligence, planning, litigation and economic impact assessment.

2.2 Model Structure and Formulation

IPM employs a linear programming structure that is particularly well-suited for analysis of the electric sector to help decision makers plan system capacity and model the dispatch of electricity from individual units or plants. The model consists of three key structural components:

- A linear "objective function,"
- A series of "decision variables," and
- A set of linear "constraints".
- The sections below describe the objective function, key decision variables, and constraints included in IPM for EPA Base Case v.5.13.

2.2.1 Objective Function

IPM's objective function is to minimize the total, discounted net present value, of the costs of meeting demand, power operation constraints, and environmental regulations over the entire planning horizon. The objective function represents the summation of all the costs incurred by the electricity sector on a net present value basis. These costs, which the linear programming formulation attempts to minimize, include the cost of new plant and pollution control construction, fixed and variable operating and maintenance costs, and fuel costs. Many of these cost components are captured in the objective function by multiplying the decision variables by a cost coefficient. Cost escalation factors are used in the objective function to reflect changes in cost over time. The applicable discount rates are applied to derive the net present value for the entire planning horizon from the costs obtained for all years in the planning horizon.

2.2.2 Decision Variables

Decision variables represent the values for which the IPM model is solving, given the cost-minimizing objective function described in section 2.2.1 and the set of electric system constraints detailed in section 2.2.3. The model determines values for these decision variables that represent the optimal least-cost solution for meeting the assumed constraints. Key decision variables represented in IPM are described in detail below.

Generation Dispatch Decision Variables: IPM includes decision variables representing the generation from each model power plant.[1] For each model plant, a separate generation decision variable is defined for each possible combination of fuel, season, model run year, and segment of the seasonal load duration curve applicable to the model plant. (See section 2.3.5 below for a discussion of load duration curves.) In the objective function, each plant's generation decision variable is multiplied by the relevant heat rate and fuel price (differentiated by the appropriate step of the fuel supply curve) to obtain a fuel cost. It is also multiplied by the applicable variable operation and maintenance (VOM) cost rate to obtain the VOM cost for the plant.

Capacity Decision Variables: IPM includes decision variables representing the capacity of each existing model plant and capacity additions associated with potential (new) units in each model run year. In the objective function, the decision variables representing existing capacity and capacity additions are multiplied by the relevant fixed operation and maintenance (FOM) cost rates to obtain the total FOM cost for a plant. The capacity addition decision variables are also multiplied by the investment cost and capital charge rates to obtain the capital cost associated with the capacity addition.

Transmission Decision Variables: IPM includes decision variables representing the electricity transmission along each transmission link between model regions in each run year. In the objective function, these variables are multiplied by variable transmission cost rates to obtain the total cost of transmission across each link.

Emission Allowance Decision Variables: For emission policies where allowance trading applies, IPM includes decision variables representing the total number of emission allowances for a given model run year that are bought and sold in that or subsequent run years. In the objective function, these year-differentiated allowance decision variables are multiplied by the market price for allowances prevailing in each run year. This formulation allows IPM to capture the inter-temporal trading and banking of allowances.

Fuel Decision Variables: For each type of fuel and each model run year, IPM defines decision variables representing the quantity of fuel delivered from each fuel supply region to model plants in each demand region. Coal decision variables are further differentiated according to coal rank (bituminous, sub-bituminous, and lignite), sulfur grade, chlorine content and mercury content (see Table 9-5). These fuel quality decision variables do not appear in the IPM objective function, but in constraints which define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant.

[1] Model plants are aggregate representations of real-life electric generating units. They are used by IPM to model the electric power sector. For a discussion of model plants in EPA Base Case v.5.13, see section 4.2.6.

2.2.3 Constraints

Model constraints are implemented in IPM to accurately reflect the characteristics of and the conditions faced by the electric sector. Among the key constraints included in EPA Base Case v.5.13 are:

Reserve Margin Constraints: Regional reserve margin constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year beyond the total capacity needed to meet future peak demand that must remain in service to that region. These reserve capacity constraints are derived from reserve margin targets that are assumed for each region based on information from reliability planning officials at NERC, RTOs or ISOs. If existing plus planned capacity is not sufficient to satisfy the annual regional reserve margin requirement, the model will “build” the required level of new capacity. Please see Section 3.6 for more information on reserve margin constraints.

Demand Constraints: The model categorizes regional annual electricity demand into seasonal load segments which are used to form summer (May 1 - September 30) and winter (October 1 - April 30) load duration curves (LDC). The seasonal load segments when taken together represent all the hourly electricity load levels that must be satisfied in a region in the particular season for a particular model run year. As such, the LDC defines the minimum amount of generation required to meet the region’s electrical demand during the specific season. These requirements are incorporated in the model’s demand constraints.

Capacity Factor Constraints: These constraints specify how much electricity each plant can generate (a maximum generation level), given its capacity and seasonal availability.

Turn Down/Area Protection Constraints: The model uses these constraints to take into account the cycling capabilities of the units, i.e., whether or not they can be shut down at night or on weekends, or whether they must operate at all times, or at least at some minimum capacity level. These constraints ensure that the model reflects the distinct operating characteristics of peaking, cycling, and base load units.

Emissions Constraints: IPM can endogenously consider an array of emissions constraints for SO_2, NO_x, HCl, mercury, and CO_2. Emission constraints can be implemented on a plant-by-plant, regional, or system-wide basis. The constraints can be defined in terms of a total tonnage cap (e.g., tons of SO_2) or a maximum emission rate (e.g., lb/MMBtu of NO_x). The scope, timing, and definition of the emission constraints depend on the required analysis.

Transmission Constraints: IPM can simultaneously model any number of regions linked by transmission lines. The constraints define either a maximum capacity on each link, or a maximum level of transmission on two or more links (joint limits) to different regions.

Fuel Supply Constraints: These constraints define the types of fuel that each model plant is eligible to use and the supply regions that are eligible to provide fuel to each specific model plant. A separate constraint is defined for each model plant.

2.3 Key Methodological Features of IPM

IPM is a flexible modeling tool for obtaining short- and long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen, but they are estimates of what might happen given the assumptions and methodologies used. Chapters 3 to 11 contain detailed discussions of the cost and performance assumptions specific to the EPA Base Case v.5.13. This section provides an overview of the essential methodological and structural features of IPM that extend beyond the assumptions that are specific to EPA Base Case v.5.13.

2.3.1 Model Plants

Model plants are a central structural component that IPM uses in three ways: (1) to represent aggregations of existing generating units, (2) to represent retrofit and retirement options that are available to existing units, and (3) to represent potential (new) units that the model can build.

Existing Units: Theoretically, there is no predefined limit on the number of units that can be included in IPM. However, to keep model size and solution time within acceptable limits, EPA utilizes model plants to represent aggregations of actual individual generating units. The aggregation algorithm groups units with similar characteristics for representation by model plants with a combined capacity and weighted-average characteristics that are representative of all the units comprising the model plant. Model plants are defined to maximize the accuracy of the model's cost and emissions estimates by capturing variations in key features of those units that are critical in the base case and anticipated policy case runs. For EPA Base Case v.5.13, IPM employed an aggregation algorithm which allowed 16,330 actual existing electric generating units to be represented by 4,971 model plants. Section 4.2.6 describes the aggregation procedure used in the EPA Base Case v.5.13.

Retrofit and Retirement Options: IPM also utilizes model plants to represent the retrofit and retirement options that are available to existing units. EPA Base Case v.5.13 provides existing model plants with a wide range of options for retrofitting with emission control equipment as well as with an option to retire. (See Chapters 5 and section 7.3 in Chapter 7 for a detailed discussion of the options that are included in the EPA Base Case v.5.13.) EPA Base Case v.5.13 model plants that represent potential (new) units are not given the option to take on a retrofit or retire.

The options available to each model plant are pre-defined at the model's set-up. The retrofit and retirement options are themselves represented in IPM by model plants, which, if actuated in the course of a model run, take on all or a portion of the capacity initially assigned to a model plant which represents existing generating units [2]. In setting up IPM, parent-child-grandchild relationships are pre-defined between each existing model plant (parent) and the specific retrofit and retirement model plants (children and grandchildren) that may replace the parent model plant during the course of a model run. The "child" and "grandchild" model-plants are inactive in IPM unless the model finds it economical to engage one of the options provided, e.g., retrofit with particular emission controls or retire.

Theoretically, there are no limits on the number of "child," "grandchild," and even "great-grandchild" model plants (i.e., retrofit and retirement options) that can be associated with each existing model plant. However, model size and computational considerations dictate that the number of successive retrofits be limited. In EPA Base Case v.5.13, a maximum of three stages of retrofit options are provided (child, grandchild and great-grandchild). For example, an existing model plant may retrofit with a limestone forced oxidation (LSFO) SO_2 scrubber and with a selective catalytic reduction (SCR) control for NO_x in one model run year (stage 1), with an activated carbon injection (ACI) for mercury control in the same or subsequent run year (stage 2) and with a CCS for CO_2 control in the same or subsequent run year (stage 3). However, if it exercises this succession of retrofit options, no further retrofit or retirement options are possible beyond the third stage.

Potential (New) Units: IPM also uses model plants to represent new generation capacity that may be built during a model run. All the model plants representing new capacity are pre-defined at set-up, differentiated by type of technology, regional location, and years available. When it is economically advantageous to do so (or otherwise required by reserve margin constraints to maintain electric reliability), IPM "builds" one or more of these predefined model plants by raising its generation capacity from zero during the course of a model run. In determining whether it is economically advantageous to "build" new plants, IPM takes into account cost differentials between technologies, expected technology

[2] IPM has a linear programming structure whose decision variables can assume any value within the specified bounds subject to the constraints. Therefore, IPM can generate solutions where model plants take retrofits/retire a portion of the model plants capacity. IPM's standard model plant outputs explicitly present these partial investment decisions.

cost improvements (by differentiating costs based on a plant's vintage, i.e., build year) and regional variations in capital costs that are expected to occur over time.

Since EPA Base Case v.5.13 results are presented at the model plant level, EPA has developed a post-processor "parsing" tool designed to translate results at the model plant level into generating unit-specific results. The parsing tool produces unit-specific emissions, fuel use, emission control retrofit and capacity projections based on model plant results. Another post-processing activity involves deriving inputs for air quality modeling from IPM outputs. This entails using emission factors to derive the levels of pollutants needed in EPA's air quality models from emissions and other parameters generated by IPM. It also involves using decision rules to assign point source locators to these emissions. (See Figure 1-1 for a graphical representation of the relationship of the post-processing tools to the overall IPM structure. The air quality ready flat file documentation is available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCase513.html)

2.3.2 Model Run Years

Another important structural feature of IPM is the use of model run years to represent the full planning horizon being modeled. Mapping each year in the planning horizon into a representative model run year enables IPM to perform multiple year analyses while keeping the model size manageable. Although IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. (See section 2.3.3 below for further details.)

Often models like IPM include a final model run year that is not included in the analysis of results. This technique reduces the likelihood that modeling results in the last represented year will be skewed due to the modeling artifact of having to specify an end point in the planning horizon, whereas, in reality, economic decision-making will continue to take information into account from years beyond the model's time horizon. Due to the number of model run years required by EPA for analytical purposes (seven in the 2016-2050 time period) and a greatly expanded suite of modeling capabilities, such an approach could not be used in EPA Base Case v.5.13. It would have increased the model's size beyond acceptable solution time constraints. However, boundary distortions are a potential factor only for results in 2050, the last modeled year. In addition, any tendency toward end-year distortions should be reduced by the longer modeling time horizon of this base case and by the relatively large number of calendar years (9) that are mapped into model run year 2050 (see Table 7-1)[3]. Nevertheless, the possibility of residual boundary effects is something to bear in mind when interpreting the model's results from the 2050 run year.

2.3.3 Cost Accounting

As noted earlier in the chapter, IPM is a dynamic linear programming model that finds the least cost investment and electricity dispatch strategy for meeting electricity demand subject to resource availability and other operating and environmental constraints. The cost components that IPM takes into account in deriving an optimal solution include the costs of investing in new capacity options, the cost of installing and operating pollution control technology, fuel costs, and the operation and maintenance costs associated with unit operations. Several cost accounting assumptions are built into IPM's objective function that ensures a technically sound and unbiased treatment of the cost of all investment options offered in the model. These features include:

[3] The primary impact of end year distortion occurs on the investment decisions as they are made by the model while accounting for costs and revenues over a short (number of years mapped to that run year) time period. As the number of years mapped to the last run year increases, more of the costs and revenues of the plant's life are captured and thus improving the quality of the decision.

The longer modeling horizon does not directly reduce the end year distortion. However, the discounting occurring over a longer time period does reduce the impact of the end year results on the overall model solution.

All costs in IPM's single multi-year objective function are discounted to a base year. Since the model solves for all run years simultaneously, discounting to a common base year ensures that IPM properly captures complex inter-temporal cost relationships.

Capital costs in IPM's objective function are represented as the net present value of levelized stream of annual capital outlays, not as a one-time total investment cost. The payment period used in calculating the levelized annual outlays never extends beyond the model's planning horizon: it is either the book life of the investment or the years remaining in the planning horizon, whichever is shorter. This approach avoids presenting artificially higher capital costs for investment decisions taken closer to the model's time horizon boundary simply because some of that cost would typically be serviced in years beyond the model's view. This treatment of capital costs ensures both realism and consistency in accounting for the full cost of each of the investment options in the model.

The cost components informing IPM's objective function represent the composite cost over all years in the planning horizon rather than just the cost in the individual model run years. This permits the model to capture more accurately the escalation of the cost components over time.

2.3.4 Modeling Wholesale Electricity Markets

Another important methodological feature worth noting about IPM is that it is designed to simulate electricity production activity in a manner that would minimize production costs, as is the intended outcome in wholesale electricity markets. For this purpose, the model captures transmission costs and losses between IPM model regions, but it is not designed to capture retail distribution costs. However, the model implicitly includes distribution losses since net energy for load,[4] rather than delivered sales,[5] is used to represent electricity demand in the model. Additionally, the production costs calculated by IPM are the wholesale production costs. In reporting costs, the model does not include embedded costs, such as carrying charges of existing units, that may ultimately be part of the retail cost incurred by end-use consumers.

2.3.5 Load Duration Curves (LDC)

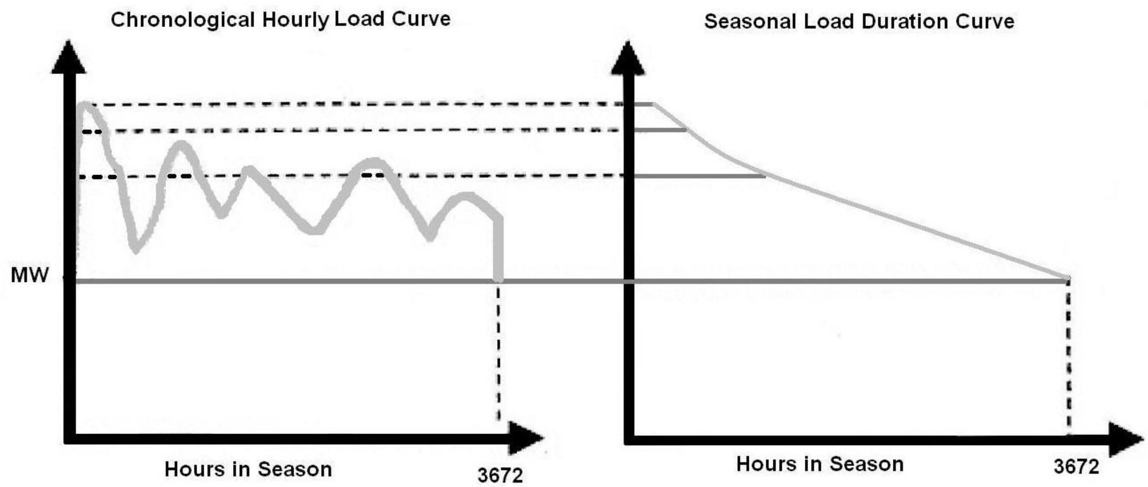
IPM uses Load Duration Curves (LDCs) to provide realism to the dispatching of electric generating units. Unlike a chronological electric load curve, which is simply an hourly record of electricity demand, the LDCs are created by rearranging the hourly chronological electric load data from the highest to lowest (MW) value. In order to aggregate such load detail into a format enabling this scale of power sector modeling, EPA applications of IPM use a 6-step piecewise linear representation of the LDC.

IPM can include any number of separate LDCs for any number of user-defined seasons. A season can be a single month or several months. For example, EPA Base Case v.5.13 contains two seasons: summer (May 1 – September 30) and winter (October 1– April 30). Separate summer and winter LDCs are created for each of IPM's model regions. Figure 2-1 below presents side-by-side graphs of a hypothetical chronological hourly load curve and a corresponding load duration curve for a season consisting of 3,672 hours.

[4] Net energy for load is the electrical energy requirements of an electrical system, defined as system net generation, plus energy received from others, less energy delivered to others through interchange. It includes distribution losses.

[5] Delivered sales is the electrical energy delivered under a sales agreement. It does not include distribution losses.

Figure 2-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve in EPA Base Case v.5.13



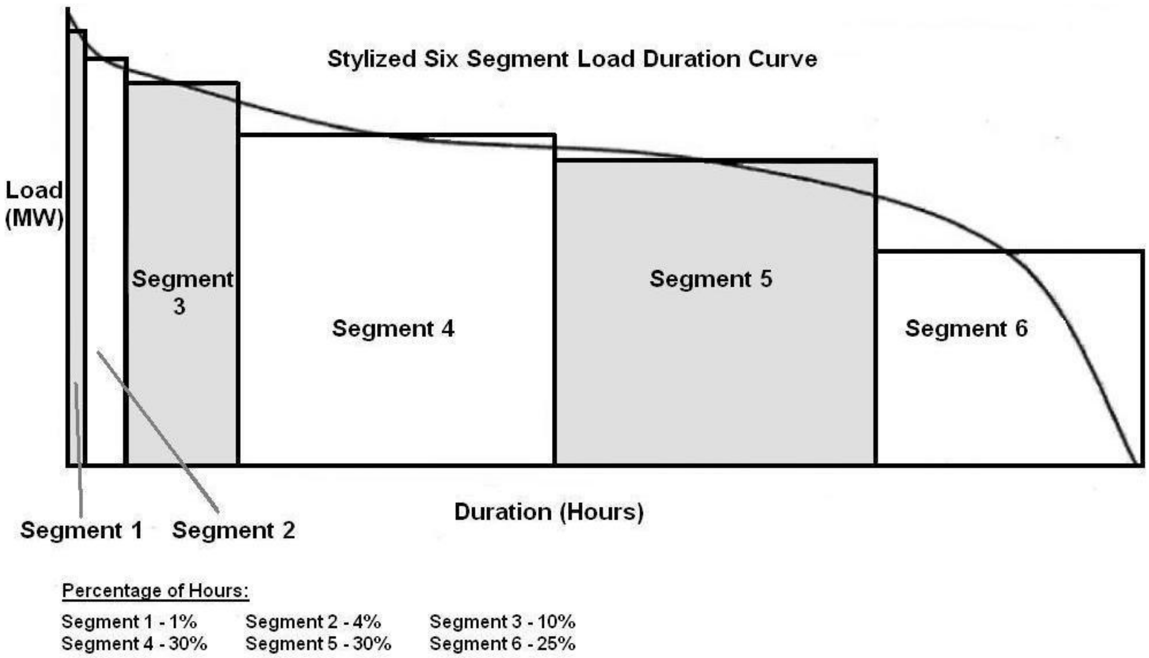
Regional forecasts of peak and total electricity demand (from AEO 2013 for EPA Base Case v5.13) and hourly load curves from FERC Form 714 and ISO/RTOs (2011 for EPA Base Case v5.13) are used to derive future seasonal load duration curves for each IPM run year in each IPM region. The results of this process are individualized seasonal LDCs that capture the unique hourly electricity demand profile of each region. The LDCs change over time to reflect projected changes in load factors.

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 2-2. EPA Base Case v.5.13 uses six load segments in its seasonal LDCs for model run years 2016-2030 and four load segments in its LDCs for model run years 2040 and 2050. The reduced number of load segments in the later years was adopted out of model size considerations and a view that having a finer grained representation of dispatch was less important that far into the future. Figure 2-2 illustrates and the following text describes the 6-segment LDCs used in the base case's earlier years. Length of time and system demand are the two parameters which define each segment of the load duration curve. The load segment represents the amount of time (along the x-axis) and the capacity that the electric dispatch mix must be producing (represented along the y-axis) to meet system load. Segment 1 in Figure 2-2 generally contains one percent of the hours in the period (i.e., "season") but represents the highest load demand value. IPM has the flexibility to model any number of load segments; however, the greater the number of segments, the greater the computational time required to reach a solution. The LDC shows all the hourly electricity load levels that must be satisfied in a region in a particular season of a particular model run year. Segment 1 (the "super peak" load segment with 1% of all the hours in the season) and Segment 2 (the "peak" load segment with 4% of all the hours in the season) represent all the hours when load is at the highest demand levels. Segments 2 through 6 represent hourly loads at progressively lower levels of demand. Plants are dispatched to meet this load based on economic considerations and operating constraints. The most cost effective plants are assigned to meet load in all 6 segments of the load duration curve. This is discussed in greater detail in section 2.3.6 below. In 2040 and 2050 run years, segments 1 & 2 are aggregated into a single segment and segments 3 & 4 are aggregated into a single segment for a total of 4 segments.

Use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, in most regions air conditioner cycling only impacts customer demand patterns during the summer season. The use of seasonal LDCs also allows IPM to capture seasonal variations in the generation resources available to respond to the customer demand depicted in an LDC. For example, power exchanges between utility systems may be seasonal in nature. Some air regulations affecting power plants are also seasonal in nature. This can impact the type of generating resources that are dispatched during a particular season. Further, because of maintenance scheduling for individual generating units, the capacity and utilization for these supply resources also vary between seasons.

Attachment 2-1 contains data of the 2012 summer and winter load duration curves in each of the 64 model regions in the lower continental U.S. for EPA Base Case v.5.13.

Figure 2-2 Stylized Depiction of Load Duration Curve Used in EPA Base Case v.5.13

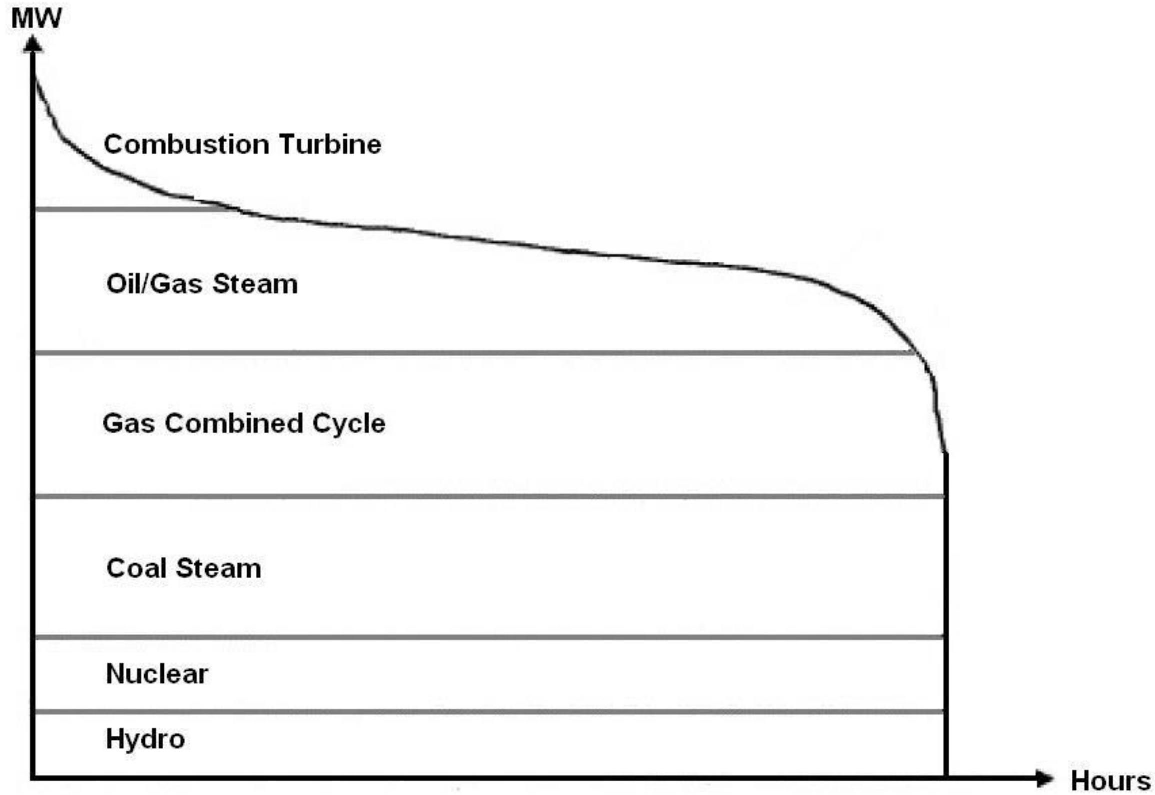


2.3.6 Dispatch Modeling

In IPM, the dispatching of electricity is based on the variable cost of generation. In the absence of any operating constraints, units with the lowest variable cost generate first. The marginal generating unit, i.e., the power plant that generates the last unit of electricity, sets the energy price. Physical operating constraints also influence the dispatch order. For example, IPM uses turndown constraints to prevent base load units from cycling, i.e., switching on and off. Turndown constraints often override the dispatch order that would result based purely on the variable cost of generation. Variable costs in combination with turndown constraints enable IPM to dispatch generation resources in a technically realistic fashion.

Figure 2-3 below depicts a highly stylized dispatch order based on the variable cost of generation of the resource options included in the EPA Base Case v.5.13. In Figure 2-3, a hypothetical load duration curve is subdivided according to the type of generation resource that responds to the load requirements represented in the curve. Notice that the generation resources with the lowest operating cost (i.e., hydro and nuclear) respond first to the demand represented in the LDC and are accordingly at the bottom of "dispatch stack." They are dispatched for the maximum possible number of hours represented in the LDC because of their low operating costs. Generation resources with the highest operating cost (e.g., peaking turbines) are at the top of the "dispatch stack," since they are dispatched last and for the minimum possible number of hours.

Figure 2-3 Stylized Dispatch Order in EPA Base Case v.5.13



Note: Figure 2-3 does not include all the plant types that are modeled in EPA Base Case v.5.13. Intermittent renewable technologies such as wind and solar are considered non dispatchable and are assigned a specific hourly generation profile.

2.3.7 Fuel Modeling

Another key methodological feature of IPM is its capability to model the full range of fuels used for electric power generation. The cost, supply, and (if applicable) quality of each fuel included in the model are defined during model set-up. Fuel price and supply are represented in EPA Base Case v.5.13 in one of three alternative ways: (1) through an embedded modeling capability that dynamically balances supply and demand to arrive at fuel prices (natural gas), (2) through a set of supply curves (coal and biomass) or (3) through an exogenous price stream (fuel oil and nuclear fuel). With the first and second approaches, the model endogenously determines the price for that fuel by balancing the supply and demand. IPM uses fuel quality information (e.g., the sulfur, chlorine or mercury content of different types of coal from different supply regions) to determine the emissions resulting from combustion of that fuel.

EPA Base Case v.5.13 includes coal, natural gas, fuel oil, nuclear fuel, biomass, and fossil and non-fossil waste as fuels for electric generation. The specific base case assumptions for these fuels are examined in chapters 9 to 11.

2.3.8 Transmission Modeling

IPM includes a detailed representation of existing transmission capabilities between model regions. The maximum transmission capabilities between regions are specified in IPM's transmission constraints. Due to uncertainty surrounding the building of new transmission lines in the U.S., EPA Base Case v5.13 does not exercise IPM's capability to model the building of new transmission lines. However, that capacity of the model is described here in case it is applied in future analyses. Additions to transmission lines are represented by decision variables defined for each eligible link and model run year. In IPM's objective function, the decision variables representing transmission additions are multiplied by new transmission line investment cost and capital charge rates to obtain the capital cost associated with the transmission addition. The specific transmission assumptions in EPA Base Case v.5.13 are described in section 3.3.

2.3.9 Perfect Competition and Perfect Foresight

Two key methodological features of IPM are its assumptions of perfect competition and perfect foresight. The former means that IPM models production activity in wholesale electric markets on the premise that these markets subscribe to all assumptions of perfect competition. The model does not explicitly capture any market imperfections such as market power, transaction costs, informational asymmetry or uncertainty. However, if desired, appropriately designed sensitivity analyses or redefined model parameters can be used to gauge the impact of market imperfections on the wholesale electric markets.

IPM's assumption of perfect foresight implies that agents know precisely the nature and timing of conditions in future years that affect the ultimate costs of decisions along the way. For example, under IPM there is complete foreknowledge of future electricity demand, fuel supplies, and other variables (including regulatory requirements) that in reality are subject to uncertainty and limited foresight. Modelers frequently assume perfect foresight in order to establish a decision-making framework that can estimate cost-minimizing courses of action given the best-guess expectations of these future variables that can be constructed at the time the projections are made.

2.3.10 Air Regulatory Modeling

One of the most notable features of IPM is its detailed and flexible modeling of air regulations. Treatment of air regulations is endogenous in IPM. That is, by providing a comprehensive representation of compliance options, IPM enables environmental decisions to be made within the model based on least cost considerations, rather than exogenously imposing environmental choices on model results. For example, unlike other models that enter allowance prices as an exogenous input during model set-up, IPM obtains allowance prices as an output of the endogenous optimization process of finding the least cost compliance options in response to air regulations. (In linear programming terminology, they are the "shadow prices" of the respective emission constraints — a standard output produced in solving a linear programming problem.) IPM can capture a wide variety of regulatory program designs including emissions trading policies, command-and-control policies, and renewable portfolio standards. IPM's representation of emissions trading policies can include allowance banking, trading, borrowing, bonus allowance mechanisms, and progressive flow controls. Air regulations can be tailored to specific geographical regions and can be restricted to specific seasons. Many of these regulatory modeling capabilities are exploited in EPA Base Case v.5.13.

2.4 Hardware and Programming Features

IPM produces model files in standard MPS linear programming format. IPM runs on most PC-platforms. Its hardware requirements are highly dependent on the size of a particular model run. For example, with almost 16.6 million decision variables and 1.8 million constraints, EPA Base Case v.5.13 is run on a 64 bit Enterprise Server - Windows 2008 R2 platform with two Intel Xeon X5675 3.07 GHz processors and 72 GB of RAM. Due to the size of the EPA base case, a commercial grade solver is required. (Benchmarking tests performed by EPA's National Environmental Scientific Computing Center using research grade solvers yielded unacceptable results.) For current EPA applications of IPM, the FICO Xpress Optimization Suite 7.5 (64 bit with multi-threads barrier and MIP capabilities) linear programming solvers are used.

Two data processors -- a front-end and the post-processing tool -- support the model. The front-end creates the necessary inputs to be used in IPM, while the post-processing tool maps IPM model-plant level outputs to individual generating units (a process called "parsing," see section 2.3.1) and creates input files in flat file format as needed by EPA's air quality models.

Before it can be run, the model requires an extensive set of input parameters. These are discussed in Section 2.4.1 below. Results of model runs are presented in a series of detailed reports. These are described in Section 2.4.2 below.

2.4.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the US electric system, economic outlook, fuel supply and air regulatory framework. Chapters 3-11 contain detailed discussions of the values assigned to these parameters in EPA Base Case v.5.13. This section simply lists the key input parameters required by IPM:

Electric System

Existing Generating Resources

- Plant Capacities
- Heat Rates
- Maintenance Schedule
- Forced Outage Rate
- Minimum Generation Requirements (Turn Down Constraint)
- Fuels Used
- Fixed and Variable O&M Costs
- Emissions Limits or Emission Rates for NO_x, SO_2, HCl, CO_2, Mercury
- Existing Pollution Control Equipment and Retrofit Options
- Output Profile for Non-Dispatchable Resources

New Generating Resources

- Cost and Operating Characteristics
- Performance Characteristics
- Limitations on Availability

Other System Requirements

- Inter-regional Transmission Capabilities
- Reserve Margin Requirements for Reliability
- Area Protection
- System Specific Generation Requirements
- Regional Specification

Economic Outlook

Electricity Demand

- Firm Regional Electricity Demand
- Load Curves

Financial Outlook

- Capital Charge Rate
- Discount Rate

Fuel Supply

Fuel Supply Curves for Coal and Biomass

- Embedded Natural Gas Model
- Fuel Price
- Fuel Quality
- Transportation Costs for Coal, Natural Gas, and Biomass

Air Regulatory Outlook

Air Regulations for NO_x, SO_2, HCl, CO_2, and Mercury

- Other Air Regulations

2.4.2 Model Outputs

IPM produces a variety of output reports. These range from extremely detailed reports, which describe the results for each model plant and run year, to summary reports, which present results for regional and national aggregates. Individual topic areas can be included or excluded at the user's discretion. Standard IPM reports cover the following topics:

- Generation
- Capacity mix
- Capacity additions and retirements
- Capacity and energy prices
- Power production costs (capital, VOM, FOM and fuel costs)
- Fuel consumption
- Fuel supply and demand
- Fuel prices for coal, natural gas, and biomass
- Emissions (NO_x, SO_2, HCl, CO_2, and Mercury)
- Emission allowance prices

Attachment 2-1 Load Duration Curves[a] Used in EPA Base Case v.5.13

This is a small excerpt of the data in Attachment 2-1. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.htm

Month	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Hours	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Day Hours	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	1	2
ERC_REST	29,087	29,081	29,428	30,073	31,131	32,672	33,837	34,243	33,469	32,063	30,593	29,370	28,122	27,173	26,764	27,133	29,534	32,765	33,125	33,279	32,700	31,281	29,582	28,464	28,103	28,113
ERC_WEST	2,655	2,678	2,726	2,765	2,836	2,903	2,961	3,110	2,989	2,762	2,582	2,490	2,358	2,249	2,188	2,181	2,350	2,603	2,716	2,750	2,749	2,713	2,593	2,579	2,565	2,585
FRCC	17,709	16,861	16,336	16,045	15,996	16,303	16,879	17,602	19,095	20,808	21,921	22,566	22,995	23,070	22,956	22,784	22,750	23,609	25,136	24,741	23,876	22,478	20,971	19,160	17,682	16,839
MAP_WAUE	2,551	2,528	2,531	2,545	2,577	2,654	2,733	2,749	2,772	2,750	2,746	2,692	2,666	2,628	2,661	2,786	2,939	2,943	2,885	2,805	2,756	2,637	2,562	2,490	2,478	2,502
MIS_IA	2,332	2,308	2,276	2,266	2,262	2,275	2,324	2,372	2,408	2,433	2,440	2,442	2,437	2,414	2,400	2,393	2,431	2,526	2,620	2,596	2,573	2,536	2,442	2,348	2,292	2,259
MIS_IL	5,892	5,842	5,823	5,855	5,911	6,045	6,207	6,299	6,319	6,281	6,250	6,204	6,143	6,071	6,019	6,059	6,313	6,693	6,774	6,765	6,691	6,539	6,333	6,149	6,066	6,039
MIS_INKY	10,885	10,709	10,617	10,588	10,645	10,757	11,010	11,302	11,470	11,525	11,482	11,438	11,368	11,272	11,157	11,088	11,206	11,701	12,306	12,417	12,382	12,225	11,929	11,548	11,230	11,087
MIS_LMI	10,211	9,916	9,712	9,605	9,552	9,557	9,629	9,793	10,034	10,198	10,389	10,547	10,623	10,680	10,675	10,675	10,665	10,839	11,503	11,984	11,971	11,813	11,458	11,025	10,605	10,292
MIS_MAPP	967	943	927	919	916	920	930	956	980	993	1,000	1,001	994	992	984	977	985	1,022	1,080	1,089	1,073	1,051	1,020	976	945	926
MIS_MIDA	3,205	3,172	3,128	3,115	3,109	3,127	3,194	3,260	3,310	3,345	3,354	3,357	3,350	3,318	3,299	3,289	3,341	3,472	3,602	3,569	3,536	3,486	3,356	3,227	3,150	3,105
MIS_MNWI	10,338	10,083	9,916	9,828	9,799	9,841	9,949	10,226	10,474	10,620	10,697	10,701	10,631	10,611	10,519	10,451	10,532	10,928	11,552	11,648	11,470	11,235	10,904	10,430	10,108	9,898
MIS_MO	5,133	5,049	5,004	4,988	5,022	5,073	5,205	5,358	5,446	5,465	5,423	5,391	5,345	5,289	5,218	5,170	5,213	5,462	5,820	5,892	5,882	5,810	5,664	5,467	5,299	5,225
MIS_WUMS	5,657	5,529	5,462	5,427	5,429	5,476	5,580	5,732	5,832	5,944	6,032	6,075	6,104	6,101	6,100	6,095	6,191	6,523	6,739	6,732	6,663	6,499	6,288	6,063	5,884	5,793
NENG_CT	3,117	3,006	2,948	2,921	2,932	2,969	3,047	3,145	3,308	3,466	3,555	3,608	3,635	3,620	3,602	3,642	3,856	4,069	4,053	3,988	3,894	3,736	3,531	3,330	3,211	3,141
NENG_ME	954	878	850	851	874	919	997	1,111	1,238	1,343	1,399	1,399	1,403	1,369	1,343	1,336	1,515	1,645	1,595	1,516	1,420	1,258	1,128	1,025	970	935
NENGREST	7,761	7,478	7,318	7,265	7,278	7,413	7,680	7,987	8,432	8,906	9,194	9,357	9,419	9,401	9,354	9,432	10,064	10,580	10,519	10,300	9,987	9,496	8,896	8,332	7,986	7,797
NY_Z_A&B	2,064	2,003	1,955	1,945	1,958	1,996	2,057	2,132	2,201	2,288	2,352	2,393	2,435	2,444	2,457	2,471	2,565	2,757	2,776	2,752	2,701	2,608	2,465	2,317	2,215	2,166

[a] The load curves for EPA Base Case v.5.13 are complied using data from 2011 FERC Form 714, ISO and RTO data.

3. Power System Operation Assumptions

This section describes the assumptions pertaining to the North American electric power system as represented in EPA Base Case v.5.13.

3.1 Model Regions

EPA Base Case v.5.13 models the US power sector in the contiguous 48 states and the District of Columbia and the Canadian power sector in the 10 provinces (with Newfoundland and Labrador represented as two regions on the electricity network even though politically they constitute a single province[6]) as an integrated network.

There are 64 IPM model regions covering the US 48 states and District of Columbia. The IPM model regions are approximately consistent with the configuration of the NERC assessment regions in the NERC Long-Term Reliability Assessments. These IPM model regions reflect the administrative structure of regional transmission organizations (RTOs) and independent system operators (ISOs). Further disaggregation of the NERC assessment regions and RTOs allows a more accurate characterization of the operation of the US power markets by providing the ability to represent transmission bottlenecks across RTOs and ISOs, as well as key transmission limits within them.

The IPM regions also provide disaggregation of the regions of the National Energy Modeling System (NEMS) to provide for a more accurate correspondence with the demand projections of the Annual Energy Outlook (AEO). Notable disaggregations are further described below:

NERC assessment regions MISO and PJM cover the areas of the corresponding RTOs and are designed to better represent transmission limits and dispatch in each area. In IPM, the MISO area is disaggregated into 9 IPM regions and the PJM assessment area is disaggregated into 9 IPM regions, where the IPM regions are selected to represent planning areas within each RTO and/or areas with internal transmission limits.

New York is now disaggregated into 7 IPM regions, to better represent flows around New York City and Long Island, and to better represent flows across New York state from Canada and other US regions.

The NERC assessment region SERC is divided into North, South, West and Southeast areas; IPM further disaggregates the North and West areas to better represent transmission between areas, including disaggregating SERC-West into four IPM regions to reflect transmission constraints in Southern Louisiana.

IPM retains the NERC assessment areas within the overall WECC regions, and further disaggregates these areas using sub-regions from the WECC Power Supply Assessment.

The 11 Canadian model regions are defined strictly along provincial political boundaries.

Figure 3-1 contains a map showing all the EPA Base Case 5.13 model regions. Using these shares of each NEMS region net energy for load that falls in each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in AEO 2013.

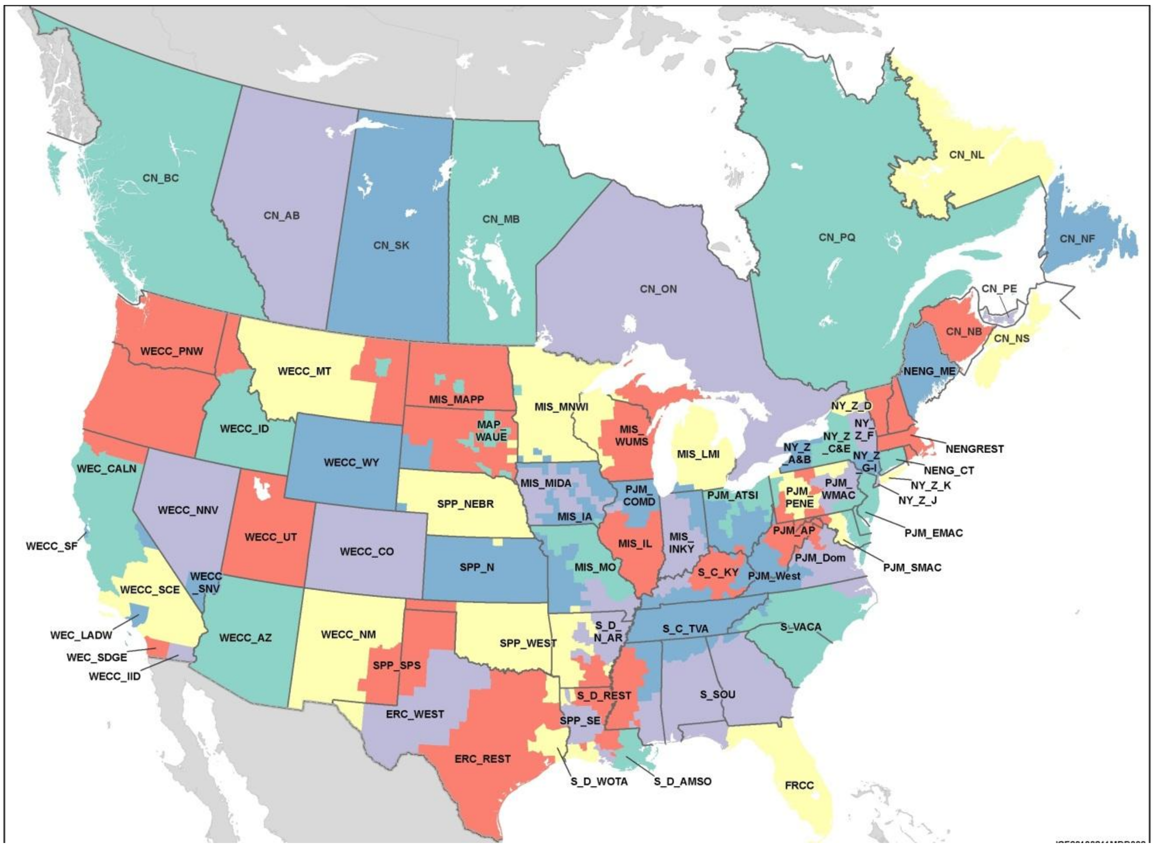
Table 3-1 defines the abbreviated region names appearing on the map and gives a crosswalk between the IPM model regions, the NERC assessment regions, and regions used in the Energy Information Administration's (EIA's) National Energy Model System (NEMS) which is the basis for EIA's Annual Energy Outlook (AEO) reports.

[6] This results in a total of 11 Canadian model regions being represented in EPA Base Case v.5.13.

3.2 Electric Load Modeling

Net energy for load and net internal demand are inputs to IPM that together are used to represent the grid-demand for electricity. Net energy for load is the projected annual electric grid-demand, prior to accounting for intra-regional transmission and distribution losses. Net internal demand (peak demand) is the maximum hourly demand within a given year after removing interruptible demand. Table 3-2 shows the electricity demand assumptions (expressed as net energy for load) used in EPA Base Case v.5.13. It is based on the net energy for load in AEO 2013.[7]

Figure 3-1 EPA Base Case v.5.13 Model Regions



For purposes of documentation, Table 3-2 presents the national net energy for load. However, EPA Base Case v.5.13 models regional breakdowns of net energy for load in each of the 64 IPM US regions in the following steps:

- The net energy for load in each of the 22 NEMS electricity regions is taken from the NEMS reference case.
- NERC balancing areas are assigned to both IPM regions and NEMS regions to determine the share of the NEMS net energy for load in each NEMS regions that falls into each IPM region. These shares are calculated in the following steps.
    - Map the NERC Balancing Authorities/ Planning Areas in the US to the 64 IPM regions.

[7] The electricity demand in EPA Base Case v.5.13 for the U.S. lower 48 states and the District of Columbia is obtained for each IPM model region by disaggregating the "Total Net Energy for Load" projected for the corresponding NEMS Electric Market Module region as reported in the Electricity and Renewable Fuel Tables 73-120" at http://www.eia.gov/forecasts/aeo/tables_ref.cfm.

- Map the Balancing Authorities/ Planning Areas in the US to the 22 NEMS regions.
- Using the 2007 data from FERC Form 714 on net energy for load in each of the balancing areas, calculate the proportional share of each of the net energy for load in 22 NEMS regions that falls in each of the 64 IPM Regions.

- Using these shares of each NEMS region net energy for load that falls in each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in AEO 2013.

Table 3-1 Mapping of NERC Regions and NEMS Regions with EPA Base Case v.5.13 Model Regions

NERC Assessment Region	AEO 2013 NEMS Region	Model Region	Model Region Description
ERCOT[a]	ERCT (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
		ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
		ERC_REST	ERCOT_Rest
		ERC_WEST	ERCOT_West
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MROW (4)	MAP_WAUE	MAPP_WAUE
		MIS_MAPP	MISO_MT, SD, ND
MISO	MROE (3), RFCW (11)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
	MROW (4)	MIS_IA	MISO_Iowa
		MIS_MIDA	MISO_Iowa-MidAmerican
		MIS_MNWI	MISO_Minnesota and Western Wisconsin
	RFCM (10)	MIS_LMI	MISO_Lower Michigan
	RFCW (11), SRCE (15)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	SRGW (13)	MIS_IL	MISO_Illinois
		MIS_MO	MISO_Missouri
ISO-NE	NEWE (5)	NENG_CT	ISONE_Connecticut
		NENG_ME	ISONE_Maine
		NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
NYISO	NYCW (6)	NY_Z_J	NY_Zone J (NYC)
	NYLI (7)	NY_Z_K	NY_Zone K (LI)
	NYUP (8)	NY_Z_A&B	NY_Zones A&B
		NY_Z_C&E	NY_Zone C&E
		NY_Z_D	NY_Zones D
		NY_Z_F	NY_Zone F (Capital)
	NYUP (8), NYCW (6)	NY_Z_G-I	NY_Zone G-I (Downstate NY)
PJM	RFCE (9)	PJM_EMAC	PJM_EMAAC
		PJM_PENE	PJM_PENELEC
		PJM_SMAC	PJM_SWMAAC
		PJM_WMAC	PJM_Western MAAC
	RFCW (11)	PJM_AP	PJM_AP
		PJM_ATSI	PJM_ATSI
		PJM_COMD	PJM_ComEd
		PJM_West	PJM West
	SRVC (16)	PJM_Dom	PJM_Dominion
SERC-E	SRVC (16)	S_VACA	SERC_VACAR
SERC-N	SRCE (15)	S_C_KY	SERC_Central_Kentucky

NERC Assessment Region	AEO 2013 NEMS Region	Model Region	Model Region Description
		S_C_TVA	SERC_Central_TVA
SERC-SE	SRSE (14)	S_SOU	SERC_Southeastern
SERC-W	SRDA (12)	S_D_AMSO	SERC_Delta_Amite South (including DSG)
		S_D_WOTA	SERC_Delta_WOTAB (including Western)
		S_D_REST	SERC_Delta_Rest of Delta (Central Arkansas)
	SRDA (12), SRCE (15)	S_D_N_AR	SERC_Delta_Northern Arkansas (including AECI)
SPP[b]	MROW (4)	SPP_NEBR	SPP Nebraska
	SPNO (17), SRGW (13)	SPP_N	SPP North- (Kansas, Missouri)
	SPSO (18)	SPP_KIAM	SPP_Kiamichi Energy Facility
		SPP_SE	SPP Southeast (Louisiana)
		SPP_SPS	SPP SPS (Texas Panhandle)
	SPSO (18), SRDA (12)	SPP_WEST	SPP West (Oklahoma, Arkansas, Louisiana)
Basin (BASN)	NWPP (21)	WECC_ID	WECC_Idaho
		WECC_NNV	WECC_Northern Nevada
		WECC_UT	WECC_Utah
Northern California (CALN)	CAMX (20)	WEC_CALN	WECC_Northern California (including SMUD)
		WECC_SF	WECC_San Francisco
Southern California (CALS)	AZNM (19)	WECC_IID	WECC_Imperial Irrigation District (IID)
	CAMX (20)	WEC_LADW	WECC_LADWP
		WEC_SDGE	WECC_San Diego Gas and Electric
		WECC_SCE	WECC_Southern California Edison
Northwest (NORW)	NWPP (21)	WECC_MT	WECC_Montana
		WECC_PNW	WECC_Pacific Northwest
Rockies (Rock)	NWPP (21), RMPA (22)	WECC_WY	WECC_Wyoming
	RMPA (22)	WECC_CO	WECC_Colorado
Desert Southwest (DSW)	AZNM (19)	WECC_AZ	WECC_Arizona
		WECC_NM	WECC_New Mexico
		WECC_SNV	WECC_Southern Nevada
Canada		CN_AB	Alberta
		CN_BC	British Columbia
		CN_MB	Manitoba
		CN_NB	New Brunswick
		CN_NF	Newfoundland
		CN_NL	Labrador
		CN_NS	Nova Scotia
		CN_ON	Ontario
		CN_PE	Prince Edward Island
		CN_PQ	Quebec
		CN_SK	Saskatchewan

[a] ERCOT_Tenaska Frontier Generating Station (ERC_FRNT) and ERCOT_Tenaska Gateway Generating Station (ERC_GWAY) regions in ERCOT are switching regions without any internal demand created to capture the ability to sell power to multiple power markets.

[b] SPP_Kiamichi Energy Facility [SPP_KIAM] region in SPP is a switching region without any internal demand created to capture the ability to sell power to multiple power markets.

Table 3-2 Electric Load Assumptions in EPA Base Case v.5.13

Year	Net Energy for Load (Billions of KWh)
2016	4,049
2018	4,135
2020	4,215
2025	4,390
2030	4,535
2040	4,887
2050	5,271

Notes:
This data is an aggregation of the model-region-specific net energy loads used in the EPA Base Case v.5.13.

3.2.1 Demand Elasticity

EPA Base Case v.5.13 has the capability to consider endogenously the relationship of the price of power to electricity demand. However, this capability is typically only exercised for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default base case assumption is that the electricity demand shown in Table 3-2, which was originally derived from EIA modeling that did consider price elasticity of demand, must be met as IPM solves for least-cost electricity supply. This approach maintains a consistent expectation of future load between the EPA Base Case and the corresponding EIA Annual Energy Outlook reference case (e.g., between EPA Base Case v5.13 and the AEO2013 reference case).

3.2.2 Net Internal Demand (Peak Demand)

EPA Base Case v5.13 has separate regional winter and summer peak demand values, as derived from each region's seasonal load duration curve (found in Attachment 2-1). Peak projections were estimated based on AEO 2013 load factors and the estimated energy demand projections shown in Table 3-2. Table 3-3 illustrates the national sum of each region's winter and summer peak demand. Because each region's seasonal peak demand need not occur at the same time, the national peak demand is defined as non-coincidental (i.e., national peak demand is a summation of each region's peak demand at whatever point in time that region's peak occurs across the given time period).

Table 3-3 National Non-Coincidental Net Internal Demand

	Peak Demand (GW)	
Year	Winter	Summer
2016	657	746
2018	670	761
2020	686	780
2025	725	826
2030	763	873
2040	845	972
2050	916	1,053

Notes:
This data is an aggregation of the model-region-specific peak demand loads used in the EPA Base Case v.5.13.

3.2.3 Regional Load Shapes

As of 2013, EPA has adopted year 2011 as the meteorological year in its air quality modeling. In order for EPA Base Case v.5.13 to be consistent, the year 2011 was selected as the "normal weather year"[8] for all IPM regions. The proximity of the 2011 cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) to the long-term average cumulative annual HHDs and CDDs over the period 1981 to 2010 was estimated and found to be reasonably close. The 2011 chronological hourly load data were assembled by aggregating individual utility load curves taken from Federal Energy Regulatory Commission Form 714 data and individual ISOs and RTOs.

3.3 Transmission

The United States and Canada can be broken down into several power markets that are interconnected by a transmission grid. As discussed earlier, EPA Base Case 5.13 characterizes the U.S. lower 48 states, the District of Columbia, and Canada into 75 different model regions by means of 61 power market regions and 3 power switching regions[9] in the U.S. and 11 power market regions in Canada. EPA Base Case 5.13 includes explicit assumptions regarding the transmission grid connecting these modeled power markets. This section details the assumptions about the transfer capabilities, wheeling costs and inter-regional transmission used in EPA Base Case 5.13.

3.3.1 Inter-regional Transmission Capability

Table 3-4[10] shows the firm and non-firm Total Transfer Capabilities (TTCs) between model regions. TTC is a metric that represents the capability of the power system to import or export power reliably from one region to another. The purpose of TTC analysis is to identify the sub-markets created by key commercially significant constraints. Firm TTCs, also called Capacity TTCs, specify the maximum power that can be transferred reliably, even after the contingency loss of a single transmission system element such as a transmission line or a transformer (a condition referred to as N-1, or "N minus one"). Firm TTCs provide a high level of reliability and are therefore used for capacity transfers. Non-firm TTCs, also called Energy TTCs, represent the maximum power that can be transferred reliably when all facilities are under normal operation (a condition referred to as N-0, or "N minus zero"). They specify the sum of the maximum firm transfer capability between sub-regions and incremental curtailable non-firm transfer capability. Non-firm TTCs are used for energy transfers since they provide a lower level of reliability than Firm TTCs, and transactions using Non-firm TTCs can be curtailed under emergency or contingency conditions.

Table 3-4 Annual Transmission Capabilities of U.S. Model Regions in EPA Base Case v.5.13

From	To	2016		2018		Transmission Tariff (2011 mills/kWh)
		Capacity TTC (MW)	Energy TTC (MW)	Incremental Capacity TTC (MW)	Incremental Energy TTC (MW)	
ERC_FRNT	ERC_REST	860	860			0
	SPP_WEST	860	860			6

[8] The term "normal weather year" refers to a representative year whose weather is closest to the long-term (e.g., 35 year) average weather. The selection of a "normal weather year" can be made, for example, by comparing the cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) in a candidate year to the long-term average. For any individual day, heating degree days indicate how far the average temperature fell below 65 degrees F; cooling degree days indicate how far the temperature averaged above 65 degrees F. Cumulative annual heating and cooling degree days are the sum of all the HDDs and CDDs, respectively, in a given year.

[9] Power switching regions are regions with no market load that represent individual generating facilities specifically configured so they can sell directly into either ERCOT or SPP: these plants are implemented in IPM as regions with transmission links only to ERCOT and to SPP.

[10] In the column headers in Table 3-4 the term "Energy TTC (MW)" is equivalent to non-firm TTCs and the term "Capacity TTC (MW)" is equivalent to firm TTCs.

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
ERC_GWAY	ERC_REST	845	845			0
	SPP_WEST	845	845			6
ERC_REST	ERC_WEST	5,529	5,529			0
	SPP_WEST	600	600			6
ERC_WEST	ERC_REST	10,555	10,555			0
	SPP_WEST	220	220			6
FRCC	S_SOU	3,600	3,600			8
MAP_WAUE	CN_SK	0	100			8
	MIS_IA	0	100			6
	MIS_MAPP	1,000	1,500			0
	MIS_MIDA	600	1,000			6
	MIS_MNWI	2,000	3,000			6
	SPP_NEBR	700	1,000			6
MIS_IA	MAP_WAUE	0	100			6
	MIS_IL	0	100			0
	MIS_MIDA	900	2,000			0
	MIS_MNWI	1,195	2,000			0
	MIS_MO	223	711			0
	PJM_COMD	0	600			3
	S_D_N_AR	0	100			1
MIS_IL	MIS_IA	0	100			0
	MIS_INKY	240	1,195			0
	MIS_MIDA	0	100			0
	MIS_MO	3,400	4,500			0
	PJM_COMD	2,500	3,000			3
	PJM_West	0	1,300			3
	S_C_TVA	1,200	1,500			6
MIS_INKY	MIS_IL	240	1,195			0
	MIS_LMI	0	100			0
	PJM_COMD	2,044	3,355			3
	PJM_West	5,441	6,509			3
	S_C_KY	2,257	3,787			6
	S_C_TVA	300	500			6
MIS_LMI	CN_ON	400	1,200			8
	MIS_INKY	0	100			0
	MIS_WUMS	0	100			0
	PJM_ATSI	1,262	2,036			3
	PJM_West	1,400	2,800			3
MIS_MAPP	CN_MB	300	500			8
	MAP_WAUE	1,000	1,500			0
	MIS_MNWI	2,150	5,000			6
MIS_MIDA	MAP_WAUE	600	1,000			6
	MIS_IA	900	2,000			0
	MIS_IL	0	100			0
	MIS_MNWI	0	0			0
	MIS_MO	0	500			0
	PJM_COMD	2,000	3,000			3
	S_D_N_AR	0	30			1
	SPP_N	0	50			6
	SPP_NEBR	1,000	2,000			6
MIS_MNWI	CN_MB	200	1,700			8

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
	CN_ON	0	162			8
	MAP_WAUE	2,000	3,000			6
	MIS_IA	1,195	2,000			0
	MIS_MAPP	2,150	5,000			6
	MIS_MIDA	0	0			0
	MIS_WUMS	1,480	2,400			0
MIS_MO	MIS_IA	223	711			0
	MIS_IL	3,400	4,500			0
	MIS_MIDA	0	500			0
	S_D_N_AR	2,100	2,804			1
	SPP_N	300	1,000			6
MIS_WUMS	MIS_LMI	0	100			0
	MIS_MNWI	1,480	2,400			0
	PJM_COMD	0	1000			3
NENG_CT	NENGREST	2,600	2,600	800	800	0
	NY_Z_G-I	900	900			3
	NY_Z_K	760	760			3
NENG_ME	CN_NB	800	800			8
	NENGREST	1,600	1,600			0
NENGREST	CN_PQ	1,650	1,650			8
	NENG_CT	2,600	2,600	800	800	0
	NENG_ME	1,600	1,600			0
	NY_Z_D	0	0			3
	NY_Z_F	800	800			3
NY_Z_A&B	CN_ON	1,200	1,200			8
	NY_Z_C&E	1,550	1,550			0
	PJM_PENE	500	1,000			6
NY_Z_C&E	NY_Z_A&B	1,300	1,300			0
	NY_Z_D	1,600	1,600			0
	NY_Z_F	3,250	3,250			0
	NY_Z_G-I	1,700	1,700			0
	PJM_PENE	755	1,500			6
NY_Z_D	CN_PQ	1,200	1,200			8
	NENGREST	150	150			3
	NY_Z_C&E	2,650	2,650			0
NY_Z_F	NENGREST	800	800			3
	NY_Z_C&E	1,999	1,999			0
	NY_Z_G-I	3,450	3,450			0
NY_Z_G-I	NENG_CT	1,130	1,130			3
	PJM_EMAC	1,000	1,000			0
	NY_Z_C&E	1,600	1,600			0
	NY_Z_F	1,999	1,999			0
	NY_Z_J	4,350	4,350			0
	NY_Z_K	1,290	1,290			0
NY_Z_J	NY_Z_G-I	3,500	3,500			0
	NY_Z_K	175	175			0
	PJM_EMAC	1,300	1,900			6
NY_Z_K	NENG_CT	760	760			3
	NY_Z_G-I	530	530			0
	NY_Z_J	283	283			0
	PJM_EMAC	660	660			6

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
PJM_AP	PJM_ATSI	1,212	2,731			0
	PJM_Dom	5,400	8,000			0
	PJM_PENE	2,400	3,200			0
	PJM_SMAC	1,100	2,200			0
	PJM_West	4,800	6,300			0
PJM_ATSI	MIS_LMI	1,262	2,036			3
	PJM_AP	1,212	2,731			0
	PJM_PENE	0	1,500			0
	PJM_West	7,400	9,700			0
PJM_COMD	MIS_IA	0	600			3
	MIS_IL	2,500	3,000			3
	MIS_INKY	3,840	5,098			3
	MIS_MIDA	2,000	3,000			3
	MIS_WUMS	0	1,000			3
	PJM_West	980	4,000			0
PJM_Dom	PJM_AP	5,400	8,000			0
	PJM_SMAC	1,195	2,812			0
	PJM_West	1,530	3,800			0
	S_VACA	1,000	2,598			6
PJM_EMAC	NY_Z_J	1,300	1,900			6
	NY_Z_K	660	660			6
	NY_Z_G-I	500	500			0
	PJM_SMAC	300	1,095			0
	PJM_WMAC	6,900	6,900			0
PJM_PENE	NY_Z_A&B	500	1,000			6
	NY_Z_C&E	755	1,500			6
	PJM_AP	2,400	3,200			0
	PJM_ATSI	0	1,500			0
	PJM_WMAC	3,565	3,565			0
PJM_SMAC	PJM_AP	1,100	2,200			0
	PJM_Dom	1,195	2,812			0
	PJM_EMAC	300	1,095			0
	PJM_WMAC	800	2,000			0
PJM_West	MIS_IL	0	1,300			3
	MIS_INKY	5,125	6,415			3
	MIS_LMI	1,400	2,800			3
	PJM_AP	4,800	6,300			0
	PJM_ATSI	7,400	9,700			0
	PJM_COMD	980	4,000			0
	PJM_Dom	1,530	3,800			0
	S_C_KY	1,255	2,074			6
	S_C_TVA	2,119	3,118			6
	S_VACA	700	1,000			6
PJM_WMAC	PJM_EMAC	6,900	6,900			0
	PJM_PENE	3,565	3,565			0
	PJM_SMAC	800	2,000			0
S_C_KY	MIS_INKY	2,257	3,787			6
	PJM_West	1,255	2,074			6
S_C_TVA	MIS_IL	1,200	1,500			6
	MIS_INKY	300	500			6
	PJM_West	2,119	3,118			6

From	To	2016		2018		Transmission Tariff (2011 mills/kWh)
		Capacity TTC (MW)	Energy TTC (MW)	Incremental Capacity TTC (MW)	Incremental Energy TTC (MW)	
	S_D_N_AR	1,732	3,019			8
	S_D_REST	1,195	2,494			8
	S_SOU	3,196	5,098			8
	S_VACA	216	276			8
S_D_AMSO	S_D_REST	2,450	2,450			0
	S_SOU	420	700			8
	SPP_SE	300	500			6
S_D_N_AR	MIS_IA	0	100			1
	MIS_MIDA	0	30			1
	MIS_MO	2,100	2,804			1
	S_C_TVA	1,732	3,019			8
	SPP_N	1,792	2,955			6
	SPP_WEST	2,000	3,000			6
S_D_REST	S_C_TVA	1,195	2,494			8
	S_D_AMSO	2,450	2450			0
	S_D_WOTA	290	1,050			0
	S_SOU	1,700	2,000			8
	SPP_SE	1,639	3,136			6
	SPP_WEST	100	900			6
S_D_WOTA	S_D_REST	1,250	1,250			0
	SPP_SE	1,491	2,835			6
S_SOU	FRCC	3,600	3,600			8
	S_C_TVA	4,411	5,893			8
	S_D_AMSO	420	700			8
	S_D_REST	1,700	2,000			8
	S_VACA	1,400	3,000			8
S_VACA	PJM_Dom	1,000	2,598			6
	PJM_West	700	1,000			6
	S_C_TVA	216	276			8
	S_SOU	1,400	3,000			8
SPP_KIAM	ERC_REST	1,178	1,178			6
	SPP_WEST	1,178	1,178			0
SPP_N	MIS_MIDA	0	50			6
	MIS_MO	300	1,000			6
	S_D_N_AR	1,792	2,955			6
	SPP_NEBR	1,217	1,666	500	500	0
	SPP_SPS	0	900			0
	SPP_WEST	2,253	3,600	500	500	0
SPP_NEBR	MAP_WAUE	700	1,000			6
	MIS_MIDA	1,000	2,000			6
	SPP_N	1,217	1,666	500	500	0
SPP_SE	S_D_AMSO	300	500			6
	S_D_REST	1,639	3,136			6
	S_D_WOTA	1,491	2,835			6
	SPP_WEST	0	852			0
SPP_SPS	SPP_N	0	900			0
	SPP_WEST	1,239	2,205	750	750	0
	WECC_NM	610	610			6
SPP_WEST	ERC_REST	600	600			6
	ERC_WEST	220	220			6
	S_D_N_AR	2,000	3,000			6

From	To	2016		2018		Transmission Tariff (2011 mills/kWh)
		Capacity TTC (MW)	Energy TTC (MW)	Incremental Capacity TTC (MW)	Incremental Energy TTC (MW)	
	S_D_REST	100	900			6
	SPP_N	2,500	2,700	500	500	0
	SPP_SE	0	688			0
	SPP_SPS	1,239	2,205	750	750	0
WEC_CALN	WECC_NNV	100	100			8
	WECC_PNW	3,675	3,675			8
	WECC_SCE	1,275	1,275			0
	WECC_SF	1,272	1,272			0
WEC_LADW	WECC_AZ	468	468			8
	WECC_PNW	2,858	2,858			8
	WECC_SCE	3,750	3,750			8
	WECC_SNV	3,883	3,883			8
	WECC_UT	1,400	1,400			8
WEC_SDGE	WECC_AZ	1,168	1,168			8
	WECC_IID	150	150			8
	WECC_SCE	2,440	2,440			0
WECC_AZ	WEC_LADW	362	362			8
	WEC_SDGE	1,163	1,163			8
	WECC_IID	195	195			8
	WECC_NM	5,522	5,522			0
	WECC_SCE	1,600	1,600			8
	WECC_SNV	4,727	4,727			0
	WECC_UT	250	250			8
WECC_CO	WECC_NM	614	614			8
	WECC_UT	650	650			8
	WECC_WY	1,400	1,400			0
WECC_ID	WECC_MT	200	200			8
	WECC_NNV	350	350			0
	WECC_PNW	1,800	1,800			8
	WECC_UT	680	680			0
	WECC_WY	0	0			8
WECC_IID	WEC_SDGE	150	150			8
	WECC_AZ	163	163			8
	WECC_SCE	600	600			8
WECC_MT	WECC_ID	325	325			8
	WECC_PNW	2,000	2,000			0
	WECC_WY	400	400			8
WECC_NM	SPP_SPS	610	610			6
	WECC_AZ	5,582	5,582			0
	WECC_CO	664	664			8
	WECC_UT	530	530			8
WECC_NNV	WEC_CALN	100	100			8
	WECC_ID	185	185			0
	WECC_PNW	300	300			8
	WECC_UT	235	235			0
WECC_PNW	CN_BC	1,000	1,000			8
	WEC_CALN	4,200	4,200			8
	WEC_LADW	2,600	2,600			8
	WECC_ID	500	500			8
	WECC_MT	1,000	1,000			0
	WECC_NNV	300	300			8

From	To	2016 Capacity TTC (MW)	2016 Energy TTC (MW)	2018 Incremental Capacity TTC (MW)	2018 Incremental Energy TTC (MW)	Transmission Tariff (2011 mills/kWh)
WECC_SCE	WEC_CALN	3,000	3,000			0
	WEC_LADW	3,750	3,750			8
	WEC_SDGE	2,200	2,200			0
	WECC_AZ	1,082	1,082			8
	WECC_IID	50	50			8
	WECC_SNV	2,814	2,814			8
WECC_SF	WEC_CALN	1,100	1,100			0
WECC_SNV	WEC_LADW	2,300	2,300			8
	WECC_AZ	4,785	4,785			0
	WECC_SCE	1,700	1,700			8
	WECC_UT	250	250			8
WECC_UT	WEC_LADW	1,920	19,20			8
	WECC_AZ	250	250			8
	WECC_CO	650	650			8
	WECC_ID	775	775			0
	WECC_NM	600	600			8
	WECC_NNV	360	360			0
	WECC_SNV	140	140			8
	WECC_WY	400	400			8
WECC_WY	WECC_CO	1,400	1,400			0
	WECC_ID	2,200	2,200			8
	WECC_MT	200	200			8
	WECC_UT	400	400			8

The amount of energy and capacity transferred on a given transmission link is modeled on a seasonal (summer and winter) basis for all run years in the EPA Base Case v.5.13. All of the modeled transmission links have the same Total Transfer Capabilities for both the winter and summer seasons, which means that the maximum firm and non-firm TTCs for each link is the same for both winter and summer. The maximum values for firm and non-firm TTCs were obtained from public sources such as market reports and regional transmission plans, wherever available. Where public sources were not available, the maximum values for firm and non-firm TTCs are based on ICF's expert view. ICF analyzes the operation of the grid under normal and contingency conditions, using industry-standard methods, and calculates the transfer capabilities between regions. ICF uses standard power flow data developed by the market operators, transmission providers, or utilities, as appropriate.

It should be noted that each transmission link between model regions shown in Table 3-4represents a one-directional flow of power on that link. This implies that the maximum amount of flow of power possible from region A to region B may be more or less than the maximum amount of flow of power possible from region B to region A, due to the physical nature of electron flow across the grid.

3.3.2 Joint Transmission Capacity and Energy Limits

Table 3-5 shows the annual joint limits to the transmission capabilities between model regions, which are identical for the firm (capacity) and non-firm (energy) transfers. The joint limits were obtained from public sources where available, or based on ICF's expert view. A joint limit represents the maximum simultaneous firm or non-firm power transfer capability of a group of interfaces. It restricts the amount of firm or non-firm transfers between one model region (or group of model regions) and a different group of model regions). For example, the New England market is connected to the New York market by four transmission links. As shown in Table 3-4, the transfer capabilities from New England to New York for the individual links are:

- NENG_CT to NY_Z_G-I: 900 MW
- NENGREST to NY_Z_F: 800 MW
- NENG_CT to NY_Z_K: 760 MW
- NENGREST to NY_Z_D: 0 MW

Without any simultaneous transfer limits, the total transfer capability from New England to New York would be 2,460 MW. However, current system conditions and reliability requirements limit the total simultaneous transfers from New England to New York to 1,730 MW. ICF uses joint limits to ensure that this and similar reliability limits are not violated. Therefore each individual link can be utilized to its limit as long as the total flow on all links does not exceed the joint limit.

Table 3-5 Annual Joint Capacity and Energy Limits to Transmission Capabilities Between Model Regions in EPA Base Case v.5.13

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
NYISO to NYISO	NY_Z_G-I to NY_Z_K NY_Z_J to NY_Z_K	1,465	
NYISO to NYISO	NY_Z_K to NY_Z_G-I NY_Z_K to NY_Z_J	285	
NYISO to ISO-NE	NY_Z_G-I to NENG_CT NY_Z_F to NENGREST NY_Z_K to NENG_CT NY_Z_D to NENGREST	1,730	
NYISO to ISO-NE	NY_Z_G-I to NENG_CT NY_Z_F to NENGREST NY_Z_K to NENG_CT NY_Z_D to NENGREST	2,205	
ISO-NE to NYISO	NENG_CT to NY_Z_G-I NENGREST to NY_Z_F NENG_CT to NY_Z_K NENGREST to NY_Z_D	1,730	
PJM to PJM	PJM_West to PJM_ATSI PJM_PENE to PJM_ATSI PJM_AP to PJM_ATSI	5,417	12,000
PJM to PJM	PJM_ATSI to PJM_West PJM_ATSI to PJM_PENE PJM_ATSI to PJM_AP	5,417	12,000
PJM to SERC-E	PJM_West to S_VACA PJM_Dom to S_VACA	1,300	2,598
SERC-E to PJM	S_VACA to PJM_West S_VACA to PJM_Dom	1,300	2,598
MAPP to MISO	MIS_MAPP to MIS_MNWI MAP_WAUE to MIS_MNWI	3,000	5,000
MISO to MAPP	MIS_MNWI to MIS_MAPP MIS_MNWI to MAP_WAUE	3,000	5,000
SERC-N to PJM	S_C_TVA to PJM_West S_C_KY to PJM_West	3,000	4,500
PJM to SERC-N	PJM_West to S_C_TVA PJM_West to S_C_KY	3,000	4,500
SERC-N to MISO	S_C_TVA to MIS_INKY S_C_KY to MIS_INKY	2,257	4,000

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
MISO to SERC-N	MIS_INKY to S_C_TVA MIS_INKY to S_C_KY	2,257	4,000
MISO to PJM	MIS_INKY to PJM_COMD MIS_INKY to PJM_West	4,586	6,509
PJM to MISO	PJM_COMD to MIS_INKY PJM_West to MIS_INKY	5,998	8,242

3.3.3 Transmission Link Wheeling Charge

Transmission wheeling charge is the cost of transferring electric power from one region to another using the transmission link. The EPA Base Case 5.13 has no charges within individual IPM regions and no charges between IPM regions that fall within the same RTO. Charges between other regions vary to reflect the cost of wheeling. The wheeling charges in 2011 mills/kWh are shown in Table 3-4 in the column labeled "Transmission Tariff".

3.3.4 Transmission Losses

The EPA Base Case 5.13 assumes a 2.8 percent inter-regional transmission loss of energy transferred.This is based on the average loss factor for the transmission grid calculated from the U.S Energy Information Administration (EIA) State Electricity Profiles 2010 report.[11] The results were validated using average loss factors derived from standard power flow data developed by the market operators, transmission providers, and utilities.

3.4 International Imports

The U.S. electric power system is connected with the transmission grids in Canada and Mexico and the three countries actively trade in electricity. The Canadian power market is endogenously modeled in EPA Base Case v.5.13 but Mexico is not. International electric trading between the U.S. and Mexico is represented by an assumption of net imports based on information from AEO 2013. Table 3-6 summarizes the assumptions on net imports into the US from Mexico.

Table 3-6 International Electricity Imports in EPA Base Case v.5.13

	2016	2018	2020	2025	2030	2040	2050
Net Imports from Mexico (billions kWh)	0.67	0.55	0.31	-0.29	-0.53	-0.53	-0.53

Notes:
Imports & exports transactions from Canada are endogenously modeled in IPM.
Source: AEO 2013

3.5 Capacity, Generation, and Dispatch

While the capacity of existing units is an exogenous input into IPM, the dispatch of those units is an endogenous decision that the model makes. The capacity of existing generating units included in EPA Base Case v.5.13 can be found in the National Electrical Energy Data System (NEEDS v.5.13), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS v.5.13 is discussed in full in Chapter 4.

A unit's generation over a period of time is defined by its dispatch pattern over that duration of time. IPM determines the optimal economic dispatch profile given the operating and physical constraints imposed

[11] State Electricity Profiles 2010, Table 3-10, U.S. Energy Information Administration, January 2012. (http://www.eia.gov/electricity/state/pdf/sep2010.pdf).

on the unit. In EPA Base Case v.5.13 unit specific operational and physical constraints are generally represented through availability and turndown constraints. However, for some unit types, capacity factors are used to capture the resource or other physical constraints on generation. The two cases are discussed in more detail in the following sections.

3.5.1 Availability

Power plant "availability" is the percentage of time that a generating unit is available to provide electricity to the grid. Availability takes into account both scheduled maintenance and forced outages; it is formally defined as the ratio of a unit's available hours adjusted for derating of capacity (due to partial outages) to the total number of hours in a year when the unit was in an active state. For most types of units in IPM, availability parameters are used to specify an upper bound on generation to meet demand. Table 3-7 summarizes the availability assumptions used in EPA Base Case v.5.13. They are based on data from NERC Generating Availability Data System (GADS) 2007-2011 and AEO 2012. Table 3-18 shows the availability assumptions for all generating units in EPA Base Case v.5.13.

Table 3-7 Availability Assumptions in the EPA Base Case v.5.13

Unit Type	Annual Availability (%)
Biomass	82 - 86
Coal Steam	77 - 90
Combined Cycle	84 - 90
Combustion Turbine	85 - 93
Fossil Waste	90
Fuel Cell	87
Geothermal	97 - 98
Hydro	81 - 91
IGCC	79 - 88
Landfill Gas	90
Municipal Solid Waste	90
Non-Fossil Waste	90
Nuclear	58 – 100
O/G Steam	70 – 92
Pumped Storage	83 – 90
Solar PV	90
Solar Thermal	90
Tires	90
Wind	95

Notes:
Values shown are a range of all of the values modeled within the EPA Base Case v.5.13. The range depends on the source of information: GADS data vary by size, AEO 2012 data may vary by projected year.

In the EPA Base Case v.5.13, separate seasonal (summer and winter) availabilities are defined. For the fossil and nuclear unit types shown in Table 3-7, summer and winter availabilities differ only in that no planned maintenance is assumed to be conducted during the on-peak summer (June, July and August) months. Characterizing the availability of hydro, solar and wind technologies is more complicated due to the seasonal and locational variations of the resources. The procedures used to represent seasonal variations in hydro are presented in section 3.5.2 and of wind and solar in section 4.4.5.

3.5.2 Capacity Factor

Generation from certain types of units is constrained by resource limitations. These technologies include hydro, wind and solar. For such technologies, IPM uses capacity factors or generation profiles, not availabilities, to define the upper bound on the generation obtainable from the unit. The capacity factor is the percentage of the maximum possible power generated by the unit. For example, a photovoltaic solar unit would have a capacity factor of 27% if the usable sunlight were only available that percent of the time. For such units, explicit capacity factors or generation profiles mimic the resource availability. The seasonal capacity factor assumptions for hydro facilities contained in Table 3-8 were derived from EIA Form-923 data 2007-2011. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in section 4.4.5 and Table 4-32 and Table 4-33.

Table 3-8 Seasonal Hydro Capacity Factors (%) in the EPA Base Case v.5.13

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
ERC_REST	12.9%	25.0%	18.0%
FRCC	44.0%	31.8%	38.9%
MIS_MAPP	81.0%	87.4%	83.7%
MAP_WAUE	29.2%	40.2%	33.8%
MIS_IL	55.0%	64.3%	58.9%
MIS_INKY	76.2%	95.9%	84.4%
MIS_IA	38.5%	48.6%	42.7%
MIS_MIDA	41.6%	49.6%	44.9%
MIS_LMI	68.8%	44.4%	58.6%
MIS_MO	42.7%	58.7%	49.4%
MIS_WUMS	66.2%	61.5%	64.2%
MIS_MNWI	33.0%	36.3%	34.4%
NENG_CT	47.3%	40.2%	44.4%
NENGREST	45.8%	34.5%	41.1%
NENG_ME	65.5%	58.1%	62.4%
NY_Z_C&E	56.9%	55.0%	56.1%
NY_Z_F	67.0%	58.9%	63.6%
NY_Z_G-I	35.8%	34.6%	35.3%
NY_Z_A&B	70.4%	65.0%	68.1%
NY_Z_D	88.3%	83.3%	86.2%
PJM_WMAC	41.5%	20.3%	32.6%
PJM_EMAC	48.3%	24.6%	38.4%
PJM_West	33.8%	28.0%	31.4%
PJM_AP	64.6%	45.5%	56.6%
PJM_COMD	36.5%	48.0%	41.3%
PJM_ATSI	23.5%	32.8%	27.4%
PJM_Dom	21.1%	12.9%	17.7%
PJM_PENE	63.0%	34.1%	50.9%
S_VACA	21.1%	14.2%	18.2%
S_C_KY	29.2%	30.2%	29.6%
S_C_TVA	38.8%	28.3%	34.4%
S_SOU	22.8%	14.5%	19.3%
S_D_WOTA	20.1%	23.0%	21.3%
S_D_N_AR	23.9%	26.7%	25.1%
S_D_REST	49.2%	56.6%	52.3%
SPP_NEBR	32.1%	43.7%	36.9%
SPP_N	15.7%	22.8%	18.7%
SPP_WEST	32.1%	39.9%	35.4%
WECC_ID	32.3%	52.3%	40.7%
WECC_NNV	49.6%	62.6%	55.1%
WECC_UT	30.1%	42.5%	35.3%
WEC_CALN	26.9%	45.1%	34.5%
WECC_IID	45.7%	78.5%	59.5%

Model Region	Winter Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
WEC_LADW	17.1%	27.9%	21.6%
WEC_SDGE	30.8%	53.7%	40.4%
WECC_SCE	28.3%	52.9%	38.6%
WECC_MT	34.4%	52.2%	41.9%
WECC_PNW	41.7%	46.5%	43.7%
WECC_CO	28.8%	36.8%	32.2%
WECC_WY	22.8%	54.1%	36.0%
WECC_AZ	28.9%	33.3%	30.8%
WECC_NM	30.1%	43.0%	35.5%
WECC_SNV	20.4%	25.6%	22.6%

Notes:
Annual capacity factor is provided for information purposes only. It is not directly used in modeling.

Capacity factors are also used to define the upper bound on generation obtainable from nuclear units. This rests on the assumption that nuclear units will dispatch to their availability, and, consequently, capacity factors and availabilities are equivalent. The capacity factors (and, consequently, the availabilities) of existing nuclear units in EPA Base Case v.5.13 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Base Case v.5.13 is contained in Section 4.5.

In EPA Base Case v5.13 capacity factors for oil/gas (O/G) steam units are treated separately and assigned minimum capacity factors under certain conditions. These capacity factors are a result of stakeholder comments that many of the O/G steam units in the national fleet may not operate under the economic conditions reflected in EPA power sector modeling. These comments note that these units often operate due to local transmission constraints, unit-specific grid reliability requirements, or other drivers that are not captured in EPA's modeling. EPA examined its modeling treatment of these units and has introduced minimum capacity factor constraints in EPA Base Case v5.13 to reflect better the real-world behavior of these units where drivers of that behavior are not fully represented in the model itself. This approach is designed to balance the continued operation of these units in the near term while also allowing for economic forces to influence decision-making over the modeling time horizon; as a result, the minimum capacity factor limitations are phased out over time and are completely removed if the capacity in question reaches 60 years of age Review of the historical operation of these units indicate that units with high capacity factors continue at similar levels over time; in order to reflect persistent operation of these units, minimum capacity factors for higher capacity factor units are phased out more slowly than lower capacity factor units. The steps followed in assigning these capacity constraints are as follows:

1) For each O/G steam unit, calculate an seasonal capacity factor over a six year baseline (2007-2012).
2) Identify the minimum capacity factor over this baseline period for each unit.
3) Remove the minimum capacity factor limitation when the unit reaches 60 year old.
4) For units less than 60 years old, remove the constraints based on the assigned minimum capacity factor and the model year, on the following schedule:
    - For model year 2016, keep minimum capacity factor unless unit > 60 years old.
    - For model year 2018, remove minimum constraint from units with capacity factor < 2.5%
    - For model year 2020, remove minimum constraint from units with capacity factor < 5%
    - For model year 2025, remove minimum constraint from units with capacity factor < 15%
    - For model year 2030, remove minimum constraint from units with capacity factor < 25%
    - For model year 2040, remove minimum constraint from units with capacity factor < 45%

3.5.3 Turndown

Turndown assumptions in EPA Base Case v.5.13 are used to prevent coal and oil/gas steam units from operating strictly as peaking units, which would be inconsistent with their operating capabilities. Specifically, the turndown constraints in EPA Base Case v.5.13 require coal steam units to dispatch no less than 50% of the unit capacity in the five base- and mid-load segments of the load duration curve in order to dispatch 100% of the unit in the peak load segment of the LDC. Oil/gas steam units are required to dispatch no less than 25% of the unit capacity in the five base- and mid-load segments of the LDC in order to dispatch 100% of the unit capacity in the peak load segment of the LDC. These turndown constraints were developed by ICF through detailed assessments of the historical experience and operating characteristics of the existing fleet of coal steam and oil/gas steam units' capacities.

3.6 Reserve Margins

A reserve margin is a measure of the system's generating capability above the amount required to meet the net internal demand (peak load) requirement. It is defined as the difference between total dependable capacity and annual system peak load divided by annual system peak load. It is expressed in percent. The reserve margin capacity contribution for renewable units is described in Section 4.4.5; the reserve margin capacity contribution for other units is the dependable capacity in the NEEDS for existing units or the capacity build by IPM for new units. In practice, each NERC region has a reserve margin requirement, or comparable reliability standard, which is designed to encourage electric suppliers in the region to build beyond their peak requirements to ensure the reliability of the electric generation system within the region.

In IPM reserve margins are used to depict the reliability standards that are in effect in each NERC region. Individual reserve margins for each NERC region are derived either directly or indirectly from NERC's electric reliability reports. They are based on reliability standards such as loss of load expectation (LOLE), which is defined as the expected number of days in a specified period in which the daily peak load will exceed the available capacity. EPA Base Case v.5.13 reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in EPA Base Case v.5.13

Model Region	Reserve Margin - Summer	Reserve Margin - Winter
CN_AB	12.2%	11.7%
CN_BC	12.5%	16.2%
CN_MB	12.0%	12.0%
CN_NB	20.0%	20.0%
CN_PE	20.0%	20.0%
CN_NS	20.0%	20.0%
CN_NF	20.0%	20.0%
CN_NL	20.0%	20.0%
CN_ON	19.2%	20.0%
CN_PQ	11.4%	12.2%
CN_SK	11.0%	11.0%
ERC_FRNT	13.8%	13.8%
ERC_GWAY	13.8%	13.8%
ERC_REST	13.8%	13.8%
ERC_WEST	13.8%	13.8%
FRCC	19.3%	19.3%
MAP_WAUE	15.0%	15.0%
MIS_IA	16.3%	16.3%
MIS_IL	16.3%	16.3%
MIS_INKY	16.3%	16.3%
MIS_LMI	16.3%	16.3%
MIS_MAPP	15.0%	15.0%

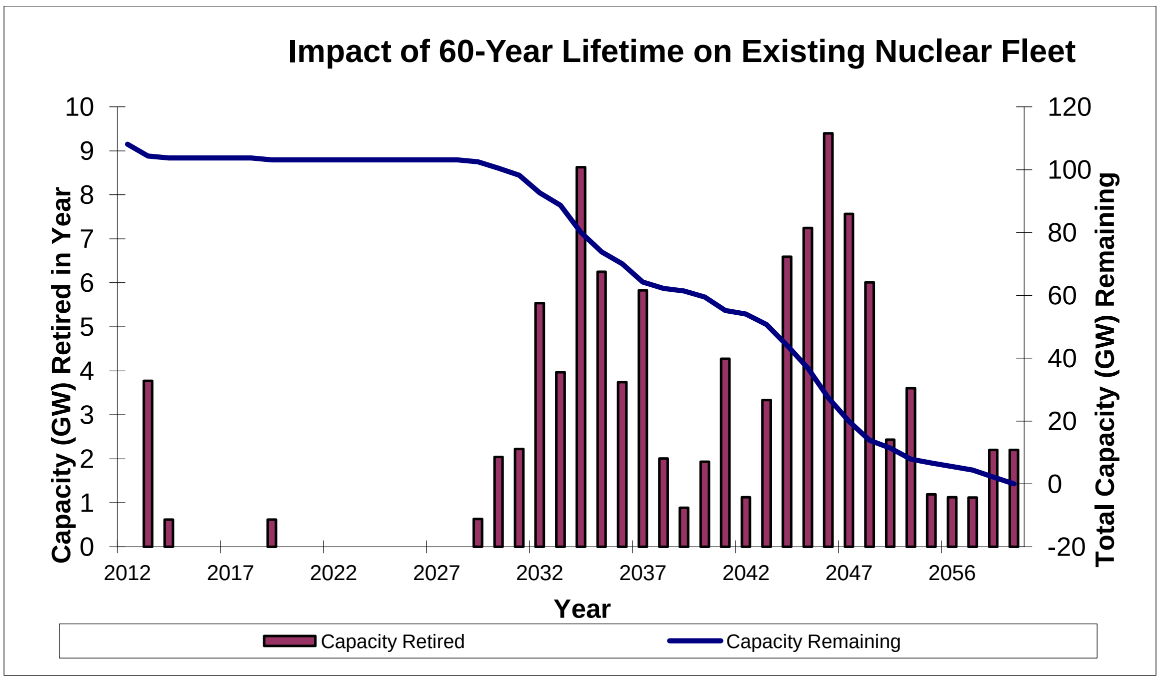
Model Region	Reserve Margin - Summer	Reserve Margin - Winter
MIS_MIDA	16.3%	16.3%
MIS_MNWI	16.3%	16.3%
MIS_MO	16.3%	16.3%
MIS_WUMS	16.3%	16.3%
NENG_CT	15.0%	15.0%
NENG_ME	15.0%	15.0%
NENGREST	15.0%	15.0%
NY_Z_A&B	16.0%	16.0%
NY_Z_C&E	16.0%	16.0%
NY_Z_D	16.0%	16.0%
NY_Z_F	16.0%	16.0%
NY_Z_G-I	16.0%	16.0%
NY_Z_J	16.0%	16.0%
NY_Z_K	16.0%	16.0%
PJM_AP	15.4%	15.4%
PJM_ATSI	15.4%	15.4%
PJM_COMD	15.4%	15.4%
PJM_Dom	15.4%	15.4%
PJM_EMAC	15.4%	15.4%
PJM_PENE	15.4%	15.4%
PJM_SMAC	15.4%	15.4%
PJM_West	15.4%	15.4%
PJM_WMAC	15.4%	15.4%
S_C_KY	15.0%	15.0%
S_C_TVA	15.0%	15.0%
S_D_AMSO	15.0%	15.0%
S_D_N_AR	15.0%	15.0%
S_D_REST	15.0%	15.0%
S_D_WOTA	15.0%	15.0%
S_SOU	15.0%	15.0%
S_VACA	15.0%	15.0%
SPP_KIAM	13.6%	13.6%
SPP_N	13.6%	13.6%
SPP_NEBR	13.6%	13.6%
SPP_SE	13.6%	13.6%
SPP_SPS	13.6%	13.6%
SPP_WEST	13.6%	13.6%
WEC_CALN	14.7%	11.9%
WEC_LADW	15.1%	11.0%
WEC_SDGE	15.1%	11.0%
WECC_AZ	13.5%	14.0%
WECC_CO	14.7%	15.7%
WECC_ID	12.6%	13.5%
WECC_IID	15.1%	11.0%
WECC_MT	17.9%	19.9%
WECC_NM	13.5%	14.0%
WECC_NNV	12.6%	13.5%
WECC_PNW	17.9%	19.9%
WECC_SCE	15.1%	11.0%
WECC_SF	14.7%	11.9%
WECC_SNV	13.5%	14.0%
WECC_UT	12.6%	13.5%
WECC_WY	14.7%	15.7%

3.7 Power Plant Lifetimes

EPA Base Case v5.13 does not include any pre-specified assumptions about power plant lifetimes except for nuclear units. All conventional fossil units (i.e., coal, oil/gas steam, combustion turbines, and combined cycle) and nuclear units can be retired during a model run if their retention is deemed uneconomic. Other types of units are not provided an economic retirement option.

Nuclear Retirement at Age 60: EPA Base Case v.5.13 assumes that commercial nuclear reactors will be retired upon license expiration, which includes a 20 year operating extension that is assumed to be granted for each reactor by the Nuclear Regulatory Commission (NRC). EPA Base Case v.5.13 continues the assumption of a 60 year life from the previous base case platforms. EPA Base Case v.5.13 modeling uses a maximum 60 year lifetime for nuclear reactors based on the current NRC licensing extension program, which states; "Based on the Atomic Energy Act, the Nuclear Regulatory Commission (NRC) issues licenses for commercial power reactors to operate for up to 40 years and allows these licenses to be renewed for up to another 20 years. Economic and antitrust considerations, not limitations of nuclear technology, determined the original 40-year term for reactor licenses. "[12] Today's nuclear fleet totals more than 100 GW. Assuming a 60-year lifetime[13] reduces the current fleet to under 5 GW in 2050. This is illustrated in Figure 3-2. For a complete listing of the existing nuclear units including their online year and other characteristics, see Table 4-34.

Figure 3-2 Scheduled Retirements of Existing Nuclear Capacity Under 60-Year Life Assumption



3.8 Heat Rates

[12] For more info regarding the NRC's licensing extension program, see NRC website: http://www.nrc.gov/reading-rm/doc-collections/fact-sheets/fs-reactor-license-renewal.html.

For an up to date list regarding license renewal status, see "Status of License Renewal Applications and Industry Activities"; NRC website: http://www.nrc.gov/reactors/operating/licensing/renewal/applications.html."

[13] Real-world retirement decisions affecting some nuclear units such as Oyster Creek and San Onofre have occurred prior to those units reaching 60 years in service.

Heat rates, expressed in BTUs per kWh, are a metric of the efficiency of a generating unit. As in previous versions of NEEDS, it is assumed in NEEDS v.5.13 that heat rates of existing units will remain constant over time. This assumption reflects two offsetting factors: (1) plant efficiencies tend to degrade over time and (2) increased maintenance and component replacement work to maintain or improve plant efficiency.

The heat rates in EPA Base Case v.5.13 are based on values from AEO 2013. These values were screened and adjusted using a procedure developed by EPA to ensure that the heat rates used in EPA Base Case v.5.13 are within the engineering capabilities of the generating unit types. Based on engineering analysis, the upper and lower heat rate limits shown in Table 3-10 were applied to coal steam, oil/gas steam, combined cycle, combustion turbine, and internal combustion engines. If the reported heat rate for such a unit was below the applicable lower limit or above the upper limit, the limit was substituted for the reported value.

Table 3-10 Lower and Upper Limits Applied to Heat Rate Data in NEEDS v.5.13

	Heat Rate (Btu/kWh)	
Plant Type	**Lower Limit**	**Upper Limit**
Coal Steam	8,300	14,500
Oil/Gas Steam	8,300	14,500
Combined Cycle - Natural Gas	5,500	15,000
Combined Cycle - Oil	6,000	15,000
Combustion Turbine - Natural Gas - ≥ 80 MW	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - ≥ 80 MW	6,000	25,000
Combustion Turbine - Oil and Oil/Gas < 80 MW	6,000	36,800
IC Engine - Natural Gas	8,700	18,000
IC Engine - Oil and Oil/Gas - 5 MW and above	8,700	20,500
IC Engine - Oil and Oil/Gas < 5 MW	8,700	42,000

3.9 Existing Environmental Regulations

This section describes the existing federal, regional, and state SO_2, NO_x, mercury, HCl and CO_2 emissions regulations that are represented in the EPA Base Case v.5.13. The first four subsections discuss national and regional regulations. The next two subsections describe state level environmental regulations and a variety of legal settlements. The last subsection presents emission assumptions for potential units.

3.9.1 SO_2 Regulations

Unit-level Regulatory SO_2 Emission Rates and Coal Assignments: Before discussing the national and regional regulations affecting SO_2, it is important to note that unit-level SO_2 regulations arising out of State Implementation Plan (SIP) requirements, which are not only state-specific but also county-specific, are captured at model set-up in the coal choices given to coal fired existing units in EPA Base Case v.5.13. The SIP requirements define “regulatory SO_2 emission rates.” Since SO_2 emissions are dependent on the sulfur content of the fuel used, the regulatory SO_2 emission rates are used in IPM to define fuel capabilities.

For instance, a unit with a regulatory SO_2 emission rate of 3.0 lbs/MMBtu would be provided only with those combinations of fuel choices and SO_2 emission control options that would allow the unit to achieve an out-of-stack rate of 3.0 lbs/MMBtu or less. If the unit finds it economical, it may elect to burn a fuel that would achieve a lower SO_2 rate than its specified regulatory emission limit. In EPA Base Case v.5.13 there are six different sulfur grades of bituminous coal, four different grades of subbituminous coal, five different grades of lignite, and one sulfur grade of residual fuel oil. There are two different SO_2 scrubber options and one DSI option for coal units. Further discussion of fuel types and sulfur content is contained in Chapter 9. Further discussion of SO_2 control technologies is contained in Chapter 5.

National and Regional SO_2 Regulations: The national program affecting SO_2 emissions in EPA Base Case v.5.13 is the Acid Rain Program established under Title IV of the Clean Air Act Amendments (CAAA) of 1990, which set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. The program, which became fully operational in year 2000, affects all SO_2 emitting electric generating units greater than 25 MWs. The program provides trading and banking of allowances over time across all affected electric generation sources.

The annual SO_2 caps over the modeling time horizon in EPA Base Case v.5.13 reflect the provisions in Title IV. Since EPA Base Case v.5.13 uses year 2016 as the first analysis year, a projection of allowance banking behavior through the end of 2015 and specification of the available 2016 allowances are needed to initialize the modeling. EPA developed the projection of the banked allowances (30.6 million) going into 2016. Calculating the available 2016 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2016 SO_2 cap of 8.95 million tons. The surrenders totaled 142 thousand tons in allowances, leaving 8.808 million of 2016 allowances remaining. Table 7-4 shows the initial bank and 2016 allowance specification along with the SO_2 caps for the entire modeling time horizon. Specifics of the allowance surrender requirements under state regulations and NSR settlements can be found in Table 3-13 and Table 3-14.

EPA Base Case v.5.13 also includes a representation of the Western Regional Air Partnership (WRAP) Program, a regional initiative involving New Mexico, Utah, and Wyoming directed toward addressing visibility issues in the Grand Canyon and affecting SO_2 emissions starting in 2018. The WRAP specifications for SO_2 are presented in Table 7-4.

3.9.2 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA Base Case v.5.13 through a combination of system level NO_x programs and generation unit-level NO_x limits. The NO_x SIP Call trading program is no longer represented since it was replaced by the requirements of the Clean Air Interstate Rule (CAIR), described in section 3.9.4 below. Rhode Island is the only state from the NOx SIP Call that is not covered in CAIR. Its NO_x emission obligations under the NO_x SIP Call are still included in EPA Base Case v.5.13.

By assigning unit-specific NO_x rates based on 2011 data, EPA Base Case v.5.13 is implicitly representing Title IV unit-specific rate limits and Clean Air Act Reasonably Available Control Technology (RACT) requirements for controlling NO_x emissions from electric generating units in ozone non-attainment areas or in the Ozone Transport Region (OTR).[14] Unlike SO_2 emission rates, NO_x emission rates are assumed not to vary with fuel, but are dependent on the combustion properties of the generating unit. Under the EPA Base Case v.5.13 the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x pollution control equipment or if it is assumed to install state-of-the-art NO_x combustion controls.

NO_x Emission Rates

Future emission projections for NO_x are a product of a unit's utilization (heat input) and emission rate (lbs/mmbtu). A unit's NO_x emission rate can vary significantly depending on the NO_X reduction requirements to which it is subject. For example, a unit may have a post-combustion control installed (e.g., SCR or SNCR), but only operate it during the particular time of the year in which it is subject to NO_x reduction requirements (i.e., the unit only operates its post-combustion control during the ozone season). Therefore, its ozone-season NO_x emission rate would be lower than its non-ozone-season NO_x emission rate. Because the same individual unit can have such large variation in its emission rate, the model needs a suite of emission rate "modes" from which it can select the value most appropriate to the conditions in any given model scenario. The different emission rates reflect the different operational conditions a unit may experience regarding upgrades to its combustion controls and operation of its

[14] The OTR consists of the following states: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, Pennsylvania, Delaware, Maryland, District of Columbia, and northern Virginia.

existing post-combustion controls. Four modes of operation are developed for each unit, with each mode carrying a potentially different NO_x emission rate for that unit under those operational conditions.

The emission rates assigned to each mode are derived from historic data (where available) and presented in the NEEDS file. When the model is run, IPM selects one of these four modes through a decision process depicted in

Figure 3-4 below. The four modes address whether or not units upgrade combustion controls and/or operate *existing* post-combustion controls; the modes themselves do not address what happens to the unit's NOx rate if it is projected to add a *new* post-combustion NOx control. In such cases, after the model selects the appropriate mode, the emission rate originally assigned to that mode is further adjusted downward to reflect the retrofit of a SCR or SNCR. In this case, an emission rate is assumed that reflects a percentage removal from the mode's emission rate or an emission rate floor (whichever is greater). The full process for determining the NOx rate of units in EPA Base Case v.5.13 model projections is summarized in Figure 3-3 below.

Figure 3-3 Modeling Process for Obtaining Projected NO_x Emission Rates

<u>NO_x Emission Rates in NEEDS, v.5.13 Database</u>

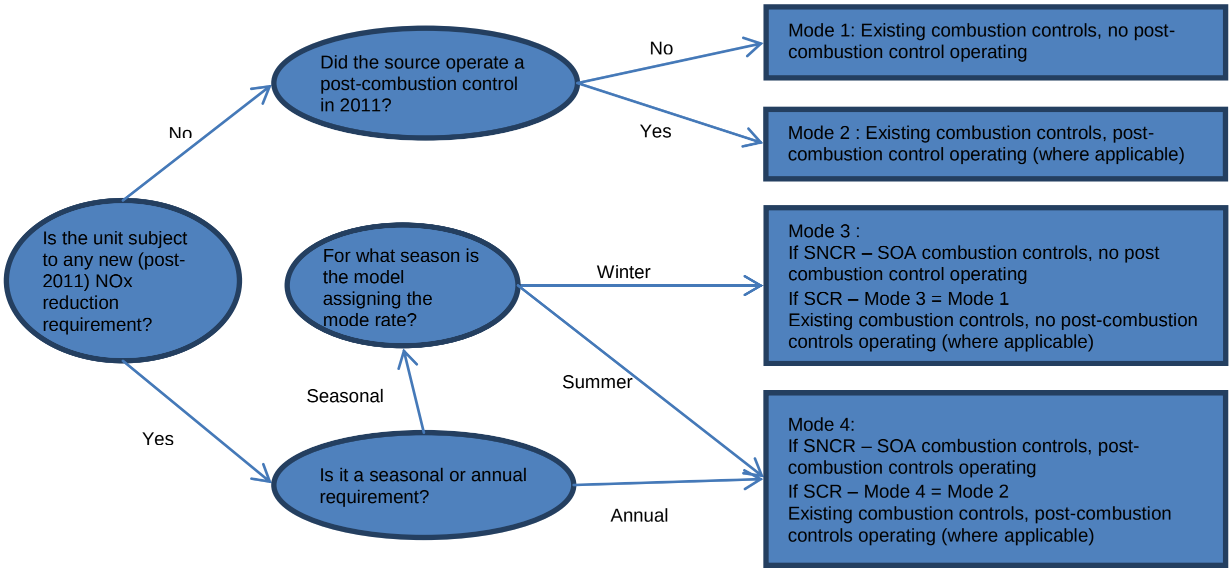
The NO_x rates in the current base case were derived, wherever possible, directly from actual monitored NO_x emission rate data reported to EPA under the Acid Rain and NO_x Budget Program in 2011. The emission rates themselves reflect the impact of applicable NO_x regulations. For coal-fired units, NO_x rates were used in combination with detailed engineering assessments of NO_x combustion control performance to prepare a set of four possible starting NO_x rates to assign to a unit, depending on the specific NO_X reduction requirements affecting that unit in a model run.

The reason for having a framework of four potential NO_x rate "modes" applicable to each unit in NEEDS is to enable the model to select from a range of NO_x rates possible at a unit, given its configuration of NO_x combustion controls and its assumed operation of existing post-combustion controls. There are up to four basic operating states for a given unit that significantly impact its NO_x rate, and thus there are four NO_X rate "modes".

Mode 1: No post-combustion control operating; existing combustion controls
Mode 2: Post-combustion control operating, existing combustion controls
Mode 3: No post-combustion control operating; state-of-the-art (SOA) combustion controls (where applicable)
Mode 4: Post-combustion control operating; state-of-the-art (SOA) combustion controls (where applicable)

Emission rates derived for each unit operating under each of these four modes are presented in the NEEDS file. Note, not every unit has a different emission rate for each mode, because certain units cannot in practice change their NO_x rates to conform to all potential operational states described above. For instance, a unit without a post-combustion control will not have different emission rates between modes 1 and 2, or between modes 3 and 4, as there is no post-combustion control that would potentially turn on or off at these units. For such units, the mode 2 rate will simply equal the mode 1 rate, and the mode 4 rate will equal the mode 3 rate.

Figure 3-4 How One of the Four NO_x Modes Is Ultimately Selected for a Unit



State-of-the-art combustion controls (SOA combustion controls)

The definition of "state-of-the-art" varies depending on the unit type and configuration. Table 3-11 indicates the incremental combustion controls that are required to achieve a "state-of-the-art" combustion control configuration for each unit. For instance if a wall-fired boiler (highlighted below) currently has LNB, the "state-of-the-art" rate calculated for such a unit would assume a NO_x emission rate reflective of overfire air being added at the unit. The cost assumptions behind such an upgrade are described in chapter 5. As described in the attachment of this chapter, the "state-of-the-art" combustion controls reflected in the modes are only assigned to a unit if it is subject to a *new* (post-2011) NO_x reduction requirement (i.e., a NO_x reduction requirement that did not apply to the unit during its 2011 operation that forms the historic basis for deriving NO_x rates for units in Base Case v.5.13). Existing reduction requirements as of 2011 (e.g., NO_x SIP Call) under which units have already made combustion control decisions would not trigger the assignment of the "state-of-the-art" modes that reflect additional combustion controls.

Table 3-11 State-of-the-Art Combustion Control Configurations by Boiler Type

Boiler Type	Existing NO_x Combustion Control	Incremental Combustion Control Necessary to Achieve "State-of-the-Art"
Cell	LNB NGR	OFA LNB AND OFA
Cyclone	--	OFA
Stoker/SPR	--	OFA
Tangential	-- LA LNB LNB + OFA LNC1[a] LNC2 OFA ROFA	LNC3 LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC1 TO LNC3 CONVERSION FROM LNC2 TO LNC3 LNC1 LNB
Vertical	--	NO_x Combustion Control - Vertically Fired Units
Wall	-- LA	LNB AND OFA LNB AND OFA

Boiler Type	Existing NO_x Combustion Control	Incremental Combustion Control Necessary to Achieve "State-of-the-Art"
	LNB	OFA
	LNF	OFA
	OFA	LNB

[a] LNC1 = low NO_x coal-and air nozzles with close-coupled overfire air, LNC2 = Low NO_x Coal-and-Air Nozzles with Separated Overfire Air, LNC3 = Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air

The emission rates for each generating unit under each mode are included in the NEEDS v5.13 database, described in Chapter 4. Attachment 3-1 and accompanying Tables 3-1.1and 3-1.2 give further information on the procedures employed to derive the four NO_x modes.

Additional NO_x rate assumptions include default NO_x rates of 0.23 lbs/MMBtu for existing biomass units and 0.044 lbs/MMBtu for existing landfill gas units.

Because of the complexity of the fleet and the completeness/incompleteness of historic data, there are instances where the derivation of a unit's modeled NO_x emission rate is more detailed than the description provided above. For a more complete step-by-step description of the decision rules used to develop the NO_x rates, please see attachment 3-1.

3.9.3 Multi-Pollutant Environmental Regulations

CAIR

The Clean Air Interstate Rule (CAIR) uses a cap and trade system to reduce the target pollutants—SO_2 and NO_x—for 27 eastern states and DC.[15] CAIR uses Title IV SO_2 allowances as currency for the SO_2 trading program. The initial bank and allowance totals for CAIR are the same as for the Acid Rain Program above. For the Annual NO_x trading program, the total Annual NO_x allowances issued for 2016 was 1.2 million and the initial bank for 2016 was projected to be 1.5 million allowances. For the Ozone Season NO_x trading program, the total seasonal NO_x allowances was 0.48 million and the initial bank going into 2016 was projected to be 0.74 million. Table 7-4shows the initial bank and 2016 allowance specification along with the caps for the entire modeling time horizon.

In 2008, the U.S. Court of Appeals for the District of Columbia Circuit remanded CAIR to EPA to correct legal flaws in the proposed regulations as cited in the Court's July 2008 ruling. The Court allowed EPA to proceed with implementation of the CAIR trading programs while EPA works on a replacement rule addressing the Court's findings. CAIR's provisions were still in effect when EPA Base Case v.5.13 was released and were included in the modeling. For more information on CAIR, go to http://www.epa.gov/cair/.

MATS

Finalized in 2011, the Mercury and Air Toxics Rule (MATS) establishes National Emissions Standards for Hazardous Air Pollutants (NESHAPS) for the "electric utility steam generating unit" source category, which includes those units that combust coal or oil for the purpose of generating electricity for sale and distribution through the electric grid to the public. EPA v.5.13 applies the input-based (lbs/MMBtu) MATS control requirements for mercury and hydrogen chloride to covered units. Treatment of the filterable PM standard in the model is detailed in section 5.6.1. EPA Base Case v.5.13 does not model the alternative SO_2 standard offered under MATS for units to demonstrate compliance with the rule's HCl control requirements. Coal steam units with access to lignite in the modeling are required to meet the "existing

[15] The states included in the Clean Air Interstate Rule are Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia and Wisconsin.

coal-fired unit low Btu virgin coal" standard. For more information on MATS, go to http://www.epa.gov/mats/.

Regional Haze

The Clean Air Act establishes a national goal for returning visibility to natural conditions through the "prevention of any future, and the remedying of any existing impairment of visibility in Class I areas [156 national parks and wilderness areas], where impairment results from manmade air pollution." On July 1, 1999, EPA established a comprehensive visibility protection program with the issuance of the regional haze rule (64 FR 35714). This rule implements the requirements of section 169B of the CAAA and requires states to submit State Implementation Plans (SIPs) establishing goals and long-term strategies for reducing emissions of air pollutants (including SO_2 and NO_x) that cause or contribute to visibility impairment. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia, and the Virgin Islands. Among the components of a long-term strategy is the requirement for states to establish emission limits for visibility-impairing pollutants emitted by certain source types (including EGUs) that were placed in operation between 1962 and 1977. These emission limits are to reflect Best Available Retrofit Technology (BART). States may perform individual point source BART determinations, or meet the requirements of the rule with an approved BART alternative. An alternative regional SO_2 cap for EGUs under Section 309 of the regional haze rule is available to certain western states whose emission sources affect Class 1 areas on the Colorado Plateau.

Since 2010, EPA has approved or, in a very few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of August 29, 2013) that will be in place for EGUs are represented in the EPA Base Case v.5.13 as follows.

- Source-specific NO_x or SO_2 BART emission limits, minimum SO_2 removal efficiency requirements for FGDs, limits on sulfur content in fuel oil, constraints on fuel type (e.g., natural gas only or prohibition of certain fuels such as petroleum coke), or commitments to retire units are applied to the relevant EGUs.
- EGUs in states that rely on CAIR trading programs to satisfy BART must meet the requirements of CAIR.
- EGUs in states that rely on state power plant rules to satisfy BART must meet the emission limits imposed by those state rules.
- For the three western states (New Mexico, Wyoming, and Utah) with approved Section 309 SIPs for SO_2 BART, emission constraints were not applied as current and projected emissions are well under the regional SO_2 cap.

Table 3-19 lists the NO_x and SO_2 limits applied to specific EGUs and other implementations applied in IPM. For more information on Regional Haze Rule, go to: http://www.epa.gov/visibility/program.html

3.9.4 CO_2 Regulations

The Regional Greenhouse Gas Initiative (RGGI) is a CO_2 cap and trade program affecting fossil fired electric power plants 25 MW or larger in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Table 7-4 shows the specifications for RGGI that are implemented in EPA Base Case v.5.13.

As part of California's Assembly Bill 32 (AB32), the Global Warming Solutions Act, a multi-sector GHG cap-and-trade program was established that targets 1990 emission levels by 2020. The cap begins in 2013 for electric utilities and large industrial facilities, with distributors of transportation, natural gas and other fuels joining the capped sectors in 2015. In addition to in-state sources, the cap-and-trade program also covers the emissions associated with qualifying, out-of-state EGUs that sell power into California. Due to the inherent complexity in modeling a multi-sector cap-and-trade program where the participation of out-of-state EGUs is determined based on endogenous behavior (i.e. IPM determines whether qualifying out-of-state EGUs are projected to sell power into California), EPA has developed a simplified methodology to model California's cap-and-trade program:

- Adopt the AB32 cap-and-trade allowance price from EIA's AEO2013 Reference Case, which fully represents the non-power sectors. All qualifying fossil-fired EGUs in California are subject to this price signal.
- Estimate a marginal CO_2 emission rate for each IPM region that exports power to California. This rate is assumed to be the CO_2 rate of the model plant with the highest variable cost in EPA Base Case v.5.13.
- For each IPM region that exports power to California, convert the $/ton CO_2 allowance price projection into a mills/kWh transmission wheeling charge using the marginal emission rate from the previous step. The additional wheeling charge for qualifying out-of-state EGUs is equal to the allowance price imposed on affected in-state EGUs. Applying the charge to the transmission link ensures that power imported into California from out-of-state EGUs must account for the cost of CO_2 emissions represented by its generation, such that the model may clear the California market in a manner consistent with AB32 policy treatment of CO_2 emissions.

3.9.5 State-Specific Environmental Regulations

EPA Base Case v.5.13 represents enacted laws and regulations in 26 states affecting emissions from the electricity sector. Table 3-13 summarizes the provisions of state laws and regulations that are represented in EPA Base Case v.5.13.

3.9.6 New Source Review (NSR) Settlements

New Source Review (NSR) settlements refer to legal agreements with companies resulting from the permitting process under the CAAA which requires industry to undergo an EPA pre-construction review of proposed environmental controls either on new facilities or as modifications to existing facilities where there would result a "significant increase" in a regulated pollutant. EPA Base Case v.5.13 includes NSR settlements with 31 electric power companies. A summary of the units affected and how the settlements were modeled can be found in Table 3-14.

Eight state settlements and nine citizen settlements are also represented in EPA Base Case v.5.13. These are summarized in Table 3-15 and Table 3-16 respectively.

3.9.7 Emission Assumptions for Potential (New) Units

Emissions from existing and planned/committed units vary from installation to installation based on the performance of the generating unit and the emissions regulations that are in place. In contrast, there are no location-specific variations in the emission and removal rate capabilities of potential new units. In IPM, potential new units are modeled as additional capacity and generation that may come online in each model region. Across all model regions the emission and removal rate capabilities of potential new units are the same, and they reflect applicable federal emission limitations on new sources. The specific assumptions regarding the emission and removal rates of potential new units in EPA Base Case v.5.13 are presented in Table 3-12. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-12 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units, see Chapter 4.

3.9.8 Energy Efficiency and Renewable Portfolio Standards

Renewable Portfolio Standards (RPS) generally refers to various state-level policies that require the addition of renewable generation to meet a specified share of state-wide generation. In EPA Base Case v.5.13 the state RPS requirements are represented at a regional level utilizing the aggregate regional representation of RPS requirements that is implemented in AEO 2013 as shown in Table 3-17.[16] This table shows the RPS requirements that apply to the NEMS (National Energy Modeling System) regions used in AEO. In addition, state level solar carve-out requirements have been implemented at a NEMS region level in EPA Base Case v.5.13.

3.10 Capacity Deployment Constraints

EPA Base Case v.5.13 includes capacity deployment constraints for the more capital intensive generation technologies and retrofits (new nuclear, advanced coal with carbon capture, and carbon capture retrofits). The deployment constraints are intended to capture factors that are likely to place an upper bound on the amount of these technologies that can be built in the real world in any given model run year over the modeling time horizon. Such limiting factors include:

- production capacity limitations (including the number of engineering and construction (E/C) firms capable of executing large power projects in the U.S., the number of large projects each such firm can handle, and the number of multi-billion dollar projects a firm can take on in parallel),
- general limitations in the domestic infrastructure for heavy manufacturing,
- financial limitations (number of projects that can obtain financing simultaneously at an acceptable level of risk),
- workforce limitations (limitations in the skilled engineering and construction labor force, replacement challenges caused by an aging workforce, on the one hand, and inadequate training infrastructure for new entrants, on the other).

The capacity deployment constraints are based on assessments by EPA power sector engineering staff of historical trends and projections of capability going forward. Conceptually, the procedure used to develop these constraints consisted of the following steps:

1. Start by estimating the maximum number of E/C firms that will be available over the time horizon.
2. Estimate the maximum number of a particular type of generating unit (e.g., 600 MW advanced coal plant with carbon capture) that a single E/C firm can complete in the first 5-year period (2015-2020).
3. Multiply the number of E/C firms estimated in Step 1 by the number of units per firm found in Step 2 to obtain the maximum number of these generating units that can be completed in the first period.
4. Determine if there will be competition from other competing technologies for the same productive capacity and labor force used for the technology analyzed in steps 2 and 3. If not, go to Step 7. If so, go to Step 5.
5. Establish an equivalency table showing how much capacity could be built if the effort required to build 1 MW of the type of technology analyzed in steps 2 and 3 were instead used to build another type of generating technology (e.g., 1600 MW nuclear plant).
6. Based on these calculations build a production possibility frontier showing the maximum mix of the two generating technologies that can be added in the first 5-year period.
7. Over the subsequent five year periods assume that the E/C firms have increased capabilities relative to the previous five year period. Represent the increased capability by a capability multiplier. For example, it might be assumed that each succeeding 5-year period the E/C firms can design and build 1.4 as much as in the immediately preceding 5-year period. Multiply the capacity deployment limit(s) from the preceding period by the capability multiplier to derive the capacity deployment limit for the subsequent period.

[16] Energy Information Administration, U.S. Department of Energy, *Assumptions to Annual Energy Outlook 2013: Renewable Fuels Module* (DOE/EIA-0554(2010)), April 15, 2013, Table 13.2 “Aggregate Regional Renewable Portfolio Standard Requirements,” http://www.eia.gov/forecasts/aeo/assumptions/pdf/renewable.pdf.

8. If necessary, prevent sudden spikes in capacity in later periods when there has been little or no build up in preceding periods by tying the amount of capacity that can be built in a given period to the amount of capacity built in preceding periods.

Attachment 3-2 shows the joint capacity deployment constraint on advanced coal with carbon capture and storage (CCS) and new nuclear. Attachment 3-3 shows the capacity deployment constraint on new nuclear in itself. The bar graph in Attachment 3-3 illustrates how building capacity in earlier years increases the maximum capacity that can be built over the entire modeling time horizon.

Table 3-12 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Base Case v.5.13

	Controls, Removal, and Emissions Rates	Supercritical Pulverized Coal	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Sequestration	Advanced Combined Cycle	Advanced Combined Cycle with Carbon Sequestration	Advanced Combustion Turbine	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas
SO_2	**Removal / Emissions Rate**	96% with a floor of 0.06 lbs/MMBtu	99%	99%	None	None	None	0.08 lbs/MMBtu	None	None
NO_x	**Emission Rate**	0.07 lbs/MMBtu	0.013 lbs/MMBtu	0.013 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.011 lbs/MMBtu	0.02 lbs/MMBtu	None	0.09 lbs/MMBtu
Hg	**Removal / Emissions Rate**	90%	90%	90%	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	Natural Gas: 0.000138 lbs/MMBtu Oil: 0.483 lbs/MMBtu	0.57 lbs/MMBtu	3.70	None
CO_2	**Removal / Emissions Rate**	202.8 - 215.8 lbs/MMBtu	202.8 - 215.8 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	90%	Natural Gas: 117.08 lbs/MMBtu Oil: 161.39 lbs/MMBtu	None	None	None
HCL	**Removal / Emissions Rate**	99% 0.0001 lbs/MMBtu	99% 0.0001 lbs/MMBtu	99% 0.0001 lbs/MMBtu						

Attachment 3-1 NO_x Rate Development in EPA Base Case v.5.13

The following questions (Q) and answers (A) are intended to provide further background on the four NO_x rates found in the NEEDS v5.13 database.

Q1: Why are four NO_x rates included in NEEDS?
A1: The four NO_x rates in NEEDS represent a menu of all the NO_x rates applicable to a specific generating unit with only its current configuration of NO_x combustion and post-combustion controls under all the conceivable operating conditions involving NO_x controls that might be modeled in the future. By defining this menu up front for every generating unit, the program that sets up an IPM run can follow a set of decision rules to select the rate(s) appropriate for the unit in the particular scenario being modeled consistent with the unit's existing set of combustion and post-combustion NO_x controls.

Q2: What operational states do the four NO_x rates represent?
A2: Before answering this question, let's name the four NO_x rates that are in NEEDS and the general control states they reflect

Mode 1= Existing combustion controls, no post-combustion control operation
Mode 2= Existing combustion controls, post-combustion control operation (where applicable)
Mode 3= SOA combustion controls (where applicable), no post-combustion control operation
Mode 4 = SOA combustion controls, post-combustion control operation (where applicable)

Please see Figure 3-4 in Section 3.9.2 for an explanation of how the model selects the appropriate NOx mode for each unit in the projection scenario.

Q3: How are emission rates calculated for each unit for each of the four NO_x modes?
A3: We start with the emission data reported to EPA for a specific year under Title IV of the Clean Air Act Amendments of 1990 (Acid Rain Program) and NO_x Budget Program. Using this data, NO_x rates are derived for the summer and winter seasons.

Calculations can get complex, so we'll illustrate it here for coal units only and with the assumption that the data were absolutely complete and consistent with what engineering theory tells us its values should be. Otherwise, we apply additional screens. Explaining the additional steps involved in those anamolous case-by-case evaluations is beyond the scope of this illustration. However, the process below describes how the values would generally be derived:

The procedure employs the following hierarchy of NO_x rate data sources:

1. 2011 ETS
2. Comments on NO_x rate
3. 2009 ETS
4. 2010 EIA Form 860
5. Defaults

The existing coal steam boilers in US are categorized into three groups depending on the configuration of NO_x combustion and post-combustion controls.

Group 1 - Coal boilers without post-combustion NO_x controls
Mode 1 = 2011 ETS Annual Average NO_x Rate
Mode 2 = Mode 1

Mode 3
Mode 3 calculation follows Steps 1-7:

Step 1: Pre-screen units that already have state of art (SOA) combustion controls from units that have non- SOA combustion controls from units that have no combustion controls

Step 2: For units listed as not having combustion controls
Make sure their NO_x rates do not indicate that they really do have SOA control
If Mode 1 > Cut-off (in Table 3-1.1), then Mode 1 = Base NO_x rate. Go to Step 6
If Mode 1 ≤ Cut-off (in Table 3-1.1), then the unit has SOA control and
Mode 3 = Mode 1
Step 3: For units listed as having SOA combustion controls.
Mode 3 = Mode 1
Step 4: For units listed as not having SOA combustion controls
Make sure their NO_x rates do not indicate that they really do have SOA control

If Mode 1 ≤ Cut-off (in Table 3-1.1), then the unit has SOA control and
Mode 3 = Mode 1
If Mode 1 > Cut-off (in Table 3-1.1), then go to Step 5
Step 5: Determine the unit's Base NO_x rate, i.e., the unit's uncontrolled emission rate without combustion controls, using the appropriate equation (not in boldface italics) in Table 3-1.2 to back calculate their Base NO_x rate. Use the default Base NO_x rate values if back calculations can't be performed. Once the Base NO_x rate is obtained, go to Step 6.

Step 6: Use the appropriate equations (in boldface italics) in Table 3-1.2 to calculate the NO_x rate with SOA combustion controls.

Step 7: Compare the value calculated in Step 6 to the applicable NO_x floor rate in Table 3-1.1.

If the value from Step 6 is ≥ floor, use the Step 6 value as Mode 3. Otherwise, use the floor as the Mode 3 NO_x rate.

Mode 4
Mode 4 =Mode 3

Group 2 - Coal boilers with SCR
Pre-screen coal boilers with 2011 ETS NO_x rates into the following four operating regimes. A coal boiler is assumed to be operating its SCR when the seasonal NO_x rate is less than 0.2 lbs/MMBtu

<u>Group 2.1 SCR is not operating in both summer and winter seasons</u>
Follow the NO_x rate rules summarized for Group 1 boilers. No state of the art combustion controls are implemented.
Mode 1 = 2011 ETS Annual Average NO_x Rate Mode 2 = maximum {(1-0.9) * Mode 1, 0.07} Mode 3 = Mode 1
Mode 4 = Mode 2

<u>Group 2.2 SCR is operating in summer only</u>
Mode 1 = 2011 ETS Winter NO_x Rate
Mode 2 = 2011 ETS Summer NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

<u>Group 2.3 SCR is operating in winter only</u>
Mode 1 = 2011 ETS Summer NO_x Rate
Mode 2 = 2011 ETS Winter NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 2.4 SCR is operating year-round
Mode 1 = if (2009 ETS Winter NO_x Rate > 0.2, 2009 ETS Winter NO_x Rate, 2011 ETS Annual Average NO_x Rate)[17]
Mode 2 = 2011 ETS Annual Average NO_x Rate
Mode 3 = Mode 1
Mode 4 = Mode 2

Group 3 - Coal boilers with SNCR
Step 1: Pre-screen coal boilers with 2011 ETS NO_x rates to verify if they have not operated their SNCR in both summer and winter seasons. A coal boiler is assumed to be not operating its SNCR when the NO_x rate is greater than 0.3 lbs/MMBtu in both summer and winter seasons.

Group 3.1 SNCR is not operating in both summer and winter seasons
Follow the NO_x rate rules summarized for Group 1 boilers

Step 2: Pre-screen coal boilers with 2011 ETS NO_x rates into the following three operating regimes. First estimate the implied removal for a coal boiler using the following equation:

Implied Removal (%) = ((Winter NO_x Rate – Summer NO_x Rate)/ Winter NO_x Rate) * 100

Second, assign the coal boiler to a specific operating regime based on the following logic.
If Implied Removal > 20% then SNCR is operating in summer season only,
Else if Implied Removal < -20% then SNCR is operating in winter season only,
Else SNCR is operating year-round

Second, assign the coal boiler to a specific operating regime based on the following logic.

Group 3.2 SNCR is operating in summer only
Mode 1 = 2011 ETS Winter NO_x Rate
Mode 2= 2011 ETS Summer NO_x Rate
Mode 3 = same as Group 1 Mode 3
Mode 4 = maximum {(1-0.25) * Mode 3, 0.1} for non FBC units
Mode 4 = maximum {(1-0.50) * Mode 3, 0.08} for FBC units

Note: The (1-.25) and (1-0.5) terms in the equations above represents the NO_x removal efficiencies of SNCR for non FBC and FBC boilers.

Group 3.3 SNCR is operating in winter only
Mode 1= 2011 ETS Summer NO_x Rate
Mode 2 = 2011 ETS Winter NO_x Rate
Mode 3 = same as Group 3.2 Mode 3
Mode 4 = same as Group 3.2 Mode 4

Group 3.4 SNCR is operating year-round
Mode 1= if (2009 ETS Winter NO_x Rate > 0.3, 2009 ETS Winter NO_x Rate, 2011 ETS Annual Average NO_x Rate)
Mode 2 = 2011 ETS Annual Average NO_x Rate
Mode 3 = same as Group 3.2 Mode 3
Mode 4 = Mode 3

Other things worth noting are:

[17] This equation implies that if a unit with a SCR operates year round in ETS 2011 and in winter in ETS 2009, then Mode 1 NO_x rate will reflect SCR operation.

(a) In general, winter NO_x rates reported in EPA's Emission Tracking System were used as proxies for assigning emission rates to Mode 1.
(b) If a unit does not report having combustion controls, but has an emission rate below a specific cut-off rate (shown in Table 3-1.1), it is considered to have combustion controls.
(c) For units with combustion controls that were not state-of-the-art, the derivation of an emission rate reflecting an upgrade to state-of-the-art combustion controls necessitated calculating (as an interim step) the unit's emission rate if it were to "uninstall" its existing combustion controls. That interim "no combustion controls" emission rate becomes the departure point for calculating the unit's emission rate assuming a state-of-the-art combustion control configuration.
(d) The NO_x rates achievable by state-of-the-art combustion controls vary by coal rank (bituminous and subbituminous) and boiler type. The equations used to derive these rates are shown in Table 3-1.2

.

Table 3-1.1 Cutoff and Floor NO_x Rates (lb/MMBtu) in EPA Base Case v.5.13

Boiler Type	Cutoff Rate (lbs/MMBtu)			Floor Rate (lbs/MMBtu)		
	Bituminous	Subbituminous	Lignite	Bituminous	Subbituminous	Lignite
Wall-Fired Dry-Bottom	0.43	0.33	0.29	0.32	0.18	0.18
Tangentially-Fired	0.34	0.24	0.22	0.24	0.12	0.17
Cell-Burners	0.43	0.43	0.43	0.32	0.32	0.32
Cyclones	0.62	0.67	0.67	0.47	0.49	0.49
Vertically-Fired	0.57	0.44	0.44	0.49	0.25	0.25

Table 3-1.2 NO_x Removal Efficiencies for Different Combustion Control Configurations in EPA Base Case v.5.13
(State of the art configurations are shown in bold italic.)

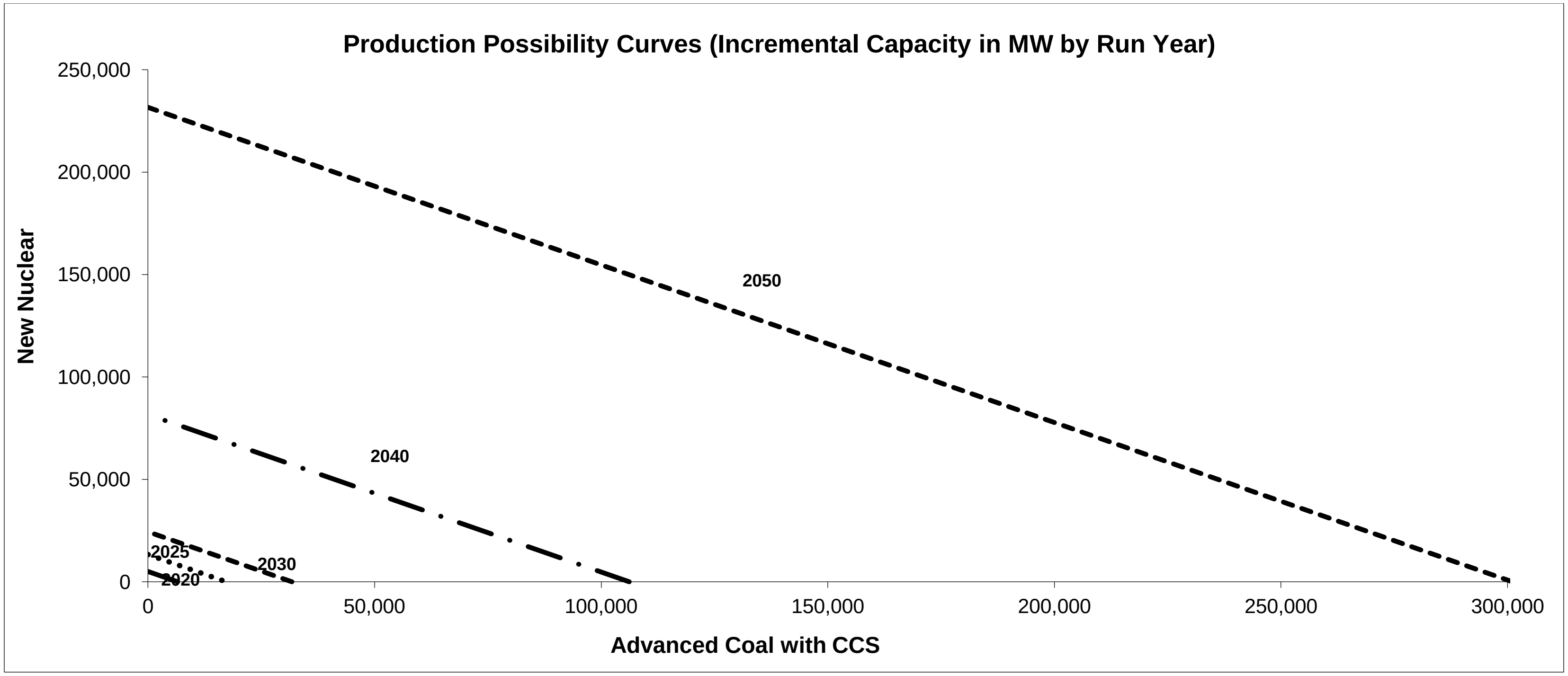
Boiler Type	Coal Type	Combustion Control Technology	Fraction of Removal	Default Removal
Dry Bottom Wall-Fired	Bituminous	LNB	0.163 + 0.272* Base NO_x	0.568
		LNB + OFA	0.313 + 0.272* Base NO_x	0.718
Dry Bottom Wall-Fired	Subbituminous/Lignite	LNB	0.135 + 0.541* Base NO_x	0.574
		LNB + OFA	0.285 + 0.541* Base NO_x	0.724
Tangentially-Fired	Bituminous	LNC1	0.162 + 0.336* Base NO_x	0.42
		LNC2	0.212 + 0.336* Base NO_x	0.47
		LNC3	0.362 + 0.336* Base NO_x	0.62
Tangentially-Fired	Subbituminous/Lignite	LNC1	0.20 + 0.717* Base NO_x	0.563
		LNC2	0.25 + 0.717* Base NO_x	0.613
		LNC3	0.35 + 0.717* Base NO_x	0.713

Notes:
LNB = Low NO_x Burner
OFA = Overfire Air
LNC = Low NO_x Control

Attachment 3-2 Capacity Deployment Limits for Advanced Coal with CCS and New Nuclear in EPA Base Case v.5.13

Run Year	Advanced Coal with CCS (MW)	New Nuclear (MW)
2016	-	-
2018	-	-
2020	6,500	5,000
2025	17,254	13,272
2030	31,750	24,423
2040	106,211	81,701
2050	301,097	231,613

Notes:
The 2020 through 2050 limits for Advanced Coal with CCS and New Nuclear technologies are a joint constraint, with the maximum amount of possible development for each technology shown by run year. If the maximum amount of one technology is developed in a given run year, zero MW of the other may be developed. See the production possibility chart below.



Attachment 3-3 Nuclear Capacity Deployment Constraint in EPA Base Case v.5.13

Run Year	Base New Nuclear Capacity	Base New Nuclear Capacity Deployment Equation	*Possible* Additional New Nuclear Capacity Deployment Equation[1]	Maximum Annual Incremental New Nuclear Capacity Deployment Allowed Equation
2020	5,000	5,000	0	5,000
2025	4,400	0.88 * 2020_Base_Capacity	+ 0.88 * *2020_Incremental_Capacity*	= 0.88 * (*2020_Base_Capacity* + *2020_Incremental_Capacity*)
2030	3,872	0.88 * *2025_Base_Capacity*	+ 0.88 * *2025_Incremental_Capacity*	= 0.88 * (*2025_Base_Capacity* + *2020_Incremental_Capacity*)
2040	19,208	4.96 * *2030_Base_Capacity*	+ 4.96 * *2030_Incremental_Capacity*	= 4.96 * (*2030_Base_Capacity* + *2030_Incremental_Capacity*)
2050	37,648	1.96 * *2040_Base_Capacity*	+ 1.96 * *2040_Incremental_Capacity*	= 1.96 * (*2040_Base_Capacity* + *2040_Incremental_Capacity*)

Run Year	Maximum Possible New Nuclear Capacity Deployment Allowed									
	Deployment Starts 2020		Deployment Starts 2025		Deployment Starts 2030		Deployment Starts 2040		Deployment Starts 2050	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2020	5,000	5,000	0	0	0	0	0	0	0	0
2025	8,272	13,272	4,400	4,400	0	0	0	0	0	0
2030	11,151	24,423	7,744	12,144	3,872	3,872	0	0	0	0
2040	57,278	81,701	43,010	55,154	26,797	30,669	19,208	19,208	0	0
2050	149,912	231,613	121,948	177,102	90,170	120,839	75,295	94,503	37,648	37,648

Notes:

No nuclear deployment is allowed before 2020

[1]Addtional new nuclear capacity deployment is *only* possible if nuclear capacity has been built in the previous run year.

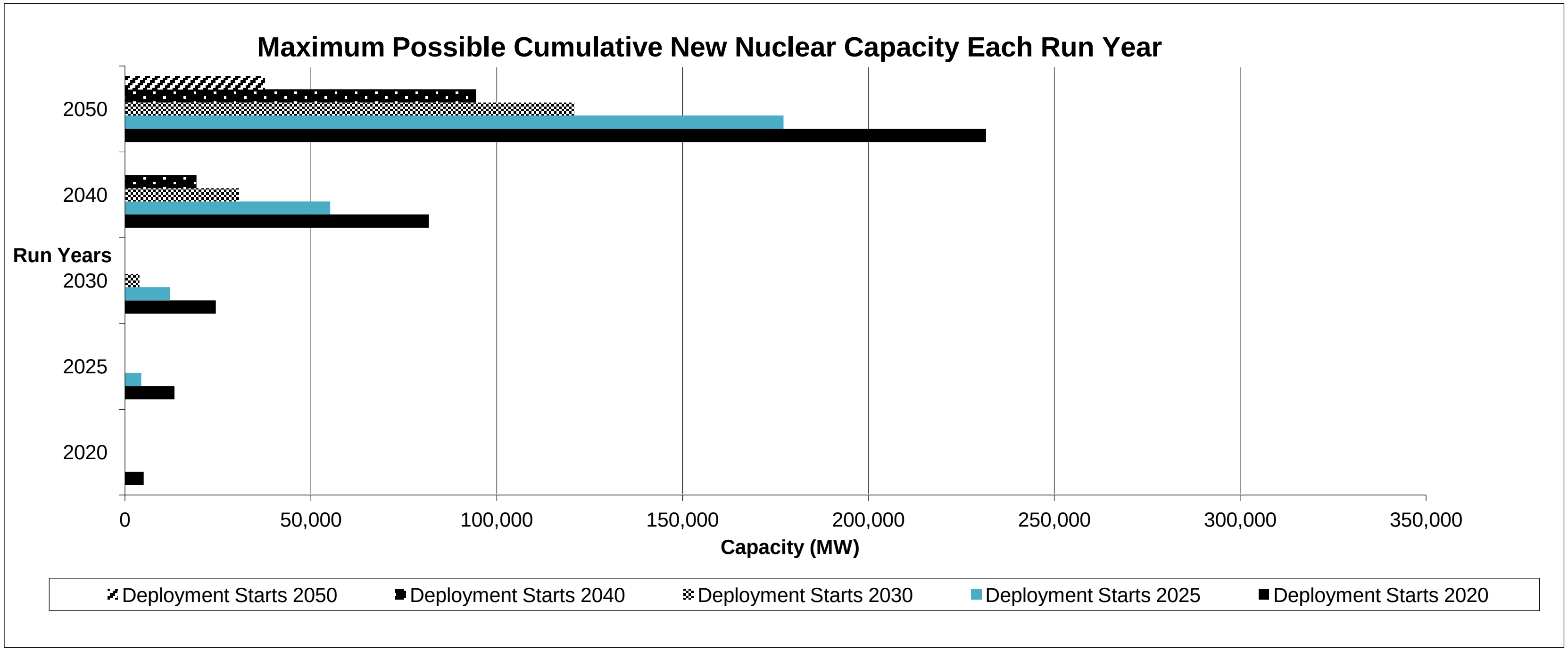

Maximum Possible Cumulative New Nuclear Capacity Each Run Year
Run Years
2050
2040
2030
2025
2020
0
50,000
100,000
150,000
200,000
250,000
300,000
350,000
Capacity (MW)
Deployment Starts 2050
Deployment Starts 2040
Deployment Starts 2030
Deployment Starts 2025
Deployment Starts 2020

Table 3-13 State Power Sector Regulations included in EPA Base Case v.5.13

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Alabama	Alabama Administrative Code Chapter 335-3-8	NO_x	0.02 lbs/MMBtu for combined cycle EGUs which commenced operation after April 1, 2003; For combined-cycle electric generating units fired by natural gas: 4.0 ppmvd at 15% O2 (0.0178 lbs/MMBtu), by fuel oil- 15.0 ppmvd at 15% O2 (0.0667 lbs/MMBtu)	2003	
Arizona	Title 18, Chapter 2, Article 7	Hg	90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all non-cogen coal units > 25 MW	2017	
California	CA Reclaim Market	NO_x	9.68 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)	1994	Since the Reclaim Trading Credits are applicable to entities besides power plants, we approximate by hardwiring the NO_x and SO_2 allowance prices for the calendar year 2006.
		SO_2	4.292 MTons annual cap for list of entities in Appendix A of "Annual RECLAIM Audit Market Report for the Compliance Year 2005" (304 entities)		
	CA AB 32	CO_2	Power sector and Non-power Sector Cap in Million metric tons: 382.40 in 2016, 358.30 in 2018 and 334.20 2020 onwards.	2012	Refer to Section 3.9.4 for details
Colorado	40 C.F.R. Part 60	Hg	2012 & 2013: 80% reduction of Hg content of fuel or 0.0174 lbs/GWh annual reduction for Pawnee Station 1 and Rawhide Station 101. 2014 through 2016: 80% reduction of Hg content of fuel or 0.0174 lbs/GWh annual reduction for all coal units > 25 MW 2017 onwards: 90% reduction of Hg content of fuel or 0.0087 lb/GWh annual reduction for all coal units > 25 MW	2012	
	Clean Air, Clean Jobs Act	NO_x, SO_2, Hg	Retire Arapahoe 3 by 2014; Cherokee 1 & 2 by 2012, Cherokee 3 by 2017; Cameo 1 & 2; Valmont 5 by 2018; W N Clark 55 & 59 by 2015 Convert following units to natural gas: Arapahoe 4 by 2015; Cherokee 4 by 2018 Install SCRs in Hayden 1 & 2 by 2016; SCR + FGD in Pawnee 1 [already installed]	2010	
Connecticut	Executive Order 19 and Regulations of Connecticut State Agencies (RCSA) 22a-174-22	NO_x	0.15 lbs/MMBtu annual rate limit for all fossil units > 15 MW	2003	
	Executive Order 19, RCSA 22a-198 & Connecticut General Statues (CGS) 22a-198	SO_2	0.33 lbs/MMBtu annual rate limit for all fossil units > 25 MW (Title IV Sources) 0.55 lbs/MMBtu annual rate limit for all non-fossil units > 15 MW and fossil units < 25MW and > 15MW (Non-Title IV Sources)		
	Public Act No. 03-72 & RCSA 22a-198	Hg	90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all coal-fired units	2008	
Delaware	Regulation 1148: Control of Stationary Combustion Turbine EGU Emissions	NO_x	0.19 lbs/MMBtu ozone season PPMDV for stationary, liquid fuel fired CT EGUs >1 MW 0.39 lbs/MMBtu ozone season PPMDV for stationary, gas fuel fired CT EGUs >1 MW	2009	
	Regulation No. 1146: Electric Generating Unit (EGU) Multi-Pollutant Regulation	NO_x	0.125 lbs/MMBtu rate limit of NO_x annually for all coal and residual-oil fired units > 25 MW	2009	The following units have specific NO_x, SO_2, and Hg annual caps in MTons: Edge Moor 3: 0.773 NO_x, 1.391
		SO_2	0.26 lbs/MMBtu annual rate limit for coal and residual-oil fired units > 25 MW		

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
		Hg	2012: 80% removal of Hg content of fuel or 0.0174 lbs/GWh annual reduction for all coal units > 25 MW 2013 onwards: 90% removal of Hg content of fuel or 0.0087 lbs/GWh annual reduction for all coal units > 25 MW	2012	SO_2, & 2012: 0.0000083 Hg, 2013 onwards: 0.0000033 Hg Edge Moor 4: 1.339 NO_x, 2.41 SO_2, & 2012: 0.0000144 Hg, 2013 onwards: 0.0000057 Hg Edge More 5: 1.348 NO_x & 2.427 SO_2 Indian River 3: 0.977 NO_x, 1.759 SO_2, & 2012: 0.0000105 Hg, 2013 onwards: 0.0000042 Hg Indian River 4: 2.032 NO_x, 3.657 SO_2, & 2012: 0.0000219 Hg, 2013 onwards: 0.0000087 Hg McKee Run 3 0.244 NO_x & 0.439 SO_2
	Regulation 1108: Distillate Fuel Oil rule	SO_2	Any relevant units are to use 0.3% sulfur distillate fuel oil		Fuel rule modeled through unit emission rates
Georgia	Multi-pollutant Control for Electric Utility Steam Generating Units	SCR, FGD, and Sorbent Injection Baghouse controls to be installed	The following plants must install controls: Bowen, Branch, Hammond, McDonough, Scherer, Wansley, and Yates	Implementation from 2008 through 2015, depending on plant and control type	
Illinois	Title 35, Section 217.706	NO_x	0.25 lbs/MMBtu summer season rate limit for all fossil units > 25 MW	2003	
	Title 35, Part 225, Subpart B 225.230	Hg	90% removal of Hg content of fuel; or a standard of .0080 lb Hg/GWh for sources at or above 25 MW; If facility commenced operation on or before December 31, 2008, start date for implementation must be July 1, 2009	2009	Not Ameren Specific
	Title 35 Part 225 Subpart B 225.233	NO_x	0.11 lbs/MMBtu annual rate limit and ozone season rate limit for all coal steam units > 25 MW	2012	Not Ameren Specific
		SO_2	2015 onwards: 0.25 lbs/MMBtu annual rate limit for all coal steam units > 25 MW or a rate equivalent to 35% of the base SO_2 emissions (whichever is more stringent)	2015	
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GWh annual reduction for all coal units > 25 MW	2015	
	Title 35 Part 225 Subpart B 225.233 (MPS Ameren specific)	NOx	0.11 lbs/MMBtu annual rate limit and ozone season rate limit Ameren coal steam units > 25 MW	2012	
		SO_2	2015 & 2016 onwards: 0.25 lbs/MMBtu annual rate limit for all Ameren coal steam units > 25 MW 2017 onwards: 0.23 lbs/MMBtu annual rate limit for all Ameren coal steam units > 25 MW	2015	
	Title 35 Part 225; Subpart F: Combined Pollutant Standards (REPEALED)	NO_x	0.11 lbs/MMBtu ozone season and annual rate limit for all specified Midwest Gen coal steam units	2012	REPEALED
		SO_2	0.44 lbs/MMBtu annual rate limit in 2013, decreasing annually to 0.11 lbs/MMBtu in 2019 for all specified Midwest Gen coal steam units	2013	
		Hg	90% removal of Hg content of fuel or 0.08 lbs/GWh annual reduction for all specified Midwest Gen coal steam units	2015	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Louisiana	Title 33 Part II - Chapter 22, Control of Nitrogen Oxides	NO_x	For units >/= 80 MMBtu/hr, rate limit in lbs/MMBtu: Coal fired : 0.21 Oil-fired: 0.18 All others (gas or liquid): 0.1 Stationary Sources >/= 10 MMBtu/hr, rate limit in lbs/MMBtu: Oil-fired: 0.3 Gas-fired: 0.2		Applicable for all units in Baton Rouge Nonattainment Area & Region of Influence. Willow Glenn, located in Iberville, obtained a permit that allows its gas-fired units to maintain a cap. These units are separately modeled.
	Title 33, Part III - Chapter 15, Emission Standards for Sulfur Dioxide	SO_2	1.2 lbs/MMBtu ozone season ppmvd for all single point sources that emit or have the potential to emit 5 tons or more of SO_2	2005	
Maine	Chapter 145 NO_x Control Program	NO_x	0.22 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity < 750 MMBtu/hr. 0.15 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW built before 1995 with a heat input capacity > 750 MMBtu/hr. 0.20 lbs/MMBtu annual rate limit for all fossil fuel fired indirect heat exchangers, primary boilers, and resource recovery units with heat input capacity > 250 MMBtu/hr	2005	
	38 MRSA Section 603-A Low Sulfur in Fuel Rule	SO_2	All fossil units require the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu]	2018	Fuel rule modeled through unit emission rates
	Statue 585-B Title 38, Chapter 4: Protection and Improvement of Air	Hg	25 lbs annual cap for any facility including EGUs	2010	
Maryland	Maryland Healthy Air Act	NO_x	7.3 MTons summer cap and 16.7 MTons annual cap for 15 specific existing coal steam units	2009	
		SO_2	2009 through 2012: 48.6 MTons annual cap for 15 specific existing coal steam units 2013 onwards: 37.2 MTons annual cap for 15 specific existing coal steam units		
		Hg	2010 through 2012: 80% removal of Hg content of fuel for 15 specific existing coal steam units 2013 onwards: 90% removal of Hg content of fuel for 15 specific existing coal steam units		
Massachusetts	310 CMR 7.29	NO_x	1.5 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor	2006	
		SO_2	3.0 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor		
		Hg	2012: 85% removal of Hg content of fuel or 0.00000625 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor 2013 onwards: 95% removal of Hg content of fuel or 0.0000025 lbs/MWh annual GPS for Brayton Point, Mystic Generating Station, Mount Tom, Canal, and Salem Harbor		Brayton units 1 through 3 have an annual Hg cap of 0.0000733 MTons Mt. Tom 1 has an annual Hg cap of 0.00000205 MTons Salem Harbor units 1 through 3 have an annual Hg cap of 0.0000106 MTons
	310 CMR 7.04	SO_2	Sulfur in Fuel Oil Rule requires the use of 0.5% sulfur residual oil [0.52 lbs/MMBtu] by July 1, 2014 for units greater than 250 MMBtu energy input; by July 1, 2018 for all residual oil units except for those located in the Berkshire APCD.	2014	Fuel rule modeled through unit emission rates

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
Michigan	Part 18 Rules – R 336.1801 (2) (a)	NO_x	For all fossil units > 25 MW, and annual PTE of NO_x >25 tons,.25 lbs/MMBtu ozone season rate, OR 65% NO_x reductions from 1990 levels	2004	
	Part 18 Rules – R 336.1801 (2) (a)	SO_2	SO_2 ppmvd rates in 50% excess air for units in Wayne county: Pulverized coal: 550;Other coal: 420;Distillate oil Nos. 1 & 2: 120;Used oil: 300;Crude and Heavy oil: 400	2012	Not modeled in IPM as limits are within SIP rates
			For all other units, with 0-500,000 lbs Steam per Hour Plant Capacity: 2.5 with >500,000 lbs Steam per Hour Plant Capacity: 1.67		
	Part 15. Emission Limitations and Prohibitions - Mercury	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2015	
Minnesota	Minnesota Hg Emission Reduction Act	Hg	90% removal of Hg content of fuel annually for all coal facilities > 500 MW combined; Dry scrubbed units must implement by December 31, 2010; Wet scrubbed units must implement by December 31, 2014.	2006	
Missouri	10 CSR 10-6.350	NO_x	0.25 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Bollinger, Butler, Cape Girardeau, Carter, Clark, Crawford, Dent, Dunklin, Gasconade, Iron, Lewis, Lincoln, Madison, Marion, Mississippi, Montgomery, New Madrid, Oregon, Pemiscot, Perry, Phelps, Pike, Ralls, Reynolds, Ripley, St. Charles, St. Francois, Ste. Genevieve, Scott, Shannon, Stoddard, Warren, Washington and Wayne 0.18 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW the following counties: City of St. Louis, Franklin, Jefferson, and St. Louis 0.35 lbs/MMBtu annual rate limit for all fossil fuel units > 25 MW in the following counties: Buchanan, Jackson, Jasper, Randolph, and any other county not listed	2004	
Montana	Montana Mercury Rule Adopted 10/16/06	Hg	0.90 lbs/TBtu annual rate limit for all non-lignite coal units 1.50 lbs/TBtu annual rate limit for all lignite coal units	2010	
New Hampshire	RSA 125-O: 11-18	Hg	80% reduction of aggregated Hg content of the coal burned at the facilities for Merrimack Units 1 & 2 and Schiller Units 4, 5, & 6	2012	
	ENV-A2900 Multiple pollutant annual budget trading and banking program	NO_x	2.90 MTons summer cap for all fossil steam units > 250 MMBtu/hr operated at any time in 1990 and all new units > 15 MW 3.64 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6	2007	
		SO_2	7.29 MTons annual cap for Merrimack 1 & 2, Newington 1, and Schiller 4 through 6		
	Env -A 2300 - Mitigation of Regional Haze	SO_2	90% SO_2 control at Merrimack 1 & 2; 0.5 lb SO_2/MMBtu 30 day rolling average at Newington 1	2013	
		NO_x	0.30 lb NO_x/MMBtu 30-day rolling average at Merrimack 2; 0.35 lb NO_x/MMBtu when burning oil and 0.25 lb NO_x/MMBtu when burning oil and gas at Newington 1(permit condition).		
New Jersey	N.J.A.C. 7:27-27.5, 27.6, 27.7, and 27.8	Hg	90% removal of Hg content of fuel annually for all coal-fired units or <= 3.0 mg/MWh (net) 95% removal of Hg content of fuel annually for all MSW incinerator units or <= 28 ug/dscm	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 1	NO_x	Annual rate limits in lbs/MMBtu for the following technologies: 1.0 for tangential and wall-fired wet-bottom coal boilers serving an EGU 0.60 for cyclone-fired wet-bottom coal boilers serving an EGU	2007	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 2	NO_x	Annual rate limits in lbs/MMBtu for the following technologies: 0.38 for tangential dry-bottom coal boilers serving an EGU 0.45 for wall-fired dry-bottom coal boilers serving an EGU 0.55 for cyclone-fired dry-bottom coal boilers serving an EGU	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 3	NO_x	Annual rate limits in lbs/MMBtu for the following technologies: 0.20 for tangential oil and/or gas boilers serving an EGU 0.28 for wall-fired oil and/or gas boilers serving an EGU 0.43 for cyclone-fired oil and/or gas boilers serving an EGU	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 6; non- High Electricity demand Day (HEDD) unit	NO_x	2.2 lbs/MWh annual GPS for gas-burning simple cycle combustion turbine units 3.0 lbs/MWh annual GPS for oil-burning simple cycle combustion turbine units 1.3 lbs/MWh annual GPS for gas-burning combined cycle CT or regenerative cycle CT units 2.0 lbs/MWh annual GPS for oil-burning combined cycle CT or regenerative cycle CT units	2007	
	N.J. A. C. Title 7, Chapter 27, Subchapter 19, Table 7; High Electricity demand Day (HEDD) unit	NO_x	1.0 lbs/MWh annual GPS for gas-burning simple cycle combustion turbine units 1.6 lbs/MWh annual GPS for oil-burning simple cycle combustion turbine units 0.75 lbs/MWh annual GPS for gas-burning combined cycle CT or regenerative cycle CT units 1.2 lbs/MWh annual GPS for oil-burning combined cycle CT or regenerative cycle CT units	2007	On and after May 1, 2015, the owner or operator of a stationary combustion turbine that is a HEDD unit or a stationary combustion turbine that is capable of generating 15 MW or more and that commenced operation on or after May 1, 2005 shall comply with limits outlines “in Table 7 during operation on high electricity demand days, regardless of the fuel combusted, unless combusting gaseous fuel is not possible due to gas curtailment."
New York	Part 237	NO_x	39.91 Mtons [Thousand tons] non-ozone season cap for fossil fuel units > 25 MW	2004	
	Part 238	SO_2	131.36 MTons [Thousand tons] annual cap for fossil fuel units > 25 MW	2005	
	Mercury Reduction Program for Coal-Fired Electric Utility Steam Generating Units	Hg	786 lbs annual cap through 2014 for all coal fired boiler or CT units >25 MW after Nov. 15, 1990. 0.60 lbs/TBtu annual rate limit for all coal units > 25 MW developed after Nov.15 1990	2010	
	Subpart 227-2 Reasonably Available Control Technology (RACT) For Major Facilities of Oxides Of Nitrogen (NO_x)	NO_x	Annual rate in lbs/MMBtu for very large boilers >250 MMBtu/hr that commenced operation prior to July 1, 2014; Gas only, tangential & wall fired : 0.2 Gas/oil tangential & wall fired : 0.25; cyclone: 0.43 Coal Wet Bottom, tangential & wall fired : 0.1; cyclone: 0.6 Coal Dry Bottom, tangential: 0.42; wall fired : 0.45; stokers: 0.301 Annual rate in lbs/MMBTu for very large boilers >250 MMBtu/hr that commenced operation after July 1, 2014; Gas only, tangential & wall fired : 0.8 Gas/oil tangential & wall fired : 0.15; cyclone: 0.2 Coal Wet Bottom, tangential & wall fired : 0.12; cyclone: 0.2 Coal Dry Bottom, tangential & wall fired : 0.12; stokers: 0.08	2004	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
			Annual rate in lbs/MMBTu for large boilers between 100 and 250 MMBtu/hr that commenced operation prior to July 1, 2014; Gas Only: 0.20 Gas/Oil: 0.30 Pulverized Coal: 0.50 Coal (Overfeed Stoker):0.301 Annual rate in lbs/MMBTu for large boilers between 100 and 250 MMBtu/hr that commenced operation after July 1, 2014; Gas Only: 0.06 Gas/Oil: 0.15 Pulverized Coal: 0.20 Coal (Overfeed Stoker/FBC): 0.8		
			Annual rate in lbs/MMBTu for mid-size boilers between 25 and 100 MMBtu/hr that commenced operation prior to July 1, 2014; Gas Only: 0.10 Distillate Oil/Gas: 0.12 Residual Oil/Gas: 0.30 Annual rate in lbs/MMBTu for mid-size boilers between 25 and 100 MMBtu/hr that commenced operation after July 1, 2014; Gas Only: 0.05 Distillate Oil/Gas: 0.08 Residual Oil/Gas: 0.20		
			For **simple cycle and regenerative combustion turbines:** (i) 50 parts per million on a dry volume basis (ppmvd), corrected to 15 percent oxygen, for sources designed to burn gaseous fuels (gaseous fuels include, but are not limited to, natural gas, landfill gas, and digester gas) only; and (ii) 100 ppmvd, corrected to 15 percent oxygen, for sources capable of firing distillate oil or more than one fuel.		Compliance with these emission limits must be determined with a one hour average during the ozone season and a 30-day average during the non-ozone season unless the owner or operator chooses to use a CEMS under the provisions of section 227- 2.6(b) of this Subpart.
			For **combined cycle combustion turbines**: (i) prior to July 1, 2014, 42 ppmvd (0.1869 lbs/MMBtu), corrected to 15 percent oxygen, when firing gas; and (ii) prior to July 1, 2014, 65 ppmvd (0.2892 lbs/MMBtu), corrected to 15 percent oxygen, when firing oil.		
			Stationary internal combustion engines having a maximum mechanical output => 200 brake horsepower in a severe ozone nonattainment area or having a maximum mechanical output rating =>400 brake horsepower outside a severe ozone nonattainment: (1) For internal combustion engines fired solely with natural gas: 1.5 grams per brake horsepower-hour. (2) For internal combustion engines fired with landfill gas or digester gas (solely or in combination with natural gas): 2.0 grams per brake horsepower-hour. (3) For internal combustion engine fired with distillate oil (solely or in combination with other fuels): 2.3 grams per brake horsepower-hour.		
	Part 251	CO_2	1450 lbs/MWh rate limit for New Combustion Turbines =>25MW 925 lbs/MWh rate limit for New Fossil Fuel except CT =>25MW	2012	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
North Carolina	NC Clean Smokestacks Act: Statute 143-215.107D	NO_x	25 MTons annual cap for Progress Energy coal plants > 25 MW and 31 MTons annual cap for Duke Energy coal plants > 25 MW	2007	
		SO_2	2012: 100 MTons annual cap for Progress Energy coal plants > 25 MW and 150 MTons annual cap for Duke Energy coal plants > 25 MW 2013 onwards: 50 MTons annual cap for Progress Energy coal plants > 25 MW and 80 MTons annual cap for Duke Energy coal plants > 25 MW	2009	
	SECTION .2500 – Mercury Rules for Electric Generators	Hg	Coal-fired electric steam >25 MW to comply with the mercury emission caps of 1.133 tons (36,256 ounces) per year between 2010 and 2017 inclusive and 0.447 tons (14,304 ounces) per year for 2018 and thereafter	2010	Vacated
	15A NCAC 02D .2511	Hg	Duke Energy and Progress Energy Hg control plans submitted on January 1, 2013 and are awaiting approval. All control technologies and limitations must be implemented by December 31, 2017.	2017	
Oregon	Oregon Administrative Rules, Chapter 345, Division 24	CO_2	675 lbs/MWh annual rate limit for new combustion turbines burning natural gas with a CF >75% and all new non-base load plants (with a CE <= 75%) emitting CO_2	1997	
	Oregon Utility Mercury Rule - Existing Units	Hg	90% removal of Hg content of fuel reduction or 0.6 lbs/TBtu limitation for all existing coal units >25 MW	2012	
	Oregon Utility Mercury Rule - Potential Units	Hg	25 lbs limit for all potential coal units > 25 MW	2009	
Texas	Senate Bill 7 Chapter 101	SO_2	273.95 MTons cap of SO_2 for all grandfathered units built before 1971 in East Texas Region	2003	
		NO_x	Annual cap for all grandfathered units built before 1971 in MTons: 84.48 in East Texas, 18.10 in West Texas, 1.06 in El Paso Region		
	Chapter 117	NO_x	East and Central Texas annual rate limits in lbs/MMBtu for units that came online before 1996: Gas fired units: 0.14 Coal fired units: 0.165 Stationary gas turbines: 0.14	2007	Units are also allowed to comply by reducing the same amount of NO_x on a monthly basis using a system cap or by purchasing credits. East and Central Texas, Dallas/Fort Worth Area, Beaumont-Port Arthur region units are assumed to be in compliance based on their reported 2011 ETS rates. The regulations for these regions are not modeled.
			Dallas/Fort Worth Area annual rate limit for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system except for CT and CC units online after 1992: 0.033 lbs/MMBtu or 0.50 lbs/MWh output or 0.0033 lbs/MMBtu on system wide heat input weighted average for large utility systems 0.06 lbs/MMBtu for small utility systems		
			Houston/Galveston region annual Cap and Trade (MECT) for all fossil units: 17.57 MTons		
			Beaumont-Port Arthur region annual rate limits for utility boilers, auxiliary steam boilers, stationary gas turbines, and duct burners used in an electric power generating system: 0.10 lbs/MMBtu		
Utah	R307-424 Permits: Mercury Requirements for Electric Generating Units	Hg	90% removal of Hg content of fuel annually for all coal units > 25 MW	2013	
Washington	Washington State House Bill 3141	CO_2	$1.45/MTons cost (2004$) for all new fossil-fuel power plant	2004	

State/Region	Bill	Emission Type	Emission Specifications	Implementation Status	Notes
	Washington State House Bill 5769	CO_2	1100 lbs/MWh rate limit for new coal plants	2011	
Wisconsin	NR 428 Wisconsin Administration Code	NO_x	Annual rate limits in lbs/MMBtu for coal fired boilers > 1,000 MMBtu/hr : Wall fired, tangential fired, cyclone fired, and fluidized bed: 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18	2009	
			Annual rate limits in lbs/MMBtu for coal fired boilers between 500 and 1,000 MMBtu/hr: Wall-fired with a heat release rate=> 17,000 Btu per cubic feet per hour; 2013 onwards: 0.17 ; if heat input is lesser: Tangential fired: 2009 onwards: 0.15 Cyclone fired: 2013 onwards: 0.15 Fluidized bed: 2013 onwards: 0.10 Arch fired: 2009 onwards: 0.18		
			Annual rate limits in lbs/MMBtu for coal fired boilers between 250 and 500 MMBtu/hr: Same as for coal boiled between 500 and 1000 MMBtu/hr in addition to: Stoker Fired: .20		
			Annual rate limits in lbs/MMBtu for coal fired boilers between 50 and 250 MMBtu/hr: Same as for coal boiled between 500 and 1000 MMBtu/hr in addition to: Stoker Fired: .25		
			Annual rate limits for CTs in lbs/MMBtu: Natural gas CTs > 50 MW: 0.11 Distillate oil CTs > 50 MW: 0.28 Biologically derived fuel CTs > 50 MW: 0.15 Natural gas CTs between 25 and 49 MW: 0.19 Distillate oil CTs between 25 and 49 MW: 0.42 Biologically derived fuel CTs between 25 and 49 MW: 0.15		
			Annual rate limits for CCs in lbs/MMBtu: Natural gas CCs > 25 MW: 0.04 Distillate oil CCs > 25 MW: 0.19 Biologically derived fuel CCs > 25 MWs: 0.15 Natural gas CCs between 10 and 24 MW: 0.19		
	Chapter NR 44.12/446.13 Control of Mercury Emissions	Hg	Large (150MW capacity or greater) or small (between 25 and 150 MW) coal-fired EGU, 2015 onwards: 90% removal of Hg content of fuel or 0.0080 lbs/GWh reduction in coal fired EGUs > 150 MW	2015	
	Chapter NR 446.14 Multi-pollutant reduction alternative for coal-fired electrical generating units	Hg	All Coal>25MW; 70% reduction in fuel, or .0190 lbs per GW-hr from CY 2015 – CY 2017 (0.00005568 lbs/MMBtu) 80% reduction in fuel, or .0130 lbs per GW-hr from CY2018 – CY 2020 (0.0000381 lbs/MMBtu) 90% reduction in fuel, or .0080 lbs per GW-hr from January 1, 2021 onwards (0.00000234 lbs/MMBtu)	2015	Alternative already modeled in IPM
		SO_2	All Coal>25MW; .10 lbs per mmBTU by January 1, 2015		
		NO_x	All Coal>25MW; 07 lbs per mmBTU by January 1, 2015		

Table 3-14 New Source Review (NSR) Settlements in EPA Base Case v.5.13

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Allowance Restriction: Effective Date	Notes	Reference
Alabama Power																		
James H. Miller	Alabama	Unit 3			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06	Within 45 days of settlement entry, APC must retire 7,538 SO_2 emission allowances.	APC shall not sell, trade, or otherwise exchange any Plant Miller excess SO_2 emission allowances outside of the APC system	1/1/21	1) Settlement requires 95% removal efficiency for SO_2 or 90% in the event that the unit combust a coal with sulfur content greater than 1% by weight. 2) The settlements require APC to retire $4,900,000 of SO_2 emission allowances within 45 days of consent decree entry. 3) EPA assumed a retirement of 7, 538 SO_2 allowances based on a current allowance price of $650.	http://www2.epa.gov/enforcement/alabama-power-company-clean-air-act-settlement
James H. Miller	Alabama	Unit 4			Install and operate FGD continuously	95%	12/31/11	Operate existing SCR continuously	0.1	05/01/08		0.03	12/31/06			1/1/21		
Minnkota Power Cooperative																		
			Beginning 1/01/2006, Minnkota shall not emit more than 31,000 tons of SO_2/year, no more than 26,000 tons beginning 2011, no more than 11,500 tons beginning 1/01/2012. If Unit 3 is not operational by 12/31/2015, then beginning 1/01/2014, the plant wide emission shall not exceed 8,500.															-
Milton R. Young	North Dakota	Unit 1			Install and continuously operate FGD	95% if wet FGD, 90% if dry	12/31/11	Install and continuously operate Over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/09		0.03 if wet FGD, .015 if dry FGD		Plant will surrender 4,346 allowances for each year 2012 – 2015, 8,693 allowances for years 2016 – 2018, 12,170 allowances for year 2019, and 14,886 allowances/year thereafter if Units 1 – 3 are operational by 12/31/2015. If only Units 1 and 2 are operational by12/31/2015, the plant shall retire 17,886 units in 2020 and thereafter.	Minnkota shall not sell or trade NO_x allowances allocated to Units 1, 2, or 3 that would otherwise be available for sale or trade as a result of the actions taken by the settling defendants to comply with the requirements		1) Settlement requires 95% removal efficiency for SO_2 at Unit 1 if a wet FGD is installed, or 90% if a dry FGD is installed. The FGD for Units 1 and 2 and the NO_x control for Unit 1 are modeled as emission constraints in EPA Base Case, the NO_x control for Unit 2 is hardwired into EPA Base Case. 2) Beginning 12/31/2010, Unit 2 will achieve a phase II average NO_x emission rate established through its NO_x BACT determination. Beginning 12/31/2011, Unit 1 will achieve a phase II NO_x emission rate established by its BACT determination.	http://www2.epa.gov/enforcement/minnkota-power-cooperative-and-square-butte-electric-cooperative-settlement
Milton R. Young	North Dakota	Unit 2			Design, upgrade, and continuously operate FGD	90%	12/31/10	Install and continuously operate over-fire AIR, or equivalent technology with emission rate < .36	0.36	12/31/07		0.03	Before 2008					
SIGECO																		
FB Culley	Indiana	Unit 1	Repower to natural gas (or retire)	12/31/06										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/southern-indiana-gas-and-electric-company-sigeco-fb-culley-plant-clean-air-act-caa
FB Culley	Indiana	Unit 2			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04											
FB Culley	Indiana	Unit 3			Improve and continuously operate existing FGD (shared by Units 2 and 3)	95%	06/30/04	Operate Existing SCR Continuously	0.1	09/01/03	Install and continuously operate a Baghouse	0.015	06/30/07					
PSEG FOSSIL																		
Bergen	New Jersey	Unit 2	Repower to combined cycle	12/31/02										The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/pseg-fossil-llc-settlement
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/06	Install SCR (or approved tech) and continually operate	0.1	05/01/07	Install Baghouse (or approved technology)	0.015	12/31/06				The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case.	

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Allowance Restriction: Effective Date	Notes	Reference
Mercer	New Jersey	Unit 1			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07		0.015	12/31/10				The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case.	
	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/12	Install SCR (or approved tech) and continually operate	0.1	01/01/07		0.015	12/31/10				The settlement requires coal with monthly average sulfur content no greater than 2% at units operating FGD -- this limit is modeled as a coal choice exception in EPA Base Case.	
TECO																		
Big Bend	Florida	Unit 1			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				http://www2.epa.gov/enforcement/tampa-electric-company-teco-clean-air-act-caa-settlement
	Florida	Unit 2			Existing Scrubber (shared by Units 1 & 2)	95% (95% or .25)	09/1/00 (01/01/13)	Install SCR	0.1	05/01/09								
	Florida	Unit 3			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	2000 (01/01/10)	Install SCR	0.1	05/01/09								
	Florida	Unit 4			Existing Scrubber (shared by Units 3 & 4)	93% if Units 3 & 4 are operating	06/22/05	Install SCR	0.1	07/01/07								
Gannon	Florida	Six units	Retire all six coal units and repower at least 550 MW of coal capacity to natural gas	12/31/04														
WEPCO																		
			WEPCO shall comply with the following system wide average NO_x emission rates and total NO_x tonnage permissible: by 1/1/2005 an emission rate of 0.27 and 31,500 tons, by 1/1/2007 an emission rate of 0.19 and 23,400 tons, and by 1/1/2013 an emission rate of 0.17 and 17, 400 tons. For SO_2 emissions, WEPCO will comply with: by 1/1/2005 an emission rate of 0.76 and 86,900 tons, by 1/1/2007 an emission rate of 0.61 and 74,400 tons, by 1/1/2008 an emission rate of 0.45 and 55,400 tons, and by 1/1/2013 an emission rate of 0.32 and 33,300 tons.															http://www2.epa.gov/enforcement/wisconsin-electric-power-company-wepco-clean-air-act-civil-settlement
Presque Isle	Wisconsin	Units 1 – 4	Retire or install SO_2 and NO_x controls	12/31/12	Install and continuously operate FGD (or approved equiv. tech)	95% or 0.1	12/31/12	Install SCR (or approved tech) and continually operate	0.1	12/31/12				The provision did not specify an amount of SO_2 allowances to be surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				
	Wisconsin	Units 5, 6						Install and operate low NO_x burners		12/31/03								
	Wisconsin	Units 7, 8						Operate existing low NO_x burners		12/31/05	Install Baghouse							
	Wisconsin	Unit 9						Operate existing low NO_x burners		12/31/06	Install Baghouse							
Pleasant Prairie	Wisconsin	Unit 1			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/06	Install and continuously operate SCR (or approved tech)	0.1	12/31/06								

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
	Wisconsin	Unit 2			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/07	Install and continuously operate SCR (or approved tech)	0.1	12/31/03								
Oak Creek	Wisconsin	Units 5, 6			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
Oak Creek	Wisconsin	Unit 7			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
Oak Creek	Wisconsin	Unit 8			Install and continuously operate FGD (or approved control tech)	95% or 0.1	12/31/12	Install and continuously operate SCR (or approved tech)	0.1	12/31/12								
Port Washington	Wisconsin	Units 1 – 4	Retire	12/31/04 for Units 1 – 3. Unit 4 by entry of consent decree														
Valley	Wisconsin	Boilers 1 – 4						Operate existing low NO_x burner		30 days after entry of consent decree								
VEPCO																		
			The Total Permissible NO_x Emissions (in tons) from VEPCO system are: 104,000 in 2003, 95,000 in 2004, 90,000 in 2005, 83,000 in 2006, 81,000 in 2007, 63,000 in 2008 – 2010, 54,000 in 2011, 50,000 in 2012, and 30,250 each year thereafter. Beginning 1/1/2013 they will have a system wide emission rate no greater than 0.15 lbs/mmBTU.															
Mount Storm	West Virginia	Units 1 – 3			Construct or improve FGD	95% or 0.15	01/01/05	Install and continuously operate SCR	0.11	01/01/08								
Chesterfield	Virginia	Unit 4						Install and continuously operate SCR	0.1	01/01/13								http://www2.epa.gov/enforcement/virginia-electric-and-power-company-vepco-clean-air-act-caa-settlement
Chesterfield	Virginia	Unit 5			Construct or improve FGD	95% or 0.13	10/12/12	Install and continuously operate SCR	0.1	01/01/12				On or before March 31 of every year beginning in 2013 and continuing thereafter, VEPCO shall surrender 45,000 SO_2 allowances.				
Chesterfield	Virginia	Unit 6			Construct or improve FGD	95% or 0.13	01/01/10	Install and continuously operate SCR	0.1	01/01/11								
Chesapeake Energy	Virginia	Units 3, 4						Install and continuously operate SCR	0.1	01/01/13								
Clover	Virginia	Units 1, 2			Improve FGD	95% or 0.13	09/01/03											
Possum Point	Virginia	Units 3, 4	Retire and repower to natural gas	05/02/03														
Santee Cooper																		
			Santee Cooper shall comply with the following system wide averages for NO_x emission rates and combined tons for emission of: by 1/01/2005 facility shall comply with an emission rate of 0.3 and 30,000 tons, by 1/1/2007 an emission rate of 0.18 and 25,000 tons, by 1/1/2010 and emission rate of 0.15 and 20,000 tons. For SO_2 emission the company shall comply with system wide averages of: by 1/1/2005 an emission rate of 0.92 and 95,000 tons, by 1/1/2007 and emission rate of 0.75 and 85,000 tons, by 1/1/2009 an emission rate of 0.53 and 70 tons, and by 1/1/2011 and emission rate of 0.5 and 65 tons.															http://www2.epa.gov/enforcement/south-carolina-public-service-
Cross	South Carolina	Unit 1			Upgrade and continuously operate FGD	95%	06/30/06	Install and continuously operate SCR	0.1	05/31/04				The provision did not specify an amount of SO_2 allowances to be				

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Allowance Restriction: Effective Date	Notes	Reference
	South Carolina	Unit 2			Upgrade and continuously operate FGD	87%	06/30/06	Install and continuously operate SCR	0.11/0.1	05/31/04 and 05/31/07				surrendered. It only provided that excess allowances resulting from compliance with NSR settlement provisions must be retired.				authority-santee-cooper-settlement
Winyah	South Carolina	Unit 1			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.11/0.1	11/30/04 and 11/30/04								
	South Carolina	Unit 2			Install and continuously operate FGD	95%	12/31/08	Install and continuously operate SCR	0.12	11/30/04								
	South Carolina	Unit 3			Upgrade and continuously operate existing FGD	90%	12/31/08	Install and continuously operate SCR	0.14/0.12	11/30/2005 and 11/30/08								
	South Carolina	Unit 4			Upgrade and continuously operate existing FGD	90%	12/31/07	Install and continuously operate SCR	0.13/0.12	11/30/05 and 11/30/08								
Grainger	South Carolina	Unit 1						Operate low NO_x burner or more stringent technology		06/25/04								
	South Carolina	Unit 2						Operate low NO_x burner or more stringent technology		05/01/04								
Jeffries	South Carolina	Units 3, 4						Operate low NO_x burner or more stringent technology		06/25/04								
OHIO EDISON																		
			Ohio Edison shall achieve reductions of 2,483 tons NO_x between 7/1/2005 and 12/31/2010 using any combination of: 1) low sulfur coal at Burger Units 4 and 5, 2) operating SCRs currently installed at Mansfield Units 1 – 3 during the months of October through April, and/or 3) emitting fewer tons than the Plant-Wide Annual Cap for NO_x required for the Sammis Plant. Ohio Edison must reduce 24,600 tons system-wide of SO_2 by 12/31/2010.															
			No later than 8/11/2005, Ohio Edison shall install and operate low NO_x burners on Sammis Units 1, 2,4,5,6, and 7 and overfired air on Sammis Units 1,2,3,6, and 7. No later than 12/1/2005, Ohio Edison shall install advanced combustion control optimization with software to minimize NO_x emissions from Sammis Units 1 – 5.															
W.H. Sammis Plant	Ohio	Unit 1			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	12/31/08	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07				Beginning on 1/1/2006, Ohio Edison may use, sell or transfer any restricted SO_2 only to satisfy the Operational Needs at the Sammis, Burger and Mansfield Plant, or new units within the FirstEnergy System that comply with a 96% removal for SO_2. For calendar year 2006 through 2017, Ohio Edison may accumulate SO_2 allowances for use at the Sammis, Burger, and Mansfield plants, or FirstEnergy units equipped with SO_2 Emission Control Standards. Beginning in 2018, Ohio Edison shall surrender unused restricted SO_2			Plant-wide NOx Annual Caps: 11,371 tons 7/1/2005 – 12/31/2005; 21,251 tons 2006; 20,596 tons 2007; 18,903 tons 2008; 17,328 tons 2009 – 2010; 14,845 tons 2011; 11,863 2012 onward. Sammis Plant-Wide Annual SO_2 Caps: 58,000 tons SO_2 7/1/2005-12/31/2005; 116,000 tons 1/1/2006 – 12/31/2007; 114,000 tons 1/1/2008-12/31/2008; 101,500 tons 1/1/2009 – 12/31/2010; 29,900 tons 1/1/2011 onward. Sammis Units 1 – 5 are also subject to the following SO_2 Monthly Caps if Ohio Edison installs the improved SO_2 control technology (Unit 5's option A): 3,242 tons May, July, and August 2010; 3,137 tons June and September 2010. Ohio Edison has installed the required SO_2 technology (Unit 5's option B), so the Monthly Caps are: 2,533 tons May, July, and August 2010; 2,451 tons June and September 2010. Add'l Monthly Caps are: 2,533 tons May, July, and August 2011; 2,451 tons June and September 2011 thereafter.	http://www2.epa.gov/enforcement/ohio-edison-company-wh-sammis-power-station-clean-air-act-2005-settlement-and-2009
	Ohio	Unit 2			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	12/31/08	Operate existing SNCR continuously	0.25	02/15/06								
	Ohio	Unit 3			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	12/31/08	Operate low NO_x burners and overfire air by 12/1/05; install SNCR (or approved alt. tech) & operate continuously by 12/31/07	0.25	12/01/05 and 10/31/07								
	Ohio	Unit 4			Install Induct Scrubber (or approved equiv. control tech)	50% removal or 1.1 lbs/mmBTU	06/30/09	Install SNCR (or approved alt. tech) & operate continuously	0.25	10/31/07								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
	Ohio	Unit 5			Install Flash Dryer Absorber or ECO_2 (or approved equiv. control tech) & operate continuously	50% removal or 1.1 lbs/mmBTU	06/29/09	Install SNCR (or approved alt. tech) & Operate Continuously	0.29	03/31/08				allowances.				
	Ohio	Unit 6			Install FGD[3] (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lbs/mmBTU	06/30/11	Install SNCR (or approved alt. tech) & operate continuously	"Minimum Extent Practicable"	06/30/05	Operate Existing ESP Continuously	0.03	01/01/10				In addition to SNCR, settlement requires installation of first SCR (or approved alt tech) on either Unit 6 or 7 by 12/31/2010; second installation by 12/31/2011. Both SCRs must achieve 90% Design Removal Efficiency by 180 days after installation date. Each SCR must provide a 30-Day Rolling average. NO_x Emission Rate of 0.1 lbs/mmBTU starting 180 days after installation dates above.	
	Ohio	Unit 7			Install FGD (or approved equiv. control tech) & operate continuously	95% removal or 0.13 lbs/mmBTU	06/30/11	Operate existing SNCR Continuously	"Minimum Extent Practicable"	08/11/05	Operate Existing ESP Continuously	0.03	01/01/10					
Mansfield Plant	Pennsylvania	Unit 1			Upgrade existing FGD	95%	12/31/05										Additional Mansfield Plant-wide SO_2 reductions are as follows: 4,000 tons in 2006, 8,000 tons in 2007, and 12,000 tons/yr for every year after. Settlement allows relinquishment of SO_2 requirement upon shutdown of unit, after which the SO_2 reductions must be made by another plant(s).	
	Pennsylvania	Unit 2			Upgrade existing FGD	95%	12/31/06											
	Pennsylvania	Unit 3			Upgrade existing FGD	95%	10/31/07											
Eastlake	Ohio	Unit 5						Install low NO_x burners, over-fired air and SNCR & operate continuously	"Minimize Emissions to the Extent Practicable"	12/31/06							Settlement requires Eastlake Plant to achieve additional reductions of 11,000 tons of NO_x per year commencing in calendar year 2007, and no less than 10,000 tons must come from this unit. The extra 1,000 tons may come from this unit or another unit in the region. Upon shutdown of Eastlake, another plant must achieve these reductions.	
Burger	Ohio	Unit 4	Repower with at least 80% biomass fuel, up to 20% low sulfur coal OR Retire by 12/31/2010	12/31/11														
	Ohio	Unit 5		12/31/11														
MIRANT[1,6]																		
			System-wide NO_x Emission Annual Caps: 36,500 tons 2004; 33,840 tons 2005; 33,090 tons 2006; 28,920 tons 2007; 22,000 tons 2008; 19,650 tons 2009; 16,000 tons 2010 onward. System-wide NO_x Emission Ozone Season Caps: 14,700 tons 2004; 13,340 tons 2005; 12,590 tons 2006; 10,190 tons 2007; 6,150 tons 2008 – 2009; 5,200 tons 2010 thereafter. Beginning on 5/1/2008, and continuing for each and every Ozone Season thereafter, the Mirant System shall not exceed a System-wide Ozone Season Emission Rate of 0.150 lbs/mmBTU NO_x.															
Potomac River Plant	Virginia	Unit 1																
	Virginia	Unit 2																
	Virginia	Unit 3						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04							Settlement requires installation of Separated Overfire Air tech (or more effective technology) by 5/1/2005. Plant-wide Ozone Season NO_x Caps: 1,750 tons 2004; 1,625 tons 2005; 1,600 tons 2006 – 2009; 1,475 tons 2010 thereafter. Plant-wide annual NO_x Caps are 3,700 tons in 2005 and each year thereafter.	http://www2.epa.gov/enforcement/mirant-clean-air-settlement
	Virginia	Unit 4						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
	Virginia	Unit 5						Install low NO_x burners (or more effective tech) & operate continuously		05/01/04								
Morgantown Plant	Maryland	Unit 1						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/07								
	Maryland	Unit 2						Install SCR (or approved alt. tech) & operate continuously	0.1	05/01/08								
Chalk Point	Maryland	Unit 1			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10							For each year after Mirant commences FGD operation at Chalk Point, Mirant shall surrender the number of SO_2 Allowances equal to the amount by which the SO_2 Allowances allocated to the Units at the Chalk Point Plant are greater than the total amount of SO_2 emissions allowed under this Section XVIII.			Mirant must install and operate FGD by 6/1/2010 if authorized by court to reject ownership interest in Morgantown Plant, or by no later than 36 months after they lose ownership interest of the Morgantown Plant. [Installed]	
	Maryland	Unit 2			Install and continuously operate FGD (or equiv. technology)	95%	06/01/10											
ILLINOIS POWER																		
			System-wide NO_x Emission Annual Caps: 15,000 tons 2005; 14,000 tons 2006; 13,800 tons 2007 onward. System-wide SO_2 Emission Annual Caps: 66,300 tons 2005 – 2006; 65,000 tons 2007; 62,000 tons 2008 – 2010; 57,000 tons 2011; 49,500 tons 2012; 29,000 tons 2013 onward.															
Baldwin	Illinois	Unit 1			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10	By year end 2008, Dynegy will surrender 12,000 SO_2 emission allowances, by year end 2009 it will surrender 18,000, by year end 2010 it will surrender 24,000, any by year end 2011 and each year thereafter it will surrender 30,000 allowances. If the surrendered allowances result in insufficient remaining allowances allocated to the units comprising the DMG system, DMG can request to surrender fewer SO_2 allowances.				http://www2.epa.gov/enforcement/illinois-power-company-and-dynegy-midwest-generation-settlement
	Illinois	Unit 2			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA & existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse	0.015	12/31/10					
	Illinois	Unit 3			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	0.1	12/31/11	Operate OFA and/or low NO_x burners	0.12 until 12/30/12; 0.1 from 12/31/12	08/11/05 and 12/31/12	Install & continuously operate Baghouse	0.015	12/31/10					
Havana	Illinois	Unit 6			Install wet or dry FGD (or approved equiv. alt. tech) & operate continuously	1.2 lbs/mmBTU until 12/30/2012; 0.1 lbs/mmBTU from 12/31/2012 onward	08/11/05 and 12/31/12	Operate OFA and/or low NO_x burners & operate existing SCR continuously	0.1	08/11/05	Install & continuously operate Baghouse, then install ESP or alt. PM equip	For Bag-house: .015 lbs/mmBTU; For ESP: .03 lbs/mmBTU	For Baghouse: 12/31/12; For ESP: 12/31/05					

			Settlement Actions: Retire/Repower		Settlement Actions: SO_2 control			Settlement Actions: NO_x Control			Settlement Actions: PM or Mercury Control			Settlement Actions: Allowance Retirement	Settlement Actions: Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
Hennepin	Illinois	Unit 1				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06				Settlement requires first installation of ESP at either Unit 1 or 2 on 12/31/2006; and on the other by 12/31/2010.	
	Illinois	Unit 2				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/06					
Vermilion	Illinois	Unit 1				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10					
	Illinois	Unit 2				1.2	01/31/07	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/10					
Wood River	Illinois	Unit 4				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05				Settlement requires first installation of ESP at either Unit 4 or 5 on 12/31/2005; and on the other by 12/31/2007.	
	Illinois	Unit 5				1.2	07/27/05	Operate OFA and/or low NO_x burners	"Minimum Extent Practicable"	08/11/05	Install ESP (or equiv. alt. tech) & continuously operate ESPs	0.03	12/31/05					
Kentucky Utilities Company																		

			Settlement Actions															
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date	Notes	Reference
EW Brown Generating Station	Kentucky	Unit 3			Install FGD	97% or 0.100	12/31/10	Install and continuously operate SCR by 12/31/2012, continuously operate low NO_x boiler and OFA.	0.07	12/31/12	Continuously operate ESP	0.03	12/31/10	KU must surrender 53,000 SO_2 allowances of 2008 or earlier vintage by March 1, 2009. All surplus NO_x allowances must be surrendered through 2020.	SO_2 and NO_x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		Annual SO_2 cap is 31,998 tons through 2010, then 2,300 tons each year thereafter. Annual NO_x cap is 4,072 tons.	http://www2.epa.gov/enforcement/kentucky-utilities-company-clean-air-act-settlement
Salt River Project Agricultural Improvement and Power District (SRP)																		
Coronado Generating Station	Arizona	Unit 1 or Unit 2			Immediately begin continuous operation of existing FGDs on both units, install new FGD.	95% or 0.08	New FGD installed by 1/1/2012	Install and continuously operate low NO_x burner and SCR	0.32 prior to SCR installation, 0.080 after	LNB by 06/01/2009, SCR by 06/01/2014	Optimization and continuous operation of existing ESPs.	0.03	Optimization begins immediately, rate limit begins 01/01/12 (date of new FGD installation)	Beginning in 2012, all surplus SO_2 allowances for both Coronado and Springerville Unit 4 must be surrendered through 2020. The allowances limited by this condition may, however, be used for compliance at a prospective future plant using BACT and otherwise specified in par. 54 of the consent decree.	SO_2 and NO_x allowances may not be used for compliance, and emissions decreases for purposes of complying with the Consent Decree do not earn credits.		Annual plant-wide NO_x cap is 7,300 tons after 6/1/2014.	http://www2.epa.gov/enforcement/salt-river-project-agriculture-improvement-and-power-district-settlement
	Arizona	Unit 1 or Unit 2			Install new FGD	95% or 0.08	01/01/13	Install and continuously operate low NO_x burner	0.32	06/01/11			Optimization begins immediately, rate limit begins 01/01/13 (date of new FGD installation)					
American Electric Power																		
Eastern System-Wide [Modified Limits for SO_2]						Annual Cap (tons)	Year											http://www.ct.gov/ag/lib/ag/press_releases/2013/20130225_aep_cdmod.pdf
						145,000	2016-2018											
						113,000	2019-2021											
						110,000	2022-2025											
						102,000	2026-2028											
						94,000	2029 and thereafter											
Eastern System-Wide						Annual Cap (tons)	Year		Annual Cap (tons)	Year				NO_x and SO_2 allowances that would have been made available by emission reductions pursuant to the Consent Decree must be surrendered.	NO_x and SO_2 allowances may not be used to comply with any of the limits imposed by the Consent Decree. The Consent Decree includes a formula for calculating excess NO_x allowances relative to the CAIR Allocations,			http://www2.epa.gov/enforcement/american-electric-power-service-corporation
						450,000	2010		96,000	2009								
						450,000	2011		92,500	2010								
						420,000	2012		92,500	2011								
						350,000	2013		85,000	2012								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower		SO₂ control			NOₓ Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction		Notes	Reference
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
						340,000	2014		85,000	2013					and restricts the use of some. See par. 74-79 for details. Reducing emissions below the Eastern System-Wide Annual Tonnage Limitations for NO_x and SO_2 earns supercompliant allowances.			
						275,000	2015		85,000	2014								
						260,000	2016		75,000	2015								
						235,000	2017		72,000	2016 and thereafter								
						184,000	2018											
						174,000	2019 and thereafter											
At least 600MW from various units	West Virginia	Sporn 1 – 4	Retire, retrofit, or re-power	12/31/18														
	Virginia	Clinch River 1 – 3																
	Indiana	Tanners Creek 1 – 3																
	West Virginia	Kammer 1 – 3																
Amos	West Virginia	Unit 1			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								-
	West Virginia	Unit 2			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		01/01/09								-
	West Virginia	Unit 3			Install and continuously operate FGD		12/31/09	Install and continuously operate SCR		01/01/08								-
Big Sandy	Kentucky	Unit 1			Burn only coal with no more than 1.75 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry								-
	Kentucky	Unit 2			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/09								-
Cardinal	Ohio	Unit 1			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09					-
	Ohio	Unit 2			Install and continuously operate FGD		12/31/08	Install and continuously operate SCR		01/01/09	Continuously operate ESP	0.03	12/31/09					-
	Ohio	Unit 3			Install and continuously operate FGD		12/31/12	Install and continuously operate SCR		01/01/09								-
Clinch River	Virginia	Units 1 – 3				Plant-wide annual cap: 21,700 tons from 2010 to 2014, then 16,300 after 1/1/2015	2010 – 2014, 2015 and thereafter	Continuously operate low NO_x burners		Date of entry								-

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Conesville	Ohio	Unit 1	Retire, retrofit, or re-power	Date of entry														-
	Ohio	Unit 2	Retire, retrofit, or re-power	Date of entry														-
	Ohio	Unit 3	Retire, retrofit, or re-power	12/31/12														-
	Ohio	Unit 4			Install and continuously operate FGD		12/31/10	Install and continuously operate SCR		12/31/10								-
	Ohio	Unit 5			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry								-
	Ohio	Unit 6			Upgrade existing FGD	95%	12/31/09	Continuously operate low NO_x burners		Date of entry								-
Gavin	Ohio	Unit 1			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09								-
	Ohio	Unit 2			Install and continuously operate FGD		Date of entry	Install and continuously operate SCR		01/01/09								-
Glen Lynn	Virginia	Units 1 – 3																-
	Virginia	Units 5, 6			Burn only coal with no more than 1.75 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry								-
Kammer	West Virginia	Units 1 – 3				Plant-wide annual cap: 35,000	01/01/10	Continuously operate over-fire air		Date of entry								-
Kanawha River	West Virginia	Units 1, 2			Burn only coal with no more than 1.75 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry								-
Mitchell	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09								-
	West Virginia	Unit 2			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/09								-
Mountaineer	West Virginia	Unit 1			Install and continuously operate FGD		12/31/07	Install and continuously operate SCR		01/01/08								-
Muskingum River	Ohio	Units 1 – 4	Retire, retrofit, or re-power	12/31/15														-
	Ohio	Unit 5			Install and continuously operate FGD		12/31/15	Install and continuously operate SCR		01/01/08	Continuously operate ESP	0.03	12/31/02					-
Picway	Ohio	Unit 9						Continuously operate low NO_x burners		Date of entry								-

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Rockport			Rockport Units 1 & 2 shall not exceed an Annual Tonnage Limit of 28 MTons of SO_2 in 2016- 2017, 26 Mtons in 2018-2019, 22 MTons in 2020-2025, 18 MTons in 2026-2028 and 10 MTons in 2029 and each year thereafter.															
	Indiana	Unit 1			Install DSI __ Install and continuously operate FGD		4/16/2015 __ 12/31/2025	Install and continuously operate SCR		12/31/25								-
	Indiana	Unit 2			Install DSI __ Install and continuously operate FGD		4/16/2015 __ 12/31/2028	Install and continuously operate SCR		12/31/28								-
Sporn	West Virginia	Unit 5	Retire, retrofit, or re-power	12/31/13														-
Tanners Creek	Indiana	Units 1 – 3			Burn only coal with no more than 1.2 lbs/mmBTU annual average		Date of entry	Continuously operate low NO_x burners		Date of entry								-
	Indiana	Unit 4			Burn only coal with no more than 1.2% sulfur content annual average		Date of entry	Continuously operate over-fire air		Date of entry								-
East Kentucky Power Cooperative Inc.																		
Dale Plant	Kentucky	Unit 1						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08				EKPC must surrender 1,000 NO_x allowances immediately under the ARP, and 3,107 under the NO_x SIP Call. EKPC must also surrender 15,311 SO_2 allowances.		Date of entry		
	Kentucky	Unit 2						Install and continuously operate low NO_x burners by 10/31/2007	0.46	01/01/08								
System-wide	Kentucky		By 12/31/2009, EKPC shall choose whether to: 1) install and continuously operate NO_x controls at Cooper 2 by 12/31/2012 and SO_2 controls by 6/30/2012 or 2) retire Dale 3 and Dale 4 by 12/31/2012.															http://www2.epa.gov/enforcement/east-kentucky-power-cooperative-settlement
						12-month rolling limit (tons)	Start of 12-month cycle		12-month rolling limit (tons)	Start of 12-month cycle								
					System-wide 12-month rolling tonnage limits apply	57,000	10/01/08	All units must operate low NO_x boilers	11,500	01/01/08	PM control devices must be operated continuously system-wide, ESPs must be optimized within 270 days of entry date, or EKPC may choose to submit a PM Pollution Control Upgrade Analysis.	0.03	1 year from entry date	All surplus SO_2 allowances must be surrendered each year, beginning in 2008.	SO_2 and NO_x allowances may not be used to comply with the Consent Decree. NO_x allowances that would become available as a result of compliance with the Consent Decree may not be sold or traded. SO_2 and NO_x allowances allocated to EKPC must be used within the EKPC system. Allowances made available due to supercompliance may be sold or traded.			
						40,000	07/01/11		8,500	01/01/13								
						28,000	01/01/13		8,000	01/01/15								

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
Spurlock	Kentucky	Unit 1			Install and continuously operate FGD	95% or 0.1	6/30/2011	Continuously operate SCR	0.12 for Unit 1 until 01/01/2013, at which point the unit limit drops to 0.1. Prior to 01/01/2013, the combined average when both units are operating must be no more than 0.1	60 days after entry								
	Kentucky	Unit 2			Install and continuously operate FGD by 10/1/2008	95% or 0.1	1/1/2009	Continuously operate SCR and OFA	0.1 for Unit 2, 0.1 combined average when both units are operating	60 days after entry								
Dale Plant	Kentucky	Unit 3	EKPC may choose to retire Dale 3 and 4 in lieu of installing controls in Cooper 2	12/31/2012														
	Kentucky	Unit 4																
Cooper	Kentucky	Unit 1																
	Kentucky	Unit 2			If EKPC opts to install controls rather than retiring Dale, it must install and continuously operate FGD or equiv. technology	95% or 0.10		If EKPC elects to install controls, it must continuously operate SCR or install equiv. technology	0.08 (or 90% if non-SCR technology is used)	12/31/12							EKPC has installed a DFGD on this unit and Dale continues to operate.	
Nevada Power Company																		
			Beginning 1/1/2010, combined NO_x emissions from Units 5, 6, 7, and 8 must be no more than 360 tons per year.															
Clark Generating Station	Nevada	Unit 5	Units may only fire natural gas					Increase water injection immediately, then install and operate ultra-low NO_x burners (ULNBs) or equivalent technology. In 2009, Units 5 and 8 may not emit more than 180 tons combined	5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)					Allowances may not be used to comply with the Consent Decree, and no allowances made available due to compliance with the Consent Decree may be traded or sold.			http://www2.epa.gov/enforcement/nevada-power-company-clean-air-act-caa-settlement
	Nevada	Unit 6							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower – Action	Retire/Repower – Effective Date	SO_2 control – Equipment	SO_2 control – Percent Removal or Rate	SO_2 control – Effective Date	NO_x Control – Equipment	NO_x Control – Rate	NO_x Control – Effective Date	PM or Mercury Control – Equipment	PM or Mercury Control – Rate	PM or Mercury Control – Effective Date	Allowance Retirement – Retirement	Allowance Restriction – Restriction	Effective Date	Notes	Reference
	Nevada	Unit 7							5ppm 1-hour average	12/31/09 (ULNB installation), 01/30/10 (1-hour average)								
	Nevada	Unit 8							5ppm 1-hour average	12/31/08 (ULNB installation), 01/30/09 (1-hour average)								
Dayton Power & Light																		
			Non-EPA Settlement of 10/23/2008															
Stuart Generating Station	Ohio	Station-wide			Complete installation of FGDs on each unit.	96% or 0.10	07/31/09	Owners may not purchase any new catalyst with SO_2 to SO_3 conversion rate greater than 0.5%	0.17 station-wide	30 days after entry		0.030 lbs per unit	07/31/09		NO_x and SO_2 allowances may not be used to comply with the monthly rates specified in the Consent Decree.			
									0.17 station-wide	60 days after entry date								
						82% including data from periods of malfunctions	7/31/09 through 7/30/11	Install control technology on one unit	0.10 on any single unit	12/31/12		Install rigid-type electro-des in each unit's ESP	12/31/15					
						82% including data from periods of malfunctions	after 7/31/11		0.15 station-wide	07/01/12								
									0.10 station-wide	12/31/14								
PSEG FOSSIL, Amended Consent Decree of November 2006																		
Kearny	New Jersey	Unit 7	Retire unit	01/01/07										Allowances allocated to Kearny, Hudson, and Mercer may only be used for the operational needs of those units, and all surplus allowances must be surrendered. Within 90 days of amended Consent Decree, PSEG must surrender 1,230 NO_x Allowances and 8,568 SO_2 Allowances not already allocated to or generated by the units listed here. Kearny allowances must be surrendered with the shutdown of those units.				http://www2.epa.gov/enforcement/pseg-fossil-llc-settlement
	New Jersey	Unit 8	Retire unit	01/01/07														
Hudson	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	12/31/10	Install Baghouse (or approved technology)	0.015	12/31/10					

Company and Plant	State	Unit	Settlement Actions														Notes	Reference
			Retire/Repower		SO_2 control			NO_x Control			PM or Mercury Control			Allowance Retirement	Allowance Restriction			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Retirement	Restriction	Effective Date		
						Annual Cap (tons)	Year		Annual Cap (tons)	Year								
						5,547	2007		3,486	2007								
						5,270	2008		3,486	2008								
						5,270	2009		3,486	2009								
						5,270	2010		3,486	2010								
Mercer	New Jersey	Unit 1			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10					
Mercer	New Jersey	Unit 2			Install Dry FGD (or approved alt. technology) and continually operate	0.15	12/31/10	Install SCR (or approved tech) and continually operate	0.1	01/01/07	Install Baghouse (or approved technology)	0.015	12/31/10					
Westar Energy																		
Jeffrey Energy Center	Kansas	All units			Units 1, 2, and 3 have a total annual limit of 6,600 tons of SO_2 starting 2011 Units 1, 2, and 3 must all install FGDs by 2011 and operate them continuously. FGDs must maintain a 30-Day Rolling Average Unit Removal Efficiency for SO_2 of at least 97% or a 30-Day Rolling Average Unit Emission Rate for SO_2 of no greater than 0.070 lbs/mmBTU.			Units 1-3 must continuously operate Low NO_x Combustion Systems by 2012 and achieve and maintain a 30-Day Rolling Average Unit Emission Rate for NO_x of no greater than 0.180 lbs/mmBTU. One of the three units must install an SCR by 2015 and operate it continuously to maintain a 30-Day Rolling Average Unit Emission Rate for NO_x of no greater than 0.080 lbs/mmBTU. By 2013 Westar shall elect to either (a) install a second SCR on one of the other JEC Units by 2017 or (b) meet a 0.100 lbs/mmBTU Plant-Wide 12-Month Rolling Average Emission Rate for NO_x by 2015			Units 1, 2, and 3 must operate each ESP and FGD system continuously by 2011 and maintain a 0.030 lbs/mmBTU PM Emissions Rate. Units 1 and 2's ESPs must be rebuilt by 2014 in order to meet a 0.030 lbs/mmBTU PM Emissions Rate							http://www2.epa.gov/enforcement/westar-energy-inc-settlement
Duke Energy																		
Gallagher	Indiana	Units 1 & 3	Retire or repower as natural gas	1/1/2012														http://www2.epa.gov/enforcement/duke-energy-gallagher-plant-clean-air-act-settlement
Gallagher	Indiana	Units 2 & 4			Install Dry sorbent injection technology	80%	1/1/2012											
American Municipal Power																		
Gorsuch Station	Ohio	Units 2 & 3	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)															http://www2.epa.gov/enforcement/american-municipal-power-clean-air-act-settlement
Gorsuch Station	Ohio	Units 1 & 4	Elected to Retire Dec 15, 2010 (must retire by Dec 31, 2012)															
Hoosier Energy Rural Electric Cooperative																		
Ratts	Indiana	Units 1 & 2						Install & continually operate SNCRS	0.25	12/31/2011	Continuously operate ESP			Annually surrender any NO_x and SO_2 allowances that Hoosier does not need in order to meet its regulatory obligations				http://www2.epa.gov/enforcement/hoo

Company and Plant	State	Unit	Settlement Actions: Retire/Repower – Action	Retire/Repower – Effective Date	SO_2 control – Equipment	SO_2 control – Percent Removal or Rate	SO_2 control – Effective Date	NO_x Control – Equipment	NO_x Control – Rate	NO_x Control – Effective Date	PM or Mercury Control – Equipment	PM or Mercury Control – Rate	PM or Mercury Control – Effective Date	Allowance Retirement – Retirement	Allowance Restriction – Restriction	Allowance Restriction – Effective Date	Notes	Reference
Merom	Indiana	Unit 1			Continuously run current FGD for 90% removal and update FGD for 98% removal by 2012	98%	2012	Continuously operate existing SCRs	0.12		Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/12							sier-energy-rural-electric-cooperative-inc-settlement
		Unit 2			Continuously run current FGD for 90% removal and update FGD for 98% removal by 2014	98%	2014				Continuously operate ESP and achieve PM rate no greater than 0.007 by 6/1/13							
Northern Indiana Public Service Co.																		
Bailly	Indiana	Units 7 & 8			Upgrade existing FGD	95% by 01/01/11 97% by 01/01/14 (95% if low sulfur coal only is burned)		OFA & SCR	0.15 lbs/mmBTU by 12/31/10 0.13 lbs/mmBTU by 12/31/13 0.12 lbs/mmBTU by 12/31/15			0.3 lbs/mmBTU (0.015 if a Baghouse is installed)	12/31/2010					http://www2.epa.gov/enforcement/northern-indiana-public-service-company-clean-air-act-settlement
Michigan City	Indiana	Unit 12			FGD	0.1 lbs/mmBTU	12/31/2018	OFA & SCR	0.14 lbs/mmBTU by 12/31/10 0.12 lbs/mmBTU by 12/31/11 0.10 lbs/mmBTU by 12/31/13			0.3 lbs/mmBTU (0.015 if a Baghouse is installed)	12/31/2018					
Schahfer	Indiana	Unit 14			FGD	0.08 lbs/mmBTU	12/31/2013	OFA & SCR	0.14 lbs/mmBTU by 12/31/10 0.12 lbs/mmBTU by 12/31/12 0.10 lbs/mmBTU by 12/31/14			0.3 lbs/mmBTU (0.015 if a baghouse is installed)	12/31/2013					
	Indiana	Unit 15			FGD	0.08 lbs/mmBTU	12/31/2015	LNB/OFA Either: SCR or SNCR	0.16 0.08 0.15	3/31/2011 12/31/2015 12/31/2012		0.3 lbs/mmBTU (0.015 if a baghouse is installed)	12/31/2015					
	Indiana	Units 17 & 18			Upgrade existing FGD	97%	1/31/2011	LNB/OFA	0.2	3/31/2011		0.3 lbs/mmBTU (0.015 if a baghouse is installed)	12/31/2010					
Dean H Mitchell	Indiana	Units 4, 5, 6, & 11	Retire	12/31/2010														
Tennessee Valley Authority																		
Colbert	Alabama	Units 1-4			FGD		6/30/2016	SCR		6/30/2016				Shall surrender all calendar year NO_x and SO_2 Allowances allocated to TVA that are not needed for compliance with its own CAA reqts. Allocated allowances may be used for TVA's own compliance with CAA reqts.	Shall not use NO_x or SO_2 Allowances to comply with any requirement of the Consent Decree, Nothing prevents TVA from purchasing or otherwise obtaining NO_x and SO_2 allowances from other sources for its compliance with CAA reqts. TVA may sell, bank, use, trade, or transfer	2011		http://www2.epa.gov/enforcement/tennessee-valley-authority-clean-air-act-settlementl
		Unit 5			FGD		12/31/15	SCR		Effective Date								
Widows Creek	Alabama	Units 1 - 6	Retire 2 units 7/31/13 Retire 2 units 7/31/14 Retire 2 units 7/31/15															
		Unit 7						SCR		Effective Date								
		Unit 8						SCR		Effective Date								
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93%	12/31/12	SCR		Effective Date								
		Unit 3			Wet FGD		Effective Date	SCR		Effective Date								

Company and Plant	State	Unit	Settlement Actions: Retire/Repower – Action	Retire/Repower – Effective Date	SO_2 control – Equipment	SO_2 control – Percent Removal or Rate	SO_2 control – Effective Date	NO_x Control – Equipment	NO_x Control – Rate	NO_x Control – Effective Date	PM or Mercury Control – Equipment	PM or Mercury Control – Rate	PM or Mercury Control – Effective Date	Allowance Retirement – Retirement	Allowance Restriction – Restriction	Effective Date	Notes	Reference
Shawnee	Kentucky	Units 1 & 4			FGD	1.2	12/31/17	SCR		12/31/17					any NO_x and SO_2 Super-Compliance" Allowances resulting from meeting System-wide limits. Except that reductions used to support new CC/CT will not be Super Allowances in that year and thereafter.			
		Units 5 - 10				1.2	Effective Date											
Allen	Tennessee	Units 1 - 3			FGD		12/31/18					0.3	12/31/18					
Bull Run	Tennessee	Unit 1			Wet FGD		Effective Date					0.3	Effective Date					
Cumberland	Tennessee	Units 1 & 2			Wet FGD		Effective Date											
Gallatin	Tennessee	Units 1 - 4			FGD		12/31/17	SCR		12/31/17		0.3	12/31/17					
John Sevier	Tennessee	Units 1 & 2	Retire 2 Units 12/31/12 and 12/31/15															
		Units 3 & 4			FGD		12/31/15	SCR		12/31/15								
Johnsonville	Tennessee	Units 1 - 10	Retire 6 Units 12/31/15 Retire 4 Units 12/31/17															
Kingston	Tennessee	Units 1 - 9			FGD		Effective Date	SCR		Effective Date		0.3	Effective Date					
Wisconsin Public Service																		
Pulliam	Wisconsin	Units 5-6	Retire, refuel or repower as natural gas	6/1/2015		0.750 lbs/mmBTU	1/1/2013 until retirement											
	Wisconsin	Units 7-8				0.750 lbs/mmBTU & plant-wide cap of 2100 tons starting 2016	1/1/2013		0.250 lbs/mmBTU & plant-wide cap of 1500 tons starting 2016	12/31/12							The modeled SO_2 rate in IPM is lower; only tonnage limitation imposed through a constraint.	
Weston	Wisconsin	Unit 1				0.750 lbs/mmBTU	1/1/2013 until retirement		0.250 lbs/mmBTU	12/31/2012 until retirement								http://www2.epa.gov/enforcement/wisconsin-public-service-corporation-settlement
	Wisconsin	Units 2	Retire, refuel or repower as natural gas	6/1/2015		0.750 lbs/mmBTU	1/1/2013 until retirement		0.280 lbs/mmBTU	12/31/2012 until retirement								
	Wisconsin	Units 3			ReACT by 12/31/2016	0.750 lbs/mmBTU until 2016 0.080 lbs/mmBTU 2016 onwards	12/31/16	ReACT by 12/31/2016	0.130 lbs/mmBTU until 2016 0.100 lbs/mmBTU 2016 onwards	12/31/16								
	Wisconsin	Units 4			Continuously Operate the existing DFGD & burn only Powder River Basin Coal	0.080 lbs/mmBTU	2/31/2013	Continuously Operate the existing SCR	0.060 lbs/mmBTU	2/31/2013								
Louisiana Generating LLC																		
			Plant-Wide Annual Tonnage Limitations for SO_2 is 18,950 tons in					Plant-Wide Annual Tonnage Limitations										

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
			2016 and thereafter					for NO_x is 8,950 tons in 2015 and thereafter										
Big Cajun 2	Louisiana	Unit 1	Retirement, Refueling, Repowering, or Retrofit	04/01/25	install and Continuously Operate DSI — install and Continuously Operate Dry FGD	0.380 lbs/mmBTU [2015] — 0.070 lbs/mmBTU	4/15/2015 [DSI] — 4/1/2025 [DFGD]	install and Continuously Operate SNCR	0.150 lbs/mmBTU	05/01/14	Continuously Operate each ESP	0.030 lbs/mmBTU	04/15/15				May trade Super-Compliant Allowances, may buy external allowances to comply. "Commencing January 1, 2013, and continuing thereafter, Settling Defendant shall burn only coal with no greater sulfur content than 0.45 percent by weight on a dry basis at Big Cajun II Units 1 and 3. "	http://www2.epa.gov/enforcement/louisiana-generating-settlement
		Unit 2	Refuel/convert to NG fired	04/15/15				install and Continuously Operate SNCR	0.150 lbs/mmBTU	05/01/14								
		Unit 3						install and Continuously Operate SNCR	0.135 lbs/mmBTU	05/01/14	Continuously Operate each ESP	0.030 lbs/mmBTU	04/15/15					
Dairyland Power Cooperative																		
Dairyland Power Cooperative shall not exceed an Annual Plant-wide Tonnage Limitation of 6800 tons of NO_x in calendar years 2016, 3700 tons 2017-2019, and 3200 tons in 2020 and thereafter; and an Annual Plant-wide Tonnage Limitation of 6070 tons of SO_2 in 2016, 6060 tons 2017-2019 and 4580 tons in 2020 and thereafter.																		
Alma	Wisconsin	Unit 1	Cease Burning Coal	06/30/12														http://www2.epa.gov/enforcement/dairyland-power-cooperative-settlement
		Unit 2	Cease Burning Coal	06/30/12														
		Unit 3	Cease Burning Coal	06/30/12														
		Unit 4	**Option 2**: Retrofit and Regulate both units more stringently	12/31/14	Install and continuously operate DFGD or DSI at Alma 4	1.00 lbs/mmBTU at Alma 4 And a joint cap of 3,737 tons until 2019, and 2,242 tons thereafter. In the event that one retires, Tonnage Cap of 2,136 tons for the remaining unit until 2019 and 1,282 tons thereafter	12/31/2014	Continuously Operate the existing Low NO_x Combustion System (including OFA) and SNCR	0.350 lbs/mmBTU — Joint cap of 1308 tons for- until 2019, and 785 tons thereafter. In the event that one retires, Tonnage Cap of 746 tons for remaining unit until 2019 and 449 tons thereafter	8/1/2012 — 12/31/2014	Continuously Operate an ESP or FF on Alma Unit 4	0.030 lbs/mmBTU [with ESP] 0.015 lbs/mmBTU [with FF] at Alma 4. Joint cap of 112 tons until 2019, and 67 tons thereafter. In the event that one retires, Tonnage Cap of 64 tons for the remaining unit until 2019 and 39 tons thereafter	12/31/14				Dairyland was provided with two options for compliance. It chose Option 2 and it is the one modeled in IPM. Details on Option 1 can be found in the settlement document referenced in the adjoining column.	
		Unit 5																
J.P. Madgett	Wisconsin	Unit 1			Install and continuously operate DFGD	0.090 lbs/mmBTU	12/31/14	Continuously Operate existing Low NO_x Combustion System — Install an SCR	0.30 lbs/mmBTU — 0.080 lbs/mmBTU	8/1/2012 — 6/30/2016	Continuously Operate the existing Baghouse	0.0150 lbs/mmBTU	07/01/13					

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
Genoa	Wisconsin	Unit 1			Continuously Operate the FGD	0.090 lbs/mmBTU	12/31/12	Continuously Operate existing Low NO_x Combustion System including OFA — Install an SNCR	0.14 lbs/mmBTU — Annual Tonnage Cap of 1,140 tons	12/31/2014 — 6/1/2015	Continuously Operate the existing Baghouse	0.0150 lbs/mmBTU	07/01/13					
Dominion Energy, Inc.																		
			In calendar year 2014, and in each calendar year thereafter, Kincaid shall not exceed a Plant-Wide Annual Tonnage Limitation of 3,500 tons of NO_x & 4,400 tons of SO_2, and Brayton Point shall not exceed a Plant-Wide Annual Tonnage Limitation of 4,600 tons of NO_x & 4,100 tons of SO_2.															
Brayton Point	Massachusetts	Unit 1			Continuously Operate the existing dry FGD	0.150 lbs/mmBTU	06/01/13	Continuously Operate the SCR, OFA, and LNB	0.080 lbs/mmBTU	05/01/13	Install/Continuously Operate a Baghouse	0.015 lbs/mmBTU [PM by 2013] 0.01 lbs/mmBTU [PM post-2013]	06/01/13					http://www2.epa.gov/enforcement/dominion-energy-inc
		Unit 2						Continuously Operate the LNB and OFA	0.280 lbs/mmBTU	05/02/13								
		Unit 3			Continuously Operate dry FGD	0.080 lbs/mmBTU	07/01/13	Continuously Operate the SCR, OFA, and LNB	0.080 lbs/mmBTU	05/01/13	Install/Continuously Operate a Baghouse	0.015 lbs/mmBTU [PM by 2013] 0.01 lbs/mmBTU [PM post-2013]	07/01/13					
Kincaid Power Station	Illinois	Unit 1			Continuously Operate DSI	0.100 lbs/mmBTU	01/01/14	Continuously Operate each SCR and OFA	0.080 lbs/mmBTU	05/01/13	Continuously Operate the ESP	0.030 lbs/mmBTU [PM by 2013] 0.015 lbs/mmBTU [PM by post-2013]	06/01/13					
		Unit 2																
State Line Power Station	Indiana	Unit 3	Retire	06/01/12														
		Unit 4																
Wisconsin Power and Light																		
					Edgewater 3-5- shall not exceed an Annual Tonnage Limitation of 2,500 tons of NO_x in calendar years 2016-2018, and 1100 tons 2019 onwards & an Annual Tonnage Limitation of 12,500 tons of SO_2 in 2016, 6000 tons 2017-2018 and 1100 tons 2019 onwards. Columbia 1 & 2 shall not exceed an Annual Tonnage Limitation of 5,600 tons of NO_x in calendar years 2016-2018, and 4300 tons 2019 onwards & an Annual Tonnage Limitation of 3290 tons of SO_2 in 2016 and thereafter.													
Edgewater Generating Station	Wisconsin	Unit 3	Retire, Refuel, or Repower	12/31/15		Unit-Specific Annual Tonnage Cap of 700 Tons of SO_2	05/21/13		Unit-Specific Annual Tonnage Cap of 250 tons of NO_x	05/21/13								http://www2.epa.gov/enforcement/wisconsin-power-and-light-et-al-settlement
		Unit 4	Retire, Refuel, or Repower	12/31/18		0.700 lbs/mmBTU	05/21/13	Operate SNCR and LNB	0.150 lbs/mmBTU	01/01/14	Continuous Operation of the existing ESP	0.030 lbs/mmBTU	12/31/13					

Company and Plant	State	Unit	Settlement Actions: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM or Mercury Control: Equipment	PM or Mercury Control: Rate	PM or Mercury Control: Effective Date	Allowance Retirement: Retirement	Allowance Restriction: Restriction	Effective Date	Notes	Reference
		Unit 5			Install and continuously operate DFGD	0.075 lbs/mmBTU	12/31/16	Install and continuously operate SCR	0.070 lbs/mmBTU	05/01/13	Install and continuously operate Fabric Filter	0.015 lbs/mmBTU	12/31/16					
Columbia Generating Station	Wisconsin	Unit 1			Install and continuously operate DFGD	0.075 lbs/mmBTU	01/01/15	Operation of the Low NO_x Combustion System	0.150 lbs/mmBTU	07/21/13	Install and continuously operate Fabric Filter	0.015 lbs/mmBTU	12/31/14					
		Unit 2				0.075 lbs/mmBTU		Operation of the Low NO_x Combustion System — Install and continuously operate SCR	0.150 lbs/mmBTU — 0.070 lbs/mmBTU	7/21/2013 — 12/31/2018		0.015 lbs/mmBTU	12/31/14					
Nelson Dewey Generating Station	Wisconsin	Unit 1	Retire, Refuel, or Repower	12/31/15	commence burning 100% Powder River Basin or equivalent fuel containing ≤ 1.00 lbs/mmBTU of SO_2	0.800 lbs/mmBTU	05/22/13		0.300 lbs/mmBTU	04/22/13		0.100 lbs/mmBTU	04/22/13				Cease Burning Petcoke and Commence Burning 100% PRB Coal or Equivalent at Nelson Dewey Units 1 and 2.	
		Unit 2	Retire, Refuel, or Repower	12/31/15														

Table 3-15 State Settlements in EPA Base Case v.5.13

Company and Plant	State	Unit	State Enforcement Actions														Notes
			Retire/Repower		SO_2 Control			NO_x Control			PM Control			Mercury Control			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	
AES																	
			If the MPC project is discontinued at Greenidge Unit 4 by 12/31/2009, Unit 4 will be subject to the following SO_2 emission caps: 2005 will be 12,125 tons, 2006 will be 11,800 tons, 2007 will be 11,475 tons, 2008 will be 11,150 tons, 2009 will be 10,825 tons. By 12/31/2009, AES shall control, repower, or cease operations at Westover Unit 7. Beginning in 2005, Unit 8 will be subject to the following SO_2 emission caps: 2005 is 9500 tons, 2006 is 9250, 2007 is 9000, 2008 is 8750, 2009 is 8500 tons.														http://www.ag.ny.gov/press-release/governor-and-attorney-general-announce-new-yorks-largest-coal-plants-slash-pollution
Greenidge	New York	Unit 4	Update: as of May 2009, CONSOL and AES describe the Greenidge Unit 4 MPC effort as a success.														http://investor.aes.com/phoenix.zhtml?c=202639&p=irol-newsArticle&ID=1274075&highlight=
					Install FGD	90%	09/01/07	Install SCR	0.15	09/01/07							1) Except when Greenidge Unit 4 is operating below minimum operating load, it will make good faith efforts to achieve a NO_x emission rate of 0.1 lbs/mmBtu. If this level cannot be achieved, the emission limit shall be the level achieved within one year of commencement of operation, no less stringent than 0.15 lbs/mmBtu. 2) Unit 4 will make good faith efforts to achieve a SO_2 removal efficiency of 95%. If this removal efficiency cannot be achieved, the emission limit shall be the level achieved by 9/1/2007, but no less stringent than 90% removal efficiency, resulting in a 0.38 lbs/mmBtu permitted limit.
	New York	Unit 3	Install BACT, repower, or cease operations		Install BACT		12/31/09	Install BACT		12/31/09							
Westover			Update: as of May 2009, NO_x emissions appear to be above the specified 0.15 lbs/mmBtu														http://www.powermag.com/print/environmental/Apply-the-fundamentals-to-improve-emissions-performance_574.html
	New York	Unit 8				90%	12/31/10	Install SCR	0.15	12/31/10							1) Except when Westover Unit 8 is operating below minimum operating load, it will make good faith efforts to achieve a NO_x emission rate of 0.1lbs/mmBtu. If this level cannot be achieved, the emission limit will be the level achieved within one year of operation that is no less stringent than 0.15 lbs/mmBtu. 2) Unit 8 will make good faith efforts to achieve a SO_2 removal efficiency of 95%. If this level cannot be achieved, a removal efficiency no less than 90% will be used, resulting in a 0.34 lbs/mmBtu permit.
	New York	Unit 7	Install BACT, repower, or cease operations		Install BACT		12/31/09	Install BACT		12/31/09							
Hickling	New York	Unit 1	Install BACT, repower, or cease operations		Install BACT		05/01/07	Install BACT		05/01/07							
	New York	Unit 2	Install BACT, repower, or cease operations		Install BACT		05/01/07	Install BACT		05/01/07							
Jennison	New York	Unit 1	Install BACT, repower, or cease		Install BACT		05/01/07	Install BACT		05/01/07							

			State Enforcement Actions														
			Retire/Repower		SO_2 Control			NO_x Control			PM Control			Mercury Control			
Company and Plant	State	Unit	Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Notes
			operations														
	New York	Unit 2	Install BACT, repower, or cease operations		Install BACT		05/01/07	Install BACT		05/01/07							
Niagara Mohawk Power																	
			NRG shall comply with the below annual tonnage limitations for its Huntley and Dunkirk Stations: In 2005 59,537 tons of SO_2 and 10,777 tons of NO_x, in 2006 34,230 of SO_2 and 6,772 of NO_x, in 2007 30,859 of SO_2 and 6,211 of NO_x, in 2008 22,733 tons of SO_2 and 6,211 tons of NO_x, in 2009 19,444 of SO_2 and 5,388 of NO_x, in 2010 and 2011 19,444 of SO_2 and 4,861 of NO_x, in 2012 16,807 of SO_2 and 3,241 of NO_x, 2013 and 14,169 of SO_2 and 3,241 of NO_x thereafter.														http://www.ag.ny.gov/press-release/governor-and-attorney-general-announce-new-yorks-largest-coal-plants-slash-pollution
Huntley	New York	Units 63 – 66	Retire	Before 2008													
Public Service Co. of NM																	
San Juan	New Mexico	Unit 1			State-of-the-art technology	90%	10/31/08	State-of-the-art technology	0.3	10/31/08	Operate Baghouse and demister technology	0.015	12/31/09	Design activated carbon injection technology (or comparable tech)		12/31/09	All four units have installed Wet Scrubbers. Unit 1 and 4 NO_x controls [SNCR] are hardwired into EPA Base Case. http://nmsierraclub.org/sites/default/files/20055-10SanJuanfinaldecreeasentered%20%282%29.pdf
	New Mexico	Unit 2					03/31/09			03/31/09			12/31/09			12/31/09	
	New Mexico	Unit 3					04/30/08			04/30/08			04/30/08			04/30/08	
	New Mexico	Unit 4					10/31/07			10/31/07			10/31/07			10/31/07	
Public Service Co of Colorado																	
Comanche	Colorado	Unit 1			Install and operate FGD	0.1 lbs/mmBtu combined average	07/01/09	Install low-NO_x emission controls	0.15 lbs/mmBtu combined average	07/01/09				Install sorbent injection technology		07/01/09	Comanche units 1 and 2 taken together shall not exceed a 0.15 heat rate for NO_x, nor 0.10 for SO_2, no later than 180 days after initial start-up of control equipment, or by 7/01/2009, whichever is earlier. http://content.sierraclub.org/coal/sites/content.sierraclub.org.coal/files/elp/docs/co-comanche_agree-sign_2004-12-02.pdf
	Colorado	Unit 2			Install and operate FGD		07/01/09	Install low-NO_x emission controls		07/01/09				Install sorbent injection technology		07/01/09	
	Colorado	Unit 3			Install and operate FGD	0.1 lbs/mmBtu		Install and operate SCR	0.08		Install and operate a fabric filter dust collection system	0.013		Install sorbent injection technology		Within 180 days of start-up	
Rochester Gas & Electric																	
Russell Plant	New York	Units 1 – 4	Retire all units														http://www.ag.ny.gov/press-release/cuomo-announces-settlement-close-rochester-gas-electrics-coal-burning-russell-power
Mirant New York																	
Lovett Plant	New York	Unit 1	Retire	05/07/07													http://www.nytimes.com/2007/05/11/nyregion/11plant.html?_r=1&pagewanted=print
	New York	Unit 2	Retire	04/30/08													Retirements are pursuant to a 2003 consent decree, and the plant's failure to comply with the required reductions.
TVA																	
Allen	Tennessee	Units 1 - 3			Remove from Service, FGD, or Retire		12/31/2015	Install SCR		Effective Date							http://www2.epa.gov/sites/production/files/documents/tvacoal-fired-cd.pdf
Bull Run	Tennessee	Unit 1			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Colbert	Alabama	Units 1 - 4			Remove from Service, FGD, Repower to Renewable Biomass, or Retire		6/30/2016	Remove from Service, SCR, Repower to Renewable Biomass, or Retire		6/30/2016							

Company and Plant	State	Unit	State Enforcement Actions														Notes
			Retire/Repower		SO_2 Control			NO_x Control			PM Control			Mercury Control			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	
		Unit 5			Remove from Service, FGD, or Retire		12/31/2015	Install SCR		Effective Date							
Cumberland	Tennessee	Units 1 & 2			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Gallatin	Tennessee	Units 1 - 4			FGD, Repower to Renewable Biomass, or Retire		12/31/2017	Install SCR, Repower to Renewable Biomass, or Retire		12/31/2017							
John Sevier	Tennessee	Units 1 & 2	Retire	12/31/2012													
		Units 3 & 4	Remove from Service	12/31/2012	FGD, Repower to Renewable Biomass, or Retire		12/31/2015	Install SCR, Repower to Renewable Biomass, or Retire		12/31/2015							
Johnsonville	Tennessee	Units 1 - 10	Retire	6 Units by 12/31/15, 4 Units by 12/31/18													
Kingston	Tennessee	Units 1 - 9			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Paradise	Kentucky	Units 1 & 2			Upgrade FGD	93% Removal	12/31/2012	Install SCR		Effective Date							
		Unit 3			Install Wet FGD		Effective Date	Install SCR		Effective Date							
Shawnee	Kentucky	Units 1 & 4			FGD, Repower to Renewable Biomass, or Retire		12/31/2017	Install SCR, Repower to Renewable Biomass, or Retire		12/31/2017							
Widows Creek	Alabama	Units 1 & 2	Retire	7/31/2013													
		Unit 3 & 4	Retire	7/31/2014													
		Units 5 & 6	Retire	7/31/2015													
		Units 7 & 8			Install Wet FGD		Effective Date	Install SCR		Effective Date							
RC Cape May Holdings, LLC																	
B L England	New Jersey	Unit 1	Retire/Repower	05/01/14													http://www.nj.gov/dep/docs/20120613104728.pdf
		Unit 2	Retire/Repower [Decision to be made by December 2013]	05/01/14													

Table 3-16 Citizen Settlements in EPA Base Case v.5.13

Company and Plant	State	Unit	Citizen Suits Provided by DOJ: Retire/Repower: Action	Retire/Repower: Effective Date	SO_2 control: Equipment	SO_2 control: Percent Removal or Rate	SO_2 control: Effective Date	NO_x Control: Equipment	NO_x Control: Rate	NO_x Control: Effective Date	PM Control: Equipment	PM Control: Rate	PM Control: Effective Date	Mercury Control: Equipment	Mercury Control: Rate	Mercury Control: Effective Date	Notes
SWEPCO (AEP)																	
Welsh	Texas	Units 1-3									Install and operate CEMs		12/31/2010				SWEPCO may attempt to demonstrate that PM CEMs are infeasible after two years of operation. http://www.ocefoundation.org/PDFs/ConsentDecree&CLtoDOJ.pdf
Allegheny Energy																	
Hatfield's Ferry	Pennsylvania	Unit 1			Install and operate wet FGD		6/30/2010				Install and operate sulfur trioxide injection systems, improve ESP performance	0.1 lbs/mmBtu in 2006, then 0.075 lbs per hour (filterable) and 0.1 lbs/mmBtu for particles less than ten microns in 2010	7/31/2006 and 6/30/2010				http://www.environmentalintegrity.org/law_library/PennFuture_EIP_Lawsuit.php
	Pennsylvania	Unit 2															
	Pennsylvania	Unit 3											11/31/2006 and 6/30/2010				
Wisconsin Public Service Corp																	
Pulliam	Wisconsin	Unit 3	Retire	12/31/2007													http://milwaukee.bizjournals.com/milwaukee/stories/2006/10/23/daily29.html
	Wisconsin	Unit 4															
University of Wisconsin																	
Charter Street Heating Plant	Wisconsin		Repower to burn 100% biomass	12/31/2012													Sierra Club suit was based on NSR. http://wisconsin.sierraclub.org/PDF/press/112607_PR_WIStateOwnedCoalSettlement.pdf
Tucson Electric Power																	
Springerville Plant	Arizona	Unit 1			Dry FGD, 85% reduction required	0.27 lbs/mmBtu	12/31/2006	SCR, LNB	0.22 lbs/mmBtu	12/31/2006	Baghouse	0.03 lbs/mmBtu	1/1/2006				Lawsuit filed by Grand Canyon Trust. Consent decree is not published. For the compliance details, see the EPA's own copy of the plant's permit revisions: http://xrl.us/springerville and http://xrl.us/springerville2
	Arizona	Unit 2															
	Arizona	Unit 3															
	Arizona	Unit 4				Four-unit cap of 10,662 tons per year once units 3 and 4 are operational			Four-unit cap of 8,940 tons per year once units 3 and 4 are operational								
Kansas City Board of Public Utilities																	
Quindaro	Kansas	Units 1	Cease burning coal/Convert to natural gas	04/16/15													
	Kansas	Units 2															
Nearman	Kansas	Unit 1									Install and continuously operate a baghouse	0.01 lbs/mmBtu	09/01/17				http://www.bpu.com/AboutBPU/MediaNewsReleases/BPUUnifiedGovernmentSettleThreatenedLawsuit.aspx http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/21193551 "end coal-fired operations at two coal units totaling 167 MW at its Quindaro station by April 2015 and to install a baghouse at its 232-MW Nearman-1 coal unit by September 2017." "BPU spokesman David Mehlhaff said the muni plans to convert the Quindaro-1 and -2 coal units to only natural gas firing, probably by April 2015; both units currently have dual-fuel capabilities."

Company and Plant	State	Unit	Citizen Suits Provided by DOJ														Notes
			Retire/Repower		SO_2 control			NO_x Control			PM Control			Mercury Control			
			Action	Effective Date	Equipment	Percent Removal or Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	Equipment	Rate	Effective Date	
MidAmerican Energy Company																	
Walter Scott, Jr Energy Center	Iowa	Units 1	Cease burning coal/Convert to natural gas	04/16/16													http://www.sec.gov/Archives/edgar/data/928576/000092857613000014/llcmec33113form10-q.htm "MidAmerican Energy has committed to cease burning solid fuel, such as coal, at its Walter Scott, Jr. Energy Center Units 1 and 2, George Neal Energy Center Units 1 and 2 and Riverside Energy Center by April 16, 2016...The George Neal Energy Center Unit 1 and Riverside Energy Center currently have the capability to burn natural gas in the production of electricity, although under current operating and economic conditions, production utilizing natural gas would be very limited"
	Iowa	Units 2															
George Neal Energy Center	Iowa	Units 1															
	Iowa	Units 2															
Riverside Energy Center	Iowa	Units 7															
	Iowa	Units 8															
	Iowa	Units 9															
Dominion Energy																	
Salem Harbor	Massachusetts	Unit 1-4	Retire	12/31/2011 for units 1&2 6/1/2014 for units 3&4													http://www.clf.org/wp-content/uploads/2012/02/Signed-Consent-Decree-12_11.pdf
Duke Energy																	
Wabash River	Indiana	Unit 2-5	Retire	2014													http://www.duke-energy.com/about-us/retired-coal-units-potential-retirements.asp
Wabash River	Indiana	Unit 6	Coal to Gas Conversion	6/12018													

Table 3-17 Renewable Portfolio Standards in EPA Base Case v.5.13

Regional Renewable Portfolio Standards- AEO 2013							
NEMS Region	**IPM Regions Covered**	**Units**	**2016**	**2018**	**2020**	**2025**	**2030-2050**
ERCOT (1)	ERC_REST, ERC_FRNT, ERC_GWAY, ERC_WEST	%	4.5%	4.5%	4.4%	4.4%	4.4%
MORE (3)	MIS_WUMS (42%)	%	10.1%	10.0%	10.0%	9.9%	10.0%
MROW (4)	MAP_WAUE, MIS_IA, MIS_MIDA, MIS_MNWI, MIS_MAPP, SPP_NEBR	%	8.9%	9.6%	10.3%	11.3%	11.4%
NEWE (5)	NENG_CT, NENGREST, NENG_ME	%	11.6%	13.0%	14.3%	14.5%	14.6%
NYCW (6), NYLI (7), NYUP (8)	NY_Z_J, NY_Z_K, NY_Z_C&E, NY_Z_F, NY_Z_G-I, NY_Z_A&B	%	25.0%	24.8%	24.6%	24.5%	24.6%
RFCE (9)	PJM_EMAC, PJM_PENE, PJM_SMAC, PJM_WMAC	%	9.7%	11.6%	13.6%	14.7%	14.8%
RFCM (10)	MIS_LMI	%	10.1%	10.1%	10.0%	9.9%	10.0%
RFCW (11)	MIS_INKY (90%), MIS_WUMS (58%), PJM_West, PJM_AP, PJM_ATSI, PJM_COMD	%	5.0%	6.0%	7.1%	9.2%	9.3%
SRDA (12)	S_D_AMSO, S_D_N_AR, S_D_REST, S_D_WOTA, SPP_WEST (10%)	%	0.7%	0.6%	0.6%	0.6%	0.6%
SRGW (13)	MIS_IL, MIS_MO, SPP_N (3%)	%	7.3%	10.2%	11.2%	15.7%	15.8%
SRCE (15)	S_C_KY, S_C_TVA, MIS_INKY (10%)	%	0.0%	0.0%	0.0%	0.1%	0.1%
SRVC (16)	PJM_Dom, S_VACA	%	3.3%	4.2%	5.0%	5.5%	5.5%
SPNO (17)	SPP_N (97%)	%	8.5%	9.7%	11.9%	13.1%	13.2%
SPSO (18)	SPP_SE, SPP_SPS, SPP_WEST (90%), SPP_KIAM	%	1.8%	1.9%	2.1%	2.2%	2.2%
AZNM (19)	WECC_AZ, WECC_IID, WECC_NM, WECC_SNV	%	7.4%	8.0%	9.4%	11.1%	11.1%
CAMX (20)	WEC_LADW, WEC_CALN, WEC_SDGE, WECC_SF, WECC_SCE	%	25.6%	29.3%	33.0%	32.9%	33.0%
NWPP (21)	WECC_ID, WECC_MT, WECC_NNV, WECC_PNW, WECC_UT, WECC_WY (58%)	%	7.2%	7.2%	10.1%	10.9%	11.0%
RMPA (22)	WECC_CO, WECC_WY (42%)	%	10.6%	13.1%	15.5%	15.3%	15.5%
Regional RPS Solar Carve-outs							
NEMS Region	**IPM Regions Covered**	**Units**	**2016**	**2018**	**2020**	**2025**	**2030-2050**
ERCOT (1)	ERC_REST, ERC_FRNT, ERC_GWAY, ERC_WEST	%	-	-	-	-	-
MORE (3)	MIS_WUMS (42%)	%	-	-	-	-	-
MROW (4)	MAP_WAUE, MIS_IA, MIS_MIDA, MIS_MNWI, MIS_MAPP, SPP_NEBR	%	0.01%	0.01%	0.58%	0.58%	0.59%
NEWE (5)	NENG_CT, NENGREST, NENG_ME	%	0.08%	0.08%	0.08%	0.08%	0.08%
NYCW (6), NYLI (7), NYUP (8)	NY_Z_J, NY_Z_K, NY_Z_C&E, NY_Z_F, NY_Z_G-I, NY_Z_A&B	%	0.00%	0.00%	0.00%	0.00%	0.00%

Regional Renewable Portfolio Standards- AO 2013							
NEMS Region	**IPM Regions Covered**	**Units**	**2016**	**2018**	**2020**	**2025**	**2030-2050**
RFCE (9)	PJM_EMAC, PJM_PENE, PJM_SMAC, PJM_WMAC	%	0.30%	0.49%	0.67%	0.71%	0.71%
RFCM (10)	MIS_LMI	%	-	-	-	-	-
RFCW (11)	MIS_INKY (90%), MIS_WUMS (58%), PJM_West, PJM_AP, PJM_ATSI, PJM_COMD	%	0.18%	0.25%	0.32%	0.43%	0.45%
SRDA (12)	S_D_AMSO, S_D_N_AR, S_D_REST, S_D_WOTA, SPP_WEST (10%)	%	-	-	-	-	-
SRGW (13)	MIS_IL, MIS_MO, SPP_N (3%)	%	0.29%	0.39%	0.46%	0.68%	0.72%
SRCE (15)	S_C_KY, S_C_TVA, MIS_INKY (10%)	%	0.001%	0.001%	0.001%	0.001%	0.001%
SRVC (16)	PJM_Dom, S_VACA	%	0.06%	0.09%	0.09%	0.09%	0.09%
SPNO (17)	SPP_N (97%)	%	0.03%	0.05%	0.05%	0.08%	0.08%
SPSO (18)	SPP_SE, SPP_SPS, SPP_WEST (90%), SPP_KIAM	%	0.10%	0.10%	0.14%	0.14%	0.14%
AZNM (19)	WECC_AZ, WECC_IID, WECC_NM, WECC_SNV	%	0.48%	0.47%	0.58%	0.60%	0.61%
CAMX (20)	WEC_LADW, WEC_CALN, WEC_SDGE, WECC_SF, WECC_SCE	%	-	-	-	-	-
NWPP (21)	WECC_ID, WECC_MT, WECC_NNV, WECC_PNW, WECC_UT, WECC_WY (58%)	%	0.05%	0.05%	0.06%	0.06%	0.06%
RMPA (22)	WECC_CO, WECC_WY (42%)	%	0.01%	0.01%	0.02%	0.02%	0.02%

Table 3-18 Complete Availability Assumptions in EPA Base Case v.5.13

This is a small excerpt of the data in Table 3-18. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html . Please see Table 3-19 for summary data

Unit ID	Plant Name	Plant Type	Winter Availability	Summer Availability	Annual Availability
55522_G_CT1	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT10	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT2	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT3	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT4	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT5	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT6	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT7	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT8	Sundance	Combustion Turbine	89.2	90.8	89.9
55522_G_CT9	Sundance	Combustion Turbine	89.2	90.8	89.9
55257_G_1	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_2	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_3	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_4	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_5	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_6	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
55257_G_7	Ina Road Water Pollution Control Fac	Combustion Turbine	88.4	90.4	89.2
82755_C_1	AZNM_AZ_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
6088_G_5	North Loop	Combustion Turbine	89.2	90.8	89.9
118_G_GE1	Saguaro	Combustion Turbine	89.8	92.2	90.8
124_G_GT2	Demoss Petrie	Combustion Turbine	89.8	92.2	90.8
82757_C_1	AZNM_CA_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
2468_G_6	Raton	Combustion Turbine	88.4	90.4	89.2
82759_C_1	AZNM_NM_Combustion Turbine	Combustion Turbine	89.8	92.2	90.8
54814_G_GENA	Milagro Cogeneration Plant	Combustion Turbine	89.2	90.8	89.9

Table 3-19 BART Regulations included in EPA Base Case v.5.13

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Colstrip	6076_B_1	BART NO_x	0.15 lb/MMBtu		2018	2018
Colstrip	6076_B_2	BART NO_x	0.15 lb/MMBtu		2018	2018
Comanche	470_B_1	BART NO_x	0.20 lb/MMBtu		2018	2018
Comanche	470_B_2	BART NO_x	0.20 lb/MMBtu		2018	2018
Craig	6021_B_C1	BART NO_x	0.27 lb/MMBtu		2018	2018
Craig	6021_B_C2	BART NO_x	0.08 lb/MMBtu		2018	2018
Four Corners	2442_B_1	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_2	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_3	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_4	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Four Corners	2442_B_5	BART NO_x	0.05 lb/MMBtu	Acutal emissions	2018	2018
Gerald Gentleman	6077_B_1	BART NO_x	0.23 lb/MMBtu	TBD	2018	2018
Gerald Gentleman	6077_B_2	BART NO_x	0.23 lb/MMBtu	TBD	2018	2018
Hayden	525_B_H1	BART NO_x	0.08 lb/MMBtu		2018	2018
Hayden	525_B_H2	BART NO_x	0.07 lb/MMBtu		2018	2018
J E Corette Plant	2187_B_2	BART NO_x	0.35 lb/MMBtu		2018	2018
Martin Drake	492_B_5	BART NO_x	0.31 lb/MMBtu		2018	2018
Martin Drake	492_B_6	BART NO_x	0.32 lb/MMBtu		2018	2018
Martin Drake	492_B_7	BART NO_x	0.32 lb/MMBtu		2018	2018
Nebraska City	6096_B_1	BART NO_x	0.23 lb/MMBtu		2018	2018
Reid Gardner	2324_B_1	BART NO_x	0.20 lb/MMBtu		2018	2018
Reid Gardner	2324_B_2	BART NO_x	0.20 lb/MMBtu		2018	2018
Reid Gardner	2324_B_3	BART NO_x	0.20 lb/MMBtu		2018	2018
San Juan	2451_B_1	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
San Juan	2451_B_2	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
San Juan	2451_B_3	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
San Juan	2451_B_4	BART NO_x	0.11 lb/MMBtu	Acutal emissions	2018	2018
Tecumseh Energy Center	1252_B_10	BART NO_x	0.18 lb/MMBtu		2018	2018
Apache Station	160_B_2	BART NO_x & BART SO_2	0.07 lb/MMBtu across 2 units	0.15 lb/MMBtu	12/1/17	12/1/16
Apache Station	160_B_3	BART NO_x & BART SO_2	0.07 lb/MMBtu across 2 units	0.15 lb/MMBtu	12/1/17	12/1/16
Cherokee	469_B_4	BART NO_x & BART SO_2	0.12 lb/MMBtu	7.81 tpy (12 month rolling)	2018	2018
Cholla	113_B_2	BART NO_x & BART SO_2	0.055 lb/MMBtu across 3 units	0.15 lb/MMBtu	12/1/17	12/5/13
Cholla	113_B_3	BART NO_x & BART SO_2	0.055 lb/MMBtu across 3 units	0.15 lb/MMBtu	12/1/17	12/5/13
Cholla	113_B_4	BART NO_x & BART SO_2	0.055 lb/MMBtu across 3 units	0.15 lb/MMBtu	12/1/17	12/5/13
Coal Creek	6030_B_1	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu or 95% efficiency	2018	2018
Coal Creek	6030_B_2	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu or 95% efficiency	2018	2018
Coronado	6177_B_U1B	BART NO_x & BART SO_2	0.065 lb/MMBtu across 2 units	0.08 lb/MMBtu	12/1/17	6/5/13
Coronado	6177_B_U2B	BART NO_x & BART SO_2	0.065 lb/MMBtu across 2 units	0.08 lb/MMBtu	12/1/17	6/5/13
Jeffrey Energy Center	6068_B_1	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.15 lb/MMBtu	2018	2018
Jeffrey Energy Center	6068_B_2	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.15 lb/MMBtu	2018	2018

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
La Cygne	1241_B_1	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu	6/1/15	6/1/15
La Cygne	1241_B_2	BART NO_x & BART SO_2	0.13 lb/MMBtu (combined both units)	0.15 lb/MMBtu	6/1/15	6/1/15
Leland Olds	2817_B_1	BART NO_x & BART SO_2	0.19 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Leland Olds	2817_B_2	BART NO_x & BART SO_2	0.35 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Merrimack	2364_B_2	BART NO_x & BART SO_2	0.30 lb/MMBtu	90 % control	2018	2018
Milton R Young	2823_B_B1	BART NO_x & BART SO_2	0.36 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Milton R Young	2823_B_B2	BART NO_x & BART SO_2	0.35 lb/MMBtu	0.15 lb/MMBtu or 95% efficiency	2018	2018
Muskogee	2952_B_4	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Muskogee	2952_B_5	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Pawnee	6248_B_1	BART NO_x & BART SO_2	0.07 lb/MMBtu	0.12 lb/MMBtu	2018	2018
Ray D Nixon	8219_B_1	BART NO_x & BART SO_2	0.21 lb/MMBtu	0.11 lb/MMBtu	2018	2018
Sooner	6095_B_1	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Sooner	6095_B_2	BART NO_x & BART SO_2	0.15 lb/MMBtu	0.06 lbs/MMBtu	2018	2018
Stanton	2824_B_1	BART NO_x & BART SO_2	0.29 lb/MMBtu	0.24 lb/MMBtu	2018	2018
Lansing Smith	643_B_1	BART NO_x & BART SO_2	4700 tpy across 2 units	0.74 lb/MMBtu	2018	2018
Lansing Smith	643_B_2	BART NO_x & BART SO_2	4700 tpy across 2 units	0.74 lb/MMBtu	2018	2018
Northeastern	2963_B_3313	BART NO_x & BART SO_2; Shutdown by 2016	0.23 lb/MMBtu	0.60 lb/MMBtu	2018	2018
Boardman	6106_B_1SG	BART NO_x & BART SO_2; Shutdown by 2020	0.7 lb/MMBtu	1.2 lb/MMBtu	2018	2018
Northeastern	2963_B_3314	BART NO_x & BART SO_2; Shutdown by 2024	0.15 lb/MMBtu	0.40 lb/MMBtu	2018	2018
Seminole	136_B_1	BART SO_2		0.25 lb/MMBtu	2018	2018
Seminole	136_B_2	BART SO_2		0.25 lb/MMBtu	2018	2018
Northside Generating Station	667_B_1	BART SO_2		3600 tpy across 3 units	2018	2018
Northside Generating Station	667_B_2	BART SO_2		3600 tpy across 3 units	2018	2018
Northside Generating Station	667_B_3	BART SO_2		3600 tpy across 3 units	2018	2018
Deerhaven Generating Station	663_B_B2	BART SO_2		5500 tpy	2018	2018
Merrimack	2364_B_2	BART SO_2		Actual Emissions [with FGD]	2018	2018
Yates	728_B_Y6BR	Coal-to-Gas by 2016				
Yates	728_B_Y7BR	Coal-to-Gas by 2016				
George Neal North	1091_B_1	Coal-to-Gas by 4/16/2016				
George Neal North	1091_B_2	Coal-to-Gas by 4/16/2016				
George Neal North	1091_B_3	Coal-to-Gas by 4/16/2016				
Walter Scott Jr. Energy Center	1082_B_3	Coal-to-Gas by 4/16/2016				
A B Brown	6137_B_1	CAIR				
Ames Electric Services Power Plant	1122_B_7	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Asbury	2076_B_1	CAIR				
Bailly	995_B_7	CAIR				
Bailly	995_B_8	CAIR				
Barry	3_B_4	CAIR				
Barry	3_B_5	CAIR				
Belle River	6034_B_1	CAIR				
Belle River	6034_B_2	CAIR				
Big Brown	3497_B_1	CAIR				
Big Brown	3497_B_2	CAIR				
Big Cajun 2	6055_B_2B1	CAIR				
Big Stone	6098_B_1	CAIR				
Blue Valley	2132_B_3	CAIR				
Bowen	703_B_1BLR	CAIR				
Bowen	703_B_2BLR	CAIR				
Bowen	703_B_3BLR	CAIR				
Bowen	703_B_4BLR	CAIR				
Bridgeport Station	568_B_BHB3	CAIR				
Bruce Mansfield	6094_B_1	CAIR				
Bruce Mansfield	6094_B_2	CAIR				
Bruce Mansfield	6094_B_3	CAIR				
Bull Run	3396_B_1	CAIR				
Burlington	1104_B_1	CAIR				
Capitol Heat and Power	54406_G_1	CAIR				
Capitol Heat and Power	54406_G_2	CAIR				
Cardinal	2828_B_1	CAIR				
Cardinal	2828_B_2	CAIR				
Cardinal	2828_B_3	CAIR				
Cayuga	1001_B_1	CAIR				
Cayuga	1001_B_2	CAIR				
Charles R Lowman	56_B_1	CAIR				
Charles R Lowman	56_B_2	CAIR				
Charles R Lowman	56_B_3	CAIR				
Chesterfield	3797_B_5	CAIR				
Chesterfield	3797_B_6	CAIR				
Cheswick	8226_B_1	CAIR				
Colbert	47_B_5	CAIR				
Coleto Creek	6178_B_1	CAIR				
Columbia	8023_B_1	CAIR				
Columbia	8023_B_2	CAIR				
Conemaugh	3118_B_1	CAIR				
Conemaugh	3118_B_2	CAIR				
Conesville	2840_B_4	CAIR				
Conesville	2840_B_5	CAIR				
Conesville	2840_B_6	CAIR				
Cooper	1384_B_1	CAIR				
Cooper	1384_B_2	CAIR				
Crawfordsville	1024_B_6	CAIR				
Cumberland	3399_B_1	CAIR				
Cumberland	3399_B_2	CAIR				
Dean H Mitchell	996_B_11	CAIR				
Dolphus M Grainger	3317_B_1	CAIR				
Dolphus M Grainger	3317_B_2	CAIR				
Dover	2914_B_4	CAIR				
E C Gaston	26_B_4	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
E C Gaston	26_B_5	CAIR				
E W Brown	1355_B_2	CAIR				
E W Brown	1355_B_3	CAIR				
East Bend	6018_B_2	CAIR				
Eckert Station	1831_B_4	CAIR				
Eckert Station	1831_B_5	CAIR				
Eckert Station	1831_B_6	CAIR				
Elmer Smith	1374_B_1	CAIR				
Elmer Smith	1374_B_2	CAIR				
Erickson Station	1832_B_1	CAIR				
F B Culley	1012_B_2	CAIR				
F B Culley	1012_B_3	CAIR				
Fair Station	1218_B_2	CAIR				
Fayette Power Project	6179_B_1	CAIR				
Fayette Power Project	6179_B_2	CAIR				
Fort Martin Power Station	3943_B_1	CAIR				
Fort Martin Power Station	3943_B_2	CAIR				
General James M Gavin	8102_B_1	CAIR				
General James M Gavin	8102_B_2	CAIR				
Genoa	4143_B_1	CAIR				
George Neal South	7343_B_4	CAIR				
Ghent	1356_B_1	CAIR				
Ghent	1356_B_2	CAIR				
Ghent	1356_B_3	CAIR				
Gibson	6113_B_1	CAIR				
Gibson	6113_B_2	CAIR				
Gibson	6113_B_3	CAIR				
Gibson	6113_B_4	CAIR				
Gorgas	8_B_10	CAIR				
Greene County	10_B_1	CAIR				
Greene County	10_B_2	CAIR				
H L Spurlock	6041_B_1	CAIR				
H L Spurlock	6041_B_2	CAIR				
Hamilton	2917_B_8	CAIR				
Hamilton	2917_B_9	CAIR				
Hammond	708_B_4	CAIR				
Harding Street	990_B_70	CAIR				
Harrington	6193_B_061B	CAIR				
Harrington	6193_B_062B	CAIR				
Harrington	6193_B_063B	CAIR				
Harrison Power Station	3944_B_1	CAIR				
Harrison Power Station	3944_B_2	CAIR				
Harrison Power Station	3944_B_3	CAIR				
Hatfields Ferry Power Station	3179_B_1	CAIR				
Hatfields Ferry Power Station	3179_B_2	CAIR				
Hatfields Ferry Power Station	3179_B_3	CAIR				
Henderson	2062_B_H3	CAIR				
HMP&L Station Two Henderson	1382_B_H2	CAIR				
Homer City Station	3122_B_1	CAIR				
Homer City Station	3122_B_2	CAIR				
Homer City Station	3122_B_3	CAIR				
Iatan	6065_B_1	CAIR				
J H Campbell	1710_B_1	CAIR				
J H Campbell	1710_B_2	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
J H Campbell	1710_B_3	CAIR				
J M Stuart	2850_B_1	CAIR				
J M Stuart	2850_B_2	CAIR				
J M Stuart	2850_B_3	CAIR				
J M Stuart	2850_B_4	CAIR				
Jack McDonough	710_B_MB1	CAIR				
Jack McDonough	710_B_MB2	CAIR				
Jack Watson	2049_B_4	CAIR				
Jack Watson	2049_B_5	CAIR				
James De Young	1830_B_4	CAIR				
James De Young	1830_B_5	CAIR				
James H Miller Jr	6002_B_2	CAIR				
James H Miller Jr	6002_B_1	CAIR				
James River Power Station	2161_B_4	CAIR				
James River Power Station	2161_B_5	CAIR				
Jasper 2	6225_B_1	CAIR				
John E Amos	3935_B_1	CAIR				
John E Amos	3935_B_2	CAIR				
John E Amos	3935_B_3	CAIR				
John P Madgett	4271_B_B1	CAIR				
Kenneth C Coleman	1381_B_C1	CAIR				
Kenneth C Coleman	1381_B_C2	CAIR				
Kenneth C Coleman	1381_B_C3	CAIR				
Keystone	3136_B_1	CAIR				
Keystone	3136_B_2	CAIR				
Labadie	2103_B_1	CAIR				
Labadie	2103_B_2	CAIR				
Labadie	2103_B_3	CAIR				
Labadie	2103_B_4	CAIR				
Lake Road	2098_B_6	CAIR				
Lake Road	2908_G_11	CAIR				
Lake Shore	2838_B_18	CAIR				
Lansing	1047_B_4	CAIR				
Logansport	1032_B_6	CAIR				
Manitowoc	4125_B_7	CAIR				
Marshall	2144_B_5	CAIR				
Martin Lake	6146_B_1	CAIR				
Martin Lake	6146_B_2	CAIR				
Martin Lake	6146_B_3	CAIR				
McIntosh	6124_B_1	CAIR				
Merom	6213_B_1SG1	CAIR				
Merom	6213_B_2SG1	CAIR				
Miami Fort	2832_B_7	CAIR				
Miami Fort	2832_B_8	CAIR				
Michigan City	997_B_12	CAIR				
Mill Creek	1364_B_1	CAIR				
Mill Creek	1364_B_2	CAIR				
Mill Creek	1364_B_3	CAIR				
Mill Creek	1364_B_4	CAIR				
Milton L Kapp	1048_B_2	CAIR				
Mitchell	3948_B_1	CAIR				
Mitchell	3948_B_2	CAIR				
Mitchell Power Station	3181_B_33	CAIR				
Monroe	1733_B_1	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Monroe	1733_B_2	CAIR				
Monroe	1733_B_3	CAIR				
Monroe	1733_B_4	CAIR				
Monticello	6147_B_1	CAIR				
Monticello	6147_B_2	CAIR				
Monticello	6147_B_3	CAIR				
Montrose	2080_B_3	CAIR				
Mountaineer	6264_B_1	CAIR				
Mt Storm	3954_B_1	CAIR				
Mt Storm	3954_B_2	CAIR				
Mt Storm	3954_B_3	CAIR				
Muscatine Plant #1	1167_B_8	CAIR				
Muskingum River	2872_B_5	CAIR				
New Madrid	2167_B_1	CAIR				
New Madrid	2167_B_2	CAIR				
Orrville	2935_B_13	CAIR				
Ottumwa	6254_B_1	CAIR				
Paradise	1378_B_1	CAIR				
Paradise	1378_B_2	CAIR				
Paradise	1378_B_3	CAIR				
Petersburg	994_B_1	CAIR				
Petersburg	994_B_2	CAIR				
Petersburg	994_B_3	CAIR				
Pleasant Prairie	6170_B_1	CAIR				
Pleasants Power Station	6004_B_1	CAIR				
Pleasants Power Station	6004_B_2	CAIR				
PPL Brunner Island	3140_B_2	CAIR				
PPL Brunner Island	3140_B_3	CAIR				
PPL Montour	3149_B_1	CAIR				
PPL Montour	3149_B_2	CAIR				
Prairie Creek	1073_B_4	CAIR				
Presque Isle	1769_B_5	CAIR				
Presque Isle	1769_B_6	CAIR				
Presque Isle	1769_B_7	CAIR				
Presque Isle	1769_B_8	CAIR				
Presque Isle	1769_B_9	CAIR				
Pulliam	4072_B_8	CAIR				
R D Green	6639_B_G1	CAIR				
R D Green	6639_B_G2	CAIR				
R D Morrow	6061_B_1	CAIR				
R D Morrow	6061_B_2	CAIR				
R M Schahfer	6085_B_14	CAIR				
R M Schahfer	6085_B_15	CAIR				
R S Nelson	1393_B_6	CAIR				
Robert A Reid	1383_B_R1	CAIR				
Rodemacher	6190_B_2	CAIR				
Rush Island	6155_B_1	CAIR				
Rush Island	6155_B_2	CAIR				
Sandow	6648_B_4	CAIR				
Scherer	6257_B_1	CAIR				
Scherer	6257_B_2	CAIR				
Shelby Municipal Light Plant	2943_B_1	CAIR				
Shelby Municipal Light Plant	2943_B_2	CAIR				
Shiras	1843_B_2	CAIR				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Sibley	2094_B_2	CAIR				
Sibley	2094_B_3	CAIR				
Sikeston Power Station	6768_B_1	CAIR				
Sioux	2107_B_1	CAIR				
Sioux	2107_B_2	CAIR				
South Oak Creek	4041_B_7	CAIR				
South Oak Creek	4041_B_8	CAIR				
Southwest Power Station	6195_B_1	CAIR				
St Clair	1743_B_7	CAIR				
St Marys	2942_B_6	CAIR				
Streeter Station	1131_B_6	CAIR				
Streeter Station	1131_B_7	CAIR				
Tanners Creek	988_B_U4	CAIR				
Thomas Hill	2168_B_MB1	CAIR				
Thomas Hill	2168_B_MB2	CAIR				
Trenton Channel	1745_B_9A	CAIR				
Valley	4042_B_1	CAIR				
Valley	4042_B_2	CAIR				
Valley	4042_B_3	CAIR				
Valley	4042_B_4	CAIR				
Victor J Daniel Jr	6073_B_1	CAIR				
Victor J Daniel Jr	6073_B_2	CAIR				
W A Parish	3470_B_WAP5	CAIR				
W A Parish	3470_B_WAP6	CAIR				
W A Parish	3470_B_WAP7	CAIR				
W H Sammis	2866_B_4	CAIR				
W H Sammis	2866_B_5	CAIR				
W H Sammis	2866_B_6	CAIR				
W H Sammis	2866_B_7	CAIR				
Wabash River	1010_B_6	CAIR				
Wansley	6052_B_1	CAIR				
Wansley	6052_B_2	CAIR				
Warrick	6705_B_2	CAIR				
Warrick	6705_B_3	CAIR				
Warrick	6705_B_4	CAIR				
Wateree	3297_B_WAT1	CAIR				
Wateree	3297_B_WAT2	CAIR				
Welsh	6139_B_1	CAIR				
Weston	4078_B_3	CAIR				
Whitewater Valley	1040_B_2	CAIR				
Widows Creek	50_B_8	CAIR				
Williams	3298_B_WIL1	CAIR				
Winyah	6249_B_1	CAIR				
Winyah	6249_B_2	CAIR				
Asheville	2706_B_1	CAIR/State EGU Rule				
Asheville	2706_B_2	CAIR/State EGU Rule				
Belews Creek	8042_B_1	CAIR/State EGU Rule				
Belews Creek	8042_B_2	CAIR/State EGU Rule				
Cliffside	2721_B_5	CAIR/State EGU Rule				
Marshall	2727_B_1	CAIR/State EGU Rule				
Marshall	2727_B_2	CAIR/State EGU Rule				
Marshall	2727_B_3	CAIR/State EGU Rule				
Marshall	2727_B_4	CAIR/State EGU Rule				
Roxboro	2712_B_1	CAIR/State EGU Rule				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Roxboro	2712_B_2	CAIR/State EGU Rule				
Roxboro	2712_B_3A	CAIR/State EGU Rule				
Roxboro	2712_B_3B	CAIR/State EGU Rule				
Roxboro	2712_B_4A	CAIR/State EGU Rule				
Roxboro	2712_B_4B	CAIR/State EGU Rule				
Lee	2709_B_3	CAIR/State EGU Rule; Shutdown by 2013				
L V Sutton	2713_B_3	CAIR/State EGU Rule; Shutdown by 2017				
Portland	3113_B_2	CAIR; Shutdown by 1/7/2015				
Harllee Branch	709_B_2	CAIR; Shutdown by 10/1/13				
Canadys Steam	3280_B_CAN1	CAIR; Shutdown by 12/1/2017				
Canadys Steam	3280_B_CAN2	CAIR; Shutdown by 12/1/2017				
Canadys Steam	3280_B_CAN3	CAIR; Shutdown by 12/1/2017				
Harllee Branch	709_B_1	CAIR; Shutdown by 12/31/13				
Chesapeake	3803_B_4	CAIR; Shutdown by 12/31/14				
Welsh	6139_B_2	CAIR; Shutdown by 12/31/14				
Conesville	2840_B_3	CAIR; Shutdown by 12/31/2012				
HMP&L Station Two Henderson	1382_B_H1	CAIR; Shutdown by 2008				
Menasha	4127_B_B24	CAIR; Shutdown by 2009				
Pella	1175_B_6	CAIR; Shutdown by 2012				
Pella	1175_B_7	CAIR; Shutdown by 2012				
Jefferies	3319_B_3	CAIR; Shutdown by 2013				
Jefferies	3319_B_4	CAIR; Shutdown by 2013				
Big Sandy	1353_B_BSU2	CAIR; Shutdown by 2015				
Frank E Ratts	1043_B_1SG1	CAIR; Shutdown by 2015				
Frank E Ratts	1043_B_2SG1	CAIR; Shutdown by 2015				
Harbor Beach	1731_B_1	CAIR; Shutdown by 2015				
Nelson Dewey	4054_B_2	CAIR; Shutdown by 2015				
Cane Run	1363_B_4	CAIR; Shutdown by 2016				
Cane Run	1363_B_5	CAIR; Shutdown by 2016				
Cane Run	1363_B_6	CAIR; Shutdown by 2016				
Harllee Branch	709_B_3	CAIR; Shutdown by 2016				
Harllee Branch	709_B_4	CAIR; Shutdown by 2016				
Kraft	733_B_3	CAIR; Shutdown by 2016				
J T Deely	6181_B_1	CAIR; Shutdown by 2018				
J T Deely	6181_B_2	CAIR; Shutdown by 2018				
State Line	981_B_4	CAIR; Shutdown by 3/25/12				
Avon Lake	2836_B_12	CAIR; Shutdown by 4/1/2015				
Walter C Beckjord	2830_B_5	CAIR; Shutdown by 4/1/2015				
Walter C Beckjord	2830_B_6	CAIR; Shutdown by 4/1/2015				
New Castle	3138_B_5	CAIR; Shutdown by 4/16/2015				
Big Sandy	1353_B_BSU1	CAIR; Shutdown by 6/1/2015				
Bay Shore	2878_B_3	CAIR; Shutdown by 9/1/2012				
Bay Shore	2878_B_4	CAIR; Shutdown by 9/1/2012				
Eastlake	2837_B_5	CAIR; Shutdown by 9/1/2012				
Edgewater	4050_B_4	CAIR; Shutdown or Coal-to-Gas by 12/31/2018				
Dave Johnston	4158_B_BW43	Proposal 5/23/13				
Dave Johnston	4158_B_BW44	Proposal 5/23/13				
Jim Bridger	8066_B_BW71	Proposal 5/23/13				
Jim Bridger	8066_B_BW72	Proposal 5/23/13				
Jim Bridger	8066_B_BW73	Proposal 5/23/13				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Jim Bridger	8066_B_BW74	Proposal 5/23/13				
Laramie River Station	6204_B_1	Proposal 5/23/13				
Laramie River Station	6204_B_2	Proposal 5/23/13				
Naughton	4162_B_1	Proposal 5/23/13				
Naughton	4162_B_2	Proposal 5/23/13				
Naughton	4162_B_3	Proposal 5/23/13				
Neil Simpson	4150_B_5	Proposal 5/23/13				
Wyodak	6101_B_BW91	Proposal 5/23/13				
Navajo	4941_B_1	Proposed				
Navajo	4941_B_2	Proposed				
Navajo	4941_B_3	Proposed				
Indian River Generating Station	594_B_3	Shutdown by 12/31/13; State EGU Rule				
Cherokee	469_B_3	Shutdown by 12/31/16				
Valmont	477_B_5	Shutdown by 12/31/17				
Crystal River	628_B_1	Shutdown by 2020				
Crystal River	628_B_2	Shutdown by 2020				
Transalta Centralia Generation	3845_B_BW21	Shutdown by 2020				
Transalta Centralia Generation	3845_B_BW22	Shutdown by 2025				
Brayton Point	1619_B_1	State Alternative Program				
Brayton Point	1619_B_2	State Alternative Program				
Brayton Point	1619_B_3	State Alternative Program				
Baldwin Energy Complex	889_B_1	State EGU Rule				
Baldwin Energy Complex	889_B_2	State EGU Rule				
Baldwin Energy Complex	889_B_3	State EGU Rule				
C P Crane	1552_B_2	State EGU Rule				
Chalk Point LLC	1571_B_1	State EGU Rule				
Chalk Point LLC	1571_B_2	State EGU Rule				
Coffeen	861_B_01	State EGU Rule				
Coffeen	861_B_02	State EGU Rule				
Dallman	963_B_31	State EGU Rule				
Dallman	963_B_32	State EGU Rule				
Dallman	963_B_33	State EGU Rule				
Dickerson	1572_B_3	State EGU Rule				
Duck Creek	6016_B_1	State EGU Rule				
E D Edwards	856_B_2	State EGU Rule				
E D Edwards	856_B_3	State EGU Rule				
Edge Moor	593_B_4	State EGU Rule				
Havana	891_B_9	State EGU Rule				
Herbert A Wagner	1554_B_3	State EGU Rule				
Indian River Generating Station	594_B_4	State EGU Rule				
Joliet 29	384_B_71	State EGU Rule				
Joliet 29	384_B_72	State EGU Rule				
Joliet 29	384_B_81	State EGU Rule				
Joliet 29	384_B_82	State EGU Rule				
Kincaid Generation LLC	876_B_1	State EGU Rule				
Kincaid Generation LLC	876_B_2	State EGU Rule				
Marion	976_B_4	State EGU Rule				
Marion	976_B_123	State EGU Rule				
Morgantown Generating Plant	1573_B_1	State EGU Rule				
Morgantown Generating Plant	1573_B_2	State EGU Rule				
Newton	6017_B_1	State EGU Rule				
Newton	6017_B_2	State EGU Rule				
Pearl Station	6238_B_1A	State EGU Rule				
Powerton	879_B_51	State EGU Rule				

BART Affected Plants	UniqueID	BART Status/ CAIR/ Shutdown/ Coal-to-Gas	NO_x BART Limit	SO_2 BART Limit	NO_x Compliance Date	SO_2 Compliance Date
Powerton	879_B_52	State EGU Rule				
Powerton	879_B_61	State EGU Rule				
Powerton	879_B_62	State EGU Rule				
PSEG Hudson Generating Station	2403_B_2	State EGU Rule				
Waukegan	883_B_8	State EGU Rule				
Will County	884_B_4	State EGU Rule				
Wood River	898_B_5	State EGU Rule				
Austin Northeast	1961_B_NEPP	TBD				
Clay Boswell	1893_B_3	TBD				
Clay Boswell	1893_B_4	TBD				
H Wilson Sundt GS	126_B_4	TBD				
Hibbing	1979_B_1	TBD				
Hibbing	1979_B_2	TBD				
Hibbing	1979_B_3	TBD				
Hoot Lake (Otter Tail)	1943_B_3	TBD				
Sherburne County	6090_B_1	TBD				
Sherburne County	6090_B_2	TBD				
Silver Bay Power	10849_B_BLR2	TBD				
Silver Lake	2008_B_3	TBD				
Silver Lake	2008_B_4	TBD				
Allen S King	1915_B_1	TBD				
Big Bend	645_B_BB01	TBD Proposed				
Big Bend	645_B_BB02	TBD Proposed				
Big Bend	645_B_BB03	TBD Proposed				
Crist	641_B_6	TBD Proposed				
Crist	641_B_7	TBD Proposed				
Crystal River	628_B_4	TBD Proposed				
Crystal River	628_B_5	TBD Proposed				
Deerhaven Generating Station	663_B_B2	TBD Proposed				
Lansing Smith	643_B_1	TBD Proposed				
Lansing Smith	643_B_2	TBD Proposed				
Flint Creek	6138_B_1	TBD State SIP disapproved				
Hunter	6165_B_1	TBD State SIP disapproved				
Hunter	6165_B_2	TBD State SIP disapproved				
Huntington	8069_B_1	TBD State SIP disapproved				
Huntington	8069_B_2	TBD State SIP disapproved				
White Bluff	6009_B_1	TBD State SIP disapproved				
White Bluff	6009_B_2	TBD State SIP disapproved				

4. Generating Resources

“Existing”, “planned-committed”, and “potential” are the three general types of generating units modeled in EPA Base Case v.5.13. Units that are currently operational in the electric industry are termed as “existing” units. Units that are not currently operating but are firmly anticipated to be operational in the future, and have either broken ground (initiated construction) or secured financing are termed “planned-committed”. “Potential” units refer to new generating options used in IPM for capacity expansion projections of the electric industry. Existing and planned-committed units are entered as exogenous inputs to the model, whereas potential units are endogenous to the model in the sense that the model determines the location and size of all the potential units that end up in the final solution for a specific model run.

This chapter is organized into the following five sections:

(1) Section 4.1 provides background information on the National Electric Energy Data System (NEEDS), the database which serves as the repository for information on existing and planned-committed units which are modeled in the EPA Base Case v.5.13,

(2) Section 4.2 provides detailed information on existing non-nuclear generating units modeled in EPA Base Case v.5.13,

(3) Section 0 provides detailed information pertaining to planned-committed units which are assumed in EPA Base Case v.5.13,

(4) Section 4.4 provides detailed information pertaining to the EPA Base Case assumptions for potential plants, and

(5) Section 4.5 describes the handling of existing and potential nuclear units in EPA Base Case v.5.13

4.1 National Electric Energy Data System (NEEDS)

EPA Base Case v.5.13 uses the NEEDS database as its source for data on all existing and planned-committed units. Table 4-1 below summarizes the resources used in developing data on existing units in NEEDS v.5.13. The data sources for planned-committed units in NEEDS are discussed below in Section 0. The population of existing units in NEEDS v.5.13 represents generating units that were in operation through the end of 2010. The population of planned-committed includes any units online or scheduled to come online from 2011 to the end of 2015 (with five exceptions listed in the note under Table 4-2 below).

4.2 Existing Units

EPA Base Case v.5.13 models existing units based on information contained in NEEDS. The sections below describe the procedures followed in determining the population of units in NEEDS, as well as each unit’s capacity, location, and configuration. Details are also given on the model plant aggregation scheme and the cost and performance characteristics associated with the existing non-nuclear units represented in EPA Base Case v.5.13.

4.2.1 Population of Existing Units

The population of existing units was taken primarily from EIA 860 (2010). A number of rules were used to screen the various data sources. These rules helped to ensure data consistency, but also made the population data adaptable for use in EPA Base Case v.5.13. Table 4-2 below summarizes the rules used in populating the NEEDS v.5.13 database. Excerpt from Table 4-35 lists all units that were not included in the NEEDS v.5.13 database based on these criteria.

Table 4-1 Data Sources for NEEDS v.5.13 for EPA Base Case v.5.13

Data Source[a]	Data Source Documentation
DOE's Form EIA-860	DOE's Form EIA-860 is an annual survey of utility and non-utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), operating status, prime mover, energy sources and in-service date of existing and proposed generators. NEEDS v.5.13 uses EIA Form 860 (2010, 2011) data as one of the primary generator data inputs. DOE's Form EIA-860 also collects data of steam boilers such as energy sources, boiler identification, location, operating status and design information; and associated environmental equipment such as NO_x combustion and post-combustion control, FGD scrubber, mercury control and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The association between boilers and generators is also provided. Note that boilers and generators are not necessarily in a one-to-one correspondence. NEEDS v.5.13 uses EIA Form 860 (2010, 2011) data as one of the primary boiler data inputs.
NERC Electricity Supply and Demand (ES&D) database	The NERC ES&D is released annually. It contains generator-level information such as summer, winter and nameplate capacity, state, NERC region and sub-region, status, primary fuel and on-line year. NEEDS v.5.13 uses NERC ES&D (2011) data as one of the data inputs.
DOE's Annual Energy Outlook (AEO)	The Energy Information Administration (EIA) Annual Energy Outlook presents annually updated forecasts of energy supply, demand and prices covering a 20-25 year time horizon. The projections are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2012 such as heat rates, planned committed units were used in NEEDS v.5.13. Nuclear unit capacities and uprates are from AEO 2013.
Ventyx's New Entrants database	Ventyx's New Entrants database has information on new power plant builds, rerates and retirements. NEEDS v.5.13 uses the dataset downloaded on April 13, 2012 and April 23, 2013, as one of the sources of development of committed generating units.
EPA's Emission Tracking System	The Emission Tracking System (ETS) database is updated quarterly. It contains boiler-level information such as primary fuel, heat input, SO_2 and NO_x controls, and SO_2 and NO_x emissions. NEEDS v.5.13 uses annual and seasonal ETS (2011) data as one of the primary data inputs for NO_x rate development and environmental equipment assignment.
Utility and Regional EPA Office Comments	Comments from utilities and regional EPA offices regarding the population in NEEDS (retirements, new units) as well as unit characteristics were incorporated in NEEDS v.5.13.

Note:

[a] Shown in Table 4-1 are the primary issue dates of the indicated data sources that were used. Other vintages of these data sources were also used in instances where data were not available for the indicated issued date or where there were methodological reasons for using other vintages of the data.

Table 4-2 Rules Used in Populating NEEDS v.5.13 for EPA Base Case v.5.13

Scope	Rule
Capacity	Excluded units with reported summer capacity, winter capacity and nameplate capacity of zero or blank.
Status	Excluded units that were out of service for two or three consecutive years (i.e., generators with status codes "OS" in the latest three reporting years and boilers with status codes "OS" in the latest two reporting years) and units that were no longer in service and not expected to be returned to service (i.e., generators or boilers with status codes of "RE"). Status of boiler(s) and associated generator(s) were taken into account for determining operation status
Planned or Committed Units	Included planned units that had broken ground or secured financing and were expected to be online by the end of 2015; one geothermal unit and four nuclear units that are scheduled to come online after 2015 were also included[a]

Scope	Rule
Firm/Non-firm Electric Sales	Excluded non-utility onsite generators that do not produce electricity for sale to the grid on a net basis Excluded all mobile and distributed generators

Note:
[a] The geothermal unit is Bonnett, unit ST2; the four nuclear units are Vogtle, units 3&4, and V C Summer, units 2&3

As with previous versions of the database, NEEDS v.5.13 includes steam units at the boiler level and non-steam units at the generator level (nuclear units are also at the generator level). A unit in NEEDS v.5.13, therefore, refers to a boiler in the case of a steam unit and a generator in the case of a non-steam unit. Table 4-3 provides a summary of the population and capacity of the existing units included in NEEDS v.5.13 through 2010. EIA Form 860 (2010) is the starting point and largest component of the existing unit population in NEEDS v.5.13 but the final population of existing units is supplemented based on information from other sources, including comments from utilities, submissions to EPA's Emission Tracking System, Annual Energy Outlook, and reported capacity in Ventyx's New Entrants database.

EPA removed capacity from the NEEDS inventory based on public announcements of future closures. Removal of such capacity from the NEEDS inventory pre-empts the model itself from making any decisions regarding that capacity's future status or configuration; such capacity is simply no longer available for the model to consider in optimizing electricity supply to meet demand. The list of units considered for removal from NEEDS is built from several data sources including:

1. Edison Electric Institute (EEI), "Coal Fleet Retirement Announcements", July 29, 2011
2. PJM, "Future Deactivation Requests", "PJM Generator Deactivations", 2012 (updated frequently)
3. EIA, "Retired U.S. Electric Generating Units by Operating Company, Plant and Month, 2012
4. Research by EPA and ICF staff

EPA only removed units from the NEEDS inventory if a high degree of certainty could be assigned to future implementation of the announced action. The available retirement-related information was reviewed for each unit individually, and a determination was made regarding the removal of the unit from NEEDS v.5.13. This assessment is based on the rules below, applied in the following order:

1. All units that are listed as retired in the 2010, 2011, 2012 and February 2013 versions of EIA Electric Power Monthly are flagged for removal from NEEDS.
2. All units with a status flag of "RE" or with a planned retirement year prior to 2016 in 2011 EIA 860 are flagged for removal from NEEDS.
3. All units that have been cleared by a regional transmission operator (RTO) or independent system operator (ISO) to retire before 2016, or whose RTO/ISO clearance to retire is contingent on actions that can be completed before 2016, are flagged for removal from NEEDS.
4. All units that have committed specifically to retire before 2016 under federal or state enforcement actions or regulatory requirements are flagged for removal from NEEDS.
5. Finally, if a retirement announcement for a given unit can be corroborated by other available information then the unit is flagged for removal from NEEDS.

Note that units which are required to retire pursuant to enforcement actions or state rules in 2016 or later are retained in the NEEDS database. Such 2016-and-later retirements are captured as constraints on those units in IPM modeling, and the capacity is retired in future year projections per the terms of the related requirements.

Table 4-36 lists all units that were removed from EPA's inventory based on announcements that were reviewed using the rules outlined above.

Table 4-3 Summary Population (through 2010) of Existing Units in NEEDS v.5.13

Plant Type	Number of Units	Capacity (MW)
Biomass	161	3,140
Coal Steam	949	275,568
Combined Cycle	1659	203,181
Combustion Turbine	5419	135,353
Fossil Waste	58	372
Fuel Cell	15	3
Geothermal	201	2,304
Hydro	3749	77,946
IGCC	6	539
Landfill Gas	1315	1,437
Municipal Solid Waste	174	2,142
Non-Fossil Waste	100	1,328
Nuclear	99	98,173
O/G Steam	529	92,909
Pumped Storage	151	22,310
Solar PV	151	390
Solar Thermal	15	548
Tires	2	46
Wind	665	39,150
US Total	**15,418**	**956,837**

4.2.2 Capacity

The NEEDS unit capacity values implemented in EPA Base Case v.5.13 reflect net summer dependable capacity[18], to the extent possible. Table 4-4 summarizes the hierarchy of primary data sources used in compiling capacity data for NEEDS v.5.13; in other words, data sources are evaluated in this order, and capacity values are taken from a particular source only if the sources listed above it do not provide adequate data for the unit in question.[19]

Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v.5.13

Sources Presented in Hierarchy
Summer Net Dependable Capacity from Comments
2010 EIA 860 Summer Capacity
2011 EIA 860 Summer Capacity
2010 EIA 860 Winter Capacity
2011 EIA 860 Winter Capacity
2010 EIA 860 Nameplate Capacity
2011 EIA 860 Nameplate Capacity

Notes:
Presented in hierarchical order that applies.
If capacity is zero, unit is not included.

As noted earlier, NEEDS v.5.13 includes boiler level data for steam units, and generator level data for non-steam units. Capacity data in EIA are generator-specific and not boiler specific. Therefore, it was necessary to develop an algorithm for parsing generator-level capacity to the boiler level for steam producing units.

[18] As used here, net summer dependable capacity is the net capability of a generating unit in megawatts (MW) for daily planning and operation purposes during the summer peak season, after accounting for station or auxiliary services.

[19] EIA 860 2010 was reviewed before 2011 because 2010 was the most recent data year available at the time NEEDS development began.

The capacity-parsing algorithm used for steam units in NEEDS v.5.13 took into account boiler-generator mapping. Fossil steam electric units have boilers attached to generators that produce electricity. There are generally four types of links between boilers and generators: one boiler to one generator, one boiler to many generators, many boilers to one generator and many boilers to many generators.

The capacity-parsing algorithm used for steam units in NEEDS utilized steam flow data with the boiler-generator mapping. Under EIA 860, steam units report the maximum steam flow from the boiler to the generator. There is, however, no further data on the steam flow of each boiler-generator link. Instead, EIA 860 contains only the maximum steam flow for each boiler. Table 4-5 summarizes the algorithm used for parsing capacity with data on maximum steam flow and boiler-generator mapping. In Table 4-5, MFB_i refers to the maximum steam flow of boiler *i* and MW_{Gj} refers to the capacity of generator *j*. The algorithm uses the available data to derive the capacity of a boiler, referred to as MW_{Bj} in Table 4-5.

Table 4-5 Capacity-Parsing Algorithm for Steam Units in NEEDS v.5.13

	Type of Boiler-Generator Links			
	One-to-One	One-to-Many	Many-to-One	Many-to-Many
For Boiler B_1 to B_N linked to Generators G_1 to G_N	$MW_{Bi} = MW_{Gj}$	$MW_{Bi} = \Sigma_j MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma_i MF_{Bi}) * MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma_i MF_{Bi}) * \Sigma_j MW_{Gj}$

Notes:
MF_{Bi} = maximum steam flow of boiler *i*
MW_{Gj} = electric generation capacity of generator *j*

Since EPA Base Case v.5.13 uses net energy for load as demand, NEEDS v.5.13 only includes generators that sell the majority of their power to the electric grid; this approach is intended to be broadly consistent with the generating capacity used in the AEO projections used as the source where demand is net energy for load. The generators that should be in NEEDS v.5.13 by this qualification are determined from the 2010 EIA Form 923 non-utility source and disposition data set.

4.2.3 Plant Location

NEEDS v.5.13 uses state, county and model region data to represent the physical location of each plant.

State and County

NEEDS v.5.13 used the state and county data in EIA 860 (2010, 2011).

Model Region

- For each unit the associated model region was derived based on NERC assessment regions reported in NERC ES&D 2011 for that unit. For units with no NERC assessment region data, state and county were used to derive associated model regions. Using these shares of each NEMS region net energy for load that falls in each IPM region, calculate the total net energy for load for each IPM region from the NEMS regional load in AEO 2013.

Table 3-1 in Chapter 3 provides a summary of the mapping between NERC assessment regions and EPA Base Case v.5.13 model regions.

4.2.4 Online Year

The EPA Base Case v.5.13 uses online year to capture when the unit entered service. NEEDS includes online years for all units in the database. In NEEDS v.5.13, online years for boilers, utility and non-utility generators were primarily derived from reported in-service dates in EIA Form 860 (2010, 2011).

EPA Base Case v.5.13 includes constraints to set the retirement year for generating units that are firmly committed to retire after 2015 based on state or federal regulations and enforcement actions. In addition, existing nuclear units must retire when they reach age 60. (See section 0 for a discussion of the nuclear lifetime assumption.) EPA Base Case v.5.13 also provides economic retirement options to coal, oil and gas steam, combined cycle, combustion turbines and nuclear units. This means that the model may elect to retire these units if it is economical to do so. In IPM, a retired plant ceases to incur FOM and VOM costs. However, retired units do continue to service debt on any previously incurred capital cost for model-installed retrofits if the model projected a retrofit on the unit prior to retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specification of a unit's design. Unit configuration in EPA Base Case v.5.13 drives model plant aggregation, modeling of pollution control options and mercury emission modification factors. NEEDS v.5.13 contains information on the firing and bottom type of coal steam boilers in the database. Great effort was taken to ensure that the inventory of existing and committed controls represented in EPA Base Case v.5.13 was comprehensive and as up-to-date as possible. The hierarchy of data sources used is shown in Table 4-6.

Table 4-6 Data Sources for Unit Configuration in NEEDS v.5.13 for EPA Base Case v.5.13

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	2010 EIA 860	EPA's Emission Tracking System (ETS) – 2011	--	--	--
Bottom Type	2010 EIA 860	EPA's Emission Tracking System (ETS) – 2011	--	--	Dry
SO_2 Pollution Control	NSR Settlement or Comments	EPA's Emission Tracking System (ETS) - 2011	2010 EIA 860	See Note	No Control
NO_x Pollution Control	NSR Settlement or Comments	EPA's Emission Tracking System (ETS) - 2011	2010 EIA 860	See Note	No Control
Mercury Control	NSR Settlement or Comments	2010 EIA 860	--	--	No Control
Particulate Matter Control	NSR Settlement or Comments	EPA's Emission Tracking System (ETS) - 2011	2010 EIA 860	--	No Control
HCl Control	NSR Settlement or Comments	--	--	See Note	No Control

Note:
In addition to the primary, secondary and tertiary data sources listed here, the following sources were consulted and emission controls were updated when corroborating information could be found: Reports filed with the Securities and Exchange Commission; websites of generating unit owners and operators; GenerationHub; state public utility service commissions; state permitting agencies; architecture and engineering firm announcements (eg.: Shaw, URS, Stanley, Black &Veatch, Peter Kewit, etc.); equipment supplier announcements (Alstom, B&W, Babcock Power); Power-Eng.com; McILVAINE Utility Upgrade Database; ICAC (Institute of Clean Air Companies).

4.2.6 Model Plant Aggregation

While EPA Base Case using IPM is comprehensive in representing all the units contained in NEEDS, an aggregation scheme is used to combine existing units with similar characteristics into "model plants". The aggregation scheme serves to reduce the size of the model and makes the model manageable while capturing the essential characteristics of the generating units. The EPA Base Case v.5.13 aggregation scheme is designed so that each model plant only represents generating units from a single state. This design makes it possible to obtain state-level results directly from IPM outputs. In addition, the aggregation scheme supports modeling plant-level emission limits on fossil generation.

The "model plant" aggregation scheme encompasses a variety of different classification categories including location, size, technology, heat rate, fuel choices, unit configuration, SO_2 emission rates and environmental regulations among others. Units are aggregated together only if they match on all the different categories specified for the aggregation. The 11 major categories used for the aggregation scheme in EPA Base Case v.5.13 are the following:

(1) Model Region

(2) Unit Technology Type

(3) Fuel Demand Region

(4) Applicable Environmental Regulations

(5) State

(6) Facility (ORIS) for fossil units

(7) Unit Configuration

(8) Emission Rates

(9) Heat Rates

(10) Fuel

(11) Size

Table 4-7 shows the number of actual units by generation technology type and the related number of aggregated "model plants" used in the EPA Base Case v.5.13. For each plant type, the table shows the number of real plants and the number of model plants representing these real plants in EPA Base Case v.5.13.[20]

Table 4-7 Aggregation Profile of Model Plants as Provided at Set Up of EPA Base Case v.5.13

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass	194	119
Coal Steam	1,003	759
Combined Cycle	1,727	702
Combustion Turbine	5,552	2,200
Fossil_Other	60	18
Fuel Cell	25	12

[20] (1) The "Number of IPM Model Plants" shown for many of the "Plant Types" in the "Retrofits" block in Table 4-7 exceeds the "Number of IPM Model Plants" shown for "Plant Type" "Coal Steam" in the block labeled "Existing and Planned/Committed Units", because a particular retrofit "Plant Type" can include multiple technology options and multiple timing options (e.g., Technology A in Stage 1 + Technology B in Stage 2 + Technology C in Stage 3, the reverse timing, or multiple technologies simultaneously in Stage 1). (3) Since only a subset of coal plants is eligible for certain retrofits, many of the "Plant Types" in the "Retrofits" block that represent only a single retrofit technology (e.g., "Retrofit Coal with Selective Non-catalytic Reduction (SNCR)") have a "Number of IPM Model Plants" that is a smaller than the "Number of IPM Model Plants" shown for "Plant Type" "Coal Steam". (4) The total number of model plants representing different types of new units often exceeds the 64 US model regions and varies from technology to technology for several reasons. First, some technologies have multiple vintages (i.e., different cost and/or performance parameters depending on which run-year in which the unit is created), which must be represented by separate model plants in each IPM region. Second, some technologies are not available in particular regions (e.g., geothermal is geographically restricted to certain regions).

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Geothermal	219	28
Hydro	3,807	160
Import	1	1
Integrated Gas Combined Cycle	10	5
Landfill Gas	1,414	225
Non Fossil_Other[a]	308	135
Nuclear[b]	105	105
Oil/Gas Steam	532	347
Pumped Storage	152	24
Solar PV	370	47
Solar Thermal	27	10
Wind	824	74
Total	**16,330**	**4,971**

New Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
New Advanced Coal with CCS	--	51
New Biomass	--	123
New Combined Cycle	--	61
New Combined Cycle with Carbon Capture	--	61
New Combustion Turbine	--	61
New Fuel Cell	--	122
New Future Technology	--	305
New Geothermal		64
New IGCC		56
New Landfill Gas	--	369
New Nuclear	--	122
New Offshore Wind	--	714
New Onshore Wind	--	1480
New Solar PV	--	228
New Solar Thermal		91
New SPC-WetFGD_SCR	--	51
Total	--	**3,959**

Retrofits		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Retrofit Coal with ACI	--	414
Retrofit Coal with ACI + CCS	--	164
Retrofit Coal with ACI + CCS + HRI	--	158
Retrofit Coal with ACI + CCS + HRI + SCR	--	78
Retrofit Coal with ACI + CCS + HRI + SCR + Scrubber	--	138
Retrofit Coal with ACI + CCS + HRI + Scrubber	--	152
Retrofit Coal with ACI + CCS + SCR	--	78
Retrofit Coal with ACI + CCS + SCR + Scrubber	--	138
Retrofit Coal with ACI + CCS + Scrubber	--	152
Retrofit Coal with ACI + DSI	--	389
Retrofit Coal with ACI + DSI + HRI	--	385

Retrofits		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Retrofit Coal with ACI + DSI + HRI + SCR	--	525
Retrofit Coal with ACI + DSI + HRI + SCR + Scrubber	--	354
Retrofit Coal with ACI + DSI + HRI + Scrubber	--	362
Retrofit Coal with ACI + DSI + HRI + SNCR	--	151
Retrofit Coal with ACI + DSI + HRI + SNCR + Scrubber	--	74
Retrofit Coal with ACI + DSI + SCR	--	528
Retrofit Coal with ACI + DSI + SCR + Scrubber	--	356
Retrofit Coal with ACI + DSI + Scrubber	--	364
Retrofit Coal with ACI + DSI + Scrubber + SNCR	--	76
Retrofit Coal with ACI + DSI + SNCR	--	173
Retrofit Coal with ACI + HRI	--	406
Retrofit Coal with ACI + HRI + SCR	--	570
Retrofit Coal with ACI + HRI + SCR + Scrubber	--	883
Retrofit Coal with ACI + HRI + Scrubber	--	737
Retrofit Coal with ACI + HRI + SNCR	--	162
Retrofit Coal with ACI + HRI + SNCR + Scrubber	--	302
Retrofit Coal with ACI + SCR	--	576
Retrofit Coal with ACI + SCR + Scrubber	--	886
Retrofit Coal with ACI + Scrubber	--	742
Retrofit Coal with ACI + Scrubber + SNCR	--	307
Retrofit Coal with ACI + SNCR	--	166
Retrofit Coal with C2G	--	621
Retrofit Coal with C2G + SCR	--	621
Retrofit Coal with CCS	--	410
Retrofit Coal with CCS + HRI	--	352
Retrofit Coal with CCS + HRI + SCR	--	124
Retrofit Coal with CCS + HRI + SCR + Scrubber	--	168
Retrofit Coal with CCS + HRI + Scrubber	--	200
Retrofit Coal with CCS + SCR	--	122
Retrofit Coal with CCS + SCR + Scrubber	--	168
Retrofit Coal with CCS + Scrubber	--	200
Retrofit Coal with DSI	--	239
Retrofit Coal with DSI + HRI	--	473
Retrofit Coal with DSI + HRI + SCR	--	658
Retrofit Coal with DSI + HRI + SCR + Scrubber	--	383
Retrofit Coal with DSI + HRI + Scrubber	--	333
Retrofit Coal with DSI + HRI + SNCR	--	129
Retrofit Coal with DSI + SCR	--	661
Retrofit Coal with DSI + SCR + Scrubber	--	385
Retrofit Coal with DSI + Scrubber	--	334
Retrofit Coal with DSI + SNCR	--	200
Retrofit Coal with HRI	--	646
Retrofit Coal with HRI + SCR	--	782
Retrofit Coal with HRI + SCR + Scrubber	--	1,347
Retrofit Coal with HRI + Scrubber	--	1,034
Retrofit Coal with HRI + Scrubber + SNCR	--	440
Retrofit Coal with HRI + SNCR	--	209
Retrofit Coal with SCR	--	399
Retrofit Coal with SCR + Scrubber	--	1,353
Retrofit Coal with Scrubber	--	524

Retrofits		
Plant Type	Number of Units	Number of IPM Model Plants
Retrofit Coal with Scrubber + SNCR	--	452
Retrofit Coal with SNCR	--	106
Retrofit Combined Cycle with CCS	--	424
Retrofit Oil/Gas steam with SCR	--	227
Total	--	**25,670**

Retirements		
Plant Type	Number of Units	Number of IPM Model Plants
CC Retirement	--	702
Coal Retirement	--	5,372
CT Retirement	--	2,200
IGCC Retirement	--	5
Non-Fossil Retirement	--	680
Nuke Retirement	--	105
O/G Retirement	--	1,195
Total	--	**10,259**
Grand Total (Existing and Planned/Committed + New + Retrofits + Retirements): 44,859		

Notes:

[a] Non Fossil_Other includes units whose fuel is municipal solid waste, tires, and other non-fossil waste.

[b] The 105 nuclear units include 99 currently operating units, 1 unit scheduled to retire in 2014 (Vermont Yankee), plus Watts Bar Nuclear Plant (Unit 2), Vogtle (Units 3&4), and V C Summer (Units 2&3), which are scheduled to come online during 2015 - 2018. All except Vermont Yankee Nuclear unit are listed in Table 4-34

4.2.7 Cost and Performance Characteristics of Existing Units

In EPA Base Case v.5.13 heat rates, emission rates, variable operation and maintenance cost (VOM) and fixed operation and maintenance costs (FOM) are used to characterize the cost and performance of all existing units in NEEDS v.5.13. For existing units, only the cost of maintaining (FOM) and running (VOM) the unit are modeled. Embedded costs, such as carrying capital charges, are not modeled; however, because such historically invested capital costs are sunk costs, they are economically irrelevant for projecting least-cost investment and operational decisions for electricity supply going forward. The section below contains a discussion of the cost and performance assumptions for existing units used in the EPA Base Case v.5.13.

Variable Operating and Maintenance Cost (VOM)

VOM represents the non-fuel variable cost associated with producing electricity. If the generating unit contains pollution control equipment, VOM includes the cost of operating the control equipment. Table 4-8 below summarizes VOM assumptions used in EPA Base Case v.5.13. The values shown in this table were obtained using a procedure developed jointly by EPA's power sector engineering staff and ICF.

Table 4-8 VOM Assumptions in EPA Base Case v.5.13

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2011$/mills/kWh)
Biomass	--	--	--	2.41
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	0.84
			ACI	2.28
		SCR	No Hg Control	1.29
			ACI	2.73
		SNCR	No Hg Control	1.85
			ACI	3.29

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2011$/mills/kWh)
	Dry FGD	No NO_x Control	No Hg Control	4.29
			ACI	5.73
		SCR	No Hg Control	4.74
			ACI	6.18
		SNCR	No Hg Control	5.30
			ACI	6.74
	Wet FGD	No NO_x Control	No Hg Control	4.77
			ACI	6.21
		SCR	No Hg Control	5.22
			ACI	6.66
		SNCR	No Hg Control	5.78
			ACI	7.22
	DSI	No NO_x Control	No Hg Control	10.07
			ACI	11.51
		SCR	No Hg Control	10.52
			ACI	11.96
		SNCR	No Hg Control	11.08
			ACI	12.52
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	2.82 - 5.96
		SCR		2.95 - 6.09
		SNCR		3.41 - 6.55
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	3.35 - 22.44
		SCR		3.48 - 22.57
		SNCR		3.94 - 23.03
Fuel Cell	--	--	--	0.00
Geothermal	--	--	--	2.86
Hydro	--	--	--	1.70
IGCC	--	--	--	3.24-6.38
Landfill Gas / Municipal Solid Waste	--	--	--	2.44
O/G Steam	No SO_2 Control	No NO_x Control	No Hg Control	0.76
		SCR		0.89
		SNCR		1.35
	Wet FGD	No NO_x Control		0.76
		SCR		0.89
		SNCR		1.35
Pumped Storage	--	--	--	9.43
Solar PV	--	--	--	0.00
Solar Thermal	--	--	--	3.51
Wind	--	--	--	2.20

Fixed Operation and Maintenance Cost (FOM)

FOM represents the annual fixed cost of maintaining a unit. FOM costs are incurred independent of generation levels and signify the fixed cost of operating and maintaining the unit’s availability to provide generation.

Table 4-9 summarizes the FOM assumptions used in EPA Base Case v.5.13. Note that FOM varies by the age of the unit, and the total FOM cost incurred by a unit depends on its capacity size. The values appearing in this table include the cost of maintaining any associated pollution control equipment. The values in

Table 4-9 are based on FERC (Federal Energy Regulatory Commission) Form 1 data maintained by Ventyx and ICF research.

Table 4-9 FOM Assumptions Used in EPA Base Case v.5.13

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2011$ /kW-Yr)
Biomass	--	--	--	All Years	35.28
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 30 Years	36.49
				30 to 40 Years	38.61
				40 to 50 Years	49.13
				Greater than 50 Years	50.83
			ACI	0 to 30 Years	36.58
				30 to 40 Years	38.70
				40 to 50 Years	49.22
				Greater than 50 Years	50.92
		SCR	No Hg Control	0 to 30 Years	37.13
				30 to 40 Years	39.26
				40 to 50 Years	49.78
				Greater than 50 Years	51.48
			ACI	0 to 30 Years	37.22
				30 to 40 Years	39.35
				40 to 50 Years	49.86
				Greater than 50 Years	51.57
		SNCR	No Hg Control	0 to 30 Years	37.11
				30 to 40 Years	39.23
				40 to 50 Years	49.75
				Greater than 50 Years	51.45
			ACI	0 to 30 Years	37.20
				30 to 40 Years	39.32
				40 to 50 Years	49.84
				Greater than 50 Years	51.54
	Dry FGD	No NO_x Control	No Hg Control	0 to 30 Years	46.51
				30 to 40 Years	48.63
				40 to 50 Years	59.15
				Greater than 50 Years	60.85
			ACI	0 to 30 Years	46.60
				30 to 40 Years	48.72
				40 to 50 Years	59.24
				Greater than 50 Years	60.94
		SCR	No Hg Control	0 to 30 Years	47.15
				30 to 40 Years	49.28
				40 to 50 Years	59.80
				Greater than 50 Years	61.50
			ACI	0 to 30 Years	47.24
				30 to 40 Years	49.37

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2011$ /kW-Yr)
				40 to 50 Years	59.88
				Greater than 50 Years	61.59
		SNCR	No Hg Control	0 to 30 Years	47.13
				30 to 40 Years	49.25
				40 to 50 Years	59.77
				Greater than 50 Years	61.47
			ACI	0 to 30 Years	47.22
				30 to 40 Years	49.34
				40 to 50 Years	59.86
				Greater than 50 Years	61.56
	Wet FGD	No NO_x Control	No Hg Control	0 to 30 Years	45.90
				30 to 40 Years	48.02
				40 to 50 Years	58.54
				Greater than 50 Years	60.24
			ACI	0 to 30 Years	45.99
				30 to 40 Years	48.11
				40 to 50 Years	58.63
				Greater than 50 Years	60.33
		SCR	No Hg Control	0 to 30 Years	46.54
				30 to 40 Years	48.67
				40 to 50 Years	59.19
				Greater than 50 Years	60.89
			ACI	0 to 30 Years	46.63
				30 to 40 Years	48.76
				40 to 50 Years	59.27
				Greater than 50 Years	60.98
		SNCR	No Hg Control	0 to 30 Years	46.52
				30 to 40 Years	48.64
				40 to 50 Years	59.16
				Greater than 50 Years	60.86
			ACI	0 to 30 Years	46.61
				30 to 40 Years	48.73
				40 to 50 Years	59.25
				Greater than 50 Years	60.95
	DSI	No NO_x Control	No Hg Control	0 to 30 Years	37.99
				30 to 40 Years	40.11
				40 to 50 Years	50.63
				Greater than 50 Years	52.33
			ACI	0 to 30 Years	38.08
				30 to 40 Years	40.20

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2011$ /kW-Yr)
				40 to 50 Years	50.72
				Greater than 50 Years	52.42
		SCR	No Hg Control	0 to 30 Years	38.63
				30 to 40 Years	40.76
				40 to 50 Years	51.28
				Greater than 50 Years	52.98
			ACI	0 to 30 Years	38.72
				30 to 40 Years	40.85
				40 to 50 Years	51.36
				Greater than 50 Years	53.07
		SNCR	No Hg Control	0 to 30 Years	38.61
				30 to 40 Years	40.73
				40 to 50 Years	51.25
				Greater than 50 Years	52.95
			ACI	0 to 30 Years	38.70
				30 to 40 Years	40.82
				40 to 50 Years	51.34
				Greater than 50 Years	53.04
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	-	24.29
		SCR	No Hg Control	-	25.56
		SNCR	No Hg Control	-	24.42
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	-	16.47
		SCR	No Hg Control	-	18.41
		SNCR	No Hg Control	-	16.91
Fuel Cell	--	--	--	All Years	370.36
Geothermal	--	--	--	All Years	40.07
Hydro	--	--	--	All Years	19.28
IGCC	No SO_2 Control	No NO_x Control	--	All Years	36.89
Landfill Gas / Municipal Solid Waste	--	--	--	All Years	46.10
O/G Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 30 Years	20.31
				30 to 40 Years	21.22
				40 to 50 Years	23.68
				Greater than 50 Years	23.68
		SCR	No Hg Control	0 to 30 Years	21.34
				30 to 40 Years	22.25
				40 to 50 Years	24.71

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2011$ /kW-Yr)
				Greater than 50 Years	24.71
		SNCR	No Hg Control	0 to 30 Years	20.47
				30 to 40 Years	21.39
				40 to 50 Years	23.84
				Greater than 50 Years	23.84
	Wet FGD	No NO_x Control	No Hg Control	0 to 30 Years	20.31
				30 to 40 Years	21.22
				40 to 50 Years	23.68
				Greater than 50 Years	23.68
		SCR	No Hg Control	0 to 30 Years	21.34
				30 to 40 Years	22.25
				40 to 50 Years	24.71
				Greater than 50 Years	24.71
		SNCR	No Hg Control	0 to 30 Years	20.47
				30 to 40 Years	21.39
				40 to 50 Years	23.84
				Greater than 50 Years	23.84
Pumped Storage	--	--	--	All Years	7.37
Solar PV	--	--	--	All Years	20.53
Solar Thermal	--	--	--	All Years	31.94
Wind	--	--	--	All Years	19.54

Heat Rates

Heat Rates describe the efficiency of the unit expressed as BTUs per kWh. The treatment of heat rates in EPA Base Case v.5.13 is discussed in Section 3.8.

Lifetimes

Unit lifetime assumptions in EPA Base Case v.5.13 are detailed in Sections 0 and 4.2.8.

SO_2 Rates

Section 3.9.1 contains a detailed discussion of SO_2 rates for existing units.

NO_x Rates

Section 3.9.2 contains a detailed discussion of NO_x rates for existing units.

Mercury Emission Modification Factors (EMF)

Mercury EMF refers to the ratio of mercury emissions (mercury outlet) to the mercury content of the fuel (mercury inlet). Section 5.4.2 contains a detailed discussion of the EMF assumptions in EPA Base Case v.5.13.

4.2.8 Life Extension Costs for Existing Units

The modeling time horizon in EPA Base Case 5.13 extends to 2050 and covers a period of almost 40 years. This time horizon requires consideration in EPA Base Case v.5.13 of investments, beyond routine maintenance, necessary to extend the life of existing units. The life extension costs for units with retirement options are summarized in Table 4-10 below. These costs were based on a review of FERC Form 1 data regarding reported annual capital expenditures made by older units.

Table 4-10 Life Extension Cost Assumptions Used in EPA Base Case v.5.13

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost as Proportion of New Unit Capital Cost (%)	Capital Cost of New Unit (2011$/kW)	Life Extension Cost (2011$/kW)
Biomass - Fluidized Bed	40	6.6%	4,429	291
Coal Steam	40	7.0%	3,160	221
Combined Cycle	30	9.3%	1,047	98
Combustion Turbine & IC Engine	30	4.2%	691	29
Oil/Gas Steam	40	3.4%	2,923	98
IGCC	40	7.4%	3,254	241
Nuclear	40	9.0%	6,168	555
Landfill Gas	20	9.1%	9,023	823

Notes:
Life extension expenditures double the lifespan of the unit.

4.3 Planned-Committed Units

EPA Base Case v.5.13 includes all planned-committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before 2016.

4.3.1 Population and Model Plant Aggregation

Like existing units, planned-committed units are contained in NEEDS. A comprehensive update of planned-committed units contained in NEEDS was performed for EPA Base Case v.5.13 using the information sources listed in Table 4-1. Table 4-11 summarizes the extent of inventory of planned-committed units in EPA Base Case v.5.13 indicating its generating capacity by unit types.

Table 4-11 Summary of Planned-Committed Units in NEEDS v.5.13 for EPA Base Case v.5.13

Type	Capacity (MW)	Year Range Described
	Renewables/Non-conventional	
Biomass	901	2011 - 2015
Fuel Cell	33	2011 - 2015
Geothermal	332	2011 - 2016
Hydro	689	2011 - 2015
Landfill Gas	576	2011 - 2015
Municipal Solid Waste	119	2011 - 2015
Non-Fossil Waste	254	2011 - 2015
Pumped Storage	40	2015 - 2015
Solar PV	5,262	2011 - 2015
Solar Thermal	1,777	2012 - 2015
Wind	18,951	2011 - 2015
Subtotal	28,933	

Type	Capacity (MW)	Year Range Described
Fossil/Conventional		
Coal Steam	9,498	2011 - 2015
Combined Cycle	18,597	2011 - 2015
Combustion Turbine	8,899	2011 - 2015
Fossil Waste	40	2015 - 2015
IGCC	1,168	2012 - 2014
Nuclear	5,522	2015 - 2018
O/G Steam	4	2015 - 2015
Subtotal	44,528	
Grand Total	72,661	

Due to data confidentiality restrictions, NEEDS v.5.13 does not list the planned-committed units on a unit-by-unit basis. Rather, all units having similar technologies and located within the same model region are aggregated together as one record. Table 4-12 gives a breakdown of planned-committed units by IPM region, unit type, number of units, and capacity included in EPA Base Case v.5.13.

Table 4-12 Planned-Committed Units by Model Region in NEEDS v.5.13 for EPA Base Case v.5.13

IPM Region	Plant Type	Capacity (MW)
ERC_REST	Biomass	144
	Coal Steam	2,869
	Combined Cycle	620
	Combustion Turbine	166
	Hydro	0.19
	Landfill Gas	15
	Non-Fossil Waste	4
	Solar PV	78
	Wind	311
ERC_WEST	Wind	585
FRCC	Biomass	110
	Combined Cycle	2,388
	Combustion Turbine	465
	Landfill Gas	10
	Non-Fossil Waste	15
	Solar PV	74
MAP_WAUE	Combustion Turbine	60
	Wind	102
MIS_IA	Combustion Turbine	5
	Wind	460
MIS_IL	Biomass	15
	Coal Steam	1,600
	Combustion Turbine	20
	Wind	415
MIS_INKY	Hydro	162
	IGCC	586
	Landfill Gas	6
	Non-Fossil Waste	4
	Solar PV	17
MIS_LMI	Landfill Gas	26
	Non-Fossil Waste	4
	Solar PV	1
	Wind	391

IPM Region	Plant Type	Capacity (MW)
MIS_MAPP	Coal Steam	99
	Geothermal	23
	Non-Fossil Waste	6
	Solar PV	0
	Wind	431
MIS_MIDA	Wind	956
MIS_MNWI	Combined Cycle	300
	Combustion Turbine	5
	Hydro	10
	Landfill Gas	2
	Non-Fossil Waste	6
	Wind	807
MIS_MO	Combustion Turbine	6
	Landfill Gas	15
	Non-Fossil Waste	3
MIS_WUMS	Biomass	57
	Coal Steam	615
	Combustion Turbine	58
	Landfill Gas	23
	Wind	162
NENG_CT	Combined Cycle	628
	Combustion Turbine	763
NENG_ME	Combined Cycle	25
	Hydro	2
	Landfill Gas	3
	Wind	131
NENGREST	Biomass	77
	Combustion Turbine	40
	Hydro	2
	Landfill Gas	42
	Non-Fossil Waste	1
	Solar PV	54
	Wind	288
NY_Z_A&B	Biomass	15
	Landfill Gas	5
	Wind	141
NY_Z_C&E	Combustion Turbine	2
	Landfill Gas	13
	Wind	129
NY_Z_D	Wind	21
NY_Z_F	Hydro	2
	Non-Fossil Waste	20
NY_Z_G-I	Landfill Gas	2
NY_Z_J	Combined Cycle	540
	Combustion Turbine	466
	Fuel Cell	5
NY_Z_K	Combustion Turbine	0.23
	Solar PV	75
PJM_AP	Coal Steam	700
	Combined Cycle	570
	Hydro	0.01
	Landfill Gas	10
	Solar PV	20
	Wind	253

IPM Region	Plant Type	Capacity (MW)
PJM_ATSI	Combined Cycle	666
	Fossil Waste	23
	Landfill Gas	21
	Non-Fossil Waste	135
	Solar PV	19
	Wind	5
PJM_COMD	Biomass	55
	Landfill Gas	7
	Solar PV	23
	Wind	996
PJM_Dom	Biomass	50
	Combined Cycle	589
	Combustion Turbine	52
	Landfill Gas	42
	Solar PV	31
PJM_EMAC	Biomass	30
	Combined Cycle	545
	Combustion Turbine	990
	Hydro	137
	Landfill Gas	32
	Non-Fossil Waste	1
	Solar PV	431
	Wind	5
PJM_PENE	Biomass	1
	Combustion Turbine	2
	Landfill Gas	7
	O/G Steam	4
	Wind	511
PJM_SMAC	Biomass	4
	Combustion Turbine	5
	Landfill Gas	5
	Solar PV	7
PJM_West	Coal Steam	585
	Combined Cycle	539
	Hydro	47
	Landfill Gas	14
	Non-Fossil Waste	3
	Solar PV	3
	Wind	806
PJM_WMAC	Biomass	30
	Combined Cycle	100
	Combustion Turbine	10
	Landfill Gas	16
	Solar PV	27
	Wind	69
S_C_KY	Coal Steam	732
	Hydro	105
	Landfill Gas	2
S_C_TVA	Biomass	13
	Combined Cycle	878
	Hydro	66
	IGCC	582
	Landfill Gas	8
	Nuclear	1,122
	Solar PV	23

IPM Region	Plant Type	Capacity (MW)
S_D_AMSO	Municipal Solid Waste	115
S_D_N_AR	Combined Cycle	495
S_D_WOTA	Hydro	24
S_SOU	Biomass	122
	Combined Cycle	2,552
	Landfill Gas	18
	Non-Fossil Waste	2
	Nuclear	2,200
	Solar PV	3
S_VACA	Biomass	58
	Coal Steam	800
	Combined Cycle	4,203
	Combustion Turbine	727
	Hydro	33
	Landfill Gas	73
	Municipal Solid Waste	2
	Non-Fossil Waste	2
	Nuclear	2,200
	Solar PV	124
SPP_N	Coal Steam	279
	Hydro	5
	Landfill Gas	3
	Municipal Solid Waste	2
	Solar PV	0.09
	Wind	1,274
SPP_NEBR	Coal Steam	220
	Wind	244
SPP_SE	Combustion Turbine	33
	Non-Fossil Waste	21
SPP_SPS	Combustion Turbine	507
	Solar PV	55
	Wind	458
SPP_WEST	Coal Steam	609
	Combustion Turbine	20
	Hydro	20
	Wind	1,673
WEC_CALN	Biomass	21
	Combined Cycle	1,240
	Combustion Turbine	1,252
	Fuel Cell	3
	Hydro	8
	Landfill Gas	3
	Non-Fossil Waste	9
	Solar PV	1,057
	Solar Thermal	30
	Wind	468
WEC_LADW	Combined Cycle	560
	Combustion Turbine	1,133
	Fuel Cell	1
	Solar PV	178
WEC_SDGE	Biomass	2
	Combustion Turbine	38
	Fuel Cell	6
	Pumped Storage	40
	Solar PV	35

IPM Region	Plant Type	Capacity (MW)
WECC_AZ	Combustion Turbine	516
	Landfill Gas	6
	Non-Fossil Waste	0.15
	Solar PV	1,153
	Solar Thermal	250
	Wind	109
WECC_CO	Combined Cycle	200
	Combustion Turbine	200
	Hydro	8
	Landfill Gas	8
	Solar PV	89
	Solar Thermal	1
	Wind	546
WECC_ID	Combined Cycle	299
	Hydro	4
	Non-Fossil Waste	10
	Solar PV	10
	Wind	593
WECC_IID	Combined Cycle	94
	Geothermal	92
	Solar PV	249
WECC_MT	Biomass	12
	Combustion Turbine	172
	Hydro	13
	Landfill Gas	2
	Wind	221
WECC_NM	Combined Cycle	142
	Fossil Waste	17
	Geothermal	10
	Hydro	3
	Solar PV	75
	Solar Thermal	1
	Wind	50
WECC_NNV	Combustion Turbine	1
	Geothermal	138
	Landfill Gas	6
	Solar PV	3
	Solar Thermal	110
	Wind	150
WECC_PNW	Biomass	86
	Geothermal	30
	Hydro	39
	Landfill Gas	83
	Non-Fossil Waste	10
	Solar PV	10
	Wind	3,057
WECC_SCE	Combustion Turbine	1,158
	Fuel Cell	5
	Landfill Gas	37
	Solar PV	1,185
	Solar Thermal	1,385
	Wind	2,027
WECC_SF	Fuel Cell	13

IPM Region	Plant Type	Capacity (MW)
WECC_SNV	Combined Cycle	424
	Landfill Gas	11
	Solar PV	155
WECC_UT	Combustion Turbine	28
	Geothermal	40
	Wind	104
WECC_WY	Coal Steam	390
	Wind	2

Note:
Any unit in NEEDS v.5.13 that has an online year of 2011 or later was considered a Planned and Committed Unit

4.3.2 Capacity

The capacity of planned-committed units in NEEDS v.5.13 was obtained from the information sources reported above in Table 4-1.

4.3.3 State and Model Region

State location data for the planned-committed units in NEEDS v.5.13 came from the information sources noted in Section 4.3.1. The state information was then used to assign planned-committed units to their respective model regions.

4.3.4 Online and Retirement Year

As noted above, planned-committed units included in NEEDS v.5.13 are only those units which are likely to come on-line before 2016. All planned-committed units were given a default online year of 2015 since 2016 is the first analysis year in EPA Base Case v.5.13.

4.3.5 Unit Configuration, Cost and Performance

All planned-committed units in NEEDS v.5.13 assume the cost, performance, and unit configuration characteristics of potential units that are available in 2015. A detailed description of potential unit assumptions is provided below in Section 4.4.

4.4 Potential Units

The EPA Base Case v.5.13 includes options for developing a variety of potential units that may be “built” at a future date in response to electricity demand and the constraints represented in the model. Defined by region, technology, and the year available, potential units with an initial capacity of 0 MW are inputs into IPM. When the model is run, the capacity of certain potential units is raised from zero to meet demand and other system and operating constraints. This results in the model’s projection of new capacity.

In Table 4-7 the block labeled “New Units” gives a breakdown of the type and number of potential units provided in EPA Base Case v.5.13. The following sections describe the cost and performance assumptions for the potential units represented in the EPA Base Case v.5.13.

4.4.1 Methodology Used to Derive the Cost and Performance Characteristics of Conventional Potential Units

The cost and performance characteristics of conventional potential units in EPA Base Case v.5.13 are derived primarily from assumptions used in the Annual Energy Outlook (AEO) 2013 published by the U.S. Department of Energy's Energy Information Administration. The capital costs for IGCC and IGCC+CCS technologies in Table 4-13 are derived from a recently updated study[21] by DOE's National Energy Technology Laboratory (NETL).

4.4.2 Cost and Performance for Potential Conventional Units

EPA's assumed cost and performance characteristics for potential conventional units are shown in Table 4-13. The cost and performance assumptions are based on the size (i.e., net electrical generating capacity in MW) indicated in the table. However, the total new capacity that is added in a given model run for these technologies is not restricted to these capacity levels.

This table includes several components of cost. The total installed cost of developing and building a new plant is captured through the capital cost. It includes expenditures on pollution control equipment that new units are assumed to install to satisfy air regulatory requirements. The capital costs shown in Table 4-13 are typically referred to as "overnight" capital costs. They include engineering, procurement, construction, startup, and owner's costs (for such items as land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, licenses, etc). The capital costs in Table 4-13 do not include interest during construction (IDC). IDC is added to the capital costs shown in Table 4-13 during the set-up of an IPM run. Calculation of IDC is based on the construction profile and the discount rate. Details on the discount rates used in the EPA Base Case v.5.13 are discussed in Chapter 8 under financial assumptions.

Table 4-13 also shows fixed operating and maintenance (FOM) and variable operating and maintenance (VOM) components of cost. FOM is the annual cost of maintaining a generating unit. It represents expenses incurred regardless of the extent that the unit is run. It is expressed in units of $ per kW per year. VOM represents the non-fuel costs incurred in running an electric generating unit. It is proportional to the electrical energy produced and is expressed in units of $ per MWh.

In addition to the three components of cost, Table 4-13 indicates the first run year available, lead time, vintage periods, heat rate, and availability for each type of unit. Lead time represents the construction time needed for a unit to come online. Vintage periods are used to capture the cost and performance improvements resulting from technological advancement and learning-by-doing. Mature technologies and technologies whose first year available is not at the start of the modeling time horizon may have only one vintage period, whereas newer technologies may have several vintage periods. Heat rate indicates the efficiency of the unit and is expressed in units of energy consumed (Btus) per unit of electricity generated (kWh). Availability indicates the percentage of time that a generating unit is available to provide electricity to the grid once it has come on line. Availability takes into account estimates of the time consumed by planned maintenance and forced outages. The emission characteristics of the potential units are not presented in Table 4-13, but can be found in Table 3-12.

4.4.3 Short-Term Capital Cost Adder

In addition to the capital costs shown in Table 4-13 and

[21] http://www.netl.doe.gov/energy-analyses/pubs/BaselineCostUpdate.pdf.

Table 4-16 EPA Base Case v.5.13 includes a short-term capital cost adder that kicks in if the new capacity deployed in a specific model run year exceeds certain upper bounds. This adder is meant to reflect the added cost incurred due to short-term competition for scarce labor and materials. Table 4-14 shows the cost adders for each type of potential unit for model run years through 2030. The adder is not imposed after 2030 on the premise that by that time market adjustments in anticipation of such longer-term deployment patterns will have eliminated the short term scarcity experienced in earlier years.

The column labeled “Step 1” in Table 4-14 indicates the total amount of capacity of a particular plant type that can be built in a given model run year without incurring a cost adder. However, if the Step 1 upper bound is exceeded, then either the Step 2 or Step 3 cost adder is incurred. Above the Step 1 upper bound, the Step 2 cost adder applies until the cumulative capacity exceeds the Step 1 + Step 2 upper bound. Beyond that point, the Step 3 capital cost adder applies. For example, the Step 1 upper bound in 2016 for coal steam potential units is 6,913 MW. If no more than this total new coal steam capacity is built in 2016, only the capital cost shown in Table 4-13 is incurred. Between 6,913 and 11,522 MW (the sum of the Step 1 and Step 2 upper bounds, i.e., 6,913 MW + 4,609 MW = 11,522 MW), the Step 2 cost adder of $916/kW applies. For all the new coal capacity built in that model run year (not just the increment of new capacity above the Step 1 upper bound of 6,913 MW), this extra cost is added to the capital cost shown in Table 4-13. If the total new coal steam capacity exceeds the Step 1 + Step 2 upper bound of 11,522 MW, then the Step 3 capacity adder of $2,370/kW is incurred.

The short-term capital cost adders shown in Table 4-14 were derived from AEO assumptions.

4.4.4 Regional Cost Adjustment

The capital costs reported in Table 4-14 are generic. Before EPA implements these capital cost values values they are converted to region-specific costs. This is done through the application of regional cost cost adjustment factors which capture regional differences in labor, material, and construction costs and and ambient conditions. The regional adjustment factors used in EPA Base Case v.5.13 are shown in in Table 4-15. They were developed from AEO 2013 by multiplying the regional and ambient multipliers and are applied to both conventional technologies shown in Table 4-13 and renewable and non-conventional technologies shown in

- Table 4-16 below.

Table 4-13 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case v.5.13

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Sequestration	Supercritical Pulverized Coal
Size (MW)	400	210	2236	600	520	1300
First Run Year Available	2016	2016	2020	2018	2020	2018
Lead Time (Years)	3	2	6	4	4	4
Availability	87%	92%	90%	85%	85%	85%
Vintage #1 (2016-2054)						
Heat Rate (Btu/kWh)	6,430	9,750	10,452	8,700	10,700	8,800
Capital (2011$/kW)	1,006	664	5,429	2,969	4,086	2,883
Fixed O&M (2011$/kW/yr)	15.1	6.9	91.7	62.3	70.6	30.6
Variable O&M (2011$/MWh)	3.2	10.2	2.1	7.2	8.2	4.4

Notes:
[a] Capital cost represents overnight capital cost.

Table 4-14 Short-Term Capital Cost Adders for New Power Plants in EPA Base Case v.5.13 (2011$)

ID #	Plant Type		2016			2018			2020			2025			2030		
			Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
1	Biomass	Upper Bound (MW)	600	400	-	1,200	800	-	1,200	800	-	3,000	2,000	-	3,000	2,000	-
		Adder ($/kW)	-	1,285	3,322	-	1,285	3,322	-	1,285	3,322	-	1,285	3,322	-	1,285	3,322
2	Coal Steam	Upper Bound (MW)	6,913	4,609	-	13,826	9,218	-	13,826	9,218	-	34,566	23,044	-	34,566	23,044	-
		Adder ($/kW)	-	916	2,370	-	916	2,370	-	916	2,370	-	916	2,370	-	916	2,370
3	Combined Cycle	Upper Bound (MW)	46,157	30,771	-	92,314	61,542	-	92,314	61,542	-	230,784	153,856	-	230,784	153,856	-
		Adder ($/kW)	-	313	809	-	313	809	-	313	809	-	313	809	-	313	809
4	Combustion Turbine	Upper Bound (MW)	23,668	15,778	-	47,335	31,557	-	47,335	31,557	-	118,338	78,892	-	118,338	78,892	-
		Adder ($/kW)	-	200	518	-	200	518	-	200	518	-	200	518	-	200	518
5	Fuel Cell	Upper Bound (MW)	600	400	-	1,200	800	-	1,200	800	-	3,000	2,000	-	3,000	2,000	-
		Adder ($/kW)	-	2,215	5,727	-	2,215	5,727	-	2,215	5,727	-	2,215	5,727	-	2,215	5,727
6	Geothermal	Upper Bound (MW)	205	137	-	410	274	-	410	274	-	1,026	684	-	1,026	684	-
		Adder ($/kW)	-	2,268	5,865	-	2,268	5,865	-	2,268	5,865	-	2,268	5,865	-	2,268	5,865

ID #	Plant Type		2016			2018			2020			2025			2030		
			Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
7	IGCC and Advanced Coal with Carbon Capture	Upper Bound (MW)	2,400	1,600	-	4,800	3,200	-	4,800	3,200	-	12,000	8,000	-	12,000	8,000	-
		Adder ($/kW)	-	944	2,441	-	944	2,441	-	944	2,441	-	944	2,441	-	944	2,441
8	Landfill Gas	Upper Bound (MW)	600	400	-	1,200	800	-	1,200	800	-	3,000	2,000	-	3,000	2,000	-
		Adder ($/kW)	-	2,669	6,904	-	2,669	6,904	-	2,669	6,904	-	2,669	6,904	-	2,669	6,904
9	Nuclear	Upper Bound (MW)	11,244	7,496	-	22,488	14,992	-	22,488	14,992	-	56,220	37,480	-	56,220	37,480	-
		Adder ($/kW)	-	1,789	4,626	-	1,789	4,626	-	1,789	4,626	-	1,789	4,626	-	1,789	4,626
10	Solar Thermal	Upper Bound (MW)	90	60	-	180	120	-	180	120	-	450	300	-	450	300	-
		Adder ($/kW)	-	1,439	3,722	-	1,439	3,722	-	1,439	3,722	-	1,439	3,722	-	1,439	3,722
11	Solar PV	Upper Bound (MW)	286	190	-	571	381	-	571	381	-	1,428	952	-	1,428	952	-
		Adder ($/kW)	-	1,025	2,651	-	1,025	2,651	-	1,025	2,651	-	1,025	2,651	-	1,025	2,651
12	Onshore Wind	Upper Bound (MW)	11,618	7,746	-	23,237	15,491	-	23,237	15,491	-	58,092	38,728	-	58,092	38,728	-
		Adder ($/kW)	-	694	1,794	-	694	1,794	-	694	1,794	-	694	1,794	-	694	1,794
13	Offshore Wind	Upper Bound (MW)	600	400	-	1,200	800	-	1,200	800	-	3,000	2,000	-	3,000	2,000	-
		Adder ($/kW)	-	2,256	5,833	-	2,256	5,833	-	2,256	5,833	-	2,256	5,833	-	2,256	5,833

Table 4-15 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in EPA Base Case v.5.13

Model Region	Pulverized Coal	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Capture	Advanced Combustion Turbine	Advanced Combined Cycle	Fuel Cell	Advanced Nuclear	Biomass	Geothermal	Landfill Gas	Onshore Wind	Offshore Wind	Solar Thermal	Solar Photovoltaic
ERC_REST	0.905	0.943	0.959	0.985	0.954	0.963	0.960	0.925	1.000	0.927	0.952	0.918	0.858	0.871
ERC_WEST	0.905	0.943	0.959	0.985	0.954	0.963	0.960	0.925	1.000	0.927	0.952	0.918	0.858	0.871
FRCC	0.921	0.961	0.981	0.977	0.959	0.972	0.966	0.940	1.000	0.944	0.963	1.000	0.891	0.901
MIS_MAPP	0.952	0.956	0.956	0.994	0.971	0.981	0.980	0.961	1.000	0.964	1.032	1.008	0.953	0.954
MAP_WAUE	0.952	0.956	0.956	0.994	0.971	0.981	0.980	0.961	1.000	0.964	1.032	1.008	0.953	0.954
MIS_IL	1.072	1.067	1.052	1.057	1.059	1.017	1.028	1.029	1.000	1.030	1.036	1.000	1.057	1.051
MIS_INKY	1.049	1.056	1.042	1.078	1.061	1.001	1.029	1.017	1.000	1.000	1.019	1.011	1.000	0.999
MIS_IA	0.952	0.956	0.956	0.994	0.971	0.981	0.980	0.961	1.000	0.964	1.032	1.008	0.953	0.954
MIS_MIDA	0.952	0.956	0.956	0.994	0.971	0.981	0.980	0.961	1.000	0.964	1.032	1.008	0.953	0.954

Model Region	Pulverized Coal	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Capture	Advanced Combustion Turbine	Advanced Combined Cycle	Fuel Cell	Advanced Nuclear	Biomass	Geothermal	Landfill Gas	Onshore Wind	Offshore Wind	Solar Thermal	Solar Photovoltaic
MIS_LMI	0.980	0.968	0.959	0.992	0.978	0.994	0.992	0.982	1.000	0.985	0.998	0.981	0.965	0.968
MIS_MO	1.072	1.067	1.052	1.057	1.059	1.017	1.028	1.029	1.000	1.030	1.036	1.000	1.057	1.051
MIS_WUMS	1.049	1.042	1.021	1.057	1.040	1.001	1.029	1.017	1.000	1.000	1.019	1.011	1.000	0.999
MIS_MNWI	0.952	0.956	0.956	0.994	0.971	0.981	0.980	0.961	1.000	0.964	1.032	1.008	0.953	0.954
NENG_CT	1.096	1.056	1.008	1.147	1.105	1.009	1.054	1.038	1.000	1.016	1.058	1.031	1.035	1.028
NENGREST	1.096	1.056	1.008	1.147	1.105	1.009	1.054	1.038	1.000	1.016	1.058	1.031	1.035	1.028
NENG_ME	1.096	1.056	1.008	1.147	1.105	1.009	1.054	1.038	1.000	1.016	1.058	1.031	1.035	1.028
NY_Z_C&E	1.107	1.071	1.012	1.180	1.119	0.996	1.067	1.034	1.000	0.996	1.008	0.988	0.976	0.977
NY_Z_F	1.107	1.071	1.012	1.180	1.119	0.996	1.067	1.034	1.000	0.996	1.008	0.988	0.976	0.977
NY_Z_G-I	1.107	1.071	1.012	1.180	1.119	0.996	1.067	1.034	1.000	0.996	1.008	0.988	0.976	0.977
NY_Z_J	1.326	1.267	1.243	1.651	1.631	1.141	1.136	1.246	1.000	1.263	1.246	1.294	1.501	1.449
NY_Z_K	1.326	1.267	1.243	1.651	1.631	1.141	1.136	1.246	1.000	1.263	1.246	1.294	1.501	1.449
NY_Z_A&B	1.107	1.071	1.012	1.180	1.119	0.996	1.067	1.034	1.000	0.996	1.008	0.988	0.976	0.977
NY_Z_D	1.107	1.071	1.012	1.180	1.119	0.996	1.067	1.034	1.000	0.996	1.008	0.988	0.976	0.977
PJM_WMAC	1.152	1.123	1.068	1.232	1.184	1.018	1.085	1.070	1.000	1.034	1.048	1.026	1.055	1.048
PJM_EMAC	1.152	1.123	1.068	1.232	1.184	1.018	1.085	1.070	1.000	1.034	1.048	1.026	1.055	1.048
PJM_SMAC	1.152	1.123	1.068	1.232	1.184	1.018	1.085	1.070	1.000	1.034	1.048	1.026	1.055	1.048
PJM_West	1.049	1.042	1.021	1.057	1.040	1.001	1.029	1.017	1.000	1.000	1.019	1.011	1.000	0.999
PJM_AP	1.049	1.042	1.021	1.057	1.040	1.001	1.029	1.017	1.000	1.000	1.019	1.011	1.000	0.999
PJM_COMD	1.049	1.042	1.021	1.057	1.040	1.001	1.029	1.017	1.000	1.000	1.019	1.011	1.000	0.999
PJM_ATSI	1.049	1.042	1.021	1.057	1.040	1.001	1.029	1.017	1.000	1.000	1.019	1.011	1.000	0.999
PJM_Dom	0.885	0.925	0.932	0.959	0.918	0.956	0.954	0.906	1.000	0.911	0.947	0.921	0.824	0.841
PJM_PENE	1.152	1.123	1.068	1.232	1.184	1.018	1.085	1.070	1.000	1.034	1.048	1.026	1.055	1.048
S_VACA	0.885	0.925	0.932	0.959	0.918	0.956	0.954	0.906	1.000	0.911	0.947	0.921	0.824	0.841
S_C_KY	0.927	0.948	0.954	0.970	0.944	0.970	0.968	0.938	1.000	0.940	0.963	1.000	0.883	0.894
S_C_TVA	0.927	0.948	0.954	0.970	0.944	0.970	0.968	0.938	1.000	0.940	0.963	1.000	0.883	0.894
S_SOU	0.919	0.957	0.973	1.011	0.979	0.969	0.964	0.933	1.000	0.937	0.961	0.930	0.877	0.888
S_D_WOTA	0.917	0.950	0.962	0.993	0.964	0.969	0.965	0.933	1.000	0.941	0.962	1.000	0.879	0.890

Model Region	Pulverized Coal	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Capture	Advanced Combustion Turbine	Advanced Combined Cycle	Fuel Cell	Advanced Nuclear	Biomass	Geothermal	Landfill Gas	Onshore Wind	Offshore Wind	Solar Thermal	Solar Photovoltaic
S_D_AMSO	0.917	0.950	0.962	0.993	0.964	0.969	0.965	0.933	1.000	0.941	0.962	1.000	0.879	0.890
S_D_N_AR	0.917	0.950	0.962	0.993	0.964	0.969	0.965	0.933	1.000	0.941	0.962	1.000	0.879	0.890
S_D_REST	0.917	0.950	0.962	0.993	0.964	0.969	0.965	0.933	1.000	0.941	0.962	1.000	0.879	0.890
SPP_NEBR	0.952	0.956	0.956	0.994	0.971	0.981	0.980	0.961	1.000	0.964	1.032	1.008	0.953	0.954
SPP_N	1.072	1.082	1.073	1.078	1.080	1.017	1.028	1.029	1.000	1.030	1.036	1.000	1.057	1.051
SPP_SE	0.980	1.002	1.007	1.032	1.016	0.991	0.992	0.979	1.000	0.982	1.018	1.000	0.974	0.974
SPP_WEST	0.980	1.007	1.014	1.039	1.024	0.991	0.992	0.979	1.000	0.982	1.018	1.000	0.974	0.974
SPP_SPS	0.980	1.002	1.007	1.032	1.016	0.991	0.992	0.979	1.000	0.982	1.018	1.000	0.974	0.974
WECC_ID	1.015	1.044	1.045	1.079	1.059	0.994	1.007	1.004	1.000	0.984	1.047	1.017	0.990	0.987
WECC_NNV	1.015	1.044	1.045	1.079	1.059	0.994	1.007	1.004	1.000	0.984	1.047	1.017	0.990	0.987
WECC_UT	1.015	1.044	1.045	1.079	1.059	0.994	1.007	1.004	1.000	0.984	1.047	1.017	0.990	0.987
WECC_SF	1.193	1.186	1.139	1.311	1.267	1.030	1.093	1.083	1.000	1.057	1.119	1.049	1.129	1.111
WEC_CALN	1.193	1.186	1.139	1.311	1.267	1.030	1.093	1.083	1.000	1.057	1.119	1.049	1.129	1.111
WECC_IID	1.000	1.092	1.135	1.188	1.166	0.995	1.001	1.000	1.000	0.988	1.035	1.000	0.993	0.991
WEC_LADW	1.193	1.186	1.139	1.311	1.267	1.030	1.093	1.083	1.000	1.057	1.119	1.049	1.129	1.111
WEC_SDGE	1.193	1.186	1.139	1.311	1.267	1.030	1.093	1.083	1.000	1.057	1.119	1.049	1.129	1.111
WECC_SCE	1.193	1.186	1.139	1.311	1.267	1.030	1.093	1.083	1.000	1.057	1.119	1.049	1.129	1.111
WECC_MT	1.015	1.044	1.045	1.079	1.059	0.994	1.007	1.004	1.000	0.984	1.047	1.017	0.990	0.987
WECC_PNW	1.015	1.044	1.045	1.079	1.059	0.994	1.007	1.004	1.000	0.984	1.047	1.017	0.990	0.987
WECC_CO	0.989	1.103	1.142	1.239	1.185	0.976	1.005	0.973	1.000	0.954	1.033	1.000	0.929	0.931
WECC_WY	1.015	1.126	1.174	1.239	1.190	0.994	1.007	1.004	1.000	0.984	1.047	1.017	0.990	0.987
WECC_AZ	1.000	1.092	1.135	1.188	1.166	0.995	1.001	1.000	1.000	0.988	1.035	1.000	0.993	0.991
WECC_NM	1.000	1.092	1.135	1.188	1.166	0.995	1.001	1.000	1.000	0.988	1.035	1.000	0.993	0.991
WECC_SNV	1.000	1.092	1.135	1.188	1.166	0.995	1.001	1.000	1.000	0.988	1.035	1.000	0.993	0.991

Table 4-16 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Base Case v.5.13

	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas			Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind
			LGHI	LGLo	LGVLo					
Size (MW)	50	50	50			10	150	100	100	400
First Run Year Available	2018	2018	2016			2016	2016	2016	2016	2018
Lead Time (Years)	4	4	3			3	2	3	3	4
Availability	83%	87%	90%			87%	90%	90%	95%	95%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch			Economic Dispatch	Generation Profile	Generation Profile	Generation Profile	Generation Profile
	Vintage #1 (2016-2054)					**Vintage #1 (2016)**				
Heat Rate (Btu/kWh)	13,500	30,000	13,648	13,648	13,648	9,246	9,756	9,756	9,756	9,756
Capital (2011$/kW)	4,041	1,187 - 15,752	8,408	10,594	16,312	7,117	3,364	4,690	2,258	6,298
Fixed O&M (2011$/kW/yr)	103.79	50 - 541	381.74	381.74	381.74	357.47	21.37	66.09	38.86	72.71
Variable O&M (2011$/MWh)	5.17	0.00	8.51	8.51	8.51	0.0	0.0	0.0	0.0	0.0
						Vintage #2 (2018)				
Heat Rate (Btu/kWh)						8,738	9,756	9,756	9,756	9,756
Capital (2011$/kW)						6995	3,281	4,636	2,250	6233
Fixed O&M (2011$/kW/yr)						357.5	21.4	66.1	38.9	72.7
Variable O&M (2011$/MWh)						0.0	0.0	0.0	0.0	0.0
						Vintage #3 (2020)				
Heat Rate (Btu/kWh)						8,230	9,756	9,756	9,756	9,756
Capital (2011$/kW)						6806	3,217	4,594	2,220	6108
Fixed O&M (2011$/kW/yr)						357.5	21.4	66.1	38.9	72.7
Variable O&M (2011$/MWh)						0.0	0.0	0.0	0.0	0.0
						Vintage #4 (2025)				
Heat Rate (Btu/kWh)						6,960	9,756	9,756	9,756	9,756
Capital (2011$/kW)						6276	3,027	4,470	2,123	5739
Fixed O&M (2011$/kW/yr)						357.5	21.4	66.1	38.9	72.7
Variable O&M (2011$/MWh)						0.0	0.0	0.0	0.0	0.0
						Vintage #5 (2030)				
Heat Rate (Btu/kWh)						6,960	9,756	9,756	9,756	9,756
Capital (2011$/kW)						5,799	2,859	4,360	2,039	5411
Fixed O&M (2011$/kW/yr)						357.5	21.4	66.1	38.9	72.7
Variable O&M (2011$/MWh)						0.0	0.0	0.0	0.0	0.0
						Vintage #6 (2040)				

	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas			Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind
			LGHI	LGLo	LGVLo					
Heat Rate (Btu/kWh)						6,960	9,756	9,756	9,756	9,756
Capital (2011$/kW)						4,872	2,533	4,147	1,864	4,759
Fixed O&M (2011$/kW/yr)						357.5	21.4	66.1	38.9	72.7
Variable O&M (2011$/MWh)						0.0	0.0	0.0	0.0	0.0
						Vintage #7 (2050)				
Heat Rate (Btu/kWh)						6,960	9,756	9,756	9,756	9,756
Capital (2011$/kW)						4872	2,533	4,147	1,864	4759
Fixed O&M (2011$/kW/yr)						357.5	21.4	66.1	38.9	72.7
Variable O&M (2011$/MWh)						0.0	0.0	0.0	0.0	0.0

Notes:
[a] Assumptions for Biomass Co-firing for Coal Plants can be found in Table 5-9

4.4.5 Cost and Performance for Potential Renewable Generating and Non-Conventional Technologies

Table 4-16 summarizes the cost and performance assumptions in EPA Base Case v.5.13 for potential renewable and non-conventional technology generating units. The parameters shown in

Table 4-16 are based on AEO 2013. The size (MW) presented in

Table 4-16 represents the capacity on which unit cost estimates were developed and does not indicate the total potential capacity that the model can build of a given technology. Due to the distinctive nature of generation from renewable resources, some of the values shown in

Table 4-16 are averages or ranges that are discussed in further detail in the following subsections. Also discussed below are additional types of data from sources other than AEO 2013 that play a role in the representation of these types of generation in EPA Base Case v.5.13

It should be noted that the short term capital cost adder in Table 4-14 and the regional cost adjustment factors in Table 4-15 apply to the renewable and non-conventional generation technologies as they do to the conventional generation technologies

Wind Generation

EPA Base Case v.5.13 includes onshore wind, offshore-shallow and offshore-deep wind generation. The following sections describe four key aspects of the representation of wind generation: wind quality and resource potential, generation profiles, reserve margin contribution, and capital cost calculation.

Wind Quality and Resource Potential: EPA worked with the U.S. Department of Energy's (DOE) National Renewable Energy Laboratory (NREL), to conduct a complete update of the wind resource assumptions for use in EPA Base Case v.5.13. The result is a complete representation of the potential onshore, offshore (shallow and deep) wind generating capacity (in MW) broken into five wind quality classes (described in greater detail below) in each IPM model region.Table 4-17, Table 4-18, and Table 4-19 present the onshore, offshore shallow and offshore deep wind resource assumptions that are used in EPA Base Case v.5.13. Wind resources in EPA Base Case v.5.13 are aggregated into five wind classes, ranging from class 3 (designated to be the least productive for wind generation) to class 7 (designated to be the most productive for wind generation).

Table 4-17 Onshore Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.5.13

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 3	Cost Class 5
ERC_REST	TX	3	3,091	12,363	1,236	601,483
		4	309	1,237	124	60,176
		5	52	208	21	10,112
		6	7	27	3	1,318
		7	0.061	0.244	0.024	12
ERC_WEST	TX	3	1,910	7,642	764	371,768
		4	1,215	4,860	486	236,421
		5	611	2,445	244	118,943
		6	222	890	89	43,298
		7	63	250	25	12,181
FRCC	FL	3	0.202	0.398	0.204	0.396
MAP_WAUE	MN	3	45	190	63	8,728
		4	12	52	17	2,398
	MT	3	45	190	63	8,731
		4	79	330	110	15,191
		5	25	106	35	4,869
		6	4	16	5	757
		7	0.411	2	1	79
	ND	3	19	80	27	3,662
		4	49	205	68	9,441
		5	52	220	73	10,144
		6	26	110	37	5,078
		7	1	2	1	112
	SD	3	42	175	58	8,078

IPM Region	State	Wind Class	Cost Class 1	2	3	5
		4	337	1,416	472	65,220
		5	125	526	175	24,219
		6	35	147	49	6,746
		7	14	58	19	2,658
MIS_IA	IA	3	834	3,503	1,168	161,316
		4	399	1,676	559	77,184
		5	141	593	198	27,319
		6	40	167	56	7,676
		7	1	3	1	131
	MN	3	7	31	10	1,411
		4	24	101	34	4,660
		5	37	155	52	7,149
		6	30	128	43	5,891
		7	8	35	12	1,628
MIS_IL	IL	3	10,275	25,688	14,128	78,349
		4	39	98	54	298
MIS_INKY	IN	3	8,570	19,045	17,141	50,470
		4	420	934	840	2,475
	KY	3	0.054	0.120	0.108	0.318
MIS_LMI	MI	3	1,620	10,798	10,798	30,774
		4	10	67	67	190
		5	1	3	3	10
		6	0.201	1	1	4
		7	0.102	1	1	2
MIS_MAPP	MT	3	739	3,103	1,034	142,878
		4	633	2,660	887	122,473
		5	391	1,644	548	75,689
		6	148	621	207	28,585
		7	30	126	42	5,795
	ND	3	462	1,940	647	89,326
		4	1,468	6,167	2,056	283,981
		5	1,112	4,669	1,556	215,001
		6	556	2,336	779	107,578
		7	105	440	147	20,282
	SD	3	412	1,731	577	79,691
		4	1,141	4,792	1,597	220,646
		5	1,171	4,920	1,640	226,544
		6	625	2,623	874	120,798
		7	125	525	175	24,168
MIS_MIDA	IA	3	509	2,138	713	98,454
		4	419	1,759	586	81,018
		5	333	1,398	466	64,366
		6	165	692	231	31,867
		7	5	21	7	990
	IL	3	57	241	80	11,089
		4	0.215	1	0.301	42
MIS_MNWI	MI	3	1	4	1	170
	MN	3	1,652	6,939	2,313	319,537

IPM Region	State	Wind Class	Cost Class 1	2	3	5
		4	311	1,304	435	60,052
		5	136	571	190	26,285
		6	154	648	216	29,818
		7	36	153	51	7,046
	SD	3	0.137	1	0.192	26
		4	11	45	15	2,078
		5	39	164	55	7,564
		6	35	146	49	6,702
		7	6	23	8	1,081
	WI	3	109	456	152	20,991
MIS_MO	IA	3	140	351	193	1,070
	MO	3	12,356	30,891	16,990	94,218
		4	326	814	448	2,483
		5	5	13	7	40
MIS_WUMS	MI	3	25	42	4	4,142
		4	0.214	0.356	0.036	35
		5	0.029	0.049	0.005	5
		6	0.006	0.010	0.001	1
	WI	3	494	824	82	80,959
		4	2	4	0.403	396
		5	0.259	0.432	0.043	42
		6	0.055	0.092	0.009	9
NENG_CT	CT	3	2	4	4	11
NENG_ME	ME	3	1,093	2,186	2,186	5,464
		4	60	120	120	300
		5	23	46	46	115
		6	15	30	30	75
		7	19	39	39	96
NENGREST	MA	3	75	150	150	374
		4	26	52	52	130
		5	14	27	27	68
		6	6	12	12	29
		7	5	10	10	26
	NH	3	177	354	354	886
		4	19	38	38	94
		5	9	17	17	44
		6	5	10	10	24
		7	5	10	10	24
	RI	3	4	7	7	18
		4	1	1	1	3
		5	3	5	5	13
	VT	3	248	496	496	1,239
		4	24	49	49	122
		5	10	21	21	52
		6	6	12	12	30
		7	6	12	12	31
NY_Z_A&B	NY	3	2,095	2,095	2,095	4,189
		4	4	4	4	8

IPM Region	State	Wind Class	Cost Class 1	2	3	5
NY_Z_C&E	NY	3	1,847	1,847	1,847	3,694
		4	19	19	19	38
		5	4	4	4	8
		6	2	2	2	4
		7	3	3	3	5
NY_Z_D	NY	3	570	570	570	1,139
		4	28	28	28	55
		5	8	8	8	17
		6	4	4	4	7
		7	4	4	4	7
NY_Z_F	NY	3	472	472	472	944
		4	17	17	17	34
		5	5	5	5	10
		6	3	3	3	6
		7	4	4	4	9
NY_Z_G-I	NY	3	66	66	66	132
		4	1	1	1	3
		5	1	1	1	1
		6	0.400	0.400	0.400	1
		7	0.240	0.240	0.240	0.480
NY_Z_K	NY	3	55	55	55	110
		4	12	12	12	23
		5	2	2	2	5
PJM_AP	MD	3	45	101	91	267
		4	1	1	1	4
	PA	3	52	116	105	308
		4	1	3	3	8
		5	1	1	1	3
		6	0.018	0.040	0.036	0.106
	VA	3	17	39	35	103
		4	3	7	7	19
		5	2	4	3	10
		6	0.360	1	1	2
		7	0.162	0.360	0.324	1
	WV	3	142	316	284	837
		4	14	31	28	82
		5	3	7	6	18
		6	1	2	2	6
		7	1	2	2	6
PJM_ATSI	OH	3	2,019	4,486	4,037	11,887
		4	1	2	2	7
PJM_COMD	IL	3	9,743	21,651	19,486	57,375
		4	99	220	198	583
PJM_Dom	NC	3	34	34	34	68
	VA	3	71	71	71	141
		4	5	5	5	10
		5	2	2	2	4
		6	1	1	1	1

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 3	Cost Class 5
		7	0.120	0.120	0.120	0.240
PJM_EMAC	DE	3	2	2	2	4
	MD	3	313	313	313	626
	NJ	3	51	51	51	101
	VA	3	362	362	362	724
		4	2	2	2	3
PJM_PENE	PA	3	415	415	415	831
		4	16	16	16	31
		5	2	2	2	5
		6	0.020	0.020	0.020	0.040
PJM_SMAC	MD	3	1	1	1	2
PJM_West	IN	3	4,353	9,674	8,707	25,637
	KY	3	1	3	2	7
	MI	3	202	449	404	1,191
	OH	3	2,931	6,513	5,862	17,260
	TN	3	2	4	4	11
		4	0.288	1	1	2
		5	0.108	0.240	0.216	1
	VA	3	36	80	72	212
		4	3	7	6	19
		5	1	3	3	9
		6	0.297	1	1	2
	WV	3	4	10	9	26
		4	0.387	1	1	2
		5	1	1	1	3
		6	0.414	1	1	2
		7	0.261	1	1	2
PJM_WMAC	PA	3	107	107	107	213
		4	2	2	2	3
S_C_KY	KY	3	10	10	10	19
S_C_TVA	AL	3	10	10	10	20
	GA	3	7	7	7	15
		4	0.160	0.160	0.160	0.320
	KY	3	0.200	0.200	0.200	0.400
	NC	3	31	31	31	62
		4	6	6	6	11
		5	3	3	3	5
		6	2	2	2	4
		7	1	1	1	2
	TN	3	55	55	55	110
		4	1	1	1	2
		5	1	1	1	1
		6	0.040	0.040	0.040	0.080
		7	1	1	1	1
	VA	3	0.080	0.080	0.080	0.160
S_D_AMSO	LA	3	48	192	192	529
S_D_N_AR	AR	3	38	152	152	417
		4	0.495	2	2	5

IPM Region	State	Wind Class	Cost Class 1	2	3	5
		5	0.050	0.200	0.200	1
	MO	3	49	196	196	539
S_D_REST	AR	3	0.220	1	1	2
S_D_WOTA	LA	3	10	40	40	109
	TX	3	98	392	392	1,079
S_SOU	AL	3	13	13	13	26
	GA	3	18	18	18	35
		4	1	1	1	2
S_VACA	NC	3	122	122	122	244
		4	3	3	3	5
		5	1	1	1	1
		6	1	1	1	2
		7	0.340	0.340	0.340	1
	SC	3	48	48	48	97
		4	0.040	0.040	0.040	0.080
SPP_N	KS	3	1,949	8,230	3,899	202,509
		4	2,297	9,697	4,594	238,608
		5	2,687	11,346	5,374	279,175
		6	1,426	6,021	2,852	148,161
		7	211	889	421	21,880
	MO	3	1,021	4,312	2,043	106,102
		4	6	25	12	619
SPP_NEBR	NE	3	811	3,404	1,135	156,753
		4	1,436	6,031	2,010	277,691
		5	1,412	5,930	1,977	273,063
		6	738	3,100	1,033	142,746
		7	133	559	186	25,741
SPP_SE	LA	3	0.406	2	1	55
SPP_SPS	NM	3	1,128	5,318	1,612	153,108
		4	253	1,192	361	34,322
		5	45	210	64	6,045
		6	20	95	29	2,724
		7	3	15	5	433
	OK	3	25	117	35	3,372
		4	123	580	176	16,699
		5	225	1,060	321	30,520
		6	85	398	121	11,470
		7	32	149	45	4,296
	TX	3	696	3,282	995	94,481
		4	582	2,744	831	78,989
		5	462	2,176	659	62,645
		6	663	3,126	947	90,002
		7	256	1,206	365	34,718
SPP_WEST	AR	3	58	273	83	7,859
		4	1	5	2	148
		5	0.129	1	0.184	17
		6	0.032	0.149	0.045	4
		7	0.022	0.102	0.031	3

IPM Region	State	Wind Class	Cost Class 1	2	3	5
	MO	3	0.042	0.198	0.060	6
	OK	3	2,002	9,437	2,860	271,662
		4	816	3,846	1,165	110,705
		5	240	1,131	343	32,558
		6	70	331	100	9,515
		7	6	30	9	864
	TX	3	0.099	0.465	0.141	13
WEC_CALN	CA	3	187	623	218	2,088
		4	5	18	6	59
		5	1	5	2	16
		6	1	2	1	7
		7	0.360	1	0.420	4
WEC_LADW	CA	3	111	369	129	1,235
		4	41	137	48	460
		5	7	22	8	75
		6	5	18	6	59
		7	3	12	4	39
WEC_SDGE	CA	3	55	183	64	613
		4	14	47	17	159
		5	4	13	5	44
		6	1	2	1	7
		7	0.384	1	0.448	4
WECC_AZ	AZ	3	98	392	218	10,170
		4	0.233	1	1	24
		5	0.014	0.058	0.032	1
WECC_CO	CO	3	1,071	4,284	2,678	259,744
		4	314	1,257	786	76,222
		5	145	578	361	35,052
		6	18	72	45	4,388
		7	1	5	3	307
WECC_ID	ID	3	50	451	669	15,547
		4	1	11	16	382
		5	0.323	3	4	100
		6	0.104	1	1	32
		7	0.038	0.346	1	12
WECC_IID	CA	3	26	103	57	2,674
		4	0.325	1	1	34
		5	0.015	0.061	0.034	2
WECC_MT	MT	3	1,260	11,340	16,800	390,608
		4	229	2,065	3,059	71,112
		5	60	542	803	18,673
		6	17	157	232	5,396
		7	8	76	113	2,629
WECC_NM	NM	3	1,464	5,855	3,253	152,057
		4	567	2,269	1,260	58,928
		5	365	1,460	811	37,926
		6	142	569	316	14,774
		7	27	108	60	2,802

IPM Region	State	Wind Class	Cost Class 1	2	3	5
	TX	3	219	875	486	22,725
		4	9	38	21	982
		5	2	6	4	168
		6	1	2	1	58
		7	0.326	1	1	34
WECC_NNV	NV	3	21	188	278	6,471
		4	0.456	4	6	141
		5	0.068	1	1	21
		6	0.013	0.119	0.176	4
WECC_PNW	CA	3	1	5	7	173
		4	0.036	0.324	0.480	11
		5	0.007	0.065	0.096	2
		6	0.001	0.011	0.016	0.372
	ID	3	2	15	23	527
		4	0.252	2	3	78
		5	0.123	1	2	38
		6	0.105	1	1	33
		7	0.088	1	1	27
	OR	3	76	681	1,008	23,440
		4	4	34	50	1,158
		5	1	10	15	355
		6	1	5	7	168
		7	0.355	3	5	110
	WA	3	51	462	685	15,930
		4	3	25	37	861
		5	1	7	10	238
		6	0.368	3	5	114
		7	0.241	2	3	75
WECC_SCE	CA	3	989	3,295	1,153	11,039
		4	69	229	80	768
		5	34	112	39	375
		6	15	50	18	169
		7	28	93	33	313
WECC_SF	CA	3	237	790	277	2,648
		4	28	92	32	309
		5	26	87	30	290
		6	4	12	4	39
WECC_SNV	NV	3	1	5	3	138
		4	0.004	0.014	0.008	0.374
WECC_UT	UT	3	39	350	519	12,062
		4	0.279	3	4	86
		5	0.039	0.351	1	12
		6	0.006	0.054	0.080	2
		7	0.003	0.027	0.040	1
WECC_WY	NE	4	2	22	32	745
		5	15	138	204	4,748
		6	16	146	216	5,026
		7	0.471	4	6	146

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 3	Cost Class 5
	SD	3	125	1,124	1,665	38,719
		4	38	344	510	11,863
		5	11	95	141	3,286
		6	1	13	19	447
		7	0.018	0.162	0.240	6
	WY	3	918	8,261	12,238	284,541
		4	338	3,046	4,513	104,927
		5	188	1,694	2,509	58,337
		6	114	1,027	1,521	35,370
		7	98	878	1,301	30,238

Table 4-18 Offshore Shallow Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.5.13

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
ERC_REST	TX	3	850	1,700	1,700
		4	6,423	12,846	12,846
		5	1,079	2,158	2,158
		6	2,625	5,251	5,251
FRCC	FL	3	57,921	115,842	115,842
		4	7	13	13
MIS_INKY	IN	3	63	125	125
		4	259	517	517
		5	85	169	169
MIS_LMI	MI	3	1,739	3,478	3,478
		4	3,784	7,567	7,567
		5	1,899	3,799	3,799
		6	416	831	831
MIS_MNWI	MI	3	118	236	236
		4	14	29	29
	MN	3	134	269	269
	WI	3	911	1,822	1,822
		4	141	282	282
MIS_WUMS	MI	3	2,275	4,550	4,550
		4	3,095	6,189	6,189
		5	477	953	953
		6	59	117	117
		7	92	185	185
	WI	3	525	1,049	1,049
		4	1,472	2,944	2,944
		5	737	1,473	1,473
		6	84	167	167
NENG_CT	CT	3	287	574	574
		4	162	323	323
NENG_ME	ME	3	619	1,238	1,238
		4	419	837	837
		5	166	331	331

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
		6	234	469	469
		7	16	33	33
NENGREST	MA	3	181	363	363
		4	579	1,158	1,158
		5	661	1,321	1,321
		6	2,307	4,615	4,615
		7	3,112	6,224	6,224
	NH	3	24	48	48
		4	52	103	103
		5	31	62	62
	RI	3	43	87	87
		4	89	177	177
		5	85	170	170
		6	225	449	449
NY_Z_A&B	NY	3	205	410	410
		4	1,092	2,184	2,184
		5	2	4	4
NY_Z_C&E	NY	3	249	499	499
		4	524	1,048	1,048
		5	2	5	5
NY_Z_G-I	NY	3	1	1	1
NY_Z_J	NY	3	46	93	93
		4	118	237	237
		5	4	8	8
NY_Z_K	NY	3	258	517	517
		4	881	1,763	1,763
		5	787	1,573	1,573
		6	1,533	3,067	3,067
PJM_ATSI	OH	3	173	347	347
		4	2,628	5,256	5,256
		5	1,261	2,523	2,523
PJM_COMD	IL	3	100	200	200
		4	267	534	534
		5	418	836	836
		6	2	4	4
PJM_Dom	NC	3	706	1,413	1,413
		4	2,776	5,551	5,551
		5	3,843	7,687	7,687
		6	553	1,107	1,107
	VA	3	809	1,619	1,619
		4	979	1,958	1,958
		5	1,313	2,626	2,626
		6	1	1	1
PJM_EMAC	DE	3	214	428	428
		4	1,079	2,159	2,159
		5	170	340	340
	MD	3	1,303	2,607	2,607
		4	1,696	3,392	3,392

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
		5	366	732	732
	NJ	3	365	729	729
		4	1,626	3,253	3,253
		5	2,981	5,962	5,962
		6	1,953	3,907	3,907
	VA	3	365	730	730
		4	3,555	7,110	7,110
		5	1,525	3,050	3,050
PJM_PENE	PA	3	23	45	45
		4	649	1,297	1,297
		5	427	853	853
PJM_SMAC	MD	3	567	1,134	1,134
		4	0.040	0.080	0.080
PJM_West	MI	3	62	123	123
		4	440	880	880
S_D_AMSO	LA	3	8,846	17,693	17,693
S_D_WOTA	LA	3	3,590	7,181	7,181
		4	586	1,172	1,172
S_SOU	TX	3	639	1,278	1,278
		4	1,145	2,290	2,290
	AL	3	1,939	3,877	3,877
	FL	3	4,827	9,654	9,654
	GA	3	5,135	10,270	10,270
		4	4,146	8,292	8,292
	MS	3	1,056	2,113	2,113
S_VACA	NC	3	1,437	2,874	2,874
		4	8,366	16,733	16,733
		5	6,468	12,935	12,935
		6	94	188	188
	SC	3	381	762	762
		4	9,932	19,864	19,864
		5	2,993	5,986	5,986
SPP_SE	LA	3	1,828	3,656	3,656
WEC_CALN	CA	3	196	391	391
		4	37	73	73
		5	11	23	23
		6	4	9	9
WEC_LADW	CA	3	10	21	21
WECC_PNW	CA	3	122	243	243
		4	43	86	86
		5	24	48	48
		6	2	4	4
	OR	3	876	1,753	1,753
		4	150	300	300
		5	46	92	92
		6	64	128	128
		7	9	18	18
	WA	3	610	1,220	1,220

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
		4	404	808	808
		5	1	1	1
WECC_SCE	CA	3	170	339	339
		4	55	109	109
		5	7	15	15
		6	0.080	0.160	0.160
WECC_SF	CA	3	326	652	652
		4	1	3	3

Table 4-19 Offshore Deep Regional Potential Wind Capacity (MW) by Wind and Cost Class in EPA Base Case v.5.13

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
ERC_REST	TX	3	10,991	21,982	21,982
		4	7,963	15,926	15,926
		5	97	194	194
FRCC	FL	3	61,964	123,927	123,927
MIS_INKY	IN	3	298	596	596
MIS_LMI	MI	3	5,068	10,136	10,136
		4	16,868	33,736	33,736
		5	259	518	518
MIS_MNWI	MI	3	464	928	928
	MN	3	4,795	9,590	9,590
	WI	3	3,608	7,216	7,216
MIS_WUMS	MI	3	9,225	18,450	18,450
		4	7,779	15,558	15,558
		5	8,557	17,114	17,114
		6	5,572	11,145	11,145
	WI	3	1,427	2,854	2,854
		4	8,953	17,906	17,906
		5	300	599	599
NENG_CT	CT	3	19	38	38
NENG_ME	ME	3	499	999	999
		4	962	1,924	1,924
		5	1,789	3,579	3,579
		6	7,377	14,755	14,755
		7	7,582	15,165	15,165
NENGREST	MA	3	279	558	558
		4	817	1,633	1,633
		5	8,923	17,845	17,845
		6	15,734	31,467	31,467
	NH	3	70	140	140
		4	369	737	737
		5	359	717	717
		6	660	1,319	1,319
	RI	3	205	411	411
		4	300	600	600

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
		5	2,624	5,248	5,248
NY_Z_A&B	NY	3	4,384	8,767	8,767
		4	37	74	74
NY_Z_C&E	NY	3	1,377	2,754	2,754
		4	0.160	0.320	0.320
NY_Z_J	NY	3	1	2	2
		4	0.240	0.480	0.480
NY_Z_K	NY	3	432	865	865
		4	981	1,963	1,963
		5	10,948	21,896	21,896
		6	69	137	137
PJM_ATSI	OH	3	4	7	7
PJM_COMD	IL	3	491	981	981
		4	1,269	2,538	2,538
PJM_Dom	NC	3	938	1,875	1,875
		4	11,658	23,316	23,316
		5	588	1,177	1,177
	VA	3	142	284	284
		4	713	1,426	1,426
PJM_EMAC	DE	3	469	938	938
		4	10	19	19
	MD	3	3,802	7,603	7,603
		4	29	58	58
	NJ	3	1,281	2,562	2,562
		4	5,085	10,171	10,171
		5	3,280	6,560	6,560
	VA	3	3,637	7,274	7,274
		4	568	1,135	1,135
PJM_PENE	PA	3	230	461	461
PJM_SMAC	MD	3	6	13	13
PJM_West	MI	3	1,462	2,925	2,925
		4	355	710	710
S_D_AMSO	LA	3	10,146	20,293	20,293
S_D_WOTA	LA	3	222	444	444
S_SOU	AL	3	3,564	7,129	7,129
	FL	3	14,264	28,527	28,527
	GA	3	2,379	4,757	4,757
	MS	3	5	10	10
S_VACA	NC	3	4,338	8,677	8,677
		4	9,454	18,909	18,909
	SC	3	7,383	14,766	14,766
		4	91	182	182
SPP_SE	LA	3	125	249	249
WEC_CALN	CA	3	12,809	25,617	25,617
		4	5,277	10,555	10,555
		5	6,043	12,087	12,087
		6	12,939	25,878	25,878
		7	3,678	7,356	7,356

IPM Region	State	Wind Class	Cost Class 1	Cost Class 2	Cost Class 4
WEC_LADW	CA	3	6,527	13,054	13,054
WECC_PNW	CA	3	299	598	598
		4	322	644	644
		5	469	938	938
		6	1,103	2,206	2,206
		7	1,538	3,076	3,076
	OR	3	6,530	13,061	13,061
		4	12,517	25,035	25,035
		5	3,759	7,518	7,518
		6	4,667	9,334	9,334
		7	4,598	9,197	9,197
	WA	3	6,716	13,431	13,431
		4	6,304	12,607	12,607
WECC_SCE	CA	3	17,439	34,877	34,877
		4	10,699	21,398	21,398
		5	5,028	10,056	10,056
WECC_SF	CA	3	3,883	7,766	7,766
		4	3,907	7,814	7,814
		5	4,064	8,127	8,127
		6	49	98	98

Generation Profiles: Unlike other renewable generation technologies, which dispatch on an economic basis subject to their availability constraint, wind and solar technologies can only be dispatched when the wind blows and the sun shines. To represent intermittent renewable generating sources like wind and solar, EPA Base Case v.5.13 uses generation profiles which specify hourly generation patterns for a representative day in winter and summer. Each eligible model region is provided with a distinct set of winter and summer generation profiles for wind, solar thermal and solar photovoltaic plants.

For Hour 1 through Hour 24 the generation profile indicates the amount of generation (kWh) per MW of available capacity. The wind generation profiles were prepared with data from NREL. This provided the separate winter and summer generation profiles for wind classes 3-7 for onshore and offshore (shallow and deep) generation in each IPM region. As an illustrative example, Excerpt of Table 4-20 shows the generation profile for onshore wind in model region WECC_CO. In IPM the seasonal average "kWh of generation per MW" (shown in the last row of the Excerpt of Table 4-20) is used to derive the generation from a particular wind class in a specific model region.

Excerpt of Table 4-20 Representative Wind Generation Profiles in EPA Base Case v.5.13

Illustrative Hourly Wind Generation Profile (kWh of Generation per MW of Electricity)
The complete data set in spreadsheet format can be downloaded via the link found at
www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Winter Hour	Wind Class 1	2	3	4	5
01	410	483	504	521	539
02	404	478	499	517	536
03	400	474	497	514	533
04	388	462	486	504	526
05	366	439	465	485	511
06	351	423	449	471	499

Summer Hour	Wind Class 1	2	3	4	5
01	273	326	385	407	431
02	263	314	373	396	422
03	252	303	362	386	412
04	234	285	343	366	394
05	208	257	312	335	364
06	187	234	286	308	339

07	348	419	443	467	495	07	170	213	263	284	315
08	355	427	448	471	500	08	166	206	254	276	306
09	346	420	440	463	493	09	159	198	243	265	294
10	331	406	426	452	483	10	162	204	244	267	298
11	319	394	415	443	475	11	175	220	254	280	312
12	317	391	412	441	474	12	191	238	267	293	326
13	317	388	409	440	473	13	202	248	273	298	332
14	319	389	410	441	475	14	210	255	276	300	334
15	322	389	411	441	475	15	216	260	279	303	336
16	319	384	405	436	471	16	218	261	279	303	336
17	308	373	390	423	459	17	215	257	275	299	330
18	309	374	389	422	458	18	220	262	280	304	333
19	332	399	412	444	478	19	241	284	306	330	357
20	369	438	450	478	506	20	268	313	342	367	391
21	395	467	480	503	525	21	284	332	370	394	417
22	410	483	497	517	536	22	289	341	386	408	430
23	415	488	504	522	540	23	286	340	392	413	435
24	413	486	505	522	540	24	281	335	391	412	435
Winter Average	**357**	**428**	**448**	**472**	**500**	**Summer Average**	**224**	**270**	**310**	**333**	**362**

Notes:
Based on Onshore Wind in Model Region WECC_CO.
This is an example of the wind data used in EPA Base Case v.5.13

To obtain the seasonal generation for the units in a particular wind class in a specific region, one must multiply the installed capacity by the capacity factor (which represents the ratio of actual productivity in a time period to the theoretical maximum in the period). Capacity factor is the average “kWh of generation per MW” from the applicable generation profile multiplied by the number of days in the time period (i.e., summer or winter) to obtain the level of generation. The capacity factors for wind generation that are used in EPA Base Case v.5.13 were obtained from NREL and are shown in Table 4-21, Table 4-22, and.Table 4-23.

Reserve Margin Contribution (also referred to as capacity credit): EPA Base Case v.5.13 uses reserve margins, discussed in detail in Section 3.6, to model reliability. Each region has a reserve margin requirement which is used to determine the total capacity needed to reliably meet peak demand. The ability of a unit to assist a region in meeting its reliability requirements is modeled through the unit’s contribution to reserve margin. If the unit has 100 percent contribution towards reserve margin, then the entire capacity of the unit is counted towards meeting the region’s reserve margin requirement. However, if any unit has less than a 100 percent contribution towards reserve margin, then only the designated share of the unit’s capacity counts towards the reserve margin requirement.

All units except those that depend on intermittent resources have 100% contributions toward reserve margin. This means that wind and solar have limited (less than 100 percent) contributions toward reserve margins in the EPA Base Case v.5.13.

Table 4-21, Table 4-22, and Table 4-23 present the reserve margin contributions apportioned to new wind plants in the EPA Base Case v.5.13 as derived from AEO 2012 and NREL. NREL is the source for capacity factors; AEO 2012 Reference Case outputs are used to develop a ratio of capacity factors to reserve contribution. The tables show the onshore and offshore (shallow and deep) reserve margins for each wind class.

Table 4-21 Onshore Reserve Margin Contribution an Average Capacity Factor by Wind Class

	Wind Class				
	1	**2**	**3**	**4**	**5**

Capacity Factor	30%	36%	39%	41%	44%
Reserve Margin Contribution[a]	20%	24%	26%	27%	29%

Note:
[a] Reserve Margin Contribution for ERC_REST and ERC_WEST is 8.7%.

Table 4-22 Offshore Shallow Reserve Margin Contribution an Average Capacity Factor by Wind Class

	Wind Class				
	1	**2**	**3**	**4**	**5**
Capacity Factor	31%	40%	43%	46%	50%
Reserve Margin Contribution[a]	20%	26%	28%	30%	33%

Note:
[a] Reserve Margin Contribution for ERC_REST and ERC_WEST is 8.7%.

Table 4-23 Offshore Deep Reserve Margin Contribution an Average Capacity Factor by Wind Class

	Wind Class				
	1	**2**	**3**	**4**	**5**
Capacity Factor	36%	45%	49%	51%	53%
Reserve Margin Contribution[a]	24%	30%	32%	34%	35%

Note:
[a] Reserve Margin Contribution for ERC_REST and ERC_WEST is 8.7%.

Capital cost calculation: EPA Base Case v.5.13 uses multipliers similar to the LT (long term) multipliers from the Energy Information Administration's NEMS model[22] to capture differences in the capital cost of new wind capacity caused by such factors as distance from existing transmission, terrain variability, slope and other causes of resource degradation, site accessibility challenges, population proximity, competing land uses, aesthetics, and environmental factors. Five cost classes are used in EPA Base Case v.5.13 with class 1 having the lowest cost adjustment factor (1) and class 5 having the highest adjustment factor (ranging from 2.00 to 2.50 depending on whether the wind resource is onshore, offshore shallow or offshore deep), as shown in Table 4-24. To obtain the capital cost for a particular new wind model plant, the base capital costs shown in

[22] Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power, Report to EIA from Princeton Energy Resources International, LLC. May 2007.

Table 4-16 are multiplied by the cost adjustment factor for the wind cost class applicable to the new plant.

Table 4-24 Capital Cost Adjustment Factors for New Wind Plants in Base Case v.5.13

	Cost Class				
	1	**2**	**3**	**4**	**5**
Onshore	1	1.1	1.25	--	2.00
Offshore Deep Water	1	1.35	--	2.5	--
Offshore Shallow Water	1	1.35	--	2.5	--

Many factors figure in whether the model determines that adding wind capacity yields the greatest incremental improvement in the system-wide (least cost) solution available to the model at a particular point in the solution process. These factors include trade-offs between such items as the cost, capacity factor, reserve margin contribution, and dispatch capabilities and constraints on the new wind capacity relative to other choices. However, to perform its trade-off computations, the model requires the values described above.

As an illustrative example, Table 4-25 shows the calculations that would be performed to derive the potential electric generation, reserve margin contribution, and cost of new (potential) onshore capacity in wind class 3, cost class 2 in the WECC_CO model region in run year 2020.

Table 4-25 Example Calculations of Wind Generation Potential, Reserve Margin Contribution, and Capital Cost for Onshore Wind in WECC_CO at Wind Class 3, Cost Class 2

Required Data

Table 4-17	Potential wind capacity (C) =	578 MW
Table 4-20	Winter average generation (G_W) per available MW =	448 kWh/MW
Table 4-20	Summer average generation (G_S) per available MW =	310 kWh/MW
	Hours in Winter (H_W) season (October – April) =	5,088 hours
	Hours in Summer (H_S)season (May – September) =	3,672 hours
Table 4-21	Reserve Margin Contribution (*RM*) WECC_CO, Wind Class 3 =	26 percent
Table 4-16	Capital Cost (Cap_{2020}) in vintage range for year 2020 =	$2,220/kW
Table 4-24	Capital Cost Adjustment Factor ($CAF_{ON,C2}$) for onshore cost class 2 =	1.1
Table 4-15	Regional Factor (RF)	1.033

Calculations

$$\begin{aligned} Generation\ \ Potential &= C \times G_W \times H_w + C \times G_S \times H_s \\ &= 578\,MW \times 448\,kWh/MW \times 5088\,hours + \\ &\quad 578\,MW \times 310\,kWh/MW \times 3672\,hours \\ &= 1{,}975\,GWh \end{aligned}$$

$$\begin{aligned} \mathrm{Re}\,serveM\arg inContribution &= RM \times C \\ &= 26\% \times 578\,MW \\ &= 149\,MW \end{aligned}$$

$$\begin{aligned} Capital\ Cost &= \mathrm{Cap}_{2020} \times \mathrm{CAF}_{\mathrm{ON,C2}} \times RF \times C \\ &= \$2{,}220/\mathrm{kW} \times 1.1 \times 1.033 \times 578\,MW \\ &= \$1{,}458{,}055 \end{aligned}$$

Solar Generation

EPA Base Case v.5.13 includes solar PV and solar thermal generation technologies. The following sections describe four key aspects of the representation of solar generation: solar resource potential, generation profiles, reserve margin contribution, and capital cost calculation.

Solar Resource Potential: The resource potential estimates for solar PV and solar thermal technologies were developed by NREL by model region and state. These are summarized in Table 4-26 and

Table 4-27.

Table 4-26 Solar PV Regional Potential Capacity (MW) in EPA Base Case v.5.13

Model Region	State	Class					
		1	2	3	4	5	6
FRCC	FL	--	466,717	2,016,007	2	--	--
ERC_REST	TX	--	5,330,140	6,734,722	17,494	--	--
ERC_WEST	TX	--	--	4,352,761	1,172,478	1,508,010	960,326
MAP_WAUE	MN	13,256	97,901	--	--	--	--
	MT	--	177,744	--	--	--	--
	ND	--	248,206	--	--	--	--
	SD	--	991,602	--	--	--	--
MIS_IA	IA	846	2,792,414	--	--	--	--
	MN	--	205,901	--	--	--	--
MIS_IL	IL	--	3,840,608	--	--	--	--
MIS_INKY	IN	11,692	2,660,403	--	--	--	--
	KY	--	454,286	--	--	--	--
MIS_LMI	MI	1,187,823	1,910,779	--	--	--	--
MIS_MAPP	MT	--	2,526,463	--	--	--	--
	ND	575,717	5,813,548	--	--	--	--
	SD	--	5,361,555	--	--	--	--
MIS_MIDA	IA	--	2,636,683	--	--	--	--
	IL	--	151,384	--	--	--	--
MIS_MNWI	MI	38,128	32,825	--	--	--	--
	MN	1,628,979	5,292,787	--	--	--	--
	SD	--	167,192	--	--	--	--
	WI	215,333	1,174,605	--	--	--	--
MIS_MO	IA	--	52,502	--	--	--	--
	MO	--	2,718,802	--	--	--	--
MIS_WUMS	MI	437,954	465,821	--	--	--	--
	WI	541,446	2,293,924	--	--	--	--
NENG_CT	CT	6,300	74,375	--	--	--	--
NENG_ME	ME	1,174,023	305,524	--	--	--	--
NENGREST	MA	30,548	118,009	--	--	--	--
	NH	34,503	101,436	--	--	--	--
	RI	49	34,073	--	--	--	--
	VT	88,147	11,168	--	--	--	--
NY_Z_A&B	NY	321,929	152,829	--	--	--	--
NY_Z_C&E	NY	482,549	176,823	--	--	--	--
NY_Z_D	NY	223,636	75,990	--	--	--	--
NY_Z_F	NY	82,765	64,662	--	--	--	--
NY_Z_G-I	NY	5,299	58,250	--	--	--	--
NY_Z_J	NY	--	676	--	--	--	--
NY_Z_K	NY	--	25,646	--	--	--	--
PJM_AP	MD	2,017	59,871	--	--	--	--
	PA	76,636	78,377	--	--	--	--
	VA	--	122,956	--	--	--	--
	WV	7,588	76,925	--	--	--	--

Model Region	State	Class					
		1	2	3	4	5	6
PJM_ATSI	OH	474,342	869,085	--	--	--	--
	PA	151,543	2,456	--	--	--	--
PJM_COMD	IL	546	1,576,218	--	--	--	--
PJM_Dom	NC	--	441,910	--	--	--	--
	VA	--	1,742,725	--	--	--	--
PJM_EMAC	DE	--	175,165	--	--	--	--
	MD	--	329,397	--	--	--	--
	NJ	183	316,902	--	--	--	--
	PA	--	146,075	--	--	--	--
	VA	--	53,494	--	--	--	--
PJM_PENE	PA	276,816	30,194	--	--	--	--
PJM_SMAC	DC	--	35	--	--	--	--
	MD	--	180,702	--	--	--	--
PJM_West	IN	11,570	745,754	--	--	--	--
	KY	--	18,542	--	--	--	--
	MI	52,303	87,422	--	--	--	--
	OH	88,741	1,452,563	--	--	--	--
	TN	--	684	--	--	--	--
	VA	--	155,747	--	--	--	--
	WV	272	28,898	--	--	--	--
PJM_WMAC	PA	72,963	208,057	--	--	--	--
S_C_KY	KY	--	816,227	--	--	--	--
	OH	--	10,749	--	--	--	--
	VA	--	3	--	--	--	--
S_C_TVA	AL	--	591,879	--	--	--	--
	GA	--	71,479	--	--	--	--
	KY	--	736,215	--	--	--	--
	MS	--	1,174,913	--	--	--	--
	NC	--	7,785	--	--	--	--
	TN	--	2,239,778	--	--	--	--
	VA	--	5,167	--	--	--	--
S_D_AMSO	LA	--	271,634	8,334	--	--	--
S_D_N_AR	AR	--	1,619,623	--	--	--	--
	MO	--	807,954	--	--	--	--
S_D_REST	AR	--	716,350	--	--	--	--
	LA	--	1,131,420	--	--	--	--
	MS	--	1,951,363	--	--	--	--
S_D_WOTA	LA	--	214,557	252	--	--	--
	TX	--	627,283	--	--	--	--
S_SOU	AL	--	3,052,382	60,455	--	--	--
	FL	--	493,841	86,080	--	--	--
	GA	--	3,322,002	986,103	--	--	--
	MS	--	948,473	2,612	--	--	--
S_VACA	GA	--	23,380	--	--	--	--
	NC	--	2,773,996	--	--	--	--
	SC	--	2,110,013	123,622	--	--	--
SPP_N	KS	--	3,558,781	5,141,266	280	--	--

Model Region	State	Class					
		1	2	3	4	5	6
	MO	--	1,721,823	--	--	--	--
SPP_NEBR	NE	--	4,965,449	1,966,681	--	--	--
SPP_SE	LA	--	1,122,714	731	--	--	--
SPP_SPS	NM	--	--	--	109,326	1,514,976	698,712
	OK	--	--	452,416	198,521	4,648	--
	TX	--	--	1,263,287	1,705,702	653,658	--
SPP_WEST	AR	--	1,206,494	--	--	--	--
	LA	--	123,494	--	--	--	--
	MO	--	3,278	--	--	--	--
	OK	--	2,497,664	3,662,342	--	--	--
WEC_CALN	CA	5	17,827	1,686,553	252,117	76,837	15,751
WEC_LADW	CA	--	190	1,721	2,111	11,541	125,266
WEC_SDGE	CA	--	--	3,150	4,613	2,169	48,580
WECC_AZ	AZ	--	--	--	4,413	173,124	6,915,162
WECC_CO	CO	--	71,601	4,752,161	608,847	210,420	171,178
WECC_ID	ID	--	531,421	2,050,967	--	--	--
WECC_IID	CA	--	--	--	1,822	294	351,868
WECC_MT	MT	1,211	4,618,469	--	--	--	--
WECC_NM	NM	--	--	25,168	432,099	1,882,143	4,735,551
	TX	--	--	--	--	7,033	521,127
WECC_NNV	NV	--	343	2,079,313	896,221	587,765	1,587,307
WECC_PNW	CA	--	3,935	413,255	--	--	--
	ID	--	137,335	--	--	--	--
	OR	90,067	700,240	2,032,709	--	--	--
	WA	310,047	1,361,856	3,472	--	--	--
WECC_SCE	CA	--	1,638	191,598	276,918	61,789	1,474,690
WECC_SF	CA	--	2,481	114,703	999	--	--
WECC_SNV	NV	--	--	--	--	--	201,386
WECC_UT	UT	--	3,040	1,896,010	751,291	521,256	275,303
WECC_WY	NE	--	--	110,382	--	--	--
	SD	--	437,434	47,535	--	--	--
	WY	--	1,828,509	3,173,479	--	--	--

Table 4-27 Solar Thermal Regional Potential Capacity (MW) in EPA Base Case v.5.13

Model Region	State	Class				
		1	2	3	4	5
FRCC	FL	95,433	--	--	--	--
ERC_REST	TX	2,115,870	740	--	--	--
ERC_WEST	TX	2,659,629	1,949,748	4,854	--	--
MIS_MAPP	MT	298,407	--	--	--	--
	ND	23,728	--	--	--	--
	SD	834,490	--	--	--	--
S_SOU	AL	41	--	--	--	--
	FL	1,740	--	--	--	--
S_VACA	SC	322	--	--	--	--
SPP_N	KS	3,918,845	74,124	--	--	--
SPP_NEBR	NE	2,195,753	--	--	--	--
SPP_SPS	NM	--	1,448,536	957	--	--
	OK	187,119	215,536	--	--	--
	TX	411,642	1,842,654	--	--	--
SPP_WEST	OK	2,119,578	--	--	--	--
WEC_CALN	CA	1,040,697	223,718	24	--	--
WEC_LADW	CA	566	8,894	9,262	12,719	48,426
WEC_SDGE	CA	1,755	5,221	4,542	10,439	1,001
WECC_AZ	AZ	--	43,388	420,953	1,953,964	1,203,911
WECC_CO	CO	1,634,219	1,546,981	110,412	99,734	2,319
WECC_ID	ID	1,351,218	73,561	--	--	--
WECC_IID	CA	1,292	24,647	42,366	121,604	34,391
WECC_MT	MT	544,703	--	--	--	--
WECC_NM	NM	26,098	991,156	1,051,211	1,072,218	325,541
	TX	--	64,109	225,279	3,306	--
WECC_NNV	NV	213,922	1,493,428	209,881	208,912	448,126
WECC_PNW	CA	89,511	135,681	--	--	--
	ID	262	--	--	--	--
	OR	1,097,342	46,192	--	--	--
	WA	436,316	--	--	--	--
WECC_SCE	CA	307,385	74,751	65,694	130,995	512,927
WECC_SF	CA	80,914	450	--	--	--
WECC_SNV	NV	--	7,080	4,996	25,427	49,166
WECC_UT	UT	571,368	1,056,308	114,414	64,245	1,491
WECC_WY	NE	68,643	--	--	--	--
	SD	191,888	--	--	--	--
	WY	1,976,069	102,883	--	--	--

Generation profiles: Like wind, solar is an intermittent renewal technology. Since it can only be dispatched when the sun shines, not on a strictly economic basis, it is represented in EPA Base Case v.5.13 with generation profiles which specify hourly generation patterns for typical winter and summer days in each eligible region. The generation profiles were prepared with data from NREL which provided separate winter and summer generation profiles for solar thermal and photovoltaic in each eligible IPM region. As an illustrative example, Excerpt of Table 4-28 shows the solar thermal and solar photovoltaic winter and summer generation profiles in model region WECC_AZ.

Excerpt of Table 4-28 Representative Solar Generation Profiles in EPA Base v.5.13

Illustrative Hourly Solar Generation Profile (kWh of Generation per MW of Electricity)
The complete data set in spreadsheet format can be downloaded via the link found at
www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Winter Hour	Solar Thermal	Solar Photovoltaic
01	0	0
02	0	0
03	0	0
04	0	0
05	0	0
06	0	446
07	70	446
08	481	446
09	869	446
10	937	446
11	856	446
12	819	446
13	832	552
14	909	552
15	987	552
16	761	552
17	245	64
18	2	64
19	0	64
20	0	64
21	0	64
22	0	0
23	0	0
24	0	0
Winter Average	**324**	**236**

Summer Hour	Solar Thermal	Solar Photovoltaic
01	0	3
02	0	3
03	0	3
04	0	3
05	0	3
06	4	574
07	702	574
08	1348	574
09	1446	574
10	1468	574
11	1418	574
12	1383	574
13	1317	600
14	1295	600
15	1261	600
16	1212	600
17	962	155
18	273	155
19	0	155
20	0	155
21	0	155
22	0	3
23	0	3
24	0	3
Summer Average	**587**	**301**

Note:
Based on model region WECC_AZ.
This is an example of the solar data used in EPA Base Case v.5.13

Reserve margin contribution:

Table 4-29 presents the annual average capacity factors (CFs) and reserve margin contributions by model region for new solar thermal and photovoltaic units in EPA Base Case v.5.13. The state specific capacity factors included in this table are from NREL and the associated reserve margin contribution estimates are based on AEO 2012 projections. NREL is the source for capacity factors; AEO 2012 Reference Case outputs are used to develop a ratio of capacity factors to reserve contribution.

Table 4-29 Solar Photovoltaic Reserve Margin Contribution and Average Capacity Factor by State and Solar Thermal Reserve Margin Contribution and Average Capacity Factor by Class

	Solar Photovoltaic	
State	Average Capacity Factor	Reserve Margin Contribution
Alabama	20%	23%
Alaska	11%	12%
Arizona	26%	30%
Arkansas	21%	24%
California	25%	29%
Colorado	26%	30%
Connecticut	18%	21%
Delaware	19%	21%
Florida	21%	24%
Georgia	20%	23%
Hawaii	21%	24%
Idaho	22%	25%
Illinois	19%	21%
Indiana	18%	21%
Iowa	20%	23%
Kansas	24%	27%
Kentucky	19%	21%
Louisiana	20%	22%
Maine	19%	22%
Maryland	18%	20%
Massachusetts	18%	21%
Michigan	17%	20%
Minnesota	19%	22%
Mississippi	20%	22%
Missouri	19%	22%
Montana	21%	24%
Nebraska	22%	25%
Nevada	26%	30%
New Hampshire	18%	21%
New Jersey	20%	23%
New Mexico	26%	30%
New York	18%	21%
North Carolina	21%	23%
North Dakota	20%	23%
Ohio	17%	20%
Oklahoma	22%	25%
Oregon	23%	26%
Pennsylvania	18%	20%
Rhode Island	18%	20%
South Carolina	20%	23%
South Dakota	21%	24%
Tennessee	20%	23%
Texas	22%	25%
Utah	25%	28%
Vermont	18%	20%
Virginia	20%	23%
Washington	20%	23%
West Virginia	17%	20%
Wisconsin	18%	21%
Wyoming	23%	26%

	Solar Thermal	
Solar Class	Average Capacity Factor	Reserve Margin Contribution
1	32%	39%
2	39%	49%
3	43%	53%
4	43%	54%
5	45%	56%

Geothermal Generation

Geothermal Resource Potential: Ten model regions in EPA Base Case v.5.13 have geothermal potential. The potential capacity in each of these regions is shown in Table 4-30. The values are based on AEO 2013 data.

Table 4-30 Regional Assumptions on Potential Geothermal Electric Capacity

IPM Model Region	Capacity (MW)
WEC_CALN	191
WEC_LADW	83
WECC_AZ	70
WECC_IID	5,058
WECC_NM	292
WECC_NNV	820
WECC_PNW	1,069
WECC_SCE	621
WECC_SF	579
WECC_UT	127
Total	**8,910**

Notes:
This data is a summary of the geothermal data used in EPA Base Case v.5.13.

Cost Calculation: EPA Base Case v.5.13 does not contain a single capital cost, but multiple geographically-dependent capital costs for geothermal generation. The assumptions for geothermal were developed using AEO 2013 cost and performance estimates for 100 known sites. Both dual flash and binary cycle technologies[23] were represented. In EPA Base Case v.5.13 the 100 sites were aggregated into 62 different options based on geographic location and cost and performance characteristics of geothermal sites in each of the ten eligible IPM regions where geothermal generation opportunities exist. Table 4-31 shows the potential geothermal capacity and cost characteristics for applicable model regions.

Table 4-31 Potential Geothermal Capacity and Cost Characteristics by Model Region

IPM Region	Capacity (MW)	Capital Cost (2011$)	FO&M (2011$/kW-yr)
WEC_CALN	5	24,731	822
	6	20,629	920
	6	29,144	791
	9	20,017	572
	11	14,841	493
	13	17,615	487
	16	5,051	221
	16	10,073	352
	19	11,692	348
	29	4,495	161
	29	7,613	315
	32	9,122	282
WEC_LADW	10	10,361	324
	73	7,200	196

[23] In dual flash systems, high temperature water (above 400°F) is sprayed into a tank held at a much lower pressure than the fluid. This causes some of the fluid to “flash,” i.e., rapidly vaporize to steam. The steam is used to drive a turbine, which, in turn, drives a generator. In the binary cycle technology, moderate temperature water (less than 400°F) vaporizes a secondary, working fluid which drives a turbine and generator. Due to its use of more plentiful, lower temperature geothermal fluids, these systems tend to be most cost effective and are expected to be the most prevalent future geothermal technology.

IPM Region	Capacity (MW)	Capital Cost (2011$)	FO&M (2011$/kW-yr)
WECC_AZ	26	29,114	1,001
	44	27,769	652
WECC_IID	10	14,320	434
	19	9,217	351
	38	11,395	360
	72	4,999	203
	84	8,041	230
	88	6,930	244
	128	8,349	234
	135	4,082	139
	347	3,533	116
	359	2,735	96
	1,866	7,447	118
	1,912	6,581	104
WECC_NM	9	23,780	756
	11	28,310	714
	24	18,793	481
	62	6,998	197
	186	4,016	103
WECC_NNV	66	3,366	142
	78	2,602	119
	93	4,080	139
	152	4,387	194
	431	5,247	187
WECC_PNW	9	24,402	986
	18	24,198	653
	19	17,474	535
	36	15,350	490
	38	20,609	620
	81	9,215	252
	101	7,760	237
	113	3,481	119
	124	2,654	110
	264	4,408	126
	266	4,074	93
WECC_SCE	7	19,885	705
	8	23,338	643
	11	16,931	553
	32	19,802	586
	274	3,091	119
	289	2,196	113
WECC_SF	14	24,018	775
	17	28,523	737
	35	12,225	417
	240	4,495	136
	273	2,713	115
WECC_UT	52	2,684	132
	75	4,049	147

Landfill Gas Electricity Generation

Landfill Gas Resource Potential: Estimates of potential electric capacity from landfill gas are based on the AEO 2012 inventory. EPA Base Case v.5.13 represents three categories of potential landfill gas units; "high", "low", and "very low". The categories refer to the amount and rate of methane production from the existing landfill site. Table 4-32 summarizes potential electric capacity from landfill gas used in EPA Base Case v.5.13.

There are several things to note about Table 4-32. The AEO 2012 NEMS region level estimates of the potential electric capacity from new landfill gas units are disaggregated to IPM regions based on electricity demand. The limits listed in Table 4-32 apply to the IPM regions indicated in column 1. In EPA Base Case v.5.13 the new landfill gas electric capacity in the corresponding IPM regions shown in column 1 cannot exceed the limits shown in columns 3-5. As noted earlier, the capacity limits for three categories of potential landfill gas units are distinguished in this table based on the rate of methane production at three categories of landfill sites: LGHI = high rate of landfill gas production, LGLo = low rate of landfill gas production, and LGLVo = very low rate of landfill gas production. The values shown in Table 4-32 represent an upper bound on the amount of new landfill capacity that can be added in each of the indicated model regions and states for each of the three landfill categories.

The cost and performance assumptions for adding new capacity in each of the three landfill categories are presented in

Table 4-16.

Table 4-32 Regional Assumptions on Potential Electric Capacity from New Landfill Gas Units (MW)

IPM Region	State	Class		
		LGHI	LGLo	LGLVo
ERC_REST	TX	12	19	296
ERC_WEST	TX	1	1	23
FRCC	FL	16	24	159
MAP_WAUE	MN	0	0	3
	MT	0	0	0
	ND	0	1	5
	SD	0	2	9
MIS_IA	IA	0	3	16
	MN	0	0	0
MIS_IL	IL	12	18	99
MIS_INKY	IN	9	14	103
	KY	0	1	7
MIS_LMI	MI	7	11	97
MIS_MAPP	MT	0	0	0
	ND	0	0	4
	SD	0	0	2
MIS_MIDA	IL	0	0	0
	IA	0	5	23
MIS_MNWI	MI	0	0	0
	MN	1	13	59
	SD	0	0	2
	WI	0	2	9
MIS_MO	IA	0	0	0
	MO	10	15	83
MIS_WUMS	MI	0	1	6
	WI	10	17	99
NENG_CT	CT	6	9	14
NENG_ME	ME	2	3	4
NENGREST	MA	11	17	25
	NH	2	3	5
	RI	1	2	4
	VT	1	1	2
NY_Z_A&B	NY	5	8	19
NY_Z_C&E	NY	5	8	17
NY_Z_D	NY	1	2	4
NY_Z_F	NY	2	3	8
NY_Z_G-I	NY	4	6	14
NY_Z_J	NY	13	20	43
NY_Z_K	NY	5	8	17
PJM_AP	MD	0	1	7
	PA	3	4	33
	VA	0	0	4
	WV	1	1	12
PJM_ATSI	OH	7	11	77

IPM Region	State	Class		
		LGHI	LGLo	LGLVo
	PA	0	0	6
PJM_COMD	IL	11	17	122
PJM_Dom	NC	0	0	2
	VA	3	5	46
PJM_EMAC	DE	1	1	9
	MD	0	1	7
	NJ	12	18	92
	PA	6	10	52
	VA	0	0	0
PJM_PENE	PA	2	3	19
PJM_SMAC	MD	8	12	65
	DC	1	1	8
PJM_West	IN	3	5	37
	KY	1	2	14
	MI	0	0	6
	OH	12	18	133
	TN	0	0	0
	VA	2	3	26
	WV	2	3	23
PJM_WMAC	PA	8	12	64
S_C_KY	KY	2	3	27
	OH	0	0	0
	VA	0	0	0
S_C_TVA	AL	1	1	13
	GA	0	0	4
	KY	0	0	8
	MS	0	1	10
	NC	0	0	2
	TN	6	8	77
	VA	0	0	0
S_D_AMSO	LA	0	1	12
S_D_N_AR	AR	0	1	11
	MO	0	0	4
S_D_REST	AR	0	0	1
	LA	0	1	9
	MS	0	1	9
S_D_WOTA	LA	0	0	2
	TX	0	1	9
S_SOU	AL	2	3	30
	FL	0	0	8
	GA	6	8	77
	MS	0	0	7
S_VACA	GA	0	0	1
	NC	5	8	73
	SC	2	4	37
SPP_N	KS	0	0	36
	MO	0	0	28
SPP_NEBR	NE	0	6	26

IPM Region	State	Class LGHI	LGLo	LGLVo
SPP_SE	LA	0	0	11
SPP_SPS	NM	0	0	5
	OK	0	0	0
	TX	0	0	17
SPP_WEST	AR	0	0	24
	LA	0	0	4
	MO	0	0	0
	OK	1	1	59
	TX	0	0	5
WEC_CALN	CA	64	97	306
WEC_LADW	CA	14	22	70
WEC_SDGE	CA	11	17	55
WECC_AZ	AZ	0	0	40
WECC_CO	CO	0	0	27
WECC_ID	ID	2	3	15
WECC_IID	CA	0	0	0
WECC_MT	MT	1	1	7
WECC_NM	NM	0	0	6
	TX	0	0	2
WECC_NNV	NV	1	1	8
WECC_PNW	CA	0	0	0
	ID	0	0	3
	OR	5	8	41
	WA	10	15	73
WECC_SCE	CA	61	92	291
WECC_SF	CA	3	4	15
WECC_SNV	NV	0	0	9
WECC_UT	UT	3	5	26
WECC_WY	NE	0	0	0
	SD	0	0	1
	WY	0	0	5

4.5 Nuclear Units

4.5.1 Existing Nuclear Units

Population, Plant Location, and Unit Configuration: To provide maximum granularity in forecasting the behavior of existing nuclear units, all 104 nuclear units in EPA Base Case v.5.13 are represented by separate model plants. As noted in Table 4-7 the 104 nuclear units include 100 currently operating units plus Watts Bar Nuclear Plant (Unit 2), Vogtle (Units 3&4), and V C Summer (Units 2&3), which are scheduled to come online during 2015 – 2018. All are listed in Table 4-34. The population characteristics, plant location, and unit configuration data in NEEDS v.5.13 were obtained primarily from EIA Form 860 and AEO 2013.

Capacity: Nuclear units are baseload power plants with high fixed (capital and fixed O&M) costs and low variable (fuel and variable O&M) costs. Due to their low VOM and fuel costs, nuclear units are run to the maximum extent possible, i.e., up to their availability. Consequently, a nuclear unit's capacity factor is equivalent to its availability. Thus, EPA Base Case v.5.13 uses capacity factor assumptions to define the upper bound on generation from nuclear units. Nuclear capacity factor assumptions in EPA Base Case v.5.13 are based on an Annual Energy Outlook projection algorithm. The nuclear capacity factor projection algorithm is described below:

- For each reactor, the capacity factor over time is dependent on the age of the reactor.
- Capacity factors increase initially due to learning, and decrease in the later years due to aging.
- For individual reactors, vintage classifications (older and newer) are used.
- For the older vintage (start before 1982) nuclear power plants, the performance peaks at 25 years:
  - Before 25 years: Performance increases by 0.5 percentage point per year;
  - 25-60 years: Performance remains flat; and
- For the newer vintage (start in or after 1982) nuclear power plants, the performance peaks at 30 years:
  - Before 30 years: Performance increases by 0.7 percentage points per year;
  - 30-60 years: Performance remains flat; and
- The maximum capacity factor is assumed to be 90 percent. That is, any given reactor is not allowed to grow to a capacity factor higher than 90 percent. However, if a unit began with a capacity factor above 90 percent, it is allowed to retain that capacity factor. Given that some units' historical capacity factors are above 90 percent, the projected capacity factors range from 60 percent to 96 percent.

Cost and Performance: Unlike non-nuclear existing conventional units discussed in section 4.2.7, emission rates are not needed for nuclear units, since there are no SO_2, NO_x, CO_2, or mercury emissions from nuclear units.

As with other generating resources, EPA Base Case v.5.13 uses variable operation and maintenance (VOM) costs and fixed operation and maintenance (FOM) costs to characterize the cost of operating nuclear units. The heat rate, FOM, and VOM values from AEO 2013, which were used to characterize the cost and performance of existing nuclear units in EPA Base Case v.5.13 are shown in Table 4-34.

EPA Base Case v.5.13 also incorporates the planned nuclear capacity uprates sourced from AEO 2013 and EPA research. These are shown in Table 4-33**.**

Table 4-33 Nuclear Upratings (MW) as Incorporated in EPA Base Case v.5.13

Name	Plant ID	Unit ID	Year	Change in MWs
Fort Calhoun	2289	1	2017	75
McGuire	6038	1	2013	18.7
McGuire	6038	2	2013	18.7

4.5.2 Potential Nuclear Units

The cost and performance assumptions for nuclear potential units that the model has the option to build in EPA Base Case v.5.13 are shown in Table 4-13 above. The cost assumptions are from AEO 2013.

Table 4-34 Characteristics of Existing Nuclear Units

Region	State	Plant Name	Unique ID	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2011$ /kW-yr)	VOM (2011 mills/kWh)
ERC_REST	Texas	Comanche Peak	6145_1	1990	1,205	10,460	182.1	0.18
		Comanche Peak	6145_2	1993	1,195	10,460	182.1	0.18
		South Texas Project	6251_1	1988	1,280	10,460	199.2	0.18
		South Texas Project	6251_2	1989	1,280	10,460	199.2	0.18

Region	State	Plant Name	Unique ID	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2011$ /kW-yr)	VOM (2011 mills/kWh)
FRCC	Florida	St Lucie	6045_1	1976	961	10,460	160.8	0.15
		St Lucie	6045_2	1983	949	10,460	160.8	0.15
		Turkey Point	621_3	1972	802	10,460	227.2	0.21
		Turkey Point	621_4	1973	802	10,460	227.2	0.21
MIS_IA	Iowa	Duane Arnold Energy Center	1060_1	1975	601	10,460	187.5	0.18
MIS_IL	Illinois	Clinton Power Station	204_1	1987	1,065	10,460	199.2	0.18
MIS_LMI	Michigan	Fermi	1729_2	1988	1,085	10,460	178.8	0.18
		Palisades	1715_1	1972	803	10,460	200.3	0.18
MIS_MNWI	Minnesota	Monticello	1922_1	1971	633	10,460	251.6	0.25
		Prairie Island	1925_1	1974	594	10,427	173.8	0.88
		Prairie Island	1925_2	1974	592	10,427	173.8	0.89
MIS_MO	Missouri	Callaway	6153_1	1984	1,190	10,460	124.4	0.12
MIS_WUMS	Wisconsin	Point Beach Nuclear Plant	4046_1	1970	591	10,460	203.6	0.18
		Point Beach Nuclear Plant	4046_2	1972	593	10,460	203.6	0.18
NENG_CT	Connecticut	Millstone	566_2	1975	869	10,460	194.4	0.19
		Millstone	566_3	1986	1,233	10,460	180.2	0.19
NENGREST	Massachusetts	Pilgrim Nuclear Power Station	1590_1	1972	685	10,460	225.7	0.18
	New Hampshire	Seabrook	6115_1	1990	1,246	10,460	199.2	0.19
NY_Z_A&B	New York	R E Ginna Nuclear Power Plant	6122_1	1970	581	10,460	216.8	0.18
NY_Z_C&E	New York	James A Fitzpatrick	6110_1	1976	828	10,460	216.1	0.18
		Nine Mile Point Nuclear Station	2589_1	1969	630	10,460	204.2	0.18
		Nine Mile Point Nuclear Station	2589_2	1987	1,143	10,460	199.2	0.18
NY_Z_G-I	New York	Indian Point 2	2497_2	1973	1,006	10,460	207.2	0.18
		Indian Point 3	8907_3	1976	1,031	10,460	194.9	0.18
PJM_ATSI	Ohio	Davis Besse	6149_1	1977	894	10,460	180.2	0.20
		Perry	6020_1	1987	1,256	10,460	186.6	0.63
PJM_COMD	Illinois	Braidwood Generation Station	6022_1	1988	1,178	10,460	194.1	0.18
		Braidwood Generation Station	6022_2	1988	1,152	10,460	194.1	0.18
		Byron Generating Station	6023_1	1985	1,164	10,460	194.3	0.17
		Byron Generating Station	6023_2	1987	1,136	10,460	194.3	0.17
		Dresden Generating Station	869_2	1970	867	10,460	212.4	0.17
		Dresden Generating Station	869_3	1971	867	10,460	212.4	0.18
		LaSalle Generating Station	6026_1	1984	1,118	10,427	169.1	0.80
		LaSalle Generating Station	6026_2	1984	1,120	10,427	169.1	0.82
		Quad Cities Generating Station	880_1	1972	908	10,460	197.0	0.17
		Quad Cities Generating Station	880_2	1972	911	10,460	197.0	0.18
PJM_Dom	Virginia	North Anna	6168_1	1978	943	10,460	114.1	0.10
		North Anna	6168_2	1980	943	10,460	114.1	0.11
		Surry	3806_1	1972	838	10,427	129.2	0.62
		Surry	3806_2	1973	838	10,427	129.2	0.61
PJM_EMAC	New Jersey	Oyster Creek	2388_1	1969	614	10,460	225.4	0.19
		PSEG Hope Creek Generating Station	6118_1	1986	1,173	10,460	180.2	0.18
		PSEG Salem Generating Station	2410_1	1977	1,166	10,460	199.2	0.18
		PSEG Salem Generating Station	2410_2	1981	1,160	10,460	199.2	0.18
	Pennsylvania	Limerick	6105_1	1986	1,146	10,460	199.9	0.17
		Limerick	6105_2	1990	1,150	10,460	199.9	0.17
		Peach Bottom	3166_2	1974	1,122	10,460	198.7	0.18
		Peach Bottom	3166_3	1974	1,122	10,460	198.7	0.17
PJM_SMAC	Maryland	Calvert Cliffs Nuclear Power Plant	6011_1	1975	855	10,460	199.2	0.18
		Calvert Cliffs Nuclear Power Plant	6011_2	1977	850	10,460	199.2	0.17
PJM_West	Michigan	Donald C Cook	6000_1	1975	1,009	10,460	150.6	0.24
		Donald C Cook	6000_2	1978	1,060	10,460	150.6	0.14
	Pennsylvania	Beaver Valley	6040_1	1976	921	10,460	229.6	0.56
		Beaver Valley	6040_2	1987	914	10,460	229.6	0.57
PJM_WMAC	Pennsylvania	PPL Susquehanna	6103_1	1983	1,260	10,460	186.3	0.20

Region	State	Plant Name	Unique ID	On-Line Year	Capacity (MW)	Heat Rate (Btu/kWh)	FOM (2011$ /kW-yr)	VOM (2011 mills/kWh)
		PPL Susquehanna	6103_2	1985	1,260	10,460	186.3	0.18
		Three Mile Island	8011_1	1974	805	10,460	194.3	0.18
S_C_TVA	Alabama	Browns Ferry	46_1	1974	1,101	10,460	199.2	0.19
		Browns Ferry	46_2	1975	1,104	10,460	199.2	0.19
		Browns Ferry	46_3	1977	1,105	10,460	199.2	0.20
	Tennessee	Sequoyah	6152_1	1981	1,152	10,460	210.3	0.18
		Sequoyah	6152_2	1982	1,126	10,460	210.3	0.18
		Watts Bar Nuclear Plant	7722_1	1996	1,123	10,460	198.0	0.18
		Watts Bar Nuclear Plant	7722_2	2015	1,122	10,460	137.0	2.16
S_D_AMSO	Louisiana	Waterford 3	4270_3	1985	1,159	10,460	180.1	0.13
S_D_N_AR	Arkansas	Arkansas Nuclear One	8055_1	1974	834	10,460	161.7	0.13
		Arkansas Nuclear One	8055_2	1980	989	10,460	161.7	0.12
S_D_REST	Louisiana	River Bend	6462_1	1986	974	10,460	163.2	0.17
	Mississippi	Grand Gulf	6072_1	1985	1,368	10,460	158.2	0.13
S_SOU	Alabama	Joseph M Farley	6001_1	1977	874	10,460	149.5	0.14
		Joseph M Farley	6001_2	1981	860	10,460	149.5	0.14
	Georgia	Edwin I Hatch	6051_1	1975	876	10,460	133.2	0.14
		Edwin I Hatch	6051_2	1979	883	10,460	133.2	0.14
		Vogtle	649_1	1987	1,150	10,460	111.3	0.09
		Vogtle	649_2	1989	1,152	10,460	111.3	0.09
		Vogtle	649_3	2017	1,100	10,400	112.9	2.16
		Vogtle	649_4	2018	1,100	10,400	112.9	2.16
S_VACA	North Carolina	Brunswick	6014_1	1977	938	10,460	155.7	0.14
		Brunswick	6014_2	1975	932	10,460	155.7	0.14
		Harris	6015_1	1987	900	10,460	186.9	0.16
		McGuire	6038_1	1981	1,100	10,460	137.5	0.11
		McGuire	6038_2	1984	1,100	10,460	137.5	0.11
	South Carolina	Catawba	6036_1	1985	1,129	10,460	137.7	0.13
		Catawba	6036_2	1986	1,129	10,460	137.7	0.12
		H B Robinson	3251_2	1971	724	10,460	142.2	0.16
		Oconee	3265_1	1973	846	10,460	137.0	0.13
		Oconee	3265_2	1974	846	10,460	137.0	0.12
		Oconee	3265_3	1974	846	10,460	137.0	0.12
		V C Summer	6127_1	1984	966	10,460	170.6	0.17
		V C Summer	6127_2	2017	1,100	10,400	112.9	2.16
		V C Summer	6127_3	2018	1,100	10,400	112.9	2.16
SPP_N	Kansas	Wolf Creek Generating Station	210_1	1985	1,175	10,460	159.6	0.16
SPP_NEBR	Nebraska	Cooper	8036_1	1974	766	10,460	199.2	0.18
		Fort Calhoun	2289_1	1973	479	10,460	187.2	0.18
WEC_CALN	California	Diablo Canyon	6099_1	1985	1,122	10,460	169.8	0.18
		Diablo Canyon	6099_2	1986	1,118	10,460	169.8	0.18
WECC_AZ	Arizona	Palo Verde	6008_1	1986	1,311	10,460	236.2	0.23
		Palo Verde	6008_2	1986	1,314	10,460	236.2	0.23
		Palo Verde	6008_3	1988	1,312	10,460	236.2	0.23
WECC_PNW	Washington	Columbia Generating Station	371_2	1984	1,097	10,460	202.3	0.19

Excerpt from Table 4-35 Capacity Not Included Based on EIA Form 860 - Existing Units

This is a small excerpt of the data in Excerpt from Table 4-35. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Notes
Hospira Inc	55788	GEN1	Combustion Turbine	New York	1.1	Dropped - Onsite Unit

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Notes
Hospira Inc	55788	GEN2	Combustion Turbine	New York	1.1	Dropped - Onsite Unit
AG Processing Inc	10223	E.C.	Coal Steam	Iowa	8.5	Dropped - Onsite Unit
Oxford Cogeneration Facility	52093	GEN1	Combustion Turbine	California	2.4	Dropped - PLANNED_RETIREMENT_YEAR <=2015
Oxford Cogeneration Facility	52093	GEN2	Combustion Turbine	California	2.4	Dropped - PLANNED_RETIREMENT_YEAR <=2015
South Belridge Cogeneration Facility	50752	GEN1	Combustion Turbine	California	19	Dropped - Onsite Unit
South Belridge Cogeneration Facility	50752	GEN2	Combustion Turbine	California	19	Dropped - Onsite Unit
South Belridge Cogeneration Facility	50752	GEN3	Combustion Turbine	California	19	Dropped - Onsite Unit
Lost Hills Cogeneration Plant	52077	GEN4	Combustion Turbine	California	2.7	Dropped - Onsite Unit
Lost Hills Cogeneration Plant	52077	GEN5	Combustion Turbine	California	2.7	Dropped - Onsite Unit
Lost Hills Cogeneration Plant	52077	GEN6	Combustion Turbine	California	2.7	Dropped - Onsite Unit
AES Hawaii	10673	GEN1	Coal Steam	Hawaii	180	Dropped - in Alaska or in Hawaii
Agrium Kenai Nitrogen Operations	54452	744A	Combustion Turbine	Alaska	2.5	Dropped - Onsite Unit
Agrium Kenai Nitrogen Operations	54452	744B	Combustion Turbine	Alaska	2.5	Dropped - Onsite Unit
Agrium Kenai Nitrogen Operations	54452	744C	Combustion Turbine	Alaska	2.5	Dropped - Onsite Unit
Agrium Kenai Nitrogen Operations	54452	744D	Combustion Turbine	Alaska	2.5	Dropped - Onsite Unit
Agrium Kenai Nitrogen Operations	54452	744E	Combustion Turbine	Alaska	2.5	Dropped - Onsite Unit
Southside Water Reclamation Plant	10339	GEN1	Non-Fossil Waste	New Mexico	2.1	Dropped - Onsite Unit
Southside Water Reclamation Plant	10339	GEN2	Non-Fossil Waste	New Mexico	2.1	Dropped - Onsite Unit
Southside Water Reclamation Plant	10339	GEN3	Non-Fossil Waste	New Mexico	1.1	Dropped - Onsite Unit
Southside Water Reclamation Plant	10339	GEN4	Non-Fossil Waste	New Mexico	1.1	Dropped - Onsite Unit
Martin Dam	16	1	Hydro	Alabama	46.5	Dropped - PLANNED_RETIREMENT_YEAR <=2015
Martin Dam	16	2	Hydro	Alabama	46.5	Dropped - PLANNED_RETIREMENT_YEAR <=2015

Table 4-36 Capacity Not Included Due to Recent Announcements

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
5 in 1 Dam Hydroelectric	10171	GEN1	Hydro	Iowa	0.7	2015
5 in 1 Dam Hydroelectric	10171	GEN2	Hydro	Iowa	0.7	2015
5 in 1 Dam Hydroelectric	10171	GEN3	Hydro	Iowa	0.7	2015
Abilene Energy Center Combustion Turbine	1251	GT1	Combustion Turbine	Kansas	64	2012
ACE Cogeneration Facility	10002	CFB	Coal Steam	California	101	2015
AES Greenidge LLC	2527	6	Coal Steam	New York	108	2012
AES Thames	10675	A	Coal Steam	Connecticut	90	2012
AES Thames	10675	B	Coal Steam	Connecticut	90	2012
AES Westover	2526	13	Coal Steam	New York	84	2012
Albany	2113	3	Combustion Turbine	Missouri	0.6	2015
Alliant SBD 9801 Aegon Martha's Way	56072	01	Combustion Turbine	Iowa	1	2012
Alloy Steam Station	50012	BLR4	Coal Steam	West Virginia	38	2007
Alma	4140	B1	Coal Steam	Wisconsin	17.4	2013
Alma	4140	B2	Coal Steam	Wisconsin	17.4	2013
Alma	4140	B3	Coal Steam	Wisconsin	20.9	2013
Alma	4140	B4	Coal Steam	Wisconsin	48	2015
Alma	4140	B5	Coal Steam	Wisconsin	72	2015
Alvarado Hydro Facility	54242	AHF	Hydro	California	1.4	2015
Animas	2465	4	O/G Steam	New Mexico	16	2015
Arapahoe	465	4	Coal Steam	Colorado	109	2013
Astoria Generating Station	8906	20	O/G Steam	New York	181	2012
B C Cobb	1695	1	O/G Steam	Michigan	62	2015
B C Cobb	1695	2	O/G Steam	Michigan	62	2015
B C Cobb	1695	3	O/G Steam	Michigan	62	2015
B C Cobb	1695	4	Coal Steam	Michigan	156	2015
B C Cobb	1695	5	Coal Steam	Michigan	156	2015
B L England	2378	1	Coal Steam	New Jersey	113	2013
B L England	2378	2	Coal Steam	New Jersey	155	2015
B L England	2378	IC1	Combustion Turbine	New Jersey	2	2015
B L England	2378	IC2	Combustion Turbine	New Jersey	2	2015
B L England	2378	IC3	Combustion Turbine	New Jersey	2	2015
B L England	2378	IC4	Combustion Turbine	New Jersey	2	2015
Balefill LFG Project	55159	UNT1	Landfill Gas	New Jersey	0.1	2010
Balefill LFG Project	55159	UNT2	Landfill Gas	New Jersey	0.1	2010

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
Ben French	3325	1	Coal Steam	South Dakota	21.6	2014
Berlin	6565	3A	Combustion Turbine	Maryland	1.8	2015
Berlin Gorham	54639	GOR1	Hydro	New Hampshire	1.2	2015
Big Sandy	1353	BSU2	Coal Steam	Kentucky	800	2014
Binghamton Cogen	55600	1	Combustion Turbine	New York	42	2012
Biodyne Lyons	55060	001	Landfill Gas	Illinois	0.9	2015
Biodyne Lyons	55060	002	Landfill Gas	Illinois	0.9	2015
Biodyne Lyons	55060	004	Landfill Gas	Illinois	0.9	2015
Biodyne Peoria	55057	001	Landfill Gas	Illinois	0.8	2015
Biodyne Peoria	55057	002	Landfill Gas	Illinois	0.8	2015
Biodyne Peoria	55057	004	Landfill Gas	Illinois	0.8	2015
Biodyne Peoria	55057	005	Landfill Gas	Illinois	0.8	2015
Biodyne Pontiac	55054	1	Landfill Gas	Illinois	4.2	2015
Biodyne Pontiac	55054	3	Landfill Gas	Illinois	4.2	2015
Biodyne Pontiac	55054	GEN2	Landfill Gas	Illinois	4.2	2015
Biron	3971	6	Hydro	Wisconsin	0.4	2015
Bluebonnet	55552	UNT2	Landfill Gas	Texas	1	2015
Bountiful City	3665	2	Combustion Turbine	Utah	1.2	2015
Bountiful City	3665	6	Combustion Turbine	Utah	2.5	2015
Brunot Island	3096	1B	Combustion Turbine	Pennsylvania	15	2011
Brunot Island	3096	1C	Combustion Turbine	Pennsylvania	15	2011
Bryan	3561	3	O/G Steam	Texas	12	2015
Bryan	3561	4	O/G Steam	Texas	22	2015
Bryan	3561	5	O/G Steam	Texas	25	2015
Bryan	3561	6	O/G Steam	Texas	50	2015
Canadys Steam	3280	CAN1	Coal Steam	South Carolina	105	2012
Canadys Steam	3280	CAN2	Coal Steam	South Carolina	115	2013
Canadys Steam	3280	CAN3	Coal Steam	South Carolina	180	2013
Cane Run	1363	4	Coal Steam	Kentucky	155	2015
Cane Run	1363	5	Coal Steam	Kentucky	168	2015
Cane Run	1363	6	Coal Steam	Kentucky	240	2015
Cape Canaveral	609	PCC1	O/G Steam	Florida	396	2010
Cape Canaveral	609	PCC2	O/G Steam	Florida	396	2010
Cape Fear	2708	5	Coal Steam	North Carolina	144	2012
Cape Fear	2708	6	Coal Steam	North Carolina	172	2012
Cape Fear	2708	1B	Combined Cycle	North Carolina	11	2012
Carbon	3644	1	Coal Steam	Utah	67	2015
Carbon	3644	2	Coal Steam	Utah	105	2015
Cedar Station	2380	CED1	Combustion Turbine	New Jersey	44	2015
Cedar Station	2380	CED2	Combustion Turbine	New Jersey	22.3	2015
CES Placerita Power Plant	10677	UNT2	Combined Cycle	California	46	2015
CES Placerita Power Plant	10677	UNT3	Combined Cycle	California	23	2015
Chamois	2169	1	Coal Steam	Missouri	16	2013
Chamois	2169	2	Coal Steam	Missouri	47	2013
Cherokee	469	3	Coal Steam	Colorado	152	2014
Chesapeake	3803	1	Coal Steam	Virginia	111	2014
Chesapeake	3803	2	Coal Steam	Virginia	111	2014
Chesapeake	3803	3	Coal Steam	Virginia	156	2014
Chesapeake	3803	4	Coal Steam	Virginia	217	2014
Chesapeake	3803	7	Combustion Turbine	Virginia	16	2011
Chesapeake	3803	8	Combustion Turbine	Virginia	16	2011
Chesapeake	3803	9	Combustion Turbine	Virginia	16	2011
Chesapeake	3803	10	Combustion Turbine	Virginia	16	2011
Clinch River	3775	3	Coal Steam	Virginia	230	2015
Coal Canyon	226	1	Hydro	California	0.9	2015
Conesville	2840	3	Coal Steam	Ohio	165	2012
Conners Creek	1726	15	O/G Steam	Michigan	58	2011
Conners Creek	1726	16	O/G Steam	Michigan	58	2011
Conners Creek	1726	17	O/G Steam	Michigan	58	2011
Conners Creek	1726	18	O/G Steam	Michigan	58	2011
Crawford	867	7	Coal Steam	Illinois	213	2012

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
Crawford	867	8	Coal Steam	Illinois	319	2012
Crosscut	143	1	O/G Steam	Arizona	7.5	2015
Crosscut	143	2	O/G Steam	Arizona	7.5	2015
Crosscut	143	3	O/G Steam	Arizona	7.5	2015
Crosscut	143	4	O/G Steam	Arizona	2.5	2015
Crosscut	143	5	O/G Steam	Arizona	2.5	2015
Crosscut	143	6	O/G Steam	Arizona	2.5	2015
Crystal River	628	3	Nuclear	Florida	1028	2013
CTV Power Purchase Contract Trust	54300	SX1S	Wind	California	0.1	2015
Cutler	610	PCU5	O/G Steam	Florida	68	2012
Cutler	610	PCU6	O/G Steam	Florida	137	2012
Cytec 1, 2 & 3	56257	CY 1	Combustion Turbine	Connecticut	2	2011
Cytec 1, 2 & 3	56257	CY 2	Combustion Turbine	Connecticut	2	2011
Cytec 1, 2 & 3	56257	CY 3	Combustion Turbine	Connecticut	2	2011
Danskammer Generating Station	2480	1	O/G Steam	New York	66	2013
Danskammer Generating Station	2480	2	O/G Steam	New York	62	2013
Danskammer Generating Station	2480	3	Coal Steam	New York	138	2013
Danskammer Generating Station	2480	4	Coal Steam	New York	237	2013
Danskammer Generating Station	2480	5	Combustion Turbine	New York	2.5	2013
Danskammer Generating Station	2480	6	Combustion Turbine	New York	2.5	2013
DeCordova Power Company LLC	8063	1	O/G Steam	Texas	818	2011
Deepwater	2384	1	O/G Steam	New Jersey	78	2015
Deepwater	2384	8	Coal Steam	New Jersey	81	2015
Dolphus M Grainger	3317	1	Coal Steam	South Carolina	83	2013
Dolphus M Grainger	3317	2	Coal Steam	South Carolina	83	2013
Dunbarton Energy Partners LP	55779	MA1	Landfill Gas	New Hampshire	0.6	2012
Dunbarton Energy Partners LP	55779	MA2	Landfill Gas	New Hampshire	0.6	2012
E F Barrett	2511	7	Combustion Turbine	New York	16.6	2011
Eagle Mountain	3489	1	O/G Steam	Texas	115	2015
Eagle Mountain	3489	2	O/G Steam	Texas	175	2015
Eagle Mountain	3489	3	O/G Steam	Texas	375	2015
Eagle Valley	991	3	Coal Steam	Indiana	40	2015
Eagle Valley	991	4	Coal Steam	Indiana	56	2015
Eagle Valley	991	5	Coal Steam	Indiana	62	2015
East Third Street Power Plant	10367	CB1302	Coal Steam	California	18.7	2012
Edgewater	4050	3	Coal Steam	Wisconsin	70	2015
El Segundo Power	330	3	O/G Steam	California	325	2013
Elrama Power Plant	3098	1	Coal Steam	Pennsylvania	93	2012
Elrama Power Plant	3098	2	Coal Steam	Pennsylvania	93	2012
Elrama Power Plant	3098	3	Coal Steam	Pennsylvania	103	2012
Elrama Power Plant	3098	4	Coal Steam	Pennsylvania	171	2012
FirstEnergy Albright	3942	1	Coal Steam	West Virginia	73	2012
FirstEnergy Albright	3942	2	Coal Steam	West Virginia	73	2012
FirstEnergy Albright	3942	3	Coal Steam	West Virginia	137	2012
FirstEnergy Armstrong Power Station	3178	1	Coal Steam	Pennsylvania	172	2012
FirstEnergy Armstrong Power Station	3178	2	Coal Steam	Pennsylvania	172	2012
FirstEnergy Ashtabula	2835	7	Coal Steam	Ohio	244	2015
FirstEnergy Bay Shore	2878	2	Coal Steam	Ohio	138	2012
FirstEnergy Bay Shore	2878	3	Coal Steam	Ohio	142	2012
FirstEnergy Bay Shore	2878	4	Coal Steam	Ohio	215	2012
FirstEnergy Eastlake	2837	1	Coal Steam	Ohio	132	2015
FirstEnergy Eastlake	2837	2	Coal Steam	Ohio	132	2015
FirstEnergy Eastlake	2837	3	Coal Steam	Ohio	132	2015
FirstEnergy Eastlake	2837	4	Coal Steam	Ohio	240	2012
FirstEnergy Eastlake	2837	5	Coal Steam	Ohio	597	2012
FirstEnergy Lake Shore	2838	18	Coal Steam	Ohio	245	2015
FirstEnergy Mitchell Power Station	3181	1	O/G Steam	Pennsylvania	27	2013
FirstEnergy Mitchell Power Station	3181	2	O/G Steam	Pennsylvania	27	2013
FirstEnergy Mitchell Power Station	3181	3	O/G Steam	Pennsylvania	27	2013
FirstEnergy Mitchell Power Station	3181	33	Coal Steam	Pennsylvania	278	2013
FirstEnergy R E Burger	2864	5	Coal Steam	Ohio	47	2011

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
FirstEnergy R E Burger	2864	6	Coal Steam	Ohio	47	2011
FirstEnergy R Paul Smith Power Station	1570	9	Coal Steam	Maryland	28	2012
FirstEnergy R Paul Smith Power Station	1570	11	Coal Steam	Maryland	87	2012
FirstEnergy Rivesville	3945	7	Coal Steam	West Virginia	37	2012
FirstEnergy Rivesville	3945	8	Coal Steam	West Virginia	88	2012
FirstEnergy Willow Island	3946	1	Coal Steam	West Virginia	54	2012
FirstEnergy Willow Island	3946	2	Coal Steam	West Virginia	181	2012
Fisk Street	886	19	Coal Steam	Illinois	326	2012
Frank E Ratts	1043	1SG1	Coal Steam	Indiana	120	2015
Frank E Ratts	1043	2SG1	Coal Steam	Indiana	121	2015
G W Ivey	665	18	Combustion Turbine	Florida	8	2015
Gaylord	1706	5	Combustion Turbine	Michigan	14	2015
George Neal North	1091	1	Coal Steam	Iowa	137	2015
George Neal North	1091	2	Coal Steam	Iowa	301	2015
Geysers Unit 5-20	286	U10	Geothermal	California	30	2015
Geysers Unit 5-20	286	U9	Geothermal	California	30	2015
Gilbert	2393	8	Combined Cycle	New Jersey	90	2015
Gilbert	2393	C1	Combustion Turbine	New Jersey	23	2015
Gilbert	2393	C2	Combustion Turbine	New Jersey	25	2015
Gilbert	2393	C3	Combustion Turbine	New Jersey	25	2015
Gilbert	2393	C4	Combustion Turbine	New Jersey	25	2015
Glen Gardner	8227	1	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	2	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	3	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	4	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	5	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	6	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	7	Combustion Turbine	New Jersey	20	2015
Glen Gardner	8227	8	Combustion Turbine	New Jersey	20	2015
Glen Lyn	3776	6	Coal Steam	Virginia	235	2015
Glen Lyn	3776	51	Coal Steam	Virginia	45	2015
Glen Lyn	3776	52	Coal Steam	Virginia	45	2015
Green River	1357	4	Coal Steam	Kentucky	68	2015
Green River	1357	5	Coal Steam	Kentucky	95	2015
Greenport	2681	2	Combustion Turbine	New York	1.5	2015
Greenport	2681	7	Combustion Turbine	New York	1.6	2015
Groveton Paper Board	56140	TUR1	Combustion Turbine	New Hampshire	4	2015
Groveton Paper Board	56140	TUR2	Combustion Turbine	New Hampshire	4	2015
H B Robinson	3251	1	Coal Steam	South Carolina	177	2012
Hanford	10373	CB1302	Coal Steam	California	25	2012
Hansel	672	21	Combined Cycle	Florida	30	2012
Hansel	672	22	Combined Cycle	Florida	8	2012
Hansel	672	23	Combined Cycle	Florida	8	2012
Harbor Beach	1731	1	Coal Steam	Michigan	95	2015
Harllee Branch	709	3	Coal Steam	Georgia	509	2015
Harllee Branch	709	4	Coal Steam	Georgia	507	2015
Harvey Couch	169	1	O/G Steam	Arkansas	12	2015
Hatfields Ferry Power Station	3179	1	Coal Steam	Pennsylvania	506	2013
Hatfields Ferry Power Station	3179	2	Coal Steam	Pennsylvania	506	2013
Hatfields Ferry Power Station	3179	3	Coal Steam	Pennsylvania	506	2013
Herington	1283	1	Combustion Turbine	Kansas	1.6	2012
Herington	1283	2	Combustion Turbine	Kansas	1	2012
Herington	1283	3	Combustion Turbine	Kansas	3.1	2012
Herington	1283	5	Combustion Turbine	Kansas	0.9	2012
Herkimer	52057	01	Hydro	New York	0.1	2015
Herkimer	52057	02	Hydro	New York	0.1	2015
Herkimer	52057	03	Hydro	New York	0.1	2015
Herkimer	52057	04	Hydro	New York	0.1	2015
High Street Station	1670	3	Combustion Turbine	Massachusetts	0.7	2015
HMDC Kingsland Landfill	55604	UNT1	Landfill Gas	New Jersey	0.1	2010
HMDC Kingsland Landfill	55604	UNT2	Landfill Gas	New Jersey	0.1	2010

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
HMDC Kingsland Landfill	55604	UNT3	Landfill Gas	New Jersey	0.1	2010
Holcomb Rock	56314	HG2	Hydro	Virginia	0.2	2015
Howard Down	2434	10	O/G Steam	New Jersey	23	2010
Hutsonville	863	05	Coal Steam	Illinois	75	2011
Hutsonville	863	06	Coal Steam	Illinois	76	2011
Indian River Generating Station	594	1	Coal Steam	Delaware	89	2011
Indian River Generating Station	594	2	Coal Steam	Delaware	89	2010
Ivy River Hydro	50890	GEN1	Hydro	North Carolina	0.2	2015
Ivy River Hydro	50890	GEN2	Hydro	North Carolina	0.2	2015
Ivy River Hydro	50890	GEN3	Hydro	North Carolina	0.2	2015
Ivy River Hydro	50890	GEN4	Hydro	North Carolina	0.2	2015
Ivy River Hydro	50890	GEN5	Hydro	North Carolina	0.2	2015
Ivy River Hydro	50890	GEN6	Hydro	North Carolina	0.2	2015
J C Weadock	1720	7	Coal Steam	Michigan	155	2015
J C Weadock	1720	8	Coal Steam	Michigan	151	2015
J R Whiting	1723	1	Coal Steam	Michigan	97	2015
J R Whiting	1723	2	Coal Steam	Michigan	101	2015
J R Whiting	1723	3	Coal Steam	Michigan	124	2015
Jefferies	3319	3	Coal Steam	South Carolina	152	2012
Jefferies	3319	4	Coal Steam	South Carolina	150	2012
John Sevier	3405	3	Coal Steam	Tennessee	176	2015
John Sevier	3405	4	Coal Steam	Tennessee	176	2015
Johnsonville	3406	1	Coal Steam	Tennessee	107	2015
Johnsonville	3406	2	Coal Steam	Tennessee	107	2015
Johnsonville	3406	3	Coal Steam	Tennessee	107	2015
Johnsonville	3406	4	Coal Steam	Tennessee	107	2015
Kammer	3947	1	Coal Steam	West Virginia	200	2015
Kammer	3947	2	Coal Steam	West Virginia	200	2015
Kammer	3947	3	Coal Steam	West Virginia	200	2015
Kanawha River	3936	1	Coal Steam	West Virginia	200	2015
Kanawha River	3936	2	Coal Steam	West Virginia	200	2015
Kaw	1294	1	O/G Steam	Kansas	42	2013
Kaw	1294	2	O/G Steam	Kansas	42	2013
Kaw	1294	3	O/G Steam	Kansas	56	2013
Kewaunee	8024	1	Nuclear	Wisconsin	566	2013
Kitty Hawk	2757	GT1	Combustion Turbine	North Carolina	16	2011
Kitty Hawk	2757	GT2	Combustion Turbine	North Carolina	15	2011
Kraft	733	3	Coal Steam	Georgia	101	2015
L V Sutton	2713	1	Coal Steam	North Carolina	97	2013
L V Sutton	2713	2	Coal Steam	North Carolina	104	2013
L V Sutton	2713	3	Coal Steam	North Carolina	389	2013
Lake Creek	3502	D1	Combustion Turbine	Texas	2	2009
Lake Creek	3502	D2	Combustion Turbine	Texas	2	2009
Lansing	1047	2	Coal Steam	Iowa	8.4	2012
Lansing	1047	3	Coal Steam	Iowa	21	2014
Lee	2709	GT1	Combustion Turbine	North Carolina	12	2012
Lee	2709	GT2	Combustion Turbine	North Carolina	21	2012
Lee	2709	GT3	Combustion Turbine	North Carolina	21	2012
Lee	2709	GT4	Combustion Turbine	North Carolina	21	2012
Lilliwaup Falls Generating	50700	4735	Hydro	Washington	0.2	2015
Lilliwaup Falls Generating	50700	4736	Hydro	Washington	0.2	2015
Lilliwaup Falls Generating	50700	4737	Hydro	Washington	0.2	2015
Lilliwaup Falls Generating	50700	4738	Hydro	Washington	0.2	2015
Lilliwaup Falls Generating	50700	4739	Hydro	Washington	0.2	2015
Lilliwaup Falls Generating	50700	4740	Hydro	Washington	0.2	2015
Lilliwaup Falls Generating	50700	4741	Hydro	Washington	0.2	2015
Loveridge Road Power Plant	10368	CB1302	Coal Steam	California	18	2012
Maine Energy Recovery	10338	ABLR	Municipal Solid Waste	Maine	9	2012
Maine Energy Recovery	10338	BBLR	Municipal Solid Waste	Maine	9	2012
Marysville	1732	9	Coal Steam	Michigan	42	2011
Marysville	1732	10	Coal Steam	Michigan	42	2011

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
Marysville	1732	11	Coal Steam	Michigan	42	2011
Marysville	1732	12	Coal Steam	Michigan	42	2011
McIntosh	6124	1	Coal Steam	Georgia	156	2015
Meredosia	864	01	Coal Steam	Illinois	26	2011
Meredosia	864	02	Coal Steam	Illinois	26	2011
Meredosia	864	03	Coal Steam	Illinois	26	2011
Meredosia	864	04	Coal Steam	Illinois	26	2011
Meredosia	864	05	Coal Steam	Illinois	203	2011
Meredosia	864	06	O/G Steam	Illinois	166	2011
Miami Fort	2832	6	Coal Steam	Ohio	163	2015
Middle Station	2382	MID1	Combustion Turbine	New Jersey	19.1	2015
Middle Station	2382	MID2	Combustion Turbine	New Jersey	19.5	2015
Middle Station	2382	MID3	Combustion Turbine	New Jersey	36	2015
Missouri Avenue	2383	MISB	Combustion Turbine	New Jersey	20.5	2015
Missouri Avenue	2383	MISC	Combustion Turbine	New Jersey	20.5	2015
Missouri Avenue	2383	MISD	Combustion Turbine	New Jersey	20.6	2015
Montgomery	8025	1	Combustion Turbine	Minnesota	20.6	2012
Morgan City	1449	1	O/G Steam	Louisiana	5.8	2015
Morgan City	1449	2	O/G Steam	Louisiana	5.8	2015
Morgan Creek	3492	5	O/G Steam	Texas	175	2015
Morgan Creek	3492	6	O/G Steam	Texas	511	2015
Morris Sheppard	3557	1	Hydro	Texas	12	2015
Morris Sheppard	3557	2	Hydro	Texas	12	2015
Muskingum River	2872	1	Coal Steam	Ohio	190	2015
Muskingum River	2872	2	Coal Steam	Ohio	190	2015
Muskingum River	2872	3	Coal Steam	Ohio	205	2015
Muskingum River	2872	4	Coal Steam	Ohio	205	2015
Muskingum River	2872	5	Coal Steam	Ohio	585	2014
Neil Simpson	4150	5	Coal Steam	Wyoming	14.6	2014
Nelson Dewey	4054	1	Coal Steam	Wisconsin	115	2015
Nelson Dewey	4054	2	Coal Steam	Wisconsin	111	2015
Neosho	1243	7	O/G Steam	Kansas	67	2012
New Albany Energy Facility	55080	1	Combustion Turbine	Mississippi	60	2015
New Albany Energy Facility	55080	2	Combustion Turbine	Mississippi	60	2015
New Albany Energy Facility	55080	3	Combustion Turbine	Mississippi	60	2015
New Albany Energy Facility	55080	4	Combustion Turbine	Mississippi	60	2015
New Albany Energy Facility	55080	5	Combustion Turbine	Mississippi	60	2015
New Albany Energy Facility	55080	6	Combustion Turbine	Mississippi	60	2015
Nichols Road Power Plant	10371	CB1302	Coal Steam	California	17.8	2012
Niles	2861	1	Coal Steam	Ohio	108	2012
Niles	2861	2	Coal Steam	Ohio	108	2012
Nine Mile	3869	1	Hydro	Washington	8.9	2015
North Branch	7537	A	Coal Steam	West Virginia	37	2014
North Branch	7537	B	Coal Steam	West Virginia	37	2014
Norton	1310	1	Combustion Turbine	Kansas	0.9	2011
Norton	1310	2	Combustion Turbine	Kansas	1.3	2011
Norton	1310	3	Combustion Turbine	Kansas	2.4	2011
Norton	1310	4	Combustion Turbine	Kansas	3.1	2011
Norton	1310	5	Combustion Turbine	Kansas	2.2	2011
O H Hutchings	2848	H-1	Coal Steam	Ohio	58	2015
O H Hutchings	2848	H-2	Coal Steam	Ohio	55	2015
O H Hutchings	2848	H-3	Coal Steam	Ohio	63	2015
O H Hutchings	2848	H-4	Coal Steam	Ohio	63	2013
O H Hutchings	2848	H-5	Coal Steam	Ohio	63	2015
O H Hutchings	2848	H-6	Coal Steam	Ohio	63	2015
Oakely	1311	1	Combustion Turbine	Kansas	1.2	2012
Oakely	1311	2	Combustion Turbine	Kansas	0.3	2012
Oakely	1311	4	Combustion Turbine	Kansas	0.8	2012
Oakely	1311	6	Combustion Turbine	Kansas	3.2	2012
Oakland Dam Hydroelectric	10433	1	Hydro	Pennsylvania	0.5	2015
Oakland Dam Hydroelectric	10433	2	Hydro	Pennsylvania	0.5	2015

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
Osage	4151	1	Coal Steam	Wyoming	10.1	2010
Osage	4151	2	Coal Steam	Wyoming	10.1	2010
Osage	4151	3	Coal Steam	Wyoming	10.1	2010
Pearl Station	6238	1A	Coal Steam	Illinois	22.2	2012
Pella	1175	6	Coal Steam	Iowa	11.5	2012
Pella	1175	7	Coal Steam	Iowa	11.5	2012
Pella	1175	8	Coal Steam	Iowa	11.5	2012
Permian Basin	3494	5	O/G Steam	Texas	115	2011
Philip Sporn	3938	11	Coal Steam	West Virginia	145	2015
Philip Sporn	3938	21	Coal Steam	West Virginia	145	2015
Philip Sporn	3938	31	Coal Steam	West Virginia	145	2015
Philip Sporn	3938	41	Coal Steam	West Virginia	145	2015
Philip Sporn	3938	51	Coal Steam	West Virginia	440	2012
Picway	2843	9	Coal Steam	Ohio	95	2015
Port Everglades	617	PPE1	O/G Steam	Florida	213	2013
Port Everglades	617	PPE2	O/G Steam	Florida	213	2013
Port Everglades	617	PPE3	O/G Steam	Florida	387	2013
Port Everglades	617	PPE4	O/G Steam	Florida	392	2013
Porterdale Hydro	50242	TB-1	Hydro	Georgia	0.7	2015
Porterdale Hydro	50242	TB-2	Hydro	Georgia	0.7	2015
Portland	3113	1	Coal Steam	Pennsylvania	158	2015
Portland	3113	2	Coal Steam	Pennsylvania	243	2015
Powerdale	3031	1	Hydro	Oregon	6	2015
Prairie Creek	1073	2	Coal Steam	Iowa	2.1	2010
Prairie River	378	1	Hydro	Minnesota	0.3	2015
Prairie River	378	2	Hydro	Minnesota	0.3	2015
PSEG Burlington Generating Station	2399	91	Combustion Turbine	New Jersey	46	2014
PSEG Burlington Generating Station	2399	92	Combustion Turbine	New Jersey	46	2014
PSEG Burlington Generating Station	2399	93	Combustion Turbine	New Jersey	46	2014
PSEG Burlington Generating Station	2399	94	Combustion Turbine	New Jersey	46	2014
PSEG Burlington Generating Station	2399	111	Combustion Turbine	New Jersey	46	2015
PSEG Burlington Generating Station	2399	112	Combustion Turbine	New Jersey	46	2015
PSEG Burlington Generating Station	2399	113	Combustion Turbine	New Jersey	46	2015
PSEG Burlington Generating Station	2399	114	Combustion Turbine	New Jersey	46	2015
PSEG Edison Generating Station	2400	11	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	12	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	13	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	14	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	21	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	22	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	23	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	24	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	31	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	32	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	33	Combustion Turbine	New Jersey	42	2015
PSEG Edison Generating Station	2400	34	Combustion Turbine	New Jersey	42	2015
PSEG Essex Generating Station	2401	101	Combustion Turbine	New Jersey	42	2015
PSEG Essex Generating Station	2401	102	Combustion Turbine	New Jersey	42	2015
PSEG Essex Generating Station	2401	103	Combustion Turbine	New Jersey	42	2015
PSEG Essex Generating Station	2401	104	Combustion Turbine	New Jersey	42	2015
PSEG Essex Generating Station	2401	111	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	112	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	113	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	114	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	121	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	122	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	123	Combustion Turbine	New Jersey	46	2015
PSEG Essex Generating Station	2401	124	Combustion Turbine	New Jersey	46	2015
PSEG Sewaren Generating Station	2411	1	O/G Steam	New Jersey	104	2015
PSEG Sewaren Generating Station	2411	2	O/G Steam	New Jersey	118	2015
PSEG Sewaren Generating Station	2411	3	O/G Steam	New Jersey	107	2015

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
PSEG Sewaren Generating Station	2411	4	O/G Steam	New Jersey	124	2015
Pulliam	4072	5	Coal Steam	Wisconsin	52	2015
Pulliam	4072	6	Coal Steam	Wisconsin	71	2015
R Gallagher	1008	1	Coal Steam	Indiana	140	2012
R Gallagher	1008	3	Coal Steam	Indiana	140	2012
Ravenswood	2500	GT8	Combustion Turbine	New York	20	2015
Reid Gardner	2324	1	Coal Steam	Nevada	100	2014
Reid Gardner	2324	2	Coal Steam	Nevada	100	2014
Reid Gardner	2324	3	Coal Steam	Nevada	98	2014
Riverside	1559	GT6	Combustion Turbine	Maryland	115	2014
Riverton	1239	39	Coal Steam	Kansas	38	2015
Riverton	1239	40	Coal Steam	Kansas	54	2015
Riviera	619	PRV3	O/G Steam	Florida	277	2011
Riviera	619	PRV4	O/G Steam	Florida	288	2011
Rochester 5	2641	2	Hydro	New York	12.9	2015
Rochester 5	2641	HY1	Hydro	New York	12.9	2015
Rochester 5	2641	HY3	Hydro	New York	18	2015
Sabetha Power Plant	1320	4	Combustion Turbine	Kansas	0.7	2012
Sabetha Power Plant	1320	8	Combustion Turbine	Kansas	2.1	2012
San Francisquito 2	6480	1	Hydro	California	14.5	2015
San Onofre Nuclear Generating Station	360	2	Nuclear	California	1094	2013
San Onofre Nuclear Generating Station	360	3	Nuclear	California	1080	2013
Schuylkill Generating Station	3169	1	O/G Steam	Pennsylvania	166	2013
Schuylkill Generating Station	3169	IC1	Combustion Turbine	Pennsylvania	2.7	2013
Shawville	3131	1	Coal Steam	Pennsylvania	122	2015
Shawville	3131	2	Coal Steam	Pennsylvania	125	2015
Shawville	3131	3	Coal Steam	Pennsylvania	175	2015
Shawville	3131	4	Coal Steam	Pennsylvania	175	2015
Shelby Municipal Light Plant	2943	1	Coal Steam	Ohio	12	2012
Shelby Municipal Light Plant	2943	2	Coal Steam	Ohio	12	2012
Small Hydro of Texas	55000	01	Hydro	Texas	0.4	2015
Small Hydro of Texas	55000	02	Hydro	Texas	0.4	2015
Small Hydro of Texas	55000	03	Hydro	Texas	0.4	2015
Smart Papers LLC	50247	B010	Coal Steam	Ohio	26	2012
Smart Papers LLC	50247	B020	Coal Steam	Ohio	15.1	2012
Smart Papers LLC	50247	B022	Coal Steam	Ohio	4.5	2012
Somerset Station	1613	6	Coal Steam	Massachusetts	109	2011
Steamboat 1	50763	OE11	Geothermal	Nevada	0.9	2015
Steamboat 1	50763	OE12	Geothermal	Nevada	0.9	2015
Steamboat 1	50763	OE13	Geothermal	Nevada	0.9	2015
Steamboat 1	50763	OE14	Geothermal	Nevada	0.9	2015
Steamboat 1	50763	OE21	Geothermal	Nevada	0.9	2015
Steamboat 1	50763	OE22	Geothermal	Nevada	0.9	2015
Steamboat 1	50763	OE23	Geothermal	Nevada	0.9	2015
Steamboat 1A Power Plant	52138	DE32	Geothermal	Nevada	0.9	2015
Swift 2	6265	21	Hydro	Washington	34	2015
Taconite Harbor Energy Center	10075	3	Coal Steam	Minnesota	76	2015
Tangier	6390	3	Combustion Turbine	Virginia	0.6	2015
Tangier	6390	4	Combustion Turbine	Virginia	0.8	2015
Tanners Creek	988	U1	Coal Steam	Indiana	145	2015
Tanners Creek	988	U2	Coal Steam	Indiana	145	2015
Tanners Creek	988	U3	Coal Steam	Indiana	200	2015
Tanners Creek	988	U4	Coal Steam	Indiana	500	2014
Teche	1400	2	O/G Steam	Louisiana	33	2011
Tecumseh Energy Center	1252	1	Combustion Turbine	Kansas	18	2012
Tecumseh Energy Center	1252	2	Combustion Turbine	Kansas	19	2012
Thomas C Ferguson	4937	1	O/G Steam	Texas	420	2013
Thousand Springs	820	1	Hydro	Idaho	0.8	2015
Thousand Springs	820	2	Hydro	Idaho	0.8	2015
Tillotson Rubber	50095	IC1	Combustion Turbine	New Hampshire	0.4	2012
Tillotson Rubber	50095	IC2	Combustion Turbine	New Hampshire	0.6	2012

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
Tillotson Rubber	50095	TG2	Biomass	New Hampshire	0.6	2012
Tillotson Rubber	50095	TGI	Biomass	New Hampshire	0.7	2012
Titus	3115	1	Coal Steam	Pennsylvania	81	2015
Titus	3115	2	Coal Steam	Pennsylvania	81	2015
Titus	3115	3	Coal Steam	Pennsylvania	81	2015
Tradinghouse Power Company LLC	3506	2	O/G Steam	Texas	818	2011
Trigen Syracuse Energy	50651	2	Coal Steam	New York	24.6	2013
Trigen Syracuse Energy	50651	3	Coal Steam	New York	24.6	2013
Trigen Syracuse Energy	50651	4	Coal Steam	New York	12.3	2013
Trigen Syracuse Energy	50651	5	Coal Steam	New York	12.3	2013
Tulsa	2965	1403	O/G Steam	Oklahoma	65	2015
Turkey Point	621	PTP2	O/G Steam	Florida	392	2013
TXU Sweetwater Generating Plant	50615	GT01	Combined Cycle	Texas	41	2009
TXU Sweetwater Generating Plant	50615	GT02	Combined Cycle	Texas	86	2009
TXU Sweetwater Generating Plant	50615	GT03	Combined Cycle	Texas	86	2009
Tyrone	1361	5	Coal Steam	Kentucky	71	2013
Union Carbide Seadrift Cogen	50150	IGT	Combined Cycle	Texas	12	2015
Upper Androscoggin	54202	2	Hydro	Maine	0.5	2015
Venice	913	GT1	Combustion Turbine	Illinois	26	2015
Vermilion	897	1	Coal Steam	Illinois	62	2011
Vermilion	897	2	Coal Steam	Illinois	99	2011
Vermilion	897	3	Combustion Turbine	Illinois	10	2011
Vermont Yankee	3751	1	Nuclear	Vermont	620.3	2014
Viking Energy of Northumberland	50771	B1	Biomass	Pennsylvania	16.2	2012
W N Clark	462	55	Coal Steam	Colorado	17.6	2013
W N Clark	462	59	Coal Steam	Colorado	24.9	2013
W S Lee	3264	1	Coal Steam	South Carolina	100	2015
W S Lee	3264	2	Coal Steam	South Carolina	100	2015
W S Lee	3264	3	Coal Steam	South Carolina	170	2015
Wabash River	1010	2	Coal Steam	Indiana	85	2014
Wabash River	1010	3	Coal Steam	Indiana	85	2014
Wabash River	1010	4	Coal Steam	Indiana	85	2014
Wabash River	1010	5	Coal Steam	Indiana	95	2014
Walter C Beckjord	2830	1	Coal Steam	Ohio	94	2012
Walter C Beckjord	2830	2	Coal Steam	Ohio	94	2015
Walter C Beckjord	2830	3	Coal Steam	Ohio	128	2015
Walter C Beckjord	2830	4	Coal Steam	Ohio	150	2015
Walter C Beckjord	2830	5	Coal Steam	Ohio	238	2015
Walter C Beckjord	2830	6	Coal Steam	Ohio	414	2015
Walter Scott Jr Energy Center	1082	1	Coal Steam	Iowa	43	2015
Walter Scott Jr Energy Center	1082	2	Coal Steam	Iowa	88	2015
Wanapum	3888	2	Hydro	Washington	97	2012
Washington Parish Energy Center	55486	CTG1	Combined Cycle	Louisiana	172	2015
Washington Parish Energy Center	55486	CTG2	Combined Cycle	Louisiana	172	2015
Washington Parish Energy Center	55486	ST1	Combined Cycle	Louisiana	215	2015
Watts Bar Fossil	3419	A	Coal Steam	Tennessee	56	2011
Watts Bar Fossil	3419	B	Coal Steam	Tennessee	56	2011
Watts Bar Fossil	3419	C	Coal Steam	Tennessee	56	2011
Watts Bar Fossil	3419	D	Coal Steam	Tennessee	56	2011
Webbers Falls	2987	3	Hydro	Oklahoma	23	2015
Welsh	6139	2	Coal Steam	Texas	528	2014
Werner	2385	GT1	Combustion Turbine	New Jersey	53	2015
Werner	2385	GT2	Combustion Turbine	New Jersey	53	2015
Werner	2385	GT3	Combustion Turbine	New Jersey	53	2015
Werner	2385	GT4	Combustion Turbine	New Jersey	53	2015
Western Renewable Energy	56358	1	Biomass	Arizona	2.5	2015
Weston	4078	1	Coal Steam	Wisconsin	58	2015
Weston	4078	2	Coal Steam	Wisconsin	81	2015
Wilbur East Power Plant	10370	CB1302	Coal Steam	California	18.1	2012
Wilbur West Power Plant	10369	CB1302	Coal Steam	California	18.2	2012
Williston	2791	2	Combustion Turbine	North Dakota	4.7	2012

Plant Name	ORIS Plant Code	Unit ID	Plant Type	State Name	Capacity (MW)	Retirement Year
Wisconsin Rapids	3974	6	Hydro	Wisconsin	0.3	2015
Wisconsin Rapids	3974	8	Hydro	Wisconsin	0.3	2015
Wiscoy 170	2646	1	Hydro	New York	0.6	2015
Wiscoy 170	2646	2	Hydro	New York	0.4	2015
Worcester Energy	10165	1	Biomass	Maine	5.7	2015
Worcester Energy	10165	2	Biomass	Maine	5.7	2015
Worcester Energy	10165	3	Biomass	Maine	5.7	2015
Wythe Park Power Petersburg Plant	54045	1	Fossil Waste	Virginia	3	2013
Yorktown	3809	1	Coal Steam	Virginia	159	2014
Yuma	524	3	Combustion Turbine	Colorado	0.2	2015

5. Emission Control Technologies

EPA Base Case v.5.13 includes an update of emission control technology assumptions. EPA contracted with engineering firm Sargent and Lundy to update and add to the retrofit emission control models previously developed for EPA and used in EPA Base Case v.4.10. EPA Base Case v.5.13 thus includes updated assumptions regarding control options for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), and particulate matter (PM). These emission control options are listed in Table 5-1. They are available in EPA Base Case v.5.13 for meeting existing and potential federal, regional, and state emission limits. It is important to note that, besides the emission control options shown in Table 5-1 and described in this chapter, EPA Base Case v.5.13 offers other compliance options for meeting emission limits. These include fuel switching, adjustments in the dispatching of electric generating units, and the option to retire a unit.

Table 5-1 Summary of Emission Control Technology Retrofit Options in EPA Base Case v.5.13

SO_2 and HCl Control Technology Options	NO_x Control Technology Options	Mercury Control Technology Options	Particulate Matter Control Technology Options	CO_2 Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Activated Carbon Injection (ACI) System	Pulse-Jet Fabric Filter (FF)	CO_2 Capture and Sequestration
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	SO_2 and NO_x Control Technology Removal Co-benefits	Electrostatic Precipitator (ESP) Upgrade Adjustment	Coal-to-Gas Conversion
Dry Sorbent Injection (DSI)	Combustion Controls			Heat Rate Improvement
FGD Upgrade Adjustment				

Detailed reports and example calculation worksheets for Sargent & Lundy retrofit emission control models used by EPA are available in Attachments 5-1 through 5-7 at: www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

5.1 Sulfur Dioxide Control Technologies - Scrubbers

Two commercially available Flue Gas Desulfurization (FGD) "scrubber" technology options for removing the SO_2 produced by coal-fired power plants are offered in EPA Base Case v.5.13: Limestone Forced Oxidation (LSFO) — a wet FGD technology and Lime Spray Dryer (LSD) — a semi-dry FGD technology which employs a spray dryer absorber (SDA). In wet FGD systems, the polluted gas stream is brought into contact with a liquid alkaline sorbent (typically limestone) by forcing it through a pool of the liquid slurry or by spraying it with the liquid. In dry FGD systems the polluted gas stream is brought into contact with the alkaline sorbent in a semi-dry state through use of a spray dryer. The removal efficiency for SDA drops steadily for coals whose SO_2 content exceeds 3 lbs SO_2/MMBtu, so this technology is provided only to plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Base Casev.5.13 when a unit retrofits with an LSD SO_2 scrubber, it loses the option of burning certain high sulfur content coals (see Table 5-2).

In EPA Base Case v.5.13 the LSFO and LSD SO_2 emission control technologies are available to existing "unscrubbed" units. They are also available to existing "scrubbed" units with reported removal efficiencies of less than fifty percent. Such units are considered to have an injection technology and classified as "unscrubbed" for modeling purposes in the NEEDS database of existing units which is used in setting up the EPA base case. The scrubber retrofit costs for these units are the same as regular unscrubbed units retrofitting with a scrubber.

Default SO_2 removal rates for wet and dry FGD were based on data reported in EIA 860 (2010). These default removal rates were the average of all SO_2 removal rates for a dry or wet FGD as reported in EIA 860 (2010) for the FGD installation year.

To reduce the incidence of implausibly high, outlier removal rates, units whose reported EIA Form 860 (2010) SO_2 removal rates are higher than the average of the upper quartile of SO_2 removal rates across all scrubbed units are instead assigned the upper quartile average unless the reported EIA 860 rate was recently confirmed by utility comments. One upper quartile removal rate is calculated across all installation years and replaces any reported removal rate that exceeds it no matter the installation year.

Existing units not reporting FGD removal rates in form EIA 860 (2010) will be assigned the default SO_2 removal rate for a dry or wet FGD for that installation year.

As shown in Table 5-2, for FGD retrofits installed by the model, the assumed SO_2 removal rates will be 96% for wet FGD and 92% for dry FGD. These are the average of the SO_2 removal efficiencies reported in EIA 860 (2008) for dry and wet FGD installed in 2008 or later. These rates have been subjected to numerous reviews from utilities and other stakeholders recently, so they remain unchanged and continue to be used in EPA Base Case v.5.13.

The procedures used to derive the cost of each scrubber type are discussed in detail in the following sections.

Table 5-2 Summary of Retrofit SO_2 Emission Control Performance Assumptions in Base Case v.5.13

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	92% with a floor of 0.08 lbs/MMBtu
Capacity Penalty	Calculated based on characteristics of the unit: See Table 5-3	Calculated based on characteristics of the unit: See Table 5-3
Heat Rate Penalty		
Cost (2011$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs SO_2/MMBtu[1]
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK and WC	BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE

[1] FBC units burning WC and PK fuels are provided with LSD retrofit options

Potential (new) coal-fired units built by the model are also assumed to be constructed with a scrubber achieving a removal efficiency of 96%. In EPA Base Case v.5.13 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

Sargent and Lundy's updated performance and cost models for wet and dry SO_2 scrubbers are implemented in EPA Base Case v.5.13 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. See Attachments 5-1 and 5-2 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html).

Capacity and Heat Rate Penalty: In IPM the amount of electrical power required to operate a retrofit emission control device is represented through a reduction in the amount of electricity that is available for sale to the grid. For example, if 1.6% of the unit's electrical generation is needed to operate the scrubber, the generating unit's capacity is reduced by 1.6%. This is the "capacity penalty." At the same time, to capture the total fuel used in generation both for sale to the grid and for internal load (i.e., for operating the control device), the unit's heat rate is scaled up such that a comparable reduction (1.6% in the previous example) in the new higher heat rate yields the original heat rate[24]. The factor used to scale up the original heat rate is called "heat rate penalty." It is a modeling procedure only and does not represent an increase in the unit's actual heat rate (i.e., a decrease in the unit's generation efficiency). In EPA Base Case v.5.13 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations from the Sargent and Lundy models that take into account the rank of coal burned, its uncontrolled SO_2 rate, and the heat rate of the model plant.

Table 5-3 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalty for two SO_2 emission control technologies (LSFO and LSD) included in EPA Base Case v.5.13 for an illustrative set of generating units with a representative range of capacities and heat rates.

[24] Mathematically, the relationship of the heat rate and capacity penalties (both expressed as positive percentage values) can be represented as follows:

$$\text{Heat Rate Penalty} = \left(\frac{1}{\left(1 - \frac{\text{Capacity Penalty}}{100}\right)} - 1 \right) \times 100$$

Table 5-3 Illustrative Scrubber Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

Scrubber Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)											
					50		100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
LSFO	9,000	-1.50	1.53	2.03	819	23.7	819	23.7	600	11.2	519	8.3	471	7.7	426	6.4
	10,000	-1.67	1.70	2.26	860	24.2	860	24.2	629	11.5	544	8.6	495	8.0	447	6.6
	11,000	-1.84	1.87	2.49	899	24.6	899	24.6	658	11.8	569	8.9	517	8.2	467	6.8
LSD	9,000	-1.18	1.20	2.51	854	29.1	701	17.3	513	8.6	444	6.5	422	5.7	422	5.3
	10,000	-1.32	1.33	2.79	894	29.6	734	17.7	538	8.9	465	6.8	442	5.9	442	5.5
	11,000	-1.45	1.47	3.07	933	30.0	766	18.0	561	9.1	485	7.0	461	6.1	461	5.7

Note: The above cost estimates assume a boiler burning 3 lb/MMBtu SO_2 Content Bituminous Coal for LSFO and 2 lb/MMBtu SO_2 Content Bituminous Coal for LSD.

5.2 Nitrogen Oxides Control Technology

The EPA Base Case v.5.13 includes two categories of NO_x reduction technologies: combustion and post-combustion controls. Combustion controls reduce NO_x emissions during the combustion process by regulating flame characteristics such as temperature and fuel-air mixing. Post-combustion controls operate downstream of the combustion process and remove NO_x emissions from the flue gas. All the specific combustion and post-combustion technologies included in EPA Base Case v.5.13 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

The EPA Base Case v.5.13 representation of combustion controls uses equations that are tailored to the boiler type, coal type, and combustion controls already in place and allow appropriate additional combustion controls to be exogenously applied to generating units based on the NO_x emission limits they face. Characterizations of the emission reductions provided by combustion controls are presented in Table 3-1.3 in Attachment 3-1. The EPA Base Case v.5.13 cost assumptions for NO_x Combustion Controls are summarized in Table 5-4. Table 3-11 provides a mapping of existing coal unit configurations and incremental combustion controls applied in EPA Base Case v.5.13 when units under certain conditions are assumed to achieve a state-of-the-art combustion control configuration.

Table 5-4 Cost (2011$) of NO_x Combustion Controls for Coal Boilers (300 MW Size)

Boiler Type	Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)
Dry Bottom Wall-Fired	Low NO_x Burner without Overfire Air (LNB without OFA)	48	0.3	0.07
	Low NO_x Burner with Overfire Air (LNB with OFA)	65	0.5	0.09
Tangentially-Fired	Low NO_x Coal-and-Air Nozzles with Close-Coupled Overfire Air (LNC1)	26	0.2	0.00
	Low NO_x Coal-and-Air Nozzles with Separated Overfire Air (LNC2)	35	0.2	0.03
	Low NO_x Coal-and-Air Nozzles with Close-Coupled and Separated Overfire Air (LNC3)	41	0.3	0.03
Vertically-Fired	NO_x Combustion Control	31	0.2	0.06
Scaling Factor				
The following scaling factor is used to obtain the capital and fixed operating and maintenance costs applicable to the capacity (in MW) of the unit taking on combustion controls. No scaling factor is applied in calculating the variable operating and maintenance cost. LNB without OFA & LNB with OFA = ($/kW for *X* MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$ LNC1, LNC2, and LNC3 = ($/kW for *X* MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.359}$ Vertically-Fired = ($/kW for *X* MW Unit) = ($/kW for 300 MW Unit) x $(300/X)^{0.553}$ where ($/kW for 300 MW Unit) is a value from the above table and *X* is the capacity (in MW) of the unit taking on combustion controls.				

5.2.2 Post-combustion NO_x Controls

The EPA Base Case v.5.13 includes two post-combustion retrofit NO_x control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Base Case v.5.13 oil/gas steam units are eligible for SCR only. NO_x reduction in a SCR system takes place by injecting ammonia (NH_3) vapor into the flue gas stream where the NO_x is reduced to nitrogen (N_2) and water (H_2O) abetted by passing over a catalyst bed typically containing titanium, vanadium oxides, molybdenum, and/or tungsten. As its name implies, SNCR operates without a catalyst. In SNCR a nitrogenous reducing agent (reagent), typically urea or ammonia, is injected into, and mixed with, hot flue gas where it reacts with the NO_x in the gas stream reducing it to nitrogen gas and water vapor. Due to the presence of a catalyst, SCR can achieve greater NO_x reductions than SNCR. However, SCR costs are higher than SNCR costs.

Table 5-5 summarizes the performance and applicability assumptions in EPA Base Case v.5.13 for each post-combustion NO_x control technology and provides a cross-reference to information on cost assumptions.

Table 5-5 Summary of Retrofit NO_x Emission Control Performance Assumptions

Control Performance Assumptions	Selective Catalytic Reduction (SCR)		Selective Non-Catalytic Reduction (SNCR)
Unit Type	Coal	Oil/Gas	Coal
Percent Removal	90%	80%	Pulverized Coal: 25% Fluidized Bed: 50%
Rate Floor	Bituminous: 0.07 lb/MMBtu Subbituminous and Lignite: 0.05 lb/MMBtu	--	Pulverized Coal: 0.1 lb/MMBtu Fluidized Bed: 0.08 lb/MMBtu
Size Applicability	Units ≥ 25 MW	Units ≥ 25 MW	Pulverized Coal: Units ≥ 25 MW and ≤ 100 MW Fluidized Bed: Units ≥ 25 MW
Costs (2011$)	See Table 5-6 Illustrative Post-combustion NOx Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13	See Table 5-7	See Table 5-6 Illustrative Post-combustion NOx Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

5.2.3 Methodology for Obtaining SCR Costs for Coal

Sargent and Lundy's updated performance/cost models for SCR and SNCR technologies are implemented in EPA Base Case v.5.13 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. See Attachments 5-3 and 5-4 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html).

Table 5-6 presents the SCR and SNCR capital, VOM, and FOM costs and capacity and heat rate penalties for an illustrative set of coal generating units with a representative range of capacities and heat rates.

Table 5-6 Illustrative Post-combustion NO_x Control Costs (2011$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capacity (MW)									
					100		300		500		700		1000	
					Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
SCR	9,000	-0.54	0.54	1.23	321	1.76	263	0.76	243	0.64	232	0.58	222	0.53
	10,000	-0.56	0.56	1.32	349	1.86	287	0.81	266	0.69	255	0.63	244	0.57
	11,000	-0.58	0.59	1.41	377	1.96	311	0.87	289	0.73	277	0.67	265	0.62
SNCR - Tangential	9,000	-0.05	0.78	1.04	55	0.48	30	0.26	22	0.20	18	0.16	15	0.13
	10,000			1.15	56	0.50	30	0.27	23	0.20	19	0.17	15	0.14
	11,000			1.27	57	0.51	31	0.27	23	0.21	19	0.17	16	0.14
SNCR - Fluidized Bed	9,000	-0.05	0.78	1.04	41	0.36	22	0.20	17	0.15	14	0.12	11	0.10
	10,000			1.15	42	0.37	23	0.20	17	0.15	14	0.12	12	0.10
	11,000			1.27	43	0.38	23	0.21	17	0.15	14	0.13	12	0.10

Note: Assumes a boiler burning bituminous coal with an input NO_x rate of 0.5 lbs/MMBtu. The technology is applied to boilers larger than 25 MW.

5.2.4 Methodology for Obtaining SCR Costs for Oil/Gas Steam Units

The cost calculations for SCR described in section 5.2.2 apply to coal units. For SCR on oil/gas steam units the cost calculation procedure shown in Table 5-7 is used in EPA Base Case v.5.13. The scaling factor for capital and fixed O&M costs, described in footnote a, applies to all size units from 25 MW and up.

Table 5-7 Post-Combustion NO_x Controls for Oil/Gas Steam Units in EPA Base Case v.5.13

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Percent Removal
SCR[a]	80	1.16	0.13	80%

Notes:
The "Coefficients" in the table above are multiplied by the terms below to determine costs.
"MW" in the terms below is the unit's capacity in megawatts.
Cost data are adjusted to 2011$ by EPA.

[a] SCR Cost Equations:
SCR Capital Cost and Fixed O&M: $(200/MW)^{0.35}$
The scaling factors shown above apply up to 500 MW. The cost obtained for a 500 MW unit applies for units larger than 500 MW.

Example for 275 MW unit:
SCR Capital Cost ($/kW) = $80 * (200/275)^{0.35} \approx 71.64$ $/kW
SCR FOM Cost ($/kW-yr) = $1.16 * (200/275)^{0.35} \approx 1.04$ $/kW-yr
SCR VOM Cost ($/MWh) = 0.13 $/MWh

5.2.5 Methodology for Obtaining SNCR Costs

In the Sargent and Lundy's cost update for SNCR a generic NO_x removal efficiency of 25% is assumed. However, the capital, fixed and variable operating and maintenance costs of SNCR on circulating fluidized bed (CFB) units are distinguished from the corresponding costs for other boiler types (e.g. cyclone, and wall fired). As with SCR an air heater modification cost applies for plants that burn bituminous coal whose SO_2 content is 3 lbs/MMBtu or greater.

5.2.6 SO_2 and NO_x Controls for Units with Capacities from 25 MW to 100 MW (25 MW ≤ capacity < 100 MW)

In EPA Base Case v.5.13 coal units with capacities between 25 MW and 100 MW are offered the same SO_2 and NO_x emission control options as larger units. However, for purposes of modeling, the costs of controls for these units are assumed to be equivalent to that of a 100 MW unit for SCR, 50 MW for Dry FGD, and 100 MW for Wet FGD. These assumptions are based on several considerations. First, to achieve economies of scale, several units in this size range are likely to be ducted to share a single common control, so the minimum capacity cost equivalency assumption, though generic, would be technically plausible. Second, single units in this size range that are not grouped to achieve economies of scale are likely to have the option of hybrid multi-pollutant controls currently under development.[25] These hybrid controls achieve cost economies by combining SO_2, NO_x and particulate controls into a single control unit. Singly, the costs of the individual control would be higher for units below 100 MW than for a 100 MW unit, but when combined in the Multi-Pollutant Technologies (MPTs) their costs would be roughly equivalent to the cost of individual controls on a 100 MW unit. While MPTs are not explicitly represented in EPA Base Case v.5.13, single units in the 25-100 MW range that take on combinations of SO_2 and NO_x controls in a model run can be thought of as being retrofitted with an MPT.

[25] See, for example, the Greenidge Multi-Pollutant Control Project, which was part of the U.S. Department of Energy, National Energy Technology Lab's Power Plant Improvement Initiative. A joint effort of CONSOL Energy Inc. AES Greenidge LLC, and Babcock Power Environmental, Inc., the project is described in greater detail at *www.netl.doe.gov/technologies/coalpower/cctc/PPII/bibliography/demonstration/environmental/bib_greenidge.html*.

Illustrative SCR costs for 25-100 MW coal units with a range of heat rates can be found by referring to the 100 MW "Capital Costs ($/kW)" and "Fixed O&M" columns in Table 5-6 and illustrative scrubber costs for 25-100 MW coal units with a range of heat rates can be found by referring to the LSFO 100 MW and LSD 50MW "Capital Costs ($/kW)" and "Fixed O&M" columns in Table 5-3. The Variable O&M cost component, which applies to units regardless of size, can be found in the fifth column in these tables.

5.3 Biomass Co-firing

Biomass co-firing is provided as a fuel choice for all coal-fired power plants in EPA Base Case v.5.13. However, logistics and boiler engineering considerations place limits on the extent of biomass that can be fired. The logistic considerations arise because it is only economic to transport biomass a limited distance from where it is grown given the low energy density of the fuel. In addition, the extent of storage that can be devoted at a power plant to this relatively low density fuel is another limiting factor. Boiler efficiency and other engineering considerations, largely due to the relatively higher moisture content and lower heat content of biomass compared to fossil fuel, also plays a role in limiting the level of co-firing.

In EPA Base Case v.5.13 the limit on biomass co-firing is expressed as the percentage of the facility level power output that is produced from biomass. Based on analysis by EPA's power sector engineering staff, a maximum of 10% of the facility level power output (not to exceed 50 MW) can be fired by biomass in modeling projections. In EPA Base Case v.5.13 "facility level" is defined as the set of generating units which share the same ORIS code[26] in NEEDS v.5.13.

The capital and FOM cost assumptions informing EPA Base Case v.5.13 regarding biomass co-firing are summarized in Table 5-8, developed by EPA's power sector engineering staff and updated to 2011$.[27]

Table 5-8 Biomass Co-firing for Coal Plants

Output From Biomass (MW)	5	10	15	20	25	30	35	40	45	50
Capital Cost (2011$/kW From Biomass)	521	439	396	368	349	333	320	309	301	293
Fixed O&M (2011$/kW-yr)	25.8	17.3	12.5	10.0	8.5	11.8	10.6	9.5	8.6	8.0

In order to economize on model space, instead of designing a biomass co-firing "retrofit" modification for units that would include direct representations of the capital and FOM costs shown in Table 5-8. The

[26] The ORIS plant locator code is a unique identifying number (originally assigned by the Office of Regulatory Information Systems from which the acronym derived). The ORIS code is given to power plants by EIA and remains unchanged ownership changes.

[27] Among the studies consulted in developing these costs were:

(a) Briggs, J. and J. M. Adams, Biomass Combustion Options for Steam Generation, Presented at Power-Gen 97, Dallas, TX, December 9 – 11, 1997.

(b) Grusha, J and S. Woldehanna, K. McCarthy, and G. Heinz, Long Term Results from the First US Low NOx Conversion of a Tangential Lignite Fired Unit, presented at 24th International Technical Conference on Coal & Fuel Systems, Clearwater, FL., March 8 – 11, 1999.

(c) EPRI, Biomass Co-firing: Field Test Results: Summary of Results of the Bailly and Seward Demonstrations, Palo Alto, CA, supported by U.S. Department of Energy Division of Energy Efficiency and Renewable Energy, Washington D.C.; U.S. Department of Energy Division Federal Energy Technology Center, Pittsburgh PA; Northern Indiana Public Service Company, Merrillville, IN; and GPU Generation, Inc., Johnstown, PA: 1999. TR-113903.

(d) Laux S., J. Grusha, and D. Tillman, Co-firing of Biomass and Opportunity Fuels in Low NOx Burners, PowerGen 2000 - Orlando, FL, www.fwc.com/publications/tech_papers/powgen/pdfs/clrw_bio.pdf.

(e) Tillman, D. A., Co-firing Biomass for Greenhouse Gas Mitigation, presented at Power-Gen 99, New Orleans, LA, November 30 – December 1, 1999.

(f) Tillman, D. A. and P. Hus, Blending Opportunity Fuels with Coal for Efficiency and Environmental Benefit, presented at 25th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 6 – 9, 2000 capital and FOM costs were implemented by in EPA Base Case v.5.13 as a $/MMBtu biomass fuel cost adder. The discrete costs shown in Table 5-8 are first represented as continuous exponential cost functions showing the FOM and capital costs for all biomass outputs between 0 and 50 MW in size. Then, for every coal generating unit represented in EPA Base Case 5.13, the annual payment to capital for the biomass co-firing capability was derived by multiplying the total capital cost obtained from the capital cost exponential function by a 12.1% capital charge rate for utility-owned units and a 16.47% capital charge rate for merchant units. The resulting value was added to the annual FOM cost obtained from the FOM exponential function to obtain the total annual cost for the biomass co-firing for each generating unit.

Then, the annual amount of fuel (in MMBtus) required for each generating unit was derived by multiplying the size of a unit (in MW) by its heat rate (in Btu/kWh) by its capacity factor (in percent) by 8,760 hours (i.e., the number of hours in a year). Dividing the resulting value by 1000 yielded the annual fuel required by the generating unit in MMBtus. Dividing this number into the previously calculated total annual cost for biomass co-firing capability resulted in the cost of biomass co-firing per MMBtu of biomass combusted. This was represented in IPM as a fuel cost adder incurred when a coal unit co-fires biomass. In this manner, the model's decision process for determining biomass consumption takes into account not just the cost of the biomass fuel, but also the capital and FOM costs associated with biomass co-firing at the units in question.

Chapter 11 discusses factors related to the delivered cost of biomass fuel in EPA Base Case v.5.13.

5.4 Mercury Control Technologies

For any power plant, mercury emissions depend on the mercury content of the fuel used, the combustion and physical characteristics of the unit, and the emission control technologies deployed. In the absence of activated carbon injection (ACI), mercury emission reductions below the mercury content of the fuel are strictly due to characteristics of the combustion process and incidental removal resulting from other pollution control technologies, e.g., the SO_2, NO_x, and particulate matter controls. The following discussion is divided into three parts. Sections 5.4.1 and 5.4.2 explain the two factors that determine mercury emissions that result from unit configurations lacking ACI under EPA Base Case v.5.13. Section 5.4.1 discusses how mercury content of fuel is modeled in EPA Base Case v.5.13. Section 5.4.2 looks at the procedure used to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.4 explains the mercury emission control options that are available under EPA Base Case v.5.13. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal: The assumptions in EPA Base Case v.5.13 on the mercury content of coal (and the majority of emission modification factors discussed below in Section 5.4.2) are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR).[28] A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit ... with a capacity greater than 25 megawatts electric [MWe]), as well as accurate information on the total amount of coal burned by each such unit," and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations.

[28] Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html.

In 2009, EPA collected some additional information regarding mecury through the Collection Effort for New and Existing Coal- and Oil-Fired Electricty Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631), however the information collected was not similarly comprehensive and was thus not used to update mercury assumptions in this EPA base case.

The ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content and other characteristics of coal burned at coal-fired utility units greater than 25 MW. To make this data usable, these data points were first grouped by IPM coal types and IPM coal supply regions. IPM coal types divide bituminous, subbituminous, and lignite coal into different grades based on sulfur content.

Oil, natural gas, and waste fuels: The EPA Base Case v.5.13 also includes assumptions on the mercury content for oil, gas and waste fuels, which were based on data derived from previous EPA analysis of mercury emissions from power plants.[29] Table 5-9 provides a summary of the assumptions on the mercury content for oil, gas and waste fuels included in EPA Base Case v.5.13.

Table 5-9 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Base Case v.5.13

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00 [a]
Petroleum Coke	2.66 [b]
Biomass	0.57
Municipal Solid Waste	71.85
Geothermal Resource	2.97 - 3.7

Note:
[a] The values appearing in this table are rounded to two decimal places. The zero value shown for natural gas is based on an EPA study that found a mercury content of 0.000138 lbs/TBtu. Values for geothermal resources represent a range.

[b] A previous computational error in the mercury emission factor for petroleum coke as presented in Table 6-3 of the EPA report titled Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report Including Errata, 3-21-02 was corrected (from 23.18 lbs/TBtu to 2.66 lb/TBtu) based on re-examination of the 1999 ICR data for petroleum coke and implementation of a procedure for flagging and excluding outlier values above the 95 percentile value.

5.4.2 Mercury Emission Modification Factors

Emission Modification Factors (EMFs) represent the mercury reductions attributable to the specific burner type and configuration of SO_2, NO_x, and particulate matter control devices at an electric generating unit. An EMF is the ratio of outlet mercury concentration to inlet mercury concentration, and depends on the unit's burner type, particulate control device, post-combustion NO_x control and SO_2 scrubber control. In other words, the mercury reduction achieved (relative to the inlet) during combustion and flue-gas treatment process is (1-EMF). The EMF varies by the type of coal (bituminous, subbituminous, and lignite) used during the combustion process.

Deriving EMFs involves obtaining mercury inlet data by coal sampling and mercury emission data by stack testing at a representative set of coal units. As noted above, EPA's EMFs were initially based on 1999 mercury ICR emission test data. More recent testing conducted by the EPA, DOE, and industry participants[30] has provided a better understanding of mercury emissions from electric generating units and mercury capture in pollution control devices. Overall the 1999 ICR data revealed higher levels of mercury capture for bituminous coal-fired plants than for subbituminous and lignite coal-fired plants, and significant capture of ionic Hg in wet-FGD scrubbers. Additional mercury testing indicates that for bituminous coals, SCR systems have the ability to convert elemental Hg into ionic Hg and thus allow easier capture in a downstream wet-FGD scrubber. This understanding of mercury capture with SCRs is incorporated in EPA Base Case v.5.13 mercury EMFs for unit configurations with SCR and wet scrubbers.

[29] Analysis of Emission Reduction Options for the Electric Power Industry," Office of Air and Radiation, US EPA, March 1999.

[30] For a detailed summary of emissions test data see Control of Emissions from Coal-Fired Electric Utility Boilers: An Update, EPA/Office of Research and Development, February 2005. This report can be found at www.epa.gov/ttnatw01/utility/hgwhitepaperfinal.pdf.

Table 5-10 below provides a summary of EMFs used in EPA Base Case v.5.13. Table 5-11 provides definitions of acronyms for existing controls that appear in

Table 5-16. Table 5-12 provides a key to the burner type designations appearing in

Table 5-16.

Table 5-10 Mercury Emission Modification Factors Used in EPA Base Case v.5.13

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF	Lignite EMF
Cyclone	Cold Side ESP	SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
Cyclone	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP	No SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP	No SCR	Wet FGD	0.34	0.84	0.56
Cyclone	Cold Side ESP	No SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP + FF	SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
Cyclone	Cold Side ESP + FF	No SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FF	No SCR	Wet FGD	0.3	0.3	0.56
Cyclone	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
Cyclone	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
Cyclone	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP + FGC	No SCR	None	0.64	0.97	1
Cyclone	Cold Side ESP + FGC	No SCR	Wet FGD	0.34	0.84	0.56
Cyclone	Cold Side ESP + FGC	No SCR	Dry FGD	0.64	0.65	1
Cyclone	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FGC + FF	No SCR	None	0.2	0.75	1
Cyclone	Cold Side ESP + FGC + FF	No SCR	Wet FGD	0.1	0.3	0.56
Cyclone	Cold Side ESP + FGC + FF	No SCR	Dry FGD	0.1	0.3	0.56
Cyclone	Fabric Filter	SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
Cyclone	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
Cyclone	Fabric Filter	No SCR	None	0.11	0.27	1
Cyclone	Fabric Filter	No SCR	Wet FGD	0.1	0.27	0.56
Cyclone	Fabric Filter	No SCR	Dry FGD	0.05	0.75	1
Cyclone	Hot Side ESP	SCR	None	0.9	0.9	1
Cyclone	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
Cyclone	Hot Side ESP	No SCR	None	0.9	0.94	1
Cyclone	Hot Side ESP	No SCR	Wet FGD	0.58	0.8	1
Cyclone	Hot Side ESP	No SCR	Dry FGD	0.6	0.85	1
Cyclone	Hot Side ESP + FF	SCR	None	0.11	0.27	1
Cyclone	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
Cyclone	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
Cyclone	Hot Side ESP + FF	No SCR	None	0.11	0.27	1
Cyclone	Hot Side ESP + FF	No SCR	Wet FGD	0.03	0.27	0.56
Cyclone	Hot Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
Cyclone	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
Cyclone	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
Cyclone	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
Cyclone	Hot Side ESP + FGC	No SCR	None	0.9	0.94	1
Cyclone	Hot Side ESP + FGC	No SCR	Wet FGD	0.58	0.8	1
Cyclone	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.85	1

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF	Lignite EMF
Cyclone	No Control	SCR	Wet FGD	0.1	0.7	1
Cyclone	No Control	No SCR	Wet FGD	0.1	0.7	1
FBC	Cold Side ESP	No SCR	None	0.65	0.65	0.62
FBC	Cold Side ESP	No SCR	Dry FGD	0.64	0.65	1
FBC	Cold Side ESP + FF	No SCR	None	0.05	0.43	0.43
FBC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
FBC	Fabric Filter	SCR	None	0.11	0.27	1
FBC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
FBC	Fabric Filter	No SCR	None	0.05	0.43	0.43
FBC	Fabric Filter	No SCR	Dry FGD	0.05	0.43	0.43
FBC	Hot Side ESP + FGC	No SCR	None	1	1	1
FBC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.85	1
FBC	No Control	No SCR	None	1	1	1
PC	Cold Side ESP	SCR	None	0.64	0.97	1
PC	Cold Side ESP	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP	No SCR	None	0.64	0.97	1
PC	Cold Side ESP	No SCR	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP	No SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FF	No SCR	None	0.2	0.75	1
PC	Cold Side ESP + FF	No SCR	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC	SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.84	0.56
PC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC	No SCR	None	0.64	0.97	1
PC	Cold Side ESP + FGC	No SCR	Wet FGD	0.34	0.84	0.56
PC	Cold Side ESP + FGC	No SCR	Dry FGD	0.64	0.65	1
PC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.3	0.56
PC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Cold Side ESP + FGC + FF	No SCR	None	0.2	0.75	1
PC	Cold Side ESP + FGC + FF	No SCR	Wet FGD	0.3	0.3	0.56
PC	Cold Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	SCR	None	0.11	0.27	1
PC	Fabric Filter	SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	SCR	Dry FGD	0.05	0.75	1
PC	Fabric Filter	No SCR	None	0.11	0.27	1
PC	Fabric Filter	No SCR	Wet FGD	0.1	0.27	0.56
PC	Fabric Filter	No SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP	SCR	None	0.9	0.9	1
PC	Hot Side ESP	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP	No SCR	None	0.9	0.94	1
PC	Hot Side ESP	No SCR	Wet FGD	0.58	0.8	1
PC	Hot Side ESP	No SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FF	SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.15	0.56
PC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.75	1

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF	Lignite EMF
PC	Hot Side ESP + FF	No SCR	None	0.11	0.27	1
PC	Hot Side ESP + FF	No SCR	Wet FGD	0.03	0.27	0.56
PC	Hot Side ESP + FF	No SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC	SCR	None	0.9	0.9	1
PC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.8	1
PC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC	No SCR	None	0.9	0.94	1
PC	Hot Side ESP + FGC	No SCR	Wet FGD	0.58	0.8	1
PC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.85	1
PC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.75	1
PC	Hot Side ESP + FGC + FF	No SCR	None	0.11	0.27	1
PC	Hot Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.75	1
PC	No Control	SCR	None	1	1	1
PC	No Control	SCR	Wet FGD	0.1	0.7	1
PC	No Control	SCR	Dry FGD	0.6	0.85	1
PC	No Control	No SCR	None	1	1	1
PC	No Control	No SCR	Wet FGD	0.58	0.7	1
PC	No Control	No SCR	Dry FGD	0.6	0.85	1
PC	PM Scrubber	SCR	None	0.9	1	1
PC	PM Scrubber	SCR	Wet FGD	0.1	0.7	1
PC	PM Scrubber	SCR	Dry FGD	0.6	0.85	1
PC	PM Scrubber	No SCR	None	0.9	0.91	1
PC	PM Scrubber	No SCR	Wet FGD	0.58	0.7	1
PC	PM Scrubber	No SCR	Dry FGD	0.6	0.85	1

Table 5-11 Definition of Acronyms for Existing Controls

Acronym	Description
ESP	Electro Static Precipitator - Cold Side
HESP	Electro Static Precipitator - Hot Side
ESP/O	Electro Static Precipitator - Other
FF	Fabric Filter
FGD	Flue Gas Desulfurization - Wet
DS	Flue Gas Desulfurization - Dry
SCR	Selective Catalytic Reduction
PMSCRUB	Particulate Matter Scrubber

Table 5-12 Key to Burner Type Designations in Table 5-10

"PC" refers to conventional pulverized coal boilers. Typical configurations include wall-fired and tangentially fired boilers (also called T-fired boilers). In wall-fired boilers the burner's coal and air nozzles are mounted on a single wall or opposing walls. In tangentially fired boilers the burner's coal and air nozzles are mounted in each corner of the boiler.

"Cyclone" refers to cyclone boilers where air and crushed coal are injected tangentially into the boiler through a "cyclone burner" and "cyclone barrel" which create a swirling motion allowing smaller coal particles to be burned in suspension and larger coal particles to be captured on the cyclone barrel wall where they are burned in molten slag.

"FBC" refers to "fluidized bed combustion" where solid fuels are suspended on upward-blowing jets of air, resulting in a turbulent mixing of gas and solids and a tumbling action which provides especially effective chemical reactions and heat transfer during the combustion process.

5.4.3 Mercury Control Capabilities

EPA Base Case v.5.13 offers two options for mercury pollution control: (1) combinations of SO_2, NO_x, and particulate controls which deliver mercury reductions as a co-benefit and (2) Activated Carbon Injection (ACI), a retrofit option specifically designed for mercury control. These two options are discussed below.

Mercury Control through SO_2 and NO_x Retrofits

In EPA Base Case v.5.13, units that install SO_2, NO_x, and particulate controls, reduce mercury emissions as a byproduct of these retrofits. Section 5.4.2 described how EMFs are used in the base case to capture mercury emissions depending on the rank of coal burned, the generating unit's combustion characteristics, and the specific configuration of SO_2, NO_x, and particulate controls (i.e., hot and cold-side electrostatic precipitators (ESPs), fabric filters (also called "baghouses") and particulate matter (PM) scrubbers).

Activated Carbon Injection (ACI)

The technology used for mercury control in EPA Base Case v.5.13 is Activated Carbon Injection (ACI) downstream of the combustion process in coal fired units. Sargent & Lundy's updated cost and performance assumptions for ACI are used.

Three alternative ACI options are represented as capable of providing 90% mercury removal for all possible configurations of boiler, emission controls, and coal types used in the U.S. electric power sector. The three ACI options differ, based on whether they are used in conjunction with an electrostatic precipitator (ESP) or a fabric filter (also called a "baghouse"). The three ACI options are:

- ACI with Existing ESP
- ACI with Existing Baghouse
- ACI with an Additional Baghouse (also referred to as Toxecon)

In the third option listed above the additional baghouse is installed downstream of the pre-existing particulate matter device and the activated carbon is injected after the existing controls. This configuration allows the fly ash to be removed before it is contaminated by the mercury.

For modeling purposes, EPA currently assumes that all three configurations use brominated ACI, where a small amount of bromine is chemically bonded to the powdered carbon which is injected into the flue gas stream. EPA recognizes that amended silicates and possibly other non-carbon, non-brominated substances are in development and may become available as alternatives to brominated carbon as a mercury sorbent.

The applicable ACI option depends on the coal type burned, its SO_2 content, the boiler and particulate control type and, in some instances, consideration of whether an SO_2 scrubber (FGD) system and SCR NO_x post-combustion control are present.

Table 5-13 shows the ACI assignment scheme used in EPA Base Case v.5.13 to achieve 90% mercury removal.

Table 5-13 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Base Case v.5.13

Air pollution controls				Bituminous Coal			Subbituminous Coal			Lignite Coal		
Burner Type	Particulate Control Type	SCR System	FGD System	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acf)	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acf)	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acf)
FBC	Cold Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
FBC	Cold Side ESP without FGC	--	--	Yes	No	5	Yes	No	5	Yes	No	5
FBC	Fabric Filter	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
FBC	Fabric Filter	--	--	Yes	No	2	Yes	No	2	Yes	No	2
FBC	Hot Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter with FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP + Fabric Filter without FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Cold Side ESP with FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP with FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Cold Side ESP without FGC	--	Dry FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	--	--	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	--	Wet FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	--	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	Dry FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Cold Side ESP without FGC	SCR	Wet FGD	Yes	No	5	Yes	No	5	Yes	No	5
Non-FBC	Fabric Filter	--	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	Dry FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Fabric Filter	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	--	Dry FGD	No	No	0	Yes	No	2	Y(b)	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	Dry FGD	No	No	0	Yes	No	2	Y(b)	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Y(b)	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	--	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	Dry FGD	No	No	0	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter without FGC	SCR	Wet FGD	Yes	No	2	Yes	No	2	Yes	No	2
Non-FBC	Hot Side ESP with FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP with FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2

Air pollution controls				Bituminous Coal			Subbituminous Coal			Lignite Coal		
Burner Type	Particulate Control Type	SCR System	FGD System	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acf)	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acf)	ACI Required?	Toxecon Required?	Sorbent Inj Rate (lb/million acf)
Non-FBC	Hot Side ESP with FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	Hot Side ESP without FGC	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	No Control	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	--	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	Dry FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	--	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2
Non-FBC	PM Scrubber	SCR	Wet FGD	Yes	Yes	2	Yes	Yes	2	Yes	Yes	2

5.4.4 Methodology for Obtaining ACI Control Costs

Sargent & Lundy's ACI model assumes that the carbon feed rate dictates the size of the equipment and resulting costs. The feed rate in turn is a function of the required removal (in this case 90%) and the type of particulate control device. Sargent & Lundy established that a carbon feed rate of 5 pounds of carbon injected for every 1,000,000 actual cubic feet per minute (acfm) of flue gas would provide the stipulated 90% mercury removal rate for units shown in Table 5-14 as qualifying for ACI systems with existing ESP. For generating units with fabric filters a lower injection rate of 2 pound per million acfm is required. Alternative sets of costs were developed for each of the three ACI options: ACI systems for units with existing ESPs, ACI for units with existing fabric filters (baghouses), and the combined cost of ACI plus an additional baghouse for units that either have no existing particulate control or that require ACI plus a baghouse in addition to their existing particulate control. There are various reasons that a combined ACI plus additional baghouse would be required. These include situations where the existing ESP cannot handle the additional particulate load associate with the ACI or where SO_3 injection is currently in use to condition the flue gas for the ESP. Another cause for combined ACI and baghouse is use of PRB coal whose combustion produces mostly elemental mercury, not ionic mercury, due to this coal's low chlorine content.

For the combined ACI and fabric filter option a full size baghouse with an air-to-cloth (A/C) ratio of 4.0 is assumed, as opposed to a polishing baghouse with a 6.0 A/C ratio[31].

Table 5-14 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalties for the three ACI options represented in EPA Base Case v.5.13. For each ACI option values are shown for an illustrative set of generating units with a representative range of capacities and heat rates. See Attachment 5-6 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html) for details on the Sargent & Lundy model of ACI for Hg control.

[31] The "air-to-cloth" (A/C) ratio is the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater area of the cloth required and the higher the cost for a given volumetric flow

5.5 Hydrogen Chloride (HCl) Control Technologies

The following sub-sections describe how HCl emissions from coal are represented in IPM for EPA Base Case v.5.13, the emission control technologies available for HCl removal, and the cost and performance characteristics of these technologies.

5.5.1 Chlorine Content of Fuels

HCl emissions from the power sector result from the chlorine content of the coal that is combusted by electric generating units. Data on chlorine content of coals had been collected as part EPA's 1999 "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR 1999) described above in section 5.4.1 This data is incorporated into the model in order to provide the capability for EPA Base Case v.5.13 to project HCl emissions. The procedures used for this are presented below.

Western subbituminous coal (such as that mined in the Powder River Basin) and lignite coal contain natural alkalinity in the form of non-glassy calcium oxide (CaO) and other alkaline and alkaline earth oxides. This fly ash (classified as 'Class C' fly ash) has a natural pH of 9 and higher and the natural alkalinity can effectively neutralize much of the HCl in the flue gas stream prior to the primary control device.

Eastern bituminous coals, by contrast, tend to produce fly ash with lower natural alkalinity. Though bituminous fly ash (classified as 'Class F' fly ash) may contain calcium, it tends to be present in a glassy matrix and unavailable for acid-base neutralization reactions.

In order to assess the extent of expected natural neutralization, the 2010 ICR[32] data was examined. According to that data, units burning some of the subbituminous coals without operating acid gas control technology emitted substantially lower HCl emissions than would otherwise be expected from the chlorine content of those coals The data also showed that some other units burning subbituminous or lignite coals with higher levels of Cl were achieving 50-85 % HCl control with only cold-side ESP (i.e., with no flue gas desulfurization or other acid gas control technology). Comparing the Cl content of the subbituminous coals modeled in IPM with the ICR results supports an assumption that combustion of those coals can expect to experience at least 75% natural HCl neutralization from the alkaline fly ash. Therefore, the HCl emissions from combustion of lignite and subbituminous coals are reduced by 75% in EPA Base Case v.5.13.

[32] Collection Effort for New and Existing Coal- and Oil-Fired Electricty Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631)

Table 5-14 Illustrative Activated Carbon Injection (ACI) Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

					Capacity (MW)									
					100		300		500		700		1000	
Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M cost (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
ACI System with an Existing ESP	9,000	-0.10	0.10	2.19	37.89	0.32	14.90	0.13	9.65	0.08	7.25	0.06	5.35	0.04
	10,000	-0.11	0.11	2.43	38.51	0.32	15.14	0.13	9.81	0.08	7.36	0.06	5.44	0.05
Sorbent Injection Rate of 5 lbs/million acfm	11,000	-0.12	0.12	2.68	39.07	0.33	15.35	0.13	9.95	0.08	7.47	0.06	5.52	0.05
ACI System with an Existing Baghouse	9,000	-0.04	0.04	1.57	33.03	0.28	12.98	0.11	8.41	0.07	6.32	0.05	4.66	0.04
	10,000	-0.04	0.04	1.75	33.54	0.28	13.18	0.11	8.54	0.07	6.42	0.05	4.74	0.04
Sorbent Injection Rate of 2 lbs/million acfm	11,000	-0.05	0.05	1.92	34.02	0.29	13.38	0.11	8.66	0.07	6.51	0.06	4.81	0.04
ACI System with an Additional Baghouse	9,000	-0.64	0.64	0.47	291.26	1.02	219.74	0.77	195.35	0.68	181.36	0.63	167.98	0.59
	10,000	-0.64	0.65	0.52	314.32	1.10	238.18	0.83	212.02	0.74	196.97	0.69	182.55	0.64
Sorbent Injection Rate of 2 lbs/million acfm	11,000	-0.65	0.65	0.57	336.91	1.18	256.26	0.90	228.37	0.80	212.28	0.74	196.83	0.69

Note: The above cost estimates assume bituminous coal consumption.

5.5.2 HCl Removal Rate Assumptions for Existing and Potential Units

SO_2 emission controls on existing and new (potential) units provide the HCl reductions indicated in Table 5-15. New supercritical pulverized coal units (column 3) that the model builds include FGD (wet or dry) which is assumed to provide a 99% removal rate for HCl. For existing conventional pulverized coal units with pre-existing FGD (column 5), the HCl removal rate is assumed to be 5% higher than the reported SO_2 removal rate up to a maximum of 99% removal. In addition, for fluidized bed combustion units (column 4) with no FGD and no fabric filter, the HCl removal rate is assumed to be the same as the SO_2 removal rate up to a maximum of 95%. FBCs with fabric filters are assumed to have an HCl removal rate of 95%.

Table 5-15 HCl Removal Rate Assumptions for Potential (New) and Existing Units in EPA Base Case v.5.13

		Potential (New)	**Existing Units with FGD**		
Gas	**Controls**	**Supercritical Pulverized Coal with Wet or Dry FGD**	**Fluidized Bed Combustion (FBC)**	**Conventional Pulverized Coal (CPC) with Wet or Dry FGD**	**Existing Coal Steam Units with FGD Upgrade Adjustment**
HCl	Removal Rate	99%	**Without fabric filter: Same as reported SO_2** removal rate up to a maximum of 95% ––– **With fabric filter: 95%**	Reported SO_2 removal rate + 5% up to a maximum of 99%	If reported SO_2 removal < 90%, unit incurs cost to upgrade FGD, so that SO_2 removal is 90%. Then, the resulting HCl removal rate is 99% ––– If reported SO_2 removal is ≥ 90% and < 94%, then the unit incurs a cost to upgrade FGD and the HCl removal rate is 99%. (The SO_2 removal rate remains as reported.) ––– If the reported SO_2 removal rate is ≥ 94%, the unit incurs no upgrade cost and the HCl removal rate is 99%.

In EPA Base Case v.5.13, coal steam units with existing FGD that do not achieve an SO_2 removal rate of at least 90% are assumed to upgrade their FGDs in order to obtain at least 90% SO_2 removal and 99% HCl removal. The cost of this “FGD Upgrade Adjustment” is assumed to be $100/kW and is considered a sunk cost for modeling purposes.

5.5.3 HCl Retrofit Emission Control Options

The retrofit options for HCl emission control are discussed in detail in the following sub-sections and summarized in

Table 5-16. The scrubber upgrade adjustment was discussed above in 5.5.2.

Wet and Dry FGD

In addition to providing SO_2 reductions, wet scrubbers (Limestone Forced Oxidation, LSFO) and dry scrubbers (Lime Spray Dryer, LSD) reduce HCl as well. For both LSFO and LSD the HCl removal rate is assumed to be 99% with a floor of 0.0001 lbs/MMBtu. This is summarized in columns 2-5 of

Table 5-16.

Table 5-16 Summary of Retrofit HCl (and SO_2) Emission Control Performance Assumptions in v.5.13

Performance Assumptions	Limestone Forced Oxidation (LSFO)		Lime Spray Dryer (LSD)		Dry Sorbent Injection (DSI)	
	SO_2	HCl	SO_2	HCl	SO_2	HCl
Percent Removal	96% with a floor of 0.06 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	92% with a floor of 0.08 lbs/MMBtu	99% with a floor of 0.0001 lbs/MMBtu	70%	90% with a floor of 0.0001 lbs/MMBtu
Capacity Penalty Heat Rate Penalty Cost (2011$)	Calculated based on characteristics of the unit: See Table 5-3		Calculated based on characteristics of the unit: See Table 5-3		Calculated based on characteristics of the unit: See Excerpt from Table 5-22	
Applicability	Units ≥ 25 MW		Units ≥ 25 MW		Units ≥ 25 MW	
Sulfur Content Applicability			Coals ≤ 3.0 lbs of SO_2/MMBtu		Coals ≤ 2.0 lbs of SO_2/MMBtu	
Applicable Coal Types	BA, BB, BD, BE, BG, BH, SA, SB, SD, SE, LD, LE, LG, LH, PK and WC		BA, BB, BD, BE, SA, SB, SD, SE, LD, and LE		BA, BB, BD, SA, SB, SD, and LD	

Dry Sorbent Injection

EPA Base Case v.5.13 includes dry sorbent injection (DSI) as a retrofit option for achieving (in combination with a particulate control device) both SO_2 and HCl removal. In DSI for HCl reduction, a dry sorbent is injected into the flue gas duct where it reacts with the HCl and SO_2 in the flue gas to form compounds that are then captured in a downstream fabric filter or electrostatic precipitator (ESP) and disposed of as waste. (A sorbent is a material that takes up another substance by either adsorption on its surface or absorption internally or in solution. A sorbent may also chemically react with another substance.) The sorbent assumed in the cost and performance characterization discussed in this section is Trona (sodium sesquicarbonate), a sodium-rich material with major underground deposits found in Sweetwater County, Wyoming. Trona is typically delivered with an average particle size of 30 µm diameter, but can be reduced to about 15 µm through onsite in-line milling to increase its surface area and capture capability.

Removal rate assumptions: The removal rate assumptions for DSI are summarized in

Table 5-16. The assumptions shown in the last two columns of

Table 5-16 were derived from assessments by EPA engineering staff in consultation with Sargent & Lundy. As indicated in this table, the assumed SO_2 removal rate for DSI + fabric filter is 70%. The retrofit DSI option on an existing unit with existing ESP is always provided in combination with a fabric filter (Toxecon configuration) in EPA Base Case v.5.13.

Methodology for Obtaining DSI Control Costs: Sargent & Lundy's updated performance/cost model for DSI is used in EPA Base Case v.5.13 to derive the cost of DSI retrofits with two alternative, associated particulate control devices, i.e., ESP and fabric filter "baghouse". Their analysis of DSI noted that the cost drivers of DSI are quite different from those of wet or dry FGD. Whereas plant size and coal sulfur rates are key underlying determinants of FGD cost, sorbent feed rate and fly ash waste handling are the main drivers of the capital cost of DSI with plant size and coal sulfur rates playing a secondary role.

In EPA Base Case v.5.13 the DSI sorbent feed rate and variable O&M costs are based on assumptions that a fabric filter and in-line trona milling are used, and that the SO_2 removal rate is 70%. The corresponding HCl removal effect is assumed to be 90%, based on information from Solvay Chemicals (H. Davidson, *Dry Sorbent Injection for Multi-pollutant Control Case Study*, CIBO IECT VIII, August, 2010).

The cost of fly ash waste handling, the other key contributor to DSI cost, is a function of the type of particulate capture device and the flue gas SO_2.

Total waste production involves the production of both reacted and unreacted sorbent and fly ash. Sorbent waste is a function of the sorbent feed rate with an adjustment for excess sorbent feed. Use of sodium-based DSI may make the fly ash unsalable, which would mean that any fly ash produced must be landfilled along with the reacted and unreacted sorbent waste. Typical ash contents for each fuel are used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for the total waste stream for the VOM analysis.

For purposes of modeling, the total VOM includes the first two component costs noted in the previous paragraph, i.e., the costs for sorbent usage and the costs associated with waste production and disposal.

Table 5-17 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalties of a DSI retrofit for an illustrative and representative set of generating units with the capacities and heat rates indicated. See Attachment 5-5 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html) for details on the Sargent & Lundy DSI model.

5.6 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option. In EPA Base Case v.5.13, an existing or new fabric filter particulate control device is a pre-condition for installing a DSI retrofit, and the cost of these retrofits at plants without an existing fabric filter include the cost of installing a new fabric filter. This cost was added to the DSI costs discussed in section 5.5.3.2. The costs associated with a new fabric filter retrofit are derived from Sargent & Lundy's performance/cost model. Similarly, dry scrubber retrofit costs also include the cost of a fabric filter.

The engineering cost analysis is based on a pulse-jet fabric filter which collects particulate matter on a fabric bag and uses air pulses to dislodge the particulate from the bag surface and collect it in hoppers for removal via an ash handling system to a silo. This is a mature technology that has been operating commercially for more than 25 years. "Baghouse" and "fabric filters" are used interchangeably to refer to such installations.

Capital Cost: The major driver of fabric filter capital cost is the "air-to-cloth" (A/C) ratio. The A/C ratio is defined as the volumetric flow, (typically expressed in Actual Cubic Feet per Minute, ACFM) of flue gas entering the baghouse divided by the areas (typically in square feet) of fabric filter cloth in the baghouse. The lower the A/C ratio, e.g., A/C = 4.0 compared to A/C = 6.0, the greater the area of the cloth required and the higher the cost for a given volumetric flow. An air-to-cloth ratio of 4.0 is used in EPA Base Case v.5.13, and it is assumed that the existing ESP remains in place and active.

Table 5-18 presents the capital, VOM, and FOM costs for fabric filters as represented in EPA Base Case v.5.13 for an illustrative set of generating units with a representative range of capacities and heat rates. See Attachment 5-7 (www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html) for details of the Sargent & Lundy fabric filter PM control model.

Table 5-17 Illustrative Dry Sorbent Injection (DSI) Costs for Representative Sizes and Heat Rates under Assumptions in EPA Base Case v.5.13

						Capacity (MW)									
						100		300		500		700		1000	
Control Type	Heat Rate (Btu/kWh)	SO_2 Rate (lb/ MMBtu)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
DSI	9,000	2.0	-0.64	0.65	8.49	138.5	3.71	63.1	1.38	43.7	0.88	34.4	0.65	31.6	0.52
Assuming	10,000	2.0	-0.71	0.72	9.44	142.8	3.75	65.0	1.40	45.1	0.89	35.1	0.66	35.1	0.55
Bituminous Coal	11,000	2.0	-0.79	0.79	10.39	146.8	3.78	66.9	1.41	46.4	0.90	38.6	0.69	38.6	0.58

Table 5-18 Illustrative Particulate Controls for Costs (2011$) for Representative Sizes and Heat Rates under the Assumptions in EPA Base Case v.5.13

					Capacity (MW)									
					100		300		500		700		1000	
Coal Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M (mills/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)
	9,000	-0.60	0.60	0.05	251	0.9	204	0.7	185	0.6	174	0.6	162	0.6
Bituminous	10,000			0.06	274	1.0	222	0.8	202	0.7	189	0.7	177	0.6
	11,000			0.07	296	1.0	240	0.8	218	0.8	204	0.7	191	0.7

5.6.1 MATS Filterable Particulate Matter (PM) Compliance

EPA Base Case v.5.13 assumes that all coal-fired generating units with a capacity greater than 25 MW will comply with the MATS filterable PM requirements through the operation of either electrostatic precipitator (ESP) or fabric filter (FF) particulate controls. The control mechanism is not modeled endogenously but supplied as an input when setting up the run as specified below.

Units with existing fabric filters are assumed to be able to meet the filterable PM compliance requirement. For units with existing ESPs the following procedure is used to determine if they already meet the filterable PM requirement, can meet it by one of three possible ESP upgrades, or can only meet it by installing a FF.

First, PM emission rate data derived either from 2005 EIA Form 767 or (where available) from EPA's 2010 Information Collection Request[33] are compared to the applicable filterable PM compliance requirement. If the unit's emission rate is equal to or less than the compliance requirement, adequate controls are assumed already to be in place and no additional upgrade costs are imposed. For units that do not meet the filterable PM compliance requirement, the incremental reduction needed (in lbs/mmBtu) is calculated by subtracting the filterable PM compliance standard from the reported emission rate. Depending on the magnitude of the incremental reduction needed, the unit is assigned one of three ESP upgrade costs (designated ESP1, ESP2, and ESP3) or the cost of a FF installation (designated ESP4), if the required incremental reduction cannot be achieved by an ESP upgrade. Table 5-19 shows the four levels of ESP upgrades (column 1), the key technologies included in each upgrade (column 2), trigger points for the upgrades (column 3), the capital cost of each upgrade (column 4), and the percent increase in collection efficiency provided by the upgrade, differentiated according to the rank (subbituminous, bituminous, or lignite) of coal burned.

The percentage improvements in collection efficiency shown in column 5 in Table 5-19 are additive in the sense that the values shown in this column are added to the pre-upgrade collection efficiency to obtain the after-upgrade collection efficiency.

Table 5-19 Electrostatic Precipitator (ESP) Upgrades as Implemented in EPA Base Case v.5.13 --- Characteristics, Trigger Points, Associated Costs, and Performance Improvements

Upgrade Level	Key Technologies Employed in Upgrade	Trigger Points for ESP Upgrade (Expressed in terms of incremental reduction needed (lbs/mmBtu) to meet the filterable PM Compliance Standard)	Capital Cost	Additive Percent Improvement[e] in Collection Efficiency as a Result of the Upgrade (differentiated by the rank of coal combusted)
1	High Frequency transformer-rectifier (TR) sets	> 0.0 to ≤ 0.005	\$55/kW[a]	0.12 for subbituminous 0.05 for bituminous 0.01 for lignite
2	High frequency transformer-rectifier (TR) sets + New internals (rigid electrodes, increased plate spacing, increased plate height)	> 0.005 to ≤ 0.01	\$80/kW[b]	0.25 for subbituminous 0.10 for bituminous 0.02 for lignite

[33] 2005 EIA Form 767 is the last year where the data was reported in the format of lb/MMBtu, which is compatible with this analysis. Since any changes to facilities since 2005 would likely have improved (reduced) emissions, the use of this data is conservative. More recent 2010 ICR test data is used where available. (Collection Effort for New and Existing Coal- and Oil-Fired Electricty Utility Steam Generating Units (EPA ICR No.2362.01 (OMB Control Number 2060-0631).

Upgrade Level	Key Technologies Employed in Upgrade	Trigger Points for ESP Upgrade (Expressed in terms of incremental reduction needed (lbs/mmBtu) to meet the filterable PM Compliance Standard)	Capital Cost	Additive Percent Improvement[e] in Collection Efficiency as a Result of the Upgrade (differentiated by the rank of coal combusted)
3	High frequency transformer-rectifier (TR) sets + New internals (rigid electrodes, increased plate spacing, increased plate height) + Additional field	> 0.01 to ≤ 0.02	\$100/kW[c]	0.50 for subbituminous 0.20 for bituminous 0.05 for lignite
4	Replacement with fabric filter (baghouse)	> 0.02	Use capital cost equations for a fabric filter[d]	(Not Applicable)

[a] Assumes upgrading the specific collection area (SCA) to 250 square-feet/1000 afm (actual feet per minute).
[b] Assumes upgrading the specific collection area (SCA) to 300 square-feet/1000 afm (actual feet per minute).
[c] Assumes upgrading the existing specific collection area (SCA) by 100 square-feet/1000 afm (actual feet per minute), a 20% height increase, and additional field.
[d] The cost equations for fabric filters are described in Section 5.5.4
[e] The percentage improvement due to the ESP upgrade as shown in this column is added to the pre-upgrade collection efficiency to obtain the after-upgrade collection removal efficiency.

Excerpt from Table 5-20 contains a complete listing of coal generating units with either cold- or hot-side ESPs but no fabric filters. For each generating unit in Excerpt from Table 5-20 shows the incremental reductions needed to meet the PM filterable compliance requirement and the corresponding ESP upgrade (if any) assigned to the unit to enable it to meet that requirement. A filterable PM limit of 0.279 lb/mmBtu was used in this analysis. This value is roughly 10% below the limit in the final MATS rule, therefore resulting in a conservative estimate of the need to upgrade existing ESPs.

5.7 Coal-to-Gas Conversions[34]

In EPA Base Case v.5.13 existing coal plants are given the option to burn natural gas in addition to coal by investing in a coal-to-gas retrofit. There are two components of cost in this option: Boiler modification costs and the cost of extending natural gas lateral pipeline spurs from the boiler to a natural gas main pipeline. These two components of cost and their associated performance implications are discussed in the following sections.

5.7.1 Boiler Modifications For Coal-To-Gas Conversions

Enabling natural gas firing in a coal boiler typically involves installation of new gas burners and modifications to the ducting, windbox (i.e., the chamber surrounding a burner through which pressurized air is supplied for fuel combustion), and possibly to the heating surfaces used to transfer energy from the exiting hot flue gas to steam (referred to as the “convection pass”). It may also involve modification of environmental equipment. Engineering studies are performed to assess operating characteristics like furnace heat absorption and exit gas temperature; material changes affecting piping and components like superheaters, reheaters, economizers, and recirculating fans; and operational changes to sootblowers, spray flows, air heaters, and emission controls.

[34] As discussed here coal-to-gas conversion refers to the modification of an existing boiler to allow it to fire natural gas. It does not refer to the addition of a gas turbine to an existing boiler cycle, the replacement of a coal boiler with a new natural gas combined cycle plant, or to the gasification of coal for use in a natural gas combustion turbine

Excerpt from Table 5-20 ESP Upgrade Provided to Existing Units without Fabric Filters so that They Meet Their Filterable PM Compliance Requirement

This is a small excerpt of the data in Excerpt from Table 5-20. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html)

Plant Name	Unit ID	State Name	Unique ID	Capacity (MW)	Level of ESP Upgrade Required to Meet Filterable PM Requirement
A B Brown	2	Indiana	6137_B_2	245	---
AES Beaver Valley Partners Beaver Valley	2	Pennsylvania	10676_B_2	43	ESP-4
AES Beaver Valley Partners Beaver Valley	3	Pennsylvania	10676_B_3	43	ESP-4
AES Beaver Valley Partners Beaver Valley	4	Pennsylvania	10676_B_4	43	ESP-1
AES Cayuga	1	New York	2535_B_1	150	---
AES Cayuga	2	New York	2535_B_2	151	---
AES Deepwater	AAB001	Texas	10670_B_AAB001	139	---
AES Somerset LLC	1	New York	6082_B_1	681	---
Allen Steam Plant	1	Tennessee	3393_B_1	245	---
Allen Steam Plant	2	Tennessee	3393_B_2	245	---
Allen Steam Plant	3	Tennessee	3393_B_3	245	---
Alma	B4	Wisconsin	4140_B_B4	51	---
Alma	B5	Wisconsin	4140_B_B5	77	ESP-4
Ames Electric Services Power Plant	7	Iowa	1122_B_7	33	---
Ames Electric Services Power Plant	8	Iowa	1122_B_8	70	---
Apache Station	2	Arizona	160_B_2	175	---
Apache Station	3	Arizona	160_B_3	175	---
Asbury	1	Missouri	2076_B_1	213	ESP-4
Asheville	1	North Carolina	2706_B_1	191	---
Asheville	2	North Carolina	2706_B_2	185	---

The following table summarizes the cost and performance assumptions for coal-to-gas boiler modifications as incorporated in EPA Base Case v.5.13. The values in the table were developed by EPA's engineering staff based on technical papers[35] and discussions with industry engineers familiar with such projects. They were designed to be applicable across the existing coal fleet.

Table 5-21 Cost and Performance Assumptions for Coal-to-Gas Retrofits

Factor	Description	Notes
Applicability:	Existing pulverized coal (PC) fired and cyclone boiler units of a size greater than 25 MW:	Not applicable for fluidized bed combustion (FBC) and stoker boilers.
Capacity Penalty:	None	The furnace of a boiler designed to burn coal is oversized for natural gas, and coal boilers include equipment, such as coal mills, that are not needed for gas. As a result, burning gas should have no impact on net power output.

[35] For an example see Babcock and Wilcox's White Paper MS-14 "Natural Gas Conversions of Exiting Coal-Fired Boilers" 2010 (www.babcock.com/library/tech-utility.html#14).

Factor	Description	Notes
Heat Rate Penalty:	+ 5%	When gas is combusted instead of coal, the stack temperature is lower and the moisture loss to stack is higher. This reduces efficiency, which is reflected in an increase in the heat rate.
Incremental Capital Cost:	PC units: $/kW = 267*(75/MW)^0.35 Cyclone units: $/kW = 374*(75/MW)^0.35	The cost function covers new gas burners and piping, windbox modifications, air heater upgrades, gas recirculating fans, and control system modifications. <u>Example for 50 MW PC unit:</u> $/kW = 267*(75/50)^0.35 = 308
Incremental Fixed O&M:	-33% of the FOM cost of the existing coal unit	Due to reduced needs for operators, maintenance materials, and maintenance staff when natural gas combusted, FOM costs decrease by 33%.
Incremental Variable O&M:	-25% of the VOM cost of the existing coal unit	Due to reduced waste disposal and miscellaneous other costs, VOM costs decrease by 25%.
Fuel Cost:	Natural gas	To obtain natural gas the unit incurs the cost of extending lateral pipeline spurs from the boiler location to the natural gas transmission pipeline. See section 5.7.2.
NO_x emission rate:	50% of existing coal unit NO_x emission rate, with a floor of 0.05 lbs/MMBtu	The 0.05 lbs/MMBtu floor is the same as the NO_x rate floor for new retrofit SCR on units burning subbituminous coal
SO_2 emissions:	Zero	

5.7.2 Natural Gas Pipeline Requirements For Coal-To-Gas Conversions

For every individual coal boiler in the U.S., EPA tasked ICF to determine the miles and associated cost of extending pipeline laterals from each boiler to the interstate natural gas pipeline system.

To develop these costs the following principles were applied:

- For each boiler, gas volume was estimated based on size and heat rate.
- Direct distance to the closest pipeline was calculated. (The analysis only considered mainlines with diameters that were 16 inches or greater. The lateral distance represented the shortest distance – “as the crow flies” – between the boiler and the mainline.)
- Gas volume (per day) of the initial lateral was not allowed to exceed more than 10 percent of the estimated capacity of the mainline.
- The mainline capacities were estimated from the pipe’s diameter using the Weymouth equation[36].
- If the gas requirement exceeded 10 percent of the estimated capacity of the mainline, the cost of a second lateral to connect to the next closest mainline was calculated.
- This procedure was repeated until the entire capacity required for the boiler was reached.
- Diameters of each lateral were then calculated using the Weymouth equation based on their required capacities.

[36] The Weymouth equation in classical fluid dynamics is used in calculating compressible gas flow as a function of pipeline diameter and friction factors. It is used for pipe sizing.

- The cost of all the laterals was calculated based on the pipeline diameter and mileage required. Thus, the final pipeline cost for each boiler was based on the total miles of laterals required.

Figure 5-1 shows the calculations performed.

Figure 5-1 Calculations Performed in Costing Lateral Pipeline Requirement

Mainline Flow Capacity, Qm (million cubic feet per day)

$Qm = 0.06745 * d^{2.667}$, where d is the diameter of the mainline in inches

Required Capacity of Lateral/s for Each Boiler, Ql (million cubic feet per day)

Ql = (Boiler Capacity * Heat Rate *24) / 1,030,000, where Boiler Capacity is in MW and the Heat Rate is in Btu/kWh

Diameter of Each Lateral, D (inches)

$D = (14.83 * Ql)^{0.37495}$, where each lateral's capacity may not exceed 10% of the mainline capacity to which the lateral connects

Cost per Lateral, C ($)

C = 90,000 *D * Number of Miles

Note: The above calculations assume a pipeline cost of $90,000 per inch-mile based on recently completed projects.

There are several points to note about the above approach. First, for relatively large boilers or in cases where the closest mainline has a relatively small diameter, multiple laterals are required to connect the boiler to the interstate gas transmission grid. This assures that each individual boiler will not become a relatively large portion of a pipelines' transmission capacity. It also reflects real-world practices where larger gas-fired power plants typically have multiple laterals connecting them to different mainlines. This increases the reliability of their gas supply and provides multiple options for gas purchase allowing them to capture favorable prices from multiple sources of gas supply at different points in time.

Second, expansion of mainlines was not included in the boiler specific pipeline cost, because the integrated gas model within IPM already includes corridor expansion capabilities. However, if in future IPM runs, multiple converted boilers are concentrated on a single pipeline along a corridor that includes multiple pipelines, a further assessment may be required to make sure that the mainline expansion is not being understated due to modeled efficiencies that may not actually be available in the field.

Figures 5-2 through 5-7 summarize the results of the pipeline costing procedure described above. They provide histograms of the number of laterals required per boiler (

Figure 5-2), miles of pipeline required per boiler (Figure 5-3), diameters of the laterals in inches (

Figure 5-4), total inch-miles of laterals required per boiler (Figure 5-5), total cost to each boiler in million$ (Figure 5-6), and cost (in $) per kW of boiler capacity (Figure 5-7). Excerpt from Table 5-22 shows the pipeline costing results for each qualifying existing coal fired unit represented in EPA Base Case v.5.13.

Figure 5-2 Number of Laterals Required per Boiler

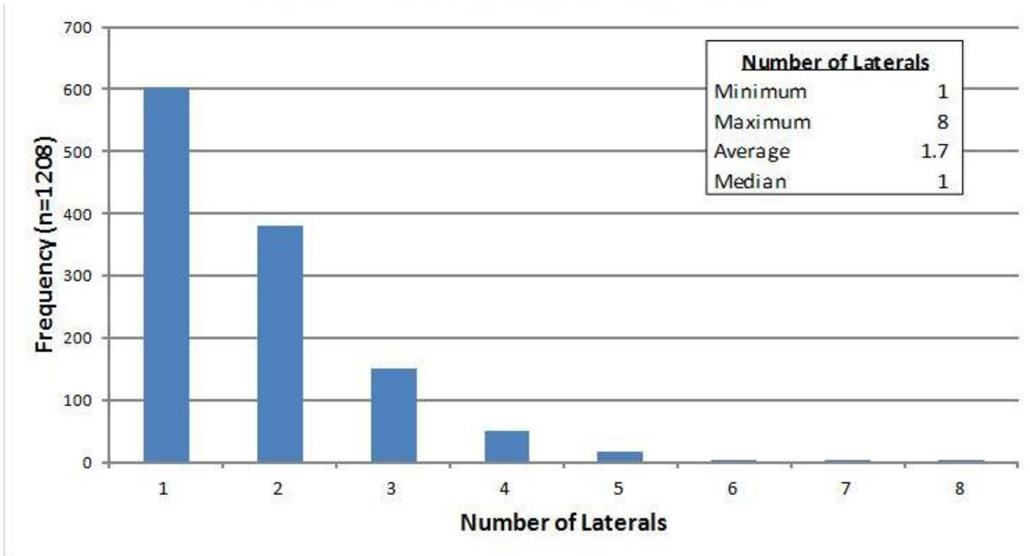


Figure 5-3 Miles of Pipeline Required per Boiler

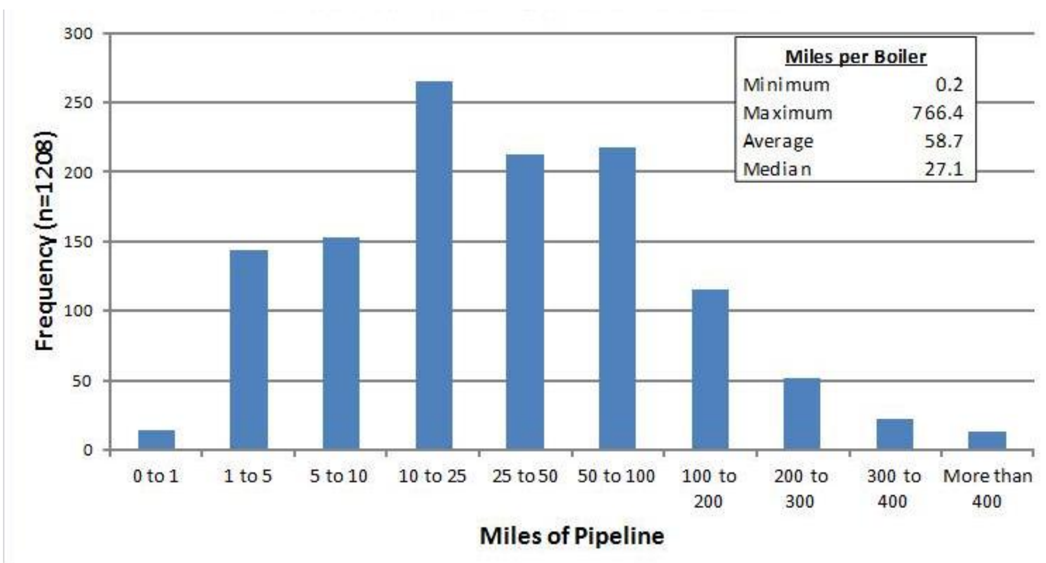


Figure 5-4 Diameter of Laterals

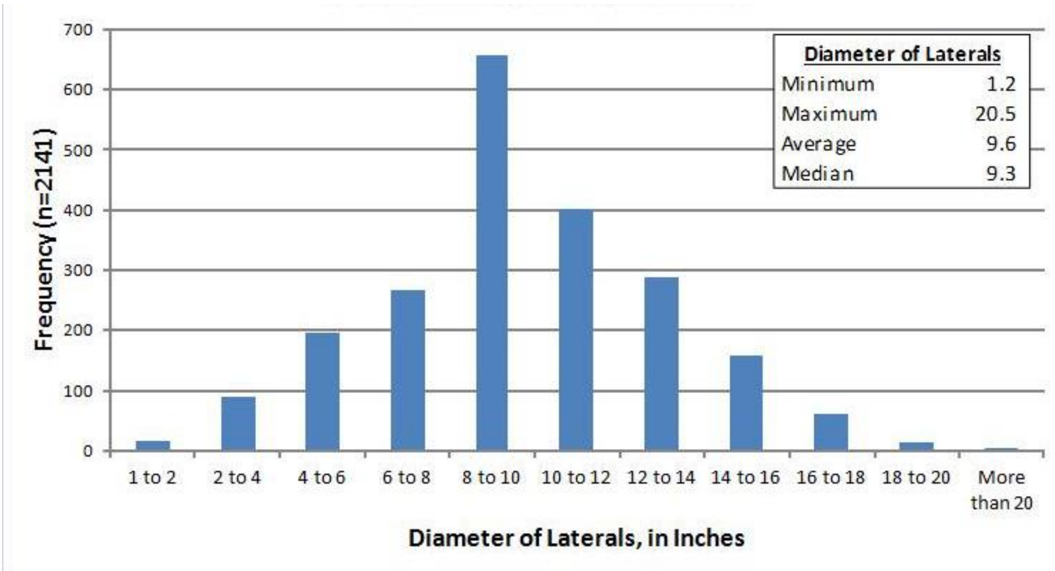


Figure 5-5 Total Inch-Miles of Laterals Required per Boiler

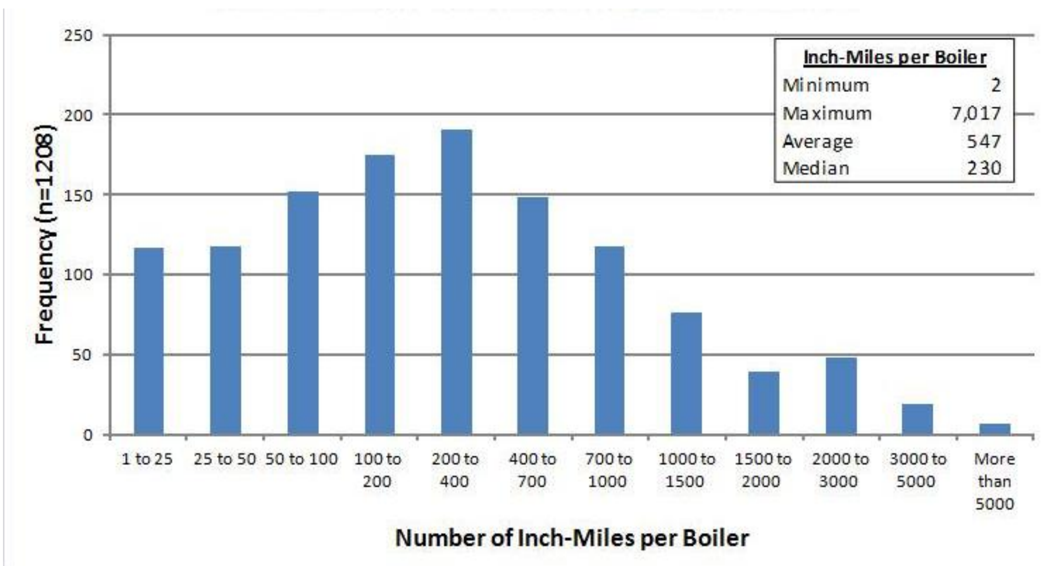


Figure 5-6 Total Cost to Each Boiler

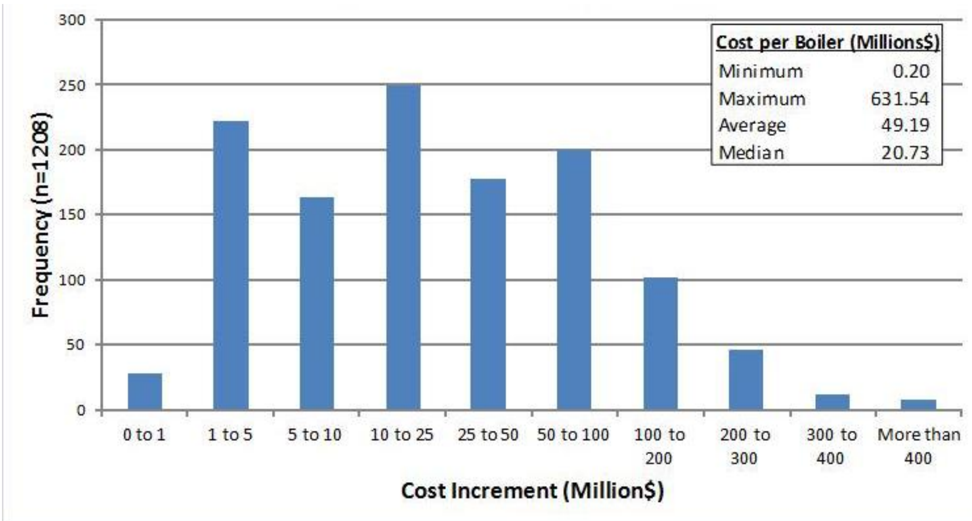
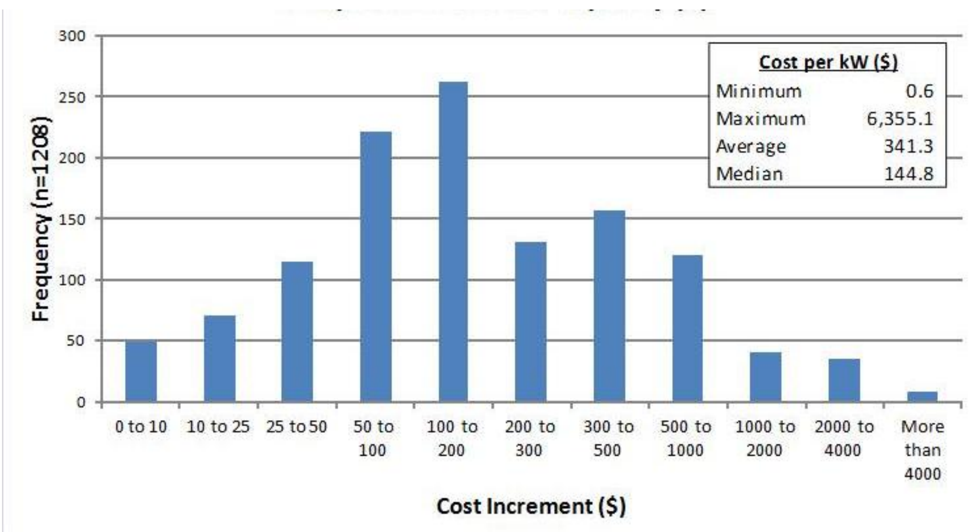


Figure 5-7 Cost per kW of Boiler Capacity



Excerpt from Table 5-22 Cost of Building Pipelines to Coal Plants

This is a small excerpt of the data in Table-22. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

Unique ID	Plant Name	State Name	Coal Boiler Capacity (MW)	Number of Laterals Required	Miles of New Pipeline Required to Hook Up Unit (miles)	Cost of New Pipeline (2011$)	Cost of New Pipeline per KW of Coal Capacity (2011$/kW)
3_B_1	Barry	Alabama	138	2	8.5	2324786	16.85
3_B_2	Barry	Alabama	137	2	8.5	2136794	15.60
3_B_3	Barry	Alabama	249	2	8.5	7209727	28.95
3_B_4	Barry	Alabama	362	2	8.5	8979092	24.80
3_B_5	Barry	Alabama	726	2	8.5	12412831	17.10
7_G_1	Gadsden	Alabama	64	1	28.7	22383509	349.74
7_G_2	Gadsden	Alabama	66	1	28.7	22617875	342.70
8_B_10	Gorgas	Alabama	703	2	68.4	87979597	125.15
8_B_6	Gorgas	Alabama	103	1	7.6	6250679	60.69
8_B_7	Gorgas	Alabama	104	1	7.6	6269532	60.28
8_B_8	Gorgas	Alabama	161	1	7.6	7407093	46.01
8_B_9	Gorgas	Alabama	170	1	7.6	7533473	44.31
10_B_1	Greene County	Alabama	254	1	6.9	7898586	31.10
10_B_2	Greene County	Alabama	243	1	6.9	7776757	32.00
26_B_1	E C Gaston	Alabama	254	1	23.0	26126943	102.86
26_B_2	E C Gaston	Alabama	256	1	23.0	26294370	102.71
26_B_3	E C Gaston	Alabama	254	1	23.0	26143766	102.93
26_B_4	E C Gaston	Alabama	256	1	23.0	26143766	102.12
26_B_5	E C Gaston	Alabama	842	3	162.4	201898208	239.78
47_B_1	Colbert	Alabama	178	1	0.7	725276	4.07
47_B_2	Colbert	Alabama	178	1	0.7	722785	4.06
47_B_3	Colbert	Alabama	178	1	0.7	722785	4.06
47_B_4	Colbert	Alabama	178	1	0.7	723409	4.06
47_B_5	Colbert	Alabama	472	2	4.6	5183155	10.98
50_B_7	Widows Creek	Alabama	473	3	253.0	231385577	489.19
50_B_8	Widows Creek	Alabama	465	3	253.0	227553333	489.36
51_B_1	Dolet Hills	Louisiana	638	4	28.3	28812871	45.16
56_B_1	Charles R Lowman	Alabama	80	1	17.3	13132673	164.16
56_B_2	Charles R Lowman	Alabama	235	2	43.8	38349442	163.19
56_B_3	Charles R Lowman	Alabama	235	2	43.8	38128365	162.25
59_B_1	Platte	Nebraska	100	1	25.8	21561000	215.61
60_B_1	Whelan Energy Center	Nebraska	77	1	8.1	6169545	80.12
60_B_2	Whelan Energy Center	Nebraska	220	1	8.1	9036600	41.08
87_B_1	Escalante	New Mexico	247	2	11.4	7831404	31.71
108_B_SGU1	Holcomb	Kansas	362	5	77.1	43429164	119.97
113_B_1	Cholla	Arizona	116	1	27.5	23648324	203.86
113_B_2	Cholla	Arizona	260	1	27.5	32391059	124.58
113_B_3	Cholla	Arizona	271	1	27.5	32691880	120.63

5.8 Natural Gas Co-firing

Existing coal plants with existing natural gas pipelines have an option of co-firing with natural gas. Gas co-firing at these units is limited to 10% of the unit's power output.

The option of co-firing with gas at an existing coal boiler is only offered if one of the following two criteria based on 2012 EIA 860, 2012 EIAForm 923 and NEEDS v.5.13 is met: (1) the unit reported the use of gas as a startup fuel, or (2) an existing gas-fired unit (e.g., NGCC) is located at the same facility (with the same ORIS) as the coal-fired unit. EPA assumes that in either of these cases, sufficient pipeline capacity exists to supply up to 10% of total power output of the coal steam boiler located at these sites. These units are detailed below in Excerpt from Table 5-23.

Similar to the coal-to-gas retrofit option, there is a 5% increase in heat rate for the share of generation fueled by natural gas (accounting for the increased flue gas moisture and stack heat loss). On a $/kWh basis, any change in capital or operating costs of co-firing with natural gas at low levels is very small. Hence, EPA do not include additional capital or operating costs for this option.

Excerpt from Table 5-23 List of Coal Steam Units with Natural Gas Co-firing option

This is a small excerpt of the data in Excerpt from Table 5-23. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

UniqueID	Plant Name	ORIS Code	State Name	Capacity (MW)
10684_G_TG5	Argus Cogen Plant	10684	California	7
1077_G_3	Sutherland	1077	Iowa	78
1554_G_2	Herbert A Wagner	1554	Maryland	135
2943_G_3	Shelby Municipal Light Plant	2943	Ohio	5
511_G_1	Trinidad	511	Colorado	3.8
54407_G_1	Waupun Correctional Central Heating Plt	54407	Wisconsin	0.2
54407_G_2	Waupun Correctional Central Heating Plt	54407	Wisconsin	0.5
56564_G_1	John W Turk Jr Power Plant	56564	Arkansas	609
56785_G_WG01	Virginia Tech Power Plant	56785	Virginia	2.5
7_G_1	Gadsden	7	Alabama	64
7_G_2	Gadsden	7	Alabama	66
728_G_4	Yates	728	Georgia	133
728_G_5	Yates	728	Georgia	135
10_B_1	Greene County	10	Alabama	254
10_B_2	Greene County	10	Alabama	243

6. CO_2 Capture, Transport, and Storage

6.1 CO_2 Capture

Among the potential (new) units that the model can build in EPA Base Case v.5.13 are advanced coal-fired units with CO_2 capture (carbon capture).[37] The cost and performance characteristics of these units are shown in Table 4-13 and are discussed in Chapter 4.

In addition to offering carbon capture capabilities on potential units that the model builds as new capacity, EPA Base Case v.5.13 provides carbon capture as a retrofit option for existing pulverized coal plants. The incremental costs and performance assumptions for these retrofits are shown in Table 6-1.

Table 6-1 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Pulverized Coal Plants

Applicability (Original MW Size)	**> 400 MW**
Incremental[a] Capital Cost (2011 $/kW)	1,794
Incremental[a] FOM (2011 $/kW-yr)	27.2
Incremental[a] VOM (2011 (mills/kWh)	3.2
Capacity Penalty (%)	-25%
Heat Rate Penalty (%)	33%
CO_2 Removal (%)	90%

Note:
[a] Incremental costs are applied to the derated (after retrofit) MW size.

The capital costs shown in Table 6-1 are based on the costs reported for Case 1 in a study performed for the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) by a team consisting of Alstom Power, Inc., American Electric Power (AEP), ABB Global, and the Ohio Coal Development Office.[38] For Case 1 this comprehensive engineering study, conducted from 1999-2001, evaluated the impacts on plant performance and the required cost to add facilities to capture greater than 90% of the CO_2 emitted by AEP's Conesville Ohio Unit #5. This is a 450 MW subcriticalpulverized bituminous coal plant with a lime based FGD, and an electrostatic precipitator for particulate control.[39] The carbon capture method that was evaluated was an amine-based scrubber using the Kerr-McGee/ABB Lummus Global commercially available monoethanolamine (MEA) process. In this system the flue gas leaves the FGD (which has been modified to reduce the SO_2 concentration as required by the MEA process) and is cooled and ducted to the MEA system where more than 96% of the CO_2 can be removed. For use in EPA Base Case v.5.13 the capital cost was converted to constant 2011$ from the 2006$ costs reported in the NETL study.

A capacity derating penalty of 25% was assumed, based on reported research and field experience as of 2010. The corresponding heat rate penalty was 33%. (For an explanation of the capacity and heat rate penalties and how they are calculated, see the discussion under VOM in section 5.1.1.)

[37] The term "New Advanced Coal with CCS" encompasses various technologies that can provide carbon capture. These include supercritical steam generators with carbon capture and integrated gasification combined cycle (IGCC) with carbon capture. For purposes of characterizing the cost and performance characteristics of advanced coal with carbon capture, supercritical steam generators with carbon capture was used in Table 4-13.

[38] Carbon Dioxide Capture from Existing Coal-Fired Power Plants" DOE/NETL-401/110907. Final Report (Original Issue Date, December 2006) Revision Date, November 2007 (http://www.netl.doe.gov/energy-analyses/pubs/CO2%20Retrofit%20From%20Existing%20Plants%20Revised%20November%202007.pdf. A summary of costs for each of the cases appears in Table 3-65 (p. 139).

[39] Subcritical" refers to thermal power plants that operate below the "critical temperature" and "critical pressure" (220 bar) where boiling (i.e., the formation of steam bubbles in water) no longer occurs. Such units are less efficient than "supercritical" and "ultra supercritical" steam generators.

Since the fixed (FOM) and variable operating and maintenance (VOM) costs from the Conesville study were given without documentation, EPA relied on a NETL study that fully documented these costs coupled with the expert judgment of EPA's engineering staff to obtain the FOM and VOM values shown in Table 6-1.[40]

6.2 CO_2 Storage

The capacity and cost assumptions for CO_2 storage in EPA Base Case v.5.13 are based on GeoCAT (Geosequestration Cost Analysis Tool), a spreadsheet model developed for EPA by ICF in support of EPA's draft Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Storage Wells.[41] The GeoCAT model combines detailed characteristics of sequestration capacity by state and geologic setting for the U.S. with costing algorithms for individual components of geologic sequestration of CO_2. The outputs of the model are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 storage cost points.

The GeoCAT model includes three modules: a unit cost specification module, a project scenario costing module, and a geologic and regional cost curve module. The unit cost module includes data and assumptions for 120 unit cost elements falling within the following cost categories:

- Geologic site characterization
- Monitoring the movement of CO_2 in the subsurface
- Injection well construction
- Area of review and corrective action (including fluid flow and reservoir modeling during and after injection and identification, evaluation, and remediation of existing wells within the area of review)
- Well operation
- Mechanical integrity testing
- Financial responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
- General and administrative

Of the ten cost categories for geologic CO_2 sequestration listed above, the largest cost drivers (in roughly descending order of magnitude) are well operation, injection well construction, and monitoring.

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for seven sequestration scenarios of geologic settings:

- Saline reservoirs
- Depleted gas fields
- Depleted oil fields
- Enhanced oil recovery
- Enhanced coal bed methane recovery

[40] Cost and Performance Baseline for Fossil Energy Plants" DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report (Original Issue Date, May 2007) Revision 1, August 2007 (http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf). The VOM and FOM cost calculations for Case 9 appear in Exhibits 4-14 (p. 349) and for Case 10 in Exhibit 4-24 (p. 373).

[41] Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells," *Federal Register*, July 25, 2008 (Volume 73, Number 144), pp. 43491-43541. www.epa.gov/fedrgstr/EPA-WATER/2008/July/Day-25/w16626.htm and www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment.

- Enhanced shale gas
- Basalt storage

EPA's application of GeoCAT includes only storage capacity for the first four scenarios. The last three reservoir types are not included because they are considered technically uncertain and minor for the foreseeable future.

The results of the project scenario costing module are taken as inputs into the geologic and regional cost curve module of GeoCAT which generates national and regional "cost curves" indicating the volume of sequestration capacity in each region and state in the U.S. as a function of cost. This module contains a database of sequestration capacity by state and geologic reservoir type. It incorporates assessments from the U.S. Department of Energy's "Carbon Sequestration Atlas of the United States and Canada," enhanced by ICF to include assessments of the Gulf of Mexico, shale gas sequestration potential, and the use of distribution of proved oil and gas recovery by region to estimate CO_2 potential in areas not covered in the DOE atlas.[42] The geologic and regional cost curve module also has a characterization of regionalized costs, drilling depths, and other factors that go into the regional cost curves.[43]

For EPA Base Case v.5.13, GeoCAT identified storage opportunities in 33 of the lower 48 continental states and storage cost curves were developed for each of them.[44] The storage curve for California is designated as California offshore. Louisiana and Texas have both onshore and offshore storage cost curves. In addition, there are Atlantic offshore and Pacific offshore storage cost curves. The result is a total of 37 storage cost curves which are shown in Excerpt from Table 6-2.[45]

The cost curves shown in Excerpt from Table 6-2 are in the form of step functions. This implies that in any given year a specified amount of storage is available at a particular step price until either the annual storage limit (column 4) or the total storage capacity (column 5) is reached. In determining whether the total storage capacity has been reached, the model tracks the cumulative storage used up through the current year. Once the cumulative storage used equals the total storage capacity, no more storage is available going forward at the particular step price.

CO_2 storage opportunities are relevant not just to power sector sources, but also to sources in other industrial sectors. Therefore, before being incorporated as a supply representation into EPA Base Case v.5.13, the original CO_2 storage capacity in each storage region was reduced by an estimate of the storage that would be occupied by CO_2 generated by other industrial sector sources at the relevant level of cost effectiveness (represented by \$/ton CO_2 storage cost). To do this, ICF first estimated the level of industrial demand for CO_2 storage in each CO_2 storage region in a scenario where the value of abating CO_2 emissions is assumed to be \$150 per ton (this abatement value is relevant not only to willingness to

[42] Carbon Sequestration Atlas of the United States and Canada", U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, March, 2007.

[43] Detailed discussions of the GeoCAT model and its application for EPA can be found in U.S. Environmental Protection Agency, Office of Water, "Geologic CO_2 Sequestration Technology and Cost Analysis, Technical Support Document" (EPA 816-B-08-009) June 2008, http://www.epa.gov/ogwdw000/uic/pdfs/support_uic_co2_technologyandcostanalysis.pdf and Harry Vidas, Robert Hugman and Christa Clapp, "Analysis of Geologic Sequestration Costs for the United States and Implications for Climate Change Mitigation," Science Digest, Energy Procedia, Volume 1, Issue 1, February 2009, Pages 4281-4288. Available online at www.sciencedirect.com.

[44] The states without identified storage opportunities in EPA Base Case v.5.13 are Connecticut, Delaware, Idaho, Iowa, Maine, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Rhode Island, Vermont, and Wisconsin. This implies that these states did not present storage opportunities for the four sequestration scenarios included in EPA's inventory, i.e., saline reservoirs, depleted gas fields, depleted oil fields, and enhanced oil recovery.

[45] For consistency across the emission costs represented in v.5.13, the costs shown in Tables 9-23 and 9-24 are expressed in units of dollars per short ton. In IPM documentation and outputs the convention is to use the word "tons" to indicate short tons and the word "tonnes" to indicate metric tons. In discussing CO_2 outside of the modeling framework, the international convention is to use metric tons. To obtain the \$/tonne equivalent multiply the \$/ton values shown In Tables 9-34 and 9-24 by 1.1023.

pay for storage but also for the cost of capture and transportation of the abated CO_2).[46] Then, for each region ICF calculated the ratio of the industrial demand to total storage capacity available for a storage price of less than $10/ton. (An upper limit of $10/ton was chosen because the considerable amount of storage available up to that price could be expected to exhaust the industrial demand.) Converting this to a percent value and subtracting from 100%, ICF obtained the percent of storage capacity available to the electricity sector at less than $10/ton. Finally, the "Annual Step Bound (MMTons)" and "Total Storage Capacity (MMTons)" was multiplied by this percentage value for each step below $10/ton[47] in the cost curves for the region to obtain the reduced storage capacity that went into the storage cost curves for the electric sector in EPA Base Case v.5.13. Thus, the values shown in Excerpt from Table 6-2 represent the storage available specifically to the electric sector.

The price steps in the Excerpt from Table 6-2 are the same from region to region. (That is, STEP5 [column 2] has a step cost value of $4.84/Ton [column 3] across all storage regions [column 1]. This across-region price equivalency holds for every step.) However, the amount of storage available in any given year (labeled "Annual Step Bound (MMTons)" in column 4) and the total storage available over all years (labeled "Total Storage Capacity (MMTons)" in column 5) vary from region to region. In any given region, the cost curves are the same for every run year. This feature implies that over the modeling time horizon no new storage will be added to augment the current storage inventory. This assumption is not meant to imply that additional storage is unavailable and may be revisited if model runs exhaust key components in the storage inventory.

Excerpt from Table 6-2 CO_2 Storage Cost Curves in EPA Base Case v.5.13

This is a small excerpt of the data in Excerpt from Table 6-2. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2011$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP1	-14.52	1	45
	STEP2	-9.68	0	0
	STEP3	-4.84	0	0
	STEP4	0.00	0	6
	STEP5	4.84	31	1,568
	STEP6	9.68	39	1,967
	STEP7	14.52	38	1,895
	STEP8	19.36	0	9
Alabama	STEP9	24.20	4	186
	STEP10	29.04	13	639
	STEP11	33.88	0	7
	STEP12	38.72	0	14
	STEP13	43.56	0	0
	STEP14	48.41	1	68
	STEP15	53.25	0	0
	STEP16	58.09	0	14
	STEP17	62.93	0	0

[46] The approach that ICF employed to estimate industrial demand for CO_2 storage is described in ICF International, "Methodology and Results for Initial Forecast of Industrial CCS Volumes," January 2009.

[47] Zero and negative cost steps represent storage available from enhanced oil recovery (EOR) where oil producers either pay or offer free storage for CO_2 that is injected into mature oil wells to enhance the amount of oil recovered. There is also a market for CO_2 injection in enhanced coal bed methane (ECBM) production. ECBM is excluded from EPA's inventory as discussed earlier.

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2011$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP18	67.77	0	0
	STEP19	72.61	0	0
Arizona	STEP1	-14.52	0	0
	STEP2	-9.68	0	0
	STEP3	-4.84	0	0
	STEP4	0.00	0	0
	STEP5	4.84	121	6,026
	STEP6	9.68	145	7,275
	STEP7	14.52	113	5,659
	STEP8	19.36	0	0
	STEP9	24.20	38	1,887
	STEP10	29.04	0	1
	STEP11	33.88	0	0
	STEP12	38.72	0	0
	STEP13	43.56	0	0
	STEP14	48.41	0	0
	STEP15	53.25	0	0
	STEP16	58.09	0	0
	STEP17	62.93	0	0
	STEP18	67.77	0	0
	STEP19	72.61	0	0

Note: The curves for each region are applicable in each model run year 2016 - 2050.

6.3 CO_2 Transport

Each of the 64 IPM model regions can send CO_2 to the 37 regions represented by the storage cost curves in Excerpt from Table 6-2. The associated transport costs (in 2011$/Ton) are shown in Excerpt from Table 6-3.

These costs were derived by first calculating the pipeline distance from each of the CO_2 Production Regions to each of the CO_2 Storage Regions listed in Excerpt from Table 6-3. Since there are large economies of scale for pipelines, CO_2 transportation costs depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. Consequently, the method assumes that the longer the distance from the source of the CO_2 to the sink for the CO_2 the greater the chance for other sources to share in the transportation costs, including pipeline costs (in $/inch-mile) and cost of service (in $/ton per 75 miles). These cost components are functions of the required diameter and thickness of the pipeline and the flow capacity of the pipeline, which themselves are functions of the assumed number of power plants using the pipeline.

Excerpt from Table 6-3 CO_2 Transportation Matrix in EPA Base Case v.5.13

This is a small excerpt of the data in Table 6-3. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

CO_2 Production Region	CO_2 Storage Region	Cost (2011$/Ton)
ERC_REST	Alabama	13.20
	Arizona	18.75
	Arkansas	8.27
	Atlantic Offshore	24.44
	California	30.21
	Colorado	17.79
	Florida	20.86
	Georgia	19.97
	Illinois	17.01
	Indiana	18.43
	Kansas	12.54
	Kentucky	20.25
	Louisiana	8.48
	Louisiana Offshore	8.61
	Michigan	23.76
	Mississippi	9.94
	Montana	26.83
	Nebraska	17.88
	Nevada	25.95
	New Mexico	16.77
	New York	28.40
	North Dakota	26.53
	Ohio	23.70
	Oklahoma	9.35
	Oregon	37.00
	Pacific Offshore	27.83
	Pennsylvania	26.33
	South Carolina	20.72
	South Dakota	23.53
	Tennessee	17.12
	Texas	4.48
	Texas Offshore	6.64
	Utah	21.96
	Virginia	23.60
	Washington	967.14
	West Virginia	22.32
	Wyoming	22.76

Notes:
Production Regions are equal to IPM model regions

7. Set-up Parameters and Rules

The EPA Base Case v.5.13 includes a number of assumptions that affect the way IPM treats the analysis time horizon, retrofit assignments, and environmental specifications for trading and banking. This section provides an overview of those assumptions.

7.1 Run Year Mapping

Although IPM is capable of representing every individual year in an analysis time horizon, individual years are typically grouped into model run years to increase the speed of modeling. While the model makes decisions only for run years, information on non-run years can be captured by mapping run years to the individual years they represent.

The analysis time horizon for EPA Base Case v.5.13 extends from 2016 through 2054, with IPM seeking the least cost solution that meets all constraints and minimizes the net present value of system cost. The seven years designated as “model run years” and the mapping of calendar years to run years is shown in Table 7-1.

Table 7-1 Run Years and Analysis Year Mapping Used in the EPA Base Case v.5.13

Run Year	Years Represented
2016	2016 - 2017
2018	2018
2020	2019 - 2022
2025	2023 - 2027
2030	2028 - 2033
2040	2034 - 2045
2050	2046 - 2054

7.2 Retrofit Assignments

In IPM, model plants that represent existing generating units have the option of maintaining their current system configuration, retrofitting with pollution controls, or retiring. The decision to retrofit or retire is endogenous to IPM and based on the least cost approach to meeting demand subject to modeled system and operational constraints. IPM is capable of modeling retrofits and retirements at each applicable model unit at three different points in time, referred to as three stages. At each stage a retrofit set may consist of a single retrofit (e.g. LSFO Scrubber) or pre-specified combinations of retrofits (e.g., ACI + LSFO Scrubber +SCR). In EPA Base Case v.5.13 first stage retrofit options are provided to existing coal-steam and oil/gas steam plants. These plants - as well as combined cycle plants, combustion turbines, and nuclear plants - are also given retirement as an option in stage one. Third stage retrofit options are offered to coal-steam plants only.

Table 7-2 presents the first stage retrofit options available by plant type; Table 7-3 presents the second and third stage retrofit options available to coal-steam plants. The cost of multiple retrofits on the same model plant, whether installed in one or multiple stages, are additive. In linear programming models such as IPM, projections of pollution control equipment capacity and retirements are limited to the pre-specified combinations listed in Table 7-2 and Table 7-3 below.

Table 7-2 First Stage Retrofit Assignment Scheme in EPA Base Case v.5.13

Plant Type	Retrofit Option 1st Stage	Criteria
Coal Steam		
	Coal Retirement	All coal steam boilers
	Coal Steam SCR	All coal steam boilers that are 25 MW or larger and do not possess an existing SCR control option
	Coal Steam SNCR – Non FBC Boilers	All non FBC coal steam boilers that are 25 MW or larger and smaller than 100 MW, and do not possess an existing post-combustion NO_x control option
	Coal Steam SNCR – FBC Boilers	All coal FBC units that are 25 MW or larger and do not possess an existing post-combustion NO_x control option
	LSD Scrubber	All unscrubbed coal steam boilers 25 MW or larger and burning less than 3 lbs/MMBtu SO_2 coal
	LSFO Scrubber	All unscrubbed and non FBC coal steam boilers 25 MW or larger
	CO_2 Capture and Storage	All scrubbed coal steam boilers 400 MW or larger
	ACI - Hg Control Option (with and without Toxecon)	All coal steam boilers larger than 25 MW that do not have an ACI and have an Hg EMF greater than 0.1. Actual ACI technology type will be based on the boilers fuel and technology configuration. See discussion in Chapter 5.
	LSD Scrubber + SCR	Combination options – Individual technology level restrictions apply
	LSD Scrubber + SNCR	
	LSFO Scrubber + SCR	
	LSFO Scrubber + SNCR	
	ACI + SCR	
	ACI + SNCR	
	ACI + LSD Scrubber	
	ACI + LSFO Scrubber	
	ACI + LSD Scrubber + SCR	
	ACI + LSFO Scrubber + SCR	
	ACI + LSD Scrubber + SNCR	
	ACI + LSFO Scrubber + SNCR	
	DSI	All unscrubbed and non FBC coal steam boilers 25 MW or larger with Fabric Filter and burning less than 2 lbs/MMBtu SO_2 coal.
	DSI + Fabric Filter	All unscrubbed and non FBC-coal steam boilers 25 MW or larger without Fabric Filter and with CESP or HESP and burning less than 2 lbs/MMBtu SO_2 coal.
	DSI + SCR	Combination options – Individual technology level restrictions apply
	DSI + SNCR	
	ACI + DSI	
	ACI + DSI + SCR	
	ACI + DSI + SNCR	
	Heat Rate Improvement	All coal steam boilers with a heat rate larger than 9,500 Btu/kWh
	Coal-to-Gas	All coal steam boilers that are 25 MW or larger
Integrated Gasification Combined Cycle		
	IGCC Retirement	All integrated gasification combined cycle units
Combined Cycle		
	CC Retirement	All combined cycle units
Combustion Turbine		
	CT Retirement	All combustion turbine units
Nuclear		
	Nuclear Retirement	All nuclear power units

Plant Type	Retrofit Option 1st Stage	Criteria
Oil and Gas Steam		
	Oil/Gas Retirement	All O/G steam boilers
	Oil and Gas Steam SCR	All O/G steam boilers 25 MW or larger that do not possess an existing post-combustion NO_x control option

Table 7-3 Second and Third Stage Retrofit Assignment Scheme in EPA Base Case v.5.13

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage	Retrofit Option 3rd Stage
Coal Steam			
	NO_x Control Option[a]	SO_2 Control Option	Heat Rate Improvement
		HCl Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	SO_2 Control Option[b]	NO_x Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	Hg Control Option[c]	NO_x Control Option	Heat Rate Improvement
		SO_2 Control Option	Heat Rate Improvement
		HCl Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	CO_2 Control Option[d]	None	None
	NO_x Control Option[a] + SO_2 Control Option[b]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	NO_x Control Option[a] + Hg Control Option[3]	SO_2 Control Option	Heat Rate Improvement
		HCl Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	SO_2 Control Option[b] + Hg Control Option[3]	NO_x Control Option	Heat Rate Improvement
		CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	NO_x Control Option[a] + SO_2 Control Option[b] + Hg Control Option[c]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	HCl Control Option[e]	NO_x Control Option	Heat Rate Improvement
		SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	NO_x Control Option[a] + HCl Control Option[e]	SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	Hg Control Option[c] + HCl Control	NO_x Control Option	Heat Rate Improvement

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage	Retrofit Option 3rd Stage
	Option[e]	SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	NO_x Control Option[a] + HCl Control Option[e] + Hg Control Option[c]	SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	Heat Rate Improvement	NO_x Control Option	None
		SO_2 Control Option	None
		HCl Control Option	None
		CO_2 Control Option	None
		Coal Retirement	None
	Coal-to-Gas	NO_x Control Option	None
		Oil/Gas Retirement	None
	Coal Retirement	None	None
Oil and Gas Steam			
	NO_x Control Option[a]	Oil/Gas Retirement	None
	Oil/Gas Retirement	None	None

Notes:

[a] "NO_x Control Option" implies that a model plant may be retrofitted with one of the following NO_x control technologies: SCR, SNCR - non-FBC, or SNCR - FBC

[b] "SO_2 Control Option" implies that a model plant may be retrofitted with one of the following SO_2 control technologies: LSFO scrubber or LSD scrubber

[c] "Hg Control Option" implies that a model plant may be retrofitted with one of the following activated carbon injection technology options for reduction of mercury emissions: ACI or ACI + Toxecon

[d] "CO_2 Control Option" implies that a model plant may be retrofitted with carbon capture and storage technology

[e] "HCl Control Option" implies that a model plant may be retrofitted with a DSI (with milled Trona)

7.3 Emissions Trading and Banking

Five environmental air regulations included in EPA Base Case v.5.13 involve regional trading and banking of emission allowances[48]: The three programs of the Clean Air Interstate Rule (CAIR) – Annual SO_2, Annual NO_x, and Ozone Season NO_x; the Regional Greenhouse Gas Initiative (RGGI) for CO_2; and the West Region Air Partnership's (WRAP) program regulating SO_2 (adopted in response to the federal Regional Haze Rule). Table 7-4 below summarizes the key parameters of these five trading and banking programs as incorporated in EPA Base Case v.5.13. EPA Base Case v.5.13 does not include any explicit assumptions on the allocation of emission allowances among model plants under any of the programs. The NO_x SIP Call requirements for ozone season NO_x for the state of Rhode Island are also included in EPA Base Case v.5.13.[49]

<u>**Intertemporal Allowance Price Calculation**</u>

Under a perfectly competitive cap-and-trade program that allows banking (with a single, fixed future cap and full "banking" allowed), the allowance price always increases by the discount rate between periods if affected sources have allowances banked between those two periods. This is a standard economic result for cap-and-trade programs and prevents sources from profiting by arbitraging allowances between two periods.

[48] For a detailed discussion of the assumptions modeled for all environmental air regulations in the EPA Base Case v.5.13, refer to Chapter 3.

[49] For more information on individual state emission caps and constraints, see the All Constraints worksheet in the SSR file.

The EPA Base Case v.5.13 uses the same discount rate assumption (4.77%) that governs all intertemporal economic decision-making in the model in order to compute the increase in allowance price for cap-and-trade programs when banking is engaged as a compliance strategy. This approach is based on the assumption that allowance trading is a standard activity engaged in by generation asset owners and that their intertemporal investment decisions as related to allowance trading will not fundamentally differ from other investment decisions. For more information on how this discount rate was calculated, please see Section 8.2.

Table 7-4 Trading and Banking Rules in EPA Base Case v.5.13

	CAIR Annual SO_2	**CAIR Annual NO_x**	**CAIR - Ozone Season NO_x**	**WRAP- SO_2**	**RGGI - CO_2**
Coverage	All fossil units > 25 MW[a]	All fossil units > 25 MW[1]	All fossil units > 25 MW[b]	All fossil units > 25 MW[d]	All fossil units > 25 MW[e]
Timing	Annual	Annual	Ozone Season (May - September)	Annual	Annual
Size of Initial Bank (MTons)	pre 2010: 5,985.768 2010-2014: 22,298.08 2015-2015:$_2$,333.776	2016: 1,514.702	2016: 740.665	The bank starting in 2018 is assumed to be zero	2016: 107,743
Rules					
Total Allowances (MTons)	2016 -2054: 8,950	2016 -2054: 1,242	2016 -2054: 484.5	2018 - 2054: 89.6	2016: 68,459 2017: 66,297 2018: 64,188 2019: 62,132 2020: 60,128 2021 - 2054: 78,175
Total Allowances Less NSR (MTons)	2016 - 2017: 8,808 2018: 8,740 2019: 8,682 2020 - 2054: 8,662	2016 -2054: 1,242	2016 -2054: 484.5	NA	NA
Retirement Ratio	2016 - 2054:$_2$.86	2016 - 2054: 1.0	2016 - 2054: 1.0	2016 - 2054: 1.0	2016 - 2054: 1.0

Notes:

[a] Alabama, Delaware, District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

[b] Alabama, Arkansas, Connecticut, Delaware, District of Columbia, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

[c] Rhode Island is the only NO_x SIP Call state not covered by the CAIR Ozone Season NO_x program.

[d] New Mexico, Utah, Wyoming

[e] Connecticut, Delaware, Maine, New Hampshire, New York, Vermont, Rhode Island, Massachusetts, Maryland

8. Financial Assumptions

This chapter presents the financial assumptions used in the EPA Base Case v.5.13 along with an in-depth explanation of the theoretical underpinnings and methods used to develop the two most important financial parameters – the discount rate and capital charge rate. Investment options in IPM are selected by the model given the cost and performance characteristics of available options, forecasts of customer demand for electricity, reliability criteria and environmental regulations. The investment decisions are made based on minimizing the net present value of capital plus operating costs over the full planning horizon. The pattern of capital costs over time is determined using capital charge rates to represent the financing of capital investments. The net present value of all future capital and operating costs is determined with the use of a discount rate.

EPA Base Case v.5.13 uses real 2011 dollars (2011$) as its real dollar baseline.[50]

8.1 Introduction to Risk

The risk of an investment in the power sector is heavily dependent on market structure risks. The range of risks has increased due to deregulation, which has resulted in a greater share of U.S. generation capacity being deregulated IPP (Independent Power Producer) capacity.[51] For example, merchant IPPs selling into spot market have more market risk than regulated plants or IPPs having long-term, known-price contracts with credit worthy counter parties. There are also technology risks and financing structure risks (corporate vs. project financings). Lastly, there is financial risk related to the extent of leverage.

The risk, especially to the extent it is correlated with overall market conditions, is an important driver of financing costs. Other risks are handled in the cash flows and are treated as non-correlated with the market. This emphasis on correlated market risk is based on the Capital Asset Pricing Model (CAPM) and associated financial theory. This analysis takes into account differences in technology and market structure risks.

Differences between corporate and project financings are highlighted but no specific adjustment has been made for them.

8.1.1 Market Structure Risks

The power sector in North America can be divided into the traditional regulated sector (also known as "cost of service" sector) and deregulated merchant sector (also known as "competitive" sector).

<u>Traditional Regulated</u>

The traditional regulated market structure is typical of the vertically integrated utilities where generation (and transmission and distribution, abbreviated T&D) investments are approved through a regulatory process and the investment is provided a regulated rate of return. In theory, returns on investment in this form of market structure are cost plus regulated returns that are administratively determined. Returns are affected by market conditions due to regulatory lag and other imperfections in the process, but overall regulated investments are less exposed to the market than deregulated investments, all else held equal. In this report, the term "utility financing" refers to this type of market structure. A closely related market structure is the situation where a plant is built under a power purchase agreement (PPA) with a utility with known pricing that allows for a very high degree of investment amortization during the contract period. In such an arrangement, the risks are more credit- and performance-related and much less market-related.

[50] Unless otherwise indicated, all rates presented in this document are provided in real terms.

[51] SNL classifies power plants as merchant and unregulated if a plant in question was not part of any rate case. Based on this classification criterion, in 2012, about 52% of all operating capacity is merchant and unregulated capacity.

Deregulated Merchant

In a deregulated merchant market structure, investments bear the full or a very high degree of market risk as the price at which that they can sell electricity is dependent on what the short-term markets will bear. Return on investment in this form of market structure is not only dependent on the state of the economy, but also on commodity prices, as well as on capital investment cycles and remaining price-related regulation, e.g., FERC price caps on capacity prices. The capital investment cycle can create a "boom and bust" cycle which imparts source risk or uncertainty in the sector that can be highly correlated with overall macro-economic trends. The operating cash flows from investments in this sector are more volatile as compared to the traditional regulated sector and hence carry more business or market risk. In this documentation, the term "merchant financing" refers to this type of market structure.

8.1.2 Technology Risks

The selection of new technology investment options is partially driven by the risk profile of these technology investments. For instance, in a deregulated merchant market, an investment in a combustion turbine is likely to be much more risky than an investment in a combined cycle unit because while a combustion turbine operates as a peaking unit and is able to generate revenues only in times of high demand, a combined cycle unit is able to generate revenues over a much larger number of hours in a year. An investor in a combined cycle unit, therefore, would require a lower risk premium than an investor in a combustion turbine.

8.1.3 Financing Structure Risks and Approach

While investments in new units differ based on market structure and technology risks, differences also may occur because of financing schemes available. There are two major types of financing schemes:

Corporate finance

Corporate finance is a category of financing where a developer raises capital on the strength of the balance sheet of a company rather than a single project. In this type of financing, the debtors have recourse to the entire company's assets. Also, a common assumption is that debt is refinanced rather than repaid such that overall debt is eliminated.

Project finance

Project finance allows developers to seek financing using only the project as recourse for the loan. For instance, a project developer may wish to develop a new combined cycle unit but will seek to use project financing in such a way that if the developer defaults on the loan, creditors have recourse only to the project itself and not against the larger holdings of the project developer. This approach can be more risky for investors than corporate finance, all else being equal, because there is less diversification of assets than the assets held by a corporation (which can be thought as a collection of projects). However, there are some projects more suitable for project financing because: (1) they may have a self-sustaining revenue stream that is greater than the corporate average, or (2) risk is reduced through a long-term PPA with a credit-worthy counterparty such as a vertically integrated utility or a regulated affiliate of a merchant company. In this situation, debt principal is commonly assumed to be repaid at the end of the asset's useful life.

There are many benefits of a project financing structure but there are also costs associated with it. A project financing structure typically has higher transaction costs (and even higher debt costs as debt financing is largely privately placed), but it also solves some of the agency problems and underinvestment issues that corporate financed structures face.[52]

[52] For more information on project financing, see paper titled "The Economic Motivations for Using Project Finance" by Benjamin C. Esty, Harvard Business School, Feb 2003.

However, as noted above, this analysis does not make an effort to quantify the relative costs and benefits of one structure over the other. Rather, the approach is based on the premise that regardless of financial structure, each project has its own risks based on market structure and technology. Further, because corporate financing is more observable than project financing,[53] and has evolved in the power sector to the level of making key risk inferences possible (e.g., IPP and utility stock trades), assessment of market-correlated risks for the purposes of deriving the financial assumptions used in EPA Base Case v.5.13 were based on IPP and utility corporate financing.

8.2 Calculation of the Financial Discount Rate

8.2.1 Introduction to Discount Rate Calculations

The real discount rate for expenditures[54] (e.g., capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Base Case v.5.13 is 4.77%. This serves as the default discount rate for all expenditures.

A discount rate is used to translate future cash flows into current dollars by taking into account factors (such as expected inflation and the ability to earn interest), which make one dollar tomorrow worth less than one dollar today. The discount rate allows intertemporal trade-offs and represents the risk adjusted time value of money.

8.2.2 Choosing a Discount Rate

The choice of discount rate often has a major effect on analytical results. The discount rate adopted for modeling investment behavior should reflect the time preference of money or the rate at which investors are willing to sacrifice present consumption for future consumption. The return on private investment represents the opportunity cost of money and is commonly used as an appropriate approximation of a discount rate.

8.2.3 Discount Rate Components

The discount rate is a function of the following parameters:

- Capital structure (Share of Equity vs. Debt)
- Post-tax cost of debt (Pre-tax cost of debt*(1-tax rate))
- Post-tax cost of equity

The weighted average cost of capital (WACC) is used as the discount rate and is calculated as follows:

WACC = [Share of Equity * Cost of Equity]
+ [Share of Preferred Stock * Cost of Preferred Stock]
+ [Share of Debt *After Tax Cost of Debt]

The focal point is on debt and equity (common stock) because preferred stock is generally a small share of capital structures. Its intermediate status between debt and equity in terms of access to cash flow also tends not to change the weighted average.

[53] Project financing data is less observable as the securities, debt and equity, are usually not explicitly traded. Also, often key financing parameters are unavailable due to confidentiality reasons. Thus, the analysis is implicitly assuming that the corporate risks and financing costs are equal to the project risks. This is especially reasonable when the corporate activities are aggregations of projects.

[54] This rate is equivalent to the real discount rate for a combine cycle plant under hybrid 75:25 utility to merchant ratio assumption. It represents a most common type of investment.

8.2.4 Market Structure: Utility-Merchant Financing Ratio

The first step in calculating the discount rate was to determine proper utility-merchant financing ratio. In EPA Base Case v.5.13, a hybrid financing model is used that assumes future new unit development activity would be split 75:25 between utility financings and pure merchant financings. This is designed to reflect a shift in the market in ownership and risk profiles for power generation assets, and recent development trends and emphasis on long term contracts.[55,56] This approach assumes that new units are financed as a weighted average of utility and merchant financing parameters. For new units the assumption is that utility and merchant components get the 75:25 weights. However, since existing coal units can be classified as belonging to a merchant or regulated structure, for retrofit investments the EPA Base Case v.5.13 assumption is that plants owned by a utility get pure utility financing parameters, whereas plants owned by merchant companies get pure merchant financing parameters.

> *Example 1*: The debt to equity capital structure of a combustion turbine is 55/45 under utility financing and 40/60 under merchant financing. Under the assumption that utility and merchant components get 75:25 weights, the debt-to-equity ratio under hybrid financing is D = (0.75*55 + 0.25*40) = 51 / E = (0.75*45 + 0.25*60) = 49.
>
> *Example 2*: The debt to equity capital structure of a retrofit is 55/45 under both utility and merchant financing. Under the assumption that utility owned plants are financed through pure utility financing parameters, and merchant owned plants are financed through pure merchant financing parameters, the debt to equity ratio remains unchanged regardless of the ownership type. A full summary for all technologies appears in Table 8-1 below.

Capital Structure: Debt-Equity Share

The second step in calculating the discount rate is the determination of the capital structures (D/E)[57] shares for the various technology types using an appropriate utility-merchant financing ratio. The utility debt capacity (and returns) is assumed to be independent of technology type based on the theoretical assumption that regulation will provide an average return to the entire rate base. This assumption is supported by empirical evidence which suggests that utility rate of return is based on an average return to the entire rate base.[58] The merchant debt capacity is based on market risk where a base load plant is

[55] An alternate approach is to categorize the United States into the two previously discussed financial regions – Cost-of-service and competitive. The cost-of-service region will have capital charge rates based on utility financial assumptions and the competitive region will have capital charge rates based on merchant financial assumptions. Such an approach could result in overbuilding in the cost-of-service region due to lower capital charge rates in the absence of regulatory prohibitions of external sales. This is similar to the public vs. IOU financing arbitrage problem, i.e. what stops government utilities from supplying all power? In fact, there are formal and informal limits, and because fully characterizing these limits are extremely complex, the EPA Base Case v.5.13 uses a hybrid approach. For example, recent proposals in PJM explicitly limit capacity expansion by some entities to be such that the total capacity does not exceed internal requirements. (Source: Current MOPR modification proposal).

[56] Based on ICF research, current operating capacity in U.S. is approximately evenly split between IPP and utility owned generation. However, in the last five years (2008-2011), 62% of all large fossil plants were built by regulated companies. In addition, another 12% of all new entrants secured long-term PPA agreements in which the risk is expected to be similar to that of utilities generally. Thus, future capacity expansion has a lower merchant component than the existing mix which is closer to 52%.

[57] A project's capital structure is the appropriate debt capacity given a certain level of equity, commonly represented as "D/E," i.e., debt/equity. The debt is the sum of all interest bearing short term and long term liabilities while equity is the amount that the project sponsors inject as equity capital.

[58] The U.S. wide average authorized rate of return on equity, authorized return on rate base, and authorized equity ratio during last 5 years (2008-2012) for all 108 companies was 10.26%, 8.00%, and 48.32% respectively. For the subset of 50 utilities that completed new rate base cases without financing new generation capacity, those averages were only slightly lower with average authorized rate of return on equity, authorized return on rate base, and authorized equity ratio of 10.09%, 7.90%, and 47.43% respectively. The lack of a substantial difference between these averages suggests that authorized rates of return and equity ratios for regulated companies are not that responsive to differences in investment choices, and are more reflective of an entire company's rate base.

likely to have a higher debt capacity than a combustion turbine plant. Table 8-1 presents the capital structure assumptions used in EPA Base Case v.5.13.

Table 8-1 Capital Structure Assumptions in EPA Base Case v.5.13

Technology	Utility	Merchant	Hybrid
Combustion Turbine	55/45	40/60	51/49
Combined Cycle	55/45	55/45	55/45
Coal & Nuclear	55/45	65/35	58/43
Renewables	55/45	55/45	55/45
Retrofits	55/45	55/45	N.A.

The risk differences across technologies are implemented by varying the capital structure. As shown in Table 8-1 and discussed above, a peaking unit such as a combustion turbine is estimated to have a capital structure of 40/60 while a base load unit such as nuclear and coal is assumed to have a capital structure of 65/35. This is based on the expectation that less risky technologies can carry more leverage. As debt is less expensive than equity, this will automatically translate into a lower discount rate that is used in deriving capital charge rate for base load technologies, and a higher discount rate that is used in deriving capital charge rate for peaking technology, assuming other components of the capital charge rate calculation remain the same.

8.2.5 Debt and Equity Shares and Technology Risk

The capitalization structure for merchant financings was estimated to be 55/45 based on empirical analyses. This ratio is based on the assumption that the overall IPP risk was an average reflective of the risk profile of combined cycle units, which in turn was assumed to be intermediate between base load and peaking. The combined cycle technology is considered to have "average" market risk being an intermediate type technology. Also, in the aggregate, the five selected IPP companies[59] have more combined cycle capacity in their supply mix than any other technology. Additionally, going forward, it is expected that gas will continue to play an increasingly important role in the supply mix of both utilities and merchant companies, with combined cycle technology playing a dominant role. For all of these reasons, it is appropriate to use the ROE corresponding to a combined cycle facility.

Each generation technology was considered to have its own risk profile because base load technologies have multiple sources of revenues, both energy and capacity, which decreases risk and facilitates hedging relative to IPP peaking units. Nearly 75% of load is in LMP markets, and the liquidity of these electrical energy markets creates the potential for near-term cross commodity hedging if the plant has significant energy sales, i.e., if the plant is non-peaking. The potential for capacity revenue hedging is more limited than for energy. Hence, greater the base load share, the lower the asset risk. Additional differentiation among different technologies e.g. nuclear, versus coal, was not implemented because there is a lack of publicly traded securities that provide an empirical basis for differentiating between the risks, and hence, financing parameters for different activities.

There are two main mechanisms for reflecting the greater risk for peak load units and the lower risk for base load. First, the ROE could have been adjusted such that for a given target leverage the ROE would be higher for peaking units, and lower for base load units. For example, an unlevered beta and ROE (which assumes zero leverage) could have been calculated using the risk differentiated capital structures and then relevered at some target leverage. This would have yielded a different ROE for each technology but the same capital structure across all technologies.

The second option was to keep the same ROE while varying the capital structure. This method was adopted for EPA Base Case v.5.13. Thus, even though the leverage of peaking units was lowered, the ROE was not lowered. This raised the weighted average cost of capital and the resulting capital charge

[59] The merchant parameters are derived from market observations of five IPP companies – Merchant ROE.

rate. This effectively also raised the unlevered beta for peaking relative to combined cycle. For base load, leverage was raised without raising ROE, effectively lowering the unlevered beta and the cost of capital.

Debt and Equity Shares

The target capitalization structure for utilities was determined using US utility capitalization ratios derived from Bloomberg data. Similar CAPM parameters were used to estimate the ROE of the utility sector. The capitalization structure for utility financings was estimated to be 55/45 based on empirical analyses and this capitalization structure was assumed to be on average reflective of all technologies.[60]

Technology Risks

For the utility financing, EPA Base Case v.5.13 assumes that the required returns for regulated utilities are independent of technology. This is a simplifying assumption, and further empirical work may be warranted here.

Cost of Debt

The third step in calculating the discount rate was an assessment of the cost of debt. The summary of historical assessment of debt rates across merchant and utility entities is summarized in Table 8-2. The utility and merchant cost of debt is assumed to be the same across all technologies.

Table 8-2 Debt Rates for EPA Base Case v.5.13

Technology	Utility	Merchant	Hybrid
Combustion Turbine	5.72%	7.58%	6.19%
Combined Cycle	5.72%	7.58%	6.19%
Coal & Nuclear	5.72%	7.58%	6.19%
Renewables	5.72%	7.58%	6.19%
Retrofits	5.72%	7.58%	N.A.

Merchant Cost of Debt. The cost of debt for the merchant sector was estimated to be 7.6%. It is calculated by taking a 5-year (2008-2012) weighted average of debt yields from existing company debt with eight or more years to maturity. The weights assigned to each company debt yields were based on that company's market capitalization. During the most recent 5 years, none of the existing long-term debt exceeded twelve years to maturity, hence above average yields are based on debt with maturity between eight and twelve years.

Utility Cost of Debt

The cost of debt for the utility sector was estimated to be 5.7%. It is calculated by taking a 5-year (2008-2012) weighted average of debt yields from four long-term (20 years) Bloomberg Utility Indexes with different debt ratings. The four indices' debt ratings ranged from BBB- to A. The weights assigned to each index were based on the number of regulated companies with the same debt rating.[61]

[60] In the last 3 years, the average utility debt/equity ratio was approximately 1.23, which translates to 55/45 debt/equity ratio.

[61] In all, 29 different regulated companies were considered when assigning weights to the Bloomberg Utility Indexes. They are: Allete Inc., Ameren Corp., American Electric Power Co. Inc., Cleco Corp., CMS Energy Corp., Empire District Electric Co., Great Plains Energy Inc., MGE Energy Inc. Vectren Corp., Westar Energy Inc., Wisconsin Energy Corp., Consolidated Edison Inc., Northeast Utilities, Southern Co., UIL Holdings Corp., Avista Corp., IDACORP Inc., PG&E Corp., Pinnacle West Capital Corp., and Xcel Energy Inc.

Return on Equity (ROE)

The final step in calculating the discount rate was the calculation of a return on equity (ROE) using a weighted average ROE under utility financing (8.8% in nominal terms) and merchant financing (16.1% in nominal terms) at a 75:25 utility/merchant ratio. These utility and merchant ROE's are estimated assuming a 55:45 debt/equity ratio. This resulted in a hybrid ROE of 10.6% (nominal). This ROE is kept the same across each technology[62] but the risk differences across technologies are implemented through the capital structure. See the discussion of capital structures in subsection 8.3.2.5 "Debt and Equity Shares and Technology Risk", and subsection 8.3.2.5.1 "Debt and Equity Shares".

Merchant ROE. The Independent Power Producer (IPP) after tax return on equity parameter was estimated to be 16.1% (nominal). This was based on empirical analysis of stock price data of five pure play comparable merchant generation companies, namely NRG, Dynegy, Calpine, RRI Energy, and Mirant.[63] First, levered betas[64] (a measure of total corporate risk, which includes business and financial risk) for the five companies were calculated using five years (2008-2012) of historical stock price data. Five years is a standard time period. Weekly returns were also used as supplementary data in the analysis. Second, unlevered betas (a measure of business risk, i.e., those affected by a firm's investment decisions) were calculated using the estimated levered beta, the companies' market debt/equity ratio, and the riskiness of debt. The goal is to correctly handle business or systemic risk and financial risk. As most comparables historically had periods of financial distress, the unlevering[65] approach was modified to include the riskiness of debt, instead of purely using the Hamada equation.[66] The unlevered betas were then relevered[67] at the target debt/equity ratio of 55/45 to get the relevered equity betas and return on equity. The target debt/equity ratio of 55/45 is based on average levels of debt/equity ratios across merchant and regulated companies over the last 3 years (2010-2012). The return on equity was determined using the Capital Asset Pricing Model (CAPM).

The CAPM parameters used to estimate the ROE are as follows:

- Risk Free Rate[68] based on 20 year T bond rate: 3.8%
- Market Risk[69] Premium: 1926-2011: 6.62%
- Size[16] Premium: 1.14%

The risk free rate assumption of 3.8% represents a 5-year (2008-2012) average of U.S. Treasury 20 year bond rates. A common practice within the CAPM construct is to utilize the most recent U.S. Treasury 20-

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[62] As indicated previously in Table 8-1 a 3% adder is applied to the cost of debt prior to adjustment for income taxes, and to cost of equity when calculating capital charge rates for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture technologies.

[63] Mirant and RRI Energy merged in December 2010 to form GenOn. Prior to their merger ICF analyzed these two companies separately, while after their merger the analysis was of the merged company. Dynegy Holdings began Chapter 11 proceedings on November 2011. The ICF analysis of Dynegy analyzed the company data until 2011. Parts of 2011 and 2012 data were not available for further analysis of Dynegy.

[64] Levered beta is directly measured from the company's stock returns with no adjustment made for the debt financing undertaken by the company.

[65] The unlevering process removes a company's financing decision from the beta calculation. The calculation therefore, attempts to isolate the business (operating risk) of the firm.

[66] The Hamada equation is described at http://www.answers.com/topic/hamada-equation as "A fundamental analysis method of analyzing a firm's costs of capital as it uses additional financial leverage, and how that relates to the overall riskiness of the firm. The measure is used to summarize the effects this type of leverage has on a firm's cost of capital (over and above the cost of capital as if the firm had no debt).

[67] The relevering process estimates the levered beta of the firm given a target capital structure and the pure business risks of the firm as determined from the unlevering process.

[68] Federal Reserve Statistical Release (H15 data), September 2012.

[69] Source: Stocks, Bonds, Bills, and Inflation, 2012 Yearbook Valuation Edition, Morningstar/Ibbotson's Associates.

year bond rate[70] which in September 2012 was 2.5%. Were EPA Base Case v.5.13 to adopt 2.5% as a risk free rate assumption, it would lower all nominal ROEs by 1.3%. Thus, capital investment would have a lower cost. The EPA Base Case v.5.13 assumptions deviate from that practice for several reasons:

- Current rates are unsustainably low due to the latest recession, and slow pace of recovery.
- Second, the EPA analysis begins in the year 2016; by that time the treasury yields are assumed to recover from their current low levels.
- The EPA Base Case financial assumptions are changed infrequently, and hence, it should not use temporary unsustainable assumptions.
- Merchant and utility cost of debt, debt-equity ratios, and historical betas are all calculated based on the last 5 years (2008-2012) of historical data. The same approach to calculate the risk free rate is used in order to remain consistent in its methodology.

The estimation of the IPP ROE described here is fairly close to what EIA has published. EIA estimates[71] an ROE of roughly 16% by 2012.

Utility ROE. The utility return on equity was calculated to be 8.8%. This was based on empirical analysis of the correlation of returns on the S&P utility Index vs. the broader S&P 500 market index for the previous five years (2008-2012) to determine the levered beta and then unlevering and relevering based on a process similar to that for merchant sector. The ROE is slightly lower than what state commissions have awarded the shareholder-owned electric utilities recently.[72]

8.3 Calculation of Capital Charge Rate

8.3.1 Introduction to Capital Charge Rate Calculations

EPA Base Case v.5.13 models a diverse set of generation and emission control technologies, each of which requires financing.[73]

The capital charge rate is used to convert the capital cost into a stream of levelized annual payments that ensures capital recovery of an investment. The number of payments is equal to book life of the unit or the years of its book life included in the planning horizon (whichever is shorter). Table 8-3 presents the capital charge rates by technology type used in EPA Base Case 5.13. Capital charge rates are a function of underlying discount rate, book and debt life, taxes and insurance costs, and depreciation schedule.

Table 8-3 U.S. Real Capital Charge Rates[a] for EPA Base Case v.5.13

New Investment Technology Capital	Capital Charge Rate
Environmental Retrofits - Utility Owned	12.10%
Environmental Retrofits - Merchant Owned	16.47%
Advanced Combined Cycle	10.26%
Advanced Combustion Turbine	10.63%
Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture[b]	12.57%

[70] An important source of statistics and common practices associated with calculating cost of capital with CAPM model is based on the Morningstar's 2012 issue of the Ibbotson® Cost of Capital Yearbook.

[71] See Electricity Market Module of NEMS, EIA Annual Energy Outlook, June 2012.

[72] SNL based rate case statistics for 2011 suggest nationwide average ROE rate of 10.3%.

[73] The capital charge rates discussed here apply to new (potential) units and environmental retrofits that IPM installs. The capital cost of existing and planned/committed generating units and the emission controls already on these units are considered "sunk costs" and are not represented in the model.

Advanced Coal with Carbon Capture	9.68%
Nuclear without Production Tax Credit (PTC)	9.44%
Nuclear with Production Tax Credit (PTC)[c]	7.97%
Biomass	9.53%
Wind, Landfill Gas, Solar and Geothermal	10.85%

Notes:

[a] Capital charge rates were adjusted for expected inflation and represent real rates. The expected inflation rate used to convert future nominal to constant real dollars is 2.0%. The future inflation rate of 2.0% is based on an assessment of implied inflation from an analysis of yields on 10 year U.S. Treasury securities and U.S. Treasury Inflation Protected Securities (TIPS) over a period of 5 years (2008-2012).

[b] EPA has adopted the procedure followed in EIA's Annual Energy Outlook 2013; the capital charge rates shown for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle (IGCC) without Carbon Capture include a 3% adder to the cost of debt and equity. See *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013* (p.2), http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf

[c] The Energy Policy Act of 2005 (Sections 1301, 1306, and 1307) provides a production tax credit (PTC) of 18 mills/kWh for 8 years up to 6,000 MW of new nuclear capacity. The financial impact of the credit is reflected in the capital charge rate shown in for "Nuclear with Production Tax Credit (PTC)." NEEDS v.5.13 integrates 4,400 MW of new nuclear capacity at V C Summer and Vogtle nuclear power plants. Therefore, in EPA Base Case v.5.13, only 1,600 MW of incremental new nuclear capacity will be provided with this tax credit.

8.3.2 Capital Charge Rate Components

The capital charge rate is a function of the parameters that overlap in part with the discount rate such as the level of the capital investment and recovery of capital, but also include parameters related to the amortization of capital:

- Capital structure (Debt/Equity shares of an investment)
- Pre-tax debt rate (or interest cost)
- Debt Life
- Post-tax Return on Equity (ROE) (or cost of equity)
- Other costs such as property taxes and insurance
- State and Federal corporate income taxes
- Depreciation Schedule
- Book Life

Table 8-4 presents a summary of various assumed lives at the national level. The EPA Base Case v.5.13 assumes a book life of 15 years for retrofits. This assumption is made to account for recent trends in financing of retrofit types of investments.

Table 8-4 Book Life, Debt Life and Depreciation Schedules for EPA Base Case v. 5.13

Technology	Book Life (Years)	Debt Life (Years)	US MACRS Depreciation Schedule
Combine Cycle	30	20	20
Combustion Turbine	30	15	15
Coal Steam and IGCC	40	20	20
Nuclear	40	20	15
Solar, Geothermal, Wind and Landfill Gas	20	20	5
Biomass	40	20	7
Retrofits	15	15	15

Book Life

The book life or useful life of a plant was estimated based on researching financial statements of utility and merchant generation companies. The financial statements[74] typically list the period over which long lived assets are depreciated for financial reporting purposes. The research conducted broadly supports the numbers outlined in the table above.

Debt Life

The debt life is assumed to be on a 20 year schedule except in the case of combustion turbine and environmental retrofits where debt life is assumed to be on a 15 year schedule.

Depreciation Schedule

The US MACRS[75] depreciation schedules were obtained from IRS Publication 946[76] that lists the schedules based on asset classes. The document specifies a 5 year depreciation schedule for wind energy projects and 20 years for Electric Utility Steam Production plants. These exclude combustion turbines which have a separate listing at 15 years. Nuclear Power Plants are separately listed as 15 years as well.

Taxation and Insurance Costs

Corporate and State Income Taxes: The maximum US corporate income tax rate[77] is 35%. State taxes vary but on a national average basis, the state taxes[78] are 6.45%. This yields a net effective tax rate of 39.1%.

US state property taxes are approximately 0.9% based on a national average basis. This is based on extensive primary and secondary research conducted by ICF using property tax rates obtained from various state agencies.

Insurance costs are approximately 0.3%. This is based on estimates of insurance costs on a national average basis.

8.3.3 Capital Charge Rate Calculation Process

The capital charge rate is calculated by solving for earnings before interest, taxes, and depreciation (EBITDA) or pure operating earnings such that the project is able to recover the cost of equity as the internal rate of return over the lifetime of the project. The sum of discounted cash flows to the equity holders over the lifetime of the project, discounted at the cost of equity is set equal to the initial investment. Put another way, it creates an annuity value when multiplied by the capital investment to recover all capital related charges and provide an IRR equal to the required return on equity. The capital charge rate so calculated is defined as follows:

Capital Charge Rate = EBITDA/Total Investment

[74] SEC 10K filings of electric utilities and pure merchant companies. For example, Calpine's 10K lists 35 years of useful life for base load plants, DTE energy uses 40 years for generation equipment; Dynegy gives a range of 20-40 years for power generation facilities; Mirant reports 14-35 years for power production equipment; Reliant: 10-35 years.

[75] MACRS refers to the Modified Accelerated Cost Recovery System, issued after the release of the Tax Reform Act of 1986. It allowed faster depreciation than with previous methods.

[76] IRS Publication 946, "How to Depreciate Property", Table B-2, Class Lives and Recovery Periods.

[77] Internal Revenue Service, Publication 542.

[78] Represents weighted average state corporate marginal income tax rate.

In other words, the capital charge rate is the annuity charge that provides for the rate of return required on invested capital, resulting from pure operations.

The discounted cash flow to the equity holders of the project is characterized in terms of the Free Cash Flow to Equity (FCFE). FCFE is a valuation technique to estimate cash flows paid to the equity shareholders of a company after all expenses, reinvestment, and debt repayment have been made. The FCFE approach is suited for valuation of assets that have finite economic lives and where debt levels vary from year to year. In the FCFE approach, it is assumed that the asset has a finite life and debt reduces over time based on a mortgage-style repayment structure.

Specifically the cash flows to the equity[79] are calculated as follows:

Cash Flows to Equity[80] = EBIT (1-tax rate)
-Interest (1-tax rate)
+ Depreciation
-Capital Expenditures
-Working Capital Change[81]
-Principal Payments
+ New Debt Issued

[79] An alternative definition of free cash flow to equity is as follows:
Net Income + Depreciation –capital expenditures – working capital change – Principal Payments + New Debt Issued

[80] Property taxes and insurance are incorporated in cash flow calculations.

[81] NERA Economic Consulting estimates that working capital and inventory constitutes about 2% of direct capital costs. NERA also indicates that working capital and inventories (inventories refer to the initial inventories of fuel, consumables, and spare parts) are normally capitalized. Therefore, this item does not need to be in the capital charge rate. See “Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator”, August 27, 2010.

9. Coal

The next three chapters cover the representation and underlying assumptions for fuels in EPA Base Case v.5.13. The current chapter focuses on coal, chapter 10 on natural gas, and chapter 11 on other fuels (fuel oil, biomass, nuclear fuel, and waste fuels) represented in the base case.

This chapter presents four main topics. The first is a description of how the coal market is represented in EPA Base Case v.5.13. This includes a discussion of coal supply and demand regions, coal quality characteristics, and the assignment of coals to power plants.

The next topic is the coal supply curves which were developed for EPA Base Case v.5.13 and the bottom-up, mine-based approach used to develop curves that would depict the coal choices and associated prices that power plants will face over the modeling time horizon. Included are discussions of the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 67 coal supply curves that are implemented in EPA Base Case v.5.13. Illustrative examples are included of the step-by-step approach employed in developing the supply curves.

The third topic is coal transportation. It includes a description of the transport network, the methodology used to assign costs to the links in the network, and a discussion of the geographic, infrastructure, and regulatory considerations that come into play in developing specific rail, barge and truck transport rates. The last topic covered in this chapter is coal exports, imports, and non-electric sector demand.

The assumptions for the coal supply curves and coal transportation were finalized in June 2013, and were developed through a collaborative process with EPA supported by the following team of coal experts (with key areas of responsibility noted in parenthesis): TetraTech (coal transportation and team coordination), Wood Mackenzie (coal supply curve development), Hellerworx (coal transportation and third party review), and ICF (representation in IPM). The coal supply curves and transportation matrix implemented in EPA Base Case v.5.13 are included in tables and attachments at the end of this chapter.

9.1 Coal Market Representation in EPA Base Case v.5.13

Coal supply, coal demand, coal quality, and the assignment of specific types of coals to individual coal fired generating units are the four key components of the endogenous coal market modeling framework in EPA Base Case v.5.13. The modeling representation attempts to realistically reflect the actual options available to each existing coal fired power plant while aggregating data sufficiently to keep the model size and solution time within acceptable bounds.

Each coal-fired power plant modeled is reflected as its own coal demand region. The demand regions are defined to reflect the coal transportation options (rail, barge, truck, conveyer belt) that are available to the plant. These demand regions are interconnected by a transportation network to at least one of the 36 geographically dispersed coal supply regions. The model's supply-demand region links reflect actual on-the-ground transportation configurations. Every coal supply region can produce and each coal demand region can demand at least one grade of coal. Based on historical and engineering data (as described in Section 9.1.5 below), each coal fired unit is also assigned several coal grades which it may use if that coal type is available within its demand region.

In EPA Base Case v.5.13 the endogenous demand for coal is generated by coal fired power plants interacting with a set of exogenous supply curves (see Table 9-24 for coal supply curve data) for each coal grade in each supply region. The curves show the supply of coal (by coal supply region and coal grade) that is available to meet the demand at a given price. The supply of and demand for each grade of coal is linked to and affected by the supply of and demand for every other coal grade across supply and demand regions. The transportation network or matrix (see

Excerpt from Table 9-23 for coal transportation matrix data) also factors into the final determination of delivered coal prices, given coal demand and supply. IPM derives the equilibrium coal consumption and prices that result when the entire electric system is operating, emission, and other requirements are met and total electric system costs over the modeling time horizon are minimized.

9.1.1 Coal Supply Regions

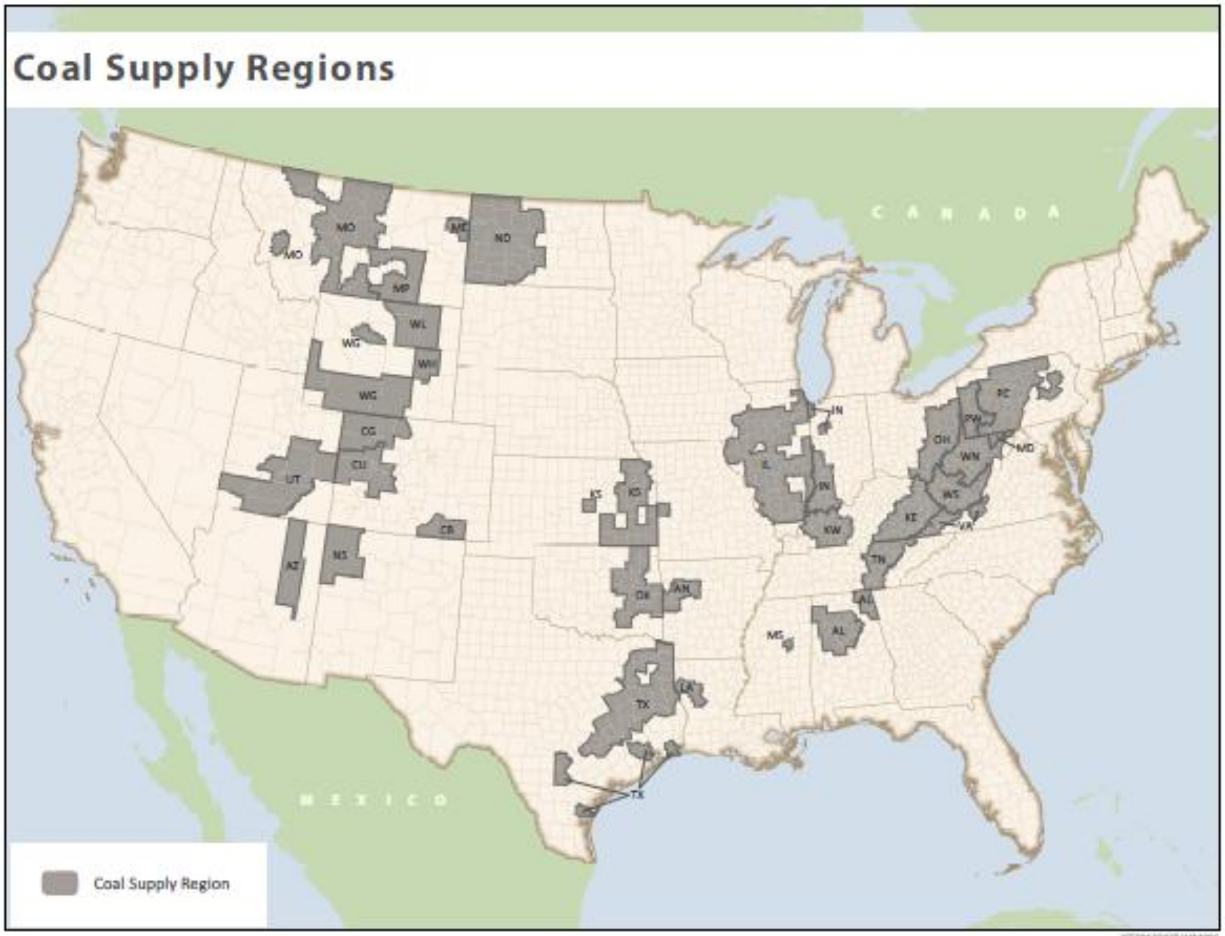
There are 36 coal supply regions in EPA Base Case v.5.13, each representing geographic aggregations of coal-mining areas that supply one or more coal grades. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 9-1 lists the coal supply regions included in EPA Base Case v.5.13.

Figure 9-1 provides a map showing the location of both the coal supply regions listed in Table 9-1 and the broader supply basins commonly used when referring to U.S. coal reserves.

Table 9-1 Coal Supply Regions in EPA Base Case

Region	State	Supply Region
Central Appalachia	Kentucky, East	KE
Central Appalachia	Tennessee	TN
Central Appalachia	Virginia	VA
Central Appalachia	West Virginia, South	WS
Dakota Lignite	Montana, East	ME
Dakota Lignite	North Dakota	ND
East Interior	Illinois	IL
East Interior	Indiana	IN
East Interior	Kentucky, West	KW
Gulf Lignite	Mississippi	MS
Gulf Lignite	Louisiana	LA
Gulf Lignite	Texas	TX
Northern Appalachia	Maryland	MD
Northern Appalachia	Ohio	OH
Northern Appalachia	Pennsylvania, Central	PC
Northern Appalachia	Pennsylvania, West	PW
Northern Appalachia	West Virginia, North	WN
Rocky Mountains	Colorado, Green River	CG
Rocky Mountains	Colorado, Raton	CR
Rocky Mountains	Colorado, Uinta	CU
Rocky Mountains	Utah	UT
Southern Appalachia	Alabama	AL
Southwest	Arizona	AZ
Southwest	New Mexico, San Juan	NS
West Interior	Arkansas, North	AN
West Interior	Kansas	KS
West Interior	Missouri	MO
West Interior	Oklahoma	OK
Western Montana	Montana, Bull Mountains	MT
Western Montana	Montana, Powder River	MP
Western Wyoming	Wyoming, Green River	WG
Wyoming Northern PRB	Wyoming, Powder River Basin	WH
Wyoming Southern PRB	Wyoming, Powder River Basin	WL
Alberta	Alberta, Canada	AB
British Columbia	British Columbia, Canada	BC
Saskatchewan	Saskatchewan, Canada	SK

Figure 9-1 Map of the Coal Supply Regions in EPA Base Case v.5.13



9.1.2 Coal Demand Regions

Coal demand regions are designed to reflect coal transportation options available to power plants. Each existing coal plant is reflected as its own individual demand region. The transportation infrastructure (i.e., rail, barge, or truck/conveyor belt), proximity to mine (i.e., mine mouth or not mine mouth), and transportation competitiveness levels (i.e., non-competitive, low-cost competitive, or high-cost competitive) are developed specific to each coal plant (demand region).

When IPM is run, it determines the amount and type of new generation capacity to add within each of IPM's 64 US model regions. These model regions reflect the administrative, operational, and transmission geographic structure of the electricity grid. Since these new plants could be located at various locations within the region, a generic transportation cost for different coal types is developed for these new plants and the methodology for deriving that cost is described in the transportation section of this chapter. See Table 9-2 for the list of coal plant demand regions reflected in the transportation matrix.

Table 9-2 Coal Demand Regions in EPA Base Case

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
1004	Edwardsport	C181	
1010	Wabash River	C183	
10684	Argus Cogen Plant	C563	
1077	Sutherland	C194	
1554	Herbert A Wagner	C227	
1606	Mount Tom	C232	
1943	Hoot Lake	C259	
2682	S A Carlson	C303	
2943	Shelby Municipal Light Plant	C339	
3319	Jefferies	C365	
511	Trinidad	C131	
54407	Waupun Correctional Central Heating Plt	C624	
55856	Prairie State Generatng Station	C637	MIS_IL
56564	John W Turk Jr Power Plant	C644	SPP_WEST
56785	Virginia Tech Power Plant	C651	
56808	Virginia City Hybrid Energy Center	C653	
7	Gadsden	C101	
7242	Polk	C495	
728	Yates	C151	
991	Eagle Valley	C176	
10	Greene County	C103	
10003	Colorado Energy Nations Company	C514	
1001	Cayuga	C180	
10043	Logan Generating Company LP	C517	
10071	Portsmouth Genco LLC	C518	
10075	Taconite Harbor Energy Center	C519	
1008	R Gallagher	C182	
10113	John B Rich Memorial Power Station	C520	
1012	F B Culley	C184	
10143	Colver Power Project	C521	
10148	White Pine Electric Power	C522	
10151	Grant Town Power Plant	C523	
1024	Crawfordsville	C185	
1032	Logansport	C186	
10328	T B Simon Power Plant	C528	
10333	Central Power & Lime	C529	
10343	Foster Wheeler Mt Carmel Cogen	C530	
1037	Peru	C187	
10377	James River Genco LLC	C540	
10378	CPI USA NC Southport	C541	
10380	Elizabethtown Power LLC	C542	
10382	Lumberton	C543	
10384	Edgecombe Genco LLC	C544	
1040	Whitewater Valley	C188	
1043	Frank E Ratts	C189	
10464	Black River Generation	C546	
1047	Lansing	C191	
1048	Milton L Kapp	C192	
10495	Rumford Cogeneration	C548	NENG_ME
10566	Chambers Cogeneration LP	C550	
10603	Ebensburg Power	C552	
10640	Stockton Cogen	C554	WEC_CALN
10641	Cambria Cogen	C555	
10670	AES Deepwater	C556	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
10671	AES Shady Point LLC	C557	
10672	Cedar Bay Generating Company LP	C558	
10675	AES Thames	C560	NENG_CT
10676	AES Beaver Valley Partners Beaver Valley	C561	
10678	AES Warrior Run Cogeneration Facility	C562	
1073	Prairie Creek	C193	
10743	Morgantown Energy Facility	C564	
10768	Rio Bravo Jasmin	C565	
10769	Rio Bravo Poso	C566	
10784	Colstrip Energy LP	C570	
108	Holcomb	C113	
1081	Riverside	C195	
1082	Walter Scott Jr Energy Center	C196	MIS_MIDA
10849	Silver Bay Power	C572	
1091	George Neal North	C197	
1104	Burlington	C198	
1122	Ames Electric Services Power Plant	C199	
113	Cholla	C114	
1131	Streeter Station	C200	
1167	Muscatine Plant #1	C201	
1217	Earl F Wisdom	C203	
1218	Fair Station	C204	
1241	La Cygne	C206	
1250	Lawrence Energy Center	C207	
1252	Tecumseh Energy Center	C208	
126	H Wilson Sundt Generating Station	C115	
127	Oklaunion	C116	ERC_WEST
1295	Quindaro	C209	
130	Cross	C117	
1355	E W Brown	C211	
1356	Ghent	C212	
136	Seminole	C118	
1364	Mill Creek	C216	
1374	Elmer Smith	C217	S_C_KY
1378	Paradise	C218	S_C_TVA
1379	Shawnee	C219	
1381	Kenneth C Coleman	C220	
1382	HMP&L Station Two Henderson	C221	
1383	Robert A Reid	C222	
1384	Cooper	C223	
1385	Dale	C224	
1393	R S Nelson	C225	S_D_WOTA
1552	C P Crane	C226	
1571	Chalk Point LLC	C229	
1572	Dickerson	C230	PJM_SMAC
1573	Morgantown Generating Plant	C231	
160	Apache Station	C119	
1619	Brayton Point	C234	
165	GRDA	C120	
1695	B C Cobb	C236	
1702	Dan E Karn	C237	
1710	J H Campbell	C238	
1720	J C Weadock	C239	
1723	J R Whiting	C240	
1731	Harbor Beach	C241	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
1733	Monroe	C243	MIS_LMI
1740	River Rouge	C244	
1743	St Clair	C245	
1745	Trenton Channel	C246	
1769	Presque Isle	C247	
1771	Escanaba	C248	
1825	J B Sims	C249	
1830	James De Young	C250	
1831	Eckert Station	C251	
1832	Erickson Station	C252	
1843	Shiras	C253	
1866	Wyandotte	C254	
1891	Syl Laskin	C255	
1893	Clay Boswell	C256	
1915	Allen S King	C258	
1961	Austin Northeast	C260	
1979	Hibbing	C261	
2008	Silver Lake	C262	
2018	Virginia	C263	
2022	Willmar	C264	
2049	Jack Watson	C265	
207	St Johns River Power Park	C121	
2076	Asbury	C267	
2079	Hawthorn	C268	
2080	Montrose	C269	
2094	Sibley	C270	
2098	Lake Road	C271	
2103	Labadie	C272	MIS_MO
2104	Meramec	C273	
2107	Sioux	C274	
2123	Columbia	C275	
2132	Blue Valley	C276	
2144	Marshall	C277	
2161	James River Power Station	C278	
2167	New Madrid	C279	
2168	Thomas Hill	C280	
2171	Missouri City	C282	
2187	J E Corette Plant	C283	
2240	Lon Wright	C284	
2277	Sheldon	C285	
2291	North Omaha	C286	
2324	Reid Gardner	C287	WECC_SNV
2364	Merrimack	C288	NENGREST
2367	Schiller	C289	
2378	B L England	C290	PJM_EMAC
2403	PSEG Hudson Generating Station	C292	
2408	PSEG Mercer Generating Station	C293	
2442	Four Corners	C295	
2451	San Juan	C296	
2526	AES Westover	C298	
2527	AES Greenidge LLC	C299	
2535	AES Cayuga	C300	NY_Z_C&E
2549	C R Huntley Generating Station	C301	
2554	Dunkirk Generating Plant	C302	
26	E C Gaston	C104	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
2706	Asheville	C304	
2712	Roxboro	C306	
2718	G G Allen	C309	S_VACA
2721	Cliffside	C311	
2727	Marshall	C312	
2790	R M Heskett	C314	
2817	Leland Olds	C315	MAP_WAUE
2823	Milton R Young	C316	
2824	Stanton	C317	MIS_MNWI
2828	Cardinal	C318	
2836	Avon Lake	C322	
2840	Conesville	C325	
2850	J M Stuart	C328	
2866	FirstEnergy W H Sammis	C331	
2876	Kyger Creek	C333	
2878	FirstEnergy Bay Shore	C334	
2914	Dover	C335	
2917	Hamilton	C336	
2935	Orrville	C337	
2936	Painesville	C338	
2952	Muskogee	C340	
2963	Northeastern	C341	
298	Limestone	C122	
3	Barry	C100	
3118	Conemaugh	C345	PJM_PENE
3122	Homer City Station	C346	
3130	Seward	C347	
3136	Keystone	C349	
3138	New Castle Plant	C350	
3140	PPL Brunner Island	C351	PJM_WMAC
3149	PPL Montour	C352	
3152	Sunbury Generation LP	C353	
3179	Hatfields Ferry Power Station	C355	
3181	FirstEnergy Mitchell Power Station	C356	
3287	McMeekin	C360	
3295	Urquhart	C361	
3297	Wateree	C362	
3298	Williams	C363	
3393	Allen Steam Plant	C367	
3396	Bull Run	C368	
3399	Cumberland	C369	
3403	Gallatin	C370	
3407	Kingston	C373	
3470	W A Parish	C375	
3497	Big Brown Power Company LLC	C376	
3775	Clinch River	C378	
3796	Bremo Bluff	C381	
3797	Chesterfield	C382	
3809	Yorktown	C384	
384	Joliet 29	C123	
3845	Transalta Centralia Generation	C385	WECC_PNW
3935	John E Amos	C386	
3943	FirstEnergy Fort Martin Power Station	C390	
3944	FirstEnergy Harrison Power Station	C391	
3948	Mitchell	C395	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
3954	Mt Storm	C396	
3992	Blount Street	C397	
4041	South Oak Creek	C398	
4042	Valley	C399	
4050	Edgewater	C400	
4072	Pulliam	C402	
4078	Weston	C403	
4125	Manitowoc	C404	
4127	Menasha	C405	
4140	Alma	C406	
4143	Genoa	C407	
4158	Dave Johnston	C410	
4162	Naughton	C411	
4259	Endicott Station	C412	
4271	John P Madgett	C413	
465	Arapahoe	C125	
469	Cherokee	C126	
47	Colbert	C105	
470	Comanche	C127	WECC_CO
477	Valmont	C128	
492	Martin Drake	C129	
4941	Navajo	C414	
50	Widows Creek	C106	
50039	Kline Township Cogen Facility	C580	
50130	G F Weaton Power Station	C581	
50366	University of Notre Dame	C588	
50388	Phillips 66 Carbon Plant	C590	WECC_SF
50397	P H Glatfelter	C592	
50410	Chester Operations	C594	
50611	WPS Westwood Generation LLC	C597	
50776	Panther Creek Energy Facility	C599	
508	Lamar Plant	C130	
50806	Stone Container Florence Mill	C601	
50835	TES Filer City Station	C602	
50879	Wheelabrator Frackville Energy	C603	
50888	Northampton Generating Company LP	C604	
50931	Yellowstone Energy LP	C606	
50951	Sunnyside Cogen Associates	C607	
50974	Scrubgrass Generating Company LP	C609	
50976	Indiantown Cogeneration LP	C610	
51	Dolet Hills	C107	
52007	Mecklenburg Power Station	C611	
52071	Sandow Station	C612	
525	Hayden	C132	
527	Nucla	C133	
54035	Roanoke Valley Energy Facililty I	C614	
54081	Spruance Genco LLC	C615	
54144	Piney Creek Project	C616	
54304	Birchwood Power	C621	
54408	UW Madison Charter Street Plant	C625	
54556	Corn Products Illinois	C626	
54634	St Nicholas Cogen Project	C627	
54677	CII Carbon LLC	C628	
54755	Roanoke Valley Energy Facility II	C629	
54775	University of Iowa Main Power Plant	C630	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
55076	Red Hills Generating Facility	C633	
55479	Wygen 1	C635	
55749	Hardin Generator Project	C636	
56	Charles R Lowman	C108	
56068	Elm Road Generating Station	C639	MIS_WUMS
56163	KUCC	C640	
56224	TS Power Plant	C641	WECC_NNV
56319	Wygen 2	C642	
564	Stanton Energy Center	C134	FRCC
56456	Plum Point Energy Station	C643	S_D_N_AR
56596	Wygen III	C645	WECC_WY
56609	Dry Fork Station	C646	
56611	Sandy Creek Energy Station	C647	
56671	Longview Power LLC	C649	PJM_AP
56708	CFB Power Plant	C650	
56786	Spiritwood Station	C652	MIS_MAPP
568	Bridgeport Station	C135	
56848	Haverhill North Cogeneration Facility	C210	
57046	Archer Daniels Midland Columbus	C654	
59	Platte	C109	SPP_NEBR
593	Edge Moor	C136	
594	Indian River Generating Station	C137	
60	Whelan Energy Center	C110	
6002	James H Miller Jr	C415	
6004	FirstEnergy Pleasants Power Station	C416	
6009	White Bluff	C417	S_D_REST
6016	Duck Creek	C418	
6017	Newton	C419	
6018	East Bend	C420	
6019	W H Zimmer	C421	
602	Brandon Shores	C138	
6021	Craig	C422	
6030	Coal Creek	C423	
6031	Killen Station	C424	
6034	Belle River	C425	
6041	H L Spurlock	C426	
6052	Wansley	C427	
6055	Big Cajun 2	C428	
6061	R D Morrow	C429	
6064	Nearman Creek	C430	
6065	Iatan	C431	SPP_N
6068	Jeffrey Energy Center	C432	
6071	Trimble County	C433	
6073	Victor J Daniel Jr	C434	
6076	Colstrip	C435	WECC_MT
6077	Gerald Gentleman	C436	
6082	AES Somerset LLC	C437	NY_Z_A&B
6085	R M Schahfer	C438	
6089	Lewis & Clark	C439	
6090	Sherburne County	C440	
6094	FirstEnergy Bruce Mansfield	C441	
6095	Sooner	C442	
6096	Nebraska City	C443	
6098	Big Stone	C444	
6101	Wyodak	C445	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
6106	Boardman	C446	
6113	Gibson	C447	MIS_INKY
6124	McIntosh	C448	
6136	Gibbons Creek	C449	
6137	A B Brown	C450	
6138	Flint Creek	C451	
6139	Welsh	C452	
6146	Martin Lake	C453	
6147	Monticello	C454	
6155	Rush Island	C455	
6165	Hunter	C456	WECC_UT
6166	Rockport	C457	
6170	Pleasant Prairie	C458	
6177	Coronado	C459	
6178	Coleto Creek	C460	
6179	Fayette Power Project	C461	ERC_REST
6180	Oak Grove	C462	
6181	J T Deely	C463	
6183	San Miguel	C464	
6190	Brame Energy Center	C465	SPP_SE
6193	Harrington	C466	
6194	Tolk	C467	SPP_SPS
6195	Southwest Power Station	C468	
6204	Laramie River Station	C469	
6213	Merom	C470	
6225	Jasper 2	C471	
6248	Pawnee	C473	
6249	Winyah	C474	
6250	Mayo	C475	
6254	Ottumwa	C476	MIS_IA
6257	Scherer	C477	
6264	Mountaineer	C478	
628	Crystal River	C139	
641	Crist	C140	
642	Scholz	C141	
643	Lansing Smith	C142	
645	Big Bend	C143	
6469	Antelope Valley	C480	
6481	Intermountain Power Project	C481	
663	Deerhaven Generating Station	C144	
6639	R D Green	C482	
6641	Independence	C483	
6648	Sandow No 4	C484	
6664	Louisa	C485	
667	Northside Generating Station	C145	
6705	Warrick	C486	
676	C D McIntosh Jr	C146	
6761	Rawhide	C487	
6768	Sikeston Power Station	C488	
6772	Hugo	C489	
6823	D B Wilson	C490	
703	Bowen	C147	S_SOU
7030	Twin Oaks Power One	C491	
708	Hammond	C148	
709	Harllee Branch	C149	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
7097	J K Spruce	C492	
7210	Cope	C493	
7213	Clover	C494	PJM_Dom
727	Mitchell	C150	
733	Kraft	C152	
7343	George Neal South	C496	
7504	Neil Simpson II	C497	
753	Crisp Plant	C153	
7549	Milwaukee County	C499	
7737	Cogen South	C501	
7790	Bonanza	C502	
7902	Pirkey	C503	
8	Gorgas	C102	
8023	Columbia	C504	
8042	Belews Creek	C505	
8066	Jim Bridger	C672	
8069	Huntington	C506	
8102	General James M Gavin	C507	
8219	Ray D Nixon	C508	
8222	Coyote	C509	
8223	Springerville	C510	WECC_AZ
8224	North Valmy	C511	
8226	Cheswick Power Plant	C512	
856	E D Edwards	C154	
861	Coffeen	C155	
87	Escalante	C112	WECC_NM
874	Joliet 9	C158	
876	Kincaid Generation LLC	C159	
879	Powerton	C160	
883	Waukegan	C161	
884	Will County	C162	PJM_COMD
887	Joppa Steam	C164	
889	Baldwin Energy Complex	C165	
891	Havana	C166	
892	Hennepin Power Station	C167	
898	Wood River	C169	
963	Dallman	C170	
976	Marion	C171	
983	Clifty Creek	C173	
990	Harding Street	C175	
994	AES Petersburg	C177	
995	Bailly	C178	
997	Michigan City	C179	
83551	Plant Ratcliffe - the Kemper IGCC Project	C633	
55360	Two Elk Generating Station	C634	
56664	Greene Energy Resource Recovery Project	C678	
70194	Genesee #3	C661	
70195	Genesee	C661	
70243	HR Milner	C662	
70269	Keephills	C663	CN_AB
70309	Lingan	C664	
70035	Belledune	C658	CN_NB
70441	Poplar River	C665	
70449	Pt. Aconi	C666	CN_NS
70450	Pt. Tupper	C667	

Plant ORIS Code	Plant Name	Coal Demand Region Codes	IPM Model Region for Which the Existing Demand Region Serves as the Surrogate*
70514	Shand	C668	
70517	Sheerness	C669	
70056	Boundary Dam	C659	CN_SK
70562	Sundance	C670	
70587	Trenton NS	C671	
3264	W S Lee	C358	
3406	Johnsonville	C372	
3803	Chesapeake	C383	
		C676	NY_Z_F
2480	Danskammer Generating Station	C297	NY_Z_G-I
		C675	NY_Z_D
2837	FirstEnergy Eastlake	C323	PJM_ATSI
		C677	S_D_AMSO
10002	ACE Cogeneration Facility	C513	WECC_SCE
70058	Brandon G.S.	C660	CN_MB
1353	Big Sandy	C210	PJM_West

*If IPM elects to build a new coal plant, that coal plant will be assigned to a particular IPM region. Therefore, the base case modeling relies on a particular existing plant in that region – generally one considered to be representative of average transportation cost for plants in that region – and uses that plant's transportation cost as a surrogate for coal transportation cost for a projected new coal plant.

9.1.3 Coal Quality Characteristics

Coal varies by heat content, SO_2 content, HCl content, and mercury content among other characteristics. To capture differences in the sulfur and heat content of coal, a two letter "coal grade" nomenclature is used. The first letter indicates the "coal rank" (bituminous, subbituminous, or lignite) with their associated heat content ranges (as shown in Table 9-3). The second letter indicates their "sulfur grade," i.e., the SO_2 ranges associated with a given type of coal. (The sulfur grades and associated SO_2 ranges are shown in Table 9-4.).

Table 9-3 Coal Rank Heat Content Ranges

Coal Type	Heat Content (Btu/lb)	Classification
Bituminous	>10,260 – 13,000	B
Subbituminous	> 7,500 – 10,260	S
Lignite	less than 7,500	L

Table 9-4 Coal Grade SO_2 Content Ranges

SO_2 Grade	SO_2 Content Range (lbs/MMBtu)
A	0.00 – 0.80
B	0.81 – 1.20
D	1.21 – 1.66
E	1.67 – 3.34
G	3.35 – 5.00
H	> 5.00

The assumptions in EPA Base Case v.5.13 on the heat, HCl, mercury, SO_2, and ash content of coal are derived from EPA's "Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort" (ICR)[82].

A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit… with a capacity greater than 25 megawatts electric, as well as accurate information on the total amount of coal burned by each such unit,", and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations. Data regarding the SO_2, chlorine, and ash content of the coal used was obtained along with mercury content.

The 1998-2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content, ash content, chlorine content, and other characteristics of coal burned at coal-fired utility units greater than 25 MW.

9.1.4 Emission Factors

To make this data usable in EPA Base Case v.5.13, the ICR data points were first grouped by IPM coal grades and IPM coal supply regions. Using the grouped ICR data, the average heat, SO_2, mercury, HCl, and ash content were calculated for each coal grade/supply region combination. In instances where no data were available for a particular coal grade in a specific supply region, the national average SO_2 and mercury values for the coal grade were used as the region's values. The coal characteristics of Canadian coal supply regions are based on the coal characteristics of the adjacent US coal supply regions. The resulting values are shown in Table 9-5.

Table 9-5 Coal Quality Characteristics by Supply Region and Coal Grade

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)
AB	SA	16.12	0.59	5.29	5.47	0.009	214.9
	SB	15.60	0.94	6.06	6.94	0.013	211.0
	SD	15.00	1.43	5.35	11.60	0.008	214.9
AL	BB	25.50	1.09	4.18	9.76	0.012	204.7
	BE	24.00	2.68	12.58	10.70	0.028	204.7
AN	BG	22.00	4.23	9.36	7.83	0.079	202.8
AZ	BB	21.50	1.05	5.27	7.86	0.067	207.1
BC	BD	21.40	1.40	6.98	8.34	0.096	205.4
CG	BB	22.74	0.90	4.09	8.42	0.021	209.6
	SB	20.00	0.93	2.03	7.06	0.007	209.6
CR	BB	23.36	1.05	5.27	7.86	0.067	209.6
CU	BB	23.56	0.86	4.01	7.83	0.009	209.6
IL	BE	23.75	2.25	6.52	6.61	0.214	203.1
	BG	23.50	4.56	6.53	8.09	0.113	203.1
	BH	22.00	5.58	5.43	9.06	0.103	203.1
IN	BB	22.00	1.00	2.29	6.67	0.050	203.1
	BE	22.70	2.31	5.21	7.97	0.036	203.1
	BG	22.40	4.27	7.20	8.22	0.028	203.1
	BH	22.40	6.15	7.11	8.63	0.019	203.1
KE	BB	25.00	1.04	4.79	6.41	0.112	206.4

[82] Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html..

Coal Supply Region	Coal Grade	Heat Content (MMBtu/Ton)	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)
	BD	24.80	1.44	5.97	7.45	0.087	206.4
	BE	24.64	2.12	7.93	7.71	0.076	206.4
KS	BG	22.00	4.84	4.09	8.47	0.133	202.8
KW	BD	23.80	1.56	5.56	6.19	0.280	203.1
	BG	23.80	4.46	6.90	8.01	0.097	203.1
	BH	23.00	5.73	8.16	10.21	0.053	203.1
LA	LE	13.80	2.49	7.32	17.15	0.014	212.6
MD	BD	23.00	1.55	7.82	9.53	0.029	204.7
	BE	23.20	2.78	15.62	11.70	0.072	204.7
ME	LE	12.97	1.83	11.33	11.69	0.019	219.3
MO	BG	22.00	4.54	5.91	9.46	0.023	202.8
MP	SA	18.20	0.62	4.24	3.98	0.007	215.5
	SD	17.20	1.49	4.53	10.13	0.006	215.5
MS	LE	10.39	2.76	12.44	21.51	0.018	212.6
MT	BB	20.90	1.05	5.27	7.86	0.067	215.5
ND	LE	13.10	2.27	8.30	12.85	0.014	219.3
NS	SB	19.60	0.89	4.60	14.51	0.014	209.2
	SE	18.40	1.90	8.65	23.97	0.008	209.2
OH	BE	24.20	3.08	18.70	7.08	0.075	204.7
	BG	24.10	3.99	18.54	8.00	0.071	204.7
	BH	24.20	6.43	13.93	9.13	0.058	204.7
OK	BG	22.00	4.65	26.07	13.54	0.051	202.8
PC	BE	24.41	2.57	17.95	9.23	0.096	204.7
	BG	24.40	3.79	21.54	9.59	0.092	204.7
PW	BE	26.00	2.51	8.40	5.37	0.090	204.7
	BG	25.40	3.69	8.56	6.48	0.059	204.7
SK	LD	13.82	1.51	7.53	11.57	0.014	219.3
	LE	10.58	2.76	12.44	21.51	0.018	215.3
TN	BB	26.20	1.14	3.78	10.35	0.083	206.4
	BE	25.23	2.13	8.43	6.47	0.043	206.4
TX	LE	13.47	3.00	14.65	25.65	0.020	212.6
	LG	12.47	3.91	14.88	25.51	0.036	212.6
	LH	10.68	5.67	30.23	23.95	0.011	212.6
UT	BA	23.00	0.67	4.37	7.39	0.015	209.6
	BE	23.90	2.34	9.20	7.41	0.095	209.6
VA	BB	25.90	1.05	4.61	6.97	0.054	206.4
	BD	25.20	1.44	5.67	7.97	0.028	206.4
	BE	25.00	2.09	8.40	8.05	0.028	206.4
WG	BB	22.00	1.13	1.82	5.58	0.005	214.3
	SD	18.80	1.33	4.33	10.02	0.008	214.3
WH	SA	17.60	0.58	5.61	5.47	0.010	214.3
WL	SB	16.79	0.94	6.44	6.50	0.012	214.3
WN	BE	25.35	2.55	10.28	7.89	0.092	204.7
	BH	25.15	6.09	8.82	9.62	0.045	204.7
WS	BB	24.40	1.09	5.75	9.15	0.091	206.4
	BD	24.50	1.32	8.09	9.25	0.098	206.4
	BE	23.83	1.94	8.80	9.89	0.102	206.4

9.1.5 Coal Grade Assignments

The grades of coal that may be used by specific generating units were determined by an expert assessment of the ranks of coal that a unit had used in the past, the removal efficiency of the installed FGD, and the SO_2 permit rate of the unit. Examples of the coal grade assignments made for individual plants in EPA Base Case v.5.13 are shown in Table 9-6. Not all of the coal grades allowed to a plant by the coal grade assignment are necessarily available in the plant's assigned coal demand region (due to transportation limitations). IPM endogenously selects the coal burned by a plant by taking into account both the constraint of the plant's coal grade assignment and the constraint of the coals actually available within a plant's coal demand region.

Table 9-6 Example of Coal Assignments Made in EPA Base Case

Plant Name	Unique ID	SIP SO_2 Limit (lbs/MMBtu)	Scrubber?	Fuels Allowed
Mt Storm	3954_B_3	0.15	Yes	BA,BB,BD
Mitchell	3948_B_1	1.2	Yes	BA,BB,BD,BE,BG,BH
Scherer	6257_B_1	1.2	Yes	BA,BB,BD,BE,BG,BH,SA,SB, SD,SE
Newton	6017_B_1	0.5	No	BA,SA
Weston	4078_B_4	0.1	Yes	BA,SA,SB
Sandow No 4	6648_B_4	1.2	Yes	LA,LD,LE,LG,LH
Monticello	6147_B_3	1.2	Yes	LA,LD,LE,LG,LH,SA,SB,SD,SE
Laramie River Station	6204_B_3	0.2	Yes	LA,SA,SB
Big Cajun 2	6055_B_2B1	0.38	No	SA
W A Parish	3470_B_WAP8	0.36	Yes	SA,SB,SD,SE

9.2 Coal Supply Curves

9.2.1 Nature of Supply Curves Developed for EPA Base Case v.5.13

In keeping with IPM's data-driven bottom-up modeling framework, a bottom-up approach (relying heavily on detailed economic and resource geology data and assessments) was used to prepare the coal supply curves for EPA Base Case v.5.13. Wood Mackenzie was chosen to develop the curves based on their extensive experience in preparing mine-by-mine estimates of cash operating costs for operating mines in the U.S., their access to both public and proprietary data sources, and their active updating of the data both through research and interviews.

In order to establish consistent nomenclature, Wood Mackenzie first mapped its internal list of coal regions and qualities to EPA's 36 coal supply regions (described above in sections 0) and 14 coal grades (described above in section 9.1.3). The combined code list is shown in Table 9-7 below with the IPM supply regions appearing in the rows and the coal grades in the columns. Wood Mackenzie then created supply curves for each region and coal-grade combination (indicated by the "x" in Table 9-7) for forecast years 2016, 2018, 2020, 2025, 2030, 2040, and 2050.

Table 9-7 Basin-Level Groupings Used in Preparing v.5.13 Coal Supply Curves

Table 9-7 Basin Level Groupings Used in Preparing v.5.13 Coal Supply Curves

			Bituminous						Lignite				Subbituminous			
Coal Supply Region	Geo Region	Geo. Sub-Region	BA	BB	BD	BE	BG	BH	LD	LE	LG	LH	SA	SB	SD	SE
AB	Canada	Alberta, Canada											x	x	x	
AK	West	Northwest	x										x			
AL	Appalachia	Southern Appalachia		x		x										
AN	Interior	West Interior					x									
AZ	West	Southwest		x												
BC	Canada	British Columbia			x											
CG	West	Rocky Mountain		x										x		
CR	West	Rocky Mountain		x												
CU	West	Rocky Mountain		x												
IL	Interior	East Interior (Illinois Basin)				x	x	x								
IN	Interior	East Interior (Illinois Basin)		x		x	x	x								
KE	Appalachia	Central Appalachia		x	x	x										
KS	Interior	West Interior					x									
KW	Interior	East Interior (Illinois Basin)			x		x	x								
LA	Interior	Gulf Lignite								x						
MD	Appalachia	Northern Appalachia			x	x										
ME	West	Dakota Lignite								x						
MO	Interior	West Interior					x									
MP	West	Powder River Basin											x		x	
MS	Gulf	Gulf Lignite Coast								x						
MT	West	Western Montana		x												
ND	West	Dakota Lignite								x						
NS	West	Southwest												x		x
OH	Appalachia	Northern Appalachia				x	x	x								
OK	West	West Interior					x									
PC	Appalachia	Northern Appalachia				x	x									
PW	Appalachia	Northern Appalachia				x	x									
SK	Canada	Saskatchewan							x	x						
TN	Appalachia	Central Appalachia		x		x										
TX	Interior	Gulf Lignite								x	x	x				
UT	West	Rocky Mountain	x			x										
VA	Appalachia	Central Appalachia		x	x	x										
WG	West	Western Wyoming		x											x	
WH	West	Powder River Basin											x			
WL	West	Powder River Basin												x		
WN	Appalachia	Northern Appalachia				x		x								
WS	Appalachia	Central Appalachia		x	x	x										

9.2.2 Cost Components in the Supply Curves

Costs are represented as total cash costs, which is a combination of a mine's operating cash costs plus royalty & levies. These costs are estimated on a Free on Board (FOB) basis at the point of sale. Capital costs (either expansionary or sustaining) are not included in the cash cost estimate. We believe that total cash cost is the best metric for the supply curves as coal prices tend to be ultimately determined by the incremental cost of production (i.e. total cash cost).

Operating cash cost

These are the direct operating cash costs and includes, where appropriate, mining, coal preparation, product transport, and overheads. No capital cost component or depreciation & amortization charge is included. Operating cash costs consist of the following elements:

- Mining costs - Mining costs are the direct cost of mining coal and associated waste material for surface and underground operations. It includes any other mine site costs, such as ongoing rehabilitation / reclamation, security, community development costs. It also includes the cost of transporting raw coal from the mining location to the raw coal stockpile at the coal preparation plant.
- Coal preparation - The cost of coal preparation includes raw coal stockpile reclaim, crushing and screening, washing and marketable coal product stockpiling (if applicable).
- Transport - This covers all transport costs of product coal to point of sale. Transport routes with multiple modes (e.g. truck and rail) are shown as total cost per marketable ton for all stages of the transport route. Loading charges are included in this cost if relevant.
- Overheads - This is any off mine site general and administration overheads that are essential to the production and sale of a mine's coal product. Examples would be essential corporate management or a sales and marketing charge.

It is important to note that although the formula for calculating mine costs is consistent across regions, some tax rates and fees vary by state and mine type. In general, there are two mine types: underground (deep) or surface mines. Underground mining is categorized as being either a longwall (LW) or a continuous room-and-pillar mine (CM). Geologic conditions and characteristics of the coal seams determine which method will be used. Surface mines are typically categorized by the type of mining equipment used in their operation such as draglines (DL), or truck & shovels (TS). These distinctions are important because the equipment used by the mine affects productivity measures and ultimately mine costs. Further information on operating cost methodology and assumptions can be found in Attachment 9-1.

Royalties and Levies

These include, where appropriate, coal royalties, mine safety levies, health levies, industry research levies and other production taxes.

9.2.3 Procedures Employed in Determining Mining Costs

The total cash costs of mines have been estimated in current year terms using public domain information including; geological reports, reported statistics on production, labor and input costs, and company reports. The estimates have been validated by reference to information gained by visits to operations, and discussions with industry participants.

Because the estimates are based only on public information and analysis, and do not represent private knowledge of an operation's actual costs, there may be deviations from actual costs. In instances where confidential information is held by Wood Mackenzie, it has not been used to produce the published estimates. Several methods are employed for cost estimation depending on the availability of information and the diversity of mining operations. When possible, Wood Mackenzie analysts developed detailed lists of mine related costs. Costs such as employee wages & benefits, diesel fuel, spare parts, roof bolts and explosives among a host of others are summed to form a mine's operating cash costs.

Where information is incomplete, cost items are grouped into categories that can be compared with industry averages by mine type and location. These averages can be adjusted up or down based on new information or added assumptions. The adjustments take the form of cost multipliers or parameter values. Specific cost multipliers are developed with the aid of industry experts and proprietary formulas. This method is at times used to convert materials and supplies, on-site trucking costs and mine and division overhead categories into unit removal costs by equipment type. To check the accuracy of these cost estimates, cash flow analysis of publicly traded companies is used. Mine cash-costs are extracted from corporate cash flows and compared with the initial estimates. Adjustments for discrepancies are made on a case-by-case basis.

Many of the cost assumptions associated with labor and productivity were taken from the Mine Safety Health Administration (MSHA) database. All active mines report information specific to production levels, number of employees and employee hours worked. Wood Mackenzie supplements the basic MSHA data with information obtained from mine personnel interviews and industry contacts. Phone conversations and conferences with industry professionals provide additional non-reported information such as work schedules, equipment types, percentages of washed coal, and trucking distances from the mine to wash-plants and load-out terminals.

For each active or proposed mine, Wood Mackenzie reports the estimated cost to take coal from the mine to a logical point-of-sale. The logical point-of-sale may be a truck or railcar load-out or even a barge facility. This is done to produce a consistent cost comparison between mines. Any transport costs beyond the point-of-sale terminal are not part of this analysis and are not reflected in the supply curves themselves.

9.2.4 Procedure Used In Determining Mine Productivity

Projected production and stripping ratios are the key determinants of surface mine productivity. Wood Mackenzie assumes mining costs increase as stripping ratios increase. The stripping ratio is the quantity of overburden removed relative to the quantity of coal recovered. Assuming that reserves are developed where they are easiest to mine and deliver to market, general theory suggests that as the easy reserves are depleted, greater amounts of overburden must be handled for the same amount of coal production; thus causing a decrease in mining productivity. However, this productivity loss is often offset by technology improvements in labor saving equipment.

While an understanding of the forces affecting productivity is important, no attempt is made to develop a complex algorithm that tries to balance increased stripping ratios with added technology improvements. Instead, Wood Mackenzie uses reported aggregate productivity (in tons per employee hour) provided by MSHA as a starting point and divides the production by the productivity calculation to obtain aggregate employee-hours. Allocating aggregate employee hours among specific mines, production forecasts for these mines can be converted back into mine-specific productivity forecasts. These forecasts are then examined on a mine-by-mine basis by an industry expert with region-specific knowledge.

A similar approach is used for underground mines. First, as background, the specific factors affecting productivity at such mines are identified. For example, underground mines do not have stripping ratios. Productivity estimates for these mines largely depend on the type of mining technique used (which is a function of the region's geology). For instance, longwall-mines can produce a high volume of low cost coal but geologic constraints like small reserve blocks and the occurrence of faulting tends to limit this technique to certain regions. In addition to geologic constraints, there are many variables that can impact underground-mine productivity but they are often difficult to quantify and forecast.

9.2.5 Procedure to Determine Total Recoverable Reserves by Region and Type

Before mine operators are allowed to mine coal, they must request various permits, conduct environmental impact studies (EIS) and, in many cases, notify corporate shareholders. In each of these instances, mine operators are asked to estimate annual production and total recoverable reserves. Wood Mackenzie uses the mine operators' statements as the starting point for production and reserves forecasts. If no other material is available, interviews with company personnel will provide an estimate.

Region and coal type determinations for unlisted reserves are based on public information reported for similarly located mines. Classifying reserves this way means considering not only a mine's geographic location but also its geologic conditions such as depth and type of overburden and the specific identity of the coal seam(s) being mined. For areas where public information is not available or is incomplete, Wood Mackenzie engineers and geologists estimate reserve amounts based on land surveys and reports of coal depth and seam thickness provided by the U.S. Geologic Service (USGS). This information is then used to extrapolate reserve estimates from known coal sources to unknown sources. Coal quality determinations for unknown reserves are assigned in much the same way.

Once a mine becomes active, actual production numbers reported in corporate SEC filings and MSHA reports are subtracted from the total reserve number to arrive at current reserve amounts. Wood Mackenzie consistently updates the reserves database when announcements of new or amended reserves are made public. As a final check, the Wood Mackenzie supply estimates are balanced against the Demonstrated Reserve Base (DRB)[83] estimates to ensure that they do not exceed the DRB estimates.

9.2.6 New Mine Assumptions

New mines have been included based on information that Wood Mackenzie maintains on each supply region. They include announced projects, coal lease applications and unassigned reserves reported by mining companies. Where additional reserves are known to exist, additional incremental steps have been added and designated with the letter "N" in the "Step Name" field of the supply curves. These incremental steps were added based on characteristics of the specific region, typical mine size, and cost trends. They do not necessarily imply a specific mine or mine type.

In the IL basin, there is a significant amount of mine projects announced and/or underway that will be completed and available by 2016. These "on the way" mines are designated as existing mines in the "step name" field as they already are, or expected to be, available by the first model run year of 2016. Wood Mackenzie has also identified technical coal reserves that may be commercial in the longer-term, but would most likely not be developed until after the completion of mine development already underway or announced. Therefore, the new mines reflecting these additional reserves are not available until 2018.

9.2.7 Other Notable Procedures

Currency Assumptions

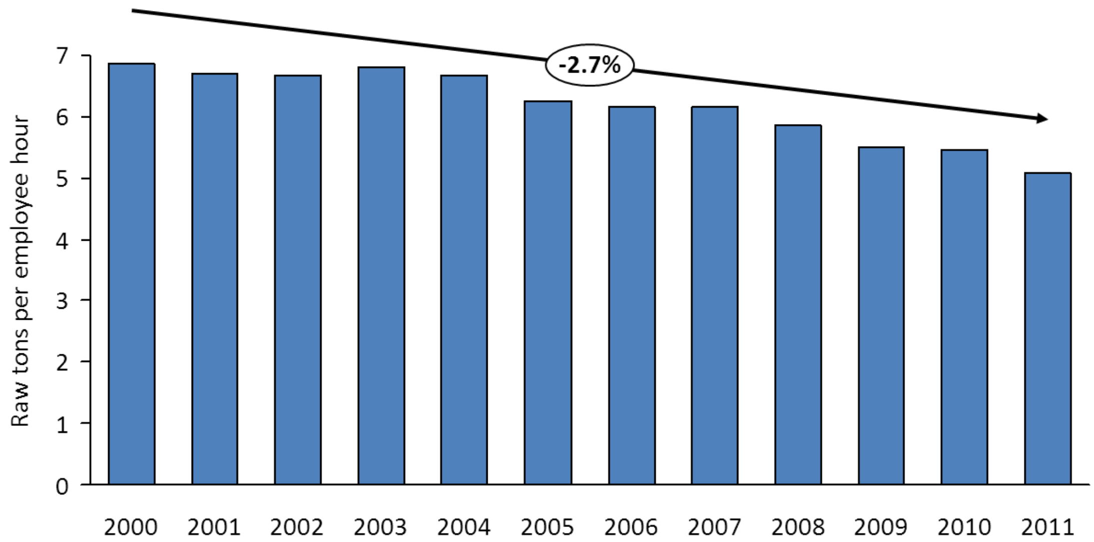
For consistency with the cost basis used in EPA Base Case v.5.13, costs are converted to real 2011$.

Future Cost Adjustments

Changes in mine productivity are a key factor impacting the evolution of costs over time. In general, mine productivity is expected to continue to decline – in large part due to worsening geology and more difficult to mine reserves Productivity has declined at -2.7% CAGR from 2000-2011 as shown in Figure 9-2.

[83] Posted by the Energy Information Administration (EIA) in its Coal Production Report.

Figure 9-2 Coal Mine Productivity (2000-2011)



Source: U.S. Department of Labor, Mine Safety and Health Administration

Figure 9-3 Average Annual Cost Growth Assumptions by Region (2012-2050)

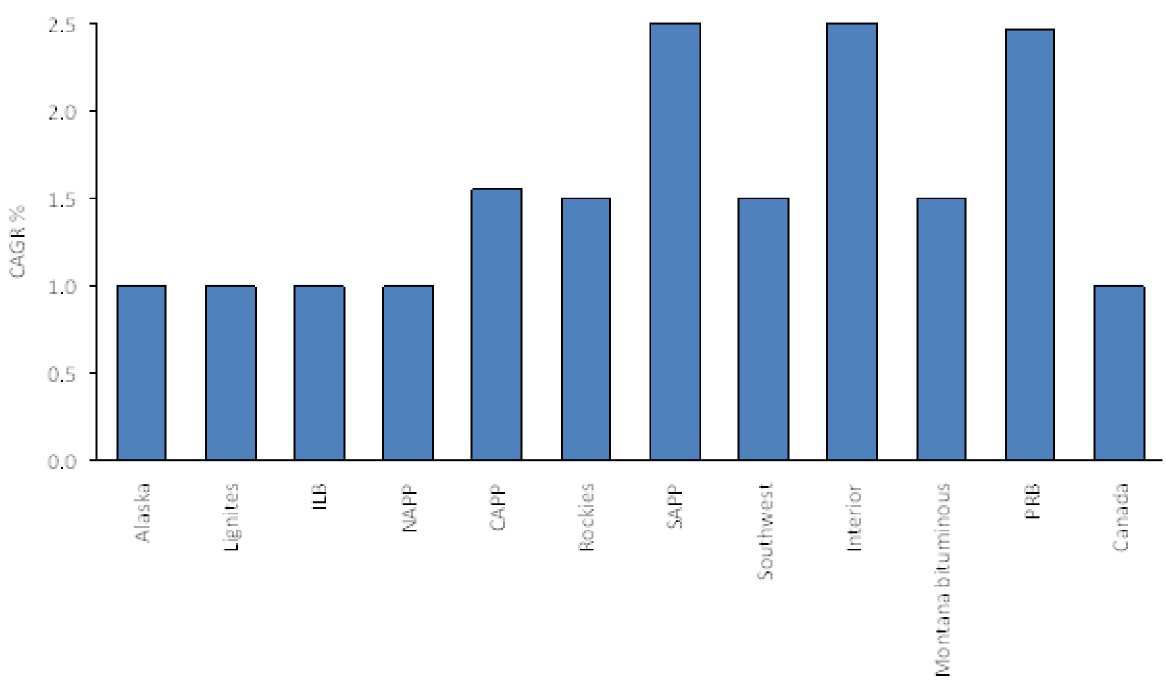


Figure 9-3 shows the compounded average annual growth rate (CAGR) of mining costs by basin over the forecast period. It should be noted that cost increases will ultimately be linked to market demand (as demand grows, the faster the rate of depletion of lower cost reserves). Costs in some supply basins are expected to increase more quickly than others due to issues such as mining conditions, productivity, infrastructure limitations, etc. Region-specific information can be found in section 9.2.9.

Supply Growth Limitations

To the maximum extent possible, the IPM model is set up to determine the optimal volume of coal supply which can be profitably supplied. For two of the lower cost basins (Powder River and Illinois basins), maximum production capacities are included as constraints (production ceilings) to more accurately reflect the upper bound of what could be produced in a given year. Those limits, represented in millions of tons per year, are shown in Figure 9-4 below. These ceilings are necessary to guard against modeling excess annual production capacity in certain basins. For instance, in the PRB, several of the “new” mines reflect expansion mines that would not be developed until the initial mine is further depleted. In this case, the production ceiling helps safeguard against a modeling scenario that would simultaneously produce from both of these mines.

Figure 9-4 Maximum Annual Coal Production Capacity

Maximum Thermal Coal Production Capacity per Year (million tons)

	2016	2018	2020	2025	2030	2040	2050
ILB	165.5	190	203.4	220.1	239.5	254.6	254.6
PRB	509	525.5	552.5	572.3	609.5	609.5	609.5

9.2.8 Supply Curve Development

The description below describes the development of the coal supply curves. The actual coal supply curves can be found www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html. For illustrative purposes, there is also an excerpt of the coal supply curves in Table 9-24 of this chapter.

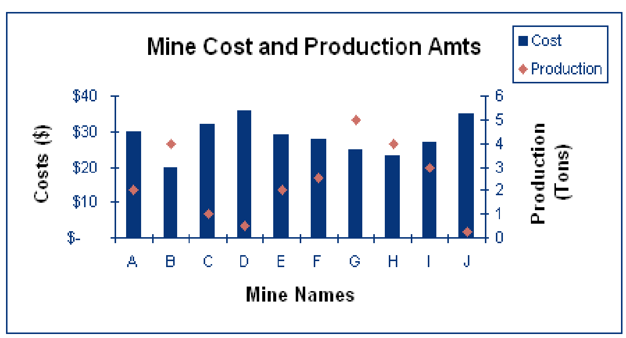
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. Mines located toward the bottom of the curve have the lowest cost and are most likely to be developed while the mines at the top of the curve are higher cost and will likely wait to be developed. The process for developing a cumulative supply curve is illustrated in Figure 9-5 and Figure 9-6 below.

Figure 9-5 Illustration of Preliminary Step in Developing a Cumulative Coal Supply Curve

Key

E = EXISTING MINE
N = NEW MINE
U = UNDERGROUND MINE
S = SURFACE MINE

New or Existing?	Mine	Type	Cost	Production
N	A	S	$ 30	2
E	B	U	$ 20	4
N	C	S	$ 32	1
N	D	S	$ 36	0.5
E	E	S	$ 29	2
N	F	S	$ 28	2.5
E	G	U	$ 25	5
E	H	U	$ 23	4
E	I	U	$ 27	3
N	J	S	$ 35	0.25



In the table and graph above, mine costs and production are sorted alphabetically by mine name. To develop a supply curve from the above table the values must be sorted by mine costs from lowest to highest. A new column for cumulative production is added, and then a supply curve graph is created which shows the costs on the ‘Y’ axis and the cumulative production on the ‘X’ axis. Notice below that the curve contains all mines – new or existing as well as both underground and surface mines. The resulting curve is a continuous supply curve but can be modified to show costs as a stepped supply curve. (Supply curves in stepped format are used in linear programming models like IPM.) See Figure 9-7 for a stepped version of the supply curve example shown in Figure 9-6. Here each step represents an individual mine, the width of the step reflects the mine's production, and its height shows the cost of production.

Figure 9-6 Illustration of Final Step in Developing a Cumulative Coal Supply Curve

New or Existing?	Mine	Type	Cost	Production	Cum Productio
E	B	U	$ 20	4	4
E	H	U	$ 23	4	8
E	G	U	$ 25	5	13
E	I	U	$ 27	3	16
N	F	S	$ 28	2.5	18.5
E	E	S	$ 29	2	20.5
N	A	S	$ 30	2	22.5
N	C	S	$ 32	1	23.5
N	J	S	$ 35	0.25	23.75
N	D	S	$ 36	0.5	24.25

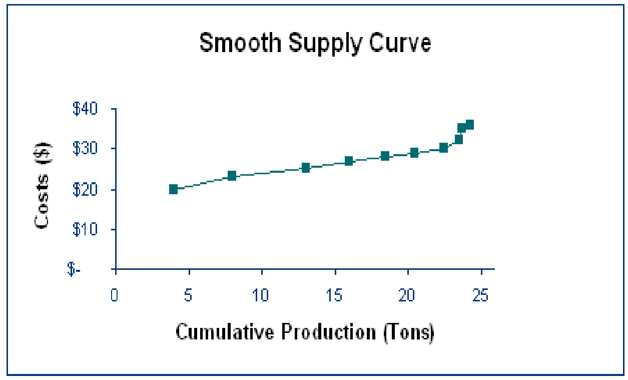
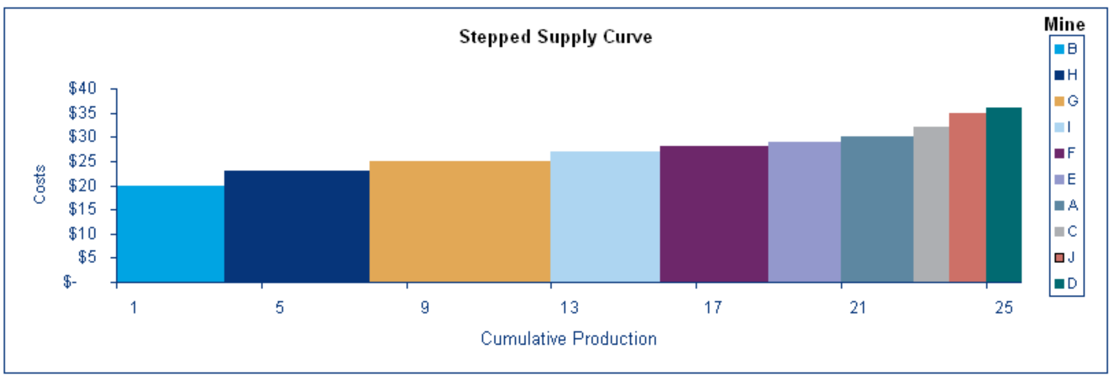


Figure 9-7 Example Coal Supply Curve in Stepped Format



PRODUCTION AMOUNT

Production Scalar

MINE NAME →		B	H	G	I	F	E	A	C	J	D
New or Existing		4	8	13	16	18.5	20.5	22.5	24	25	25.5
E	1	$ 20	-	-	-	-	-	-	-	-	-
E	2	$ 20	-	-	-	-	-	-	-	-	-
E	3	$ 20	-	-	-	-	-	-	-	-	-
E	4	-	$ 23	-	-	-	-	-	-	-	-
E	5	-	$ 23	-	-	-	-	-	-	-	-
E	6	-	$ 23	-	-	-	-	-	-	-	-
E	7	-	$ 23	-	-	-	-	-	-	-	-
E	8	-	-	$ 25	-	-	-	-	-	-	-
E	9	-	-	$ 25	-	-	-	-	-	-	-
E	10	-	-	$ 25	-	-	-	-	-	-	-
E	11	-	-	$ 25	-	-	-	-	-	-	-
E	12	-	-	$ 25	-	-	-	-	-	-	-
E	13	-	-	-	$ 27	-	-	-	-	-	-
E	14	-	-	-	$ 27	-	-	-	-	-	-
E	15	-	-	-	$ 27	-	-	-	-	-	-
N	16	-	-	-	-	$ 28	-	-	-	-	-
N	17	-	-	-	-	$ 28	-	-	-	-	-
N	18	-	-	-	-	$ 28	-	-	-	-	-
E	19	-	-	-	-	-	$ 29	-	-	-	-
E	20	-	-	-	-	-	$ 29	-	-	-	-
N	21	-	-	-	-	-	-	$ 30	-	-	-
N	22	-	-	-	-	-	-	$ 30	-	-	-
N	23	-	-	-	-	-	-	-	$ 32	-	-
N	24	-	-	-	-	-	-	-	-	$ 35	-
N	25	-	-	-	-	-	-	-	-	-	$ 36

9.2.9 EPA Base Case v.5.13 Assumptions and Outlooks for Major Supply Basins

Powder River Basin (PRB)

The PRB is somewhat unique to other US coal basins; in that producers have the ability to add significant production volumes relatively easily and at a profit. That said, the decisions on production volumes are largely based on the market conditions, namely the price. For instance, in a low price environment producers tend to moderate production volumes to maintain attractive prices, and choose to ramp up production when prices are higher. The evolution of costs in the PRB will be strongly correlated to the rate at which producers ramp up production at existing mines, which as indicated will depend on market conditions.

Wood Mackenzie anticipates productivity at most existing PRB mining operations to decline at very modest rates over the forecast horizon, with increasing strip ratios at least partly offset by improved usage of labor and capital. As most PRB mines are progressing downward, the ratios of overburden to coal (strip ratios) will increase in the future. The productivity of new mines will be quite low during the early stages of their life span.

Mining at several locations is steadily proceeding production westward toward the Joint Line railroad and, at current and forecasted levels of production, around 2019 several mines are expected to eventually reach the line. This event will result in a costly movement across the railroad, requiring significant capital investment and reduced production as the transition is made. During the move across the Joint Line railroad, strip ratios will spike and productivity will fall as new box cuts are created.

Illinois Basin (ILB)

Production costs in the Illinois basin have been steadily decreasing in recent years as new low cost mines are opened using more efficient longwall mining techniques. Wood Mackenzie expects that average costs will continue to decline as additional new mines are developed. However, as new low cost mines are brought on, higher cost mines will be unable to compete. In the long-term, the shape of the ILB supply curve is expected to decrease in cost and increase in production capacity.

Given its large scale growth potential, investments in rail infrastructure development will have to keep pace. While Wood Mackenzie expect there to be some bottlenecks in expanding transportation in the basin early on, they project that once utilities begin committing to taking ILB coal, railroads will make the necessary changes to accommodate the change. However, there is a risk that rail infrastructure in the basin will not be able to keep up with the rate of growth in ILB which could limit the region’s otherwise strong growth potential.

Central Appalachia (CAPP)

Geologic conditions in the CAPP region are challenging, with thin seams and few underground reserves amenable to more efficient longwall mining techniques. Costs of production in CAPP have risen substantially in recent years as the region has struggled with mining thinner seams as reserves deplete, mining accidents have led to increased inspections, and mine permitting has become increasingly difficult as opposition to surface mining intensifies – with the revocation of some section 404 permits that regulate the discharge into US waterways. Since surface mining is the lowest cost form of production in CAPP, reduced growth in surface mining operations is adding to increasing cost in the region

As producers cut back on production over the course of 2012 in order to manage the falling demand, productivity suffered and production costs per ton in the region rose roughly 10%. In an effort to retain margins, producers implemented a variety of tactics to try to keep production costs from continuing to increase; including, shifting more production to lower cost operations and selling lesser quality raw coal to save on coal preparation/washing costs.

Northern Appalachia (NAPP)

Mining cost escalation in NAPP has slowed considerably recently. Future cost for the basin as a whole will depend largely on the development of new reserve areas.

Northern Appalachia has an estimated 5 billion short tons (Bst) of thermal coal reserves. However, only about 2.3 Bst is associated with currently operating mines and 90 Mst of that with existing mines that are idled. Many major producers within the region are within years of depleting currently assigned reserves.

9.3 Coal Transportation

The description below describes the transportation matrix. The actual transportation matrix can be found www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html. For illustrative purposes, there is also an excerpt of the transportation matrix in Excerpt from Table 9-23 of this chapter.

Within the United States, steam coal for use in coal-fired power plants is shipped via a variety of transportation modes, including barge, conveyor belt, rail, truck, and lake/ocean vessel. A given coal-fired plant typically only has access to a few of these transportation options and, in some cases, only has access to a single type. The number of transportation options that a plant has when soliciting coal deliveries influences transportation rate levels that plant owners are able to negotiate with transportation providers.

Within the Eastern United States, rail service is provided predominately by two major rail carriers in the region, Norfolk Southern (NS) and CSX Transportation (CSX). Within the Western United States, rail service is also provided predominately by two major rail carriers, Burlington Northern Santa Fe (BNSF) and Union Pacific (UP). Plants in the Midwestern United States may have access to rail service from BNSF, CSX, NS, UP, the Canadian National (CN), Canadian Pacific (CP), or short-line railroads. Barge, truck, and vessel service is provided by multiple firms, and conveyor service is only applicable to coal-fired plants directly located next to mining operations (e.g., mine-mouth plants).

In recent years, transportation rates for most modes of coal transportation have increased significantly due to significant increases in input costs (including fuel prices, steel prices and labor costs), as well as a number of Surface Transportation Board (STB) rail rate case decisions that have allowed higher rail rates to be charged at plants that are served only by a single railroad.

The transportation methodology and rates presented below reflect expected long-run equilibrium transportation rates as of March 2012, when the coal transportation rate assumptions for EPA Base Case v.5.13 were finalized. The forecasted changes in transportation rates during the 2016-2050 forecast period reflect expected changes in long-term equilibrium transportation rate levels, including the long-term market dynamics that will drive these pricing levels.

All rates are represented in 2011 real dollars.

9.3.1 Coal Transportation Matrix Overview

Description

In previous versions of EPA Base Case using IPM, the coal transportation matrix connected coal supply regions with coal demand regions that represented the aggregated coal demand from several coal-fired generating plants. In EPA Base Case v.5.13, the demand side of the coal transportation matrix has been expanded, so that each of the approximately 560 U.S. and Canadian coal-fired generating plants included in EPA Base Case v.5.13 is individually represented in the coal transportation matrix. This allows the coal transportation routings, coal transportation distances, and coal transportation rates associated with each individual coal-fired generating plant to be estimated more accurately in EPA Base Case v. 5.13.

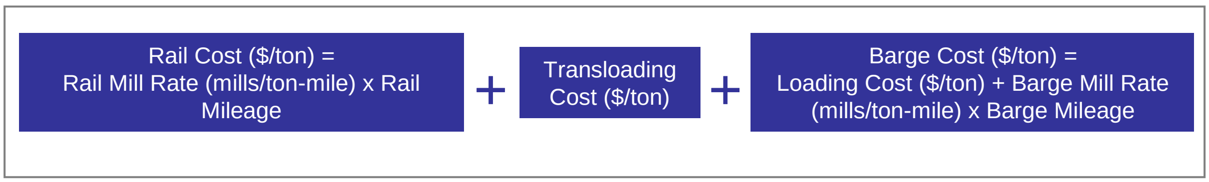
The coal transportation matrix shows the total coal transportation rate which is expected to be required to transport coal from selected coal supply regions to each individual coal-fired generating plant.

The coal supply regions associated with each coal-fired generating plant in EPA Base Case v.5.13 are largely unchanged from previous versions of IPM. The coal supply regions associated with each coal-fired generating plant are the coal supply regions which were supplying each plant as of late 2011, have supplied each plant in previous years, or are considered economically and operationally feasible sources of additional coal supply during the forecast period in EPA Base Case v. 5.13 (2016-2050.) A more detailed discussion of the coal supply regions can be found in previous sections.

Methodology

Each coal supply region and coal-fired generating plant is connected via a transportation link, which can include multiple transportation modes. For each transportation link, cost estimates, in terms of $/ton, were calculated utilizing mode-based transportation cost factors, analysis of the competitive nature of the moves, and overall distance that the coal type must move over each applicable mode. An example of the calculation methodology for movements including multiple transportation modes is shown in Figure 9-8.

Figure 9-8 Calculation of Multi-Mode Transportation Costs (Example)



9.3.2 Calculation of Coal Transportation Distances

Definition of applicable supply/demand regions

Coal-fired generating plants are linked to coal supply regions based on historical coal deliveries, as well as based on the potential for new coal supplies to serve each coal-fired generating plant going forward. A generating plant will almost always have transportation links with more than one supply region, depending on the various coal types that can be physically delivered and burned at that particular plant. On average, each coal-fired generating plant represented in IPM is linked with about nine coal supply regions. Some plants may have more than the average number of transportation links and some may have fewer, depending on the location of each plant, the transportation modes available to deliver coal to each plant, the boiler design and emissions control technologies associated with each plant, and other factors that affect the types of coal that can be burned at each plant.

For "mine-mouth" plants (plants for which the current coal supply is delivered from a single nearby mine, generally by conveyor belt or using truck transportation) that are 200 MW or larger, Hellerworx and Tetratech have estimated the cost of constructing facilities that would allow rail delivery of alternative coal supplies, and the transportation rates associated with the delivery of alternative coal supplies. This includes the construction of rail spurs (between one and nine miles in length depending on the proximity of each plant to existing railroad lines) to connect each plant with existing railroad lines.

Transportation Links for Existing Coal-Fired Plants

Transportation routings from particular coal supply regions to particular coal-fired generating plants were developed based on third-party software[84] and other industry knowledge available to Hellerworx and Tetratech. Origins for each coal supply region were based on significant mines or other significant

[84] Rail routing and mileage calculations utilize ALK Technologies PC*Miler software.

delivery points within the supply region, and the destination points were plant-specific for each coal-fired generating plant represented in IPM. For routes utilizing multiple modes (e.g. rail-to-barge, truck-to-rail, etc.), distances were developed separately for each transportation mode.

Transportation Links for New Coal-Fired Plants

Transportation links for new coal-fired plants that were under construction as of March 2012 were developed using the same methodology as for existing plants, and these committed new plants were included in IPM as of their expected date of commercial operation.

Coal transportation costs for new coal-fired plants not yet under construction (i.e., coal transportation costs for new coal plants modeled by IPM) were estimated by selecting an existing coal plant within each IPM Region whose coal supply alternatives, and coal transportation costs, were considered representative of the coal supply alternatives and coal transportation costs that would likely be faced by new coal plants within that same IPM Region. This methodology helps ensure that coal transportation costs for new coal plants are properly integrated with and assessed fairly vis-à-vis existing coal-fired assets within the IPM modeling structure.

9.3.3 Overview of Rail Rates

Competition within the railroad industry is limited. Two major railroads in the Western U.S. (BNSF and UP) and two major railroads in the Eastern U.S. (CSX and NS) currently originate most of the U.S. coal traffic that moves by rail.

In recent years, railroads have increased coal transportation rates in real terms wherever they have the opportunity. However, rail rates at plants captive to a single rail carrier are now close to the maximum levels prescribed by the STB, which limits the potential for further real increases in these rates. Moreover, as of March 2012, the differential between rates at captive plants and rates at competitively-served plants was relatively narrow. The current relatively small differentials between captive and competitive rates are expected to persist over the long-term.

All of the rail rates discussed below include railcar costs, and include fuel surcharges at expected 2012 fuel price levels.

Overview of Rail Competition Definitions

Within the transportation matrix, rail rates are classified as being either captive or competitive (seeTable 9-8), depending on the ability of a given coal demand region to solicit supplies from multiple suppliers. Competitive rail rates are further subdivided into high- and low-cost competitive subcategories. Competition levels are affected both by the ability to take delivery of coal supplies from multiple rail carriers, the use of multiple rail carriers to deliver coal from a single source (e.g., BNSF/UP transfer to NS/CSX for PRB coal moving east), or the option to take delivery of coal via alternative transportation modes (e.g., barge, truck or vessel).

Table 9-8 Rail Competition Definitions

Competition Type	Definition
Captive	Demand source can only access coal supplies through a single provider; demand source has limited power when negotiating rates with railroads.
High-Cost Competitive	Demand source has some, albeit still limited, negotiating power with rail providers; definition typically applies to demand sources that have the option of taking delivery from either of the two major railroads in the region.
Low-Cost Competitive	Demand source has a strong position when negotiating with railroads; typically, these demand sources also have the option of taking coal supplies via modes other than rail (e.g., barge, truck, or lake/ocean vessel).

Rail Rates

As previously discussed, rail rates are subdivided into three competitive categories: captive, high-cost competitive, and low-cost competitive. Moves are further subdivided based on the distance that the coal supply must move over rail lines: <200 miles, 200-299 miles, 300-399 miles, 400-649 miles, and 650+ miles. Within the Western U.S., mileages are only subdivided into two categories (<300 miles and 300+ miles), given the longer distances that these coal supplies typically move.

Initial rate level assumptions were determined based on an analysis of recent rate movements, current rate levels in relation to maximum limits prescribed by the STB, expected coal demand, diesel prices, recent capital expenditures by railroads, and projected productivity improvements. In general, shorter moves result in higher applicable rail rates due to the lesser distance over which fixed costs can be spread. As previously discussed, rail rates reflect anticipated 2012 costs in 2011 real dollars.

Rates Applicable to Eastern Moves

Rail movements within the Eastern U.S. are handled predominately by the region's two major carriers, NS and CSX. Some short movements are handled by a variety of short-line railroads. Most plants in the Eastern U.S. are served solely by a single railroad (i.e., they are captive plants). The practical effect of this is that CSX and NS do not compete aggressively at the limited number of plants that have access to both major railroads, and the rates for high-cost competitive plants tend to be similar to the rates for captive plants. Table 9-9 presents the 2012 eastern rail rates.

Table 9-9 Assumed Eastern Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	85	85	72
200-299	71	71	60
300-399	69	69	59
400-649	61	61	52
650+	43	43	37

Rates Applicable to Midwestern Moves

Plants in the Midwestern U. S. may be served by BNSF, CN, CP, CSX, NS, UP or short-line railroads. However, the rail network in the Midwestern U.S. is very complex, and most plants are served by only one of these railroads. The Midwestern U.S. also includes a higher proportion of barge-served and truck-served plants than is the case in the Eastern or Western U.S. Table 9-10 depicts 2012 rail rates in the Midwest.

Table 9-10 Assumed Midwestern Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	85	85	72
200-299	67	67	57
300-399	49	49	42
400-649	46	46	39
650+	43	43	37

Rates Applicable to Western Moves

Rail moves within the Western U.S. are handled predominately by BNSF and UP. Due to industry concerns about potential future regulation of carbon dioxide (CO_2) emissions and other factors, it now appears very unlikely that the CP will construct a third rail line into the PRB, so this analysis assumes the PRB will continue to be served only by BNSF and UP. Rates for Western coal shipments from the PRB are forecast separately from rates for Western coal shipments from regions other than the PRB. This reflects the fact that in many cases coal shipments from the PRB are subject to competition between BNSF and UP , while rail movements of Western coal from regions other than the PRB consist primarily of Colorado and Utah coal shipments that originate on UP, and New Mexico coal shipments that originate on BNSF. PRB coal shipments also typically involve longer trains moving over longer average distances than coal shipments from the other Western U.S. coal supply regions, which means these shipments typically have lower costs per ton-mile than non-PRB coal shipments. In the west, there are enough plants that have access to both BNSF and UP or a neutral carrier that the western railroads are concerned of losing coal volume to the competing railroad, and do offer more of a rate discount to plants that can access both railroads (e.g., high-cost competitive).

<u>Non-PRB Coal Moves</u>

The assumed non-PRB western rail rates for 2012 are shown in Table 9-11.

Table 9-11 Assumed Non-PRB Western Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	53	45	45
300+	28	25	25

The assumed PRB western rail rates for 2012 are available in Table 9-12.

<u>PRB Moves Confined to BNSF/UP Rail Lines</u>

Table 9-12 Assumed PRB Western Rail Rates for 2012
(2011 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	32	27	27
300+	26	23	23

<u>PRB Moves Transferring to Eastern Railroads</u>

For PRB coal moving west-to-east, the coal transportation matrix assumes that the applicable low-cost competitive assumption is applied to the BNSF/UP portion of the rail mileage, and an assumption of either $2.20 per ton or 41 mills per ton-mile (whichever is higher) is applied to the portion of the movement that occurs on railroads other than BNSF and UP. (The $2.16 per ton assumption is a minimum rate for short-distance movements of PRB coal on Eastern railroads.)

9.3.4 Truck Rates

Truck rates include loading and transport components, and all trucking flows are considered competitive because highway access is open to any trucking firm. The truck rates shown in Table 9-13 are expected long-term equilibrium levels reflective of current rates as of March 2012, and expected changes in labor costs, fuel prices, and steel prices.

Table 9-13 Assumed Truck Rates for 2012
(2011 Real Dollars)

Market	Loading Cost ($/ton)	Transport (mills/ton-mile)
All Markets	1.00	120

9.3.5 Barge and Lake Vessel Rates

As with truck rates, barge rates include loading and transport components, and all flows are considered competitive because river access is open to all barge firms. The transportation matrix subdivides barge moves into three categories, which are based on the direction of the movement (upstream vs. downstream) and the size of barges that can be utilized on a given river. As with the other types of transportation rates forecast in this analysis, the barge rate levels shown in Table 9-14 are expected long-term equilibrium levels reflective of current rates as of March 2012, and expected changes in labor costs, fuel prices, and steel prices.

Table 9-14 Assumed Barge Rates for 2012
(2011 Real Dollars)

Type of Barge Movement	Loading Cost ($/ton)	Transport (mills/ton-mile)
Upper Mississippi River, and Downstream on the Ohio River System	2.70	9.7
Upstream on the Ohio River System	2.45	11.5
Lower Mississippi River	2.70	6.9

Notes:
1. The Upper Mississippi River is the portion of the Mississippi River north of St. Louis.
2. The Ohio River System includes the Ohio, Big Sandy, Kanawha, Allegheny, and Monongahela Rivers.
3. The Lower Mississippi River is the portion of the Mississippi River south of St. Louis.

Rates for transportation of coal by lake vessel on the Great Lakes were forecast on a plant-specific basis, taking into account the lake vessel distances applicable to each movement, the expected backhaul economics applicable to each movement (if any), and the expected changes in labor costs and fuel and steel prices over the long-term.

9.3.6 Transportation Rates for Imported Coal

Transportation rates for imported coal reflect expectations regarding the long-term equilibrium level for ocean vessel rates, taking into account expected long-run equilibrium levels for fuel and steel prices, and expected continued strong demand for shipment of dry bulk commodities (especially coal and iron ore) from China and other Asian nations.

In EPA Base Case v.5.13, it is assumed that imported coal is likely to be used only at plants that can receive this coal by direct water delivery (i.e., via ocean vessel or barge delivery to the plant). This is based on an assessment of recent transportation market dynamics, which suggests that railroads are unlikely to quote rail rates that will allow imported coal to be cost-competitive at rail-served plants. Moreover, import rates are higher for the Alabama and Florida plants than for New England plants because many of the Alabama and Florida plants are barge-served (which requires the coal to be transloaded from ocean vessel to barge at an ocean terminal, and then moved by barge to the plant), whereas most of the New England plants can take imported coal directly by vessel. The assumed costs are summarized in

Excerpt from Table 9-23.

9.3.7 Other Transportation Costs

In addition to the transportation rates already discussed, the transportation matrix assumes various other rates that are applied on a case-by-case basis, depending on the logistical nature of a move. These charges apply when coal must be moved between different transportation modes (e.g., rail-to-barge or truck-to-barge) – see Table 9-15.

Table 9-15 Assumed Other Transportation Rates for 2012 (2011 Real Dollars)

Type of Transportation	Rate ($/ton)
Rail-to-Barge Transfer	1.50
Rail-to-Vessel Transfer	2.00
Truck-to-Barge Transfer	2.00
Rail Switching Charge for Short line	2.00
Conveyor	1.00

9.3.8 Long-Term Escalation of Transportation Rates

Overview of Market Drivers

According to data published by the Association of American Railroads (AAR), labor costs accounted for about 33% of the rail industry's operating costs in 2010, and fuel accounted for an additional 18%. The remaining 49% of the rail industry's costs relate primarily to locomotive and railcar ownership and maintenance, and track construction and maintenance.

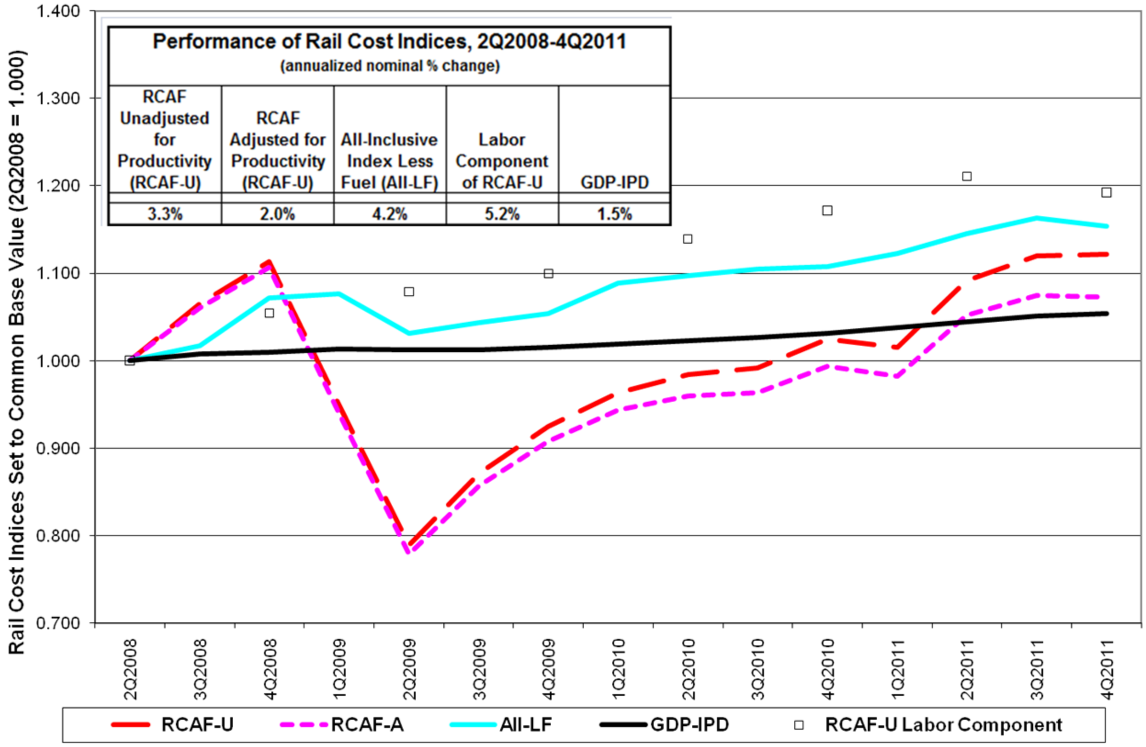
The RCAF[85] Unadjusted for Productivity (RCAF-U), which tracks operating expenses for the rail industry, increased at an annualized rate of 3.3%/year between the second quarter of 2008 and the fourth quarter of 2011, see Table 9-9, more than double the increase of 1.5%/year in general inflation (GDP-IPD) over the same period. This is largely the result of unusually steep increases in labor costs, which reflected the effect of new labor agreements negotiated prior to the economic downturn that occurred in late 2008 and 2009. Hellerworx expects that going forward, the rail industry's labor costs will increase at a more moderate rate (assumed to be 1% more than overall inflation), which is more in line with longer-term historical increases in these costs.

According to data from the AAR, the net change in the rail industry's fuel costs between 2Q2008 and 4Q2011 was a nominal decline of about 9% (or an annualized decline of about 2.6% per year. Over the same time period, equipment and other costs for the rail industry increased by an average of about 2.0% per year, only slightly faster than overall inflation of 1.5% per year.

[85] The Rail Cost Adjustment Factor (RCAF) refers to several indices created for regulatory purposes by the STB, calculated by the AAR, and submitted to the STB for approval. The indices are intended to serve as measures of the rate of inflation in rail inputs. The meaning of various RCAF acronyms that appear in this section can be found in the insert in

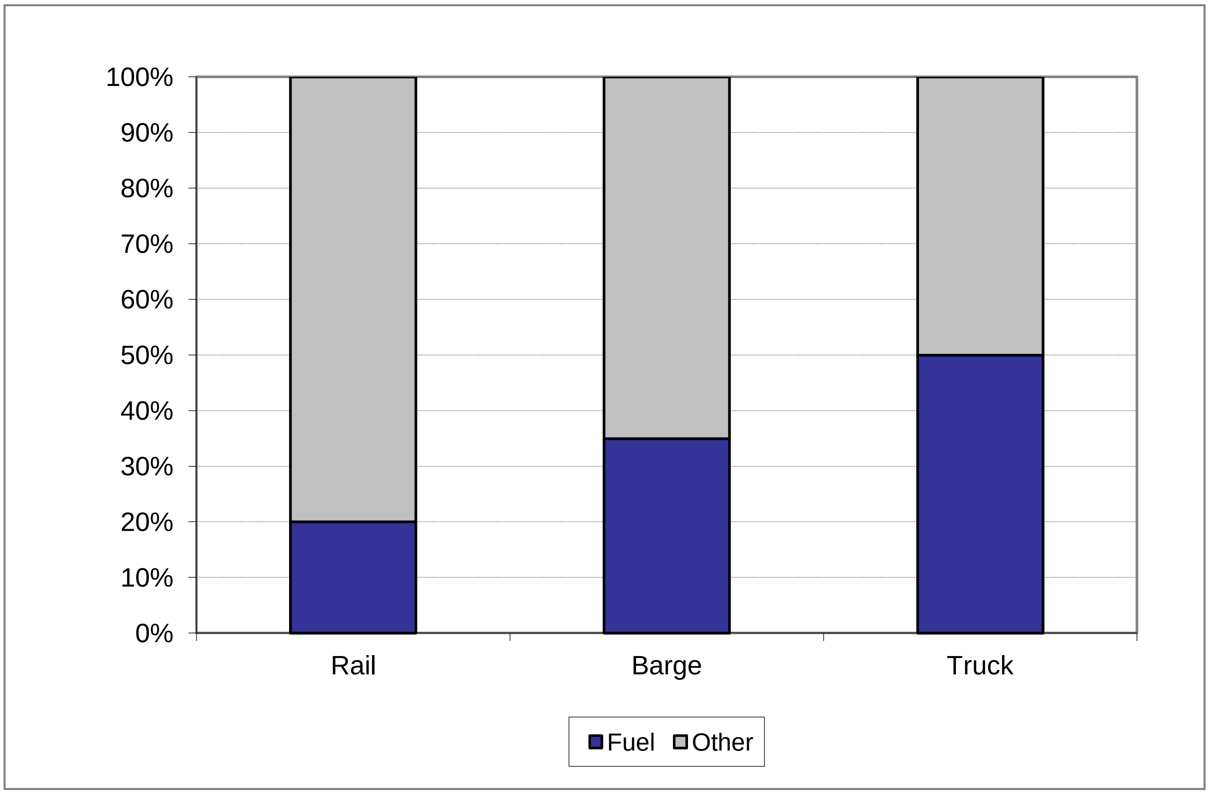
Figure 9-9.

Figure 9-9 Rail Cost Indices Performance
(2Q2008-4Q2011)



The other major transportation modes used to ship coal (barge and truck) have cost drivers broadly similar to those for rail transportation (labor costs, fuel costs, and equipment costs). However, a significant difference in cost drivers between the transportation modes relates to the relative weighting of fuel costs for the different transportation modes. Estimates as shown in Figure 9-10 show that, at 2012 fuel prices, fuel costs accounted for about 20% of long-run marginal costs for the rail industry, 35% of long-run marginal costs for barges, and 50% of long-run marginal costs for trucks.

Figure 9-10 Long-Run Marginal Cost Breakdown by Transportation Mode



9.3.9 Market Drivers Moving Forward

Diesel Fuel Prices

The Energy Information Administration's (EIA's) Annual Energy Outlook (AEO)[86] forecast of long-term equilibrium prices for diesel fuel used in the transportation sector (see Table 9-16) shows expected prices ranging from about $3.83/gallon in 2012 to about $4.58/gallon in 2035 (2011 real dollars). This represents an annual real increase in diesel fuel prices of about 0.8%/year during 2012-2035. The coal transportation rate forecast for EPA Base Case v.5.13 assumes that this average rate of increase in diesel fuel prices will apply over EPA's entire forecast period (2016-2050).

Table 9-16 EIA AEO Diesel Fuel Forecast, 2012-2030 (2011 Real Dollars)

Year	Rate ($/gallon)
2012	3.83
2015	3.84
2020	4.06
2025	4.27
2030	4.48
2035	4.58
Annualized % Change, 2025-2035	0.8%

Source: EIA

[86] As noted at the beginning of this section, the coal transportation rate assumptions for EPA Base Case v5.13 were finalized in March 2012. At that time, the Annual Energy Outlook 2012 forecast was the latest available.

Iron Ore Prices

ABARES's[87] forecast of iron ore prices as depicted in Table 9-17 shows an expectation that iron ore prices will decline by about 22% in real terms for their 5-year forecast period (2012-2017) as a whole.

Table 9-17 ABARES Forecast of Iron Ore Prices

	2011 US$/metric tonne
ABARE Forecast of Average Contract Price for Australian Iron Ore Exports, 2012	137
ABARE Forecast for 2013	129
ABARE Forecast for 2014	125
ABARE Forecast for 2015	121
ABARE Forecast for 2016	115
ABARE Forecast for 2017	107
Total Percent Change (2012-2017)	-22%

Source: ABARES, Resources and Energy Quarterly, March 2012.

Labor Costs

As noted earlier, labor costs for the rail industry are expected to increase approximately 1% faster than overall inflation, on average over the forecast period. Due to the fact that competition is stronger in the barge and trucking industries than in the rail industry, labor costs in the barge and truck industries are expected to increase at approximately the same rate as overall inflation, on average over the forecast period.

Productivity Gains

The most recent data published by AAR (covering 2006-2010) shows that rail industry productivity increased at an annualized rate of approximately 0.8% per year during this period. However, due to limited competition in the rail industry, these productivity gains were generally not passed through to shippers. In addition, the potential for significant productivity gains in the trucking industry is relatively limited since truck load sizes, operating speeds, and truck driver hours are all regulated by law. Although increased lock outages and the associated congestion on the inland waterway system as the river infrastructure ages may reduce the rate of future productivity gains in the barge industry, limited productivity gains are expected to occur, and these productivity gains are expected to be largely passed through to shippers since the barge industry is highly competitive.

Long-Term Escalation of Coal Transportation Rates

Based on the foregoing discussion, rail rates are expected to escalate at an average rate of 0.5% per year in real terms during 2013-2050. Over the same period, barge and lake vessel rates are expected to decline at an average rate of 0.2% per year, which reflects some pass-through of productivity gains in those highly competitive industries. Truck rates are expected to escalate at an average rate of 0.4%/year during 2013-2050, rates for conveyor transportation and transloading services are expected to be flat in real terms, on average over the forecast period.

The basis for these forecasts is summarized in

Table 9-18.

[87] ABARES (the Australian Bureau of Agricultural and Resource Economics and Sciences) is a branch of the Australian government that forecasts prices and trade volumes for a wide variety of commodities that Australia exports. Australia is a major exporter of iron ore, accounting for about 41% of total worldwide iron ore exports in 2011. See www.daff.gov.au/abares.

Mode	Component	Component Weighting	Real Escalation Before Productivity Adjustment (%/year)	Productivity Gains Passed Through to Shippers (%/year)	Real Escalation After Productivity Adjustment (%/year)
Rail	Fuel	20%	0.8%		
	Labor	35%	1.0%		
	Equipment	45%	0.0%		
	Total	**100%**	**0.5%**	**0.0%**	**0.5%**
Barge & Vessel	Fuel	35%	0.8%		
	Labor & Equip.	65%	0.0%		
	Total	**100%**	**0.3%**	**0.5%**	**-0.2%**
Truck	Fuel	50%	0.8%		
	Labor & Equip.	50%	0.0%		
	Total	**100%**	**0.4%**	**0.0%**	**0.4%**
Conveyor	**Total**		**0.0%**	**0.0%**	**0.0%**
Transloading Terminals	**Total**		**0.0%**	**0.0%**	**0.0%**

Table 9-18 Summary of Expected Escalation for Coal Transportation Rates, 2013-2050

9.3.10 Other Considerations

<u>Estimated Construction Costs for Railcar Unloaders and Rail Spurs at Mine-Mouth Plants</u>

In order to allow mine-mouth generating plants (i.e., coal-fired generating plants which take all of their current coal supply from a single nearby mine) to access additional types of coal, the costs of constructing facilities that would allow rail delivery of coal was estimated for almost all[88] of the mine-mouth generating plants with total capacity of 200 MW or more.

The facilities needed for rail delivery of coal to generating plants of this relatively large size were assumed to be: a) a rotary dump railcar unloader capable of handling unit train coal shipments, which is estimated to cost about $25 million installed (in 2011$). b) at least three miles of loop track, which would allow for one trainload of coal to be unloaded, and a second trainload of coal to simultaneously be parked on the plant site preparatory to unloading, and c) at least one mile of additional rail spur track to connect the trackage on the plant site with the nearest railroad main line. Since construction costs for rail trackage capable of handling coal trains is estimated at about $3 million per mile (in 2011$), the minimum investment required to construct the facilities needed for rail delivery of coal was estimated at $37 million. In some cases, the length of the rail spur required to reach the nearest main line (which was estimated on a plant-specific basis) is considerably longer than one mile. In cases where a rail spur longer than one mile was required to reach the main line, the cost of the additional trackage was estimated using the same construction cost of $3 million per mile (2011$) referenced earlier.

[88] The costs of rail coal delivery were not estimated for mine-mouth plants located in the Powder River Basin or Illinois Basin coal fields, since the coal reserves in these coal fields are among the largest, and among the cheapest to mine, anywhere in the United States.

The total cost of the facilities required for rail delivery of coal was converted to an annualized basis based on each plant's historical average coal burn from 2007-2011, and a capital recovery factor of 11.29%.

The cost of transporting additional types of coal to each mine-mouth generating plant was then calculated using the same methodology described earlier in this section, and added to the annualized cost for the rail delivery facilities, to arrive at an estimated "all-in" cost for delivering additional types of coal to the mine-mouth plants.

9.4 Coal Exports, Imports, and Non-Electric Sectors Demand

The coal supply curves used in EPA Base Case v.5.13 represent the total steam coal supply in the United States. While the U.S. power sector is the largest consumer of native coal – roughly 93% of mined U.S. coal in 2012 was used in electricity generation – non-electricity demand must also be taken into consideration in IPM modeling in order to determine the market clearing price. Furthermore, some coal mined within the U.S. is exported out of the domestic market, and some foreign coal is imported for use in electricity generation, and these changes in the coal supply must also be detailed in the modeling of the coal supply available to coal power plants. The projections for imports, exports, non-electric sector coal demand, and coal to liquids demand are based on EIA's AEO 2013.

In EPA Base Case v.5.13, coal exports, coal-serving residential, commercial and industrial demand, and coal to liquids demand are designed to correspond as closely as possible to the projections in AEO 2013 both in terms of the coal supply regions and coal grades that meet this demand. The projections used exclude exports to Canada, as the Canadian market is modeled endogenously within IPM. First, the subset of coal supply regions and coal grades in EPA Base Case v.5.13 are identified that are contained in or overlap geographically with those in EIA Coal Market Module (CMM) supply regions and coal grades that are projected as serving exports and non-electric sector demand in AEO 2013. Next, coal for exports and non-electricity demand are constrained by CMM supply region and coal grade to meet the levels projected in AEO 2013. These levels are shown in Table 9-19.

Table 9-19 Coal Exports

Name	2016	2018	2020	2025	2030	2040-2050
Alaska/Washington - Subbituminous Low Sulfur	1.37	1.44	1.52	1.71	2.04	2.84
Central Appalachia - Bituminous Medium Sulfur	9.33	9.08	8.78	7.58	7.73	6.33
East Interior - Bituminous High Sulfur	16.54	18.23	20.10	25.65	32.74	45.51
Northern Appalachia - Bituminous High Sulfur	4.18	4.15	4.07	3.58	3.65	2.98
Northern Appalachia - Bituminous Medium Sulfur	0.44	0.32	0.23	0.10	0.10	0.10
Rocky Mountain - Bituminous Low Sulfur	3.21	3.54	3.90	3.92	4.73	4.45
Western Montana - Subbituminous Low Sulfur	8.22	9.07	4.85	12.83	16.49	27.28
Wyoming Southern PRB - Subbituminous Low Sulfur	0.42	0.31	6.21	0.10	0.10	0.10

Table 9-20 and Table 9-21. (Since the AEO 2013 time horizon extends to 2040 and EPA Base Case v.5.13 to 2050, the AEO projected levels for 2040 are maintained through 2050.). IPM then endogenously determines which IPM coal supply region(s) and coal grade(s) will be selected to meet the required export or non-electric sector coal demand as part of the cost-minimization coal market equilibrium. Since there are more coal supply regions and coal grades in EPA Base Case v.5.13 than in AEO 2013, the specific regions and coal grades that serve export and non-electric sector demand are not pre-specified but modeled.

Table 9-20 Residential, Commercial, and Industrial Demand

Name	2016	2018	2020	2025	2030	2040-2050
Alaska/Washington - Subbituminous Low Sulfur	0.59	0.59	0.59	0.59	0.59	0.60
Central Appalachia - Bituminous Low Sulfur	4.02	4.03	4.05	4.08	4.08	4.28
Central Appalachia - Bituminous Medium Sulfur	11.68	11.68	11.75	11.82	11.83	12.41

Name	2016	2018	2020	2025	2030	2040-2050
East Interior - Bituminous High Sulfur	7.04	7.00	7.00	6.97	6.89	7.04
East Interior - Bituminous Medium Sulfur	0.82	0.83	0.83	0.83	0.83	0.85
Northern Appalachia - Bituminous High Sulfur	1.63	1.62	1.62	1.62	1.61	1.66
Northern Appalachia - Bituminous Medium Sulfur	3.04	3.05	3.06	3.08	3.08	3.24
Rocky Mountain - Bituminous Low Sulfur	4.05	4.06	4.08	4.10	4.10	4.36
Southern Appalachia - Bituminous Low Sulfur	0.17	0.17	0.17	0.17	0.18	0.19
Southern Appalachia - Bituminous Medium Sulfur	1.13	1.13	1.14	1.15	1.16	1.24
Wyoming Southern PRB - Subbituminous Low Sulfur	2.58	2.56	2.56	2.55	2.52	2.58
Dakota Lignite - Lignite Medium Sulfur	6.37	6.34	6.34	6.31	6.25	6.38
Wyoming Northern PRB - Subbituminous Low Sulfur	5.04	5.04	5.06	5.09	5.09	5.31
West Interior - Bituminous High Sulfur	0.67	0.67	0.68	0.69	0.69	0.74
Arizona/New Mexico - Bituminous Low Sulfur	0.46	0.47	0.47	0.47	0.47	0.50
Arizona/New Mexico - Subbituminous Medium Sulfur	0.11	0.11	0.11	0.11	0.12	0.12
Western Wyoming - Subbituminous Low Sulfur	1.03	1.03	1.04	1.04	1.05	1.12
Western Wyoming - Subbituminous Medium Sulfur	1.12	1.13	1.13	1.14	1.15	1.24
Gulf Lignite - Lignite High Sulfur	0.84	0.85	0.85	0.87	0.87	0.93

Table 9-21 Coal to Liquids Demand

Name	2016	2018	2020	2025	2030	2040-2050
Rocky Mountain - Bituminous Low Sulfur	0	0	0	5.61	3.36	4.02
Wyoming Southern PRB - Subbituminous Low Sulfur	0	0	0	0.00	0.00	8.94
Wyoming Northern PRB - Subbituminous Low Sulfur	0	0	0	0.42	5.49	0.00
Western Montana - Subbituminous Low Sulfur	0	0	0	0.00	0.00	1.36

Imported coal is only available to 39 coal facilities which are eligible to receive imported coal. These facilities which may receive imported coal, along with the cost of transporting this coal to the demand regions, are in Excerpt from

Excerpt from Table 9-23. The total US imports of steam coal are limited to AEO 2013 projections as shown in Table 9-22**.**

Table 9-22 Coal Import Limits

	2016	2018	2020	2025	2030	2040-2050
Annual Coal Imports Cap (Million Short Tons)	1.50	0	0	3.60	3.78	34.28

Attachment 9-1 Mining Cost Estimation Methodology and Assumptions

Labor Costs

Productivity and labor cost rates are utilized to estimate the total labor cost associated with the mining operation. This excludes labor involved in any coal processing / preparation plant.

Labor productivity is used to calculate mine labor and salaries by applying an average cost per employee hour to the labor productivity figure reported by MSHA or estimated based on comparable mines.

Labor costs rates are estimated based on employment data reported to MSHA. MSHA data provides employment numbers, employee hours worked and tons of coal produced. These data are combined with labor rate estimates from various sources such as union contracts, census data and other sources such as state employment websites to determine a cost per ton for mine labor. Hourly labor costs vary between United Mine Workers of America (UMWA) and non-union mines, and include benefits and payroll taxes. Employees assigned to preparation plants, surface activities, and offices are excluded from this category and are accounted for under coal washing costs and mine overhead.

Surface Mining

The prime (raw coal) strip ratio and overburden volume is estimated on a year by year basis. Estimates are entered of the amount of overburden[89] moved each year, split by method to allow for different unit mining costs. The unit rate cost for each method excludes any drill and blast costs, and labor costs, as these are accounted for separately. Drill and blast costs are estimated as an average cost per volume of prime overburden. If applicable, dragline re-handle is estimated separately and a summation gives the total overburden moved.

The different overburden removal methods are:

- Dragline - the estimated volume of prime overburden moved
- Dragline re-handle - the estimated volume of any re-handled overburden
- Truck and shovel - including excavators.
- Other - examples would be dozer push, front end loader, or cast blasting. If overburden is moved by cast blasting the unit rate is taken to be zero as the cost is already included in the drill and blast estimate.

Surface mining costs also include the cost of coal mining estimated on a raw ton basis.

Underground Mining

Raw coal production is split by type into either continuous miner or longwall. Cost estimates can be input either on a unit rate or a fixed dollar amount, as the cost structure of underground mining generally has a large fixed component from year to year. Costs are divided into:

- Longwall
- Continuous miner
- Underground services

Underground services costs cover categories such as ventilation, conveyor transport, gas drainage, secondary roof support etc.

[89] Overburden refers to the surface soil and rock that must be removed to uncover the coal.

Mine Site Other

This covers any mine site costs that are outside the direct production process. Examples are ongoing rehabilitation/reclamation, security, community development costs.

Raw Haul

Costs for transporting raw coal from the mining location to the raw coal stockpile at the coal preparation plant or rail load out. A distance and a unit rate allows for an increasing cost over time if required.

Excerpt from Table 9-23 Coal Transportation Matrix in EPA Base Case v.5.13

This is a small excerpt of the data in Table 9-23. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Link #	Plant Name	ORIS Plant Code	Coal Supply Region Code	Coal Supply Region Description	Total Cost (2012 Rate in 2011$/Ton)	Escalation/Year (2013-2025)	Escalation/Year (2026-2050)
1	Aurora Energy LLC Chena	79	AK	Alaska	$3.52	1.0050	1.0050
2	Eielson AFB Central Heat & Power Plant	50392	AK	Alaska	$4.32	1.0050	1.0050
3	Healy	6288	AK	Alaska	$1.00	1.0000	1.0000
4	Barry	3	CG	Colorado, Green River	$44.85	1.0039	1.0039
5	Barry	3	CR	Colorado, Raton	$42.85	1.0039	1.0039
6	Barry	3	CU	Colorado, Uinta	$48.85	1.0040	1.0040
7	Barry	3	IL	Illinois	$20.50	1.0031	1.0031
8	Barry	3	IN	Indiana	$24.00	1.0034	1.0034
9	Barry	3	KE	Kentucky East	$26.04	1.0031	1.0031
10	Barry	3	KW	Kentucky West	$19.78	1.0031	1.0031
11	Barry	3	PW	Pennsylvania, West	$25.77	1.0028	1.0028
12	Barry	3	WH	Wyoming, Powder River Basin (8800)	$43.13	1.0039	1.0039
13	Barry	3	WL	Wyoming, Powder River Basin (8400)	$42.90	1.0039	1.0039
14	Barry	3	WN	West Virginia, North	$23.04	1.0028	1.0028
15	Barry	3	WS	West Virginia, South	$27.45	1.0031	1.0031
16	Barry	3	I1	Imports-1 (Colombia)	$14.75	0.9995	0.9995
17	Charles R Lowman	56	CG	Colorado, Green River	$45.25	1.0039	1.0039
18	Charles R Lowman	56	CR	Colorado, Raton	$43.25	1.0039	1.0039
19	Charles R Lowman	56	CU	Colorado, Uinta	$49.25	1.0040	1.0040
20	Charles R Lowman	56	IL	Illinois	$20.90	1.0031	1.0031

Table 9-24 Coal Supply Curves in EPA Base Case v.5.13

This is a small excerpt of the data and graphs in Table 9-24. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/short ton)	Cost of Production (2011$/short ton)	Coal Production (Million short tons per annum)	End 2015 Coal Reserves (Million short tons)
2016	AL	BB	E1	25.5	47.51	0.09	0.19
2016	AL	BB	E2	25.5	75.16	0.06	0.30
2016	AL	BB	E3	25.5	81.84	1.18	8.37
2016	AL	BB	E4	25.5	88.23	0.14	1.39
2016	AL	BB	E5	25.5	96.45	0.47	4.51
2016	AL	BB	E6	25.5	101.89	0.07	0.69
2016	AL	BB	E7	25.5	103.68	0.10	0.94
2016	AL	BB	E8	25.5	110.04	0.08	0.75
2016	AL	BB	N1	25.5	115.74	0.12	500.00
2016	AL	BE	E1	24	35.96	0.21	0.36

Year	Coal Supply Region	Coal Grade	Step Name	Heat Content (MMBtu/short ton)	Cost of Production (2011$/short ton)	Coal Production (Million short tons per annum)	End 2015 Coal Reserves (Million short tons)
2016	AL	BE	E2	24	47.51	0.30	0.37
2016	AL	BE	E3	24	52.89	3.41	13.66
2016	AL	BE	E4	24	71.05	0.38	1.87
2016	AL	BE	E5	24	90.23	2.20	18.68
2016	AL	BE	E6	24	102.49	2.64	25.32
2016	AL	BE	E7	24	104.83	0.30	2.80
2016	AL	BE	E8	24	137.98	0.09	0.90
2016	AL	BE	N1	24	108.27	0.28	500.00

10. Natural Gas

This chapter describes how natural gas supply, demand, and costing are modeled in EPA Base Case v.5.13. Section 0 indicates that natural gas supply dynamics are directly (i.e., endogenously) modeled in the base case. Section 10.2 gives an overview of the new natural gas module. Sections 10.3 and 10.4 describe the very detailed process-engineering model and data sources used to characterize North American conventional and unconventional natural gas resources and reserves and to derive all the cost components incurred in bringing natural gas from the ground to the pipeline. These sections also discuss resource constraints affecting production and the assumptions (in the form of cost indices) used to depict expected changes in costs over the 2016-2050 modeling time horizon.

Section 10.5 describes how liquefied natural gas (LNG) imports are represented in the natural gas module. The section covers the assumptions regarding liquefaction facilities, LNG supply, regasification capacity, and related costs. Section 10.6 turns to demand-side issues, in particular, how non-power sector residential, commercial, and industrial consumer demand is represented. This section also describes the use of the gas demand sub-module to model LNG exports. Section 10.7 describes the detailed characterization of the natural gas pipeline network, the pipeline capacity expansion logic, and the assumptions and procedures used to capture pipeline transportation costs. Section 10.8 treats issues related to natural gas storage: capacity characterization and expansion logic, injection/withdrawal rates, and associated costs. Section 10.9 describes the crude oil and natural gas liquids (NGL) price projections that are exogenous inputs in the natural gas module. They figure in the modeling of natural gas because they are a source of revenue which influence the exploration and development of hydrocarbon resources. The chapter concludes in Section 10.10 with a discussion of key gas market parameters in the natural gas report of EPA Base Case v.5.13.

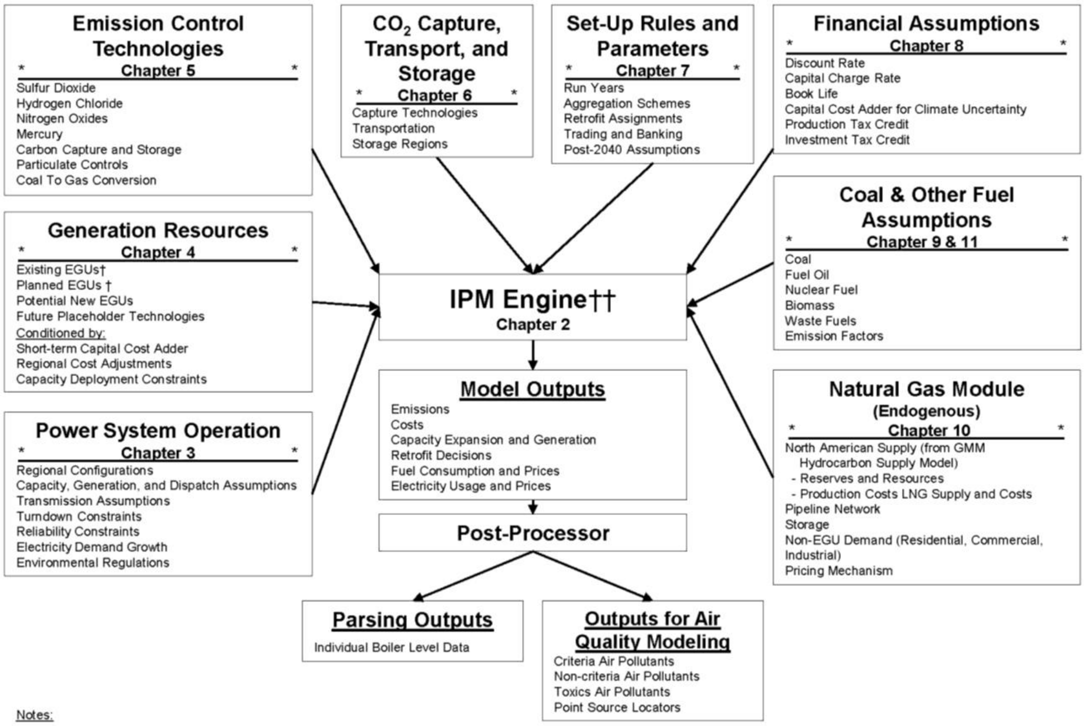
10.1 Overview of IPM's Natural Gas Module

In EPA Base Case v.5.13 natural gas supply, demand, transportation, storage, and related costs are modeled directly in IPM through the incorporation of a natural gas module. Natural gas supply curves are generated endogenously for each region, and the balance between the natural gas supply and demand is solved in all regions simultaneously. Figure 10-1 and Figure 10-2 illustrate the integration of the natural gas module in IPM. The integration allows direct interaction between the electric and the gas modules and captures the overall gas supply and demand dynamic.

To a certain extent, the design and assumptions of the new natural gas module are similar to those in ICF International's private practice Gas Market Model (GMM) which has been used extensively for forecasting and market analyses in the North American natural gas market. To provide these new natural gas modeling capabilities within IPM and still maintain an acceptable model size and solution time, however, simplifications of some of the GMM design and assumptions were made.

Seasonality in the gas module is made consistent with that in IPM and is currently modeled with two seasons (summer and winter), each with up to six IPM load periods that correspond to the IPM electric sector load duration curve (LDC) segments. The gas module also employs a similar run year concept as in IPM where, in order to manage model size, individual calendar years over the entire modeling period are mapped to a lesser number of run years. In the current version, both modules use the same run year mapping.

Figure 10-1 Modeling and Data Structure in EPA Base Case v.5.13

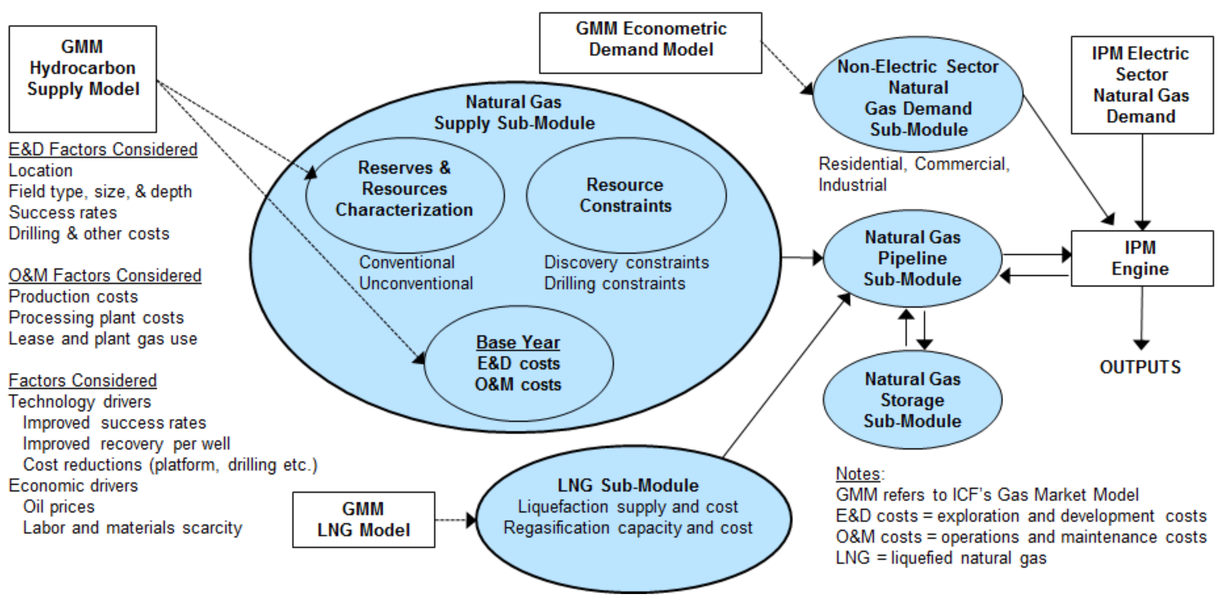


Notes:

† Information on existing and planned electric generating units (EGUs) is contained in the National Electrical Energy Data System (NEEDS) data base maintained for EPA by ICF International. Planned EGUs are those which were under construction or had obtained financing at the time that the EPA Base Case was finalized.

††IPM Engine is the model structure described in Chapter 2

Figure 10-2 Natural Gas Module in EPA Base Case v.5.13



10.2 Key Components of the New IPM Natural Gas Module

The gas module is a full supply/demand equilibrium model of the North American gas market. Most of the structure and data for the gas module are derived from ICF's Gas Market Model (GMM). It consists of 118 supply/demand/storage nodes, 15 LNG regasification (import) facility locations, and 3 LNG export facility locations that are tied together by a series of links that represent the North American natural gas transmission network as shown in Figure 10-3. The list of the 118 nodes is tabulated in Table 10-1.

Key elements of the natural gas module (which are described in detail in Sections 10.3-10.9) include:

Natural Gas Resources are modeled by a set of base year resource cost curves, which represent undiscovered resource availability or recoverable resource as a function of exploration & development (E&D) cost for 81 supply regions. "Resource Appreciation"[90] is added to the resource base to account for additional resources from plays that are not included in the resource base estimates due to lack of knowledge and technology to economically recover the resources. The construction of the resource cost curves are based on resource characterizations and economic evaluations from the Hydrocarbon Supply Model (HSM) of the GMM. (The HSM is discussed in greater detail in Sections 10.3 and 10.4 below.) Figure 10-4 depicts the geographic locations of the supply regions and Table 10-2 provides a list of the supply regions and a mapping of the regions to the modeling nodes.

Natural Gas production from the 81 supply regions is calculated from the resource cost curves based on exploration and development activities that are a function of drilling success rate, rigs availability, reserves-to-production (R/P) ratio, and the costs of exploration, reserves development, and production that are applicable in the specific regions.

LNG import level for each of the LNG regasification facilities is calculated from LNG supply availability curves (derived from the LNG supply curve module of GMM) based on the solution gas price and the regasification capacity at the corresponding LNG node. Availability and regasification capacity of the facilities are specified as inputs. The model has the capability to expand regasification capacity. However, due to a current excess of LNG regasification capacity and robust natural gas supply in the U.S. and Canada combined with a relatively low electricity demand growth assumption in the EPA Base Case v.5.13, the regasification expansion feature is currently turned off. If future economic growth demands more LNG capacity, it can be turned back on.

End use natural gas demand for the non-power sectors (i.e. the residential, commercial, and industrial sectors) is incorporated in IPM through node-level interruptible and firm demand curves derived from the GMM natural gas demand module. (These are discussed in greater detail in Section 10.6 below.) The gas consumption in the non-power sectors is calculated within the gas module and the power sector consumption is calculated within the IPM electricity dispatch module. Figure 10-5 shows the geographic locations of the demand regions.

LNG export modeling

The gas module does not currently have a specific sub-module for LNG exports. The modeling of LNG export is currently performed within the gas demand sub-module using a set of fixed or inelastic firm demand curves. The EPA Base Case v.5.13 includes two LNG export terminals in the U.S. Gulf Coast and one LNG export terminal in Western Canada. The LNG export modeling is discussed in more detail in Section 10.6 below.

[90] Resource appreciation represents growth in ultimate resource estimates attributed to success in extracting resource from known plays such as natural gas from shale, coal seams, offshore deepwater, and gas hydrates that are not included in the resource base estimates.

Figure 10-3 Gas Transmission Network Map

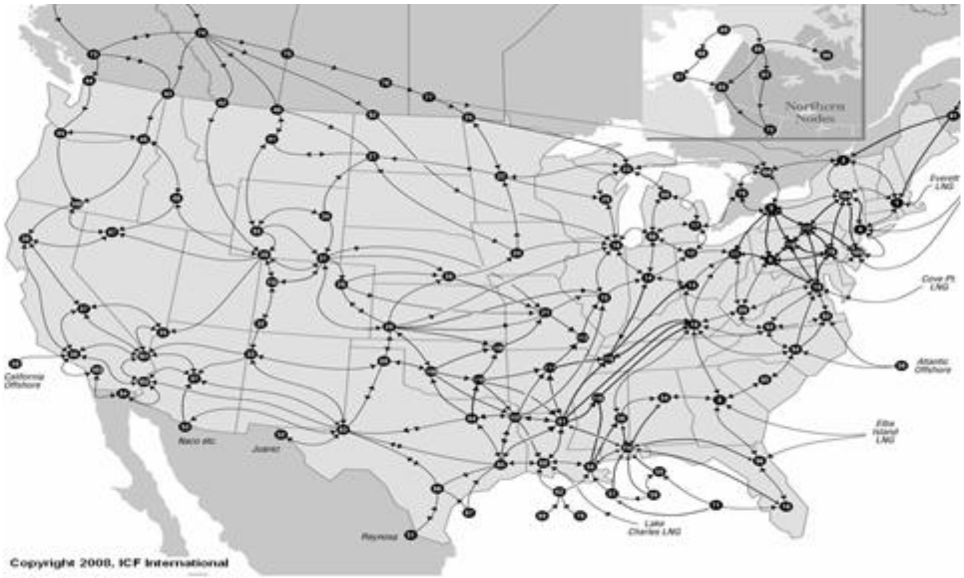


Table 10-1 List of Nodes

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage (existing and potential)
1	New England		X			X
2	Everett TRANS			X		
3	Quebec		X		X	X
4	New York City		X			X
5	Niagara	X	X		X	X
6	Southwest PA	X	X		X	X
7	Cove Point TRANS			X		
8	Georgia		X			X
9	Elba Is TRANS			X		
10	South Florida		X			X
11	East Ohio	X	X		X	X
12	Maumee/Defiance	X	X			X
13	Lebanon	X	X			X
14	Indiana	X	X		X	X
15	South Illinois	X	X		X	X
16	North Illinois	X	X		X	X
17	Southeast Michigan	X	X		X	X
18	East KY/TN	X	X		X	X
19	MD/DC/Northern VA		X			X
20	Wisconsin	X	X			X
21	Northern Missouri	X	X			X
22	Minnesota	X	X		X	X
23	Crystal Falls	X	X			X
24	Ventura	X	X		X	X
25	Emerson Imports			X		
26	Nebraska	X	X			X
27	Great Plains			X		
28	Kansas	X	X		X	X
29	East Colorado	X	X		X	X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage (existing and potential)
30	Opal	X	X		X	X
31	Cheyenne	X	X		X	
32	San Juan Basin	X	X		X	
33	EPNG/TW	X	X			X
34	North Wyoming	X	X		X	
35	South Nevada	X	X			X
36	SOCAL Area	X	X		X	X
37	Enhanced Oil Recovery Region	X	X			
38	PGE Area	X	X		X	X
39	Pacific Offshore	X				
40	Monchy Imports			X		
41	Montana/North Dakota	X	X		X	X
42	Wild Horse Imports			X		
43	Kingsgate Imports			X		
44	Huntingdon Imports			X		
45	Pacific Northwest	X	X		X	X
46	NPC/PGT Hub		X			X
47	North Nevada	X	X			X
48	Idaho	X	X			X
49	Eastern Canada Offshore	X				
50	Atlantic Offshore	X				
51	Reynosa Imp/Exp			X		
52	Juarez Imp/Exp			X		
53	Naco Imp/Exp			X		
54	North Alabama	X	X		X	X
55	Alabama Offshore	X				
56	North Mississippi	X	X		X	X
57	East Louisiana Shelf	X				
58	Eastern Louisiana Hub	X	X		X	X
59	Viosca Knoll/Desoto/Miss Canyon	X				
60	Henry Hub	X	X		X	X
61	North Louisiana Hub	X	X		X	X
62	Central and West Louisiana Shelf	X				
63	Southwest Texas	X	X		X	
64	Dallas/Ft Worth	X	X		X	X
65	E. TX (Katy)	X	X		X	X
66	S. TX	X	X			X
67	Offshore Texas	X				
68	NW TX	X	X			X
69	Garden Banks	X				
70	Green Canyon	X				
71	Eastern Gulf	X				
72	North British Columbia	X	X			X
73	South British Columbia		X		X	X
74	Caroline	X	X		X	X
75	Empress			X		
76	Saskatchewan	X	X		X	X
77	Manitoba	X	X			X
78	Dawn	X	X		X	X
79	Philadelphia		X			X
80	West Virginia	X	X		X	X
81	Eastern Canada Demand		X			X

Node	Name	Supply	Demand	Transit, Import/ Export	Underground Storage	Peakshaving Storage (existing and potential)
82	Alliance Border Crossing			X		
83	Wind River Basin	X	X		X	
84	California Mexican Exports			X		
85	Whitehorse			X		
86	MacKenzie Delta	X				
87	South Alaska	X		X		
88	Central Alaska	X				
89	North Alaska	X				
90	Arctic	X				
91	Norman Wells	X				
92	Southwest VA	X	X		X	X
93	Southeast VA		X			X
94	North Carolina		X			X
95	South Carolina		X			X
96	North Florida	X	X			X
97	Arizona		X			X
98	Southwest Michigan	X	X		X	X
99	Northern Michigan	X	X		X	X
100	Malin Interchange			X		
101	Topock Interchange			X		
102	Ehrenberg Interchange			X		
103	SDG&E Demand		X			X
104	Eastern New York		X			X
105	New Jersey		X			X
106	Toronto		X			X
107	Carthage	X	X		X	X
108	Southwest Oklahoma	X	X		X	X
109	Northeast Oklahoma	X	X		X	X
110	Southeastern Oklahoma	X	X		X	X
111	Northern Arkansas	X	X			X
112	Southeast Missouri	X	X		X	X
113	Uinta/Piceance	X	X		X	X
114	South MS/AL	X	X		X	X
115	West KY/TN	X	X		X	
116	Kosciusko MS			X		
117	Northeast PA	X	X		X	
118	Leidy	X	X		X	

Figure 10-4 Gas Supply Regions Map

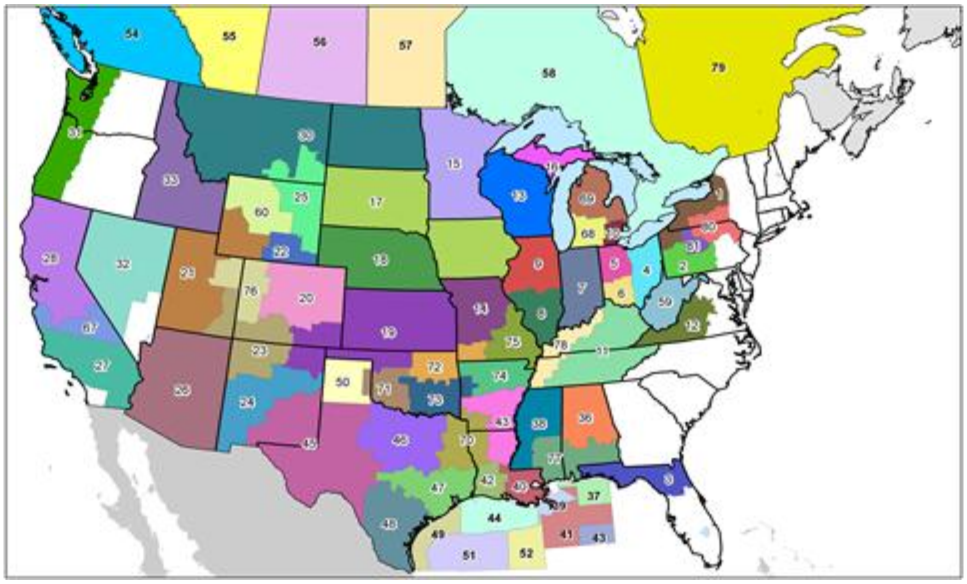


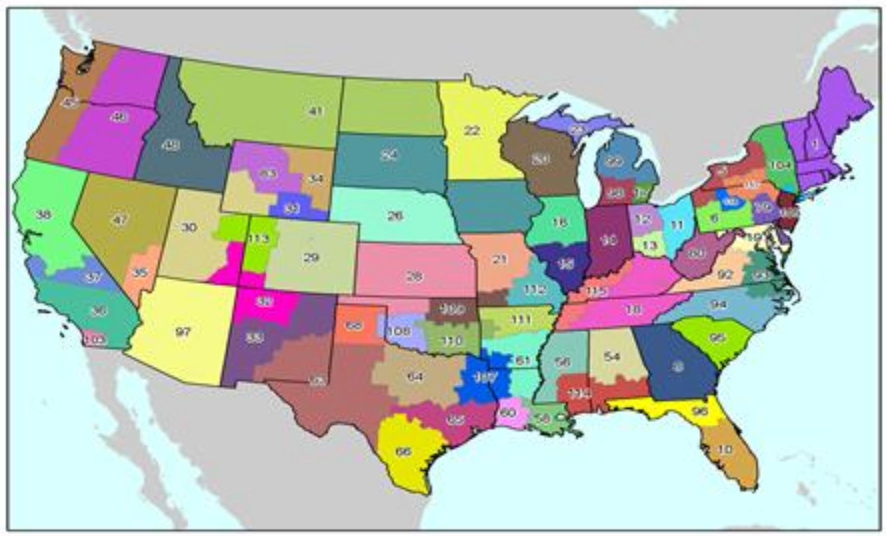
Table 10-2 List of Gas Supply Regions

Supply Region Number	Node Number	Region Name
1	5	Niagara
2	6	Southwest PA
3	96	Florida
4	11	East Ohio
5	12	Maumee/ Defiance
6	13	Lebanon
7	14	Indiana
8	15	South Illinois
9	16	North Illinois
10	17	Southeast Michigan
11	18	Eastern KY/TN
12	92	SW Virginia
13	20	Wisconsin
14	21	Northern Missouri
15	22	Minnesota
16	23	Crystal Falls
17	24	Ventura
18	26	Nebraska
19	28	Kansas
20	29	East Colorado
21	30	Opal
22	31	Cheyenne
23	32	San Juan Basin
24	33	EPNG/TW
25	34	North Wyoming
26	97	Arizona
27	36	SOCAL Area
28	38	PGE Area

Supply Region Number	Node Number	Region Name
29	39	California Offshore
30	41	Montana/ North Dakota
31	45	Pacific Northwest
32	47	North Nevada
33	48	Idaho
34	49	Eastern Canada Offshore
35	50	Atlantic Offshore
36	54	North Alabama
37	55	Alabama Offshore
38	56	North Mississippi
39	57	East Louisiana Shelf
40	58	Eastern Louisiana Hub
41	59	Viosca Knoll S./ Desoto Canyon/Mississippi Canyon
42	60	Henry Hub
43	61	North Louisiana Hub
44	62	Central and West Louisiana Shelf
45	63	Southwest Texas
46	64	Dallas/Fort Worth
47	65	E. TX (Katy)
48	66	S. TX
49	67	Offshore Texas
50	68	NW TX
51	69	Garden Banks
52	70	Green Canyon
53	71	Florida off-shore moratorium area
54	72	North British Columbia
55	74	Caroline
56	76	Saskatchewan
57	77	Manitoba
58	78	Dawn
59	80	West Virginia
60	83	Wind River Basin
61	86	McKenzie Delta
62	87	Southern Alaska
63	88	Central Alaska
64	89	Northern Alaska
65	90	Arctic
66	91	Norman Wells
67	37	Enhanced Oil Recovery Region
68	98	Southwest Michigan
69	99	Central Michigan
70	107	Carthage
71	108	Southwest Oklahoma
72	109	Northeast Oklahoma
73	110	Southeastern Oklahoma
74	111	Northern Arkansas
75	112	Southeast Missouri
76	113	Uinta/Piceance
77	114	South MS/AL

Supply Region Number	Node Number	Region Name
78	115	Western KY/TN
79	3	Eastern Canada Onshore
80	117	NE PA/SC NY
81	118	Leidy

Figure 10-5 Gas Demand Regions Map



Natural gas pipeline network is modeled by 380 transmission links or segments (excluding pipeline connections with LNG import nodes) that represent major interstate transmission corridors throughout North America (Figure 10-3). The pipeline corridors represent a group of interstate pipelines along the corridor. The list of key interstate pipelines by links is tabulated in Table 10-3. Each of the links has an associated discount curve (derived from GMM natural gas transportation module), which represents the marginal value of gas transmission on that pipeline segment as a function of the pipeline's load factor.[91] Starting year of operation and transmission capacity (in units of BBtu/day) are specified as inputs and the model allows for capacity expansions.

Table 10-3 List of Key Pipelines

Link	Pipeline
1 - 4	Iroquois Pipeline Co
1 - 104	Tennessee Gas Pipeline Co
1 - 104	Algonquin Gas Trans Co
3 - 104	Iroquois Pipeline Co
5 - 6	Tennessee Gas Pipeline Co
5 - 104	Tennessee Gas Pipeline Co
5 - 117	Tennessee Gas Pipeline Co
6 - 5	National Fuel Gas Supply Co
6 - 11	Dominion Trans (CNG)
6 - 11	Columbia Gas Trans Corp
6 - 19	Dominion Trans (CNG)
6 - 79	Texas Eastern Trans Corp

[91] In this context "load factor" refers to the percentage of the pipeline capacity that is utilized at a given time.

Link	Pipeline
6 - 80	Dominion Trans (CNG)
6 - 80	Columbia Gas Trans Corp
6 - 118	Dominion Trans (CNG)
6 - 118	Tennessee Gas Pipeline Co
8 - 18	Southern Natural Gas Co
8 - 95	Transcontinental Gas Pipeline Co
8 - 96	Southern Natural Gas Co
9 - 8	Southern Natural Gas Co
10 - 96	Florida Gas Trans Co
11 - 6	Texas Eastern Trans Corp
11 - 6	Tennessee Gas Pipeline Co
11 - 80	Columbia Gas Trans Corp
12 - 11	Columbia Gas Trans Corp
12 - 17	ANR Pipeline Co
12 - 17	Panhandle Eastern Pipeline Co
12 - 98	ANR Pipeline Co
13 - 11	Dominion Trans (CNG)
13 - 11	Texas Eastern Trans Corp
13 - 14	Panhandle Eastern Pipeline Co
14 - 12	Panhandle Eastern Pipeline Co
14 - 12	ANR Pipeline Co
14 - 13	Texas Eastern Trans Corp
14 - 98	Trunkline Gas Co
15 - 14	Panhandle Eastern Pipeline Co
15 - 16	Nat Gas Pipeline Co of America
16 - 20	ANR Pipeline Co
16 - 98	ANR Pipeline Co
17 - 78	Great Lakes Gas Trans Ltd
17 - 98	Panhandle Eastern Pipeline Co
17 - 99	Michcon
18 - 8	East Tennessee Nat Gas Co
18 - 11	Texas Eastern Trans Corp
18 - 11	Tennessee Gas Pipeline Co
18 - 13	Columbia Gas Trans Corp
18 - 80	Columbia Gas Trans Corp
18 - 80	Tennessee Gas Pipeline Co
18 - 92	East Tennessee Nat Gas Co
19 - 79	Transcontinental Gas Pipeline Co
19 - 92	Columbia Gas Trans Corp
19 - 93	Dominion Trans (CNG)
21 - 15	Panhandle Eastern Pipeline Co
23 - 20	ANR Pipeline Co
23 - 22	Great Lakes Gas Trans Ltd
23 - 99	Great Lakes Gas Trans Ltd
23 - 106	Great Lakes Gas Trans Ltd
24 - 16	Nat Gas Pipeline Co of America
25 - 23	Great Lakes Gas Trans Ltd
26 - 24	Nat Gas Pipeline Co of America
27 - 24	Williston Basin Pipeline Co

Link	Pipeline
27 - 41	Williston Basin Pipeline Co
28 - 15	Panhandle Eastern Pipeline Co
28 - 16	ANR Pipeline Co
28 - 21	Panhandle Eastern Pipeline Co
28 - 26	Nat Gas Pipeline Co of America
28 - 29	Colorado Interstate Gas
28 - 68	Colorado Interstate Gas
28 - 108	Nat Gas Pipeline Co of America
28 - 109	Southern Star Central (Williams)
30 - 31	Colorado Interstate Gas
30 - 48	Northwest Pipeline Corp
30 - 113	Northwest Pipeline Corp
31 - 28	Southern Star Central (Williams)
31 - 29	Colorado Interstate Gas
32 - 33	El Paso Nat Gas Co
32 - 33	Transwestern Pipeline Co
32 - 113	Northwest Pipeline Corp
33 - 63	El Paso Nat Gas Co
33 - 68	Transwestern Pipeline Co
33 - 97	El Paso Nat Gas Co
33 - 101	El Paso Nat Gas Co
33 - 101	Transwestern Pipeline Co
34 - 27	Williston Basin Pipeline Co
34 - 31	Wyoming Interstate Co
36 - 37	Socal Gas
36 - 103	Socal Gas
37 - 38	Pacific Gas & Electric
40 - 41	Northwest Energy
41 - 83	Williston Basin Pipeline Co
43 - 73	Terasen (BC Gas)
44 - 45	Northwest Pipeline Corp
45 - 46	Northwest Pipeline Corp
46 - 48	Northwest Pipeline Corp
48 - 47	Northwest Pipeline Corp
51 - 66	Texas Eastern Trans Corp
54 - 8	Transcontinental Gas Pipeline Co
54 - 8	Southern Natural Gas Co
55 - 114	Transcontinental Gas Pipeline Co
56 - 18	Tennessee Gas Pipeline Co
56 - 54	Transcontinental Gas Pipeline Co
56 - 54	Southern Natural Gas Co
56 - 58	Gulf South (Koch)
56 - 114	Gulf South (Koch)
57 - 58	Tennessee Gas Pipeline Co
57 - 58	Southern Natural Gas Co
57 - 58	Texas Eastern Trans Corp
58 - 56	Transcontinental Gas Pipeline Co
58 - 56	Southern Natural Gas Co
58 - 56	Tennessee Gas Pipeline Co

Link	Pipeline
58 - 60	Transcontinental Gas Pipeline Co
58 - 60	Southern Natural Gas Co
58 - 60	Texas Eastern Trans Corp
58 - 60	Tennessee Gas Pipeline Co
58 - 60	Florida Gas Trans Co
58 - 114	Florida Gas Trans Co
58 - 114	Gulf South (Koch)
58 - 116	Texas Eastern Trans Corp
59 - 57	Tennessee Gas Pipeline Co
60 - 61	Trunkline Gas Co
60 - 61	Gulf South (Koch)
60 - 61	ANR Pipeline Co
60 - 61	Tennessee Gas Pipeline Co
60 - 65	Nat Gas Pipeline Co of America
61 - 18	Tennessee Gas Pipeline Co
61 - 56	Southern Natural Gas Co
61 - 115	ANR Pipeline Co
61 - 115	Trunkline Gas Co
61 - 116	Texas Eastern Trans Corp
62 - 60	Tennessee Gas Pipeline Co
62 - 60	ANR Pipeline Co
62 - 60	Trunkline Gas Co
62 - 60	Transcontinental Gas Pipeline Co
62 - 60	Texas Eastern Trans Corp
63 - 53	El Paso Nat Gas Co
63 - 64	Epgt Texas Pipeline (Valero)
63 - 64	Txu Lonestar Gas Pipeline
63 - 65	Oasis
63 - 66	Epgt Texas Pipeline (Valero)
63 - 68	Epgt Texas Pipeline (Valero)
63 - 68	Nat Gas Pipeline Co of America
63 - 97	El Paso Nat Gas Co
64 - 65	Txu Lonestar Gas Pipeline
64 - 108	Nat Gas Pipeline Co of America
65 - 60	Trunkline Gas Co
65 - 60	Transcontinental Gas Pipeline Co
65 - 60	Texas Eastern Trans Corp
65 - 61	Tennessee Gas Pipeline Co
65 - 107	Nat Gas Pipeline Co of America
66 - 51	Tennessee Gas Pipeline Co
66 - 65	Epgt Texas Pipeline (Valero)
66 - 65	Texas Eastern Trans Corp
66 - 65	Tennessee Gas Pipeline Co
66 - 65	Nat Gas Pipeline Co of America
66 - 65	Transcontinental Gas Pipeline Co
67 - 65	Nat Gas Pipeline Co of America
67 - 66	Transcontinental Gas Pipeline Co
68 - 28	Nat Gas Pipeline Co of America
68 - 108	Nat Gas Pipeline Co of America

Link	Pipeline
77 - 25	Great Lakes Gas Trans Ltd
78 - 106	Union Gas
79 - 105	Texas Eastern Trans Corp
79 - 105	Transcontinental Gas Pipeline Co
80 - 11	Dominion Trans (CNG)
80 - 19	Columbia Gas Trans Corp
80 - 92	Columbia Gas Trans Corp
83 - 31	Colorado Interstate Gas
92 - 18	Dominion Trans (CNG)
92 - 93	Columbia Gas Trans Corp
94 - 19	Transcontinental Gas Pipeline Co
94 - 92	Transcontinental Gas Pipeline Co
94 - 93	Transcontinental Gas Pipeline Co
95 - 94	Transcontinental Gas Pipeline Co
97 - 102	El Paso Nat Gas Co
98 - 99	ANR Pipeline Co
99 - 17	Great Lakes Gas Trans Ltd
101 - 35	El Paso Nat Gas Co
101 - 36	Socal Gas
101 - 37	Pacific Gas & Electric
101 - 102	El Paso Nat Gas Co
102 - 36	Socal Gas
104 - 1	Iroquois Pipeline Co
104 - 4	Tennessee Gas Pipeline Co
104 - 79	Columbia Gas Trans Corp
105 - 4	Transcontinental Gas Pipeline Co
105 - 4	Texas Eastern Trans Corp
105 - 104	Algonquin Gas Trans Co
106 - 5	Tennessee Gas Pipeline Co
107 - 15	Nat Gas Pipeline Co of America
107 - 61	Gulf South (Koch)
107 - 61	Centerpoint Energy (Reliant)
107 - 64	Txu Lonestar Gas Pipeline
107 - 111	Texas Eastern Trans Corp
108 - 28	ANR Pipeline Co
108 - 107	Nat Gas Pipeline Co of America
108 - 109	Nat Gas Pipeline Co of America
108 - 110	Centerpoint Energy (Reliant)
109 - 21	Southern Star Central (Williams)
110 - 107	Nat Gas Pipeline Co of America
110 - 109	Centerpoint Energy (Reliant)
110 - 111	Centerpoint Energy (Reliant)
111 - 112	Texas Eastern Trans Corp
111 - 115	Centerpoint Energy (Reliant)
112 - 15	Nat Gas Pipeline Co of America
113 - 30	Wyoming Interstate Co
114 - 54	Transcontinental Gas Pipeline Co
114 - 96	Florida Gas Trans Co
115 - 14	Trunkline Gas Co

Link	Pipeline
115 - 14	ANR Pipeline Co
116 - 18	Texas Eastern Trans Corp
117 - 5	Dominion Trans (CNG)
117 - 104	Dominion Trans (CNG)
117 - 105	Transcontinental Gas Pipeline Co
117 - 118	Transcontinental Gas Pipeline Co
117 - 118	Dominion Trans (CNG)
117 - 118	Tennessee Gas Pipeline Co
117 - 118	National Fuel Gas Supply Co
118 - 5	National Fuel Gas Supply Co

Natural gas storage is modeled by 190 underground and LNG peak shaving[92] storage facilities that are linked to individual nodes. The underground storage is grouped into three categories based on storage "Days Service"[93]: (1) 20-day for high deliverability[94] storage such as salt caverns, (2) 80-day for depleted[95] and aquifer[96] reservoirs, and (3) over 80 days mainly for depleted reservoirs. The level of gas storage withdrawals and injections are calculated within the supply and demand balance algorithm based on working gas[97] levels, gas prices, and extraction/injection rates and costs. Starting year of operation and working gas capacity (in units of BBtu) are specified as inputs and the model allows for capacity expansions. The location of the storage facilities is shown in Figure 10-6.

Natural gas prices are market clearing prices derived from the supply and demand balance at each of the model's nodes for each segment of IPM's electricity sector's seasonal load duration curve (LDC). On the supply-side, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also affected by the "pipeline discount" curves discussed earlier, which represent the marginal value of gas transmission as a function of a pipeline's load factor and result in changes in basis differential. On the demand-side, the price/quantity relationship is represented by demand curves that capture the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes and yields market clearing prices determined by the specific shape of the supply and demand curves at each node.

10.2.1 Note on the Modeling Time Horizon and Pre- and Post-2040 Input Assumptions

The time horizon of the EPA's Base Case v.5.13 extends through 2050. Projections through the year 2040 in EPA's Base Case v.5.13 are based on a detailed bottom-up development of natural gas assumptions from available data sources. Beyond 2040, where detailed data are not readily available, various technically plausible simplifying assumptions were made. For example, natural gas demand growth from 2040 to 2050 for the non-power sectors (i.e. residential, commercial, and industrial) is

[92] LNG peak shaving facilities supplement deliveries of natural gas during times of peak periods. LNG peak shaving facilities have a regasification unit attached, but may or may not have a liquefaction unit. Facilities without a liquefaction unit depend upon tank trucks to bring LNG from nearby sources.

[93] "Days Service" refers to the number of days required to completely withdraw the maximum working gas inventory associated with an underground storage facility.

[94] High deliverability storage is depleted reservoir storage facility or Salt Cavern storage whose design allows a relatively quick turnover of the working gas capacity.

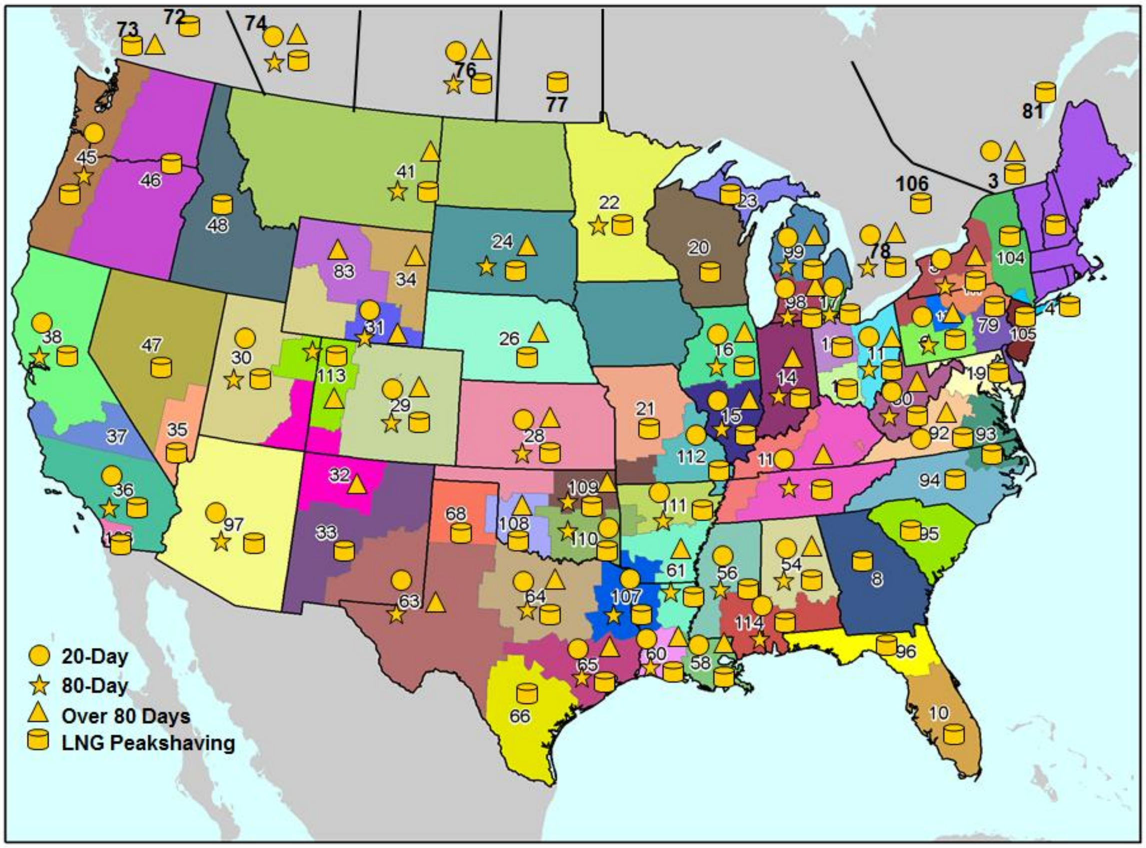
[95] A gas or oil reservoir that is converted for gas storage operations. Its economically recoverable reserves have usually been nearly or completely produced prior to the conversion.

[96] The underground storage of natural gas in a porous and permeable rock formation topped by an impermeable cap rock, the pore space of which was originally filled with water.

[97] The term "working gas" refers to natural gas that has been injected into an underground storage facility and stored therein temporarily with the intention of withdrawing it. It is distinguished from "base (or cushion) gas" which refers to the volume of gas that remains permanently in the storage reservoir in order to maintain adequate pressure and deliverability rates throughout the withdrawal season.

assumed to be the same as the level of growth from 2020 to 2040. Resource growth assumptions (for resource appreciation) that were applied for pre-2040 are extended beyond 2040. Post-2040 price projections for crude oil and natural gas liquids[98] (NGLs) are assumed to be flat at 2040 price levels. The pre-2040 price projections were adapted from AEO 2013.

Figure 10-6 Natural Gas Storage Facility Node Map



10.3 Resource Characterization and Economic Evaluation

The GMM Hydrocarbon Supply Model (HSM) provides data related to resource characterization and economic evaluation for use in the IPM natural gas module. The current section describes data sources and methods used in the HSM to characterize the North American natural gas resource base. This section concludes with a description of how the HSM resource characterization is used in the EPA Base Case v.5.13 gas module. The next section (i.e., Section 10.4) describes the economic evaluation procedures applied to Exploration and Development (E&D) activities in the HSM and various constraints affecting E&D activities.

The HSM was designed for the simulation, forecasting and analysis of natural gas, crude oil and natural gas liquids supply and cost trends in the United States and Canada. The HSM includes a highly detailed description of both the undiscovered and discovered resources in the U.S. and Canada. The resource base is described on a field-by-field basis. The individual fields are characterized by type (i.e., oil or gas), size, and location. Location is defined both geographically and by depth. The HSM is a process-engineering model with a very detailed representation of potential gas resources and the technologies

[98] Those hydrocarbons in natural gas that are separated from the gas as liquids in gas processing or cycling plants. Generally such liquids consist of ethane, propane, butane, and heavier hydrocarbons.

with which those resources can be proven[99] and produced. The degree and timing by which resources are proven and produced are determined in the model through discounted cashflow analyses of alternative investment options and behavioral assumptions in the form of inertial and cashflow constraints, and the logic underlying producers' market expectations (e.g., their response to future gas prices).

Supply results from the HSM model include undeveloped resource accounting and detailed well, reserve addition, decline rate, and financial results. These results are utilized to provide estimates of base year economically recoverable natural gas resources and remaining reserves as a function of E&D cost for the 81 supply regions in the IPM natural gas module. The HSM also provides other data such as the level of remaining resource that could be discovered and developed in a year, exploration and development drilling requirements, production operation and maintenance (O&M) cost, resource share of crude oil and natural gas liquids, natural gas reserves to production ratio, and natural gas requirement for lease and plant use.[100]

10.3.1 Resource and Reserves[101] Assessment

Data sources: The HSM uses the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Canadian Gas Potential Committee (CGPC) play-level[102] resource assessments as the starting point for the new field/new pool[103] assessments. Beyond the resource assessment data, ICF has access to numerous databases that were used for the HSM model development and other analysis. Completion-level production is based on IHS Energy completion level oil and gas production databases for the U.S. and Canada. The U.S. database contains information on approximately 300,000 U.S. completions. A structured system is employed to process this information and add certain ICF data (region, play, ultimate recovery, and gas composition) to each record. ICF also performs extensive quality control checks using other data sources such as the MMS completion and production data for Outer Continental Shelf (OCS) areas and state production reports.

In the area of unconventional gas[104], ICF has worked for many years with the Gas Research Institute (GRI)/Gas Technology Institute (GTI) to develop a database of tight gas, coalbed methane, and Devonian Shale reservoirs in the U.S. and Canada. Along with USGS assessments of continuous plays, the

[99] The term “proven” refers to the estimation of the quantities of natural gas resources that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Among the factors considered are drilling results, production, and historical trends. Proven reserves are the most certain portion of the resource base.

[100] As discussed more fully in Section 10.4, natural gas for “lease and plant use” refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants.

[101] When referring to natural gas a distinction is made between “resources” and “reserves.” “Resources” are concentrations of natural gas that are or may become of potential economic interest. “Reserves” are that part of the natural gas resource that has been fully evaluated and determined to be commercially viable to produce.

[102] A “play” refers to a set of known or postulated natural gas (or oil) accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.

[103] A “pool” is a subsurface accumulation of oil and other hydrocarbons. Pools are not necessarily big caverns. They can be small oil-filled pores. A “field” is an accumulation of hydrocarbons in the subsurface of sufficient size to be of economic interest. A field can consist of one or more pools.

[104] Unconventional gas refers to natural gas found in geological environments that differ from conventional hydrocarbon traps. It includes: (a) “tight gas,” i.e., natural gas found in relatively impermeable (very low porosity and permeability) sandstone and carbonate rocks; (b) “shale gas,” i.e., natural gas in the joints, fractures or the matrix of shales, the most prevalent low permeability low porosity sedimentary rock on earth; and (c) “coal bed methane,” which refers to methane (the key component of natural gas) found in coal seams, where it was generated during coal formation and contained in the microstructure of coal. Unconventional natural gas is distinguished from conventional gas which is extracted using traditional methods, typically from a well drilled into a geological formation exploiting natural subsurface pressure or artificial lifting to bring the gas and associated hydrocarbons to the wellhead at the surface.

database was used to help develop the HSM's "cells", which represent resources in a specific geographic area, characterizing the unconventional resource in each basin, historical unconventional reserves estimates and typical decline curves.[105] ICF has recently revised the unconventional gas resource assessments based on new gas industry information on the geology, well production characteristics, and costs. The new assessments include major shale units such as the Fort Worth Barnett Shale, the Marcellus Shale, the Haynessville Shale, and Western Canada shale plays. ICF has built up a database on gas compositions in the United States and has merged that data with production data to allow the analysis of net versus raw gas production.[106]

In Canada, gas composition data are obtained from provincial agencies. These data were used to develop dry gas[107] production/reserves by region and processing costs in the HSM and to characterize ethane rejection[108] by regions. Information on oil and gas fields and pools in the U.S. come originally from Dwight's Energydata (now IHS Energy) TOTL reservoir database. ICF has made extensive modifications to the database during the creation of the Gas Information System (GASIS) database for the U.S. Department of Energy (DOE) and other projects. Field and reservoir data for Canada comes from the provincial agency databases. These data are used to estimate the number and size of undiscovered fields or pools and their rate of discovery per increment of exploratory drilling. Additional data were obtained from the Significant Field Data Base of NRG Associates.

<u>Methodology and assumptions</u>: Resources in the HSM model are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

<u>Conventional resource – new fields/new pools</u>: The modeling of conventional resource is based on a modified "Arps Roberts" equation[109] to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its area extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. Finding that the original Arps-Roberts equation did not replicate historical discovery patterns for many of the smaller field sizes, ICF modified the equation to improve its ability to accurately track discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas of the U.S. and Western Canada Sedimentary Basin (WCSB), the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas. An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and the economics of developing each.

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[105] A decline curve is a plot of the rate of gas production against time. Since the production rate decline is associated with pressure decreases from oil and gas production, the curve tends to smoothly decline from a high early production rate to lower later production rate. Exponential, harmonic, and hyperbolic equations are typically used to represent the decline curve.

[106] Raw gas production refers to the volumes of natural gas extracted from underground sources, whereas net gas production refers to the volume of purified, marketable natural gas leaving the natural gas processing plant.

[107] Natural gas is a combustible mixture of hydrocarbon gases. Although consisting primarily of methane, the composition of natural gas can vary widely to include propane, butane, ethane, and pentane. Natural gas is referred to as 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.

[108] Ethane rejection occurs when the ethane component in the natural gas stream is not recovered in a gas processing plant but left in the marketable natural gas stream. Ethane rejection is deployed when the value of ethane is worth more in the gas stream than as an a separate commodity or as a component of natural gas liquids (NGL), which collectively refers to ethane, propane, normal butane, isobutane, and pentanes in processed and purified finished form. Information that characterizes ethane rejection by region can play a role in determining the production level and cost of natural gas by region.

[109] "Arps-Roberts equation" refers to the statistical model of petroleum discovery developed by J. J. Arps, and T. G. Roberts, T. G., in the 1950's.

Conventional resource – field appreciation: The model maintains inventories of potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or "probables." As the model simulation proceeds, these probables inventories are drawn down as the resources are proved. At the same time, the inventories of probables are increased due to future year appreciation of new fields that are added to the discovered fields' data set during the model simulation.

Unconventional resource: Originally, the assessments of the unconventional resources were based on the Enhanced Recovery Module (or ERM) within the HSM. The ERM covers that portion of the resource base which falls outside the scope of the "conventional" oil and gas field discovery process dealt with elsewhere in the model. The ERM includes coalbed methane, shale gas, and tight gas. These resources generally correspond to the "continuous plays" designated by the USGS in its resource assessments. The ERM is organized by "cells", which represent resources in a specific geographic area. A cell can represent any size of area ranging from the entire region/depth interval to a single formation in a few townships of a basin. Each cell is evaluated in the model using the same discounted cashflow analysis used for new and old field investments. The ERM cells also are subject to the inertial and cashflow constraints affecting the other types of investment options in the model. The model reports total wells drilled, reserve additions, production, and dollars invested for each type of ERM cell (e.g., coalbed methane) within a region.

As described earlier, ICF has recently revised the unconventional gas resource assessments based on new gas industry information on the geology, well production characteristics, and costs. The new assessment method is a "bottom-up" approach that first generates estimates of unrisked and risked gas-in-place (GIP) from maps of depth, thickness, organic content, and thermal maturity. Then ICF uses a reservoir simulator to estimate well recoveries and production profiles. Unrisked GIP is the amount of original gas-in-place determined to be present based upon geological factors without risk reductions. Risked GIP includes a factor to reduce the total gas volume on the basis of proximity to existing production and geologic factors such as net thickness (e.g., remote areas, thinner areas, and areas of high thermal maturity have higher risk). ICF calibrates well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data.

10.3.2 Frontier Resources (Alaska and Mackenzie Delta)

Besides the three general categories of resources described above, the handling of frontier resources in the HSM is worth noting. Frontier resources such as Alaska North Slope and Mackenzie Delta are subject to similar resource assessment and economic evaluation procedures as applied to other regions. However, unlike other regions, the resources from these regions are stranded to date due to lack of effective commercial access to markets. In fact, 6-8 Bcf/d of gas that is currently produced as part of the oil activities in the Alaska North Slope is re-injected back into the Slope's oil reservoirs as part of the pressure maintenance programs. Several development proposals have been put forward for bringing this Alaska North Slope and Mackenzie Delta gas to market.

In developing the gas resource assumptions for EPA Base Case v.5.13, two gas pipeline projects were identified for bringing the two frontier gas supply resources to the markets in the U.S. and Canada. However, due to uncertainties in the economics and the timing of these pipeline projects, they are not included in the EPA Base Case v.5.13.

10.3.3 Use of the HSM resource and reserves data in EPA Base Case using IPM v.5.13 Natural Gas Module

The base year for the integrated gas-electricity module in EPA Base Case using IPM v.5.13 is 2016. Having a base year in the future has implications on how the model is run and how the gas reserves and resources data are set up. The IPM run begins with a gas module only run for year 2015 to provide beginning of year (BOY) 2016 reserves and resources as the starting point for the integrated run from 2016 onward. This in turn requires the reserves and resources data to be provided for the BOY 2015. Since the data from the HSM are as of BOY 2011, adjustments have to be made to account for reserves development, production, and also resource appreciation between 2011 and 2014. In the EPA Base Case using IPM v.5.13, these adjustments are made based on a four-year production and reserves development forecast using the GMM and a set of resource appreciation growth assumptions. The resource growth assumptions are discussed in "Undiscovered Resource Appreciation" section below.

Table 10-4 provides a snapshot of the starting natural gas resource and reserve assumptions for the EPA Base Case v.5.13. In this table, undiscovered resources represent the economic volume of dry gas that could be discovered and developed with current technology through exploration and development at a specified maximum wellhead gas price. Since the IPM natural gas module differentiates conventional gas from unconventional gas, these are shown separately in Table 10-4. The conventional gas is subcategorized into non-associated gas from gas fields and associated gas[110] from oil fields. The unconventional gas is subdivided into coalbed methane (CBM), shale gas, and tight gas. In Table 10-4, the shale gas resource availability in the Northeast region is constrained by as assumption of limited access in accordance with current permitting procedures mostly affecting the Marcellus play. The full resource is about 925 Tcf.

The reserves are remaining dry gas volumes to be produced from existing developed fields. For EPA Base Case v.5.13 the maximum wellhead price for the resource cost curves is capped at $16/MMBtu (in real 2011 dollars). The ultimate potential undiscovered resources available are actually higher than those presented in Table 10-4 but it would cost more than $16/MMBtu to recover them. (It is important to note that this price is for wet[111] gas at the wellhead in the production nodes. The dry gas price at the receiving nodes can be higher than $16/MMBtu which depends on the share of dry gas, lease and plant use, gas processing cost, production O&M cost, and pipeline transportation costs.) The approach used in the HSM to derive these costs is described more fully in section 10.4 below.

Table 10-4 U.S. and Canada Natural Gas Resources and Reserves

Region	Beginning of Year 2015	
	Undiscovered Dry Gas Resource (Tcf)	**Dry Gas Reserves (Tcf)**
Lower 48 Onshore Non Associated	**2,049**	**325**
Conventional (includes tight)	**566**	**101**
Northeast	49	9
Gulf Coast	144	18
Midcontinent	48	16
Southwest	19	13
Rocky Mountain	288	46
West Coast	18	0
Shale Gas	**1,408**	**212**
Northeast	647	79
Gulf Coast	492	89
Midcontinent	151	22
Southwest	67	15
Rocky Mountain	50	8
West Coast	0	-
Coalbed Methane	**75**	**11**
Northeast	10	1
Gulf Coast	4	1

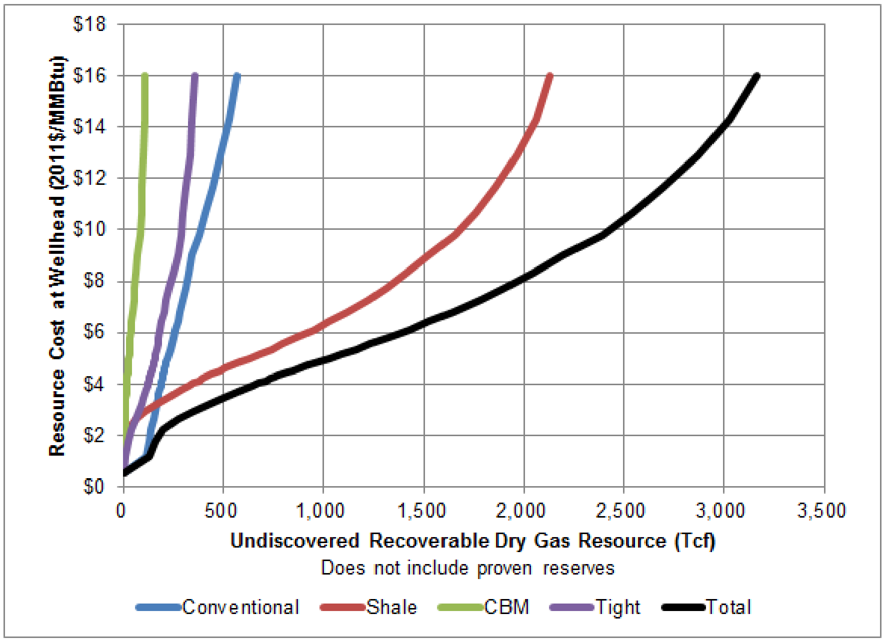
[110] Associated gas refers to natural gas that is produced in association with crude oil production, whereas non-associated gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

[111] A mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical non-hydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium.

Region	Beginning of Year 2015	
	Undiscovered Dry Gas Resource (Tcf)	**Dry Gas Reserves (Tcf)**
Midcontinent	10	1
Southwest	-	-
Rocky Mountain	50	9
West Coast	1	-
Lower 48 Offshore Non Associated	**85**	**6**
Gulf of Mexico	85	6
Pacific	-	0
Atlantic	-	-
Associated-Dissolved Gas	**116**	**13**
Alaska	**51**	**10**
Total U.S.	**2,300**	**355**
Canada Non Associated	**858**	**59**
Conventional and Tight	104	30
Shale Gas	723	24
Coalbed Methane	31	5
Canada Associated-Dissolved Gas	**4**	**3**
Total Canada	**862**	**62**
Total U.S and Canada	**3,162**	**416**

Figure 10-7 presents dry gas resource cost curves for the BOY 2015 initializing gas assumptions for EPA Base Case v.5.13. The resource cost curves show the undiscovered recoverable dry gas resources at different price levels. The curves do not include dry gas reserves. Separate resource cost curves are shown for conventional, shale, coalbed methane (CBM), and tight gas. The recoverable resources shown at maximum wellhead prices in these graphs are those tabulated in Table 10-4 under "Undiscovered Dry Gas Resource" column. The y-axis of the resource cost curves shows the cost at the wellhead of bringing the volume of undiscovered resource indicated on the x-axis into the reserves category. Figure 10-8 diagrams the exploration & development and production processes and the associated costs required to bring undiscovered resource into reserves and production.

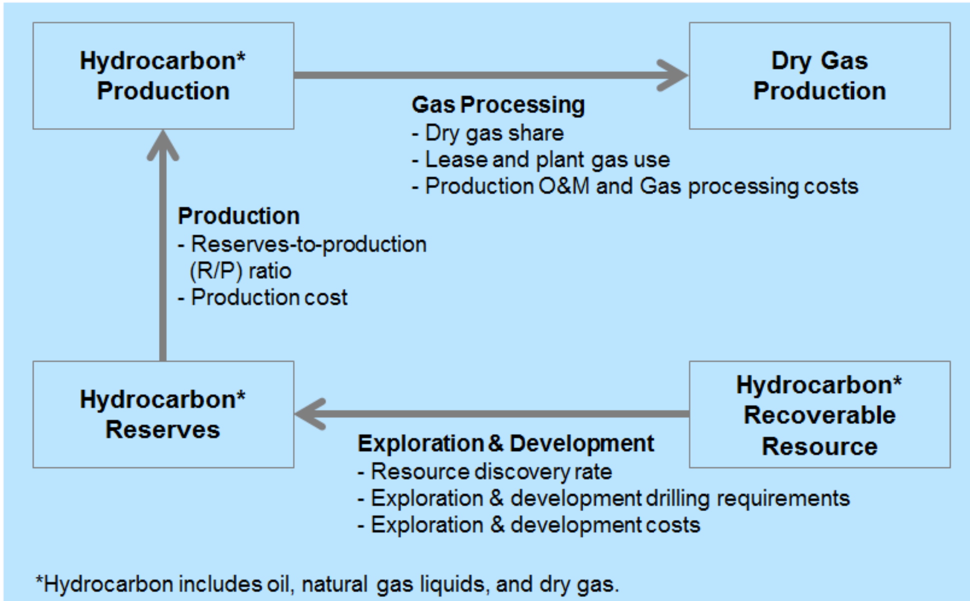
Figure 10-7 Resource Cost Curves at the Beginning of Year 2015



10.3.4 Undiscovered Resource Appreciation

Undiscovered resource appreciation is additional resources from hydrocarbon plays that were not included in the resource base estimates. It differs from field appreciation or reserves appreciation category discussed above which comes from already discovered fields. Natural gas from shales, coal seams, offshore deepwater, and gas hydrates may not be included in the resource base assessments due to lack of knowledge and technology to economically recover the resource. As new technology becomes available, these untapped resources can be produced economically in the future. One example is the advancements in horizontal drilling and hydraulic fracture technologies to produce gas from shale formations. For EPA Base Case, the undiscovered gas resource is assumed to grow at 0.2% per year for conventional gas and 0.75% per year for unconventional gas. The BOY 2015 undiscovered recoverable gas resources in Table 10-4 and Figure 10-7 include resource appreciation between 2011 and 2014.

Figure 10-8 Exploration & Development and Production Processes and Costs to Bring Undiscovered Resource into Reserves and Production



10.4 Exploration, Development, and Production Costs and Constraints

10.4.1 Exploration and Development Cost

Exploration and development (E&D) cost or resource cost is the expenditure for activities related to discovering and developing hydrocarbon resources. The E&D cost for natural gas resources is a function of many factors such as geographic location, field type, size, depth, exploratory success rates, and platform, drilling and other costs. The HSM contains base year cost for wells, platforms, operating costs and all other relevant cost items. In addition to the base year costs, the HSM contains cost indices that adjust costs over time. These indices are partly a function of technology drivers such as improved exploratory success rates, cost reductions in platform, drilling and other costs, improved recovery per well, and partly a function of regression-based algorithms that relate cost to oil and gas prices and industry activity. As oil and gas prices and industry activity increase, the cost for seismic, drilling & completion services, casing and tubing and lease equipment goes up.

Other technology drivers affect exploratory success rates and reduce the need to drill exploratory wells. A similar adjustment is made to take into account changes over time in development success rates, but the relative effect is much smaller because development success rates are already rather high. The technology drivers that increase recovery per well are differentiated in the HSM by region and by type of gas. Generally, the improvements are specified as being greater for unconventional gas because their recovery factors are much lower than those of conventional gas.

The HSM model provides estimates of E&D cost and the level of economically viable gas resource by region as a function of E&D cost. The HSM increased recovery as a function of technology improvement by region is converted to E&D and production technology improvement over time in the form of cost reduction factors by onshore, offshore shelf, and offshore deepwater as shown in Figure 10-9. The average cost reduction factors for onshore, offshore shelf, and offshore deepwater E&D activities are -0.9% per year, -0.7% per year, and -0.4% per year, respectively. These factors are predominantly affected by the level of E&D investments in the regions. The expected aggressive onshore E&D activities to find and produce unconventional gas resources, such as shale gas, will lead to more research in horizontal drilling and hydraulic fracturing technologies to improve productions and lower the costs. This is reflected in higher cost reduction factors for the onshore regions.

Figure 10-9 E&D and Production Technology Improvement Factor

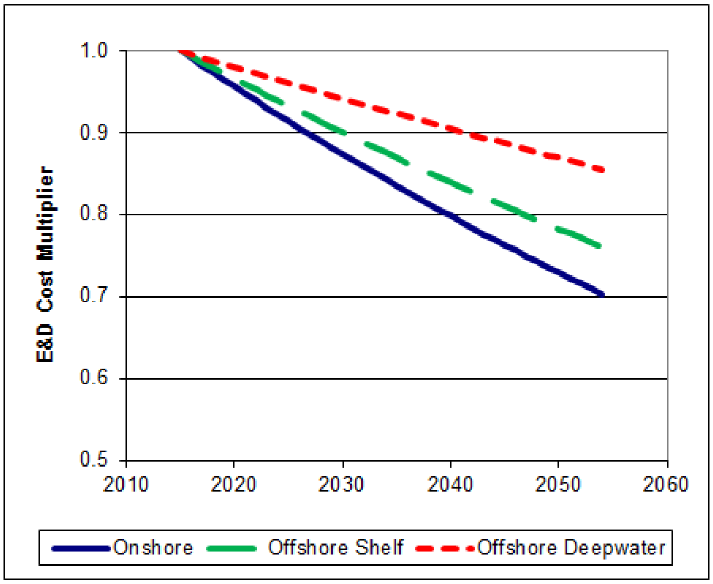
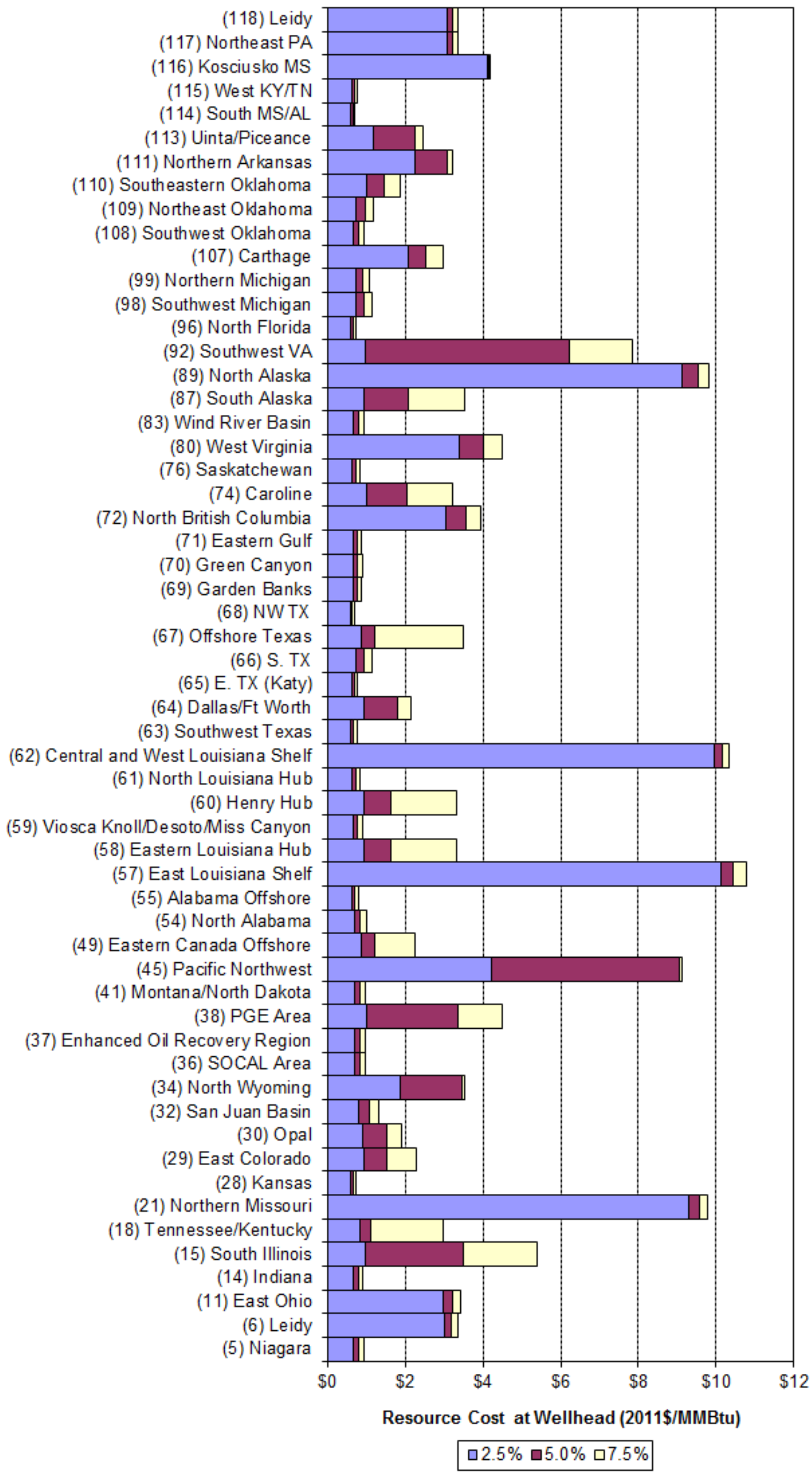


Figure 10-10 shows E&D cost needed to discover and develop 2.5%, 5%, and 7.5% of the remaining undiscovered resource in BOY 2015 by natural gas supply region.

Figure 10-10 Incremental E&D Cost (BOY 2015) by Percentage of Dry Gas Resource Found



10.4.2 Resource Discovery and Drilling Constraints

As mentioned above the simulation in HSM also provides other data such as resource discovery factors which describe the maximum share of remaining undiscovered resource that could be discovered and developed in a year and drilling requirements which describe the drilling required for successful exploration and development. These two parameters are constraints to the development of the resource and their values are not time dependent. The resource discovery constraint is the same for all regions and is assumed to be 6% of the remaining undiscovered resource (column 4 in Table 10-5). The drilling requirement constraint (column 5 in Table 10-5) varies from 2,500 feet for every billion cubic feet of incremental resource discovered (feet/Bcf) for offshore U.S. and between 3,000 feet/Bcf to 10,000 feet/Bcf for onshore regions and offshore Canada.

Table 10-5 Exploration and Development Assumptions for EPA Base Case v.5.13

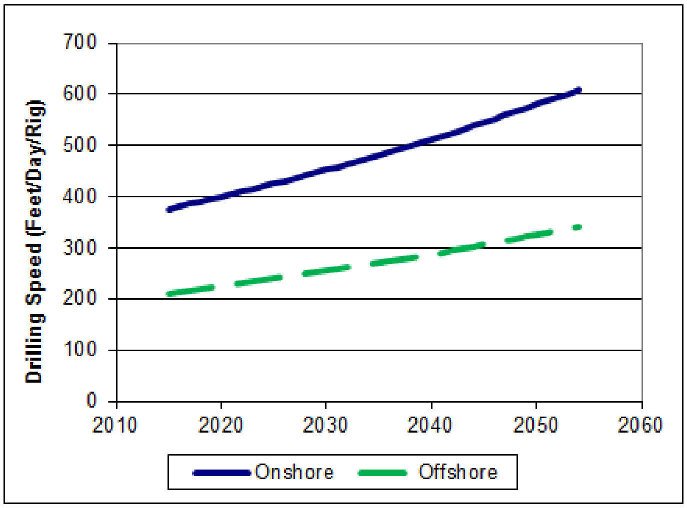
Region	Fraction of Hydrocarbons that are Natual Gas Liquids (NGLs) (Fraction)	Fraction of Hydrocarbons that are Crude Oil (Fraction)	Max Share of Resources that can be Developed per Year (Fraction)	Exploration, Development Drilling Required (Ft/Bcf)	Lease and Plant Use (Fraction)
(5) Niagara	0.02	0.12	0.06	10,000	0.05
(6) Leidy	0.01	0.02	0.06	4,556	0.03
(11) East Ohio	0.10	0.01	0.06	9,400	0.01
(14) Indiana	0.00	0.99	0.06	10,000	0.02
(15) South Illinois	0.00	0.96	0.06	10,000	0.30
(16) North Illinois	0.00	1.00	0.06	10,000	0.30
(18) Tennessee/Kentucky	0.11	0.02	0.06	10,000	0.04
(21) Northern Missouri	0.11	0.00	0.06	10,000	0.04
(28) Kansas	0.12	0.25	0.06	7,454	0.04
(29) East Colorado	0.11	0.03	0.06	9,349	0.05
(30) Opal	0.08	0.29	0.06	4,862	0.05
(32) San Juan Basin	0.11	0.04	0.06	6,323	0.13
(34) North Wyoming	0.11	0.00	0.06	3,688	0.05
(36) SOCAL Area	0.08	0.56	0.06	9,320	0.13
(37) Enhanced Oil Recovery Region	0.04	0.74	0.06	10,000	0.13
(38) PGE Area	0.08	0.61	0.06	9,376	0.13
(41) Montana/North Dakota	0.05	0.64	0.06	10,000	0.13
(45) Pacific Northwest	0.14	0.00	0.06	10,000	0.02
(49) Eastern Canada Offshore	0.03	0.00	0.06	10,000	0.06
(54) North Alabama	0.07	0.04	0.06	6,099	0.03
(55) Alabama Offshore	0.01	0.84	0.06	2,500	0.03
(57) East Louisiana Shelf	0.04	0.74	0.06	2,500	0.04
(58) Eastern Louisiana Hub	0.13	0.24	0.06	6,884	0.04
(59) Viosca Knoll/Desoto/Miss Canyon	0.07	0.56	0.06	2,500	0.04
(60) Henry Hub	0.13	0.25	0.06	6,927	0.04
(61) North Louisiana Hub	0.11	0.01	0.06	9,823	0.04
(62) Central and West Louisiana Shelf	0.04	0.74	0.06	2,500	0.04
(63) Southwest Texas	0.17	0.36	0.06	7,925	0.05
(64) Dallas/Ft Worth	0.06	0.05	0.06	4,510	0.05
(65) E. TX (Katy)	0.14	0.42	0.06	8,819	0.05
(66) S. TX	0.12	0.24	0.06	7,596	0.05
(67) Offshore Texas	0.09	0.31	0.06	2,500	0.05
(68) NW TX	0.22	0.08	0.06	7,584	0.05
(69) Garden Banks	0.07	0.49	0.06	2,500	0.04
(70) Green Canyon	0.07	0.53	0.06	2,500	0.04
(71) Eastern Gulf	0.04	0.71	0.06	2,500	0.04

Region	Fraction of Hydrocarbons that are Natual Gas Liquids (NGLs) (Fraction)	Fraction of Hydrocarbons that are Crude Oil (Fraction)	Max Share of Resources that can be Developed per Year (Fraction)	Exploration, Development Drilling Required (Ft/Bcf)	Lease and Plant Use (Fraction)
(72) North British Columbia	0.01	0.00	0.06	9,948	0.08
(74) Caroline	0.04	0.04	0.06	9,752	0.10
(76) Saskatchewan	0.01	0.54	0.06	10,000	0.07
(80) West Virginia	0.06	0.00	0.06	3,539	0.05
(83) Wind River Basin	0.11	0.01	0.06	7,013	0.05
(86) MacKenzie Delta	0.00	1.00	0.06	10,000	0.08
(87) South Alaska	0.05	0.59	0.06	10,000	0.08
(89) North Alaska	0.04	0.62	0.06	10,000	0.99
(90) Arctic	0.00	1.00	0.06	10,000	0.08
(92) Southwest VA	0.00	0.00	0.06	5,787	0.02
(96) North Florida	0.01	0.94	0.06	9,937	0.21
(98) Southwest Michigan	0.08	0.09	0.06	10,000	0.04
(99) Northern Michigan	0.05	0.21	0.06	7,946	0.04
(107) Carthage	0.07	0.02	0.06	3,228	0.05
(108) Southwest Oklahoma	0.15	0.06	0.06	6,905	0.04
(109) Northeast Oklahoma	0.16	0.03	0.06	9,089	0.04
(110) Southeastern Oklahoma	0.16	0.02	0.06	4,445	0.04
(111) Northern Arkansas	0.00	0.05	0.06	4,437	0.04
(113) Uinta/Piceance	0.10	0.13	0.06	7,715	0.05
(114) South MS/AL	0.06	0.16	0.06	7,012	0.03
(115) West KY/TN	0.11	0.06	0.06	10,000	0.04
(116) Kosciusko MS	0.11	0.00	0.06	10,000	0.04
(117) Northeast PA	0.01	0.01	0.06	3,394	0.04
(118) Leidy	0.01	0.01	0.06	3,993	0.04

Other drilling constraints include rig capacity, rig retirement, rig growth, and drilling speed. Values for the constraints are specified for each of the three drilling category: (1) onshore, (2) offshore shelf, and (3) offshore deepwater. The drilling rig capacity constraint shows the number of drilling rigs initially available in the BOY 2015. The initial rig counts are 4,050 rigs for onshore, 125 rigs for offshore shelf, and 125 rigs for offshore deepwater and the numbers can change over time controlled by rig retirement and rig growth constraints. The drilling rig retirement constraint is the share of rig capacity that can retire in a year. The drilling rig growth constraint is the maximum increase of total rig count in a year. The drilling retirement and growth are assumed to be the same for all drilling category and the constraints are set to 0.5% per year and 3.5% per year, respectively.

Another growth constraint, minimum drilling capacity increase, is implemented to force the rig count to grow by at least one rig in each drilling category. The drilling speed constraint is the required speed in feet/day/rig for successful exploration and development. The drilling speed required for successful E&D grows over time, as shown in Figure 10-11 and differs for onshore and offshore (which in this case includes both shelf and deep shelf).

Figure 10-11 Drilling Rig Speed Constraint



10.4.3 Reserves-to-Production (R/P) Ratio

The reserves-to-production ratio is the remaining amount of reserves, expressed in years, to be produced with a current annual production rate. In the IPM gas module, the R/P data obtained from the HSM is provided in the form of production-to-reserves (P/R) ratio (or reciprocal of the R/P ratio). The P/R ratio is used to calculate annual wet gas production from the reserves and the value varies by resource type and production node. For conventional gas the P/R ratio ranges from 0.04 (or 25 years of R/P) to 0.25 (or 4 years of R/P) with average of 0.13 (or 8 years of R/P). The P/R ratio of shale and tight gas is half of that of the conventional gas with average P/R ratio of 0.06 (or 17 years of R/P). Coalbed methane gas has the lowest P/R ratio with average of 0.04 (or 25 years of R/P).

10.4.4 Variable Costs, Natural Gas Liquid Share, and Crude Oil Share

In the IPM natural gas module, the variable costs include production operations and maintenance (O&M) cost and gas processing cost. The production O&M cost for 2015 is estimated to be $0.54/MMBtu (in real 2011 dollars) and is assumed to be the same for all supply regions. The production O&M cost is expected to decline over time due to improvements in production technology. In the model the same technology improvement factor shown in Figure 10-9 is applied to the production O&M cost.

The resource data from the HSM is provided in the form of total hydrocarbon (oil, gas, and NGL) resource. The HSM also provides the allocations of the hydrocarbon for dry gas, oil, and NGL. Table 10-5 shows the shares of NGL (column 2) and crude oil (column 3) by supply region. Wet gas production from the wellhead is processed in gas processing plants to produce pipeline quality dry gas. Node level gas processing cost for IPM natural gas module is obtained from the GMM. The processing cost varies from $0.07/MMBtu (of wet gas in real 2011 dollars) to $0.61/MMBtu with average of $0.23/MMBtu.

10.4.5 Lease and Plant Gas Use

The term “lease and plant gas” refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants. The data for lease and plant gas use is derived for the HSM as a fraction of wet gas production and varies by region. The value ranges from 0.01 to as high as 0.3 with an average of around 0.06 (column 6 in Table 10-5). Lease and plant for North Alaska is set to 0.99 to represent the portion of gas production that is re-injected back into the Slope’s oil reservoirs.

10.5 Liquefied Natural Gas (LNG) Imports

As described earlier, most of the data related to North American LNG imports is derived from the GMM LNG model. Based on a comprehensive database of existing and potential liquefaction and regasification facilities and worldwide LNG import/export activities, the model uses a simulation procedure to create the BOY 2015 North American LNG supply curves and projections of regasification capacity and costs.

Key elements of the LNG model are described below.

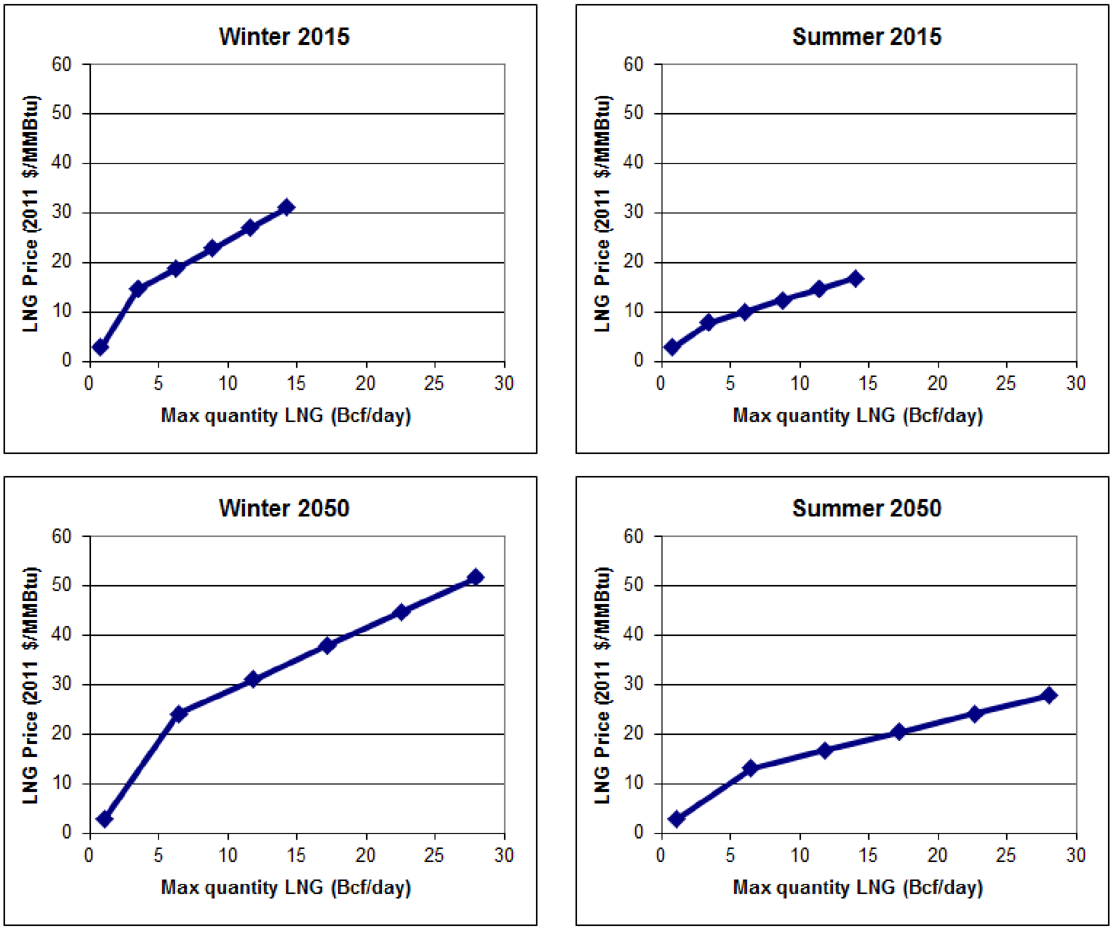
10.5.1 Liquefaction Facilities and LNG Supply

The supply side of the GMM LNG model takes into account capacities from existing as well as potential liquefaction facilities. The lower and upper boundaries of supply capacity allocated for each North American regasification facility are set by available firm contracts and swing supplies. Three point LNG supply curves are generated within this envelope where: (1) the lower point is the amount of firm LNG supply, (2) the upper bound is the firm imports plus the maximum swing imports available for that facility, and (3) the midpoint is the average of the minimum and maximum values. Prices for the minimum and maximum points are tied to Refiner Acquisition Cost of Crude (RACC) price.[112] The minimum price represents minimum production cost for liquefaction facilities and is set at 0.5 of RACC price and the maximum price is set at 1.5 of RACC price. The prices are then shifted up for winter months and shifted down in the summer months to represent the seasonal variation in competition from Asian and European LNG consumers.

The individual LNG supply curves from the GMM LNG model are aggregated to create total North American LNG supply curves describing LNG availability serving the North American regasification facilities. The three point curves are converted to six points by linear interpolation to provide more supply steps in the IPM natural gas module. Two LNG supply curves, one for winter and one for summer, are specified for each year starting from 2015 until 2054 to capture growth as well as seasonal variation of the LNG supplies. Figure 10-12 shows the North American LNG supply curves for the winters and summers of 2015 and 2050.

[112] Refiner Acquisition Cost of Crude Oil (RACC) is a term commonly use in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.

Figure 10-12 North American LNG Supply Curves



10.5.2 Regasification Facilities

For the EPA Base Case, 15 North American LNG regasification facilities are considered in the IPM natural gas module. Table 10-6 lists the 15 facilities, the destination nodes where the LNG are delivered, and the BOY 2015 capacity for each of the regasification facility. Figure 10-13 provides a map of these facilities. Existing Penuelas LNG facilities in Puerto Rico are not included because they are not part of the natural gas network in the IPM gas module. In EPA Base Case v.5.13. the Penuelas LNG facilities are modeled with a fixed 150 MMcfd gas supply into Florida node and a link to connect the gas supply to the electric generating units in Puerto Rico.

Table 10-6 North American LNG Regasification Facilities

No	LNG Regasification Facility	Node Location	Beginning of Year 2015 Regasification Capacity (Bcf/day)
1	Cove Point	(7) Cove Point TRANS	1.50
2	Elba Island	(9) Elba Is TRANS	2.40
3	Everett	(2) Everett TRANS	0.70
4	Gulf Gateway	(69) Garden Banks	0.50
5	Lake Charles	(60) Henry Hub	2.10
6	Altamira	(51) Reynosa Imp/Exp	1.00
7	Costa Azul	(84) California Mexican Exports	2.00

No	LNG Regasification Facility	Node Location	Beginning of Year 2015 Regasification Capacity (Bcf/day)
8	Cameron LNG	(60) Henry Hub	1.50
9	Freeport LNG	(65) E. TX (Katy)	1.50
10	Golden Pass	(65) E. TX (Katy)	2.00
11	Canaport	(81) Eastern Canada Demand	1.00
12	Sabine Pass	(60) Henry Hub	2.60
13	Gulf LNG Energy LLC	(114) South MS/AL	1.00
14	Northeast Gateway	(1) New England	0.80
15	Manzanillo	(51) Reynosa Imp/Exp	0.75

Figure 10-13 North American LNG Regasification Facilities Map

10.5.3 LNG Regasification Capacity Expansions

The IPM natural gas module has two constraints for the regasification capacity expansion: (1) minimum LNG regasification facility capacity expansion and (2) maximum LNG regasification facility capacity expansion. The values are specified for each facility and year where the minimum constraint is used to force the model to add regasification capacity and the maximum constraint is the upper bound for the capacity expansion.

The decision of whether to expand regasification capacity is controlled by the two constraints and by a levelized capital cost for regasification capacity expansion. The BOY 2015 levelized capital cost for capacity expansion (in real 2011 dollars per MMBtu of capacity expansion) is specified for each facility. A cost multiplier can be applied to represent the increase in levelized capital cost over time. The constraints for the capacity expansion can be used to turn on or off the regasification capacity expansion feature in the model. Setting both constraints to zero will deactivate this feature.

If the regasification capacity is allowed to expand, the model can add capacity to a facility within the minimum and maximum constraints if the cost of the regasification expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for adding new regasification capacity less their revenues. The model takes into account all possible options/projects (including regasification capacity expansions) in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function value. In this way, regasification capacity expansion projects will compete with each other and even with other projects such as pipeline expansions, storage expansions, etc.

Due to excess LNG regasification capacity already in the system, the regasification capacity expansion feature is not deployed in EPA Base Case v.5.13. EPA scenario results show very low total LNG utilizations throughout the projection period because of robust natural gas supply in the U.S. and Canada combined with a relatively low electricity demand growth assumption. The results suggest the base year LNG regasification capacity is already high and requires no expansion.

10.6 End Use Demand

Non-power sector demand (i.e. the residential, commercial, and industrial) is modeled in the new gas module in the form of node-level firm and interruptible demand curves[113]. The firm demand curves are developed and used for residential, commercial, and some industrial sources, while the interruptible demand curves are developed and used exclusively for industrial sources.

A three step process is used to prepare these curves for use in the IPM gas module. First, GMM is used to develop sector specific econometric models representing the non-power sector demand. Since the GMM econometric models are functions of weather, economic growth, price elasticity, efficiency and technology improvements, and other factors, these drivers, in effect, are embedded in the resulting IPM natural gas module demand curves. Second, projections are made using the GMM econometric models and assembled into monthly gas demand curves by sector and demand node. Third, using a second model, seasonal and load segment specific demand curves are derived from the monthly gas demand curves. The sections below describe each of these steps in further detail.

10.6.1 Step 1: Developing Sector Specific Econometric Models of Non-Power Sector Demand

<u>Residential/Commercial Sector</u>

The GMM econometric models of residential and commercial demand are based on regression analysis of historical data for 41 regions and are adjusted to reflect conservation, efficiency, and technology changes over time. The regional data is allocated to the node level based on population data and information from the Energy Information Administration's "Annual Report of Natural and Supplemental Gas Supply & Disposition" (EIA Form-176). Specifically, the econometric models used monthly Department of Energy/Energy Information Administration (DOE/EIA) data from January 1984 through December 2002 for the U.S. and monthly Statistics Canada data from January 1988 through December 2000 for Canada.

The GMM econometric models showed node-level residential and commercial gas demand to be a function of heating degree days, elasticity of gas demand relative to GDP, and elasticity of gas demand relative to gas price. The GDP elasticity was generally about 0.4 for the residential sector and 0.6 for the commercial sector. The gas price elasticity was generally less than 0.1 for both sectors. Since gas demand in these sectors is relatively inelastic, GDP and price changes have small effects on demand.

[113] "Firm" refers to natural gas demand that is not subject to interruptions from the supplier, whereas "interruptible" refers to natural gas demand that is subject to curtailment or cessation by the supplier.

U.S. Industrial Sector

The GMM econometric model of U.S. industrial gas demand employed historical data for 11 census-based regions and ten industry sectors, focusing on gas-intensive industries such as:

- Food
- Pulp and Paper
- Petroleum Refining
- Chemicals
- Stone, Clay and Glass
- Iron and Steel
- Primary Aluminum
- Other Primary Metals
- Other Manufacturing
- Non-Manufacturing

For each of these sectors three end-use categories (process heat, boilers, and other end uses) are modeled separately:

- Process heat: This includes all uses of gas for direct heating as opposed to indirect heating (e.g., steam production). The GMM econometric modeling indicated that forecasts for process heat for each industrial sector are a function of growth in output, the energy intensity trend, and the price elasticity. Growth in output over time for most industries is controlled by industrial production indices. Energy intensity is a measure of the amount of gas consumed per unit of output. Energy intensity tends to decrease over time as industries become more efficient.
- Boilers: This category includes natural gas-fired boilers whose purpose is to meet industrial steam demand. GMM econometric models indicated that gas demand for boilers is a function of the growth in industrial output and the amount of gas-to-oil switching. Industry steam requirements grow based on industrial production growth. A large percentage of the nominally “dual-fired” boilers cannot switch due to environmental and technical constraints.
- Other end uses: This category includes all other uses for gas, including non-boiler cogeneration, on-site electricity generation, and space heating. Like the forecasts for process heat, the GMM econometric modeling showed “other end uses” for each industrial sector to be a function of growth in output, the energy intensity trend, and the price elasticity.

In addition to these demand models, a separate regression model was use to characterize the chemicals sector’s demand for natural gas as a feedstock for ammonia, methanol, and non-refinery hydrogen. Growth in the chemicals industry is represented by a log-linear regression model that relates the growth to GDP and natural gas prices. As GDP growth increases, chemical industry production increases; and as gas prices increase, chemical industry production decreases.

The GMM econometric models for the U.S. industrial sector used DOE/EIA monthly data from January 1991 through December 2000.

Canada Industrial Sector

The industrial sector in Canada is modeled in less detail. Canada is divided into 6 regions based on provincial boundaries. The approach employs a regression fit of historic data similar to that used in the residential/commercial sectors. Sub-sectors of Canadian industrial demand are not modeled separately. The Canadian industrial sector also includes power generation gas demand. The model used Statistics Canada monthly data from January 1991 through December 2000.

10.6.2 Step 2: Use projections based on the GMM econometric models to produce monthly gas demand curves by sector and demand node

The regression functions resulting from the econometric exercises described in Step 1 are used to create monthly sector- and nodal-specific gas demand curves. To do this the functions are first populated with the macroeconomic assumptions that are consistent with those used in EPA Base Case v.5.13. Then, a range of natural gas prices are fed into the regression functions. At each gas price the regression functions report out projected monthly demand by sector and node. These are the GMM's nodal demand curves.

10.6.3 Step 3: Develop non-electric sector natural gas demand curves that correspond to the seasons and segments in the load duration curves used in IPM

A second model, the Daily Gas Load Model (DGLM), is used to create daily gas load curves based on the GMM monthly gas demand curves obtained in Step 2. The DGLM uses the same gas demand algorithms as the GMM, but uses a daily temperature series to generate daily variations in demand, in contrast to the seasonal variations in gas demand that are obtained from the GMM.

The resulting daily nodal demand data for each non-power demand sector are then re-aggregated into the two gas demand categories used in the IPM gas module: all of the residential and commercial demand plus 10% of the industrial demand is allocated to the firm gas demand curves, and the remaining 90% of the industrial demand is allocated to the interruptible gas demand curves.

IPM, the power sector model, has to take into account natural gas demand faced by electric generating units that dispatch in different segments of the load duration curves, since demand for natural gas and its resulting price may be very different for units dispatching in the peak load segment than it is for units dispatching in the base, high shoulder, mid shoulder, or low shoulder load segments. In addition, since seasonal differences in demand can be significant, IPM requires separate load segment demand data for each season that is modeled. In EPA Base Case v.5.13, there are two seasons: Summer (May 1 – September 30) and winter (October 1 – April 30). Therefore, the firm and interruptible daily gas demand and associated prices are allocated to the summer and winter load segment based on the applicable season and prevailing load conditions to produce the final non-electric sector gas demand curves that are used in IPM.

In EPA Base Case v.5.13, each of the summer and winter periods uses 6 load segments for pre-2030 and 4 load segments for post-2030 as shown in Table 10-7. The "Peak" load segment in post-2030 is an aggregate of "Needle Peak" and "Near Peak" load segments in the pre-2030. The "High Shoulder" load segment in post-2030 is an aggregate of "High Shoulder" and "Middle Shoulder" load segments in the pre-2030. The same definitions of "Low Shoulder" and "Base" load segments are applied to both pre-2030 and post-2030. Input data for firm and interruptible demand curves are specified for all six load segments listed in the pre-2030 column of Table 10-7.

Table 10-7 Summer and Winter Load Segments in EPA Base Case v.5.13

<table>
<tr><th colspan="2">Pre 2030</th><th colspan="2">Post 2030</th></tr>
<tr><td>1</td><td>Needle Peak</td><td rowspan="2">1</td><td rowspan="2">Peak</td></tr>
<tr><td>2</td><td>Near Peak</td></tr>
<tr><td>3</td><td>High Shoulder</td><td rowspan="2">2</td><td rowspan="2">High Shoulder</td></tr>
<tr><td>4</td><td>Middle Shoulder</td></tr>
<tr><td>5</td><td>Low Shoulder</td><td>3</td><td>Low Shoulder</td></tr>
<tr><td>6</td><td>Base</td><td>4</td><td>Base</td></tr>
</table>

Aggregation of summer and winter load segments from six in the pre-2030 to four in the post-2030 is performed endogenously in the model.

The non-electric sector demand curves (firm and interruptible) are generated based on GMM regressions described above with macroeconomic assumptions consistent with those of EPA Base Case v.5.13. A set of firm and interruptible gas demand curves is generated for each node and year. Examples of node-specific firm and interruptible demand curves, for summer and winter load segments are shown in Figure 10-14 and Figure 10-15. Figure 10-14 is very inelastic; only a small fraction of demand is shed as prices increase. The interruptible gas demand in the peak segments is also very inelastic as expected with higher elasticities in the shoulder and base load segments.

It is important to note that the non-electric gas demand curves provided to the IPM/Gas model are static inputs. The implied elasticities in the curves represent short-term elasticities based on EPA Base Case v.5.13 macroeconomic assumptions. Long-term elasticity is not factored into the gas demand curves. In other words, changes in the assumptions that affect the price/volume solutions have no effect to the long-term gas demand elasticity assumed here.

Figure 10-14 Examples of Firm Demand Curves by Electric Load Segment

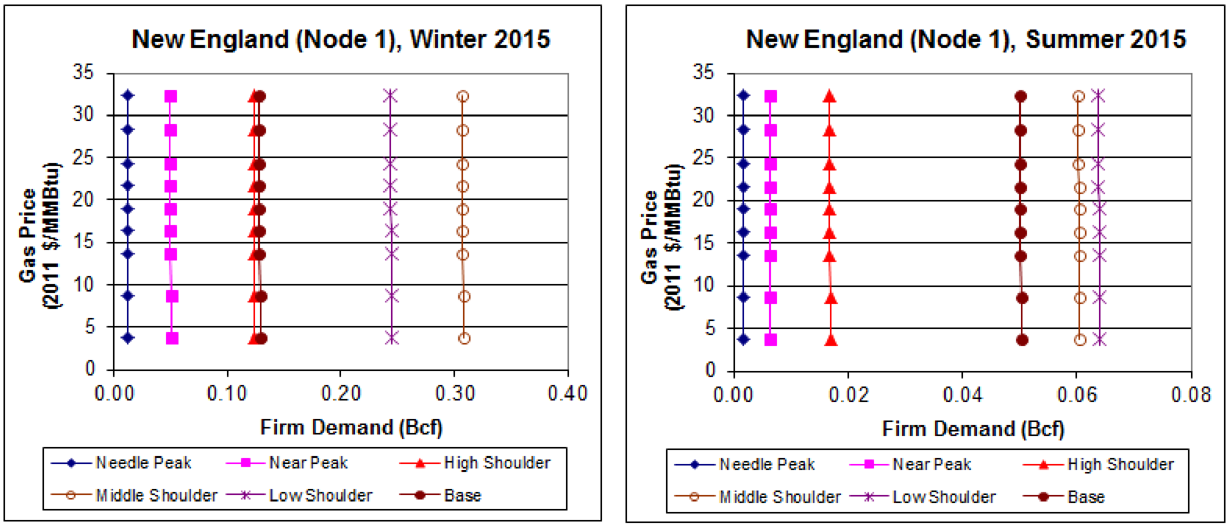
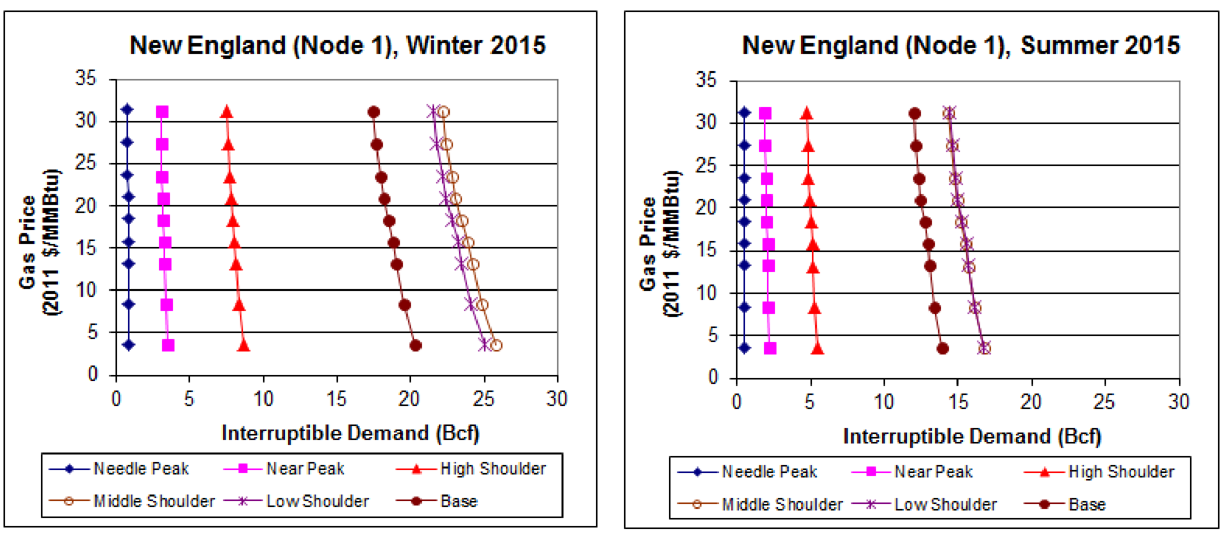


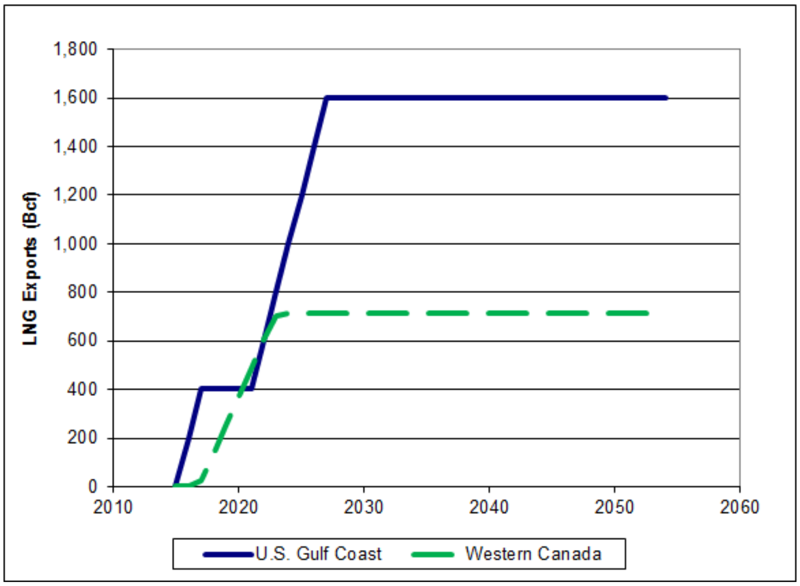
Figure 10-15 Examples of Interruptible Demand Curves by Electric Load Segment



10.6.4 The Use of Firm Gas Demand to Represent LNG Exports

As described earlier, the gas module does not currently have a specific sub-module for LNG exports. In the EPA Base Case v.5.13, the LNG exports are treated as firm demand in the form of fixed or inelastic firm demand curves. Three additional demand nodes are added to represent the three LNG export terminals, two in the U.S. Gulf Coast and one in Western Canada. The U.S. Gulf Coast LNG nodes are linked to nodes (60) Henry Hub and (65) E. TX (Katy) and the Western Canada LNG export node is linked to node (72) North British Columbia. The assumptions for LNG exports from the U.S. Gulf Coast, starting from 2016, are adapted from AEO 2013. The assumptions for LNG exports from Western Canada, starting from 2017, are derived from GMM LNG Model. Figure 10-16 shows LNG exports projection from the U.S. and Canada.

Figure 10-16 LNG Export Assumptions in EPA Base Case v.5.13.



10.7 Pipeline Network

10.7.1 Network Structure

The pipeline network in the IPM natural gas module represents major transmission corridors (not individual pipelines) throughout North America. It contains 380[114] gas pipeline corridors (including bi-directional links) between the 118 nodes (Figure 10-3). Each corridor is characterized by maximum capacity and a "value of service" (discount curve) relationship that determines the market value of capacity as a function of load factor.[115] The node structure is developed to reflect points of change or influence on the pipeline system such as:

- Major demand and supply centers
- Pipeline Hubs and market centers
- Points of divergence in pipeline corridors

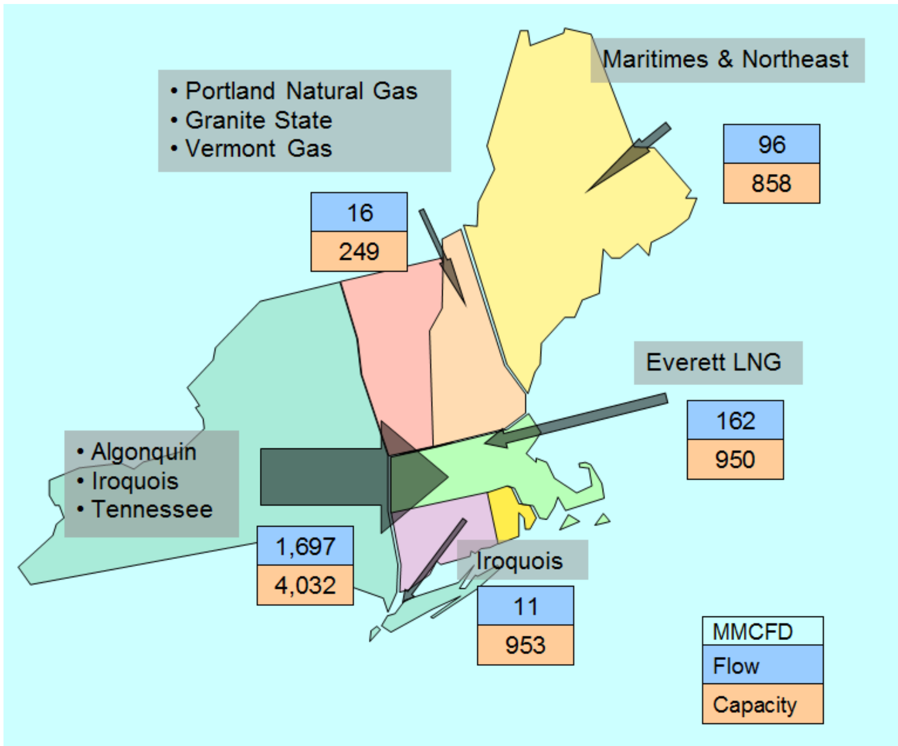
To illustrate the relationship of corridors and pipelines, Figure 10-17 shows the flow and capacity of five pipeline corridors in New England in 2020. Gas flows into New England along three pipeline corridors

[114] Excluding LNG import Terminal nodes and their pipeline connections.

[115] See footnote 88 above for a definition of "load factor."

(indicated in Figure 10-17 by 3 of the 4 arrows that point into the region) representing a total of seven pipeline systems (indicated by name labels in Figure 10-17). New England also receives gas via the Everett LNG terminal (indicated in Figure 10-17 by the 4th arrow that points into the region). Also, some of the gas that flows into New England on the Iroquois system flows through the region and back to downstate New York; this is represented on the map as an export from New England (indicated in Figure 10-17 by the arrow that points away from the region).

Figure 10-17 New England Pipeline Corridors in 2020



10.7.2 Pipeline Transportation Costs

In the IPM natural gas module, the natural gas moves over the pipeline network at variable cost. The variable cost as a function pipeline throughput (or pipeline discount curve) is used to determine transportation basis[116] (i.e., the market value of capacity) for each period in the forecast for each pipeline link. The 4-point pipeline discount curves in the IPM natural gas module are simplified forms of the more robust continuous discount curves from the GMM pipeline module. The GMM pipeline discount curves have been derived in the course of extensive work to calibrate the model to actual history. The curves have been fit to basis differentials observed from actual gas prices and to annual load factors from pipeline electronic bulletin boards via Lippman Consulting, Inc.

The GMM continuous discount curves are converted to 4-point linear curves for the IPM natural gas module capturing deflection points in the GMM discount curves. Figure 10-18 depicts the BOY 2015 discount curve for the pipeline corridor connecting nodes (61) North Louisiana Hub and (18) Tennessee/Kentucky. Cost growth factors shown in

[116] In natural gas discussions "basis" refers to differences in the price of natural gas in two different geographical locations. In the marketplace "basis" typically means the difference between the NYMEX futures price at the Henry Hub and the cash price at other market points. In the modeling context "basis" means the difference in natural gas prices between any two nodes at the same instance in time.

Figure 10-19 are applied to the pipeline discount curves to reflect cost increase over time. The cost is assumed to grow at an average rate of 0.5 percent per year.

Figure 10-18 Example Pipeline Discount Curve

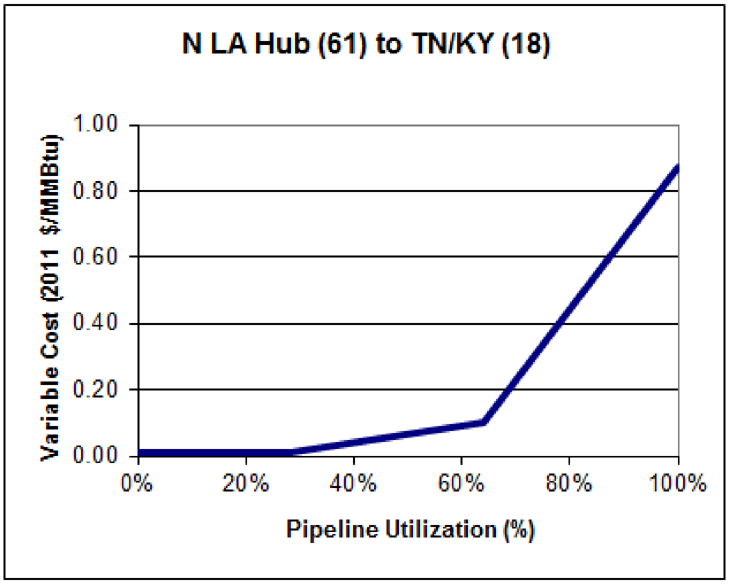
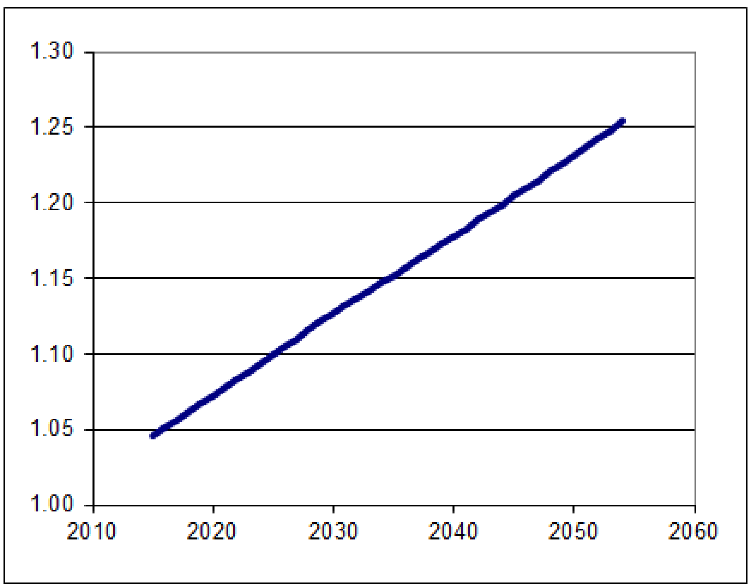


Figure 10-19 Pipeline Cost Growth Factor



10.7.3 Pipeline Capacity Expansion Logic

Initial pipeline capacity, derived from GMM, includes existing capacities and planned capacities that are expected to be operational from the beginning of 2015. The IPM natural gas module has the capability to endogenously expand the pipeline capacity. The decision of whether to expand pipeline capacity is controlled by two constraints, which stipulate minimum and maximum capacity additions and by the levelized capital cost of expanding pipeline capacity in the specific corridor and year. The minimum capacity addition constraint forces the model to add capacity in a specified corridor and year. The maximum capacity constraint is the upper bound on capacity additions in a specified corridor and year. For most pipeline corridors there is no minimum or maximum capacity requirement, and so they are assigned a value of zero as their minimum capacity addition requirement and infinity[117] as their maximum capacity addition requirement. Where this occurs, the pipeline expansion is only controlled by the pipeline capital cost.

The model is allowed to add capacity to a pipeline corridor within the minimum and maximum capacity addition constraints if the cost of the pipeline expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for pipeline capacity expansion, less their revenues. The model takes into account all possible options/projects including capacity additions for pipeline corridors in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function. In this way, pipeline corridor expansion projects will compete with each other and even with other projects such as LNG regasification capacity expansions, storage expansions, etc.

For EPA Base Case v.5.13, pipeline corridors connecting North Alaska (node 89) and Mackenzie Delta (node 86) to North British Columbia (node 72) have the minimum and maximum capacity addition constraints. Due to uncertainties of these pipeline projects as discussed in Section 3, the North Alaska and Mackenzie Delta pipeline projects are not made available throughout the projection. Both capacity addition constraints for North Alaska and Mackenzie delta pipeline corridors are set to zero.

Expansions in other pipeline corridors are not restricted. The model is allowed to build capacity to any pipeline corridors at any time as long as it contributes to minimization of the objective function.

The BOY 2015 levelized pipeline capital cost (in real 2011 dollars per MMBtu/Day of pipeline capacity addition) is specified for each of the 380 pipeline links. The cost growth factors shown in

Figure 10-19 are applied to derive the cost increase over time. The average levelized capital cost for pipeline capacity expansion for 2015 is $165 per MMBtu/Day.

10.8 Gas Storage

The IPM natural gas module has 118 underground storage facilities that are linked to 51 nodes. The underground storage is grouped into three categories based on storage “Days Service.”[118]

- “20-Day” high deliverability storage – 37 storage facilities
- “80-Day” depleted/aquifer reservoirs – 41 storage facilities
- “Over 80 Days” depleted/aquifer reservoirs – 40 storage facilities

The model also includes existing and potential LNG peak shaving storage facilities. The existing facilities are linked to 24 nodes with allocations based on historical capacity data. There are 48 other nodes that are linked to LNG peakshaving storage. These facilities do not currently have capacity but are included in the storage database for the purpose of future expansion. The map of storage facility locations is shown in Figure 10-6 and the list of storage facility nodes is shown in

Table 10-8.

In

Table 10-8 an X in columns 2 (“20-Day”), 3 (“80-Day”), or 4 (“Over 80-Days”) represents an underground storage facility. There are 118 such X’s which correspond to the 118 underground storage facilities noted

[117] In the model this is achieved by assigning a large number, e.g., 100 Bcfd, for every year where there is no constraint on maximum capacity.

[118] See footnote 90 above for a definition of “Days Service.”

in the previous paragraph. These 118 X's appear in 51 rows, which represent the linked nodes noted in the previous paragraph. The identities of these nodes are found in column 1 ("Node"). Similarly, 24 X's in columns 5 ("Existing") represent the 24 existing LNG peakshaving facilities and 48 X's in column 6 ("Potential") represent the 48 prospective LNG storage facilities.

Table 10-8 List of Storage Nodes

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(1) New England				X	
(3) Quebec	X		X		X
(4) New York City				X	
(5) Niagara	X	X	X		X
(6) Southwest PA	X	X	X		X
(8) Georgia				X	
(10) South Florida					X
(11) East Ohio	X	X	X		X
(12) Maumee/Defiance					X
(13) Lebanon					X
(14) Indiana		X	X	X	
(15) South Illinois	X	X	X		X
(16) North Illinois	X	X	X	X	
(17) Southeast Michigan	X	X			X
(18) East KY/TN	X	X	X	X	
(19) MD/DC/Northern VA				X	
(20) Wisconsin				X	
(21) Northern Missouri					X
(22) Minnesota		X		X	
(23) Crystal Falls					X
(24) Ventura		X	X	X	
(26) Nebraska			X	X	
(28) Kansas	X	X	X		X
(29) East Colorado	X	X	X		X
(30) Opal	X	X	X		X
(31) Cheyenne		X	X		
(32) San Juan Basin			X		
(33) EPNG/TW					X
(34) North Wyoming			X		
(35) South Nevada					X
(36) SOCAL Area	X	X			X
(38) PGE Area	X	X	X		X
(41) Montana/North Dakota		X	X		X
(45) Pacific Northwest	X	X		X	
(46) NPC/PGT Hub				X	
(47) North Nevada				X	
(48) Idaho				X	
(54) North Alabama	X	X	X	X	
(56) North Mississippi	X	X			X
(58) Eastern Louisiana Hub	X		X		X
(60) Henry Hub	X	X	X		X

Node	Underground Storage Facility			LNG Peakshaving Facility	
	20-Day	80-Day	Over 80 Days	Existing	Potential
(61) North Louisiana Hub	X	X	X		X
(63) Southwest Texas	X	X	X		
(64) Dallas/Ft Worth	X	X	X		X
(65) E. TX (Katy)	X	X	X		X
(66) S. TX					X
(68) NW TX					X
(72) North British Columbia					X
(73) South British Columbia			X		X
(74) Caroline	X	X	X		X
(76) Saskatchewan	X	X	X		X
(77) Manitoba					X
(78) Dawn	X	X	X		X
(79) Philadelphia				X	
(80) West Virginia	X	X	X		X
(81) Eastern Canada Demand					X
(83) Wind River Basin			X		
(92) Southwest VA	X		X	X	
(93) Southeast VA				X	
(94) North Carolina				X	
(95) South Carolina				X	
(96) North Florida					X
(97) Arizona	X	X			X
(98) Southwest Michigan	X	X	X		X
(99) Northern Michigan	X	X	X		X
(103) SDG&E Demand				X	
(104) Eastern New York					X
(105) New Jersey				X	
(106) Toronto					X
(107) Carthage	X	X			X
(108) Southwest Oklahoma			X		X
(109) Northeast Oklahoma		X	X		X
(110) Southeastern Oklahoma	X	X			X
(111) Northern Arkansas	X	X		X	
(112) Southeast Missouri	X				X
(113) Uinta/Piceance		X	X		X
(114) South MS/AL	X	X			X
(115) West KY/TN	X	X	X		
(117) Northeast PA	X	X	X		
(118) Leidy		X	X		

10.8.1 Storage Capacity and Injection/Withdrawal Constraints

The expected working gas capacity as of BOY 2015 by location and storage type is obtained from the GMM as are injection and withdrawals rates. These serve as inputs to the IPM gas module, which uses them to endogenously derive gas storage withdrawals, injections, storage expansions, and associated costs. To give a sense of the BOY 2015 GMM storage input assumption in the IPM gas module, Table 10-9 shows the total working gas capacity and the average daily injection and withdrawal rates as percentage of working gas capacity for the four types of storage. Note that these are aggregated values (i.e., totals and averages); the actual GMM BOY 2015 inputs to the IPM gas module vary by location and storage type.

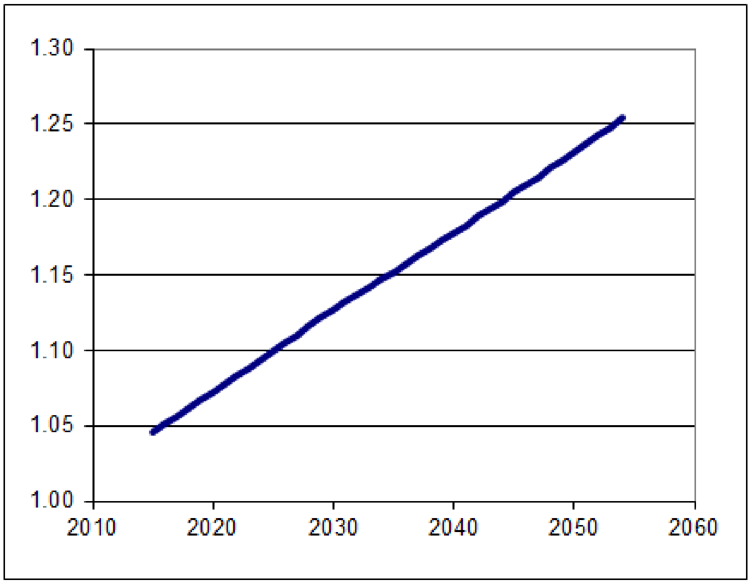
Table 10-9 Storage Capacity and Injection/Withdrawal Rates (BOY 2015)

	Working Gas Capacity (Bcf)	Average Daily Injection Rate (Percent of WG Capacity)	Average Daily Withdrawal Rate (Percent of WG Capacity)
Underground Storage			
20 Day	622	6.3%	9.6%
80 Day	3,522	1.4%	2.3%
Over 80 Days	1,235	0.6%	1.0%
Total	5,379		
LNG Peakshaving Storage	84	0.4%	12.5%

10.8.2 Variable Cost and Fuel Use

In the IPM natural gas module, the natural gas is injected to storage or withdrawn from storage at variable cost. The BOY 2015 variable cost or commodity[119] charge for underground storage facilities is assumed to be 1.6 cents/MMBtu (in real 2011 dollars) and is the same for all underground storage nodes and types. The variable cost for LNG peakshaving facility is much higher at 37.4 cents/MMBtu as it includes variable costs for gas liquefaction (in gas injection cycle) and LNG regasification (in gas withdrawal cycle). The variable cost is assumed to be the same for all LNG peakshaving nodes. A storage cost growth factor shown in Figure 10-20 is applied to the injection/withdrawal cost to reflect cost increase over time. The cost is assumed to grow at an average rate of 0.5 percent per year.

Figure 10-20 Storage Cost Growth Factor



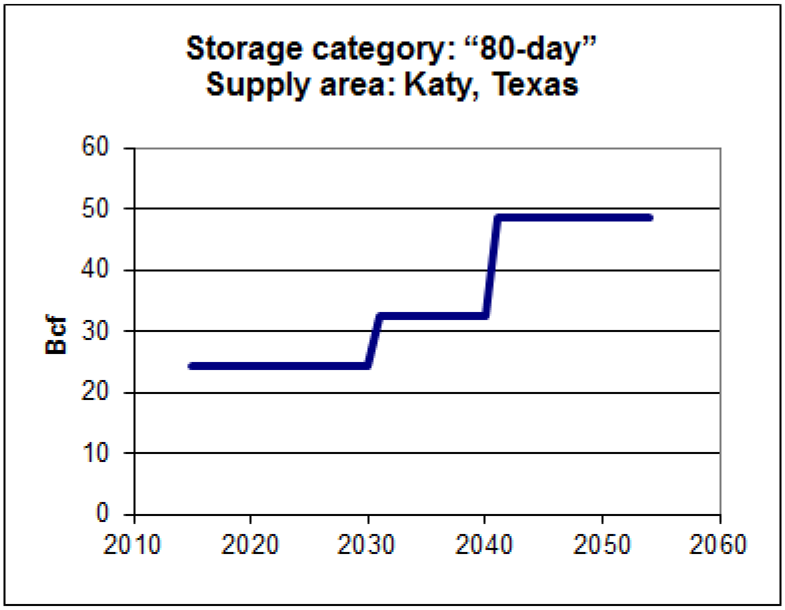
[119] Storage commodity (variable) charge is generally a charge per unit of gas injected and/or withdrawn from storage as per the rights and obligations pertaining to a gas storage lease. Analogous to commodity charges for gas pipeline service

Fuel use for injection and withdrawal for underground storage is 1% of the gas throughput. The withdrawal fuel use for the LNG peakshaving storage is also 1% but the injection fuel use is much higher at 11% of the injection gas as it includes fuel use for gas liquefaction.

10.8.3 Storage Capacity Expansion Logic

The endogenous modeling decision of whether to expand working gas storage capacity is controlled by two constraints, which stipulate minimum and maximum capacity additions for each storage facility and year, and by the levelized capital cost of the storage expansion. The two constraints are specified as input data for each storage facility and year. The minimum constraint forces the model to add working gas capacity to the specified facility and year and the maximum constraint is the cap for the expansion. Figure 10-21 shows projected maximum storage expansion constraints for the "80-day" category storage facility in supply area Katy, Texas.

Figure 10-21 Example Maximum Storage Capacity Expansion



The model is allowed to add working gas capacity to a storage facility within the two constraints if the cost of storage expansion contributes to the optimal solution, i.e., minimizes the overall costs to the power sector, including the capital cost for working gas capacity expansion less their revenues. The model takes into account all possible options/projects including working gas capacity additions for storage facilities in any year that do not violate the constraints and selects the combination of options/projects that provide the minimum objective function value. In this way, storage capacity expansion projects will compete with each other and even with other projects such as LNG regasification capacity expansions, pipeline expansions, etc.

The BOY 2015 levelized storage capital cost (in real 2011 dollars per MMBtu of storage capacity addition) is specified for each of the 190 storage facilities. Table 10-10 lists the average BOY 2015 levelized storage capital cost for the four types of storage facility. Amongst the underground storage facilities the higher capital costs represent more storage cycles[120] that could be achieved in a year. On average, the capital costs for the "80-Day" and "20-Day" storage facilities are assumed to be about 20 percent and 40

[120] One storage cycle is the theoretical time required to completely inject and withdraw the working gas quantity for any given underground gas storage facility or the turnover time for the working gas capacity rating of the facility. The cycle rate of any storage facility is usually expressed in cycles per year and is the number of times the working gas volumes can theoretically be turned over each storage year. The cycle rating for Porous Storage varies from 1 to 6 per year while that for Salt Cavern Storage are as high as 12 per year.

percent, respectively, higher than that of the “Over 80 Days” storage facility. The levelized capital cost for LNG peakshaving storage is much higher due to higher capital cost for the liquefaction unit. The cost growth factors shown in Figure 10-20 are applied to the capital cost to derive the cost increase over time. The capital cost is assumed to grow at an average rate of 0.5 percent per year.

Table 10-10 Base Year 2015 Average Levelized Storage Capital Cost

Storage Type	Average Levelized Storage Capital Cost (2011 $/MMBtu)
Underground Storage	
20-Day	1.19
80-Day	0.99
Over 80 Days	0.83
LNG Peakshaving Storage	5.34

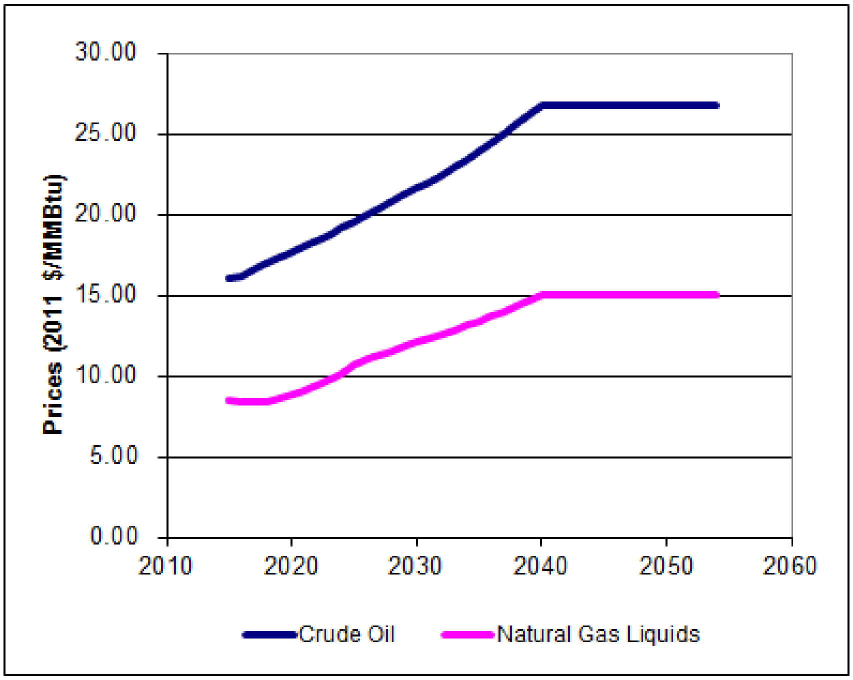
10.9 Fuel Prices

10.9.1 Crude Oil and Natural Gas Liquids Prices

Since a fraction of the hydrocarbons produced in the natural gas exploration and development process are crude oil and NGLs (see columns 2 and 3 in Table 10-5), revenues from crude oil and NGL production play a key role in determining the extent of exploration and development for natural gas. To take into account these revenues, crude oil and NGL price projections are provided as inputs to the IPM natural gas module and factored into the calculation of costs in the IPM objective function.

The crude oil and NGL price projections used in the IPM natural gas module are shown in Figure 10-22. These price projections were adapted from AEO 2013. No attempt was made to project prices beyond 2040 other than to assume that prices remain at their 2040 levels. The projected prices shown in Figure 10-22 are expressed in units of 2011$ per MMBtu. Using a crude oil Btu content of 5.8 MMBtu/Bbl, the projected crude oil prices in Figure 10-22 can be translated into the more familiar units of dollars per barrel (Bbl), in which case, prices in this figure are equivalent to $93/Bbl in 2015, $102/Bbl in 2020, $126/Bbl in 2020, and constant at $155/Bbl from 2040 (in real 2011 dollars) onward.

Figure 10-22 Crude Oil and NGL Prices



10.9.2 Natural Gas Prices

Node-level natural gas prices are outputs of the model and are obtained from the optimal solution of the combined IPM electric power sector and natural gas linear programming (LP) model. From a technical modeling standpoint, the node gas prices are what are called "shadow prices" or "dual variable values" associated with the node mass balance constraints at the optimal LP solution.

10.10 Outputs and Glossary of Terms

10.10.1 Outputs from the IPM Natural Gas Module

The EPA Base Case v.5.13 reports natural gas consumption (in TBtu), Henry Hub and delivered natural gas prices (in $/MMBtu). It also reports natural gas supply (in Tcf), disposition (in Tcf), prices (in $/MMBtu), production (in Tcf) by supply region, end-of-year reserves and annual reserve additions (in Tcf), imports and exports (in Tcf), consumption by end-use sector and census division (in Tcf), prices by census division (in $/MMBtu), and inter-regional pipeline flows and LNG imports (in Bcf).

10.10.2 Glossary of Terms Used in this Section

For ease of reference Table 10-11 assembles in one table terms that have been defined in footnotes throughout this chapter.

Table 10-11 Glossary of Natural Gas Terms Used in Documentation

Term	Definition
Arps-Roberts equation	"Arps-Roberts equation" refers to the statistical model of petroleum discovery developed by J. J. Arps, and T. G. Roberts, T. G., in the 1950's.
Associated gas	Associated gas refers to natural gas that is produced in association with crude oil production, whereas non-associated gas is natural gas that is not in contact with significant quantities of crude oil in the reservoir.

Term	Definition
Basis	In natural gas discussions “basis” refers to differences in the price of natural gas in two different geographical locations. In the marketplace “basis” typically means the difference between the NYMEX futures price at the Henry Hub and the cash price at other market points. In the modeling context “basis” means the difference in natural gas prices between any two nodes at the same instance in time.
Decline curve	A decline curve is a plot of the rate of gas production against time. Since the production rate decline is associated with pressure decreases from oil and gas production, the curve tends to smoothly decline from a high early production rate to lower later production rate. Exponential, harmonic, and hyperbolic equations are typically used to represent the decline curve.
Depleted reservoir storage	A gas or oil reservoir that is converted for gas storage operations. Its economically recoverable reserves have usually been nearly or completely produced prior to the conversion.
Dry gas	Natural gas is a combustible mixture of hydrocarbon gases. Although consisting primarily of methane, the composition of natural gas can vary widely to include propane, butane, ethane, and pentane. Natural gas is referred to as 'dry' when it is almost pure methane, having had most of the other commonly associated hydrocarbons removed. When other hydrocarbons are present, the natural gas is called 'wet'.
Ethane rejection	Ethane rejection occurs when the ethane component in the natural gas stream is not recovered in a gas processing plant but left in the marketable natural gas stream. Ethane rejection is deployed when the value of ethane is worth more in the gas stream than as an a separate commodity or as a component of natural gas liquids (NGL), which collectively refers to ethane, propane, normal butane, isobutane, and pentanes in processed and purified finished form. Information that characterizes ethane rejection by region can play a role in determining the production level and cost of natural gas by region.
Firm and interruptible demand	“Firm” refers to natural gas demand that is not subject to interruptions from the supplier, whereas “interruptible” refers to natural gas demand that is subject to curtailment or cessation by the supplier.
High deliverability storage	High deliverability storage is depleted reservoir storage facility or Salt Cavern storage whose design allows a relatively quick turnover of the working gas capacity.
Lease and plant use	Natural gas for “lease and plant use” refers to the gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and as fuel in gas processing plants.
Liquefied Natural Gas (LNG)	LNG is natural gas converted to liquid form by cooling it down to about -260° F. Known as liquefaction, the cooling process is performed in an “LNG train” (the liquefaction and purification facilities in LNG plants), which reduces the gas to 1/600th of its original volume. The volume reduction resulting from liquefaction makes it cost effective to transport the LNG over long distances, typically by specially designed, double-hulled ships known as LNG carriers. Once the carriers reach their import terminal destination, the LNG is transferred in liquid form to specially designed storage tanks. When needed for customers, the LNG is warmed back to a gaseous state in a regasification facility and transported to its final destination by pipelines.
LNG peakshaving facility	LNG peakshaving facilities supplement deliveries of natural gas during times of peak periods. LNG peak shaving facilities have a regasification unit attached, but may or may not have a liquefaction unit. Facilities without a liquefaction unit depend upon tank trucks to bring LNG from nearby sources.
Load factor	In the natural gas context “load factor” refers to the percentage of the pipeline capacity that is utilized at a given time.
Natural gas liquids (NGL)	Those hydrocarbons in natural gas that are separated from the gas as liquids in gas processing or cycling plants. Generally such liquids consist of ethane, propane, butane, and heavier hydrocarbons.

Term	Definition
Play	A “play” refers to a set of known or postulated natural gas (or oil) accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
Pool	A “pool” is a subsurface accumulation of oil and other hydrocarbons. Pools are not necessarily big caverns. They can be small oil-filled pores. A “field” is an accumulation of hydrocarbons in the subsurface of sufficient size to be of economic interest. A field can consist of one or more pools.
Proven (or proved)	The term “proven” refers to the estimation of the quantities of natural gas resources that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Among the factors considered are drilling results, production, and historical trends. Proven reserves are the most certain portion of the resource base.
RACC price	Refiner Acquisition Cost of Crude Oil (RACC) is a term commonly use in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. The composite cost is the weighted average of domestic and imported crude oil costs.
Raw gas	Raw gas production refers to the volumes of natural gas extracted from underground sources, whereas net gas production refers to the volume of purified, marketable natural gas leaving the natural gas processing plant.
Reserves-to-production (R/P) ratio	Reserves-to-production ratio is the remaining amount of reserves, expressed in years, to be produced with a current annual production rate.
Resource and reserves	When referring to natural gas a distinction is made between “resources” and “reserves.” “Resources” are concentrations of natural gas that are or may become of potential economic interest. “Reserves” are that part of the natural gas resource that has been fully evaluated and determined to be commercially viable to produce.
Resource appreciation	Resource appreciation represents growth in ultimate resource estimates attributed to success in extracting resource from known plays such as natural gas from shales, coal seams, offshore deepwater, and gas hydrates that are not included in the resource base estimates.
Storage "Days Service"	Storage “Days Service” refers to the number of days required to completely withdraw the maximum working gas inventory associated with an underground storage facility.
Storage commodity charge	Storage commodity (variable) charge is generally a charge per unit of gas injected and/or withdrawn from storage as per the rights and obligations pertaining to a gas storage lease. Analogous to commodity charges for gas pipeline service
Storage cycle	One storage cycle is the theoretical time required to completely inject and withdraw the working gas quantity for any given underground gas storage facility or the turnover time for the working gas capacity rating of the facility. The cycle rate of any storage facility is usually expressed in cycles per year and is the number of times the working gas volumes can theoretically be turned over each storage year. The cycle rating for Porous Storage varies from 1 to 6 per year while that for Salt Cavern Storage are as high as 12 per year.

Term	Definition
Unconventional gas	Unconventional gas refers to natural gas found in geological environments that differ from conventional hydrocarbon traps. It includes: (a) “tight gas,” i.e., natural gas found in relatively impermeable (very low porosity and permeability) sandstone and carbonate rocks; (b) “shale gas,” i.e., natural gas in the joints, fractures or the matrix of shales, the most prevalent low permeability low porosity sedimentary rock on earth; and (c) “coal bed methane,” which refers to methane (the key component of natural gas) found in coal seams, where it was generated during coal formation and contained in the microstructure of coal. Unconventional natural gas is distinguished from conventional gas which is extracted using traditional methods, typically from a well drilled into a geological formation exploiting natural subsurface pressure or artificial lifting to bring the gas and associated hydrocarbons to the wellhead at the surface.
Underground storage	The underground storage of natural gas in a porous and permeable rock formation topped by an impermeable cap rock, the pore space of which was originally filled with water.
Wet gas	A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in porous rock formations at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentane. Typical nonhydrocarbon gases that may be present in reservoir natural gas are water vapor, carbon dioxide, hydrogen sulfide, nitrogen and trace amounts of helium.
Working gas	The term “working gas” refers to natural gas that has been injected into an underground storage facility and stored therein temporarily with the intention of withdrawing it. It is distinguished from “base (or cushion) gas” which refers to the volume of gas that remains permanently in the storage reservoir in order to maintain adequate pressure and deliverability rates throughout the withdrawal season.

11. Other Fuels and Fuel Emission Factor Assumptions

Besides coal (chapter 9) and natural gas (chapter 10), EPA Base Case v.5.13 also includes assumptions for residual fuel oil, distillate fuel oil, biomass, nuclear fuels, and various waste fuels. The assumptions described in this chapter pertain to fuel characteristics, fuel market structures, and fuel prices for these fuels. As seen in the previous chapter, there is an endogenous resource costing model for natural gas built into EPA Base Case v.5.13. Coal is represented via an elaborate set of supply curves and a detailed representation of the associated coal transport network. Together they are designed to capture the intricacies of the resource base and market for these fuels which accounted for about 68% of U.S. electric generation in 2012. As with coal, the price and quantity of biomass combusted is determined by balancing supply and demand using a set of geographically differentiated supply curves. In contrast, fuel oil and nuclear fuel prices are exogenously determined and entered into IPM during model set-up as constant price points which apply to all levels of supply. Generally, the waste fuels are also modeled using price points. In this chapter each of the remaining fuels is treated in turn. The chapter concludes with a discussion of the emission factors for all the fuels represented in EPA Base Case v.5.13.

11.1 Fuel Oil

Two petroleum derived fuels are included in EPA Base Case v.5.13. As its name implies distillate fuel oil is distilled from crude oil, whereas residual fuel oil is left as a residue of the distillation process. The fuel oil prices in EPA Base Case v.5.13 are from AEO 2013 and are shown in Table 11-1. They are regionally differentiated according to the NEMS (National Energy Modeling System) regions used in AEO 2013 and are mapped to their corresponding IPM regions for use in EPA Base Case v.5.13.

Table 11-1 Fuel Oil Prices by NEMS Region in EPA Base Case v.5.13

Residual Fuel Oil Prices (2011$/MMBtu)						
NEMS Region	**2016**	**2018**	**2020**	**2025**	**2030**	**2040 - 2050**
ERCT	21.94	26.06	30.09	41.37	53.54	82.89
FRCC	16.93	21.06	25.09	36.37	48.54	77.88
MROE	83.45	87.58	91.61	102.89	115.05	144.40
MROW	20.32	24.45	28.48	39.76	51.92	81.27
NEWE	11.00	11.65	12.27	14.04	24.33	23.74
NYCW	12.29	12.94	13.56	15.33	17.50	22.14
NYLI	12.29	12.94	13.56	15.33	17.50	22.14
NYUP	12.29	12.94	13.56	15.33	17.50	22.14
RFCE	15.05	16.02	16.63	19.13	21.30	25.94
RFCM	92.33	96.45	100.48	111.76	123.93	153.28
RFCW	84.13	88.26	92.29	103.57	115.73	145.08
SRDA	20.92	25.05	29.08	40.36	52.52	81.87
SRGW	83.45	87.58	91.61	102.89	115.05	144.40
SRSE	16.09	20.22	24.25	35.53	47.69	77.04
SRCE	82.14	86.26	90.29	101.57	113.74	143.09
SRVC	16.09	16.74	17.36	19.13	31.30	60.65
SPNO	20.32	24.45	28.48	39.76	51.92	81.27
SPSO	21.94	26.06	30.09	41.37	53.54	82.89
AZNM	21.94	26.06	30.09	41.37	53.54	82.89
CAMX	10.31	14.44	18.47	29.75	41.91	71.26
NWPP	24.78	25.46	26.07	28.17	30.15	34.93
RMPA	83.91	88.03	92.06	103.34	115.51	144.86

Distillate Fuel Oil Prices (2011$/MMBtu)						
NEMS Region	**2016**	**2018**	**2020**	**2025**	**2030**	**2040 - 2050**
ERCT	21.40	22.17	22.96	25.13	27.30	32.56
FRCC	21.56	22.35	23.13	25.29	27.46	32.72
MROE	20.44	21.23	22.01	24.18	26.43	31.68
MROW	20.09	20.90	21.69	23.85	26.04	31.30
NEWE	21.17	21.96	22.75	24.91	27.08	32.34
NYCW	20.36	21.15	21.93	24.09	26.26	31.52
NYLI	20.36	21.15	21.93	24.09	26.26	31.52
NYUP	20.36	21.15	21.93	24.09	26.26	31.52
RFCE	20.74	21.53	22.33	24.48	26.68	31.94
RFCM	20.44	21.23	22.01	24.18	26.43	31.68
RFCW	20.67	21.46	22.25	24.41	26.63	31.89
SRDA	21.40	22.17	22.96	25.13	27.30	32.56
SRGW	20.40	21.19	21.97	24.14	26.38	31.63
SRSE	21.32	22.08	22.86	25.03	27.19	32.46
SRCE	20.92	21.70	22.48	24.64	26.83	32.09
SRVC	21.56	22.35	23.13	25.29	27.46	32.72
SPNO	20.07	20.86	21.64	23.80	25.98	31.25
SPSO	21.31	22.08	22.87	25.04	27.21	32.47
AZNM	22.08	23.01	23.73	25.88	28.13	33.29
CAMX	21.76	22.75	23.47	25.62	27.87	33.02
NWPP	21.68	22.61	23.41	25.55	27.81	32.97
RMPA	22.08	23.01	23.73	25.88	28.13	33.29

11.2 Biomass

Biomass is offered as a fuel for existing dedicated biomass power plants and potential (new) biomass direct fired boilers. In addition to its use as the prime mover fuel for these plants, it is also offered for co-firing to all coal fired power plants. (See section 5.3 for a discussion of the representation of biomass co-firing in EPA Base Case v.5.13.)

EPA Base Case v.5.13 uses biomass supply curves based on those in AEO 2013. These NEMS-coal demand region level supply curves are translated into state-level supply curves for use in EPA Base Case v.5.13 using proportions developed from agricultural statistic district (ASD) level intermediate AEO 2011 biomass supply curves. Plants demand biomass from the supply curve corresponding to the state in which they are located. No inter-state trading of biomass is allowed. Each biomass supply curve depicts the price-quantity relationship for biomass and varies over time. There is a separate curve for each model run year. Each supply curve contains 74 price steps for each run year. The supply component of the curve represents the aggregate supply in each state of four types of biomass fuels: urban wood waste and mill residue, public forestry residue, private forestry residue and agricultural residue[121]. The price component of the curve includes transportation costs, which AEO[122] assumed to be $12/ dry ton for all four biomass types in all states. The supply curves represent the state-specific delivered biomass fuel cost at the plant gate. IPM adds a storage cost of $20/dry ton to each step of the agricultural residue supply curves to reflect the limited agricultural growing season[123].

[121] The AEO 2013 biomass supply is described in the NEMS *Renewable Fuels Module* documentation, http://www.eia.gov/forecasts/aeo/assumptions/pdf/renewable.pdf

[122] http://www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2013).pdf, p. 83.

[123] http://www.extension.iastate.edu/agdm/crops/pdf/a1-22.pdf , http://www.rand.org/content/dam/rand/pubs/technical_reports/2011/RAND_TR876.pdf

Excerpt from Table 11-2 Biomass Supply Curves in EPA Base Case v.5.13

This is a small excerpt of the data in Excerpt from Table 11-2. The complete data set in spreadsheet format can be downloaded via the link found at www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html

Year	Biomass Supply Region	Step Name	Cost of Production (2011$/MMBtu)	Biomass Production (TBtu/Year)
2016	AL	BM01	0	0
2016	AL	BM02	1.42	0.87
2016	AL	BM03	1.74	0
2016	AL	BM04	2.06	25.12
2016	AL	BM05	2.38	0
2016	AL	BM06	2.71	29
2016	AL	BM07	3.03	0
2016	AL	BM08	3.35	2.44
2016	AL	BM09	3.67	0
2016	AL	BM10	3.79	0
2016	AL	BM11	4.00	2.78
2016	AL	BM12	4.13	0.23
2016	AL	BM13	4.32	0
2016	AL	BM14	4.48	2.59
2016	AL	BM15	4.64	3.83
2016	AL	BM16	4.82	0.89
2016	AL	BM17	4.96	0
2016	AL	BM18	5.16	0.28
2016	AL	BM19	5.28	9.94
2016	AL	BM20	5.51	0.24
2016	AL	BM21	5.61	0
2016	AL	BM22	5.85	0.53
2016	AL	BM23	5.93	18.47
2016	AL	BM24	6.19	0.13
2016	AL	BM25	6.25	0.74
2016	AL	BM26	6.54	0
2016	AL	BM27	6.57	0.74
2016	AL	BM28	6.88	0
2016	AL	BM29	6.89	0.74
2016	AL	BM30	7.22	0.74
2016	AL	BM31	7.22	0.14
2016	AL	BM32	7.54	0.74
2016	AL	BM33	7.57	0.07
2016	AL	BM34	7.86	0.74
2016	AL	BM35	7.91	0.10
2016	AL	BM36	8.18	0.74
2016	AL	BM37	8.25	0
2016	AL	BM38	8.51	0.74
2016	AL	BM39	8.60	0
2016	AL	BM40	8.83	0.74
2016	AL	BM41	8.94	0
2016	AL	BM42	9.15	0.74
2016	AL	BM43	9.28	0.28
2016	AL	BM44	9.47	0.74
2016	AL	BM45	9.62	0
2016	AL	BM46	9.79	0.74
2016	AL	BM47	9.97	0
2016	AL	BM48	10.12	0.74

Year	Biomass Supply Region	Step Name	Cost of Production (2011$/MMBtu)	Biomass Production (TBtu/Year)
2016	AL	BM49	10.31	0
2016	AL	BM50	10.44	0.74
2016	AL	BM51	10.65	0
2016	AL	BM52	10.76	0.74
2016	AL	BM53	11.00	0
2016	AL	BM54	11.08	0.74
2016	AL	BM55	11.34	0
2016	AL	BM56	11.41	0.74
2016	AL	BM57	11.68	0.13
2016	AL	BM58	11.73	0.74
2016	AL	BM59	12.03	0
2016	AL	BM60	12.05	0.74
2016	AL	BM61	12.37	0
2016	AL	BM62	12.37	0.74
2016	AL	BM63	12.69	0.74
2016	AL	BM64	13.02	0.74
2016	AL	BM65	13.34	0.74
2016	AL	BM66	13.66	0.74
2016	AL	BM67	13.98	0.74
2016	AL	BM68	14.31	0.74
2016	AL	BM69	14.63	0.74
2016	AL	BM70	14.95	0.74
2016	AL	BM71	15.27	0.74
2016	AL	BM72	15.59	0.74
2016	AL	BM73	15.92	0.74
2016	AL	BM74	16.24	0.74

The supply curves in Excerpt from Table 11-2 represent the biomass available to both the electric and non-electric sectors. In any given region at any point in time the power sector demand from IPM has to be combined with the non-electric sector demand for biomass to obtain the price faced by the power sector. The non-electric sector demand distribution is by census division based on AEO 2013**.** Table 11-3 shows the non-electric sector demand by run year and census divisions.

Table 11-3 Non-Electric Biomass Demand by Census Division in EPA Base Case v.5.13

Non-Electric Biomass Demand (TBtu)							
	Census Division	**2016**	**2018**	**2020**	**2025**	**2030**	**2040-2050**
1	CT, MA, ME, NH, RI, and VT	--	--	--	1.87	0.80	0.51
2	NJ, NY, and PA	--	0.0004	1.70	1.76	1.62	1.15
3	IL, IN, MI, OH, and WI	2.16	2.16	1.16	0.26	2.06	9.01
4	IA, KS, MN, MO, ND, NE, and SD	5.74	5.74	3.07	0.70	0.22	0.14
5	DE, FL, GA, MD, NC, SC, VA, and WV	6.80	6.80	5.13	7.69	5.38	3.98
6	AL, KY, MS, and TN	--	--	--	--	2.92	1.71
7	AR, LA, OK, and TX	1.08	1.08	0.58	0.13	2.33	1.34
8	AZ, CO, ID, MT, NM, NV, UT, and WY	1.10	1.10	0.59	0.13	0.89	0.53
9	CA, OR, and WA	2.70	2.70	7.35	7.02	3.35	1.19

Once the non-electricity demand for biomass is factored in, biomass prices in EPA Base Case v.5.13 are derived endogenously based on the aggregate power sector demand for biomass in each state. The results are unique market-clearing prices for each state. All plants using biomass from that state face the same market-clearing price.

11.3 Nuclear Fuel

The AEO 2013 price assumption for nuclear fuel is used as the nuclear fuel price assumption for 2016-2050 in EPA Base Case v.5.13. The 2016, 2018, 2020, 2025, 2030 and 2040 prices are 0.89, 0.90, 0.90, 0.96, 1.01 and 1.06 2011 $/MMBtu, respectively.

11.4 Waste Fuels

Among the “modeled fuels” shown for existing generating units in the NEEDS v.5.13 (the database which serves as the source of data on existing units for EPA Base Case v.5.13), are a number of waste fuels, including waste coal, petroleum coke, fossil waste, non-fossil waste, tires, and municipal solid waste (MSW). Table 11-4 describes these fuels, shows the extent of their representation in NEEDS, and then indicates the assumptions adopted in EPA Base Case v.5.13 to represent their use and pricing. It should be noted that these fuels are only provided to existing and planned committed units in EPA Base Case v.5.13. Potential new generating units that the model “builds” are not given the option to burn these fuels. In IPM reported output, tires, MSW, and non-fossil waste are all included under existing non-fossil other, while waste coal and petroleum coke are included under coal.

Table 11-4 Waste Fuels in NEEDS v.5.13 and EPA Base Case v.5.13

NEEDS				Supply and Cost	
Modeled Fuel	Number of Units	Capacity (MW)	Description	Modeled By	Assumed Price
Waste Coal	27	2,432	“Usable material that is a byproduct of previous coal processing operations. Waste coal is usually composed of mixed coal, soil, and rock (mine waste). Most waste coal is burned as-is in fluidized-bed combustors. For some uses, waste coal may be partially cleaned by removing some extraneous noncombustible constituents. Examples of waste coal include fine coal, coal obtained from a refuse bank or slurry dam, anthracite culm, bituminous gob, and lignite waste.” http://www.eia.gov/tools/glossary/index.cfm?id=W	Supply Curve Based on AEO 2013	AEO 2013
Petroleum Coke	22	3,170	A residual product, high in carbon content and low in hydrogen, from the cracking process used in crude oil refining	Price Point	$83.3/Ton
Fossil Waste	60	412	Waste products of petroleum or natural gas including blast furnace and coke oven gas. They do not include petroleum coke or waste coal which are specified separately among the “Modeled Fuels”	Price Point	0
Non-Fossil Waste	143	1,600	Non-fossil waste products that do not themselves qualify as biomass. These include waste products of liquid and gaseous renewable fuels (e.g., red and black liquor from pulping processes, digester gases from waste water treatment). They do not include urban wood waste which is included in biomass.	Price Point	0
Tires	2	46	Discarded vehicle tires.	Price Point	0
Municipal Solid Waste	179	2,279	“Residential solid waste and some nonhazardous commercial, institutional, and industrial wastes.” http://www.eia.doe.gov/glossary/index.cfm	Price Point	0

11.5 Fuel Emission Factors

Table 11-5 brings together all the fuel emission factor assumptions as implemented in EPA Base Case v.5.13. For sulfur dioxide, chlorine, and mercury in coal, where emission factors vary widely based on the rank, grade, and supply seam source of the coal, cross references are given to tables that provide more detailed treatment of the topic. Nitrogen oxides (NO_x) are not included in Table 11-5 because NO_x emissions are a factor of the combustion process, and are not primarily fuel based.

Table 11-5 Fuel Emission Factor Assumptions in EPA Base Case v.5.13

Fuel Type		Carbon Dioxide (lbs/MMBtu)	Sulfur Dioxide (lbs/MMBtu)[a]	Mercury (lbs/TBtu)[a]	HCl (lbs/MMBtu)[a]
Coal					
	Bituminous	202.8 - 209.6	0.67 - 6.43	1.82 - 26.07	0.005 - 0.280
	Subbituminous	209.2 - 215.8	0.58 - 1.90	2.03 - 8.65	0.006 - 0.014
	Lignite	212.6 - 219.3	1.46 - 5.67	7.51 - 30.23	0.011 - 0.036
Natural Gas		117.1	0	0.00014	0
Fuel Oil					
	Distillate	161.4	0 - 2.65	0.48	0
	Residual	173.9	1.04	0.48	0
Biomass		--[b]	0.08	0.57	0
Waste Fuels					
	Waste Coal	204.7	7.14	63.9	0.0921
	Petroleum Coke	225.1	7.27	2.66[c]	0.0213
	Fossil Waste	321.1	0.08	0	0
	Non-Fossil Waste	0	0	0	0
	Tires	189.5	1.65	3.58	0
	Municipal Solid Waste	91.9	0.35	71.85	0

Notes:

[a] Also see Table 5-9

[b] CO_2 emissions from biomass are not currently included in EPA Base Case v.5.13. CO_2 emission factors are not currently available for the four aggregate biomass fuels used in the biomass supply representation in EPA Base Case v. 5.13. EPA is currently developing methods to estimate the amount of CO_2 emitted on-site during biomass co-firing at coal fired power plants.

[c] A previous computational error in the mercury emission factor for petroleum coke as presented in Table 6-3 of the EPA report titled Control of Mercury Emissions from Coal-fired Electric Utility Boilers: Interim Report Including Errata, 3-21-02 was corrected (from 23.18 lbs/TBtu to 2.66 lb/TBtu) based on re-examination of the 1999 ICR data for petroleum coke and implementation of a procedure for flagging and excluding outlier values above the 95 percentile value.