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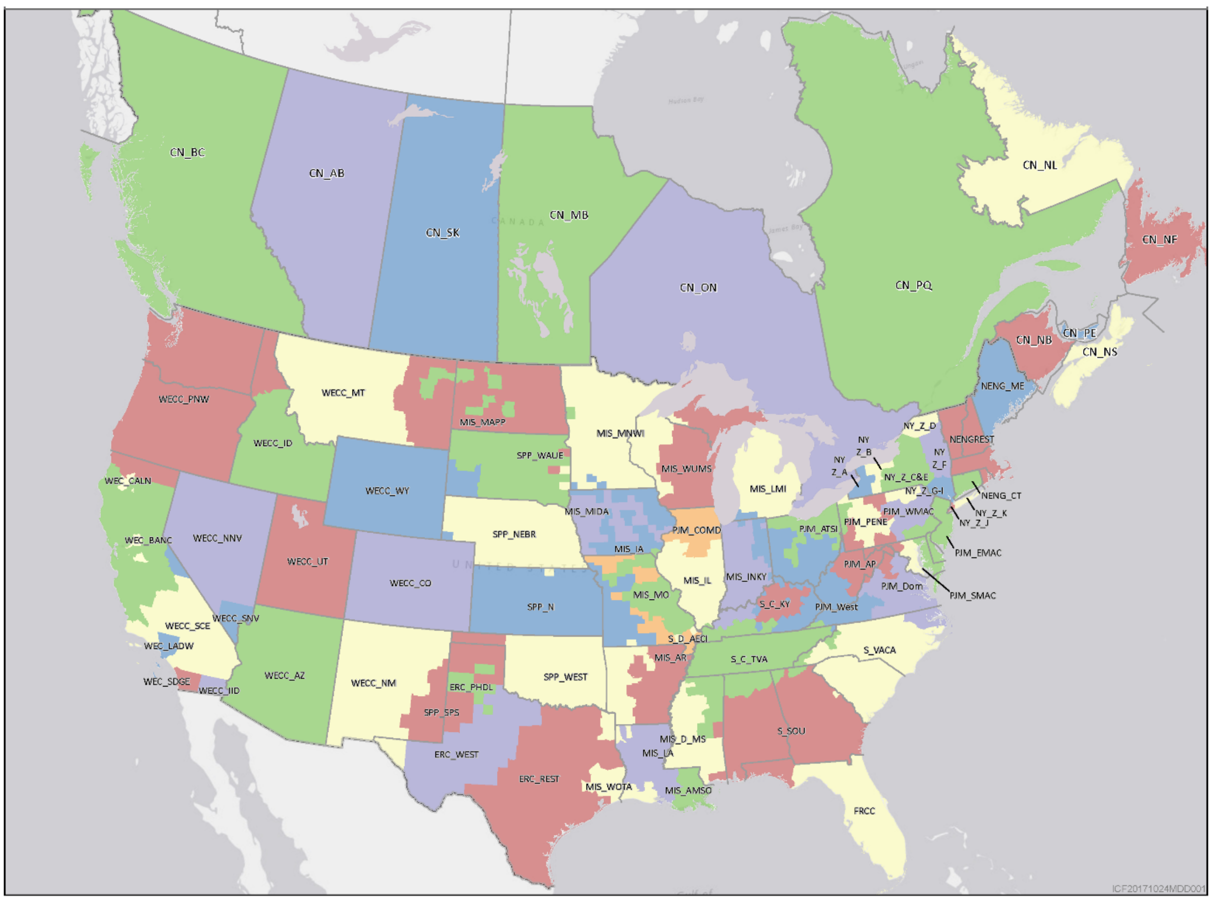
Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model



Cover: EPA's Power Sector Modeling Platform v6 is used by the U.S. Environmental Protection Agency as a platform to conduct various scenario and sensitivity analysis on the key drivers of the power sector behavior and 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 67 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's Power Sector Modeling Platform v6 using the Integrated Planning Model (IPM®) was developed by EPA's Clean Air Markets Division with technical support from ICF, Inc. The IPM is a product of ICF, 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's Power Sector Modeling Platform v6
Using the Integrated Planning Model

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1. Introduction

1.1 Executive Summary

This document describes the nature, structure, and capabilities of the Integrated Planning Model (IPM) and the assumptions underlying the EPA's Power Sector Modeling Platform version 6 (EPA Platform v6) that was developed by the U.S. Environmental Protection Agency (EPA) with technical support from ICF, Inc. 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, 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 introduction chapter summarizes the key modeling capabilities and major data elements that are described in greater detail in the subsequent chapters.

EPA Platform v6 incorporates important structural improvements and data updates with respect to the previous version (v5.13). A new version number (moving from v5 to v6) indicates a substantial change to the architecture (such as this version's significantly more detailed representation of the load segments and seasons). EPA Platform v6's November 2018 Reference Case uses Energy Information Agency's (EIA) Annual Energy Outlook (AEO) 2018 demand projections.

EPA Platform v6 documentation includes assumptions and data values that were used to produce the November 2018 Reference Case; for subsequent runs that examine various future scenarios, we include separate documentation that makes clear where any assumptions or data values differ from the November 2018 Reference Case conditions shown in this core documentation for Platform v6. EPA Platform v6 November 2018 Reference Case serves as the starting point against which key drivers of the power system dynamics (such as level of fuel prices, high or low costs for generation technologies and high or low demand growth) are compared and analyzed. EPA Platform v6 is coupled with a Results Viewer to facilitate easy comparison of different scenario projections and linking them with historical data.

When policy analysis is conducted using EPA Platform v6, relevant assumptions and documentation will be provided elsewhere accordingly.

EPA Platform v6 November 2018 Reference Case 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 as documented in Section 3.9. Section 3.9 contains a detailed discussion of the environmental regulations included in EPA Platform v6, which are summarized below.

- EPA Platform v6 includes the Cross-State Air Pollution Rule (CSAPR) Update Rule, a federal regulatory measure affecting 22 states to address transport under the 1997 and 2006 National Ambient Air Quality Standards (NAAQS) for ozone and fine particles.
- EPA Platform v6 reflects the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.[1]
- EPA Platform v6 includes the Mercury and Air Toxics Rule (MATS),[2] which was finalized in 2011. MATS establishes National Emissions Standards for Hazardous Air Pollutants (NESHAP) for the "electric utility steam generating unit" source category.

[1] 80 FR 64510

[2] 82 FR 16736

- EPA Platform v6 reflects current and existing state regulations. A summary of these state regulations can be found in Table 3-23.
- EPA Platform v6 reflects the final actions EPA has taken to implement the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations Final Rule[3]. 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 summer 2017) that will be in place for EGUs are represented in the EPA Platform v6.
- EPA Platform v6 also includes three non-air federal rules affecting EGUs: National Pollutant Discharge Elimination System-Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities, Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; and the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category.[4]

Table 1-1 lists key updates included in EPA Platform v6 incremental to the previous major platform (v5) with the corresponding data sources. Highlighted items are the updates incremental to the previous release of EPA's v6 Platform (May 2018). The updates are listed in the order in which they appear in the documentation.

Table 1-1 Key Updates in the EPA Platform v6 November 2018 Reference Case

Description	For More Information
Modeling Framework	
Modeling time horizon out to 2050 with eight model run years (2021, 2023, 2025, 2030, 2035, 2040, 2045, 2050)	Table 2-1
Incorporation of three seasons	Section 2.3.5
Increasing the number of load segments to 72 per year	Section 2.3.5
All costs and prices are in 2016 dollars	
Power System Operation	
Updates based on recent data from EIA, NERC, and FERC	Chapter 3
Updated inventory of state emission regulations	Section 3.9
CSAPR, MATS, and BART are reflected	Section 3.9.3
Updated RPS standards for CT and NJ	Table 3-19
Updated inventories of NSR, state, and citizen settlements (as of May 2018)	Table 3-24, Table 3-25, and Table 3-26
Updated transmission Total Transfer Capability's (TTC) and regional reserve margins (2015-2016 ISO/RTO NERC Reports)	Table 3-5 and Table 3-21
AEO 2018 NEMS region level electricity demand is disaggregated to IPM model region level. IPM model region level peak load projection is based on the future load factors from NERC 2017 ES&D and AEO 2018	Section 3.2
Implemented the NY minimum oil burn rule through facility level minimum generation constraints	Table 3-13

[3] 70 FR 39104

[4] 79 FR 48300, 80 FR 21302, 80 FR 67838

Description	For More Information
Updated ELG costs	Section 3.9.5
Generating Resources	
Updates to NEEDS planned units, retirements, and emission control configurations (July 2018 EIA Form 860m, 2017 EIA Form 860 ER, AEO 2018, AMPD 2017 and recent lists of deactivations from PJM, MISO, and ERCOT)	Table 4-1
Updates to unit level NO_x rates (EPA ETS 2017, 2016 CARB, and 2014 NEI)	Section 3.9.2
Providing life extension costs to allow existing nuclear units to continue operation over the extended 80 year life (Sargent & Lundy 2017)	Section 4.5.1
Updated cost and performance characteristics for potential (new) conventional, renewable, and nuclear generating units (AEO 2017 and NREL ATB 2017)	Table 4-13 and Table 4-16
Wind and solar technologies have revised cost and resource base estimates, capacity credit calculation methodology, hourly generation profiles, and time of day based load segments to improve curtailment modeling (NREL 2017)	Section 4.4.5
Implemented energy storage options based on AEO 2018 cost and performance assumptions. Included the energy storage mandates for CA, NY, NJ, OR and MA.	Table 4-35 and Table 4-36
Emission Control Technologies	
Complete update of cost and performance assumptions for SO_2, NO_x, Hg, HCl and CO_2 emission controls based on engineering studies by Sargent & Lundy	Chapter 5
Inclusion of cost and performance assumptions for coal-to-gas conversion and capability to model heat rate improvement technologies	Section 5.7
Carbon Capture, Transport, and Storage	
Updated CO_2 storage cost curves based on a $75 crude oil price, average EOR efficiency of 10 Mcf of CO_2 per incremental barrel of crude oil and adjustment to geologic storage curve for industrial uses of storage capacity	Table 6-4
Updated CO_2 transportation cost adders	Table 6-5
Coal	
Complete update of coal supply curves and transportation matrix (Wood Mackenzie 2016 and Hellerworx 2016)	Table 7-25 and Table 7-26
Natural Gas	
Natural gas assumptions modeled through annual gas supply curves and IPM region level seasonal basis differentials (ICF 2017)	Section 8.6
Other Fuels	
Incorporation of biomass supply curves at a state and IPM region level (DOE 2016)	Section 9.2
Update of price assumptions for fuel oil, nuclear fuel, and waste fuel (AEO 2017)	Chapter 9
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	Chapter 10
Use of separate capital charge rates for retrofits based on utility and merchant finance structures	Section 10.4.2
Cost adder for new non-peaking fossil units associated with future CO_2 emissions	Section 10.7.3
Incorporated the implications of the Tax Reform Bill in the discount rate and capital charge rate calculations	Section 10.3

Table 1-2 lists the types of plants included in the EPA Platform v6.

Table 1-2 Plant Types in EPA Platform v6

Conventional Technologies
Coal Steam
Oil/Gas Steam
Combustion Turbine
Combined-Cycle Combustion Turbine
Integrated Gasification Combined-Cycle (IGCC) Coal
Ultra-Supercritical Coal with and without Carbon Capture
Fluidized Bed Combustion
Nuclear
Renewables and Non-Conventional Technologies
Hydropower
Pumped Storage
Energy Storage
Biomass
Onshore Wind
Offshore Wind
Fuel Cells
Solar Photovoltaics
Solar Thermal
Geothermal
Landfill Gas
Other[1]

Note:

[1] Included are fossil and non-fossil waste plants.

Table 1-3 lists the emission control technologies available for meeting emission limits in EPA Platform v6.

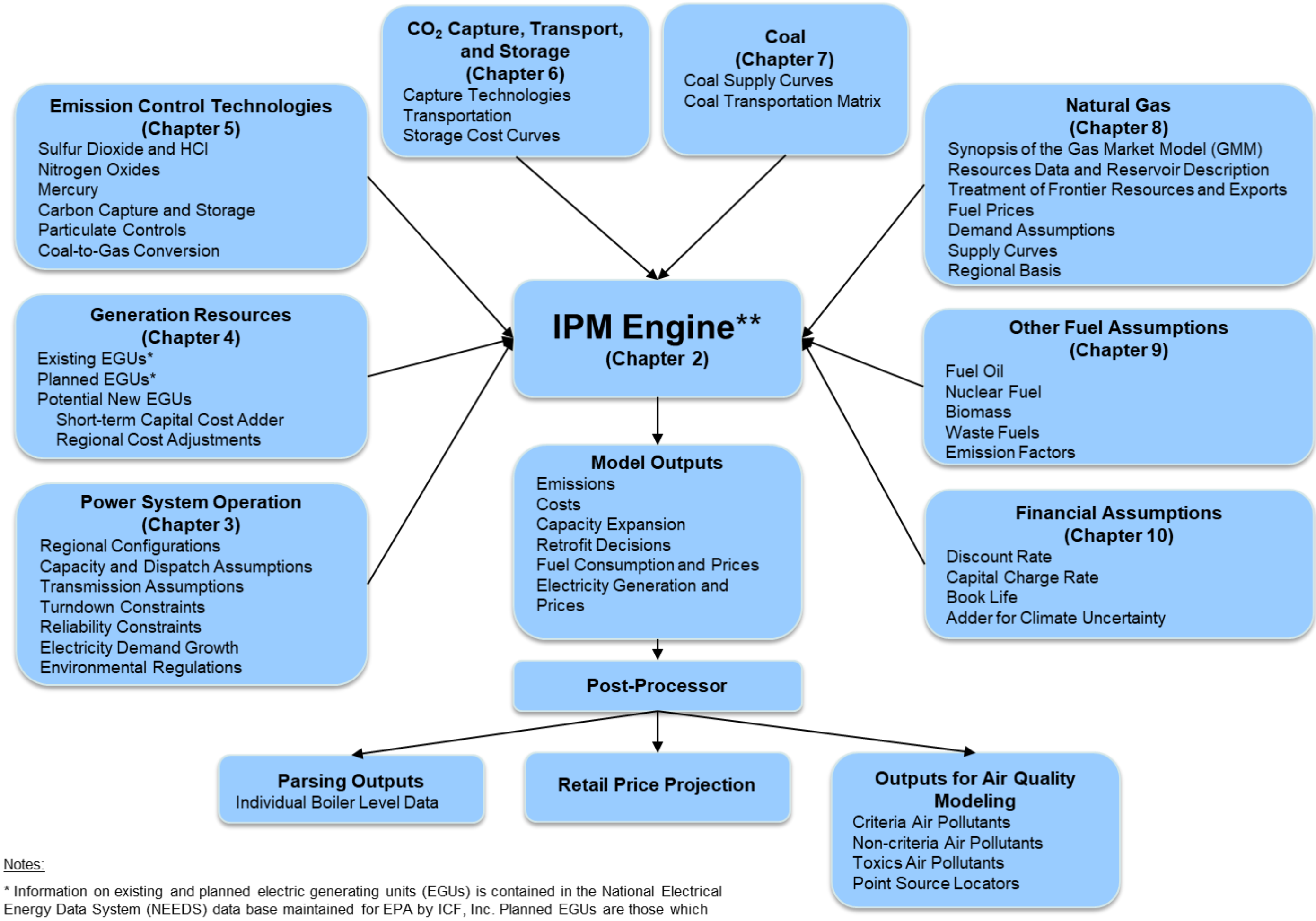
Table 1-3 Emission Control Technologies in EPA Platform v6

Sulfur Dioxide (SO_2)
Limestone Forced Oxidation (LSFO)
Lime Spray Dryer (LSD)
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
Hydrogen Chloride (HCl)
Dry Sorbent Injection (with milled Trona)
Carbon Dioxide (CO_2)
Heat rate improvement
Coal-to-gas
Carbon Capture and Sequestration

Notes:
Fuel switching between coal types is also a compliance option for reducing emissions in EPA Platform v6.

Figure 1-1 provides a schematic of the components of the modeling and data structure used for EPA Platform v6. The document contains separate chapters devoted to all the key components shown in Figure 1-1. Chapter 2 provides an overview of IPM's modeling framework (also 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 Platform v6. Chapter 3 covers the power system operating characteristics captured in EPA Platform v6. 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. The next three chapters discuss the representation and assumptions for fuels in the EPA Platform v6. Coal is covered in chapter 7, natural gas in chapter 8, and other fuels (i.e., fuel oil, biomass, nuclear fuel, and waste fuels) in chapter 9 (along with fuel emission factors). Finally, Chapter 10 summarizes the financial assumptions.

Figure 1-1 Modeling and Data Structures in EPA Platform v6



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, Inc. Planned EGUs are those which were under construction or had obtained financing at the time EPA's Platform v6 was finalized.

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

1.2 Review and Ongoing Improvement of the Integrated Planning Model

A customized, fully documented version of the data assumptions underlying IPM has been developed and used by EPA to help inform power plant air regulatory and legislative efforts for over 20 years, following the enactment of the Clean Air Act Amendments of 1990. The model has been tailored to meet the unique environmental considerations important to EPA, while also fully capturing the detailed and complex economic and electric dispatch dynamics of power plants across the country. It has been EPA's goal to thoroughly explain and document the agency's use of the model in a transparent and publicly accessible manner, while also providing for concurrent channels for improving the model's assumptions and representation by soliciting constructive feedback so that the model may be continually improved. This includes making all inputs and assumptions to the model, as well as all output files from the model, publicly available on EPA's website (and, when applied to inform a rulemaking, in the relevant publicly accessible regulatory docket).

EPA's use of IPM depends upon a variety of environmental, policy, and regulatory considerations. Generally, EPA's version of the model input assumptions has undergone significant updates and architectural improvements every 2-4 years in order to best reflect the evolving dynamics of the power sector, and smaller ongoing updates (1-2 times a year) to reflect changes in fleet composition (retirements, new capacity builds, and installed retrofits). Currently, EPA's implementation of IPM is in its sixth major version, not including Coal and Electric Utility Model (CEUM), the model used by EPA before its use of IPM.

Federal Regulatory efforts:

EPA has used IPM for many regulatory efforts affecting the power sector, including:

- The NO_x SIP Call, the Clean Air Interstate Rule (2004-2006), the Clean Air Visibility Rule, the Clean Air Mercury Rule (2005), the Cross-State Air Pollution Rule and Updates (2010-2016), the Mercury and Air Toxics Rule (2012), the Clean Power Plan (2015), and various Ozone, PM NAAQS, and regional haze regulatory efforts.

National Legislative efforts:

EPA has used IPM to support legislative efforts that affect the power sector, including:

- The Clear Skies Act (2002-2005), the Clean Air Planning Act (2002-2005), the Clean Power Act (2002-2005), the Climate Stewardship and Innovation Act (2007), the Low Carbon Economy Act (2007-2008), the Lieberman-Warner Climate Security Act (2007-2008), and the American Clean Energy and Security Act (2008-2009).

Notable Versions and Updates/Improvements/Enhancements:

EPA Base Case using IPM - 1996

- Designed for projections covering the US with 4 run years
- Disaggregated the US into 17 IPM model regions
- Modeled coal and gas markets through coal and gas supply curves

EPA Base Case using IPM – 1998

- Updated unit inventory of power plants
- Increased the number of IPM model regions covering the US from 17 to 21
- Disaggregated New York into 4 IPM model regions
- Increased the number of run years from 4 to 6

EPA Base Case 2000 using IPM Version 2.1 (2000-2003)

- Updated unit inventory of power plants
- Increased the number of IPM model regions covering the US from 21 to 26
- Increased the modeling time horizon to 2030
- Increased the overall number of emission control technology options modeled
- Incorporated Activated Carbon Injection (ACI) retrofit options for mercury control modeling
- Expanded coal supply representation

EPA Base Case 2004 using IPM Version 2.1.9 (2004)

- Updated unit inventory of power plants
- Improved the characterization of SO_2 and NO_x emissions
- Revised coal choice assumptions for individual coal units
- Updated natural gas supply curves, incorporating recommendations from the natural gas peer review

EPA Base Case 2006 using IPM Version 3 (2005-2009)

- Updated unit inventory of power plants
- Improved environmental pollution control retrofit assumptions
- Increased the number of IPM model regions covering the US from 26 to 32 to enhance regional representation
- Increased the number of load segments from 5 to 6 to enhance electric load representation
- Updated natural gas supply curves based on ICF's North American Natural Gas Systems Analysis (NANGAS) model
- Updated coal supply curves
- Enhanced electric transmission capabilities and imports/exports
- Enhanced power plant representation detail

EPA Base Case using IPM Version 4.10 (2010-2013)

- Updated unit inventory of power plants
- Integrated Canada into the modeling framework
- Incorporated HCl emissions and Dry Sorbent Injection retrofit options
- Improved resolution of Carbon Capture and Storage, including regional storage representation and transportation network
- Updated coal supply modeling with significantly more resolution of coal mine data
- Incorporated natural gas resource model for North America to reflect emerging shale resource
- Enhanced power plant representation detail to support toxic air pollutant emissions and controls

EPA Base Case using IPM Version 5 (2014-2017)

- Updated unit inventory of power plants
- Doubled the number of IPM model regions from 36 to 64
- Revised environmental pollution control retrofit assumptions for conventional pollutants and toxic emissions
- Incorporated additional technology options for new power plants
- Overhauled coal supply assumptions, with even further resolution to reflect mine-by-mine geography and coal characteristics
- Improved coal transportation network by modeling each individual coal plant as its own coal demand region
- Updated gas modeling assumptions to reflect natural gas shale supply/trends and pipeline capacity expansion

Background on EPA Base Case using IPM Review:

Peer Reviews:

EPA conducts periodic formal peer review of the EPA Base Case application of IPM. These reviews have included separate expert panels on the model itself, and EPA's key modeling input assumptions. For example, separate panels of independent experts have been convened to review IPM's coal supply and transportation assumptions, natural gas assumptions, and model formulation.

EPA Base Case v5.13 Data Assumption Review

In 2015, an independent peer review panel provided expert feedback on whether the analytical framework, assumptions, and applications of data in IPM were sufficient for the EPA's needs in estimating the economic and emissions impacts associated with the power sector. The panel identified a number of strengths associated with the model and underlying data and assumptions. For example, the report stated that EPA's platform exceeds other model capabilities in providing a relevant feedback mechanism between the electric power model and key fuel inputs that drive simulation results[5].

Other strengths the panel identified include:

- The detail with which pollution control technology options and costs are represented
- The level of detail at which federal Clean Air Act (CAA) regulations are represented
- The ability of the model to allow for the detailed representation of a variety of potential changes in energy and environmental policies, including important features of market-based programs
- The accuracy of the emissions control costs and their relationship to retirement decisions
- The expansion of model regions from 32 to 64, which allows the model to better represent current power market operations and existing transmission bottlenecks even within regional transmission organization (RTO) regions
- Continuous updates of the representation of domestic coal and natural gas market conditions

The peer review panel has also provided several areas for investigation and additional recommendations for the EPA's consideration, including:

- Improved documentation of the input assumptions
- Changes to certain cost functions and financial assumptions
- Consideration of certain improvements to the Base Case architecture (additional seasonal representation, representation of electric demand, transmission considerations, and renewable energy representation among others)

The updated EPA Platform v6 using IPM addresses many of these recommendations (seasons, renewable energy representation, regional representation, etc.), and this peer review has also lead to additional work at EPA to further understand and better represent some of the emerging issues in the power sector. EPA intends to add more capabilities and continue to refine the modeling platform to reflect these comments, and adopt those changes at an appropriate time after further research and testing of the model.

Coal Market Assumptions Review

In 2003, a group of experts in the field of cost, quality, reserves, and availability of coal were selected as peer reviewers to assess whether the choice, use, and interpretation of data and methodology employed in the derivation of the IPM coal supply curves was appropriate and analytically sound. The peer reviewers were charged with:

- Evaluating the appropriateness of the overall methodology used to develop the new coal supply curves,
- Assessing the adequacy of the individual components employed in building the coal supply curves in terms of both the approach and data used,
- Assessing the technical soundness of the resulting coal supply curves for each coal type and supply region in terms of the cost/quantity relationship and the characteristics associated with the coal (e.g., sulfur, heat, and mercury content), and
- Assessing the appropriateness of the use of this set of supply curves for use in production cost models in general (of which IPM is a particular example).

The review process produced useful and specific recommendation for improvements and updates to the coal supply information that is represented in IPM, which were subsequently incorporated into the model.

[5] https://www.epa.gov/airmarkets/response-and-peer-review-report-epa-base-case-version-513-using-ipm

Gas Market Assumptions Review

In 2003, a peer review of the natural gas supply assumptions implemented in EPA Base Case using IPM v.2.1.6 (2003) was performed. The peer reviewers were charged with evaluating the following:

- The appropriateness of the representation of all the key natural gas market fundamentals in NANGAS,
- The reasonableness of the natural gas supply curves, non-electricity demand assumptions and transportation adders, and
- The reasonableness of the iteration process between NANGAS and IPM.

The review commended the comprehensiveness of the approach used to generate the gas supply curves implemented in the EPA Base Case. The review further identified assumptions that could be revised in generating a new set of natural gas supply curves, as well as nonelectric-sector gas demand curves, for the next update of the EPA Base Case.

IPM Formulation Review

Conducted in 2008, this peer review focused on IPM's core mathematical formulation. The objective of the review was to obtain expert feedback on the adequacy of the formulation in representing the economic and operational behavior of the power sector over a modeling time horizon of 20-50 years.

The panel identified several strengths of IPM, including:

- The model's ability to compute optimal capacity that combined short-term dispatch decisions with long-term investment decisions.
- The model's integration of relevant markets, including the electric power, fuel, and environmental markets, into a single modeling framework.
- And the model's ability to represent a very detailed level of data with regard to the emissions modeling capability.

The peer review panel also provided several areas for investigation and recommendations for the EPA's consideration. These peer reviews led to concrete changes, enhancements, and updates to the IPM framework to better represent the power sector and related markets (i.e., fossil fuels).

Regulatory Review:

The formal rulemaking process provides opportunity for expert review and comment by key stakeholders. Formal comments as part of a rulemaking are reviewed and evaluated, and changes/updates are made to IPM where appropriate. Stakeholders to EPA regulatory efforts are a diverse group, including regulated entities and impacted industries, fuel supply companies, states, environmental organizations, developers of other models of the U.S. electricity sector, and others. The feedback provides a highly detailed review of input assumptions, model representation, and model results.

Other Uses and Reviews:

- IPM has been used by many regional organizations for regulatory support, including the Regional Greenhouse Gas Initiative (RGGI), the Western Regional Air Partnership (WRAP), and the Ozone Transport Assessment Group (OTAG). IPM has also been used by other Federal agencies (e.g., FERC, USDA), environmental groups, and many electric utilities,
- The Science Advisory Board reviewed EPA's application of IPM as part of the CAAA Section 812 prospective study 1997-1999.
- The President's Council of Economic Advisors (2002-2003) performed head-to-head comparison of IPM and EIA's NEMS system for use in multi-pollutant control analysis.

- IPM has been used in a number of comparative model exercises sponsored by Stanford University’s Energy Modeling Forum and other organizations.

EPA Platform v6 using IPM represents another major iteration of EPA’s application of IPM, with notable structural and platform improvements/enhancements, as well as universal updates to reflect the most current set of data and assumptions.

2. Modeling Framework

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

IPM is a long-term capacity expansion and production-costing model of the electric power sector. Its mathematical formulation is based on a Linear Programming (LP) structure. The structure provides for several advantages, one of which is the guarantee of a globally optimal solution. Fast and efficient commercial solvers exist to solve LP models. The solved dual variables (also known as shadow prices) of each constraint modeled in IPM inform EPA rule-making or policy analysis process in regards to the marginal cost pricing of energy, capacity, fuels, and emission allowances. Also, reasonable solution times for an LP model allow EPA to gain insights by modeling a large number of scenarios in a relatively short period of time.

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's model structure and formulation (2.2), key methodological characteristics (2.3), and programming features (2.4), 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 power plant 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 that are placed on the power, emissions, and fuel markets. The constraints include, but are not limited to, emission limits, transmission capabilities, renewable generation requirements, and fuel market constraints. The model is designed to accommodate complex treatment of emission regulations involving trading, banking, and special provisions affecting emission allowances (e.g., 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 operational characteristics. The model regions 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 the Independent System Operators (ISOs) that 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 utility-owned existing electric generating units, including renewable resources, as well as independent power producers and cogeneration facilities selling electricity to the grid, are modeled.

IPM provides a detailed representation of new and existing resource options. These include fossil, nuclear, renewable, and non-conventional options. Fossil options include coal steam, oil/gas steam, combined cycles, and gas-fired simple cycle combustion turbines. Renewable options include wind, landfill gas, geothermal, solar thermal, solar photovoltaic, and biomass. Non-conventional options include fuel cell, pump storage, and battery storage.

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 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:

<u>Air Regulatory Assessment:</u> 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.

<u>Integrated Resource Planning:</u> 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.

<u>Strategic Planning:</u> 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.

<u>Options Assessment:</u> 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.

<u>Cost and Price Estimation:</u> 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 Platform v6.

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.

<u>Generation Dispatch Decision Variables:</u> IPM includes decision variables representing the generation from each model power plant.[6] 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.

<u>Capacity Decision Variables:</u> 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.

<u>Transmission Decision Variables:</u> 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.

<u>Emission Allowance Decision Variables:</u> 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.

<u>Fuel Decision Variables:</u> 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

[6] 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 Platform v6, see section 4.2.6.

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 7-4). 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.

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 Platform v6 are:

<u>Reserve Margin Constraints:</u> 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 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 assumptions.

<u>Demand Constraints:</u> The model categorizes regional annual electricity demand into seasonal load curves which are used to form winter (December 1 – February 28), winter shoulder (March 1 – April 30, October 1 – November 30), and summer (May 1 – September 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.

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

<u>Turn Down Constraints:</u> 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.

<u>Emissions Constraints:</u> 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.

<u>Transmission Constraints:</u> 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 (i.e., joint limits) to different regions.

<u>Fuel Supply Constraints:</u> 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 10 contain detailed discussions of the cost and performance assumptions specific to EPA Platform v6. This section provides an overview of the essential methodological and structural features of IPM that extend beyond the assumptions that are specific to EPA Platform v6.

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 November 2018 Reference Case and anticipated policy case runs. For EPA Platform v6, IPM employed an aggregation algorithm, which allowed 21,931 actual existing electric generating units to be represented by 5,747 model plants. Section 4.2.6 describes the aggregation procedure used in the EPA Platform v6.

Retrofit and Retirement Options: IPM also utilizes model plants to represent the retrofit and retirement options that are available to existing units. EPA Platform v6 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 Chapter 5 for a detailed discussion of the options that are included in the EPA Platform v6.) EPA Platform v6 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[7]. 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 Platform v6, a maximum of three stages of retrofit options are provided (child, grandchild and great-grandchild). For example, an existing model plant may retrofit with an activated carbon injection (ACI) for mercury control in one model run year (stage 1), with a selective catalytic reduction (SCR) control for NO_x 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

[7] 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 retrofit or retire a portion of the model plants capacity. IPM's standard model plant outputs explicitly present these partial investment decisions.

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 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.

Parsing: Since EPA Platform v6 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.)

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. Although IPM can represent an individual year in an analysis time horizon, 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. IPM takes into account the costs in all years in the planning horizon while reporting results only for model run years. (See section 2.3.3 below for further details.)

The analysis time horizon for EPA Platform v6 extends from 2021 through 2054. The eight years designated as "model run years" and the mapping of calendar years to run years is shown in Table 2-1.

Table 2-1 Run Year and Analysis Year Mapping Used in EPA Platform v6

Run Year	Years Represented
2021	2021
2023	2022 - 2023
2025	2024 - 2027
2030	2028 - 2032
2035	2033 - 2037
2040	2038 - 2042
2045	2043 - 2047
2050	2048 - 2054

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. This should be considered when assessing model projections from the last output year.

2.3.3 Cost Accounting

As noted earlier in the chapter, IPM is a dynamic linear programming model that solves for 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:

- 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 lower 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 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,[8] rather than delivered sales,[9] 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, which 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 24-step piecewise linear representation of the LDC.

IPM can include any number of user-defined seasons. A season can be a single month or several months. EPA Platform v6 contains three seasons: summer (May through September), winter (December through February), and a winter shoulder season (October, November and March, April). The summer season corresponds to the ozone season for modeling seasonal NO_x policies. The residual seven months are split into a three-month winter and four-month winter shoulder seasons to better capture winter peak and seasonality in wind and solar hourly generation profiles. Separate summer, winter, and winter shoulder season 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 summer season.

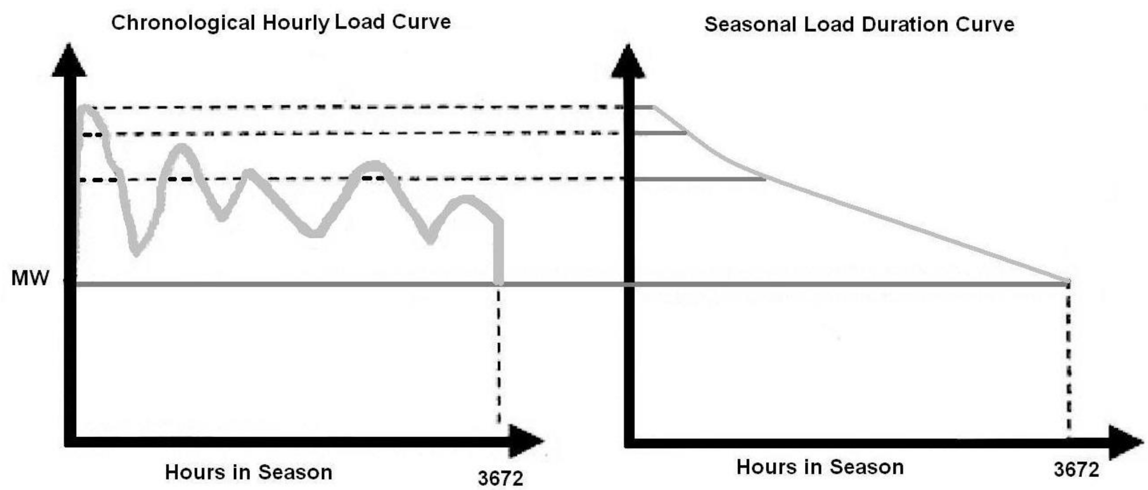
Use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, in most regions air conditioner cycling only

[8] 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.

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

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.

Figure 2-1 Hypothetical Chronological Hourly Load Curve and Seasonal Load Duration Curve in EPA Platform v6 for Summer



In EPA Platform v6, regional forecasts of peak and total electricity demand from AEO 2018 and hourly load curves from FERC Form 714 and ISO/RTOs[10] 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 because of future variations in electricity consumption patterns.[11]

Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 2-2. EPA Platform v6 uses 24 load segments in its seasonal LDCs. Figure 2-2 illustrates and the following text describes the 24-segment LDCs used in EPA Platform v6. 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. In EPA Platform v6, the hours in the LDC are initially clustered into six groups. Group 1 incorporates 1% of all hours in the season with the highest load. Groups 2 to 6 have 4%, 10%, 30%, 30%, and 25% of the hours with progressive lower levels of demand. Each of these 6 groups of hours are further separated into four time of day categories to result in a possible maximum of 24 load segments. This approach better accounts for the impact of solar generation during periods of high demand. The four time-of-day categories are 8PM – 6AM, 6AM – 9AM, 9AM – 5PM and 5PM – 8PM. Plants are dispatched to meet this load based on economic considerations and operating constraints. The most cost effective plants are assigned to meet

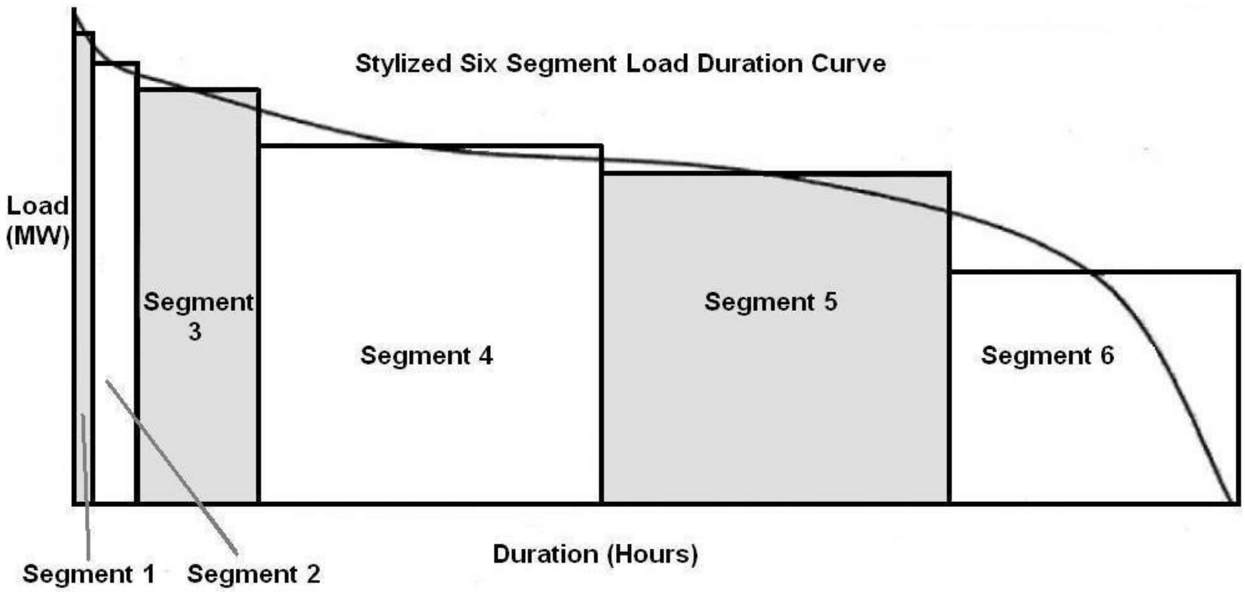
[10] The 2016 load curves are used for IPM model regions in ERCOT. The 2011 load curves are used for all remaining model regions. For further details, see Section 3.2.3.

[11] For further details in regards to the source of the load factors used in EPA Platform v6, see Section 3.2.2.

load in all 24 segments of the load duration curve. This is discussed in greater detail in section 2.3.6 below.

Table 2-2 contains data of the seasonal 2021 load duration curves in each of the 67 model regions in the lower continental U.S. for EPA Platform v6.

Figure 2-2 Stylized Depiction of a Six Segment Load Duration Curve Used in EPA Platform v6

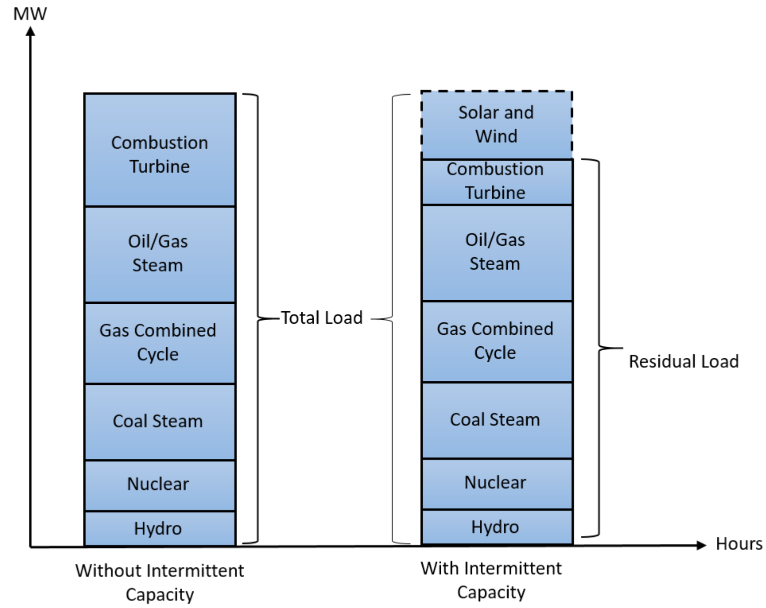


2.3.6 Dispatch Modeling

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 Platform v6. In Figure 2-3, two hypothetical load segments are subdivided according to the type of generation resource that responds to the load requirements represented in that segment. 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. In the load segment with non-dispatchable generating capacity such as solar, the conventional power plants are dispatched to the residual load level where residual load is defined as the difference between the total load and the load met by non-dispatchable resources.

Figure 2-3 Stylized Dispatch Order in Illustrative Load Segments



Note: Figure 2-3 does not include all the plant types that are modeled in EPA Platform v6. 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 Platform v6 in one of two alternative ways: (1) through a set of supply curves (coal, natural gas, and biomass) or (2) through an exogenous price stream (fuel oil and nuclear fuel). With the first approach, 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 Platform v6 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 7 to 9.

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 Platform v6 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 Platform v6 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 Scenario Analysis and Regulatory Modeling

One of the most notable features of IPM is its detailed and flexible modeling features enabling for scenario analysis involving different outlooks of key drivers of the power sector and environmental regulations. Treatment of environmental 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 utilized in EPA Platform v6.

2.4 Hardware and Programming Features

IPM produces model files in standard MPS linear programming format. The model runs on most PC-platforms. Hardware requirements are highly dependent on the size of a particular model run. For example, with almost 19.7 million decision variables and 1.32 million constraints, EPA Platform v6 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 Platform v6, 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 8.3 (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 electric generating units (a process called "parsing," see section 2.3.1) and creates input files in flat-file format as required by EPA's air quality models.

In preparation for a model run, IPM requires an extensive set of input parameters. The input parameters are discussed in Section 2.5.1 below. Results from a model run are presented in a series of detailed reports. The reports are described in Section 2.5.2 below.

2.5 Model Inputs and Outputs

2.5.1 Data Parameters for Model Inputs

IPM requires input parameters that characterize the U.S. electric system, economic outlook, fuel supply and air regulatory framework. Chapters 3-10 contain detailed discussions of the values assigned to these parameters in EPA Platform v6. This section simply lists the key input parameters required by IPM:

Electric System

Existing Generating Resources

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

New Generating Resources

- Cost and Operating Characteristics
- Resource Limits and Generation Profiles
- Limitations on Availability

Other System Requirements

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

Economic Outlook

Electricity Demand

- Firm Regional Electricity Demand
- Load Curves

Financial Outlook

- Capital Charge Rates
- Discount Rate

Fuel Supply

Fuel Supply Curves for Coal, Gas, and Biomass

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

Regulatory Outlook

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

- Other Air Regulations
- Non-air Regulations (affecting electric generating unit operations)

2.5.2 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

List of tables that are uploaded directly to the web:

Table 2-2 Load Duration Curves used in EPA Platform v6

3. Power System Operation Assumptions

This section describes the assumptions pertaining to the North American electric power system as represented in EPA Platform v6.

3.1 Model Regions

EPA Platform v6 models the U.S. 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[12]) as an integrated network[13].

There are 67 IPM model regions covering the U.S. 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 U.S. 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 approximate 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, PJM, and SPP 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 14 IPM regions, PJM assessment area is disaggregated into 9 IPM regions, and SPP is disaggregated into 5 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 8 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 U.S. regions.

The NERC assessment region SERC is divided into Kentucky, TVA, AECI, the Southeast, and the Carolinas. New England is disaggregated into CT, ME, and rest of New England regions. ERCOT is also disaggregated into three regions.

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 along provincial political boundaries.

Figure 3-1 contains a map showing all the EPA Platform v6 model regions.

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) that is the basis for EIA's Annual Energy Outlook (AEO) reports.

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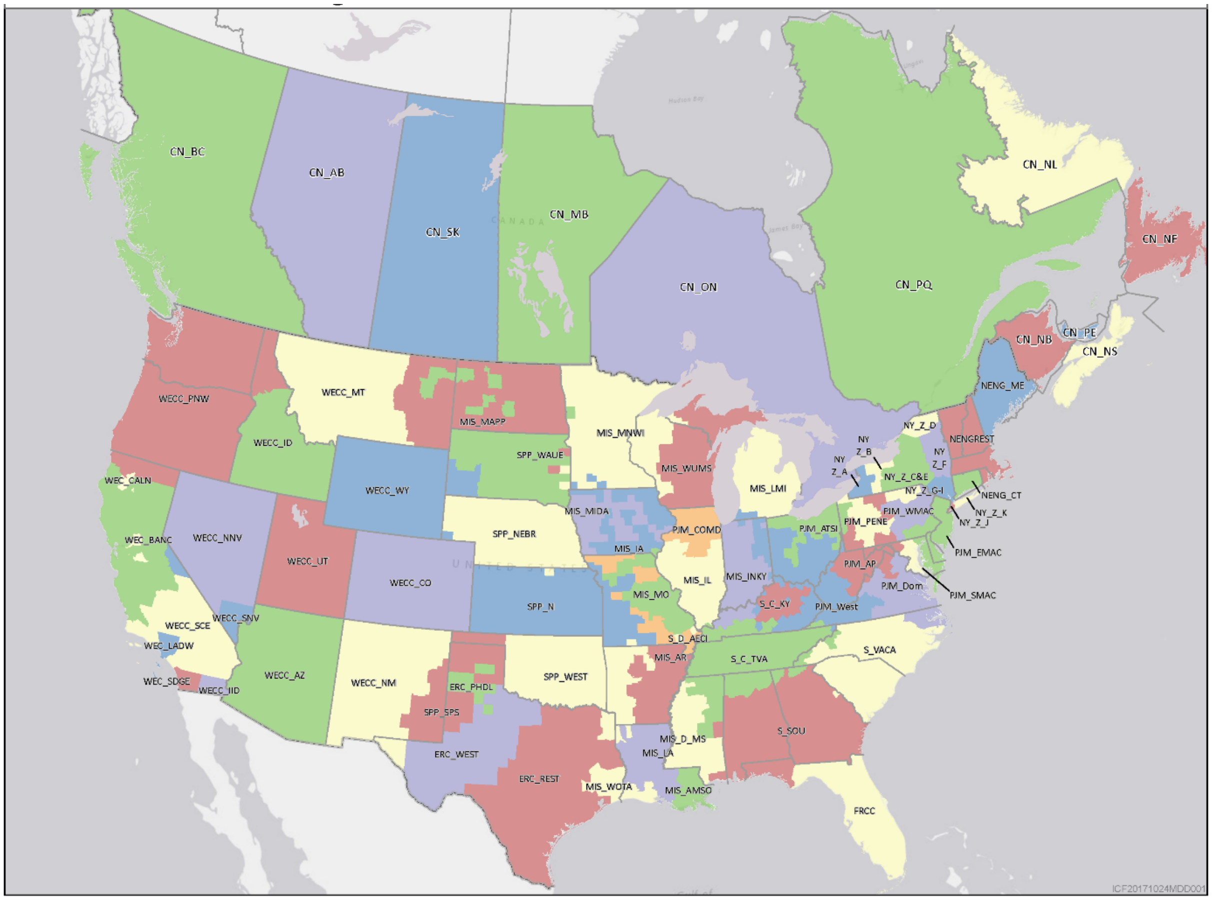
[12] This results in a total of 11 Canadian model regions being represented in EPA Platform v6.

[13] Because United States and the Canadian power markets are being modeled in an integrated manner, IPM can model the transfer of power in between these two countries endogenously. This transfer of power is limited by the available transmission capacity in between the two countries. Hence, it is possible for the model to build capacity in one country to meet demand in the other country when economic and is operationally feasible.

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 Platform v6. It is based on the net energy for load in AEO 2018.[14]

Figure 3-1 EPA Platform v6 Model Regions



For purposes of documentation, Table 3-2 and Table 3-3 present the net energy for load on a national and regional basis respectively. EPA Platform v6 models regional breakdowns of net energy for load in each of the 67 IPM U.S. 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.

[14] The electricity demand in EPA Platform v6 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 NERC Balancing Authorities/ Planning Areas in the US to the 67 IPM regions.
- Map the Balancing Authorities/ Planning Areas in the US to the 22 NEMS regions.
- Using the 2007 data from FERC Form 714 for non WECC regions and 2011 data for WECC regions 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 67 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 2018.

Table 3-1 Mapping of NERC Regions and NEMS Regions with EPA Platform v6 Model Regions

NERC Assessment Region	AEO 2017 NEMS Region	Model Region	Model Region Description
ERCOT	ERCT (1)	ERC_REST	ERCOT_Rest
	ERCT (1)	ERC_GWAY	ERCOT_Tenaska Gateway Generating Station
	ERCT (1)	ERC_FRNT	ERCOT_Tenaska Frontier Generating Station
	ERCT (1)	ERC_WEST	ERCOT_West
	ERCT (1)	ERC_PHDL	ERCOT_Panhandle
FRCC	FRCC (2)	FRCC	FRCC
MAPP	MROW (4)	MIS_MAPP	MISO_MT, SD, ND
MISO	SRGW (13)	MIS_IL	MISO_Illinois
	RFCW (11), SRCE (15)	MIS_INKY	MISO_Indiana (including parts of Kentucky)
	MROW (4)	MIS_IA	MISO_Iowa
	MROW (4)	MIS_MIDA	MISO_Iowa-MidAmerican
	RFCM (10)	MIS_LMI	MISO_Lower Michigan
	SRGW (13)	MIS_MO	MISO_Missouri
	MROE (3), RFCW (11)	MIS_WUMS	MISO_Wisconsin- Upper Michigan (WUMS)
	MROW (4)	MIS_MNWI	MISO_Minnesota and Western Wisconsin
	SRDA (12)	MIS_WOTA	MISO_WOTAB (including Western)
	SRDA (12)	MIS_AMSO	MISO_Amite South (including DSG)
	SRDA (12)	MIS_AR	MISO_Arkansas
	SRDA (12)	MIS_D_MS	MISO_Mississippi
	SPSO (18)	MIS_LA	MISO_Louisiana
ISO-NE	NEWE (5)	NENG_CT	ISONE_Connecticut
	NEWE (5)	NENGREST	ISONE_MA, VT, NH, RI (Rest of ISO New England)
	NEWE (5)	NENG_ME	ISONE_Maine
NYISO	NYUP (8)	NY_Z_C&E	NY_Zone C&E
	NYUP (8)	NY_Z_F	NY_Zone F (Capital)
	NYUP (8)	NY_Z_G-I	NY_Zone G-I (Downstate NY)
	NYCW (6)	NY_Z_J	NY_Zone J (NYC)
	NYLI (7)	NY_Z_K	NY_Zone K (LI)
	NYUP (8)	NY_Z_A	NY_Zone A (West)
	NYUP (8)	NY_Z_B	NY_Zone B (Genesee)
	NYUP (8)	NY_Z_D	NY_Zone D (North)
PJM	RFCE (9)	PJM_WMAC	PJM_Western MAAC
	RFCE (9)	PJM_EMAC	PJM_EMAAC
	RFCE (9)	PJM_SMAC	PJM_SWMAAC
	RFCW (11)	PJM_West	PJM West
	RFCW (11)	PJM_AP	PJM_AP

NERC Assessment Region	AEO 2017 NEMS Region	Model Region	Model Region Description
	RFCW (11)	PJM_COMD	PJM_ComEd
	RFCW (11)	PJM_ATSI	PJM_ATSI
	SRVC (16)	PJM_Dom	PJM_Dominion
	RFCE (9)	PJM_PENE	PJM_PENELEC
SERC-E	SRVC (16)	S_VACA	SERC_VACAR
SERC-N	SRCE (15)	S_C_KY	SERC_Central_Kentucky
	SRDA (12)	S_D_AECI	SERC_Delta_AECI
	SRCE (15)	S_C_TVA	SERC_Central_TVA
SERC-SE	SRSE (14)	S_SOU	SERC_Southeastern
SPP	MROW (4)	SPP_NEBR	SPP Nebraska
	SPNO (17), SRGW (13)	SPP_N	SPP North- (Kansas, Missouri)
	SPSO (18)	SPP_KIAM	SPP_Kiamichi Energy Facility
	SPSO (18), SRDA (12)	SPP_WEST	SPP West (Oklahoma, Arkansas, Louisiana)
	SPSO (18)	SPP_SPS	SPP SPS (Texas Panhandle)
	MROW (4)	SPP_WAUE	SPP_WAUE
California/Mexico (CA/MX)	CAMX (20)	WEC_CALN	WECC_Northern California (not including BANC)
	CAMX (20)	WEC_LADW	WECC_LADWP
	CAMX (20)	WEC_SDGE	WECC_San Diego Gas and Electric
	CAMX (20)	WECC_SCE	WECC_Southern California Edison
Northwest Power Pool (NWPP)	NWPP (21)	WECC_MT	WECC_Montana
	CAMX (20)	WEC_BANC	WECC_BANC
	NWPP (21)	WECC_ID	WECC_Idaho
	NWPP (21)	WECC_NNV	WECC_Northern Nevada
	AZNM (19)	WECC_SNV	WECC_Southern Nevada
	NWPP (21)	WECC_UT	WECC_Utah
	NWPP (21)	WECC_PNW	WECC_Pacific Northwest
Rocky Mountain Reserve Group (RMRG)	RMPA (22)	WECC_CO	WECC_Colorado
	NWPP (21), RMPA (22)	WECC_WY	WECC_Wyoming
Southwest Reserve Sharing Group (SRSG)	AZNM (19)	WECC_AZ	WECC_Arizona
	AZNM (19)	WECC_NM	WECC_New Mexico
	AZNM (19)	WECC_IID	WECC_Imperial Irrigation District (IID)
Canada		CN_AB	Canada_Alberta
		CN_BC	Canada_British Columbia
		CN_MB	Canada_Manitoba
		CN_NB	Canada_New Brunswick
		CN_NF	Canada_New Foundland
		CN_NL	Canada_Labrador
		CN_PE	Canada_Prince Edward island
		CN_NS	Canada_Nova Scotia
		CN_ON	Canada_Ontario
		CN_PQ	Canada_Quebec
		CN_SK	Canada_Saskatchewan

Table 3-2 Electric Load Assumptions in EPA Platform v6

Year	Net Energy for Load (Billions of kWh)
2021	4,076
2023	4,121
2025	4,167
2030	4,282
2035	4,393
2040	4,542
2045	4,692
2050	4,872

Notes:

The data represents an aggregation of the model-region-specific net energy loads used in the EPA Platform v6.

Table 3-3 Regional Electric Load Assumptions in EPA Platform v6

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
ERC_FRNT	0	0	0	0	0	0	0	0
ERC_GWAY	0	0	0	0	0	0	0	0
ERC_PHDL	0	0	0	0	0	0	0	0
ERC_REST	352	360	366	383	400	419	437	456
ERC_WEST	28	29	29	30	32	33	35	36
FRCC	240	243	247	256	267	279	292	308
MIS_AMSO	33	34	35	36	38	40	41	43
MIS_AR	39	40	41	43	45	47	48	50
MIS_D_MS	23	24	24	25	26	27	28	29
MIS_IA	22	22	22	23	24	24	25	26
MIS_IL	46	47	47	48	50	51	53	54
MIS_INKY	93	94	95	97	100	103	105	109
MIS_LA	48	49	50	52	54	57	59	61
MIS_LMI	102	103	104	106	108	111	114	117
MIS_MAPP	8	8	9	9	9	9	10	10
MIS_MIDA	30	30	31	32	32	34	35	36
MIS_MNWI	90	91	92	95	98	101	104	108
MIS_MO	39	40	40	41	42	43	45	46
MIS_WOTA	35	36	36	38	39	41	43	44
MIS_WUMS	65	66	67	68	70	72	74	76
NENG_CT	30	29	29	29	29	29	29	29
NENG_ME	10	10	10	10	10	10	10	10
NENGREST	77	76	76	76	75	75	76	77
NY_Z_A	16	16	16	16	16	16	16	16
NY_Z_B	10	10	10	10	10	10	10	10

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	2030	2035	2040	2045	2050
NY_Z_C&E	25	25	24	24	24	24	25	25
NY_Z_D	7	7	7	6	6	7	7	7
NY_Z_F	12	12	12	12	12	12	12	12
NY_Z_G-I	19	19	18	18	18	18	18	19
NY_Z_J	47	47	47	46	45	45	46	47
NY_Z_K	20	20	20	20	19	20	20	20
PJM_AP	45	46	46	48	49	50	51	53
PJM_ATSI	67	68	68	70	72	74	76	78
PJM_COMD	98	98	99	102	104	107	110	113
PJM_Dom	97	99	101	105	109	114	118	124
PJM_EMAC	138	139	139	140	142	145	148	153
PJM_PENE	17	17	17	17	17	18	18	19
PJM_SMAC	63	63	64	64	65	66	68	70
PJM_West	203	205	208	213	218	224	230	237
PJM_WMAC	55	55	55	56	57	58	59	61
S_C_KY	31	32	33	34	35	36	37	39
S_C_TVA	173	176	180	186	192	199	205	213
S_D_AECI	18	18	18	18	19	19	20	21
S_SOU	238	242	247	257	265	276	287	299
S_VACA	224	228	232	242	251	262	273	285
SPP_KIAM	0	0	0	0	0	0	0	0
SPP_N	71	72	73	75	77	80	82	86
SPP_NEBR	34	34	35	36	37	38	39	40
SPP_SPS	29	30	30	31	33	34	36	37
SPP_WAUE	23	23	24	24	25	26	27	27
SPP_WEST	129	131	134	140	146	153	159	166
WEC_BANC	14	14	14	14	14	14	14	15
WEC_CALN	111	110	109	108	107	109	111	116
WEC_LADW	27	27	27	26	26	27	27	28
WEC_SDGE	21	21	21	21	21	21	21	22
WECC_AZ	91	92	93	96	100	105	109	115
WECC_CO	66	67	69	71	74	77	81	85
WECC_ID	22	23	23	23	23	24	25	26
WECC_IID	4	4	4	4	4	5	5	5
WECC_MT	13	13	13	13	13	14	14	15
WECC_NM	24	24	24	25	26	27	29	30
WECC_NNV	13	13	13	13	13	13	14	14
WECC_PNW	173	174	174	176	179	185	191	199

IPM Region	Net Energy for Load (Billions of kWh)							
	2021	2023	2025	2030	2035	2040	2045	2050
WECC_SCE	108	108	107	106	105	106	109	113
WECC_SNV	27	27	28	29	30	31	32	34
WECC_UT	28	28	28	28	29	30	31	32
WECC_WY	17	18	18	18	18	19	20	21

3.2.1 Demand Elasticity

EPA Platform v6 has the capability to consider endogenously the relationship of the price of power to electricity demand. However, the capability is exercised only for sensitivity analyses where different price elasticities of demand are specified for purposes of comparative analysis. The default assumption is that the electricity demand shown in Table 3-2, which was derived from EIA modeling that already considered 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 Platform and the corresponding EIA Annual Energy Outlook reference case (e.g., between EPA Platform v6 and the AEO 2018 reference case).

3.2.2 Net Internal Demand (Peak Demand)

EPA Platform v6 has separate regional winter, winter shoulder, and summer peak demand values, as derived from each region's seasonal load duration curve (found in Table 2-2). Peak projections for the 2021-2027 period were estimated based on NERC ES&D 2017 load factors[15], and the estimated energy demand projections shown in Table 3-3. For post 2027 years when NERC ES&D 2017 load factors were not available, the NERC ES&D 2017 load factors for 2027 were projected forward using growth factors embedded in the AEO 2018 load factor projections.

Table 3-4 illustrates the national sum of each region's seasonal peak demand and Table 3-20 presents each region's seasonal 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 3-4 National Non-Coincidental Net Internal Demand

Year	Peak Demand (GW)		
	Winter	Winter Shoulder	Summer
2021	653	586	769
2023	660	592	776
2025	669	599	786
2030	690	618	812
2035	714	638	843
2040	745	664	880
2045	779	692	923
2050	818	724	972

Notes:

This data is an aggregation of the model-region-specific peak demand loads.

[15] Load factors can be calculated at the NERC assessment region level based on the NERC ES&D 2017 projections of net energy for load and net internal demand. All IPM regions that map to a particular NERC assessment region are assigned the same load factors. In instances where sub regional level load factor details could be estimated in selected ISO/RTO zones, those load factors were assigned to the associated IPM region.

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 Platform v6 to be consistent, the year 2011 was selected as the "normal weather year"[16] for all IPM regions except for ERCOT, where 2016 data was used. The proximity of the 2011 cumulative annual heating degree days (HDDs) and cooling degree days (CDDs) to the long-term average cumulative annual HDDs and CDDs over the period 1981 to 2010 was estimated and found to be reasonably close. The 2011 and 2016 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 Platform v6 characterizes the US lower 48 states, the District of Columbia, and Canada into 78 different model regions by means of 64 power market regions and 3 power switching regions[17] in the US and 11 power market regions in Canada. EPA Platform v6 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 Platform v6.

3.3.1 Inter-regional Transmission Capability

Table 3-21[18] 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 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.

The amount of energy and capacity transferred on a given transmission link is modeled on a seasonal basis for all run years in the EPA Platform v6. All of the modeled transmission links have the same Total Transfer Capabilities for all seasons, which means that the maximum firm and non-firm TTCs for each link is the same for winter, winter shoulder, 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

[16] The term "normal weather year" refers to a representative year whose weather is closest to the long-term (e.g., 30 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.

[17] 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.

[18] In the column headers in Table 3-21, the term "Energy TTC (MW)" is equivalent to non-firm TTCs and the term "Capacity TTC (MW)" is equivalent to firm TTCs.

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.

Furthermore, each transmission link between model regions shown in Table 3-21 represents 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.

Table 3-21, the transfer capabilities from New England to New York for the individual links are:

- NENG_CT to NY_Z_G-I: 600 MW
- NENGREST to NY_Z_F: 800 MW
- NENG_CT to NY_Z_K: 760 MW

Without any simultaneous transfer limits, the total transfer capability from New England to New York would be 2,160 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 Platform v6

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
NY_Zone G-I (Downstate NY) & NY_Zone J (NYC) to NY_Zone K (LI)	NY_Z_G-I to NY_Z_K NY_Z_J to NY_Z_K	1,528	
NY_Zone K(LI) to NY_Zones G-I (Downstate NY) & NY_Zone J (NYC)	NY_Z_K to NY_Z_G-I NY_Z_K to NY_Z_J	282	
ISO NE to NYISO	NENG_CT to NY_Z_G-I NENGREST to NY_Z_F NENG_CT to NY_Z_K	1,730	
NYISO to ISO NE	NY_Z_G-I to NENG_CT NY_Z_F to NENGREST NY_Z_K to NENG_CT	1,730	
PJM West & PJM_PENELEC & PJM_AP to PJM_ATSI	PJM_West to PJM_ATSI PJM_PENE to PJM_ATSI PJM_AP to PJM_ATSI	7,881	12,000
PJM_ATSI to PJM West & PJM_PENELEC & PJM_AP	PJM_ATSI to PJM_West	7,881	12,000

Region Connection	Transmission Path	Capacity TTC (MW)	Energy TTC (MW)
	PJM_ATSI to PJM_PENE PJM_ATSI to PJM_AP		
PJM_West & PJM_Dominion to SERC VACAR	PJM_West to S_VACA PJM_Dom to S_VACA	2,208	3,424
SERC VACAR to PJM_West & PJM_Dominion	S_VACA to PJM_West S_VACA to PJM_Dom	2,208	3,424
MIS_MAPP & SPP_WAUE to MIS_MNWI	MIS_MAPP to MIS_MNWI SPP_WAUE to MIS_MNWI	3,000	5,000
MIS_MNWI to MIS_MAPP & SPP_WAUE	MIS_MNWI to MIS_MAPP MIS_MNWI to SPP_WAUE	3,000	5,000
SERC_Central_TVA & SERC_Central_Kentucky to PJM West	S_C_TVA to PJM_West S_C_KY to PJM_West	3,000	4,500
PJM West to SERC_Central_TVA & SERC_Central_Kentucky	PJM_West to S_C_TVA PJM_West to S_C_KY	3,000	4,500
MIS_INKY to PJM_COMD & PJM_West	MIS_INKY to PJM_COMD MIS_INKY to PJM_West	4,586	6,509
PJM_COMD & PJM_West to MIS_ INKY	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 Platform v6 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 2016 mills/kWh are shown in Table 3-21 in the column labeled "Transmission Tariff".

3.3.4 Transmission Losses

The EPA Platform v6 assumes a 2.8 percent inter-regional transmission loss of energy transferred in the WECC interconnect and 2.4 percent inter-regional transmission loss of energy transferred in ERCOT and Eastern interconnects. This is based on average loss factors calculated from standard power flow data developed by the transmission providers.

3.4 International Imports

The US 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 Platform v6 but Mexico is not. International electric trading between the US and Mexico is represented by an assumption of net imports based on information from AEO 2017. Table 3-6 summarizes the assumptions on net imports into the US from Mexico.

Table 3-6 International Electricity Imports (billions kWh) in EPA Platform v6

	2021	2023	2025	2030	2035	2040	2045	2050
Net Imports from Mexico	6.34	6.34	6.34	6.34	6.34	6.34	6.34	6.34

Note 1: Source: AEO 2017

Note 2: Imports & exports transactions from Canada are endogenously modeled in IPM.

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 Platform v6 can be found in the National Electrical Energy Data System (NEEDS v6), a database which provides IPM with information on all currently operating and planned-committed electric generating units. NEEDS v6 is discussed in full in Chapter 4.

A unit's generation over a time period 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 on the unit. In EPA Platform v6, unit specific operational and physical constraints are 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 Platform v6. They are based on data from NERC Generating Availability Data System (GADS) 2011-2015 and AEO 2017. NERC GADS summarizes the availability data by plant type and size class. Unit level availability assignments in EPA Platform v6 are made based on the unit's plant type and size as presented in NEEDS v6. Table 3-27 shows the availability assumptions for all generating units in EPA Platform v6.

Table 3-7 Availability Assumptions in EPA Platform v6

Unit Type	Annual Availability (%)
Biomass	83
Coal Steam	76 - 85
Combined Cycle	85
Combustion Turbine	84 - 91
Energy Storage	90
Fossil Waste	90
Fuel Cell	87
Geothermal	87
Hydro	79 - 84
IGCC	79 - 85
Landfill Gas	90
Municipal Solid Waste	90
Non-Fossil Waste	90
Nuclear	75 - 97
Oil/Gas Steam	69 - 89
Offshore Wind	95
Onshore Wind	95
Pumped Storage	82
Solar PV	90
Solar Thermal	90

Notes:
Values shown are a range of all of the values modeled within the EPA Platform v6.

In the EPA Platform v6, separate (seasonal winter, winter shoulder, and summer) availabilities are defined. For the fossil and nuclear unit types shown in Table 3-27, seasonal availabilities differ only in that no planned maintenance is assumed to be conducted during the onpeak- summer (June, July, and August) months for summer peaking regions and onpeak – winter (December, January, and February) months for winter peaking regions. 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 for the 2007-2016 period. A discussion of capacity factors and generation profiles for wind and solar technologies is contained in section 4.4.5 and Table 4-20, Table 4-22, Table 4-24, Table 4-26, Table 4-46 and Table 4-47.

Table 3-8 Seasonal Hydro Capacity Factors (%) in EPA Platform v6

Model Region	Winter Capacity Factor	Winter Shoulder Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
ERC_REST	10%	11%	17%	13%
FRCC	51%	42%	35%	42%
MIS_AR	44%	40%	46%	43%
MIS_IA	42%	48%	57%	50%
MIS_IL	56%	61%	60%	59%
MIS_INKY	70%	76%	84%	78%
MIS_LA	62%	56%	64%	61%
MIS_LMI	61%	76%	48%	60%
MIS_MAPP	76%	76%	84%	79%
MIS_MIDA	26%	29%	32%	29%
MIS_MNWI	47%	57%	62%	57%
MIS_MO	36%	43%	55%	47%
MIS_WOTA	20%	20%	20%	20%
MIS_WUMS	51%	62%	54%	56%
NENG_CT	41%	42%	37%	40%
NENG_ME	65%	58%	57%	59%
NENGREST	39%	43%	33%	38%
NY_Z_A	70%	66%	63%	66%
NY_Z_B	35%	31%	24%	29%
NY_Z_C&E	53%	52%	51%	52%
NY_Z_D	71%	75%	79%	76%
NY_Z_F	55%	54%	49%	52%
NY_Z_G-I	34%	34%	33%	33%
PJM_AP	64%	56%	50%	55%
PJM_ATSI	17%	20%	25%	21%
PJM_COMD	38%	42%	50%	44%

Model Region	Winter Capacity Factor	Winter Shoulder Capacity Factor	Summer Capacity Factor	Annual Capacity Factor
PJM_Dom	24%	19%	15%	18%
PJM_EMAC	44%	40%	24%	35%
PJM_PENE	58%	57%	36%	48%
PJM_West	34%	31%	29%	31%
PJM_WMAC	41%	40%	23%	33%
S_C_KY	31%	25%	22%	25%
S_C_TVA	52%	36%	30%	37%
S_D_AECI	13%	18%	21%	18%
S_SOU	30%	22%	16%	21%
S_VACA	27%	20%	17%	20%
SPP_N	13%	16%	20%	17%
SPP_NEBR	30%	34%	43%	37%
SPP_WAUE	32%	34%	43%	37%
SPP_WEST	26%	26%	32%	29%
WEC_BANC	16%	19%	31%	23%
WEC_CALN	21%	26%	40%	31%
WEC_LADW	12%	13%	21%	16%
WEC_SDGE	25%	30%	49%	37%
WECC_AZ	27%	28%	32%	29%
WECC_CO	30%	24%	34%	30%
WECC_ID	31%	32%	46%	38%
WECC_IID	30%	37%	61%	45%
WECC_MT	37%	37%	50%	43%
WECC_NM	23%	24%	32%	27%
WECC_NNV	38%	49%	55%	49%
WECC_PNW	44%	41%	45%	43%
WECC_SCE	19%	25%	46%	32%
WECC_SNV	19%	24%	26%	24%
WECC_UT	28%	29%	39%	33%
WECC_WY	15%	22%	53%	34%

Note: Annual capacity factor is provided for information purposes only. It is not 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 Platform v6 vary from region to region and over time. Further discussion of the nuclear capacity factor assumptions in EPA Platform v6 is contained in Section 4.5.

In EPA Platform v6, capacity factors for oil/gas steam units are treated separately and assigned minimum capacity factors under certain conditions. These minimum capacity factor constraints reflect stakeholder comments that if left unconstrained, IPM does not project as much operation from oil/gas steam units as stakeholders expect will continue to occur based on observed market outcomes to date. 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 introduced minimum capacity factor constraints 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 economic forces to influence decision-making over the modeling time horizon; as a result, the minimum capacity factor limitations are imposed for limited time horizons (and are terminated even earlier if the capacity in question reaches 60 years of age). Historical operational data indicate that oil/gas steam units with high capacity factors have maintained a high level of generation over many years; in order to reflect persistent operation of these units, minimum capacity factors for higher capacity factor units are phased out more slowly than those constraints for lower capacity factor units. The steps in assigning these capacity constraints are as follows:

1) For each oil/gas steam unit, calculate an annual capacity factor over a ten-year baseline (2007-2016).
2) Identify the minimum capacity factor over this baseline period for each unit.
3) Terminate the constraints in the earlier of (a) the run-year in which the unit reaches 60 years of age, or (b) based on the assigned minimum capacity factor and the model year indicated in the following schedule:
   - For model year 2021, remove minimum constraint from units with capacity factor < 5%
   - For model year 2023, remove minimum constraint from units with capacity factor < 10%
   - 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 2035, remove minimum constraint from units with capacity factor < 35%
   - For model year 2040, remove minimum constraint from units with capacity factor < 45%

3.5.3 Turndown

Turndown assumptions in EPA Platform v6 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 Platform v6 require coal steam and oil/gas steam units to dispatch no less than a fixed percentage of the unit capacity in the 23 base and mid-load segments of the load duration curve in order to dispatch 100% of the unit in the peak load segments of the LDC. Oil/gas steam units are required to dispatch no less than 25% of the unit capacity in the 23 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. The unit level turndown percentages for coal units were estimated based on a review of recent hourly Air Markets Program Data (AMPD) data and are shown in Table 3-22.

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. 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 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. These margins are imposed throughout the entire time horizon. EPA Platform v6 reserve margin assumptions are shown in Table 3-9.

Table 3-9 Planning Reserve Margins in EPA Platform v6

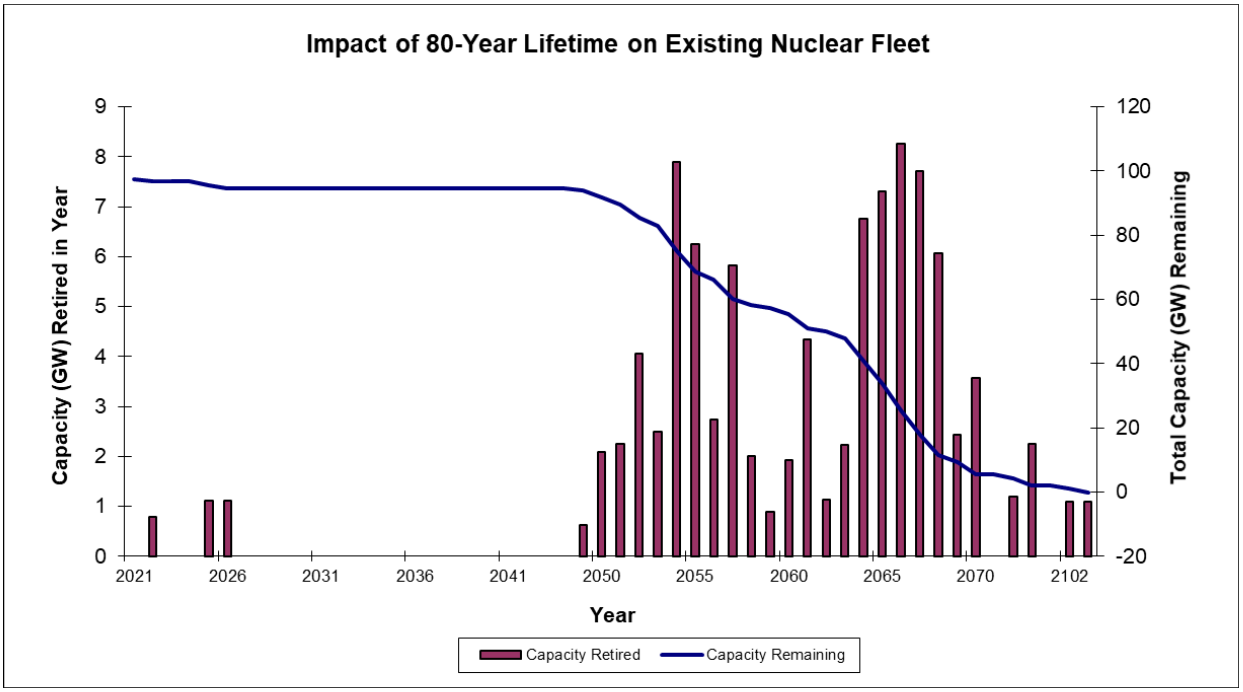
Model Region	Reserve Margin
CN_AB	11.0%
CN_BC	12.1%
CN_MB	12.0%
CN_NB	20.0%
CN_NF	20.0%
CN_NL	20.0%
CN_NS	20.0%
CN_ON	17.00%
CN_PE	20.0%
CN_PQ	12.70%
CN_SK	11.00%
ERC_FRNT	13.8%
ERC_GWAY	13.8%
ERC_PHDL	13.8%
ERC_REST	13.8%
ERC_WEST	13.8%
FRCC	18.6%
MIS_AR	15.2%
MIS_D_MS	15.2%
MIS_IA	15.2%
MIS_IL	15.2%
MIS_INKY	15.2%
MIS_LA	15.2%
MIS_LMI	15.2%
MIS_MAPP	15.2%
MIS_MIDA	15.2%
MIS_MNWI	15.2%
MIS_MO	15.2%
MIS_AMSO	15.2%
MIS_WOTA	15.2%
MIS_WUMS	15.2%
NENG_CT	15.9%
NENG_ME	15.9%
NENGREST	15.9%
NY_Z_A	15.0%
NY_Z_B	15.0%
NY_Z_C&E	15.0%
NY_Z_D	15.0%
NY_Z_F	15.0%
NY_Z_G-I	15.0%
NY_Z_J	15.0%
NY_Z_K	15.0%
PJM_AP	16.5%
PJM_ATSI	16.5%
PJM_COMD	16.5%
PJM_Dom	16.5%
PJM_EMAC	16.5%
PJM_PENE	16.5%
PJM_SMAC	16.5%
PJM_West	16.5%
PJM_WMAC	16.5%
S_C_KY	15.0%
S_C_TVA	15.0%
S_D_AECI	15.0%
S_SOU	15.0%
S_VACA	15.0%
SPP_KIAM	12.0%
SPP_N	12.0%
SPP_NEBR	12.0%
SPP_SPS	12.0%
SPP_WAUE	12.0%
SPP_WEST	12.0%
WEC_BANC	16.3%
WEC_CALN	16.2%
WEC_LADW	16.2%
WEC_SDGE	16.2%
WECC_AZ	15.8%
WECC_CO	14.1%
WECC_ID	16.3%
WECC_IID	15.8%
WECC_MT	16.3%
WECC_NM	15.8%
WECC_NNV	16.3%
WECC_PNW	16.3%
WECC_SCE	16.2%
WECC_SNV	16.3%
WECC_UT	16.3%
WECC_WY	14.1%

3.7 Power Plant Lifetimes

EPA Platform v6 does not include any pre-specified assumptions about power plant lifetimes (i.e., the duration of service allowed) except for nuclear units. All conventional fossil units (coal, oil/gas steam, combustion turbines, and combined cycle), nuclear and biomass units can be retired during a model run if their retention is deemed uneconomic.

Nuclear Retirement at Age 80: EPA Platform v6 assumes that commercial nuclear reactors will be retired upon license expiration, which includes two 20-year operating extensions that are assumed to be granted for each reactor by the Nuclear Regulatory Commission (NRC). EPA Platform v6 assumes an 80-year life. EPA Platform v6 incorporates life extension costs to enable these operating life extensions. (See Sections 4.2.8 and 4.5)

Figure 3-2 Scheduled Retirements of Existing Nuclear Capacity Under 80-Year Life Assumption



3.8 Heat Rates

Heat rates, expressed in British thermal units (Btus) per kilowatt-hour (kW-hr), are a measure of an Electric Generating Unit's (EGU's) generating efficiency. As in previous versions of NEEDS, it is assumed in NEEDS v6 that, with the exception of deploying the heat rate improvement option described below, heat rates of existing EGUs 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 act to maintain, or improve, an EGU's generating efficiency.

The heat rates for the model plants in EPA Platform v6 are based on values from Annual Energy Outlook 2017 (AEO 2017) informed by fuel use and net generation data reported on Form EIA-923. These values were screened and adjusted using a procedure developed by EPA (as described below) to ensure that the heat rates used in EPA Platform v6 are within the engineering capabilities of the various EGU 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 (IC) engines. If the reported heat rate for such a unit was below the applicable lower limit or above the upper limit, the upper or lower limit was substituted for the reported value.

Table 3-10 Lower and Upper Limits Applied to Heat Rate Data in EPA Platform v6

Plant Type	Heat Rate (Btu/kWh)	
	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 and above	8,700	18,700
Combustion Turbine - Natural Gas < 80 MW	8,700	36,800
Combustion Turbine - Oil and Oil/Gas - 80 MW and above	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

EPA Platform v6 is capable of offering to coal steam model plants a heat rate improvement option that is fully integrated into the Integrated Planning Model (IPM) framework. This capability enables IPM to determine economic uptake of heat rate improvements at each model plant, and it can be activated or deactivated as an investment option in any given scenario analyzed in IPM. Note that the heat rate improvement option is deactivated in EPA Platform v6, and is assumed to remain deactivated unless otherwise noted in EPA analyses using EPA Platform v6.

As an EGU's heat rate improves, less fuel is needed to produce the same amount of electricity. Because less fuel is combusted to produce the same amount of electricity, pollutant emissions are reduced per kW-hr of electricity produced. Furthermore, heat rate improvement has accompanying economic benefits, such as reducing fuel costs associated with generating the same amount of electricity. EPA is aware that a variety of technical approaches has been applied at existing coal steam EGUs to reduce auxiliary power consumption and fuel consumption and thereby increase net electrical output per unit of heat input. Heat rate improvement studies have examined opportunities for efficiency improvements as a means of reducing heat rate and regulating air pollutant emissions from coal-fired power plants. EPA is also aware that a diverse range of factors affects site-specific EGU heat rate improvements. Heat rate improvement cost and performance assumptions will be documented for any scenario analysis that activates the heat rate improvement option, and EPA welcomes further technical engagement on that option accordingly.

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 Platform v6. EPA Platform v6 also includes three non-air federal rules affecting EGUs: Cooling Water Intakes (316(b)) Rule and Coal Combustion Residuals from Electric Utilities (CCR), both promulgated in 2014, and the Effluent Limitations and Guidelines Rule finalized in 2015. The first four subsections discuss national and regional regulations. The next four subsections describe state level environmental regulations, a variety of legal settlements, emission assumptions for potential units and renewable portfolio standards. Finally, the NY minimum oil rule follows the subsection presenting the Canadian regulations for CO_2 and renewables.

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 permit rates including 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 Platform v6. Since SO_2 emissions are dependent on the sulfur content of the fuel used, the SO_2 permit rates are used in IPM to define fuel capabilities.

For instance, a unit with a SO_2 permit 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 permit limit. In EPA Platform v6, there are six different sulfur grades of bituminous coal, four different grades of subbituminous coal, four 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 7. 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 Platform v6 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 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 Platform v6 reflect the provisions in Title IV. For allowance trading programs like the Acid Rain Program that allow banking of unused allowances over time, we usually estimate an allowance bank that is assumed to be available by the first year of the modeling horizon (which is 2021 in EPA Platform v6). However, the Acid Rain Program has demonstrated a substantial oversupply of allowances that continues to grow over time, and we anticipate projecting that the program's emission caps will not bind the model's determination of SO_2 emissions regardless of any level of initial allowance bank assumed. Therefore, EPA Platform v6 does not assume any Title IV SO_2 allowance bank amount for the November 2018 Reference Case year of 2021 (notwithstanding that a large allowance bank will exist in that year in practice), because such an assumption would have no material impact on projections given the nonbinding nature of that program. Calculating the available 2021 allowances involved deducting allowance surrenders due to NSR settlements and state regulations from the 2021 SO_2 cap of 8.95 million tons. The surrenders totaled 977 thousand tons in allowances, leaving 7.973 million of 2021 allowances remaining. Specifics of the allowance surrender requirements under state regulations and NSR settlements can be found in Table 3-23 and Table 3-24.

EPA Platform v6 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 3-15.

3.9.2 NO_x Regulations

Much like SO_2 regulations, existing NO_x regulations are represented in EPA Platform v6 through a combination of system level NO_x programs and generation unit-level NO_x limits. In EPA Platform v6, the NO_x SIP Call trading program, Cross State Air Pollution Rule (CSAPR), and the CSAPR Update Rule are represented. Table 3-15 shows the specification for the entire modeling time horizon.

By assigning unit-specific NO_x rates based on 2017 data, EPA Platform v6 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).[19] Unlike SO_2 emission rates, NO_x rates are calculated off

[19] 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.

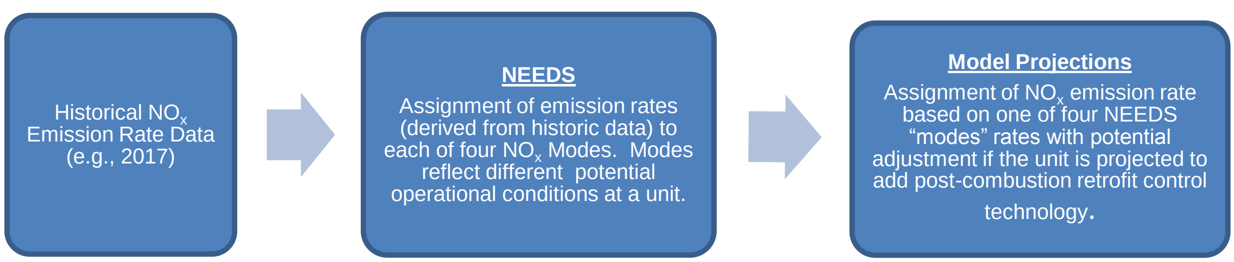
historical data and reflect the fuel mix for that particular year and burn at the unit. NEEDs represents up to four scenario NO_x rates based on historical data to capture seasonal and existing control variability. These rates are constant and do not change independent of fuel mix assumed in the model. If the unit undertakes a post-combustion control retrofit or a coal-to-gas retrofit, then these rates would change in the model projections.

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 (i.e., SCR or SNCR), but only operate it during the particular time of the year in which it is subject to NO_x reduction requirements (e.g., 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 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 historical data (where available) and presented in NEEDS v6. 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 NO_x rate if it is projected to add a *new* post-combustion NO_x control. If a unit is projected to add a new post-combustion control, then after the model selects the appropriate mode it adjusts downward its emission rate to reflect the retrofit of SCR or SNCR; the adjusted rate will reflect the greater of a percentage removal from the mode's emission rate or an emission rate floor. The full process for determining the NO_x rate of units in EPA Platform v6 model projections is summarized in Figure 3-3 below.

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



NO_x Emission Rates in NEEDS v6 Database

The NO_x rates were derived, wherever possible, directly from actual monitored NO_x emission rate data reported to EPA under the Acid Rain and Cross-State Air Pollution Rule in 2017.[20] The emission rates

[20] By assigning unit-specific NO_x rates based on 2017 data, EPA Platform v6 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). Unlike SO_2 emission rates, NO_x emission rates are assumed not to vary with coal type, but are dependent on the combustion properties of the generating unit. Under the EPA Platform v6, the NO_x emission rate of a unit can only change if the unit is retrofitted with NO_x post-combustion control equipment or if it is assumed to install state-of-the-art

themselves reflect the impact of applicable NO_x regulations[21]. For coal-fired units, NO_x rates were used in combination with empirical 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 and mode 2 reflect a unit's emission rates with its existing configuration of combustion and post-combustion (i.e., SCR or SNCR) controls.

- For a unit with an existing post-combustion control, mode 1 reflects the existing post-combustion control not operating and mode 2 the existing post-combustion control operating. However:
    - If a unit has operated its post-combustion control year round during 2017, 2016, 2015, 2014, 2011, 2009, and 2007 years then mode 1 = mode 2, which reflects that the control will likely continue to operate year round.
    - If a unit has not operated its post-combustion control during 2017, 2016, 2015, 2014, 2011, 2009, and 2007 years, mode 1 will be based on historic data and mode 2 will be calculated using the method described under Question 3 in Attachment 3-1.
    - If a unit has operated its post-combustion control seasonally in recent years (i.e., either only in the summer or winter, but not both), mode 1 will be based on historic data from when the control was not operating, and mode 2 will be based on historic data from when the SCR was operating.
- For a unit without an existing post-combustion control, mode 1 = mode 2 which reflects the unit's historic NO_x rates from a recent year.

Mode 3 and mode 4 emission rates parallel modes 1 and 2 emission rates, but are modified to reflect installation of state-of-the-art combustion controls on a unit if it does not already have them.

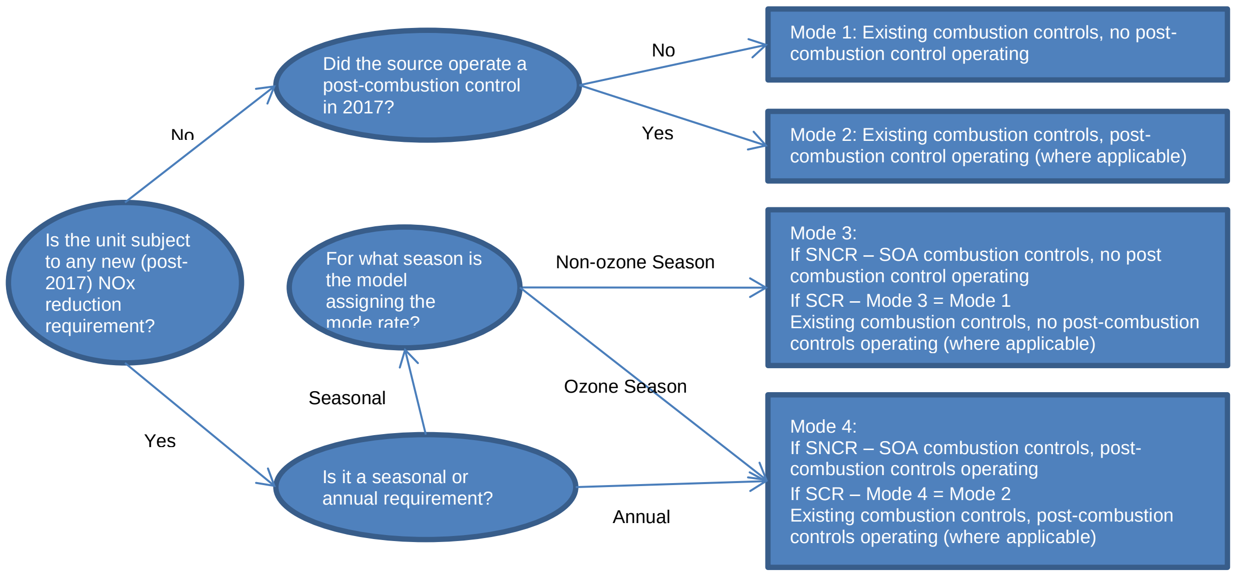
- For units that already have state-of-the-art combustion controls: Mode 3 = mode 1 and mode 4 = mode 2.

Emission rates derived for each unit operating under each of these four modes are presented in NEEDS v6. Note that 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.

NO_x combustion controls. In instances where a coal steam unit converts to natural gas, the NO_x rate is assumed to reduce by 50%.

[21] Because 2017 NO_x rates reflect CSAPR, we no longer apply any incremental CSAPR related NO_x rate adjustments exogenously for CSAPR affected units in EPA Platform v6.

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



<u>State-of-the-art combustion controls (SOA combustion controls)</u>

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, dry bottom boiler (highlighted below) currently has LNB but no overfire air (OFA), 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. 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-2017) NO_x reduction requirement (i.e., a NO_x reduction requirement that did not apply to the unit during its 2017 operation that forms the historic basis for deriving NO_x rates for units in EPA Platform v6). Existing reduction requirements as of 2017 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"
Tangential Firing	Does not Include LNC1 and LNC2	LNC3
	Includes LNC1, but not LNC2	CONVERSION FROM LNC1 TO LNC3
	Includes LNC2, but not LNC3	CONVERSION FROM LNC2 TO LNC3
	Includes LNC1 and LNC2 or LNC3	-
Wall Firing, Dry Bottom	Does not Include LNB and OFA	LNB + OFA
	Includes LNB, but not OFA	OFA
	Includes OFA, but not LNB	LNB
	Includes both LNB and OFA	-

Note:
LNB = Low NO_x Burner Technology, 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, OFA = Overfire Air

The emission rates for each generating unit under each mode are included in the NEEDS v6 database, described in Chapter 4. Attachment 3-1 gives further information on the procedures employed to derive the four NO_x mode rates.

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

CSAPR

EPA Platform v6 includes the Cross-State Air Pollution Rule (CSAPR) Rule and CSAPR Update Rule, federal regulatory measures affecting 23 states to address transport under the 1997, 2006, and 2008 National Ambient Air Quality Standards (NAAQS) for fine particle pollution and ozone. CSAPR requires fossil-fired EGUs greater than 25 MW in a total of 22 states to reduce annual SO_2 emissions, annual NO_x emissions, and/or ozone season NO_x emissions to assist in attaining the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). The CSAPR Phase 2 combined annual emissions budgets are 1,372.631 thousand tons SO_2 for CSAPR SO_2 Group 1;[22] 597.579 thousand tons SO_2 for CSAPR SO_2 Group 2;[23] and 1,069.256 thousand tons for annual NO_x.[24] As the budgets are significantly above current emission levels, i.e. they are not binding, the EPA did not include a starting bank of allowances for these programs for simplicity.

The original Phase 2 combined ozone season NO_x emissions budget was 0.59 million tons; however, several of the state budgets were remanded. As the CSAPR Update Rule addresses the D.C. Circuit's remand, the remanded budgets were not included in the EPA Platform v6. The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget in a given year through the use of banked or traded allowances to 18% or 21% of the state's budget are also included. For more information on CSAPR, go to https://www.epa.gov/csapr/overview-cross-state-air-pollution-rule-csapr.

The state budgets for Ozone Season NO_x for the CSAPR Update Rule are shown in Table 3-12. Additionally, Georgia was modeled as a separate region, with Georgia units unable to trade allowances with units in other states, and received its CSAPR Phase 2 budget and assurance level, as shown in the table below. This is because Georgia, unlike the other states covered by the CSAPR Update Rule, did not significantly contribute to a downwind nonattainment or maintenance receptor for the 2008 NAAQS and, furthermore, did not have a remanded Ozone Season NO_x budget related to a D.C. Circuit Court decision on the original Cross-State Air Pollution Rule.

The programs' assurance provisions, which restrict the maximum amount of exceedance of an individual state's emissions budget in each year through the use of banked or traded allowances to 18% or 21% of the state's budget, are also implemented. The starting allowance bank in 2021 is 98,670 tons, which is equal to the number of banked allowances at the start of the CSAPR Update program after old CSAPR allowances were converted. This is equal to one-and-a-half times the sum of the states' 21% variability

[22] Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, Wisconsin

[23] Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina

[24] Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin

limits. For more information on CSAPR, go to https://www.epa.gov/csapr. For more information on the CSAPR Update, go to https://www.epa.gov/airmarkets/final-cross-state-air-pollution-rule-update.

Table 3-12 CSAPR Update State Budgets, Variability Limits, and Assurance Levels for Ozone-Season NO_x (Tons)

	Budget	Variability Limit	Assurance Level
Alabama	13,211	2,774	15,985
Arkansas	9,210	1,934	11,144
Iowa	11,272	2,367	13,639
Illinois	14,601	3,066	17,667
Indiana	23,303	4,894	28,197
Kansas	8,027	1,686	9,713
Kentucky	21,115	4,434	25,549
Louisiana	18,639	3,914	22,553
Maryland	3,828	804	4,632
Michigan	17,023	3,575	20,598
Missouri	15,780	3,314	19,094
Mississippi	6,315	1,326	7,641
New Jersey	2,062	433	2,495
New York	5,135	1,078	6,213
Ohio	19,522	4,100	23,622
Oklahoma	11,641	2,445	14,086
Pennsylvania	17,952	3,770	21,722
Tennessee	7,736	1,625	9,361
Texas	52,301	10,983	63,284
Virginia	9,223	1,937	11,160
Wisconsin	7,915	1,662	9,577
West Virginia	17,815	3,741	21,556
CSAPR Update Region Total	**313,626**	**N/A**	**N/A**
Georgia Budget, Variability Limit, and Assurance Level for Ozone-Season NO_x			
Georgia	24,041	5,049	29,090

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 Platform v6 applies the input-based (lbs/MMBtu) MATS control requirements for mercury and hydrogen chloride to covered units.

EPA Platform v6 assumes that all active coal-fired generating units with a capacity greater than 25 MW have complied with the MATS filterable PM requirements through the operation of either electrostatic precipitator (ESP) or fabric filter (FF) particulate controls. No additional PM controls beyond those in NEEDS v6 are modeled in EPA Platform v6.

EPA Platform v6 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 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). The 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 regional haze State Implementation Plans (SIPs) or, in a few cases, put in place regional haze Federal Implementation Plans for several states. The BART limits approved in these plans (as of August 2017) that will be in place for EGUs are represented in the EPA Platform v6 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 CSAPR trading programs to satisfy BART must meet the requirements of CSAPR.
- 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 3-28 lists the NO_x and SO_2 limits applied to specific EGUs and other implementations applied in IPM. For more information on the Regional Haze Rule, go to https://www.epa.gov/visibility.

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.[25] Table 3-15 shows the specifications for RGGI that are implemented in EPA Platform v6.

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.[26] 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 economy-wide cap-and-trade program as follows.

- Adopt the AB32 cap-and-trade allowance price from EIA's AEO2017 Reference Case, which fully represents the non-power sectors. All qualifying fossil-fired EGUs in California are subject to this price signal, which is applied through the end of the modeled time horizon since the underlying legislation requires those emission levels to be maintained.
- Assume the marginal CO_2 emission rate for each IPM region that exports power to California to be 0.428 MT/MWh.
- 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.

Federal CO_2 standards for existing sources are not modeled, given ongoing litigation and regulatory review of the Clean Power Plan.[27] For new fossil fuel-fired sources, EPA Platform v6 continues to include the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (New Source Rule).[28] Although this rule is also being reviewed,[29] the standards of performance are legally in effect until such review is completed and/or revised (unlike the Clean Power Plan, which has been stayed by the Supreme Court).

3.9.5 Non-Air Regulations Impacting EGUs

<u>Cooling Water Intakes (316(b)) Rule</u>

Section 316(b) of the Clean Water Act requires that National Pollutant Discharge Elimination System (NPDES) permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the best technology available to minimize harmful

[25] As of this publication, the states of New Jersey and Virginia have expressed intent to join RGGI but have not yet concluded state regulatory proceedings to do so. If/when RGGI's composition and/or policy details change through applicable final rules by participating states, we will adjust that program's representation in our modeling platform and issue updated documentation accordingly.

[26] In July of 2017, AB 398 was signed into law. AB 398 extends the timeframe for cap-and-trade program through 2030 and further lowered the cap to at least 40% below the 1990 levels. This new regulation will be considered in future updates to IPM.

[27] 80 FR 64662 (Clean Power Plan, which has been stayed by the Supreme Court) and 82 FR 16329 (Clean Power Plan Review).

[28] 80 FR 64510

[29] 82 FR 16330

impacts on the environment. Under a 1995 consent decree with environmental organizations, EPA divided the section 316(b) rulemaking into three phases. All new facilities except offshore oil and gas exploration facilities were addressed in Phase I in December 2001; all new offshore oil and gas exploration facilities were later addressed in June 2006 as part of Phase III. This final rule also removes a portion of the Phase I rule to comply with court rulings. Existing large electric-generating facilities were addressed in Phase II in February 2004. Existing small electric-generating and all manufacturing facilities were addressed in Phase III (June 2006). However, Phase II and the existing facility portion of Phase III were remanded to EPA for reconsideration because of legal proceedings. This final rule combines these remands into one rule, and provides a holistic approach to protecting aquatic life impacted by cooling water intakes. The rule covers roughly 1,065 existing facilities that are designed to withdraw at least 2 million gallons per day of cooling water. EPA estimates that 544 power plants are affected by this rule.

The final regulation has three components for affected facilities: 1) reduce fish impingement through a technology option that meets best technology available requirements, 2) conduct site-specific studies to help determine whether additional controls are necessary to reduce entrainment, and 3) meet entrainment standards for new units at existing facilities when additional capacity is added. EPA Platform v6 includes cost of complying with this rule. The cost assumptions and analysis for 316(b) can be found in Chapter 8.7 of the Rule's Technical Development Document for the Final Section 316(b) Existing Facilities Rule at https://www.epa.gov/sites/production/files/2015-04/documents/cooling-water_phase-4_tdd_2014.pdf.

For more information on 316(b), go to http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

Combustion Residuals from Electric Utilities (CCR)

In December of 2014, EPA finalized national regulations to provide a comprehensive set of requirements for the safe disposal of coal combustion residuals (CCRs), commonly known as coal ash, from coal-fired power plants. The final rule is the culmination of extensive study on the effects of coal ash on the environment and public health. The rule establishes technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act.

EPA Platform v6 includes cost of complying with this rule's requirements by taking the estimated plant-level compliance cost identified in the 2014 Regulatory Impact Analysis (RIA) for the CCR final rule and apportioning them into unit-level cost. Three categories of unit-level cost were quantified; capital cost, fixed operating and maintenance cost (FOM), and variable operating and maintenance (VOM) cost. The method for apportioning these costs to the unit-level for inclusion in EPA Platform is discussed in the Addendum to the RIA for EPA's 2015 Coal combustion Residuals (CCR) Final Rule. The initial plant-level cost estimates are discussed in the Rule's Regulatory Impact Analysis.

In September of 2017, EPA granted petitions to reconsider some provisions of the rule. In granting the petitions, EPA determined that it was appropriate, and in the public's interest to reconsider specific provisions of the final CCR rule based in part on the authority provided through the Water Infrastructure for Improvements to the Nation (WIIN) Act. At time of this modeling update, EPA had not committed to changing any part of the rule, or agreeing with the merits of the petition – the Agency is simply granting petitions to reconsider specific provisions. Should EPA decide to revise specific provisions of the final CCR rule, it will go through notice and comment period, and the rules corresponding model specification would be subsequently changed in future base case platforms.

For more information on CCR, go to http://www2.epa.gov/coalash/coal-ash-rule.

Effluent Limitation and Guidelines (ELG)

In September of 2015, EPA finalized a rule revising the regulations for Steam Electric Power Generating category (40 CFR Part 423).[30] The rule established federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. The rule established or updated standards for wastewater streams from flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels. EPA estimated that approximately 12% of steam electric power plants would incur some compliance cost. EPA reflects this rule in this base case by apportioning the estimated total capital and FOM costs to likely affected units based on controls and capacity. The cost adders are reflected in the model inputs and were applied starting in 2023, by which point the requirements were expected to be fully implemented.

In August of 2017, EPA noted that it would conduct a rulemaking to potentially revise the limitations and standards for bottom ash transport water and flue gas desulfurization wastewater. EPA noted that, given the typical timeline to propose and finalize a rulemaking, it would postpone earliest compliance dates by 2 years. Therefore, in EPA Platform v6, EPA has postponed the full implementation by 2 years, but has not made any capital or FOM adjustments reflecting new limitations and standards as no new standards have been finalized at the time of model update.

3.9.6 State-Specific Environmental Regulations

EPA Platform v6 represents enacted laws and regulations in 27 states affecting emissions from the electricity sector. Table 3-23 summarizes the provisions of state laws and regulations that are represented in EPA Platform v6.

The NY minimum oil burn rule was implemented for the following units through facility level minimum generation constraints in the 2021, 2023, and 2025 run years. The minimum generation limits are calculated using the capacity factors shown in Table 3-13.

Table 3-13 NY Minimum Oil Burn Rule Plant Level Oil Capacity Factor Requirements

	Oil Capacity Factor (%)		
	Winter	**Winter Shoulder**	**Summer**
Steam Facilities (Heavy Oil)			
Astoria	2.10%	0.20%	0.50%
East River	3.00%	0.40%	0.60%
Northport	5.20%	0.50%	2.00%
Ravenswood	0.70%	0.20%	0.60%
Combined Cycle (Light Oil)			
Astoria Energy	2.90%	0.00%	0.00%
Charles Polletti Power Plant	3.00%	0.40%	0.00%
Ravenswood	1.00%	0.10%	0.00%

3.9.7 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 Platform v6 includes NSR

[30] https://www.epa.gov/eg/steam-electric-power-generating-effluent-guidelines-2015-final-rule

settlements with 34 electric power companies. A summary of the units affected and how the settlements were modeled can be found in Table 3-24.

Nine state settlements and ten citizen settlements are also represented in EPA Platform v6. These are summarized in Table 3-25 and Table 3-26 respectively.

3.9.8 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 Platform v6 are presented in Table 3-17. (Note: Nuclear, wind, solar, and fuel cell technologies are not included in Table 3-17 because they do not emit any of the listed pollutants.) For additional details on the modeling of potential new units, see Chapter 4.

3.9.9 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 statewide generation. In EPA Platform v6, the state RPS requirements are represented at a state level based on requirements. Table 3-19 shows the state level RPS requirements. In addition, state level solar carve-out requirements have been implemented in EPA Platform v6.

3.9.10 Canada CO_2 and Renewable Regulations

Several CO_2 regulations in Canada are represented in EPA Platform v6. Under the Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations, the CO_2 standard of 420 tonne /GWh of electricity produced apply to both new coal-fired electricity generating units commissioned after July 1, 2015, and existing coal units that have reached their end-of-life date as defined by the regulation. EPA Platform v6 also models the British Columbia's carbon tax, Manitoba’s Emissions Tax on Coal and Petroleum Coke Act, and the Ontario and Quebec’s participation in Western Climate Initiative (WCI) cap-and-trade program. British Columbia's carbon tax sets a tax rate of $35 per tonne of CO_2 equivalent emissions beginning April 1, 2018 and increases it each year by $5 per tonne until it reaches $50 per tonne in 2021. Coming into force on January 1, 2012, Manitoba’s Emissions Tax on Coal and Petroleum Coke Act requires a tax rate of $10 per tonne of CO_2 equivalent emissions on coal-fired and petroleum coke-fired units. Ontario and Quebec’s participation in WCI is modeled through the application of the CO_2 allowance price from CA AB32. EPA Platform v6 also models the province level renewable electricity programs in Canada. Table 3-14 shows the province level renewable electricity requirements as a percentage of electricity sales.

Table 3-14 Canada Renewable Electricity Requirements (%) in EPA Platform v6

Province	2021	2023	2025	2030	2035	2040	2045	2050
British Columbia	93	93	93	93	93	93	93	93
Alberta				30	30	30	30	30
Saskatchewan				50	50	50	50	50
New Brunswick	40	40	40	40	40	40	40	40
Nova Scotia	40	40	40	40	40	40	40	40
Prince Edward Island	30	30	30	30	30	30	30	30

3.10 Emissions Trading and Banking

Several environmental air regulations included in EPA Platform v6 involve regional trading and banking of emission allowances: This includes the five programs of the Cross-State Air Pollution Rule (CSAPR) – SO_2 Region 1, SO_2 Region 2, Annual NO_x, CSAPR Update Rule Ozone Season NO_x Region 1, and CSAPR Update Rule Ozone Season NO_x Region 2; the Regional Greenhouse Gas Initiative (RGGI) for CO_2; the SIP Call Ozone Season NO_x; and the West Region Air Partnership's (WRAP) program regulating SO_2 (adopted in response to the federal Regional Haze Rule).

Table 3-15 and Table 3-16 summarize the key parameters of these trading and banking programs as incorporated in EPA Platform v6. EPA Platform v6 does not include any explicit assumptions on the allocation of emission allowances among model plants under any of the programs.

3.10.1 Intertemporal Allowance Price Calculation

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 is consistent with producing a least-cost solution.

EPA Platform v6 uses the same discount rate assumption that governs all intertemporal economic decision-making in the model to compute the increase in allowance price for cap-and-trade programs when banking is engaged as a compliance strategy. The approach assumes 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 10.4.

Table 3-15 Trading and Banking Rules in EPA Platform v6 – Part 1

	SIP Call - Ozone Season NO_x	WRAP- SO_2	RGGI - CO_2
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW[2]	All fossil units > 25 MW[3]
Timing	Ozone Season (May - September)	Annual	Annual
Size of Initial Bank (MTons)	The bank starting in 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	2021: 49,442
Total Allowances (MTons)	2016 - 2054: 72.845	2018 - 2054: 89.6	2021: 75,148 2022: 72,873 2023: 70,598 2024: 68,323 2025: 66,048 2026: 63,773 2027: 61,498 2028: 59,223 2029: 56,948 2030 - 2054: 54,673

Notes:

1 Rhode Island, Connecticut, Delaware, District of Columbia, Massachusetts, North Carolina, and South Carolina are the NO_x SIP Call states not covered by the CSAPR Ozone Season program.

2 New Mexico, Utah, Wyoming

3 Connecticut, Delaware, Maine, New Hampshire, New York, Vermont, Rhode Island, Massachusetts, Maryland

Table 3-16 CASPR Trading and Banking Rules in EPA Platform v6 – Part 2

	CSAPR - SO_2 - Region 1	CSAPR - SO_2 - Region 2	CSAPR - Annual NO_x	CSAPR Update Rule - Ozone Season NO_x - Region 1	CSAPR Update Rule - Ozone Season NO_x - Region 2
Coverage	All fossil units > 25 MW[1]	All fossil units > 25 MW[2]	All fossil units > 25 MW[3]	All fossil units > 25 MW[4]	All fossil units > 25 MW[5]
Timing	Annual	Annual	Annual	Ozone Season (May - September)	Ozone Season (May - September)
Size of Initial Bank (MTons)	The bank starting in 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	The bank starting in 2021 is assumed to be zero	The cap in 2021 includes 21% of banking	The bank starting in 2021 is assumed to be zero
Total Allowances (MTons)	2021 - 2054: 1372.631	2021 - 2054: 597.579	2021 - 2054: 1069.256	2021: 411.9106 2022 - 2054: 313.24	2021 - 2054: 24.041

Notes:

[1] Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, Wisconsin

[2] Alabama, Georgia, Kansas, Minnesota, Nebraska, South Carolina

[3] Alabama, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Minnesota, Missouri, Nebraska, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin

[4] Alabama, Arkansas, Iowa, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maryland, Michigan, Missouri, Mississippi, New Jersey, New York, Ohio, Oklahoma, Pennsylvania, Tennessee, Texas, Virginia, Wisconsin, West Virginia

[5] Georgia

Table 3-17 Emission and Removal Rate Assumptions for Potential (New) Units in EPA Platform v6

	Controls, Removal, and Emissions Rates	Ultra Supercritical Pulverized Coal	Ultra Supercritical Pulverized Coal with 30% CCS	Ultra Supercritical Pulverized Coal with 90% CCS	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**	98% with a floor of 0.06 lbs/MMBtu	98% with a floor of 0.06 lbs/MMBtu	98% with a floor of 0.06 lbs/MMBtu	None	None	None	0.08 lbs/MMBtu	None	None
NO_x	**Emission Rate**	0.07 lbs/MMBtu	0.07 lbs/MMBtu	0.07 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	30%	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% 0.001 lbs/MMBtu	99% 0.001 lbs/MMBtu	99% 0.001 lbs/MMBtu						

Table 3-18 Recalculated NO_x Emission Rates for SCR Equipped Units Sharing Common Stacks with Non-SCR Units

Plant Name	UniqueID_ Final	Capacity (MW)	NO_x Post-Comb Control	SCR_Online _Year	Mode 1 NO_x Rate	Mode 2 NO_x Rate	Mode 3 NO_x Rate	Mode 4 NO_x Rate
Ghent	1356_B_2	484			0.340	0.253	0.340	0.253
Ghent	1356_B_3	480	SCR	2004	0.075	0.075	0.075	0.075
Chalk Point LLC	1571_B_1	331	SCR	2009	0.075	0.075	0.075	0.075
Chalk Point LLC	1571_B_2	336	SNCR		0.270	0.237	0.270	0.237
FirstEnergy W H Sammis	2866_B_5	300	SNCR		0.283	0.258	0.283	0.258
FirstEnergy W H Sammis	2866_B_6	600	SCR	2010	0.075	0.075	0.075	0.075
FirstEnergy W H Sammis	2866_B_7	600	SCR	2010	0.075	0.075	0.075	0.075
Charles R Lowman	56_B_1	80			0.252	0.723	0.155	0.155
Charles R Lowman	56_B_2	235	SCR	2008	0.302	0.075	0.302	0.075
Crist	641_B_4	75	SNCR		0.285	0.285	0.139	0.139
Crist	641_B_5	75	SNCR		0.285	0.285	0.139	0.139
Crist	641_B_6	291	SCR	2012	0.075	0.075	0.075	0.075
Crist	641_B_7	465	SCR	2004	0.075	0.075	0.075	0.075
Gorgas	8_B_10	703	SCR	2002	0.100	0.100	0.100	0.100
Gorgas	8_B_8	161			0.355	0.296	0.355	0.296
Gorgas	8_B_9	170			0.355	0.296	0.355	0.296
Clifty Creek	983_B_4	196	SCR	2003	0.260	0.075	0.260	0.075
Clifty Creek	983_B_5	196	SCR	2003	0.258	0.075	0.258	0.075
Clifty Creek	983_B_6	196			0.325	0.309	0.325	0.309

Table 3-19 Renewable Portfolio Standards in EPA Platform v6

State Renewable Portfolio Standards in % - AEO 2018								
State	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Arizona	6.3%	7.4%	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%
California	34.8%	38.3%	41.7%	50.0%	50.0%	50.0%	50.0%	50.0%
Colorado	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%	21.2%
Connecticut	26.5%	30.0%	34.0%	44.0%	44.0%	44.0%	44.0%	44.0%
District of Columbia	20.0%	20.0%	26.0%	42.0%	50.0%	50.0%	50.0%	50.0%
Delaware	15.2%	16.6%	18.1%	18.1%	18.1%	18.1%	18.1%	18.1%
Iowa	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.5%	0.5%
Illinois	9.8%	11.5%	13.1%	14.0%	14.0%	14.0%	14.0%	14.0%
Massachusetts	21.5%	23.5%	25.5%	30.5%	35.5%	40.5%	45.5%	50.5%
Maryland	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Maine	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%	40.0%
Michigan	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Minnesota	25.7%	25.7%	28.4%	28.4%	28.4%	28.4%	28.4%	28.4%
Missouri	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%	10.6%
Montana	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%
North Carolina	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
New Hampshire	19.8%	21.2%	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%
New Jersey	28.6%	35.6%	42.3%	54.7%	53.6%	53.6%	53.6%	53.6%
New Mexico	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%	15.8%
Nevada	17.3%	17.3%	21.9%	21.9%	21.9%	21.9%	21.9%	21.9%
New York	25.3%	28.9%	32.5%	41.4%	41.4%	41.4%	41.4%	41.4%
Ohio	6.7%	8.5%	10.2%	11.1%	11.1%	11.1%	11.1%	11.1%
Oregon	14.1%	14.1%	21.0%	27.6%	36.1%	41.1%	42.6%	42.6%
Pennsylvania	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
Rhode Island	17.5%	20.5%	23.5%	31.0%	38.5%	38.5%	38.5%	38.5%
Texas	4.3%	4.2%	4.1%	3.9%	3.7%	3.5%	3.4%	3.2%
Vermont	62.4%	67.6%	68.8%	79.8%	85.0%	85.0%	85.0%	85.0%
Washington	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%	11.8%
Wisconsin	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.6%	9.65%
State RPS Solar Carve-outs								
State	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
District of Columbia	1.9%	2.5%	2.9%	4.5%	5.0%	5.0%	5.0%	5.0%
Delaware	1.8%	2.2%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Illinois	1.05%	1.23%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Massachusetts	0.17%	0.18%	0.20%	0.24%	0.28%	0.32%	0.36%	0.40%
Maryland	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Minnesota	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%	1.19%
Missouri	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%
North Carolina	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
New Hampshire	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%
New Jersey	5.10%	5.10%	4.80%	2.21%	1.10%	1.10%	1.10%	1.10%
New Mexico	3.17%	3.17%	3.17%	3.17%	3.17%	3.17%	3.17%	3.17%
Nevada	1.04%	1.04%	1.31%	1.31%	1.31%	1.31%	1.31%	1.31%
Ohio	0.27%	0.34%	0.41%	0.45%	0.45%	0.45%	0.45%	0.45%
Pennsylvania	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Note 1: The Renewable Portfolio Standard percentages are applied to modeled electricity sale projections.
Note 2: North Carolina standards are adjusted to account for swine waste and poultry waste set-asides.

List of tables and attachments that are uploaded directly to the web:

4. Generating Resources

Existing, planned-committed, and potential are the three types of generating units modeled in EPA Platform v6. Electric generating units currently in operation are termed as existing units. Units that are anticipated to be in operation in the near future, for having broken ground or secured financing, are planned-committed units. Potential units refer to new generating options that IPM builds to meet industry capacity expansion projections. Existing and planned-committed units enter IPM as exogenous inputs, whereas potential units are endogenous to IPM in that the model determines the location and size of the potential units to build.

This chapter is organized as follows.

(1) Section 4.1 provides background information on the National Electric Energy Data System (NEEDS), the database that serves as the repository for information on existing and planned-committed electric generating units modeled,

(2) Section 4.2 provides detailed information on existing non-nuclear generating units,

(3) Section 4.3 provides detailed information on planned-committed units,

(4) Section 4.4 provides detailed information on potential units, and

(5) Section 4.5 describes assumptions pertaining to existing and potential nuclear units.

4.1 National Electric Energy Data System (NEEDS)

EPA Platform v6 uses the NEEDS v6 database as its source for data on all existing and planned-committed units. Section 4.2 discusses the sources used in developing data on existing units. The population of existing units in the NEEDS v6 represents electric generating units that were in operation through the end of 2017. Section 4.3 discusses the sources used in developing data on planned-committed units. The population of planned-committed includes units online or scheduled to come online from 2018 through June 30, 2021, with the exception of Vogtle nuclear units 3 and 4 that are scheduled to come online after 2021.

4.2 Existing Units

The sections below describe the procedures for determining the population of existing units in NEEDS v6, as well as the capacity, location, and configuration information of each unit in the population. Details are also given on the model plant aggregation scheme and associated cost and performance characteristics of the units.

4.2.1 Population of Existing Units

The October 2017 EIA Form 860M is the primary data source on existing units. Table 4-2 specifies the screening rules applied to the data source to ensure data consistency and adaptability for use in EPA Platform v6. Table 4-50 lists all units that are excluded from the NEEDS v6 population based on application of the screening rules.

Table 4-1 Data Sources for NEEDS v6 for EPA Platform v6

Data Source[1]	Data Source Documentation
EIA Form 860	EIA Form 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 v6 uses the annual 2015 EIA Form 860, annual 2016 Early Release EIA Form 860, 2017 Early Release EIA Form 860, May 2017 EIA Form 860M, October 2017 EIA Form 860M and the July 2018 EIA Form 860M as the primary generator data inputs. EIA Form 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 controls, 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 v6 uses 2015 EIA Form 860 and 2016 Early Release EIA Form 860 as the primary boiler data inputs.
EIA'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 30-year time horizon. The projections are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2017 such as heat rates and planned-committed units were used in NEEDS v6.
EPA's Emission Tracking System	The Emission Tracking System (ETS) database is updated quarterly. It contains information including primary fuel, heat input, SO_2, NO_x, Mercury, and HCl controls, and SO_2 and NO_x emissions. NEEDS v6 uses annual and seasonal ETS (2017) 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, regional EPA offices and other stakeholders regarding the prior versions of NEEDS.

Note:
[1] Shown in Table 4-1 are the primary issue dates of the indicated data sources 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 v6 for EPA Platform v6

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 three consecutive years (i.e., generators or boilers with status codes "OS" or "OA" in the latest three 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 June 30, 2021; two nuclear units that are scheduled to come online after 2021 were also included
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:

The two nuclear units are Vogtle, units 3&4

The NEEDS v6 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 v6, 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 v6 through 2017. 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 other research.

EPA Platform v6 removes units from the NEEDS inventory based on public announcements of future closures. The removal of such units pre-empts IPM from making any further decisions regarding the operational status or configuration of the units. The units considered for removal from NEEDS are identified from reviewing several data sources including:

1. EIA Electric Generator Capacity data (EIA Form 860M), July 2018 release
2. PJM Future Deactivation Requests and PJM Generator Deactivations, July 2018 (updated frequently)
3. ERCOT Generator Interconnection Status Report, July 2018 (updated frequently)
4. MISO Generation Interconnection Queue, July 2018 (updated frequently)
5. Research by EPA and ICF staff

Units are removed from the NEEDS inventory only 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, and the following rules are applied to remove:

1. Units that are listed as retired in the July 2018 EIA Form 860M
2. Units with a planned retirement year prior to June 30, 2021 in July 2018 EIA Form 860M
3. Units that have been cleared by a regional transmission operator (RTO) or independent system operator (ISO) to retire before 2021, or whose RTO/ISO clearance to retire is contingent on actions that can be completed before 2021
4. Units that have committed specifically to retire before 2021 under federal or state enforcement actions or regulatory requirements
5. And finally, units for which a retirement announcement can be corroborated by other available information.

Units required to retire pursuant to enforcement actions or state rules in 2022 or later are retained in NEEDS v6. Such 2022-or-later retirements are captured as constraints on those units in IPM modeling, and the units are retired in future year projections per the terms of the related requirements. Table 4-50 and Table 4-51 list all units that are removed from the NEEDS v6 inventory.

Table 4-3 Summary Population (through 2017) of Existing Units in NEEDS v6

Plant Type	Number of Units	Capacity (MW)
Biomass	186	3,876
Coal Steam	593	226,339
Combined Cycle	1,837	246,866
Combustion Turbine	5,381	143,285
Energy Storage	81	659
Fossil Waste	81	1,049
Fuel Cell	72	130
Geothermal	164	2,396
Hydro	3,805	79,186
IGCC	5	815
Landfill Gas	1,576	1,913
Municipal Solid Waste	165	2,123
Non-Fossil Waste	216	2,027
Nuclear	90	92,260

Plant Type	Number of Units	Capacity (MW)
O/G Steam	443	74,999
Offshore Wind	1	29
Onshore Wind	1,185	87,185
Pumped Storage	148	22,196
Solar PV	2,452	24,144
Solar Thermal	16	1,754
Tires	2	52
US Total	**18,499**	**1,013,283**

4.2.2 Capacity

The unit capacity data implemented in NEEDS v6 reflects net summer dependable capacity[31]. Table 4-4 summarizes the hierarchy of data sources used in compiling capacity data. In other words, 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.[32]

Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS v6

Sources Presented in Hierarchy
Net Summer Capacity from Comments / ICF Research
July 2018 EIA Form 860M Net Summer Capacity
October 2017 EIA Form 860M Net Summer Capacity
May 2017 EIA Form 860M Net Summer Capacity
2015 EIA Form 860 Net Summer Capacity

Notes:

If the capacity of a unit is zero MW, the unit is excluded from NEEDS population.

As noted earlier, NEEDS v6 includes boiler-level data for steam units and generator-level data for non-steam units. Capacity data in EIA Form 860 are generator-specific, not boiler-specific. Therefore, it was necessary to develop an algorithm for parsing generator-level capacity to the boiler level for steam producing units.

The capacity-parsing algorithm used for steam units in NEEDS v6 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 v6 utilizes steam flow data with the boiler-generator mapping. Under EIA Form 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 Form 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.

[31] 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.

[32] EIA Form 860M (July, 2018 release) was the most recent data available at the time when NEEDS v6 was finalized.

Table 4-5 Capacity-Parsing Algorithm for Steam Units in NEEDS v6

Type of Boiler-Generator Links				
For Boiler B1 to BN linked to Generators G1 to GN	One-to-One	One-to-Many	Many-to-One	Many-to-Many
	MWBi = MWGj	MWBi = ΣjMWGj	MWBi = (MFBi / ΣiMFBi) * MWGj	MWBi = (MFBi / ΣiMFBi) * ΣjMWGj

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

Since EPA Platform v6 uses net energy for load as demand, the NEEDS includes only generators that sell the majority of their power to the electric grid. The approach is intended to be broadly consistent with the generating capacity used in the AEO projections where demand is net energy for load. The generators that should be in NEEDS v6 by this qualification are determined from the 2014 EIA Form 923 non-utility source and disposition data set.

4.2.3 Plant Location

The physical location of each unit in NEEDS is represented by the unit's model region, state, and county data.

State and County

NEEDS v6 uses the state and county data from October 2017 EIA Form 860M.

Model Region

For each unit, the associated model region was derived based on NERC assessment regions reported in EIA Form 860 and ISO/RTO reports. For units with no NERC assessment region data, state and county data were used to derive associated model regions. Table 3-1 in Chapter 3 provides a summary of the mapping between NERC assessment regions and EPA Platform v6 model regions.

4.2.4 Online Year

The EPA Platform v6 uses online year to capture when a unit entered service. NEEDS includes online years for all units in the population. Online years for boilers were from 2015 EIA Form 860, and online years for generators were derived primarily from reported in-service dates in May 2017 version of EIA Form 860M.

EPA Platform v6 includes constraints to set the retirement year for generating units that are firmly committed to retiring after June 30, 2021 based on state or federal regulations and enforcement actions. In addition, existing nuclear units must retire when they reach age 80. (See section 3.7 for a discussion of the nuclear lifetime assumption.) Economic retirement options are also provided to coal, oil and gas steam, combined cycle, combustion turbines, biomass, and nuclear units to allow the model the option to retire a unit if it finds economical to do so. In IPM, a retired unit ceases to incur FOM and VOM costs. The unit, however, continues to make annualized capital cost payment on any previously incurred capital cost for model-installed retrofits projected prior to retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specification of a unit's design. Unit configuration in EPA Platform v6 drives model plant aggregation and modeling of pollution control options and mercury emission modification factors. NEEDS v6 contains for each unit, data on the firing and bottom type, as well as existing and committed emission controls the unit has. Table 4-6 shows the hierarchy of data sources used in determining a unit configuration. The sources listed below are also supplemented by recent ICF and EPA research to ensure the unit configuration data in NEEDS is the most comprehensive and up-to-date possible.

Table 4-6 Data Sources for Unit Configuration in NEEDS v6

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	--	--	--
Bottom Type	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	--	--	Dry
SO_2 Pollution Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	No Control
NO_x Pollution Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	No Control
Particulate Matter Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	--
Mercury Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	--
HCL Control	2015/2016 EIA 860	EPA's Emission Tracking System (ETS) – 2015/2017	NSR Settlement or Comments	--	--

4.2.6 Model Plant Aggregation

While EPA Platform v6 using IPM is comprehensive in representing all the units contained in NEEDS v6, 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, making the model manageable while capturing the essential characteristics of the generating units. The aggregation scheme is designed so that each model plant represents only generating units from a single state. The design makes it possible to obtain state-level results directly from IPM outputs. In addition, the aggregation scheme supports the modeling of plant-level emission limits on fossil generation.

The 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 Platform v6 are the following.

(1) Model Region

(2) Unit Technology Type

(3) Cogen

(4) Fuel Demand Region

(5) Applicable Environmental Regulations

(6) State

(7) Facility (ORIS) for fossil units

(8) Unit Configuration

(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 in the EPA Platform v6. For each plant type, the table shows the number of generating units and the number of model plants representing the generating units.[33]

Table 4-7 Aggregation Profile of Model Plants as Provided at Set up of EPA Platform v6

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass	300	165
Coal Steam	675	527
Combined Cycle	2,032	891
Combustion Turbine	5,988	2,535
Energy Storage	85	41
Fossil Waste	86	25
Fuel Cell	72	35
Geothermal	174	31
Hydro	5,455	252
IGCC	5	2
IMPORT	1	1
Landfill Gas	1,643	307
Municipal Solid Waste	166	60
Non-Fossil Waste	267	140
Nuclear	115	115
O/G Steam	590	399
Offshore Wind	1	1
Onshore Wind	1,570	89
Pumped Storage	155	27
Solar PV	2,532	98
Solar Thermal	17	5
Tires	2	1
Total	**21,931**	**5,747**

New Units	
Plant Type	**Number of IPM Model Plants**
New Battery Storage	168
New Biomass	134

[33] (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).

(2) 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 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”.

(3) The total number of model plants representing different types of new units often exceeds the 67 U.S. 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).

New Combined Cycle	456
New Combined Cycle with Carbon Capture	228
New Combustion Turbine	456
New Fuel Cell	150
New Geothermal	93
New Hydro	153
New Landfill Gas	379
New Nuclear	132
New Offshore Wind	894
New Onshore Wind	5,358
New Solar PV	1,373
New Solar Thermal	261
New Ultrasupercritical Coal with 30% CCS	266
New Ultrasupercritical Coal with 90% CCS	266
New Ultrasupercritical Coal without CCS	138
Total	**10,905**
Retrofits	
Plant Type	**Number of IPM Model Plants**
Retrofit Coal with ACI	74
Retrofit Coal with ACI + CCS	92
Retrofit Coal with ACI + CCS + HRI	92
Retrofit Coal with ACI + CCS + HRI + SCR	20
Retrofit Coal with ACI + CCS + HRI + SNCR	29
Retrofit Coal with ACI + CCS + SCR	20
Retrofit Coal with ACI + DSI	20
Retrofit Coal with ACI + DSI + HRI	20
Retrofit Coal with ACI + DSI + HRI + SCR	31
Retrofit Coal with ACI + DSI + HRI + SCR + Scrubber	22
Retrofit Coal with ACI + DSI + HRI + Scrubber	18
Retrofit Coal with ACI + DSI + HRI + Scrubber + SNCR	14
Retrofit Coal with ACI + DSI + HRI + SNCR	27
Retrofit Coal with ACI + DSI + SCR	31
Retrofit Coal with ACI + DSI + SCR + Scrubber	22
Retrofit Coal with ACI + DSI + Scrubber	18
Retrofit Coal with ACI + DSI + Scrubber + SNCR	14
Retrofit Coal with ACI + DSI + SNCR	31
Retrofit Coal with ACI + HRI	74
Retrofit Coal with ACI + HRI + SCR	62
Retrofit Coal with ACI + HRI + SCR + Scrubber	62
Retrofit Coal with ACI + HRI + Scrubber	53
Retrofit Coal with ACI + HRI + Scrubber + SNCR	74
Retrofit Coal with ACI + HRI + SNCR	61
Retrofit Coal with ACI + SCR	62
Retrofit Coal with ACI + SCR + Scrubber	62
Retrofit Coal with ACI + Scrubber	52

Retrofit Coal with ACI + Scrubber + SNCR	75
Retrofit Coal with ACI + SNCR	62
Retrofit Coal with C2G	454
Retrofit Coal with C2G + SCR	454
Retrofit Coal with CCS	791
Retrofit Coal with CCS + HRI	788
Retrofit Coal with CCS + HRI + SCR	252
Retrofit Coal with CCS + HRI + SCR + Scrubber	208
Retrofit Coal with CCS + HRI + Scrubber	232
Retrofit Coal with CCS + HRI + Scrubber + SNCR	152
Retrofit Coal with CCS + HRI + SNCR	180
Retrofit Coal with CCS + SCR	255
Retrofit Coal with CCS + SCR + Scrubber	212
Retrofit Coal with CCS + Scrubber	240
Retrofit Coal with CCS + Scrubber + SNCR	156
Retrofit Coal with CCS + SNCR	183
Retrofit Coal with DSI	21
Retrofit Coal with DSI + HRI	70
Retrofit Coal with DSI + HRI + SCR	75
Retrofit Coal with DSI + HRI + SCR + Scrubber	21
Retrofit Coal with DSI + HRI + Scrubber	26
Retrofit Coal with DSI + HRI + SNCR	69
Retrofit Coal with DSI + SCR	109
Retrofit Coal with DSI + SCR + Scrubber	33
Retrofit Coal with DSI + Scrubber	38
Retrofit Coal with DSI + SNCR	103
Retrofit Coal with HRI	482
Retrofit Coal with HRI + SCR	432
Retrofit Coal with HRI + SCR + Scrubber	450
Retrofit Coal with HRI + Scrubber	357
Retrofit Coal with HRI + Scrubber + SNCR	408
Retrofit Coal with HRI + SNCR	342
Retrofit Coal with SCR	242
Retrofit Coal with SCR + Scrubber	582
Retrofit Coal with Scrubber	224
Retrofit Coal with Scrubber + SNCR	544
Retrofit Coal with SNCR	203
Retrofit Combined Cycle with CCS	2787
Retrofit Oil/Gas steam with SCR	222
Total	**13,691**
Retirements	
Plant Type	**Number of IPM Model Plants**
Biomass Retirement	165
CC Retirement	891
Coal Retirement	5,394

CT Retirement	2,535
Geothermal Retirement	31
Hydro Retirement	252
IGCC Retirement	2
Landfill Gas Retirement	307
Nuke Retirement	115
Oil/Gas steam Retirement	1,075
Total	**10,767**
Grand Total (Existing and Planned/Committed + New + Retrofits + Retirements):41,110	

4.2.7 Cost and Performance Characteristics of Existing Units[34]

In EPA Platform v6, the cost and performance characteristics of an existing unit are determined by the unit's heat rates, emission rates, variable operation and maintenance cost (VOM), and fixed operation and maintenance costs (FOM). For existing units, only the cost of maintaining (FOM) and running (VOM) the unit are modeled because capital costs and all related carrying capital charges are sunk, and hence, economically irrelevant for projecting least-cost investment and operational decisions going forward. The section below discusses the cost and performance assumptions for existing units used in the EPA Platform v6.

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 Platform v6. The following further discusses the components of VOM costs and the VOM modeling methodology.

Variable O&M Approach: EPA Platform v6 uses a modeling construct termed as Segmental VOM to capture the variability in operation and maintenance costs that are treated as a function of the unit's dispatch pattern. Generally speaking the construct captures costs associated with major maintenance and consumables. The VOM for combined cycles and combustion turbine units includes the costs of both major maintenance and consumables while for coal steam and oil/gas steam units includes only the cost of consumables. The VOM cost of various emission control technologies is also incorporated.

Major maintenance: Major maintenance costs are those required to maintain a unit at its delivered performance specifications and whose terms are usually dictated through its long term service agreement (LTSA). The three main areas of maintenance for gas turbines include combustion inspection, hot gas path inspection, and major inspections. All of these costs are driven by the hours of operation and the number of starts that are incurred within that time period of operation. In a cycling or mid-merit type mode of operation, there are many starts, accelerating the approach of an inspection. As more starts are incurred compared to the generation produced, cost per generation increase. For base load operation there are fewer starts spread over more generation, lowering the cost per generation. While this nomenclature is for gas-turbine based systems, steam turbine based systems have a parallel construct.

Consumables: The model captures consumable costs, as purely a function of output and does not varies across the segmented time-period. In other words, the consumables cost component is held constant over both peak and off-peak segments. Consumables include chemicals, lube oils, make-up water, waste water disposal, reagents, and purchased electricity.

[34] All units excluding nuclear units.

Data Sources for Gas-Turbine Based Prime Movers:
ICF has engaged its deep expertise in operation & maintenance costs for these types of prime movers to develop generic variable O&M costs as a function of technology.

As mentioned above the variable O&M for gas-turbine based systems tracks Long Term Service Agreement costs, start-up and consumables.

Data Sources for Stand-Alone Steam Turbine Based Prime Movers:
The value levels of non-fuel variable O&M data for stand-alone steam turbine plants is based on ICF experience. The VOM cost adders of various emission control technologies are based on cost functions described in Chapter 5.

Table 4-8 VOM Assumptions in EPA Platform v6

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2016$/mills/kWh)
Biomass	--	--	--	7.29
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	1.43
			ACI	2.90
		SCR	No Hg Control	2.39
			ACI	3.86
		SNCR	No Hg Control	2.36
			ACI	3.83
	Dry FGD	No NO_x Control	No Hg Control	3.5
			ACI	4.97
		SCR	No Hg Control	4.46
			ACI	5.93
		SNCR	No Hg Control	4.43
			ACI	5.9
	Wet FGD	No NO_x Control	No Hg Control	3.95
			ACI	5.43
		SCR	No Hg Control	4.91
			ACI	6.39
		SNCR	No Hg Control	4.88
			ACI	6.35
	DSI	No NO_x Control	No Hg Control	8.21
			ACI	9.68
		SCR	No Hg Control	9.17
			ACI	10.64
		SNCR	No Hg Control	9.14
			ACI	10.61
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	1.98 - 3.78
		SCR		2.12 - 3.92
		SNCR		2.61 - 4.41
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	3.31 - 15.7
		SCR		3.45 - 15.84
		SNCR		3.94 - 16.33

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2016$/mills/kWh)
Fuel Cell	--	--	--	44.91
Geothermal	--	--	--	5.49
Hydro	--	--	--	2.66
IGCC	--	--	--	2.28-4.04
Landfill Gas / Municipal Solid Waste	--	--	--	6.54
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0.83
		SCR		0.97
		SNCR		1.46
Pumped Storage	--	--	--	10.17
Solar PV	--	--	--	0
Solar Thermal	--	--	--	0
Wind	--	--	--	0

Fixed Operation and Maintenance Cost (FOM)

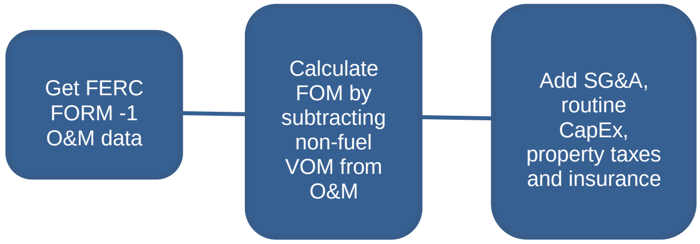
FOM represents the annual fixed cost of maintaining a unit. FOM costs are incurred independent of generation levels and signify the fixed cost of operating and maintaining the unit's availability to provide generation. Table 4-9 summarizes the FOM assumptions[35]. Note that FOM varies by the age of the 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 SNL and ICF research. The following further discusses the procedure for developing the FOM costs.

Stand Alone – Steam Turbines Based Prime Movers

O&M cost data for existing coal and oil/gas steam units were developed starting with FERC Form 1 data sets from the years 2011 to 2016. The FERC Form-1 database does not explicitly report separate fixed and variable O&M expenses. In deriving Fixed O&M costs, generic variable O&M costs are assigned to each individual power plant. Next, the assumed variable O&M cost is subtracted from the total O&M reported by FERC Form-1 to calculate a starting point for fixed O&M. Thereafter, other cost items which are not reported by FERC Form-1 are added to the raw FOM starting point. These unreported cost items are selling, general, and administrative expenses (SG&A), property taxes, insurance, and routine capex. A detailed description of the fixed O&M derivation methodology is provided below.

[35] Cogen units whose primary purpose is to provide process heat are called as bottoming cycle units and are identified based on Form EIA 860. Such units are provided a FOM of zero in EPA Platform v6. This is to acknowledge the fact that the economics of such a unit cannot be comprehensively modeled in a power sector focused model.

Figure 4-1 Derivation of Plant Fixed O&M Data



i) Assign generic VOM cost to each unit in FERC Form 1 based on the control configuration. Subtract this VOM from the total O&M cost from FERC Form 1 to calculate raw FOM cost. The FOM cost of operating the existing controls is estimated based on cost functions in Chapter 5 and deducted from the raw FOM cost. Aggregate this unit level raw FOM cost data into age based categories. The weighted average raw FOM costs for uncontrolled units by age group is the output of this step and is used as the starting point for subsequent steps.

ii) An owner/operator fee for SG&A services in the range of 20-30% is added to raw fixed O&M figures in step 1.

iii) Property tax and insurance cost estimates in $/kW-year are also added. These figures vary by plant type.

iv) A generic percentage value to cover routine capex is added to raw fixed O&M figures in step 1. The percentage varies by prime mover and is based on a review of FERC Form 1 data

v) Finally, generic FOM cost adders for various emission control technologies are estimated using cost functions described in Chapter 5. Based on the emission control configuration of each unit in NEEDS, the appropriate emission control cost adder is added to the FOM cost of an uncontrolled unit from step iv.

The fixed O&M derivation approach relies on top-down derivation of fixed costs based on FERC Form-1 data and ICF's own non-fuel variable O&M, SG&A, routine capex, property tax, and insurance.

<u>Gas-Turbine Based Prime Movers</u>

Similar to the stand-alone steam turbine based prime movers, the Fixed O&M for gas-turbine based systems tracks: labor, routine maintenance, property taxes, insurance, owner/operator SG&A, and routine capital expenditures. These generic Fixed O&M costs as a function of technology are based on ICF's deep expertise in fixed O&M costs for these types of prime movers

Table 4-9 FOM Assumptions in EPA Platform v6

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2016$ /kW-Yr)
Biomass	--	--	--	All Years	134.52
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	28.34
				40 to 50 Years	32.4
				Greater than 50 Years	41.63
			ACI	0 to 40 Years	28.42
				40 to 50 Years	32.49
				Greater than 50 Years	41.72
		SCR	No Hg Control	0 to 40 Years	29.12
				40 to 50 Years	33.18
				Greater than 50 Years	42.41
			ACI	0 to 40 Years	29.2
				40 to 50 Years	33.27

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2016$ /kW-Yr)
				Greater than 50 Years	42.5
		SNCR	No Hg Control	0 to 40 Years	28.62
		SNCR	No Hg Control	40 to 50 Years	32.69
		SNCR	No Hg Control	Greater than 50 Years	41.92
		SNCR	ACI	0 to 40 Years	28.71
		SNCR	ACI	40 to 50 Years	32.77
		SNCR	ACI	Greater than 50 Years	42
	Dry FGD	No NO_x Control	No Hg Control	0 to 40 Years	38
	Dry FGD	No NO_x Control	No Hg Control	40 to 50 Years	42.06
	Dry FGD	No NO_x Control	No Hg Control	Greater than 50 Years	51.29
	Dry FGD	No NO_x Control	ACI	0 to 40 Years	38.08
	Dry FGD	No NO_x Control	ACI	40 to 50 Years	42.15
	Dry FGD	No NO_x Control	ACI	Greater than 50 Years	51.38
	Dry FGD	SCR	No Hg Control	0 to 40 Years	38.78
	Dry FGD	SCR	No Hg Control	40 to 50 Years	42.84
	Dry FGD	SCR	No Hg Control	Greater than 50 Years	52.07
	Dry FGD	SCR	ACI	0 to 40 Years	38.86
	Dry FGD	SCR	ACI	40 to 50 Years	42.93
	Dry FGD	SCR	ACI	Greater than 50 Years	52.16
	Dry FGD	SNCR	No Hg Control	0 to 40 Years	38.28
	Dry FGD	SNCR	No Hg Control	40 to 50 Years	42.35
	Dry FGD	SNCR	No Hg Control	Greater than 50 Years	51.58
	Dry FGD	SNCR	ACI	0 to 40 Years	38.36
	Dry FGD	SNCR	ACI	40 to 50 Years	42.43
	Dry FGD	SNCR	ACI	Greater than 50 Years	51.66
	Wet FGD	No NO_x Control	No Hg Control	0 to 40 Years	37.59
	Wet FGD	No NO_x Control	No Hg Control	40 to 50 Years	41.66
	Wet FGD	No NO_x Control	No Hg Control	Greater than 50 Years	50.89
	Wet FGD	No NO_x Control	ACI	0 to 40 Years	37.68
	Wet FGD	No NO_x Control	ACI	40 to 50 Years	41.75
	Wet FGD	No NO_x Control	ACI	Greater than 50 Years	50.97
	Wet FGD	SCR	No Hg Control	0 to 40 Years	38.37
	Wet FGD	SCR	No Hg Control	40 to 50 Years	42.44
	Wet FGD	SCR	No Hg Control	Greater than 50 Years	51.67
	Wet FGD	SCR	ACI	0 to 40 Years	38.46
	Wet FGD	SCR	ACI	40 to 50 Years	42.53
	Wet FGD	SCR	ACI	Greater than 50 Years	51.75
	Wet FGD	SNCR	No Hg Control	0 to 40 Years	37.88
	Wet FGD	SNCR	No Hg Control	40 to 50 Years	41.95
	Wet FGD	SNCR	No Hg Control	Greater than 50 Years	51.17
	Wet FGD	SNCR	ACI	0 to 40 Years	37.96
	Wet FGD	SNCR	ACI	40 to 50 Years	42.03
	Wet FGD	SNCR	ACI	Greater than 50 Years	51.26
	DSI	No NO_x Control	No Hg Control	0 to 40 Years	29.7
	DSI	No NO_x Control	No Hg Control	40 to 50 Years	33.77
	DSI	No NO_x Control	No Hg Control	Greater than 50 Years	43
	DSI	No NO_x Control	ACI	0 to 40 Years	29.78
	DSI	No NO_x Control	ACI	40 to 50 Years	33.85
	DSI	No NO_x Control	ACI	Greater than 50 Years	43.08

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2016$ /kW-Yr)
		SCR	No Hg Control	0 to 40 Years	30.48
				40 to 50 Years	34.55
				Greater than 50 Years	43.78
			ACI	0 to 40 Years	30.57
				40 to 50 Years	34.63
				Greater than 50 Years	43.86
		SNCR	No Hg Control	0 to 40 Years	29.98
				40 to 50 Years	34.05
				Greater than 50 Years	43.28
			ACI	0 to 40 Years	30.07
				40 to 50 Years	34.14
				Greater than 50 Years	43.37
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	-	29.19
		SCR	No Hg Control	-	30.54
		SNCR	No Hg Control	-	29.89
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	-	18.7
		SCR	No Hg Control	-	20.72
		SNCR	No Hg Control	-	19.23
Fuel Cell	--	--	--	All Years	0
Geothermal	--	--	--	All Years	93.51
Hydro	--	--	--	All Years	14.89
IGCC	No SO_2 Control	No NO_x Control	--	All Years	102.34
Landfill Gas / Municipal Solid Waste	--	--	--	All Years	234.69
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	16.94
				40 to 50 Years	25.72
				Greater than 50 Years	33.51
		SCR	No Hg Control	0 to 40 Years	18.05
				40 to 50 Years	26.84
				Greater than 50 Years	34.62
		SNCR	No Hg Control	0 to 40 Years	17.15
				40 to 50 Years	25.93
				Greater than 50 Years	33.72
Pumped Storage	--	--	--	All Years	17.27
Solar PV	--	--	--	All Years	27.99
Solar Thermal	--	--	--	All Years	77.93
Wind	--	--	--	All Years	28.18

Heat Rates

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

Lifetimes

Unit lifetime assumptions are detailed in Sections 3.7 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 Platform v6.

Cogeneration Units

For cogeneration units, the dispatch decisions in IPM are only based on the benefits obtained from the electric portion of a cogeneration unit. In IPM, a cogeneration unit uses a net heat rate, which is calculated by dividing heat content of fuel consumed for power generation by electricity generated from this fuel. To capture the total emissions from the cogeneration unit, a multiplier is applied to the power only emissions. The multiplier is calculated as a ratio between the total heat rate and the net heat rate where the total heat rate is calculated by dividing the heat content of fuel consumed for power and steam generation by electricity generated from this fuel.

Coal Switching

Recognizing that boiler modifications and fuel handling enhancements may be required for unrestricted switching from bituminous to subbituminous coal, and vice versa, the following procedure applies in EPA Platform v6 to coal units that have the option to burn both bituminous and subbituminous coals.

(i) An examination of the EIA Form 923 coal delivery data for the period 2008-2016 is conducted for each unit to determine the unit's historical maximum share of bituminous coal and that of subbituminous coal. For example, if in at least one year during the period 2008-2016 a unit burned 90% or less subbituminous coal, its historical maximum share of subbituminous coal is set at 90%.

(ii) The following rules then apply.

Blending Subbituminous Coal:

If a unit's historical maximum share of subbituminous coal is greater than 90%, the unit incurs no fuel switching cost adder to increase its subbituminous coal burn. The unit is assumed to have already made the fuel handling and boiler investments needed to burn up to 100% subbituminous coal. It would therefore face no additional cost. In addition, the unit's heat rate is assumed to reflect the impact of burning the corresponding proportion of subbituminous coal.

If a unit's historical maximum share of subbituminous coal is less than 90%, the unit incurs a heat rate penalty of 5% and a fuel switching cost adder. The heat rate penalty reflects the impact of the higher moisture content subbituminous coal on the unit's heat rate. And the cost adder is designed to cover boiler modifications, or alternative power purchases in lieu of capacity deratings that would otherwise be associated with burning subbituminous coal with its lower heating value relative to bituminous coal. The cost adder is determined as follows:

- If the unit's historical maximum share of subbituminous coal is less than 20%, the unit can burn up to 20% subbituminous coal at no cost adder. Burning beyond 20% subbituminous coal, the unit incurs a cost adder of 270 (2016$ per kW).

- If the unit's historical maximum share of subbituminous coal is greater than 20% but less than 90%, the unit can burn up to its historical maximum share of subbituminous coal at no cost adder. Burning beyond its historical maximum share of subbituminous coal, the unit incurs a cost adder calculated by the following equation:

$$Fuel\ Switching\ Cost\ Adder\ (2016\$\ per\ kW) =$$

$$270\ \times \left\{\frac{(100 - Historical\ Maximun\ Share\ of\ Subbituminous)}{(100 - 20)}\right\}$$

Blending Bituminous Coal:

If a unit's historical maximum share of bituminous coal is greater than 90%, the unit incurs no fuel switching cost adder.

If a unit's historical maximum share of bituminous coal is less than 90%, the unit incurs a fuel switching cost adder determined as follows:

- If the unit's historical maximum share of bituminous coal is less than 20%, the unit can burn up to 20% bituminous coal at no cost adder. Burning beyond 20% bituminous coal, the unit incurs a cost adder of 54 (2016$ per kW).

- If the unit's historical maximum share of bituminous coal is greater than 20% but less than 90%, the unit can burn up to its historical maximum share of bituminous coal at no cost adder. Burning beyond its historical maximum share of bituminous coal, the unit incurs a cost adder calculated by the following equation:

$$Fuel\ Switching\ Cost\ Adder\ (2016\$\ per\ kW) =$$

$$54\ \times \left\{\frac{(100 - Historical\ Maximun\ Share\ of\ Bituminous)}{(100 - 20)}\right\}$$

4.2.8 Life Extension Costs for Existing Units

The modeling time horizon in EPA Platform v6 extends to 2050 and covers a period of almost 30 years. This time horizon requires consideration of investments, beyond routine maintenance, necessary to extend the life of existing units. The life extension costs for different unit types are summarized in Table 4-10 below. Each unit has the option to retire or incorporate the life extension costs. These costs were based on a review of 2007-2016 FERC Form 1 data maintained by SNL regarding reported annual capital expenditures made by older units. The life extension costs were added once the unit reaches its assumed lifespan. However, if the unit reaches its lifespan before the first run year, then the life extension cost was applied when the unit reaches twice its lifespan age. The assumption implies if the unit has reached its lifespan before the first run year, it has already incurred the necessary life extension related investment costs and is considered sunk. Life extension costs for nuclear units are discussed in Section 4.5.1.

Table 4-10 Life Extension Cost Assumptions Used in EPA Platform v6

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost (2016$/kW)	Capital Cost of New Unit (2016$/kW)	Life Extension Cost as Proportion of New Unit Capital Cost (%)
Biomass	40	291	4,429	6.6
Coal Steam	40	212	3,639	5.84
Combined Cycle	30	89	978	9.06
Combustion Turbine	30	246	678	36.3
IC Engine	30	177	1,342	13.2
Oil/Gas Steam	40	182	3,311	5.5
IGCC	40	241	3,254	7.4
Landfill Gas	20	823	9,023	9.1

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

4.3 Planned-Committed Units

EPA Platform v6 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 June 30, 2021.

4.3.1 Population and Model Plant Aggregation

Table 4-11 summarizes the extent of inventory of planned-committed units represented by unit types and generating capacity.

Table 4-11 Summary of Planned-Committed Units in NEEDS v6 for EPA Platform v6

Plant Type	Capacity (MW)	Year Range Described
Renewables/Non-conventional		
Biomass	12	2019 - 2019
Energy Storage	22	2018 - 2019
Hydro	244	2018 - 2020
Non-Fossil Waste	44	2018 - 2020
Onshore Wind	3,483	2018 - 2019
Solar PV	431	2018 - 2020
Subtotal	4,237	
Fossil/Conventional		
Combined Cycle	18,195	2018 - 2020
Combustion Turbine	2,302	2018 - 2021
Nuclear	2,200	2022 - 2023
O/G Steam	23	2018 - 2018
Subtotal	22,720	
Grand Total	26,957	

Table 4-12 gives a breakdown of planned-committed units by IPM region, plant type, and capacity.

Table 4-12 Planned-Committed Units by Model Region in NEEDS v6 for EPA Platform v6

IPM Region	Plant Type	Capacity (MW)
ERC_PHDL	Onshore Wind	588
ERC_REST	Combustion Turbine	1,061
	Non-Fossil Waste	23
	Onshore Wind	160
ERC_WEST	Onshore Wind	660
FRCC	Biomass	12
	Combined Cycle	1,640
	Solar PV	149
MIS_AMSO	Combined Cycle	1,000
MIS_IA	Onshore Wind	66
MIS_INKY	Combined Cycle	644
MIS_MAPP	Combustion Turbine	218
MIS_MNWI	Combustion Turbine	215
	Onshore Wind	40
MIS_WUMS	Combined Cycle	700
	Solar PV	2
NENG_CT	Combined Cycle	1,230
	Combustion Turbine	90
NENG_ME	O/G Steam	23
NY_Z_C&E	Solar PV	4
NY_Z_G-I	Combined Cycle	705
	Non-Fossil Waste	19
PJM_ATSI	Combined Cycle	273
PJM_Dom	Combined Cycle	1,585
	Combustion Turbine	300
PJM_EMAC	Combined Cycle	1,368
PJM_PENE	Combined Cycle	926
	Combustion Turbine	13
PJM_SMAC	Combined Cycle	755
PJM_West	Combined Cycle	1,187
PJM_WMAC	Combined Cycle	3,472
S_C_TVA	Combined Cycle	1,052
S_SOU	Nuclear	2,200
S_VACA	Combined Cycle	1,072
SPP_N	Combustion Turbine	6
SPP_SPS	Onshore Wind	800
SPP_WAUE	Onshore Wind	98
SPP_WEST	Combustion Turbine	399
	Onshore Wind	200
WEC_CALN	Combined Cycle	586
	Non-Fossil Waste	2
	Solar PV	200
WECC_CO	Onshore Wind	30
WECC_NM	Onshore Wind	580
WECC_PNW	Hydro	244
	Onshore Wind	60

IPM Region	Plant Type	Capacity (MW)
	Solar PV	56
WECC_SCE	Energy Storage	22
	Onshore Wind	171
	Solar PV	20
WECC_WY	Onshore Wind	30

Note:

Any unit in NEEDS v6 that has an online year of 2018 or later was considered a Planned/Committed Unit.

4.3.2 Capacity

The capacity data of planned-committed units in NEEDS v6 was obtained from the sources reported in Table 4-1.

4.3.3 State and Model Region

State location data for the planned-committed units in NEEDS v6 came from the information sources noted in Section 4.3.1. The state-county 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 v6 are only those likely to come on-line before June 2021, as 2021 is the first analysis year in the EPA Platform v6. All planned-committed units were assigned an online year and given a default retirement year of 9999.

4.3.5 Unit Configuration, Cost, and Performance

All planned-committed units in NEEDS v6 assume the cost, performance, and unit configuration characteristics of potential units that are available in 2021. A detailed description of potential unit assumptions is provided below in Section 4.4.

4.4 Potential Units

The EPA Platform v6 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 zero 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" provides the type and number of potential units available in EPA Platform v6. The following sections describe the cost and performance assumptions for the potential units represented in the EPA Platform v6.

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 Platform v6 are derived primarily from assumptions used in the Annual Energy Outlook (AEO) 2017 published by the U.S. Department of Energy's Energy Information Administration.

4.4.2 Cost and Performance for Potential Conventional Units

Table 4-13 shows the cost and performance assumptions for potential conventional units. 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 each model run for these technologies is not restricted to these capacity levels.

The table includes several components of cost. The total installed cost of developing and building a new plant is captured through 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 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, and licenses). The capital costs of new non-wind and non-solar units are increased to account for the cost of maintaining and expanding the transmission network. This cost based on AEO 2017 is equal to 97 $/kW outside of WECC and NY regions and 145 $/kW within these regions. The capital costs do not include interest during construction (IDC). IDC is added to the capital costs during the set-up of an IPM run. Calculation of IDC is based on the construction profile of the build option and the discount rate. Details on the discount rates used in the EPA Platform v6 are provided in Chapter 10 of this documentation.

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 variable 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 is online. Availability takes into account estimates of the time consumed by planned maintenance and forced outages. The emission characteristics of the potential units can be found in Table 3-17.

4.4.3 Short-Term Capital Cost Adder

In addition to the capital costs shown in Table 4-13 and Table 4-16, EPA Platform v6 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 2035. The adder is not imposed after 2035, assuming markets for labor and materials have sufficient time to respond to changes in demand.

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 by the entire amount of capacity deployed, where the level of the cost adder depends upon the total amount of new capacity added in that run year. For example, the Step 1 upper bound in 2021 for landfill gas potential units is 625 MW. If no more than this total new landfill gas capacity is built in 2021, only the capital cost shown in Table 4-16 is incurred. If the model builds between 625 and 1,088 MW, the Step 2 cost adder of $3,979/kW applies to the entire capacity deployed. If the total new landfill gas capacity exceeds the Step 2 upper bound of 1,088 MW, then the Step 3 capacity adder of $12,639/kW is incurred by the entire capacity deployed in that run year. 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 4-13 are generic. Before implemented, the capital cost values are converted to region-specific costs by applying regional cost adjustment factors that capture regional differences in labor, material, and construction costs and ambient conditions. These factors are calculated by multiplying the regional cost and ambient condition multipliers. The regional cost multipliers are based on county level estimates developed by the Energy Institute at University of Texas at Austin[36]. The ambient condition multipliers are from AEO 2017. Table 4-15 summarizes the regional cost adjustment factors at the IPM region and technology level. The factors are applied to both conventional technologies shown in Table 4-13 and renewable and nonconventional technologies shown in Table 4-16. However, they are not applied to hydro and geothermal technologies as site-specific costs are used for these two technologies.

[36] New U.S. Power Costs: by County, with Environmental Externalities, University of Texas at Austin, Energy Institute. July 2016

Table 4-13 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Platform v6

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Advanced Combustion Turbine	Nuclear	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Size (MW)	429	429	237	2234	650	650	650
First Year Available	2021	2021	2021	2023	2021	2021	2021
Lead Time (Years)	3	3	2	6	4	4	4
Availability	87%	87%	93%	90%	85%	85%	85%
Vintage #1 (2021)							
Heat Rate (Btu/kWh)	6,267	7,514	9,264	10,459	9,644	11,171	8,704
Capital (2016$/kW)	1,081	2,104	662	5,644	4,953	5,477	3,580
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #2 (2023)							
Heat Rate (Btu/kWh)	6,233	7,504	8,907	10,459	9,433	10,214	8,514
Capital (2016$/kW)	1,064	2,059	651	5,300	4,863	5,378	3,516
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #3 (2025)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	1,041	2,003	636	5,164	4,746	5,249	3,431
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #4 (2030)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	963	1,833	580	4,804	4,434	4,904	3,205
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #5 (2035)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	902	1,698	536	4,527	4,198	4,642	3,035
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #6 (2040)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Advanced Combustion Turbine	Nuclear	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Capital (2016$/kW)	857	1,589	505	4,283	3,991	4,413	2,885
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #7 (2045)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	816	1,487	477	4,049	3,792	4,193	2,741
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6
Vintage #8 (2050)							
Heat Rate (Btu/kWh)	6,200	7,493	8,550	10,459	9,221	9,257	8,323
Capital (2016$/kW)	778	1,390	454	3,810	3,585	3,965	2,592
Fixed O&M (2016$/kW/yr)	9.9	33.2	6.8	99.7	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2.0	7.1	10.6	2.3	7.1	9.5	4.6

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

Table 4-14 Short-Term Capital Cost Adders for New Power Plants in EPA Platform v6 (2016$)

Plant Type		2021			2023			2025			2030			2035		
		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
Biomass	Upper Bound (MW)	1,904	3,312	No limit	1,270	2,208	No limit	1,270	2,208	No limit	3,174	5,520	No limit	3,174	5,520	No limit
	Adder ($/kW)	-	1,714	5,443	-	1,685	5,352	-	1,646	5,230	-	1,543	4,903	-	1,466	4,658
Coal Steam - UPC	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	1,640	5,209	-	1,610	5,115	-	1,572	4,992	-	1,468	4,664	-	1,390	4,415
Coal Steam - UPC30	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	2,269	7,206	-	2,228	7,076	-	2,174	6,906	-	2,031	6,452	-	1,923	6,108
Coal Steam - UPC90	Upper Bound (MW)	18,361	31,932	No limit	12,241	21,288	No limit	12,241	21,288	No limit	30,602	53,220	No limit	30,602	53,220	No limit
	Adder ($/kW)	-	2,509	7,969	-	2,463	7,825	-	2,404	7,636	-	2,246	7,134	-	2,126	6,754
Combined Cycle	Upper Bound (MW)	132,125	229,782	No limit	88,083	153,188	No limit	88,083	153,188	No limit	220,208	382,970	No limit	220,208	382,970	No limit
	Adder ($/kW)	-	490	1,555	-	481	1,528	-	469	1,491	-	433	1,376	-	406	1,290
Combustion Turbine	Upper Bound (MW)	66,275	115,260	No limit	44,183	76,840	No limit	44,183	76,840	No limit	110,458	192,100	No limit	110,458	192,100	No limit
	Adder ($/kW)	-	298	945	-	291	924	-	281	893	-	255	809	-	235	747
Fuel Cell	Upper Bound (MW)	1,725	3,000	No limit	1,150	2,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	3,101	9,850	-	3,007	9,551	-	2,896	9,200	-	2,615	8,305	-	2,386	7,578
Geothermal	Upper Bound (MW)	883	1,536	No limit	589	1,024	No limit	589	1,024	No limit	1,472	2,560	No limit	1,472	2,560	No limit
	Adder ($/kW)	-	3,772	11,983	-	3,763	11,954	-	3,744	11,892	-	3,700	11,754	-	3,636	11,549
Landfill Gas	Upper Bound (MW)	625	1,088	No limit	417	725	No limit	417	725	No limit	1,042	1,813	No limit	1,042	1,813	No limit
	Adder ($/kW)	-	3,979	12,639	-	3,915	12,437	-	3,822	12,140	-	3,577	11,361	-	3,379	10,733
Nuclear	Upper Bound (MW)	32,327	56,220	No limit	21,551	37,480	No limit	21,551	37,480	No limit	53,878	93,700	No limit	53,878	93,700	No limit
	Adder ($/kW)	-	2,499	7,939	-	2,347	7,456	-	2,287	7,264	-	2,127	6,757	-	2,005	6,368
Solar Thermal	Upper Bound (MW)	2,830	4,921	No limit	1,886	3,281	No limit	1,886	3,281	No limit	4,716	8,202	No limit	4,716	8,202	No limit
	Adder ($/kW)	-	2,327	7,390	-	2,736	8,691	-	2,640	8,385	-	2,430	7,719	-	2,286	7,262
Solar PV	Upper Bound (MW)	25,858	46,265	No limit	18,406	32,011	No limit	18,406	32,011	No limit	46,016	80,027	No limit	46,016	80,027	No limit
	Adder ($/kW)	-	366	1,163	-	398	1,263	-	384	1,218	-	359	1,141	-	339	1,077
Onshore Wind	Upper Bound (MW)	33,941	67,466	No limit	30,238	52,588	No limit	30,238	52,588	No limit	75,595	131,470	No limit	75,595	131,470	No limit
	Adder ($/kW)	-	716	2,275	-	693	2,200	-	667	2,120	-	602	1,911	-	575	1,827
Offshore Wind	Upper Bound (MW)	1,725	3,000	No limit	1,150	2,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	2,143	6,808	-	1,933	6,139	-	1,893	6,012	-	1,798	5,712	-	1,752	5,565
Hydro	Upper Bound (MW)	10,360	18,018	No limit	6,907	12,012	No limit	6,907	12,012	No limit	17,267	30,030	No limit	17,267	30,030	No limit
	Adder ($/kW)	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313	-	1,043	3,313

Table 4-15 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in EPA Platform v6

Model Region	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Nuclear	Biomass	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra supercritical Coal without CCS	Ultra supercritical Coal with 30% CCS	Ultra supercritical Coal with 90% CCS
ERC_PHDL	1.006	1.006	1.042	0.979	0.922	0.92	1.002	1.002	0.96	0.916	0.9	1.005	1.005	0.992
ERC_REST	0.977	0.977	1.027	0.969	0.922	0.92	0.968	0.968	0.94	0.889	0.9	0.981	0.981	0.969
ERC_WEST	0.999	0.999	1.038	0.976	0.922	0.92	0.989	0.989	0.95	0.909	0.9	0.997	0.997	0.985
FRCC	0.983	0.983	1.033	0.976	0.948	0.949	0.961	0.961	0.94	0.899	1	1.001	1.001	0.991
MIS_AMSO	0.955	0.955	1.015	0.963	0.93	0.933	0.949	0.949	0.92	0.865	0.9	0.958	0.958	0.947
MIS_AR	0.977	0.977	1.022	0.977	0.93	0.933	0.977	0.977	0.95	0.914	0.9	0.995	0.995	0.987
MIS_D_MS	0.958	0.958	1.013	0.968	0.93	0.933	0.958	0.958	0.93	0.884	0.9	0.972	0.972	0.962
MIS_IA	1.001	1.001	1.017	0.999	0.968	0.968	1.041	1.041	1.01	0.993	1	1.013	1.013	1.008
MIS_IL	1	1	1.016	0.999	1.017	1.019	1.014	1.014	1	0.99	1	1.021	1.021	1.02
MIS_INKY	0.987	0.987	1.007	0.998	1.01	0.994	1.003	1.003	0.99	0.972	1	1.009	1.009	1.008
MIS_LA	0.958	0.958	1.013	0.967	0.93	0.933	0.957	0.957	0.93	0.879	0.9	0.968	0.968	0.956
MIS_LMI	1.009	1.009	1.015	1.016	0.995	0.997	1.024	1.024	1.01	1.002	1	1.025	1.025	1.022
MIS_MAPP	0.97	0.97	1.003	0.986	0.968	0.968	1.035	1.035	0.99	0.945	1	0.976	0.976	0.967
MIS_MIDA	0.996	0.996	1.015	0.997	0.968	0.968	1.04	1.04	1.01	0.984	1	1.007	1.007	1
MIS_MNWI	1.006	1.006	1.02	1	0.968	0.968	1.05	1.05	1.02	1.008	1	1.015	1.015	1.01
MIS_MO	0.995	0.995	1.015	0.995	1.017	1.019	1.016	1.016	1	0.981	1	1.013	1.013	1.009
MIS_WOTA	0.956	0.956	1.01	0.966	0.93	0.933	0.956	0.956	0.92	0.875	0.9	0.964	0.964	0.952
MIS_WUMS	1.028	1.028	1.032	1.013	1.01	0.994	1.045	1.045	1.03	1.029	1	1.046	1.046	1.044
NENG_CT	1.181	1.181	1.146	1.068	1.03	1.009	1.081	1.081	1.08	1.103	1	1.112	1.112	1.116
NENG_ME	1.064	1.064	1.074	1.042	1.03	1.009	1.065	1.065	1.02	0.993	1	1.048	1.048	1.047
NENGREST	1.115	1.115	1.105	1.053	1.03	1.009	1.068	1.068	1.04	1.034	1	1.075	1.075	1.075
NY_Z_A	1.061	1.061	1.072	1.039	1.034	0.999	1.021	1.021	1	0.988	1	1.05	1.05	1.046
NY_Z_B	1.076	1.076	1.081	1.043	1.034	0.999	1.027	1.027	1	0.992	1	1.058	1.058	1.054
NY_Z_C&E	1.11	1.11	1.111	1.056	1.034	0.999	1.038	1.038	1.02	1.005	1	1.08	1.08	1.078
NY_Z_D	1.076	1.076	1.092	1.045	1.034	0.999	1.043	1.043	1.01	0.986	1	1.056	1.056	1.053
NY_Z_F	1.129	1.129	1.122	1.055	1.034	0.999	1.06	1.06	1.04	1.04	1	1.085	1.085	1.085
NY_Z_G-I	1.195	1.195	1.161	1.068	1.034	0.999	1.079	1.079	1.09	1.13	1	1.119	1.119	1.122

Model Region	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Nuclear	Biomass	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra supercritical Coal without CCS	Ultra supercritical Coal with 30% CCS	Ultra supercritical Coal with 90% CCS
NY_Z_J	1.257	1.257	1.205	1.074	1.227	1.26	1.093	1.093	1.12	1.216	1.2	1.157	1.157	1.162
NY_Z_K	1.241	1.241	1.196	1.073	1.227	1.26	1.092	1.092	1.1	1.163	1.2	1.153	1.153	1.158
PJM_AP	1.073	1.073	1.088	1.034	1.01	0.994	1.008	1.008	0.98	0.961	1	1.072	1.072	1.069
PJM_ATSI	1.031	1.031	1.046	1.018	1.01	0.994	1.007	1.007	0.99	0.974	1	1.043	1.043	1.039
PJM_COMD	1.022	1.022	1.026	1.009	1.01	0.994	1.04	1.04	1.03	1.042	1	1.039	1.039	1.039
PJM_Dom	1.144	1.144	1.153	1.046	0.913	0.911	1.018	1.018	0.99	0.964	0.9	1.13	1.13	1.127
PJM_EMAC	1.209	1.209	1.179	1.073	1.065	1.033	1.066	1.066	1.06	1.09	1	1.144	1.144	1.148
PJM_PENE	1.097	1.097	1.105	1.047	1.065	1.033	1.024	1.024	1	0.988	1	1.083	1.083	1.081
PJM_SMAC	1.155	1.155	1.144	1.063	1.065	1.033	1.036	1.036	1.01	0.99	1	1.118	1.118	1.118
PJM_West	0.991	0.991	1.019	1.004	1.01	0.994	0.989	0.989	0.97	0.939	1	1.012	1.012	1.008
PJM_WMAC	1.151	1.151	1.144	1.06	1.065	1.033	1.043	1.043	1.02	1.018	1	1.113	1.113	1.113
S_C_KY	0.981	0.981	1.015	0.99	0.934	0.933	0.979	0.979	0.95	0.919	0.9	1.006	1.006	1.004
S_C_TVA	0.957	0.957	1.003	0.979	0.934	0.933	0.968	0.968	0.94	0.899	0.9	0.981	0.981	0.975
S_D_AECI	0.989	0.989	1.014	0.992	1.017	1.019	1.013	1.013	0.99	0.971	1	1.005	1.005	0.999
S_SOU	0.963	0.963	1.02	0.969	0.925	0.925	0.953	0.953	0.92	0.873	0.9	0.982	0.982	0.972
S_VACA	1.015	1.015	1.059	1.003	0.913	0.911	0.975	0.975	0.94	0.896	0.9	1.033	1.033	1.025
SPP_N	1	1	1.032	0.986	0.973	0.975	1.016	1.016	0.98	0.948	1	1.009	1.009	0.998
SPP_NEBR	0.976	0.976	1.009	0.988	0.968	0.968	1.029	1.029	0.98	0.945	1	0.982	0.982	0.971
SPP_SPS	0.992	0.992	1.028	0.98	0.956	0.952	1.005	1.005	0.96	0.92	1	0.991	0.991	0.979
SPP_WAUE	0.974	0.974	1.006	0.987	0.968	0.968	1.034	1.034	0.99	0.947	1	0.979	0.979	0.97
SPP_WEST	0.978	0.978	1.02	0.978	0.956	0.952	0.991	0.991	0.96	0.918	1	0.989	0.989	0.978
WEC_BANC	1.232	1.232	1.173	1.072	1.076	1.055	1.124	1.124	1.1	1.112	1	1.208	1.208	1.203
WEC_CALN	1.23	1.23	1.172	1.071	1.076	1.055	1.123	1.123	1.1	1.109	1	1.207	1.207	1.201
WEC_LADW	1.183	1.183	1.141	1.055	1.076	1.055	1.104	1.104	1.07	1.076	1	1.167	1.167	1.151
WEC_SDGE	1.154	1.154	1.12	1.046	1.076	1.055	1.084	1.084	1.05	1.049	1	1.141	1.141	1.123
WECC_AZ	1.187	1.187	1.19	1.011	1	0.982	1.035	1.035	1	0.97	1	1.181	1.181	1.166
WECC_CO	1.157	1.157	1.194	0.988	0.936	0.947	1.027	1.027	0.98	0.932	1	1.156	1.156	1.142
WECC_ID	1.045	1.045	1.07	1.004	1.002	0.982	1.048	1.048	1	0.965	1	1.066	1.066	1.058
WECC_IID	1.262	1.262	1.236	1.036	1	0.982	1.069	1.069	1.04	1.028	1	1.252	1.252	1.233

Model Region	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Nuclear	Biomass	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra supercritical Coal without CCS	Ultra supercritical Coal with 30% CCS	Ultra supercritical Coal with 90% CCS
WECC_MT	1.021	1.021	1.054	0.992	1.002	0.982	1.039	1.039	0.99	0.953	1	1.037	1.037	1.03
WECC_NM	1.131	1.131	1.161	0.99	1	0.982	1.018	1.018	0.98	0.938	1	1.129	1.129	1.115
WECC_NNV	1.157	1.157	1.137	1.04	1.002	0.982	1.087	1.087	1.05	1.045	1	1.157	1.157	1.147
WECC_PNW	1.123	1.123	1.109	1.035	1.002	0.982	1.074	1.074	1.04	1.032	1	1.145	1.145	1.144
WECC_SCE	1.18	1.18	1.139	1.054	1.076	1.055	1.1	1.1	1.07	1.071	1	1.163	1.163	1.144
WECC_SNV	1.23	1.23	1.22	1.03	1	0.982	1.071	1.071	1.04	1.042	1	1.237	1.237	1.219
WECC_UT	1.05	1.05	1.075	1.002	1.002	0.982	1.043	1.043	1	0.962	1	1.063	1.063	1.051
WECC_WY	1.016	1.016	1.055	0.987	1.002	0.982	1.031	1.031	0.98	0.927	1	1.024	1.024	1.012

Table 4-16 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technology Capacity in EPA Platform v6

	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	100	100	100	600
First Year Available	2021	2021	2021			2021	2021	2021	2021	2021
Lead Time (Years)	4	4	3			3	1	3	3	3
Availability	83%	90% - 95%	90%			87%	90%	90%	95%	95%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch			Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile
	Vintage #1 (2021-2054)					**Vintage #1 (2021)**				
Heat Rate (Btu/kWh)	13,500	30,000	18,000	18,000	18,000	8,653	0	0	0	0
Capital (2016$/kW)	3,733	3,072 - 21,106	8,556	10,780	16,598	6,889	1034	6,717	1,404	4,529
Fixed O&M (2016$/kW/yr)	110.34	105 - 542	410.32	410.32	410.32	0.00	11.35	62.69	49.46	116.64
Variable O&M (2016$/MWh)	5.49	0.00	9.14	9.14	9.14	44.9	0	3.5	0	0
						Vintage #2 (2023)				
Heat Rate (Btu/kWh)						7,807	0	0	0	0
Capital (2016$/kW)						6680	1009	6,555	1,372	4,169
Fixed O&M (2016$/kW/yr)						0.0	10.74	59.9	48.72	111.15
Variable O&M (2016$/MWh)						44.9	0	3.5	0	0
						Vintage #3 (2025)				
Heat Rate (Btu/kWh)						6,960	0	0	0	0

	Biomass-Bubbling Fluidized Bed (BFB)	Geothermal	Landfill Gas			Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind
			LGHI	LGLo	LGVLo					
Capital (2016$/kW)						6434	984	6,396	1,337	4,122
Fixed O&M (2016$/kW/yr)						0.0	10.13	57.12	47.98	109.58
Variable O&M (2016$/MWh)						44.9	0	3.5	0	0
						Vintage #4 (2030)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						921	6,047	1,242	4,006	921
Fixed O&M (2016$/kW/yr)						10.13	50.15	46.13	105.66	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #5 (2035)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						870	5,762	1,234	3,952	870
Fixed O&M (2016$/kW/yr)						10.13	50.15	44.29	104.98	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #6 (2040)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						819	5,527	1,218	3,898	819
Fixed O&M (2016$/kW/yr)						10.13	50.15	42.44	104.29	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #7 (2045)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						772	5,354	1,195	3,837	772
Fixed O&M (2016$/kW/yr)						10.13	50.15	40.6	103.54	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0
						Vintage #8 (2050)				
Heat Rate (Btu/kWh)						0	0	0	0	0
Capital (2016$/kW)						726	5,243	1,165	3,775	726
Fixed O&M (2016$/kW/yr)						10.13	50.15	38.75	102.8	10.13
Variable O&M (2016$/MWh)						0	3.5	0	0	0

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 Platform v6 for potential renewable and non-conventional technology generating units. The parameters shown in the table are based on AEO 2017 for biomass, landfill gas, and fuel cell. For onshore wind, solar PV, and solar thermal technologies, the parameters shown are based on the National Renewable Energy Laboratory's (NREL's) 2017 Annual Technology Baseline (ATB) mid-case. For offshore wind, the parameters shown are based on the NREL's 2016 ATB mid-case. The size (MW) shown 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 are averages or ranges that are discussed in further detail in the following subsections. The short-term capital cost adder in Table 4-14 and the regional cost adjustment factors in Table 4-15 apply equally to the renewable and non-conventional generation technologies as to the conventional generation technologies.

Wind Generation

EPA Platform v6 includes onshore wind, offshore-shallow, offshore-mid depth, and offshore-deep wind generation technologies. The following sections describe key aspects of the representation of wind generation: wind quality and resource potential, distance to transmission, generation profiles, reserve margin contribution, and capital cost calculation.

Wind Quality and Resource Potential: The NREL resource base for onshore wind is represented by ten techno-resource groups (TRG). Based on a review of levelized cost of electricity, EPA Platform v6 only models the resource categories TRG1–TRG8. The NREL resource base for offshore wind is represented by shallow (TRG1-TRG4), mid-depth (TRG5-TRG7), and deep (TRG8-TRG10) categories. In EPA Platform v6, the resource categories TRG1, TRG2, TRG3, TRG5, TRG6, and TRG8 are modeled. Table 4-38, Table 4-17, Table 4-18, and Table 4-19 present the onshore, offshore shallow, offshore mid-depth, and offshore deep wind resource assumptions.

Table 4-17 Offshore Shallow Regional Potential Wind Capacity (MW) by Wind TRG and Cost Class in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	2	143		
		3	1,000	991	1,760
CN_MB	MB	3	997	997	13,978
CN_NB	NB	2	994	862	
		3	999	997	1,389
CN_NF	NF	1	982	1,017	10,824
		2	997	985	15,445
		3	952	1,014	11,688
CN_NL	NL	1	985	1,007	109,060
		2	980	1,017	102,486
		3	984	1,006	32,049
CN_NS	NS	1	727		
		2	985	997	16,158
		3	999	960	34,831
CN_ON	ON	2	999	370	
		3	995	992	46,890
CN_PE	PE	2	650		

IPM Region	State	TRG	Cost Class		
			1	2	3
		3	986	959	13,816
CN_PQ	PQ	1	989	970	46,105
		2	968	996	17,275
		3	959	984	53,478
ERC_REST	TX	2	2,990	2,992	5,030
		3	2,962	3,035	13,893
MIS_INKY	IN	3	385		
MIS_LMI	MI	2	2,499	306	
		3	2,482	2,512	8,878
MIS_MNWI	MI	3	53		
	WI	3	184		
MIS_WOTA	LA	3	983	108	
	TX	3	12		
MIS_WUMS	MI	1	302		
		2	489		
		3	1,484	1,502	6,397
	WI	2	743		
		3	1,498	1,499	2,031
NENG_CT	CT	3	259		
NENG_ME	ME	1	76		
		2	469	412	
		3	495	498	646
NENGREST	MA	1	2,474	2,459	6,487
		2	2,497	2,409	4,104
		3	2,403		
	NH	3	181		
	RI	1	0		
		2	707		
		3	416		
NY_Z_A	NY	3	389	544	1,203
NY_Z_B	NY	3	492	470	
NY_Z_C&E	NY	3	475	520	293
NY_Z_J	NY	3	355		
NY_Z_K	NY	2	930	1,064	4,102
		3	998	980	1,495
PJM_ATSI	OH	2	189		
		3	1,496	1,423	8,263
PJM_COMD	IL	2	973		
		3	971		
PJM_Dom	NC	2	2,449	2,510	2,953
		3	2,374	2,603	8,061
	VA	2	1,471		
		3	2,462	2,444	
PJM_EMAC	DE	3	2,989	879	
	MD	3	2,897	3,009	
	NJ	2	2,950	3,042	1,786

IPM Region	State	TRG	Cost Class		
			1	2	3
		3	2,905	3,028	5,414
	VA	2	948		
		3	2,944	2,903	7,832
PJM_PENE	PA	2	155		
		3	492	447	1,917
PJM_West	MI	3	1,134		
S_SOU	GA	3	2,892	2,958	3,740
S_VACA	NC	2	2,932	2,022	
		3	2,929	3,046	34,677
	SC	2	1,261		
		3	2,956	2,520	31,482
WEC_CALN	CA	2	42		
		3	147		
WECC_PNW	CA	2	39		
		3	134		
	OR	1	46		
		2	281		
		3	469		
	WA	3	1,018		
WECC_SCE	CA	2	75		
		3	151		

Table 4-18 Offshore Mid-Depth Regional Potential Wind Capacity (MW) by Wind TRG and Cost Class in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	6	987	1,012	2,526
CN_NB	NB	6	995	1,000	3,159
CN_NF	NF	5	989	1,008	7,419
		6	991	994	2,148
CN_NL	NL	5	996	993	28,647
		6	992	997	6,691
CN_NS	NS	5	994	962	8,245
		6	955	1,034	45,843
CN_ON	ON	6	986	998	3,149
CN_PE	PE	5	376		
		6	982	1,002	13,613
CN_PQ	PQ	5	975	946	89,535
		6	993	1,003	34,451
ERC_REST	TX	6	2,983	2,864	9,713
MIS_LMI	MI	6	2,487	2,511	1,480
MIS_WUMS	MI	5	619		
		6	1,169		
	WI	6	1,498	987	
NENG_ME	ME	5	500	111	
		6	489	501	643

IPM Region	State	TRG	Cost Class		
			1	2	3
NENGREST	MA	5	2,494	2,149	48,461
		6	2,469	2,365	4,730
	NH	6	5		
	RI	5	2,492	779	
		6	2,472	131	
NY_Z_K	NY	5	962	924	659
		6	878	1,013	20,641
PJM_COMD	IL	6	1,357		
PJM_Dom	NC	6	2,482	2,443	5,735
	VA	6	2,041		
PJM_EMAC	DE	6	342		
	MD	6	623		
	NJ	6	2,742	3,028	18,787
	VA	6	2,972	3,001	1,472
PJM_PENE	PA	6	37		
S_VACA	NC	6	2,887	2,999	14,190
	SC	6	2,825	587	
WEC_CALN	CA	5	48		
		6	308		
WECC_PNW	CA	6	18		
	OR	5	317		
		6	481		
WECC_SCE	CA	6	49		

Table 4-19 Offshore Deep Regional Potential Wind Capacity (MW) by Wind TRG and Cost Class in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_NF	NF	8	939	976	145,825
CN_NL	NL	8	992	991	448,905
CN_NS	NS	8	990	1,005	87,606
CN_PQ	PQ	8	989	1,010	198,807
MIS_WUMS	MI	8	1,489	1,348	27,571
NENG_ME	ME	8	422	560	75,668
NENGREST	MA	8	951	2,091	149,968
	RI	8	2,477	2,437	745
NY_Z_K	NY	8	725	1,087	20,795
WEC_CALN	CA	8	2,480	1,797	
WECC_PNW	CA	8	2,113		
	OR	8	2,973	3,008	118
WECC_SCE	CA	8	2,047		

Generation Profiles: Unlike other generation technologies, which dispatch on an economic basis subject to their availability constraint, wind and solar technologies can dispatch only when the wind blows and the sun shines. To represent intermittent renewable generating sources such as wind and solar, EPA Platform v6 uses hourly generation profiles. Each eligible wind and solar photovoltaic plant is provided with 8760 hourly generation profiles. These profiles are customized for each wind TRG within an IPM region and state combination.

The generation profile indicates the amount of generation (kWh) per MW of available capacity. The wind generation profiles were prepared with data from NREL. Table 4-39 shows the generation profiles for onshore and offshore wind plants in all model region, state, and TRG combinations for vintage 2021. Improvements in onshore wind and offshore wind capacity factors over time are modeled through three vintages (2021, 2030, and 2040) of new wind units.

To obtain the seasonal generation for the units in a particular wind class in a specific region, the installed capacity is multiplied by the number of hours in the season and the seasonal capacity factor. Capacity factor is the average “kWh of generation per MW” from the applicable generation profile. The annual capacity factors for wind generation that are used in EPA Platform v6 were obtained from NREL and are shown in Table 4-20, Table 4-22, Table 4-24, and Table 4-26.

Reserve Margin Contribution (also referred to as capacity credit): EPA Platform v6 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.

Capacity credit assumptions for onshore wind, offshore wind, and solar PV units are estimated as the function of penetration of solar and wind in the EPA Platform v6. A two-step approach is developed to estimate the capacity credit at a unit level. In the first step, the method estimates the sequence of solar and wind units to build in each IPM region. To do so each solar and wind unit in an IPM Region is sorted from cheapest to most expensive in-terms of cost and potential revenue generation. Unit level capital costs, FOM costs, capital charge rate, and average energy price in each IPM region are used in this analysis. In the second step, capacity credit is calculated for each unit in the sequence as the ratio between the MW of peak reduced and the capacity of the unit. Unit level hourly generation profiles and regional hourly load curves are used in this analysis. These initial regional capacity credit curves are scaled at the NEMS region level to approximately result in capacity credits equal to those projected in AEO 2017 at the same level of penetration. This approach allows the EPA Platform v6 to endogenously account for the decline of capacity credit for intermittent resources with their rising penetration. Table 4-21, Table 4-23, Table 4-25 and Table 4-27 present the reserve margin contributions apportioned to new wind plants in the EPA Platform v6.

Table 4-20 Onshore Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	50.16%	52.30%	54.05%
2	49.05%	51.24%	53.01%
3	48.23%	50.71%	52.70%
4	46.92%	49.52%	51.63%
5	44.71%	47.76%	50.25%
6	41.12%	44.74%	47.67%
7	35.74%	39.48%	42.49%
8	28.93%	32.25%	34.95%
9	22.71%	26.13%	28.93%
10	14.32%	16.77%	18.79%

Table 4-21 Onshore Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 49%	0% - 51%	0% - 53%
2	0% - 84%	0% - 87%	0% - 90%
3	0% - 83%	0% - 87%	0% - 90%
4	0% - 82%	0% - 87%	0% - 90%
5	0% - 81%	0% - 86%	0% - 90%
6	0% - 78%	0% - 85%	0% - 90%
7	0% - 76%	0% - 84%	0% - 90%
8	0% - 75%	0% - 83%	0% - 90%
9	0% - 1%	0% - 1%	0% - 1%
10	0% - 1%	0% - 1%	0% - 1%

Table 4-22 Offshore Shallow Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	51%	52%	53%
2	47%	48%	48%
3	43%	44%	44%

Table 4-23 Offshore Shallow Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
1	0% - 88%	0% - 89%	0% - 90%
2	0% - 88%	0% - 89%	0% - 90%
3	0% - 88%	0% - 89%	0% - 90%

Table 4-24 Offshore Mid Depth Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	51%	52%	52%
6	48%	49%	49%

Table 4-25 Offshore Mid Depth Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
5	0% - 88%	0% - 89%	0% - 90%
6	0% - 88%	0% - 89%	0% - 90%

Table 4-26 Offshore Deep Average Capacity Factor by Wind TRG

TRG	Capacity Factor		
	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	53%	54%	55%

Table 4-27 Offshore Deep Reserve Margin Contribution by Wind TRG

TRG	Vintage #1 (2021-2054)	Vintage #2 (2030-2054)	Vintage #3 (2040-2054)
8	0% - 87%	0% - 89%	0% - 90%

Capital cost calculation: Capital costs for wind units include spur-line transmission costs. The resources for wind and solar are highly sensitive to location. These spur-line costs represent the cost of needed spur lines, and are based on an estimated distance to transmission infrastructure. NREL develops these supply curves based on a geographic-information-system analysis, which estimates the resource accessibility costs in terms of supply curves based on the expected cost of linking renewable resource sites to the high-voltage, long-distance transmission network. For IPM modeling purposes, the NREL spur line cost curves are aggregated into a piecewise step curve for each resource class within each model region and state combination. The sizes of the initial steps are based on the model region load, while the last step holds the residual resource. The TRG level spur line cost curves for each model region and state combination are aggregated into a six-step cost curve for onshore wind and into a three-step cost curve for offshore wind. To obtain the capital cost for a particular new wind model plant, the capital cost adder applicable to the new plant by resource and cost class shown in Table 4-28, Table 4-29, Table 4-30, and Table 4-40 is added to the base capital cost shown in Table 4-16.

The tax credit extensions for new wind units as prescribed in H.R. 2029, the Consolidated Appropriations Act of 2016, are implemented through reductions in capital costs. As the credits are based on construction start date, the 2019 production tax credit (40% of initial value) is assigned to the 2021 run-year builds for wind units.

Table 4-28 Capital Cost Adder (2016$/kW) for New Offshore Shallow Wind Plants in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	2	1,010		
		3	1,004	1,040	1,091
CN_MB	MB	3	2,062	2,090	2,183
CN_NB	NB	2	746	802	
		3	242	597	741
CN_NF	NF	1	783	790	870
		2	791	800	958
		3	863	919	1,261
CN_NL	NL	1	228	289	839
		2	202	236	688
		3	148	230	785

IPM Region	State	TRG	Cost Class 1	Cost Class 2	Cost Class 3
CN_NS	NS	1	867		
		2	89	187	570
		3	51	60	574
CN_ON	ON	2	797	912	
		3	172	202	1,116
CN_PE	PE	2	768		
		3	380	394	544
CN_PQ	PQ	1	715	722	842
		2	649	671	1,540
		3	623	628	1,535
ERC_REST	TX	2	17	43	82
		3	3	8	42
MIS_INKY	IN	3	3		
MIS_LMI	MI	2	54	99	
		3	5	15	50
MIS_MNWI	MI	3	74		
	WI	3	94		
MIS_WOTA	LA	3	39	82	
	TX	3	26		
MIS_WUMS	MI	1	76		
		2	116		
		3	8	23	69
	WI	2	57		
		3	4	12	52
NENG_CT	CT	3	10		
NENG_ME	ME	1	63		
		2	43	74	
		3	18	38	73
NENGREST	MA	1	12	45	86
		2	9	30	71
		3	24		
	NH	3	10		
	RI	1	75		
		2	44		
		3	25		
NY_Z_A	NY	3	5	7	12
NY_Z_B	NY	3	9	34	
NY_Z_C&E	NY	3	22	61	75
NY_Z_J	NY	3	2		
NY_Z_K	NY	2	1	3	34
		3	2	16	56
PJM_ATSI	OH	2	6		
		3	1	2	8
PJM_COMD	IL	2	7		
		3	5		
PJM_Dom	NC	2	15	56	119

IPM Region	State	TRG	Cost Class		
			1	2	3
		3	2	6	41
	VA	2	27		
		3	22	30	
PJM_EMAC	DE	3	6	24	
	MD	3	10	35	
	NJ	2	4	21	24
		3	3	9	22
	VA	2	24		
		3	17	30	44
PJM_PENE	PA	2	9		
		3	4	6	12
PJM_West	MI	3	6		
S_SOU	GA	3	6	13	25
S_VACA	NC	2	39	99	
		3	4	9	45
	SC	2	37		
		3	2	3	24
WEC_CALN	CA	2	63		
		3	73		
WECC_PNW	CA	2	19		
		3	17		
	OR	1	8		
		2	10		
		3	15		
	WA	3	36		
WECC_SCE	CA	2	96		
		3	171		

Table 4-29 Capital Cost Adder (2016$/kW) for New Offshore Mid Depth Wind Plants in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_BC	BC	6	1,037	1,116	1,151
CN_NB	NB	6	428	717	841
CN_NF	NF	5	766	775	851
		6	820	1,046	1,329
CN_NL	NL	5	262	430	955
		6	253	555	863
CN_NS	NS	5	585	760	847
		6	73	88	659
CN_ON	ON	6	318	365	678
CN_PE	PE	5	659		
		6	562	577	741
CN_PQ	PQ	5	681	689	872
		6	646	665	1,366
ERC_REST	TX	6	2	9	50

IPM Region	State	TRG	Cost Class		
			1	2	3
MIS_LMI	MI	6	15	44	90
MIS_WUMS	MI	5	77		
		6	95		
	WI	6	35	106	
NENG_ME	ME	5	53	95	
		6	32	50	87
NENGREST	MA	5	6	8	45
		6	20	56	78
	NH	6	36		
	RI	5	62	74	
		6	34	65	
NY_Z_K	NY	5	16	43	57
		6	1	4	20
PJM_COMD	IL	6	5		
PJM_Dom	NC	6	2	9	57
	VA	6	27		
PJM_EMAC	DE	6	1		
	MD	6	12		
	NJ	6	2	3	14
	VA	6	19	25	34
PJM_PENE	PA	6	8		
S_VACA	NC	6	6	19	49
	SC	6	38	38	
WEC_CALN	CA	5	74		
		6	64		
WECC_PNW	CA	6	15		
	OR	5	5		
		6	11		
WECC_SCE	CA	6	47		

Table 4-30 Capital Cost Adder (2016$/kW) for New Offshore Deep Wind Plants in EPA Platform v6

IPM Region	State	TRG	Cost Class		
			1	2	3
CN_NF	NF	8	759	761	1,158
CN_NL	NL	8	321	560	1,131
CN_NS	NS	8	566	588	913
CN_PQ	PQ	8	695	737	1,071
MIS_WUMS	MI	8	14	31	90
NENG_ME	ME	8	2	3	72
NENGREST	MA	8	2	3	42
	RI	8	66	72	75
NY_Z_K	NY	8	8	8	25
WEC_CALN	CA	8	71	95	
WECC_PNW	CA	8	12		
	OR	8	5	12	18
WECC_SCE	CA	8	51		

As an illustrative example, Table 4-31 shows the calculations that would be performed to derive the potential electric generation, reserve margin contribution, and cost of potential (new) onshore capacity in wind class 3, cost class 1 in the WECC_CO model region in run year 2021.

Table 4-31 Example Calculations of Wind Generation Potential, Reserve Margin Contribution, and Capital Cost for Onshore Wind in WECC_CO at Wind Class 3, Cost Class 1.

Required Data

Table 4-30	Potential wind capacity (C) =	951 MW
Table 4-31	Winter average generation (G_W) per available MW =	558 kWh/MW
Table 4-31	Winter Shoulder average generation (G_{WS}) per available MW =	569 kWh/MW
Table 4-31	Summer average generation (G_S) per available MW =	477 kWh/MW
	Hours in Winter (H_W) season (December - February) =	2160 hours
	Hours in Winter Shoulder (H_{WS}) season (Mar, Apr, Oct. Nov.) =	2928 hours
	Hours in Summer (H_S)season (May – September) =	3672 hours
Table 4-20b	Reserve Margin Contribution (RM) WECC_CO, Wind Class 3 =	19 percent
Table 4-16	Capital Cost (Cap_{2050}) in vintage range for year 2050 =	$1165/kW
Table 4-32	Capital Cost Adder ($CCA_{ON,C1}$) for onshore cost class 1 =	$342/kW
Table 4-15	Regional Factor (RF)	1.027

Calculations

$$\begin{aligned} \textit{Generation Potential} &= C \times G_W \times H_W + C \times G_{WS} \times H_{WS} + C \times G_S \times H_S \\ &= 951\ MW \times 558\ kWh/MW \times 2160\ hours + \\ &\quad 951\ MW \times 569\ kWh/MW \times 2928\ hours + \\ &\quad 951\ MW \times 477\ kWh/MW \times 3672\ hours \\ &= 4.395\ GWh \end{aligned}$$

$$\begin{aligned} \textit{Reserve Margin Contribution} &= RM \times C \\ &= 19\% \times 951\ MW \\ &= 185\ MW \end{aligned}$$

$$\begin{aligned} \textit{Capital Cost} &= \left(Cap_{2050} \times RF + CCA_{ON,C1}\right) \times C \\ &= (\$1,165/kW \times 1.027 + \$342) \times 951\ MW \\ &= \$1,463,507 \end{aligned}$$

Solar Generation

EPA Platform v6 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, state, and resource class. The NREL resource base for solar PV is represented by eight resource classes. In EPA Platform v6, the higher capacity factor resource classes of 3-8 are modeled for solar PV. The NREL resource base for solar thermal is represented by five resource classes. The solar thermal technology has a ten hour thermal energy storage (TES) and is considered a dispatchable resource for modeling purposes. These are summarized in Table 4-41 and Table 4-42.

Generation Profiles: Table 4-43 shows the generation profiles for solar PV plants in all model region, state, and resource combinations. The capacity factors for solar generation that are used in EPA Platform v6 were obtained from NREL and are shown in Table 4-46 and Table 4-47.

Reserve margin contribution (also referred to as capacity credit): The reserve margin contribution section for wind units summarizes the approach followed for calculating the reserve margin contribution for solar PV units. Table 4-32 presents the reserve margin contributions apportioned to new solar PV units in the EPA Platform v6. The solar thermal units are assumed to have 10 hour TES and are assigned 100% reserve margin contribution.

Table 4-32 Solar Photovoltaic Reserve Margin Contribution by Resource Class

	Resource Class						
	2	**3**	**4**	**5**	**6**	**7**	**8**
Reserve Margin Contribution	0% - 6%	0% - 71%	0% - 90%	0% - 90%	0% - 90%	0% - 90%	0% - 36%

Capital Costs: Similar to wind, capital costs for solar units include transmission spur line cost adders. The resource class level spur line cost curves for each model region and state combination are aggregated into a six-step cost curve. Table 4-44 and Table 4-45 illustrate the capital cost adder by resource and cost class for new solar plants.

The solar PV tariffs are incorporated through capital cost adders in 2021 run year. The tariffs are calculated as an average of the tariffs for 2018-2020 ((30% + 25% + 20%)/3 = 25%). The solar PV module cost in 2021 is assumed to be 350 2017$/kW based on an analysis performed by NREL.

The tax credit extensions for new solar units as prescribed in H.R. 2029, the Consolidated Appropriations Act of 2016, are implemented through reductions in capital costs. As the credits are based on construction start date, the 2020 Investment tax credit (ITC) of 26% is assigned to the 2021 run-year builds for solar PV units.

Geothermal Generation

Geothermal Resource Potential: Thirteen model regions in EPA Platform v6 have geothermal potential. The potential resource in each of these regions is shown in Table 4-33 and is based on NREL ATB 2016. GEO-Hydro Flash[37], GEO-Hydro Binary, GEO-NF EGS Flash and GEO-NF EGS Binary are the included technologies.

[37] 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.

Table 4-33 Regional Assumptions on Potential Geothermal Electric Capacity

IPM Model Region	Capacity (MW)
WEC_CALN	530
WEC_LADW	93
WECC_AZ	33
WECC_CO	26
WECC_ID	277
WECC_IID	3,203
WECC_MT	36
WECC_NM	178
WECC_NNV	1,900
WECC_PNW	1,272
WECC_SCE	561
WECC_UT	225
WECC_WY	48
Grand Total	**8,382**

Cost Calculation: EPA Platform v6 does not contain a single capital cost, but multiple geographically dependent capital costs for geothermal generation. The assumptions for geothermal were developed using NREL 2016 ATB cost and performance estimates for 152 sites. Both dual flash and binary cycle technologies were represented. The 152 sites were aggregated into 93 different options based on geographic location and cost and performance characteristics of geothermal sites in each of the 13 eligible IPM regions where geothermal generation opportunities exist. Table 4-34 shows the potential geothermal capacity and cost characteristics for applicable model regions.

Table 4-34 Potential Geothermal Capacity and Cost Characteristics by Model Region

IPM Region	Capacity (MW)	Capital Cost (2016$)	FO&M (2016$/kW-yr)
WEC_CALN	7	13,379	417
	10	19,535	518
	14	12,347	341
	15	20,164	535
	37	4,247	125
	68	4,988	128
	70	6,020	138
	111	8,767	259
	199	6,228	168
WEC_LADW	34	9,006	269
	59	5,976	169
WECC_AZ	33	19,005	501
WECC_CO	10	19,550	518
	15	13,945	379
WECC_ID	8	19,997	531
	10	21,106	542
	12	17,579	457
	13	16,325	439
	20	12,987	344
	23	18,113	497
	26	9,563	267

IPM Region	Capacity (MW)	Capital Cost (2016$)	FO&M (2016$/kW-yr)
	34	8,564	234
	46	11,742	331
	86	11,455	285
WECC_IID	6	7,898	236
	23	7,297	224
	25	8,885	267
	66	6,085	163
	79	9,470	278
	93	3,202	118
	119	4,630	143
	203	5,803	145
	2,589	4,050	107
WECC_MT	9	19,797	525
	11	16,457	443
	16	16,068	430
WECC_NM	6	17,611	408
	11	19,491	517
	34	6,047	169
	127	4,341	129
WECC_NNV	11	9,991	294
	12	15,737	375
	13	17,289	481
	14	20,232	536
	16	10,693	337
	16	13,199	351
	19	16,757	451
	30	11,792	342
	44	14,311	390
	50	12,296	344
	97	3,072	106
	103	6,335	195
	131	5,437	167
	139	9,420	280
	154	7,285	211
	171	8,617	259
	241	7,978	246
	262	4,542	153
	377	4,016	146
WECC_PNW	8	15,294	437
	10	9,883	263
	10	17,327	488
	11	14,223	413
	12	14,225	388
	12	15,323	403
	12	12,498	345
	13	12,648	366

IPM Region	Capacity (MW)	Capital Cost (2016$)	FO&M (2016$/kW-yr)
	16	11,821	318
	18	10,850	316
	19	19,668	522
	21	16,483	462
	28	15,623	413
	40	12,170	291
	50	8,752	258
	51	5,115	161
	126	7,132	212
	155	3,240	114
	202	7,023	203
	457	4,146	131
WECC_SCE	9	16,223	445
	25	7,936	260
	25	14,164	386
	45	6,671	156
	110	5,628	143
	347	3,072	105
WECC_UT	2	15,681	400
	7	11,025	343
	12	6,723	224
	15	16,101	462
	16	10,080	320
	64	3,072	115
	108	7,389	228
WECC_WY	48	13,175	348

Landfill Gas Electricity Generation

Landfill Gas Resource Potential: Estimates of potential electric capacity from landfill gas are based on the AEO 2014 inventory. EPA Platform v6 represents the “high”, “low”, and “very low” categories of potential landfill gas units. The categories refer to the amount and rate of methane production from the existing landfill site. Table 4-48 summarizes potential electric capacity from landfill gas.

There are several things to note about Table 4-48. The AEO 2014 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 4-48 apply to the IPM regions indicated in column 1. In EPA Platform v6, 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 4-48 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.

Energy Storage

Energy storage is the capture of energy produced at one time for use at a later time. Presently, the most common energy storage technologies are pumped storage and lithium-ion battery storage. EPA Platform v6 now includes battery storage by IPM region and state.

Table 4-35 summarizes the key cost and performance assumptions for new battery storage as implemented in November 2018 Reference Case. These assumptions are based on Annual Energy Outlook (AEO) 2018 inputs.

Table 4-35 Performance and Unit Cost Assumptions for Potential (New) Battery Storage

	Battery Storage
Size (MW)	30
First Year Available	2021
Lead Time (Years)	1
Availability (%)	96.4
Reserve Margin Contribution (%)	100
Generation Capability	Economic Dispatch
Storage System Efficiency (%)	85
Charge Capacity (Hours)	4
Fixed O&M (2016$/kW-Yr)	35
Variable O&M (2016$/MWh)	7.1
Capital Cost without IDC (2016$/kW)	
2021	2,048
2023	1,977
2025	1,906
2030	1,740
2035	1,574
2040	1,418
2045	1,271
2050	1,131

Multiple U.S. states have instituted standalone targets and mandates for energy storage procurement. Table 4-36 summarizes the state-specific energy storage mandates that are included in the November 2018 Reference Case. Under Assembly Bill No. 2514 and Assembly Bill No. 2868, the California Public Utilities Commission (CPUC) established energy storage targets for the state's three investor-owned utilities (IOUs) Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric. Hence, the California state mandates are modeled at the utility level in the November 2018 Reference Case.

Table 4-36 Energy Storage Mandates in the November 2018 Reference Case

State/Region	Bill	Mandate Type	Mandate Specifications	Implementation Status
California	Assembly Bill No. 2514	Target in MW	Energy storage target of 1,325 megawatts for Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric by 2020, with installations required no later than the end of 2024.	2020
	Assembly Bill No. 2868	Target in MW	500 MW of distributed energy storage systems (166.66 MW for each of PG&E, SCE, and SDG&E).	2020
	Senate Bill No. 801	Target in MW	SB 801 directs LADWP to work with the city council of Los Angeles regarding potential deployment of 100 MW of energy storage solutions. SCE is procuring 20 MW.	2019
New York	New York State Energy Storage Target	Target in MW	1,500 Megawatts by 2025.	2025
New Jersey	Assembly Bill No. 3723	Target in MW	600 megawatts of energy storage by 2021 and 2,000 megawatts of energy storage by 2030.	2021
Oregon	House Bill 2193	Target in MWh per electric company	An electric company shall procure one or more qualifying energy storage systems that have the capacity to store at least five-megawatt hours of energy on or before January 1, 2020.	2020
Massachusetts	Chapter 188	Target in MWh	200 Megawatt hour (MWh) energy storage target for electric distribution companies to procure viable and cost-effective energy storage systems to be achieved by January 1, 2020.	2020

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 96 nuclear units in EPA Platform v6 are represented by separate model plants. As noted in Table 4-7, the 96 nuclear units include 94 currently operating units plus Vogtle Units 3 and 4, which are scheduled to come online post 2021. All are listed in Table 4-49. The population characteristics, plant location, and unit configuration data in NEEDS v6 were obtained primarily from EIA Form 860 and AEO 2018.

Capacity: Nuclear units are baseload power plants with high fixed (capital and fixed O&M) costs and relatively low variable (fuel and variable O&M) costs. Due to their low variable 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 Platform v6 uses capacity factor assumptions to define the upper bound on generation from nuclear units. Nuclear capacity factor assumptions in EPA Platform v6 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;
  - 25-80 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;
  - 30-80 years: Performance remains flat; and
- The maximum capacity factor is assumed to be 90 percent. Hence, a unit 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 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 Platform v6 uses heat rate, variable O&M costs (VOM) and fixed O&M costs (FOM) to characterize the cost of operating existing nuclear units. The data are from AEO 2018 and are shown in Table 4-49.

EPA Platform v6 also uses the nuclear capacity uprates from AEO 2017 and ICF research. These are shown in Table 4-37**.**

Table 4-37 Nuclear Uprates (MW) as Incorporated in EPA Platform v6

Name	Plant ID	Unit ID	Year	Change in MWs
Columbia	371	1	2017	19.3
Browns Ferry	46	1	2017	164.7
Browns Ferry	46	2	2017	164.7
Browns Ferry	46	3	2017	164.7
Peach Bottom	3166	2	2017	21.7
Peach Bottom	3166	3	2017	21.7

EPA Platform v6 imposes lifetime extension costs for nuclear units (See Section 4.2.8) and a maximum lifetime of 80 years (See Section 3.7).

As nuclear units have aged, some units have been retired from service, or are planning to retire over the modeled time horizon. For a list of remaining nuclear units, see the NEEDS v6 database. Furthermore, IPM provides nuclear units with the choice to retire, based on the economics.

Zero Emission Credit (ZEC) Programs: New York and Illinois passed legislation in 2017 to provide support to selected existing nuclear units that could be at risk of early closure due to declining profitability.

The New York Clean Energy Standard for a 12-year period creates ZECs that are currently applicable for Fitzpatrick, Ginna, and Nine Mile Point nuclear power plants. The New York load-serving entities (LSEs) are responsible for purchasing ZECs equal to their share of the statewide load, providing an additional revenue stream to the nuclear power plants holding the ZECs. Similar to the New York program, the Illinois Future Energy Jobs Bill creates a ZEC program covering a 10-year term for Clinton and Quad Cities nuclear power plants.

EPA Platform v6 implicitly models the effect of ZECs by disabling the retirement options for Fitzpatrick, Ginna, Nine Mile Point, Clinton, and Quad Cities nuclear power plants in the 2021, 2023, and 2025 run years.

Nuclear Retirement Limits: In EPA Platform v6, endogenous retirements in 2021 of nuclear units are limited to 8,000 MW[38]. It is assumed that nuclear units will retire at a pace of 2000 MW per year during the 2018-2021 period. This 2000 MW per year rate is estimated based on a review of nuclear retirements in recent years.

Life Extension Costs: Attachment 4-1 summarizes the approach to estimate unit level life extension costs for existing nuclear units. Nuclear units are assumed to have a maximum lifetime of 80 years (see Section 3.7). Unlike other plant types, life extension costs for nuclear units are calculated as a function of age and are applied starting 2021 run year and continue through age 80.

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 Platform v6 are shown in Table 4-13. The cost assumptions are from AEO 2017.

[38] The 8,000 MW limit includes the scheduled retirements of Oyster Creek, Three Mile Island, Pilgrim, and Indian Point nuclear units 2 and 3.

List of tables that are uploaded directly to the web:

5. Emission Control Technologies

EPA Platform v6 includes an update of emission control technology assumptions. EPA contracted with engineering firm Sargent & Lundy to update and add to the retrofit emission control cost models originally developed for EPA and used in EPA Base Case v.4.10 and updated in EPA Base Case v.5.13. EPA Platform v6 includes updated assumptions regarding control options for sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (Hg), carbon dioxide (CO_2), and acid gases (HCl). These emission control options are listed in Table 5-1. They are available in EPA Platform v6 for meeting existing and potential federal, regional, and state emission limits. Besides the emission control options shown in Table 5-1 and described in this chapter, EPA Platform v6 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 Platform v6

SO_2 Control Technology Options	NO_x Control Technology Options	Mercury Control Technology Options	CO_2 Control Technology Options	HCl Control Technology Options
Limestone Forced Oxidation (LSFO) Scrubber	Selective Catalytic Reduction (SCR) System	Activated Carbon Injection (ACI) System	CO_2 Capture and Sequestration	Limestone Forced Oxidation (LSFO) Scrubber
Lime Spray Dryer (LSD) Scrubber	Selective Non-Catalytic Reduction (SNCR) System	SO_2 and NO_x Control Technology Removal Cobenefits	Coal-to-gas	Lime Spray Dryer (LSD) Scrubber
Dry Sorbent Injection (DSI)			Heat Rate Improvement	Dry Sorbent Injection (DSI)

Detailed reports and example calculation worksheets for Sargent & Lundy retrofit emission control models used by EPA are available in Attachment 5-1 through Attachment 5-7.

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 Platform v6: 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, the technology is therefore provided to only plants which have the option to burn coals with sulfur content no greater than 3 lbs SO_2/MMBtu. In EPA Platform v6 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).

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 50%. Such units are considered to have an injection technology and are classified as unscrubbed for modeling purposes in the NEEDS v6 database. The scrubber retrofit costs for these units are the same as those for 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 (2015). These default removal rates were the average of all SO_2 removal rates for a dry or wet FGD as reported in EIA 860 (2015) for the FGD installation year.

To reduce the incidence of implausibly high, outlier removal rates, the following adjustment is made. Units for which reported EIA Form 860 (2015) SO_2 removal rates are higher than the average of the upper quartile of SO_2 removal rates across all scrubbed units are assigned the upper quartile average. The adjustment is not made, however, if a unit's reported removal rate was recently confirmed by utility comments. Furthermore, 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 EIA Form 860 (2015) 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 98% for wet FGD and 95% for dry FGD.

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 EPA Platform v6

Performance Assumptions	Limestone Forced Oxidation (LSFO)	Lime Spray Dryer (LSD)
Percent Removal*	98% with a floor of 0.06 lbs/MMBtu	95% 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 (2016$)		
Applicability	Units ≥ 25 MW	Units ≥ 25 MW
Sulfur Content Applicability		Coals ≤ 3 lbs 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

* If the SO_2 permit rate of the unit is lower than the floor rate then the SO_2 permit rate is considered as the floor rate.

Potential (new) coal-fired units built by IPM are also assumed to be constructed with a wet scrubber achieving a removal efficiency of 98%. In EPA Platform v6 the costs of potential new coal units include the cost of scrubbers.

5.1.1 Methodology for Obtaining SO_2 Controls Costs

Sargent & Lundy's updated performance/cost models for wet and dry SO_2 scrubbers are implemented in EPA Platform v6 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. For details of Sargent & Lundy Wet FGD and SDA FGD cost models, see Attachment 5-1 and Attachment 5-2.

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[39]. The factor used to scale up

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

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

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)[40]. In EPA Platform v6 specific LSFO and LSD heat rate and capacity penalties are calculated for each installation based on equations from the Sargent & 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 Platform v6 for an illustrative set of generating units with a representative range of capacities and heat rates.

[40] The NEEDS heat rate is an unmodified, “original” heat rate to which this retrofit-based heat rate penalty procedure is applied. This procedure is limited to units at which IPM adds a retrofit in the model.

Table 5-3 Illustrative Scrubber Costs (2016$) for Representative Sizes and Heat Rates under the Assumptions in EPA Platform v6

Scrubber 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)
LSFO														
Minimum Cutoff: ≥ 25 MW	9,000	-1.60	1.63	2.24	879	24.3	638	11.6	550	8.6	499	8.0	450	6.6
Maximum Cutoff: None	10,000	-1.78	1.82	2.47	919	24.7	667	11.9	575	8.9	522	8.2	470	6.8
Assuming 3 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.96	2.00	2.70	956	25.1	694	12.2	599	9.1	543	8.4	490	7.0
LSD														
Minimum Cutoff: ≥ 25 MW	9,000	-1.18	1.20	2.60	745	17.8	546	8.9	472	6.8	424	5.8	424	5.3
Maximum Cutoff: None	10,000	-1.32	1.33	2.89	779	18.2	571	9.2	494	7.0	443	5.9	443	5.5
Assuming 2 lb/MMBtu SO_2 Content Bituminous Coal	11,000	-1.45	1.47	3.17	812	18.5	594	9.4	514	7.3	461	6.1	461	5.7

Note 1: 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.
Note 2: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the Sargent & Lundy tool as for modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

5.2 Nitrogen Oxides Control Technology

There are two main 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 technologies included in EPA Platform v6 are commercially available and currently in use in numerous power plants.

5.2.1 Combustion Controls

EPA Platform v6 does not model combustion control upgrades as a retrofit option. The decision was based on two considerations, the relatively low cost of combustion controls compared with that of post combustion NO_x controls and the possible impact on model size. EPA identified units in NEEDS that have not employed state-of-the-art combustion controls. EPA then estimated the NO_x rates for such units based on an analysis of historical rates of units with state-of-the-art NO_x combustion controls. Emission rates provided by State-of-the-Art combustion controls are presented in Attachment 3-1.

5.2.2 Post-combustion NO_x Controls

EPA Platform v6 provides two post-combustion retrofit NO_x control technologies for existing coal units: Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR). In EPA Platform v6, oil/gas steam units are provided with only SCR retrofits. 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 5-4 summarizes the performance and applicability assumptions for each post-combustion NO_x control technology and provides a cross-reference to information on cost assumptions.

Table 5-4 Summary of Retrofit NO_x Emission Control Performance Assumptions in EPA Platform v6

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% (25-200 MW), 20% (200-400 MW), 15% (>400 MW) 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	Units ≥ 25 MW
Costs (2016$)	See Table 5-5	See Table 5-6	See Table 5-5

5.2.3 Methodology for Obtaining SCR Costs for Coal

The updated performance and cost models for SCR and SNCR technologies developed for EPA by Sargent & Lundy are implemented in EPA Platform v6 to develop the capital, fixed O&M (FOM), and variable O&M (VOM) components of cost. For details of Sargent & Lundy SCR and SNCR cost models, see Attachment 5-3 and Attachment 5-4.

Table 5-5 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 5-5 Illustrative Post-combustion NO_x Control Costs (2016$) for Coal Plants for Representative Sizes and Heat Rates under the Assumptions in EPA Platform v6

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	1.35	373	1.95	304	0.85	282	0.72	269	0.66	257	0.60
Minimum Cutoff: ≥ 25 MW	10,000	-0.56	0.56	1.45	405	2.06	333	0.91	309	0.78	295	0.71	282	0.66
	11,000	-0.58	0.59	1.56	437	2.17	361	0.97	335	0.83	321	0.76	307	0.71
SNCR - Tangential, 25% Removal Efficiency	9,000			1.17	55	0.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Cutoff: ≥ 25 MW	10,000	-0.05	0.78	1.29	56	0.51	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Maximum Cutoff: 200 MW	11,000			1.42	58	0.52	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SNCR - Tangential, 20% Removal Efficiency	9,000			0.93	N/A	N/A	29	0.26	N/A	N/A	N/A	N/A	N/A	N/A
Minimum Cutoff: ≥ 200 MW	10,000	-0.05	0.63	1.04	N/A	N/A	30	0.26	N/A	N/A	N/A	N/A	N/A	N/A
Maximum Cutoff: 400 MW	11,000			1.14	N/A	N/A	31	0.27	N/A	N/A	N/A	N/A	N/A	N/A
SNCR - Tangential, 15% Removal Efficiency	9,000	-0.05	0.49	0.70	N/A	N/A	N/A	N/A	21	0.19	18	0.16	15	0.13
Minimum Cutoff: ≥ 400 MW	10,000			0.78	N/A	N/A	N/A	N/A	22	0.19	18	0.16	15	0.13
Maximum Cutoff: None	11,000			0.85	N/A	N/A	N/A	N/A	22	0.20	19	0.16	15	0.13
SNCR - Fluidized Bed	9,000	-0.05	1.51	2.33	44	0.38	24	0.21	18	0.16	15	0.13	12	0.11
Minimum Cutoff: ≥ 25 MW	10,000			2.59	45	0.39	24	0.21	18	0.16	15	0.13	12	0.11
Maximum Cutoff: None	11,000			2.85	46	0.40	25	0.22	19	0.16	15	0.13	13	0.11

Note 1: *Assumes Bituminous Coal, NO_x rate: 0.5 lb/MMBtu, and SO_2 rate: 2.0 lb/MMBtu
Note 2: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the S&L tool as for modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.
Note 3: Heat rate penalty includes the effect of capacity penalty.

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

The cost calculations for SCR described in section 5.2.3 apply to coal units. For SCR on oil/gas steam units, the cost calculation procedure shown in Table 5-6 is used. 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 5-6 Post-Combustion NO_x Controls for Oil/Gas Steam Units in EPA Platform v6

Post-Combustion Control Technology	Capital ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Percent Removal
SCR[a]	86.38	1.25	0.14	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 2016$ 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) = 86.38 * $(200/275)^{0.35}$ ≈ 77.27 $/kW

SCR FOM Cost ($/kW-yr) = 1.25 * $(200/275)^{0.35}$ ≈ 1.12 $/kW-yr

SCR VOM Cost ($/MWh) = 0.14 $/MWh

5.2.5 Methodology for Obtaining SNCR Costs for Coal

In the Sargent & Lundy's cost update for SNCR, the NO_x removal efficiency varies by unit size and burner type as summarized in Table 5-4. Additionally, 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 Controls for Units with Capacities from 25 MW to 100 MW (25 MW ≤ capacity < 100 MW)

In EPA Platform v6, coal units with capacities between 25 MW and 100 MW are offered the same SO_2 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 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 switch to a lower sulfur coal, repower or convert to natural gas firing, use dry sorbent injection, and/or reduce operating hours.

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 100MW "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 this table.

5.3 Biomass Co-firing

Biomass co-firing is provided as an option for those coal-fired units in EPA Platform v6 that per EIA Form 923 had co-fired biomass during the 2012-2016 period. Table 5-7 lists the units provided with the co-firing option and the limit on share of the biomass co-firing. The remaining coal power plants are not provided this choice as logistics and boiler engineering considerations place limits on the extent of biomass that can be fired. The logistical considerations arise primarily because biomass is only economic to transport a limited distance from where it is grown due to its relatively low energy density. In addition, the extent of storage that can be devoted at a power plant to such a fuel is another limiting factor. Boiler efficiency and other engineering considerations, largely driven by the relatively higher moisture content and lower heat content of biomass compared to fossil fuel, also plays a role in limiting the potential adoption of co-firing.

Table 5-7 Coal Units with Biomass Co-firing Option in EPA Platform v6

Plant Name	Unit ID	Biomass Co-Firing Share Limit (%)[41]
Virginia City Hybrid Energy Center	1	8
Virginia City Hybrid Energy Center	2	8
University of Iowa Main Power Plant	BLR11	10
University of Iowa Main Power Plant	BLR10	10
Northampton Generating Company LP	BLR1	10
TES Filer City Station	2	10
TES Filer City Station	1	10
Manitowoc	9	10
Schiller	6	10
Schiller	4	10
T B Simon Power Plant	BLR4	10

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 Platform v6. Section 5.4.1 discusses how mercury content of fuel is modeled in EPA Platform v6. Section 5.4.2 looks at the procedure used in EPA Platform v6 to capture the mercury reductions resulting from different unit and (non-mercury) control configurations. Section 5.4.3 explains the mercury emission control options that are available under EPA Platform v6. Each section indicates the data sources and methodology used.

5.4.1 Mercury Content of Fuels

Coal

Assumptions pertaining to 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).[42] A two-year effort

[41] In EPA Platform v6, the limit on biomass co-firing is expressed as the percentage of the facility (ORIS code) 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.

[42] 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 mercury through the Collection Effort for New and Existing Coal- and Oil-Fired Electricity 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 Platform.

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.

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

Assumptions pertaining to the mercury content for oil, gas, and waste fuels are based on data derived from previous EPA analysis of mercury emissions from power plants.[43] Table 5-8 provides a summary of the assumptions on the mercury content for oil, gas, and waste fuels.

Table 5-8 Assumptions on Mercury Concentration in Non-Coal Fuel in EPA Platform v6

Fuel Type	Mercury Concentration (lbs/TBtu)
Oil	0.48
Natural Gas	0.00 [a]
Petroleum Coke	2.66
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.

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), such that the lower the EMF, the greater the mercury reduction. If the EMF is 0.25, then only 25% of the inlet mercury concentration is emitted as outlet mercury concentration, and therefore the unit has achieved a 75% reduction in mercury that would otherwise be emitted without the properties influencing the 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

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

participants[44] 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 Platform v6 mercury EMFs for unit configurations with SCR and wet scrubbers.

Table 5-9 below provides a summary of EMFs used in EPA Platform v6. Table 5-10 provides definitions of acronyms for existing controls that appear in Table 5-9. Table 5-11 provides a key to the burner type designations appearing in Table 5-9.

Table 5-9 Mercury Emission Modification Factors Used in EPA Platform v6

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF*	Lignite EMF
FBC	Cold Side ESP	No SCR	None	0.65	0.1	0.62
FBC	Cold Side ESP	No SCR	Dry FGD	0.64	0.1	1
FBC	Cold Side ESP + FF	No SCR	None	0.05	0.1	0.43
FBC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.1	1
FBC	Fabric Filter	No SCR	None	0.05	0.1	0.43
FBC	Fabric Filter	No SCR	Dry FGD	0.05	0.1	0.43
FBC	Hot Side ESP + FGC	No SCR	None	1	0.1	1
FBC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.1	1
FBC	No Control	No SCR	None	1	0.1	1
Non FBC	Cold Side ESP	SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP	SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP	No SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP	No SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP + FF	SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FF	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Cold Side ESP + FF	No SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FF	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Cold Side ESP + FGC	SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP + FGC	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP + FGC	SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP + FGC	No SCR	None	0.64	0.1	1
Non FBC	Cold Side ESP + FGC	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP + FGC	No SCR	Dry FGD	0.64	0.1	1
Non FBC	Cold Side ESP + FGC + FF	SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FGC + FF	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Cold Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Cold Side ESP + FGC + FF	No SCR	None	0.2	0.1	1
Non FBC	Cold Side ESP + FGC + FF	No SCR	Wet FGD	0.05	0.1	0.56
Non FBC	Cold Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Fabric Filter	SCR	None	0.11	0.1	1
Non FBC	Fabric Filter	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Fabric Filter	SCR	Dry FGD	0.05	0.1	1

[44] 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.

Burner Type	Particulate Control	Post-combustion Control - NO_x	Post-combustion Control - SO_2	Bituminous EMF	Subbituminous EMF*	Lignite EMF
Non FBC	Fabric Filter	No SCR	None	0.11	0.1	1
Non FBC	Fabric Filter	No SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Fabric Filter	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP	SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP	SCR	Wet FGD	0.1	0.1	1
Non FBC	Hot Side ESP	SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP	No SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP	No SCR	Wet FGD	0.05	0.1	1
Non FBC	Hot Side ESP	No SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP + FF	SCR	None	0.11	0.1	1
Non FBC	Hot Side ESP + FF	SCR	Wet FGD	0.1	0.1	0.56
Non FBC	Hot Side ESP + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FF	No SCR	None	0.11	0.1	1
Non FBC	Hot Side ESP + FF	No SCR	Wet FGD	0.03	0.1	0.56
Non FBC	Hot Side ESP + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FGC	SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP + FGC	SCR	Wet FGD	0.1	0.1	1
Non FBC	Hot Side ESP + FGC	SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP + FGC	No SCR	None	0.9	0.1	1
Non FBC	Hot Side ESP + FGC	No SCR	Wet FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FGC	No SCR	Dry FGD	0.6	0.1	1
Non FBC	Hot Side ESP + FGC + FF	SCR	Dry FGD	0.05	0.1	1
Non FBC	Hot Side ESP + FGC + FF	No SCR	None	0.11	0.1	1
Non FBC	Hot Side ESP + FGC + FF	No SCR	Dry FGD	0.05	0.1	1
Non FBC	No Control	SCR	None	1	0.1	1
Non FBC	No Control	SCR	Wet FGD	0.1	0.1	1
Non FBC	No Control	SCR	Dry FGD	0.6	0.1	1
Non FBC	No Control	No SCR	None	1	0.1	1
Non FBC	No Control	No SCR	Wet FGD	0.58	0.1	1
Non FBC	No Control	No SCR	Dry FGD	0.6	0.1	1
Non FBC	PM Scrubber	SCR	None	0.9	0.1	1
Non FBC	PM Scrubber	SCR	Wet FGD	0.1	0.1	1
Non FBC	PM Scrubber	SCR	Dry FGD	0.6	0.1	1
Non FBC	PM Scrubber	No SCR	None	0.9	0.1	1
Non FBC	PM Scrubber	No SCR	Wet FGD	0.05	0.1	1
Non FBC	PM Scrubber	No SCR	Dry FGD	0.6	0.1	1

Note: 2017 annual emissions data suggests that, with subbituminous coal, many configurations are now achieving at least 90% removal of mercury. This table was updated from previous versions to reflect this recent observation. For 2017 emissions data, see: https://ampd.epa.gov.

Table 5-10 Definition of Acronyms for Existing Controls

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

Table 5-11 Key to Burner Type Designations in Table 5-9

"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.
"Stoker" refers to stoker boilers where lump coal is fed continuously onto a moving grate or chain, which moves the coal into the combustion zone in which air is drawn through the grate and ignition takes place. The carbon gradually burns off, leaving ash which drops off at the end into a receptacle, from which it is removed for disposal.
"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.
"Other" refers to miscellaneous burner types including cell burners and arch- , roof- , and vertically-fired burner configurations.

5.4.3 Mercury Control Capabilities

EPA Platform v6 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

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 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 Platform v6 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 (and are described further below).

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 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 5-12 shows the ACI assignment scheme used to achieve 90% mercury removal. EPA Platform v6 does not explicitly model ACI retrofit options.

Table 5-12 Assignment Scheme for Mercury Emissions Control Using Activated Carbon Injection (ACI) in EPA Platform v6

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 acfm)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**
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	--	--	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	Yes	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	Yes	No	2
Non-FBC	Hot Side ESP + Fabric Filter with FGC	SCR	--	Yes	No	2	Yes	No	2	Yes	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

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 acfm)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**	**ACI Required?**	**Toxecon Required?**	**Sorbent Inj Rate (lb/million acfm)**
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
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

Note: In the table above "Toxecon" refers to the option described as "ACI System with an Additional Baghouse" and "ACI + Full Baghouse with a Sorbent Injection (Inj) Rate of 2 lbs/million acfm" elsewhere in this chapter.

5.4.4 Methodology for Obtaining ACI Control Costs

The updated ACI model developed by Sargent & Lundy 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. The model assumes 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 5-13 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[45].

Table 5-13 presents the capital, VOM, and FOM costs as well as the capacity and heat rate penalties for the three ACI options represented in EPA Platform v6. For each ACI option, values are shown for an illustrative set of generating units with a representative range of capacities and heat rates. For details of Sargent & Lundy ACI cost model, see Attachment 5-6.

5.5 Hydrogen Chloride (HCl) Control Technologies

The following sub-sections describe how HCl emissions from coal are represented, the emission control technologies available for HCl removal, and the cost and performance characteristics of these technologies in EPA Platform v6.

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 of 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 Platform v6 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.

[45] 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

Table 5-13 Illustrative Activated Carbon Injection (ACI) Costs (2016$) for Representative Sizes and Heat Rates under the Assumptions in EPA Platform v6

Control Type	Heat Rate (Btu/kWh)	Capacity Penalty (%)	Heat Rate Penalty (%)	Variable O&M cost (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)
ACI System with an Existing ESP ACI with a Sorbent Injection Rate of 5 lbs/million acfm assuming Bituminous Coal	9,000	-0.02	0.02	2.22	40.08	0.32	15.76	0.13	10.21	0.08	7.67	0.06	5.66	0.05
	10,000	-0.02	0.02	2.47	40.73	0.33	16.01	0.13	10.37	0.08	7.79	0.06	5.75	0.05
	11,000	-0.02	0.02	2.71	41.32	0.33	16.24	0.13	10.52	0.08	7.90	0.06	5.84	0.05
ACI System with an Existing Baghouse ACI with a Sorbent Injection Rate of 2 lbs/million acfm Assuming Bituminous Coal	9,000	-0.02	0.02	1.59	34.94	0.28	13.74	0.11	8.90	0.07	6.68	0.05	4.94	0.04
	10,000	-0.02	0.02	1.77	35.50	0.29	13.95	0.11	9.04	0.07	6.79	0.05	5.01	0.04
	11,000	-0.02	0.02	1.95	36.02	0.29	14.16	0.11	9.17	0.07	6.89	0.06	5.09	0.04
ACI System with an Additional Baghouse ACI + Full Baghouse with a Sorbent Injection Rate of 2 lbs/million acfm Assuming Bituminous Coal	9,000	-0.62	0.62	0.47	293.68	1.03	221.56	0.77	196.97	0.69	182.87	0.64	169.38	0.59
	10,000	-0.62	0.62	0.52	316.91	1.11	240.14	0.84	213.77	0.75	198.60	0.69	184.06	0.64
	11,000	-0.62	0.62	0.58	339.68	1.19	258.37	0.90	230.25	0.81	214.02	0.75	198.45	0.69

Note 1: The above cost estimates assume bituminous coal consumption.
Note 2: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the S&L tool as for modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

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, resulting in large part from the alkalinity of the fly ash, the 2010 ICR[46] 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 if the emissions were based solely on the chlorine content of those coals. Comparing the assumed Cl content of the subbituminous coals modeled in EPA Platform v6 with the estimated values based on responses to the 2010 ICR supports the EPA Platform v6 assumption that combustion of subbituminous and lignite coals results in a 95% reduction in HCl emissions relative to the assumed chlorine content of the coal.

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 5-14. 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 5-14 HCl Removal Rate Assumptions for Potential (New) and Existing Units in EPA Platform v6

		Potential (New)	Existing Units with FGD	
Gas	**Controls ==>**	**Ultra-Supercritical Pulverized Coal with 30%/90% CCS**	**Fluidized Bed Combustion (FBC)**	**Conventional Pulverized Coal (CPC) with Wet or Dry FGD**
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%

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 5-15.

<u>Wet and Dry FGD</u>

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 0.001 lbs/MMBtu. This is summarized in columns 2-5 of Table 5-15.

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

Table 5-15 Summary of Retrofit HCl (and SO_2) Emission Control Performance Assumptions in EPA Platform v6

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	98% with a floor of 0.06 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu	95% with a floor of 0.08 lbs/MMBtu	99% with a floor of 0.001 lbs/MMBtu	50%	98% with a floor of 0.002 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		Calculated based on characteristics of the unit: See Excerpt from Table 5-17	
Heat Rate Penalty						
Cost (2011$)						
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 Platform v6 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. While the Sargent & Lundy description of the DSI technology includes references to the hydrated lime option, only the Trona option is implemented in EPA Platform v6.

Removal rate assumptions: The removal rate assumptions for DSI are summarized in Table 5-15. The assumptions shown in the last two columns of Table 5-15 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 50%. The retrofit DSI option on an existing unit with existing ESP is always provided in combination with a fabric filter (Toxecon configuration).

Methodology for Obtaining DSI Control Costs: The cost and performance model for DSI was updated by Sargent & Lundy. The model is used to derive the cost of DSI retrofits with two alternative, associated particulate control devices, i.e., ESP and fabric filter "baghouse". The cost model notes 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.

Furthermore, 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 50%. The corresponding HCl removal effect is estimated to be 98% for units with fabric filter.

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 5-16 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. For details of Sargent & Lundy DSI cost model, see Attachment 5-5.

5.6 Fabric Filter (Baghouse) Cost Development

Fabric filters are not endogenously modeled as a separate retrofit option. In EPA Platform v6, 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. The costs associated with a new fabric filter retrofit are derived from the cost and performance updated by Sargent & Lundy. 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 Platform v6, and it is assumed that the existing ESP remains in place and active.

Table 5-17 presents the capital, VOM, and FOM costs for fabric filters as represented in EPA Platform v6 for an illustrative set of generating units with a representative range of capacities and heat rates. See Attachment 5-7 for details of the Sargent & Lundy fabric filter PM control cost model.

Table 5-16 Illustrative Dry Sorbent Injection (DSI) Costs (2016$) for Representative Sizes and Heat Rates under Assumptions in EPA Platform v6

Control Type	Heat Rate (Btu/kWh)	SO_2 Rate (lb/ MMBtu)	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)
DSI	9,000	2.0	-0.37	0.37	5.86	124.2	3.57	56.6	1.31	39.2	0.83	30.8	0.62	23.9	0.45
Assuming Bituminous	10,000	2.0	-0.41	0.41	6.51	128.0	3.60	58.3	1.33	40.4	0.84	31.8	0.62	24.6	0.46
Coal	11,000	2.0	-0.45	0.45	7.16	131.5	3.63	59.9	1.34	41.5	0.85	32.6	0.63	25.3	0.46

Note 1: A SO_2 removal efficiency of 50% is assumed in the above calculations.
Note: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the S&L tool as for modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

Table 5-17 Illustrative Particulate Controls Costs (2016$) for Representative Sizes and Heat Rates under the Assumptions in EPA Platform v6

Coal 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)
	9,000			0.05	254	0.9	206	0.7	187	0.7	175	0.6	164	0.6
Bituminous	10,000	-0.60	0.60	0.06	276	1.0	224	0.8	203	0.7	191	0.7	178	0.6
	11,000			0.07	298	1.0	242	0.8	220	0.8	206	0.7	193	0.7

Note: The Variable O&M costs in this table do not include the cost of additional auxiliary power (VOMP) component in the S&L tool as for modeling purposes, IPM reflects the auxiliary power consumption through capacity penalty.

5.7 Coal-to-Gas Conversions[47]

In EPA Platform v6, 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.

The following table summarizes the cost and performance assumptions for coal-to-gas boiler modifications as incorporated in EPA Platform v6. The values in the table were developed by EPA's engineering staff based on technical papers[48] and discussions with industry engineers familiar with such projects. They were designed to be broadly applicable across the existing coal fleet (with the exceptions noted in the table). Coal-to-gas retrofit options in EPA Platform v6 force a permanent change in fuel type from coal to natural gas. Coal therefore can no longer be fired.

Table 5-18 Cost and Performance Assumptions for Coal-to-Gas Retrofits in EPA Platform v6

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.
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: 2016$/kW = 288*(75/MW)^0.35 Cyclone units: 2016$/kW = 403*(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 = 288*(75/50)^0.35 = 332

[47] 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

[48] For an example see Babcock and Wilcox's White Paper MS-14 "Natural Gas Conversions of Exiting Coal-Fired Boilers" 2010 (https://slidex.tips/download/natural-gas-conversions-of-existing-coal-fired-boilers).

Factor	Description	Notes
Incremental Fixed O&M:	-33% 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% 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 to the local transmission mainline. 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 had ICF to determine the miles and associated cost of extending pipeline laterals from each boiler to the interstate natural gas pipeline system. This work was performed for EPA Base Case v5.13 and has not been updated for EPA Platform v6. For further detail, please see EPA Base Case v5.13 documentation.

Table 5-21 shows the pipeline costing results for each qualifying existing coal fired unit represented in EPA Platform v6.

5.8 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 Platform v6, 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, biomass 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 5-19 presents the first stage retrofit options available by plant type; Table 5-20 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 5-19 and Table 5-20 below.

Table 5-19 First Stage Retrofit Assignment Scheme in EPA Platform v6

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 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, 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

Plant Type	Retrofit Option 1st Stage	Criteria
Combined Cycle		
	CC Retirement	All combined cycle units
Combustion Turbine		
	CT Retirement	All combustion turbine units
Nuclear		
	Nuclear Retirement	All nuclear power units
Oil and Gas Steam		
	Oil/Gas Retirement	All oil/gas steam boilers
	Oil/Gas Steam SCR	All oil/gas steam boilers 25 MW or larger that do not possess an existing post combustion NO_x control option

Table 5-20 Second and Third Stage Retrofit Assignment Scheme in EPA Platform v6

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage	Retrofit Option 3rd Stage
Coal Steam			
	NO_x Control Option[1]	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[2]	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[3]	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[4]	None	None
	NO_x Control Option[1] + SO_2 Control Option[2]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	NO_x Control Option[1] + 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[2] + Hg	NO_x Control Option	Heat Rate Improvement

Plant Type	Retrofit Option 1st Stage	Retrofit Option 2nd Stage	Retrofit Option 3rd Stage
	Control Option[3]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	NO_x Control Option[1] + SO_2 Control Option[2] + Hg Control Option[3]	CO_2 Control Option	None
		Heat Rate Improvement	CO_2 Control Option
		Coal Retirement	None
	HCl Control Option[5]	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[1] + HCl Control Option[5]	SO_2 Control Option	Heat Rate Improvement
		Heat Rate Improvement	None
		Coal Retirement	None
	Hg Control Option[3] + HCl Control Option[5]	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[1] + HCl Control Option[5] + Hg Control Option[3]	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[1]	Oil/Gas Retirement	None
	Oil/Gas Retirement	None	None

Notes:
[1]"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
[2]"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
[3]"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
[4]"CO_2 Control Option" implies that a model plant may be retrofitted with carbon capture and storage technology
[5]"HCl Control Option" implies that a model plant may be retrofitted with a DSI (with milled Trona)

List of tables and attachments that are directly uploaded to the web:

6. CO_2 Capture, Storage, and Transport

6.1 CO_2 Capture

The EPA Platform v6 using IPM can build Ultra-Supercritical (USC) coal and Natural Gas Combined Cycle (NGCC) Electric Generating Units (EGUs) with Carbon Capture[49] and Storage (CCS) technology. In addition, IPM includes a retrofit option to add CCS technology to existing coal steam and NGCC EGUs.

6.1.1 CO_2 Capture for Potential EGUs

Carbon capture for potential USC EGUs is represented as two model plant options with different CO_2 capture efficiencies of 30 percent and 90 percent. EPA Platform v6 can offer CCS with a CO_2 capture efficiency of 90 percent for new NGCC units. [50] The USC with CCS and NGCC with CCS model plant options are configured assuming construction at greenfield sites. The cost and performance data provided in Table 6-1 is based on the Annual Energy Outlook 2017 (AEO 2017). The basis for these costs are studies prepared for the U.S. Department of Energy's (DoE's) Energy Information Administration (EIA).[51,52]

The USC costs were developed for a generic 650-megawatt (MW) net output USC EGU with a nominal heat rate of 8,609 British Thermal Units (Btus) per kilowatt-hour (kW-hr) in 2021. The USC EGU uses a "one-on-one" configuration. That is, the EGU is comprised of one pulverized coal (PC) steam generator and one steam turbine (ST). The steam generator is fired with Illinois No. 6 (Herrin seam, Old Ben Mine) bituminous coal and operates at steam conditions of 3,800 pounds per square inch-absolute (psia) and 1,112 degrees Fahrenheit (ºF). USC with a CCS is equipped with an amine-based, post-combustion CO_2 capture system. Mercury (Hg), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter (PM) emissions from the USC EGU are controlled with state-of-the-art air pollution control equipment including Dry Sorbent Injection (DSI), Activated Carbon Injection (ACI), Wet Flue Gas Desulfurization (WFGD) scrubber; low NO_x burners (LNBs), Selective Catalytic Reduction (SCR), and a fabric filter baghouse.

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[49] The term "carbon capture" refers primarily to removing carbon dioxide (CO_2) from the flue gases emitted by fossil fuel-fired EGUs.

[50] Note that the NGCC with CCS option is disabled in the EPA Platform v6 November 2018 Reference Case.

[51] Energy Information Administration (EIA). "*Capital Cost Estimates for Utility Scale Electricity Generating Plants*" (November 2016). "*Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017*"(January 2017). "*Addendum: Capital Cost Estimates for Utility Scale Electricity Generating Plants*" (April 2017).

[52] Note that the science of thermodynamics only refers to subcritical and supercritical states. "Ultra-Supercritical" is an industry term that refers to operating at higher temperatures and/or pressures within the supercritical regime. Distinct liquid and gas phases do not exist in a substance at a temperature and pressure above its critical point.

Table 6-1 Cost and Performance Assumptions for Potential USC and NGCC with and without Carbon Capture[53]

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Vintage #1 (2021)					
Heat Rate (Btu/kWh)	6,267	7,514	9,644	11,171	8,609
Capital (2016$/kW)	1,081	2,104	4,953	5,477	3,580
Fixed O&M (2016$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2	7.1	7.1	9.5	4.6
Vintage #2 (2023)					
Heat Rate (Btu/kWh)	6,233	7,504	9,433	10,214	8,514
Capital (2016$/kW)	1,064	2,059	4,863	5,378	3,516
Fixed O&M (2016$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2	7.1	7.1	9.5	4.6
Vintage #3 (2025-2054)					
Heat Rate (Btu/kWh)	6,200	7,493	9,221	9,257	8,323
Capital (2016$/kW)	1,041	2,003	4,746	5,249	3,431
Fixed O&M (2016$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016$/MWh)	2	7.1	7.1	9.5	4.6

The NGCC costs were developed for a generic 702-MW net output NGCC EGU with a nominal heat rate of 6,267 Btus per kW-hr in 2021. The USC EGU uses a "two-on-two-on-one" configuration. That is, the combined cycle technology EGU is comprised of two natural gas-fired F5-class combustion turbines (CTs), two supplementary Heat Recovery Steam Generators (HRSGs), and one ST. The NGCC facility is fueled with pipeline-quality natural gas with a higher heating value (HHV) of 1,040 Btus per standard cubic foot (scf). Steam is produced at 3,800 psia and 1,112 oF. The two HRSGs extract heat from the two CTs to power the one ST. NGCC with a CCS is equipped with an amine-based, post-combustion CO_2 capture system. NO_x emissions from the NGCC EGU are controlled with LNBs and a SCR system.

6.1.2 CO_2 Capture via Retrofitting Existing EGUs

EPA Platform v6 offers the option of retrofitting CCS to existing coal-fired power plants and NGCCs at a CO_2 capture efficiency of 90 percent.[54] The CO_2 capture process is modeled assuming the use of an amine-based, post-combustion CO_2 capture system.

The cost and performance data provided in Table 6-2 is based on the Sargent & Lundy[55] cost algorithm (Attachment 6-1 summarizes this study) and a DoE/National Environmental Technology Laboratory (NETL)

[53] The cost and performance characteristics for these new units are also shown in Table 4-13 and discussed further in Chapter 4.

[54] Note that the NGCC with CCS option is disabled in the EPA Platform v6 November 2018 Reference Case.

[55] Sargent & Lundy. "*IPM Model – Updates to Cost and Performance for APC Technologies – CO_2 Reduction Cost Development Methodology.*" Project 13527-001; February 2017.

study.[56] As part of developing documentation for EPA Platform v6, the capital costs were converted to 2016 dollars from the 2011 dollar basis used in the referenced DoE/NETL study. Note that one of the carbon capture information resources is the Shell Cansolv® technology, which was installed on Unit 3[57] at SaskPower's Boundary Dam Power Station near Estevan, Saskatchewan, Canada in October 2014.[58] One issue that must be addressed when installing an amine-based, post-combustion CO_2 capture system is that sulfur oxides (e.g., SO_2 and sulfur trioxide (SO_3)) in the EGU flue gas can degrade the amine-based solvent used to absorb the CO_2 from the EGU flue gas. Since the amine will preferentially absorb SO_2 before CO_2, it will be necessary to treat the EGU flue gas to lower the sulfur oxide concentration to 10 parts per million by volume (ppmv) or less. Meeting this constraint will require installing supplemental WFGD technology (e.g., the SO_2 "polishing" scrubber referenced in footnote 58), or retrofitting existing FGD.

Table 6-2 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Coal Plants

Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)[2]	Capacity Penalty (%)	Heat Rate Penalty (%)
400	9,000	2,595	36.9	3.15	33.6	50.6
	10,000	2,960	41.2	3.71	37.3	59.5
	11,000	3,373	46.1	4.32	41.0	69.6
700	9,000	1,852	23.7	2.57	19.2	23.7
	10,000	2,071	26.1	2.93	21.3	27.0
	11,000	2,302	28.6	3.31	23.4	30.6
1,000	9,000	1,625	19.7	2.40	13.4	15.5
	10,000	1,810	21.6	2.71	14.9	17.5
	11,000	2,001	23.6	3.03	16.4	19.6

Note:
[1]Incremental costs are applied to the derated (after retrofit) MW size.
[2]The CO_2 Transportation, Storage, and Monitoring portion of the variable O&M has been removed from Sargent & Lundy cost method and modeled separately.

The capacity-derating penalty and associated heat rate penalty are an output of the Sargent & Lundy model (see section 5.1.1 for further details in regards to these penalties.)

6.2 CO_2 Storage

The capacity and cost assumptions for CO_2 storage in EPA Platform v6 are based on the Geosequestration Cost Analysis Tool (GeoCAT); a spreadsheet model developed for the U.S. EPA by ICF, Inc. (ICF) in support of the U.S. EPA's Underground Injection Control (UIC) Program for CO_2 Geologic Storage Wells.[59] For EPA Platform v6, ICF updated the major cost components in the GeoCAT model, including revising onshore and offshore injection and monitoring costs to reflect 2016 industry drilling

[56] DoE/NETL. "*Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity. Revision 3*." DoE/NETL-2015/1723. July 6, 2015. (See https://www.netl.doe.gov/projects/files/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGastoElectRev3_070615.pdf)

[57] At the time of project execution, Sask Power's Boundary Dam Unit 3 was a 43-year old lignite-fired 139 MW net generating unit. Upon completion, Boundary Dam Unit 3 became the first utility-scale power plant retrofitted with CCS technology. Sask Power estimates that the $1.2 billion project extended Unit 3's life by 30 years. Note that the associated energy penalty for installing the CCS technology derated Unit 3 from 139 to 110 MWs.

[58] The Shell Cansolv® carbon capture system at Boundary Dam Unit 3 uses a proprietary amine solvent to absorb SO_2 and CO_2 from the EGU flue gases. The carbon capture process requires very low SO_2 levels in the flue gases prior to CO_2 capture because, if present, the amine would preferentially absorb SO_2 before CO_2. The Shell Cansolv® SO_2 capture process was installed upstream of the CO_2 scrubber to "polish" the feed to the CO_2 scrubber.

[59] Federal Requirements Under the UIC Program for CO_2 Geologic Sequestration Wells, Federal Register, December 10, 2010 (Volume 75, Number 237), pages 77229-77303.

costs.[60] All cost components in the model were also converted to a 2016 dollar basis. In addition to updating costs in the model, ICF updated storage capacity, well injectivity, and other assumptions by state and offshore area primarily using data from the research program conducted at DoE/NETL. Assumptions for the amount of carbon dioxide injected for EOR was updated using the past several years of performance data.

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 CO_2 geologic sequestration. The model outputs 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:

1. A unit cost specification module,
2. A project scenario costing module, and
3. A geologic and regional cost curve module.

The unit cost specification module includes data and assumptions for 120 cost elements falling within the following categories:

1. Geologic site characterization
2. 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)
3. Injection well and other facilities construction
4. Well operation
5. Monitoring the movement of CO_2 in the subsurface
6. Mechanical integrity testing
7. Financial responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
8. Post injection site care
9. Site closure
10. 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 and other facilities construction, and monitoring the movement of CO_2 in the subsurface. The cost estimates are consistent with the requirements for geologic storage facilities under the UIC Class VI rule[61] and Greenhouse Gas (GhG) Reporting Program Subpart RR[62]. The price of oil assumed for the calculation of EOR economics is $75/barrel.

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[60] The major data sources for updating costs was the Bureau of Labor Statistics (BLS) Producers Price Index (PPI) for various products and services related to oil and gas well drilling (https://www.bls.gov/ppi/), the "Joint Association Survey of Drilling Costs" published by the American Petroleum Institute (http://www.api.org/products-and-services/statistics#tab_overview), and the "Well Cost Study" published by the Petroleum Services Association of Canada (https://www.psac.ca/resources/well-cost-study-overview/).

[61] *Supra* Note 59.

[62] Title 40 of the Code of Federal Regulations (CFR), Part 98 (Mandatory GhG Reporting), Subpart RR (Geologic Sequestration of CO_2). See https://ecfr.io/Title-40/sp40.23.98.rr.

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for eight sequestration scenarios compliant with UIC Class VI standards and GhG Reporting Program Subpart RR:

1. Deep saline formations
2. Depleted gas fields
3. Depleted oil fields
4. Enhanced oil recovery
5. Enhanced coal bed methane recovery
6. Enhanced shale gas
7. Basalt storage
8. Unmineable coal seams

EPA's GeoCAT application for CO_2 sequestration includes only storage capacity for the first four sequestration scenarios. The last four reservoir types are not included because they are not considered technically mature enough to allow CO_2 storage in the foreseeable future.

The current GeoCAT model includes the most recent DoE analysis of the lower-48 states CO_2 sequestration capacities from the "Carbon Sequestration Atlas of the United States and Canada Version 5."[63] ICF enhanced these assessments to include additional details needed for economic modeling such as the distribution of capacity by state, drilling depth, injectivity, etc. The geologic and regional cost curve module applies regionalized unit cost factors to these geologic characterizations to develop regional geologic storage cost curves.[64] The analysis of storage volumes is carried out by regional carbon sequestration partnerships as overseen by NETL in Morgantown, West Virginia. State level onshore and offshore capacity volumes are reported for storage in oil and gas reservoirs and deep saline formations. The great majority of storage volume is in deep saline formations, which are present in many states and in most states with oil and gas production. In the most recent version of the Atlas, offshore storage volumes have also been broken out by DoE into the Gulf of Mexico, Atlantic, and Pacific Outer Continental Shelf (OCS) regions. ICF carried out a separate analysis to break out CO_2 EOR storage potential from the total potential in oil and gas reservoirs reported in NATCARB.

Efficiency Assumptions for EOR Uses of CO_2

Relying on recent performance data, the geologic storage cost curve for EOR is based on an average EOR efficiency of 10 thousand cubic feet (Mcf) of CO_2 per incremental barrel of crude oil. The NETL "CO_2 EOR Primer"[65] shows that from the start of CO_2 floods in 1972 to 2008 the average efficiency was 7.66 Mcf per bbl. Data for the most recent seven year has shown a lower average efficiency of over 10.32 Mcf/bbl. This creates an average of 8.62 Mcf/bbl for all years from 1972 to 2016.

[63] Carbon Sequestration Atlas of the United States and Canada – Version 5 (2015), U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV https://www.netl.doe.gov/research/coal/carbon-storage/atlasv. Accessed mid-October 2016 with data updates through 2015.

[64] 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, https://www.epa.gov/sites/production/files/2015-07/documents/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 https://www.sciencedirect.com/science/article/pii/S1876610209008832.

[65] National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery", 2010, https://www.netl.doe.gov/file%20library/research/oil-gas/CO2_EOR_Primer.pdf

Historical CO_2 EOR: 1972-2008	
Billion cubic feet of CO_2	11,000
Million barrels of crude oil	1,437
Mcf/barrel	7.66
Source: NETL, "Carbon Dioxide Enhanced Oil Recovery", 2010	
Historical CO_2 EOR: 2009-2016	
Billion cubic feet of CO_2	8,339
Million barrels of crude oil	808
Mcf/barrel	10.32
Source: ICF estimates based on EPA GHG Inventory and Oil & Gas Journal Annual EOR Survey	
Historical CO_2 EOR: 1972-2016	
Billion cubic feet of CO_2	19,339
Million barrels of crude oil	2,244
Mcf/barrel	8.62
Source: Sum of prior two tables	

The average of all historical and ongoing EOR projects <u>through the end of their lifetimes</u> is likely to exceed 9.0 Mcf/bbl as they continue to operate at ratios above 10 Mcf/bbl.[66] ICF has chosen a calibration point of 10 Mcf/bbl for the average of potential future CO_2 EOR under the belief that the quality of future projects would likely be worse (i.e., require more CO_2 per unit of incremental oil production) than historical projects. The historical projects were presumably chosen, in part, because of their favorable characteristics, as well as their proximity to sources of CO_2. Future projects are likely to have poorer characteristics and would be expected to require more CO_2. Also, because of the economic incentive to get the 45Q tax credits, it is possible that project designs might change to use more CO_2, particularly in the years the credit is available. The revised average efficiency value of 10 Mcf/bbl is approximately 15 percent higher than the original version of GeoCAT, which was calibrated to the older historical data.

There is considerable variation in CO_2 requirements among projects initiated in the US. The most efficient projects use less than 3 Mcf of net CO_2 per barrel produced, while the least efficient can use up to 20 Mcf/bbl.[67] This wide variation is represented in GeoCAT where assumed efficiencies across all state and geologic reservoir qualities is approximately 5 to 25 Mcf/bbl. There are 19 Mcf of CO_2 per metric ton, so in terms of weight, GeoCAT has a range of 0.26 to 1.32 tons of carbon dioxide per barrel of increment crude oil produced by CO_2 flooding. The average is 0.53 metric tons CO_2 per incremental barrel.

[66] For example, assuming an average of 10 years of future operation at the 2016 ratios leads to a lifetime average for all historical and ongoing CO_2 EOR project of 9.09 Mcf/bbl.

[67] During the EOR operations, some CO_2 is produced with the oil and then separated and recycled back into the reservoir. "Net volume" of CO_2 is the original amount of CO_2 delivered to the EOR project, while "gross injected volume" includes both original volumes and reinjected volumes. The gross volumes are typically about twice the net volumes.

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 total cost per ton of CO_2 including all capital and operating costs. The result is a database of sequestration capacity by state, geologic reservoir type, and cost step.

Table 6-3 shows the NATCARB V storage volumes for the U.S. Lower-48 as allocated to GeoCAT categories. Total Lower-48 capacity is assessed at 8,216 gigatonnes. There are no volumes in the current model for potential storage in depleted gas field reservoirs because these are not reported in NATCARB.

For EPA Platform v6, GeoCAT represents storage opportunities in 37 of the lower 48 continental states.[68] Louisiana and Texas have both onshore and offshore state-level storage cost curves. In addition, because NATCARB does not provide state-level data, there are multi-state Atlantic offshore and Pacific offshore storage cost curves. The result is 41 storage cost curves shown in Table 6-4.

Table 6-3 Lower-48 CO_2 Sequestration Capacity by Region

					Offshore Allocation in GeoCAT					
		Onshore	Offshore	Total	Louisiana	Texas	GOM Total	Pacific	Atlantic	Total
CO2 Enhanced Oil Recovery	Low	11.2	1.1	12.3						
	Mid	**15.0**	**1.5**	**16.4**	**1.5**	**0.0**	**1.5**	**0.0**	**0.0**	**1.5**
	High	22.5	2.2	24.7						
Depleted Oil	Low	128.0	11.8	139.8						
	Mid	**170.7**	**15.7**	**186.4**	**12.7**	**3.0**	**15.7**	**0.1**	**0.0**	**15.7**
	High	256.0	23.6	279.6						
Unmineable Coal	Low	47.8	2.0	49.8						
	Mid	**63.7**	**2.6**	**66.4**	**0.0**	**0.0**	**0.0**	**2.6**	**0.0**	**2.6**
	High	95.6	4.0	99.5						
Saline	Low	4,252	1,708	5,960						
	Mid	**5,669**	**2,277**	**7,947**	**1,240**	**798**	**2,038**	**37**	**202**	**2,277**
	High	12,477	3,416	15,893						
Totals	Low	4,439	1,723	6,162						
	Mid	**5,919**	**2,297**	**8,216**	**1,254**	**801**	**2,055**	**40**	**202**	**2,297**
	High	12,851	3,446	16,297						
Oil Subtotal	Low	139.2	12.9	152.1						
(EOR plus Depleted Oil Flds.)	**Mid**	**185.6**	**17.2**	**202.8**	**14.16**	**2.97**	**17.13**	**0.05**	**0.00**	**17.18**
	High	278.5	25.8	304.2						

Note: Individual values may not sum to reported totals due to rounding.

The cost curves in Table 6-4 are in the form of step functions. In any given year within the IPM model, a specified amount of storage is available at a particular step price until either the annual storage limit or the total storage capacity 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 at that price step, no more storage is available going forward at that particular step price and, so, higher priced steps must be used.

[68] The states without identified storage opportunities in EPA Reference Case v6 are Connecticut, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Hampshire, New Jersey, Rhode Island, Vermont, and Wisconsin. These states were either not assessed or were found to not have storage opportunities in NATCARB for the four sequestration scenarios included in EPA's inventory, (i.e., deep saline formations, depleted gas fields, depleted oil fields, and enhanced oil recovery).

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 Platform v6, 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 $50 per ton (this abatement value is relevant not only to willingness to pay for storage but also for the cost of capture and transportation of the abated CO_2).[69] The quantity of industrial sequestration economic at $50/ton represent the "high quality" industrial sources that have high CO_2 purity and would be easiest to capture, rehydrate, and compress. They are made up of ethanol plants, hydrogen production at refineries and merchant plants and gas processing plants where CO_2 is removed from the natural gas. This amount was calculated as 128 million tons per year.

Then, for each region, ICF calculated the ratio of the industrial demand to total storage capacity available for a storage price of less than zero dollars per ton. An upper limit of $0.00 per ton was chosen under the belief that the earliest uses of CO_2 from industrial sources would continue the current practice of targeting EOR opportunities. Converting this quantity of capacity reserved for industrial CCS to a percent value and subtracting from 100 percent, ICF obtained the percent of storage capacity available to the electricity sector at less than zero dollars per ton. Finally, the "Annual Step Bound (MMTons)" and "Total Storage Capacity (MMTons)" was multiplied by this percentage value for each step below zero dollars[70] 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 Platform v6 November 2018 Reference Case. Thus, the values shown in Table 6-4 represent the storage available specifically to the electric sector.

The price steps in the Table 6-4 are the same from region to region. (That is, STEP9 [column 2] has a step cost value of $9.07/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, indicating that over the modeling time horizon no new storage is being identified to augment the current storage capacity estimates. This assumption is not meant to imply that no additional storage could be added. Such additional capacity could be represented in the model if model runs exhaust key components of the currently estimated storage capacity.

6.3 CO_2 Transport

Each of the 64 IPM model regions can send CO_2 to the 41 regions represented by the storage cost curves in Table 6-4. The associated transport costs (in 2016$/Ton) are shown in Table 6-5. For the model, ICF has also updated assumptions about the costs of CO_2 pipelines. 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 Table 6-4. 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

[69] 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.

[70] 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. The value of the CO_2 for EOR is calculated using the average price of crude oil of $75/bbl taken from ICF's Base Case forecast of mid-2018. 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.

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. CO_2 transportation cost are based on a pipeline cost of $183,000 per inch-mile, which is consistent with ICF's natural gas supply curve and basis differential assumptions from GMM. This pipeline cost estimate is based on recent pipeline cost trends as represented in ICF's 2017 report to API entitled "U.S. Oil and Gas Infrastructure Investment Through 2030."[71]

<u>List of tables that are uploaded directly to the web:</u>

Table 6-4 CO_2 Storage Cost Curves in EPA Platform v6

Table 6-5 CO_2 Transportation Matrix in EPA Platform v6

Attachment 6-1 CO_2 Reduction Cost Development Methodology

[71] See: https://www.api.org/news-policy-and-issues/energy-infrastructure/oil-gas-infrastructure-study-2017

7. Coal

The next three chapters cover the representation and underlying assumptions for fuels in EPA Platform v6. The current chapter focuses on coal, chapter 8 on natural gas, and chapter 9 on other fuels (fuel oil, biomass, nuclear fuel, and waste fuels) represented in EPA Platform v6.

This chapter presents four main topics. The first is a description of how the coal market is represented in EPA Platform v6. This includes a discussion of coal supply and demand regions, coal quality characteristics, and the assignment of coals to power plants.

The second topic is the coal supply curves which were developed for EPA Platform v6 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 81 coal supply curves that are implemented in EPA Platform v6. 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.

Finally, EPA addresses competing sources of supply and competing sources of demand. On the supply side, this includes imported coal that arrives from non-U.S. or non-Canadian basins. On the demand side, EPA addresses power plants competition for demand in the form of international thermal exports, as well as domestic industrial/residential/commercial demand for thermal coal. These assumptions are discussed in Section 7.4.

The assumptions for the coal supply curves and coal transportation were finalized in December 2016, and were developed through a collaborative process with EPA supported by the following independent team of coal experts (with key areas of responsibility noted in parenthesis): ICF (IPM model integration and team coordination), Wood Mackenzie (coal supply curve development), and Hellerworx (coal transportation).

7.1 Coal Market Representation in EPA Platform v6

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 Platform v6. 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 pathways. 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 7.1.5 below), each coal fired plant is also assigned several coal grades which it may use if that coal type is available within its demand region.

In EPA Platform v6 the endogenous demand for coal is generated by coal fired power plants interacting with a set of exogenous supply curves (see Table 7-26 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 and demand for each grade of coal is linked to and affected by the supply and demand for every other coal grade across supply and demand regions.

The transportation network or matrix in Table 7-25 provides delivery cost to move coal from a free-on-board point of sale in the coal basin to the end-use power plant. The transportation cost combined with the free-on-board supply cost reflects the delivered cost a plant sees when making its coal selection. IPM derives the equilibrium coal consumption and prices that result when the entire electric system is operating at least cost while meeting emission constraints and other operating requirements over the modeling time horizon.

7.1.1 Coal Supply Regions

There are 36 coal supply regions in EPA Platform v6, 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 7-1 lists the coal supply regions included in EPA Platform v6.

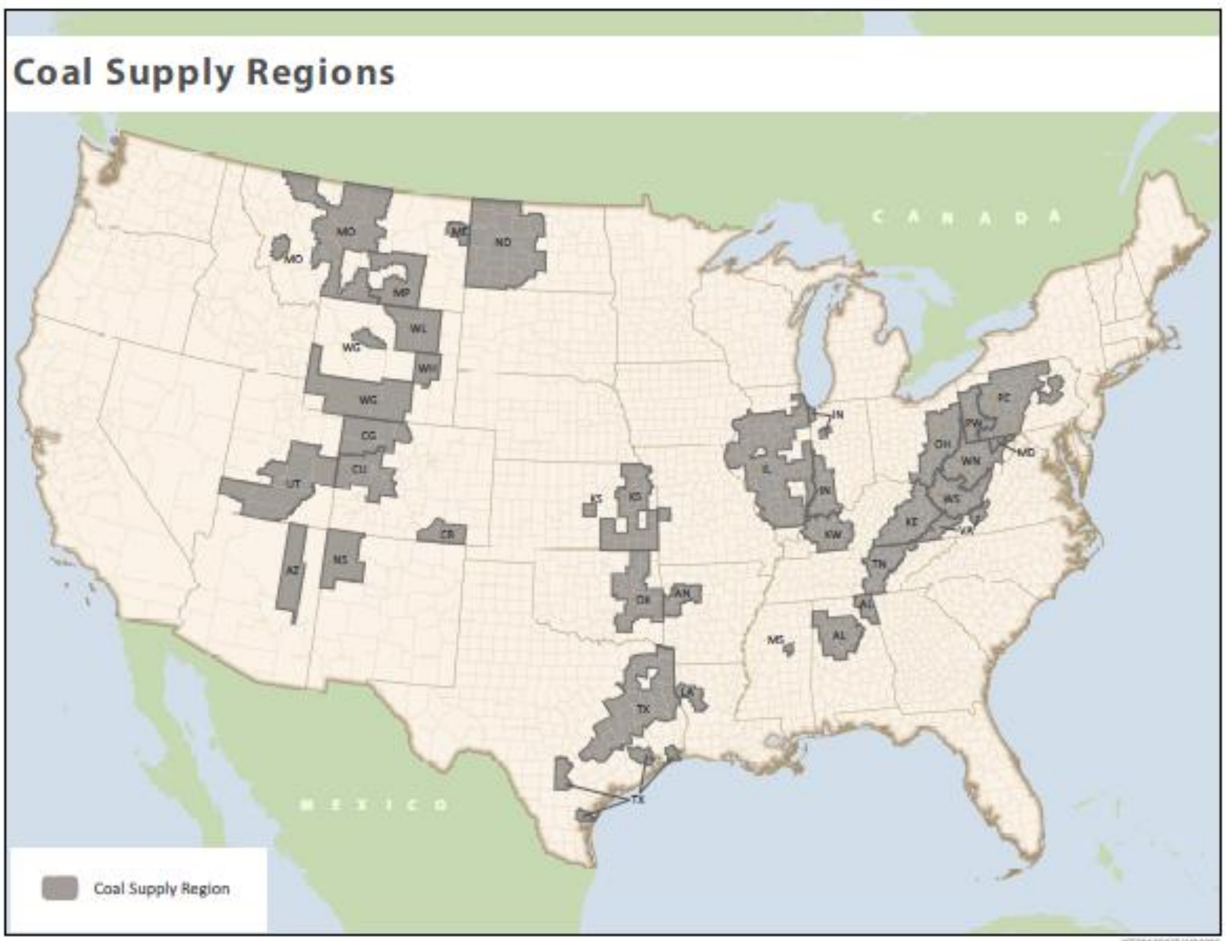
Figure 7-1 provides a map showing the location of both the coal supply regions listed in Table 7-1 and the broader supply basins commonly used when referring to U.S. coal reserves.

Table 7-1 Coal Supply Regions in EPA Platform v6

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	Indiana	IN
East Interior	Kentucky, West	KW
East Interior	Illinois	IL
Gulf Lignite	Texas	TX
Gulf Lignite	Louisiana	LA
Gulf Lignite	Mississippi	MS
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	Utah	UT
Rocky Mountains	Colorado, Green River	CG
Rocky Mountains	Colorado, Raton	CR
Rocky Mountains	Colorado, Uinta	CU
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

Region	State	Supply Region
Western Montana	Montana, Powder River	MP
Western Wyoming	Wyoming, Green River	WG
Wyoming Northern PRB	Wyoming, Powder River Basin (8800)	WH
Wyoming Southern PRB	Wyoming, Powder River Basin (8400)	WL
Alberta	Alberta	AB
British Columbia	British Columbia	BC
Saskatchewan	Saskatchewan	SK

Figure 7-1 Map of the Coal Supply Regions in EPA Platform v6



7.1.2 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 67 U.S. 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 7-27 for the list of coal plant demand regions reflected in the transportation matrix.

7.1.3 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 7-2). 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 7-3).

Table 7-2 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 7-3 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 Platform v6 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)[72].

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 ICR captured the origin of the coal burned, and thus provided a pathway for linking emission properties to coal basins.

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

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.

Annual fuel characteristic and delivery data reported on EIA Form 923 also provide continual data points on coal heat content, sulfur content, and geographic origin, which are used as a check against characteristics initially identified through the ICR.

7.1.4 Coal Emission Factors

To make this data usable in EPA Platform v6, 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 U.S. coal supply regions. The resulting values are shown in Table 7-4. The CO_2 values were derived from data in the Energy Information Administration's Annual Energy Outlook 2016.

Table 7-4 Coal Quality Characteristics by Supply Region and Coal Grade

Coal Supply Region	Coal Grade	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)	Cluster Number
AB	SA	0.59	5.29	5.47	0.009	215.5	1
	SB	0.94	6.06	6.94	0.013	215.5	5
	SD	1.43	5.35	11.60	0.008	215.5	1
AL	BB	1.09	4.18	9.76	0.012	204.7	4
	BD	1.35	7.28	10.83	0.029	204.7	1
	BE	2.68	12.58	10.70	0.028	204.7	1
AN	BG	4.23	9.36	7.83	0.079	202.8	1
AZ	BB	1.05	5.27	7.86	0.067	207.1	2
BC	BD	1.40	6.98	8.34	0.096	216.1	4
CG	BB	0.90	4.09	8.42	0.021	209.6	4
	SB	0.93	2.03	7.06	0.007	212.8	1
CR	BB	1.05	5.27	7.86	0.067	209.6	2
CU	BB	0.86	4.01	7.83	0.009	209.6	4
IL	BE	2.25	6.52	6.61	0.214	203.1	2
	BG	4.56	6.53	8.09	0.113	203.1	3
	BH	5.58	5.43	9.06	0.103	203.1	1
IN	BE	2.31	5.21	7.97	0.036	203.1	3
	BG	4.27	7.20	8.22	0.028	203.1	3
	BH	6.15	7.11	8.63	0.019	203.1	3
KE	BB	1.04	4.79	6.41	0.112	206.4	5
	BD	1.44	5.97	7.45	0.087	206.4	2
	BE	2.12	7.93	7.71	0.076	206.4	4
	BG	3.79	11.99	10.21	0.041	206.4	4
KS	BG	4.84	4.09	8.47	0.133	202.8	5
KW	BG	4.46	6.90	8.01	0.097	203.1	3
	BH	5.73	8.16	10.21	0.053	203.1	3
LA	LE	2.49	7.32	17.15	0.014	212.6	1

Coal Supply Region	Coal Grade	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)	Cluster Number
MD	BE	2.78	15.62	11.70	0.072	204.7	5
	BG	3.58	16.64	16.60	0.018	204.7	7
ME	LE	1.83	11.33	11.69	0.019	219.3	2
MO	BG	4.54	5.91	9.46	0.023	215.5	3
MP	SA	0.62	4.24	3.98	0.007	215.5	1
	SB	0.98	6.25	5.81	0.023	215.5	2
	SD	1.49	4.53	10.13	0.006	215.5	1
MS	LE	2.76	12.44	21.51	0.018	216.5	3
MT	BB	1.05	5.27	7.86	0.067	215.5	2
ND	LE	2.27	8.30	12.85	0.014	219.3	1
NS	SB	0.89	4.60	14.51	0.014	209.2	3
	SD	1.55	7.54	23.09	0.007	209.2	2
	SE	1.90	8.65	23.97	0.008	209.2	1
OH	BE	3.08	18.70	7.08	0.075	204.7	6
	BG	3.99	18.54	8.00	0.071	204.7	7
	BH	6.43	13.93	9.13	0.058	204.7	4
OK	BG	4.65	26.07	13.54	0.051	202.8	6
PC	BB	1.06	23.03	58.98	0.032	204.7	6
	BD	1.42	21.67	49.31	0.066	204.7	3
	BE	2.57	17.95	9.23	0.096	204.7	6
	BG	3.79	21.54	9.59	0.092	204.7	2
	BH	6.29	34.71	13.89	0.148	204.7	5
PW	BE	2.51	8.35	5.37	0.090	204.7	4
	BG	3.69	8.56	6.48	0.059	204.7	1
	BH	7.78	16.46	11.56	0.046	204.7	2
SK	LD	1.51	7.53	11.57	0.014	219.3	1
	LE	2.76	12.44	21.51	0.018	219.3	3
TN	BE	2.13	8.43	6.47	0.043	206.4	4
TX	LE	3.00	14.65	25.65	0.020	212.6	4
	LG	3.91	14.88	25.51	0.036	212.6	1
	LH	5.67	30.23	23.95	0.011	212.6	1
UT	BA	0.67	4.37	7.39	0.015	209.6	1
	BB	0.94	3.93	8.58	0.016	209.6	4
	BD	1.37	4.38	10.50	0.026	209.6	4
	BE	2.34	9.22	7.41	0.095	209.6	4
VA	BB	1.05	4.61	6.97	0.054	206.4	5
	BD	1.44	5.67	7.97	0.028	206.4	2
	BE	2.09	8.40	8.05	0.028	206.4	4
WG	BB	1.13	1.82	5.58	0.005	214.3	3
	SB	1.06	4.22	8.72	0.009	214.3	4
	SD	1.33	4.33	10.02	0.008	214.3	1
	SE	2.22	4.41	5.71	0.008	214.3	2
WH	SA	0.52	5.61	5.51	0.010	214.3	2
WL	SA	0.71	5.61	7.09	0.010	214.3	3
	SB	0.93	6.44	7.92	0.012	214.3	5

Coal Supply Region	Coal Grade	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/Tbtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)	Cluster Number
WN	BD	1.46	10.27	9.18	0.099	204.7	6
	BE	2.55	10.28	7.89	0.092	204.7	7
	BG	4.00	9.27	6.92	0.074	204.7	1
	BH	6.09	8.82	9.62	0.045	204.7	3
WS	BB	1.09	5.75	9.15	0.091	206.4	1
	BD	1.32	8.09	9.25	0.098	206.4	5
	BE	1.94	8.83	9.89	0.102	206.4	4
	BG	4.67	7.13	6.39	0.051	206.4	3

Next, a clustering algorithm was used to further aggregate the data in EPA Platform v6 for model size management purposes. The clustering analysis was performed on the SO_2, mercury, and HCl data shown in Table 7-4 using the SAS statistical software package. Clustering analysis places objects into groups or clusters, such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. First, the number of clusters of SO_2, mercury, and HCl concentrations for each IPM coal type was determined based on the range in SO_2, mercury, and HCl concentrations across all coal supply regions for a specific coal grade. Each coal type used either one to seven clusters. The total number of clusters for each coal grade was limited to keep the model size and run time within feasible limits. Second, for each coal grade the clustering procedure was applied to all the regional SO_2, mercury, and HCl values shown in Table 7-4 for that coal grade. Using the SAS cluster procedure, each of the constituent regional values was assigned to a cluster and the cluster average SO_2, mercury, and HCl were estimated. The resulting values are shown in Table 7-5 through Table 7-9.

Table 7-5 Coal Clustering by Coal Grade – SO_2 Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	SO_2 Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	0.67	0.67	0.67	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	1.09	1.09	1.09	1.05	1.05	1.05	1.13	1.13	1.13	0.95	0.86	1.09	1.04	1.04	1.05	1.06	1.06	1.06	--	--	--
Low Medium Sulfur Bituminous (BD)	1.35	1.35	1.35	1.44	1.44	1.44	1.42	1.42	1.42	1.39	1.37	1.40	1.32	1.32	1.32	1.46	1.46	1.46	--	--	--
Medium Sulfur Bituminous (BE)	2.68	2.68	2.68	2.25	2.25	2.25	2.31	2.31	2.31	2.19	1.94	2.51	2.78	2.78	2.78	2.82	2.57	3.08	2.55	2.55	2.55
High Sulfur Bituminous (BG)	3.98	3.69	4.23	3.79	3.79	3.79	4.50	4.27	4.67	3.79	3.79	3.79	4.84	4.84	4.84	4.65	4.65	4.65	3.78	3.58	3.99
High Sulfur Bituminous (BH)	5.58	5.58	5.58	7.78	7.78	7.78	5.99	5.73	6.15	6.43	6.43	6.43	6.29	6.29	6.29	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	0.60	0.59	0.62	0.52	0.52	0.52	0.71	0.71	0.71	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	0.93	0.93	0.93	0.98	0.98	0.98	0.89	0.89	0.89	1.06	1.06	1.06	0.94	0.93	0.94	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	1.42	1.33	1.49	1.55	1.55	1.55	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	1.90	1.90	1.90	2.22	2.22	2.22	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	1.51	1.51	1.51	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	2.38	2.27	2.49	1.83	1.83	1.83	2.76	2.76	2.76	3.00	3.00	3.00	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	3.91	3.91	3.91	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	5.67	5.67	5.67	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-6 Coal Clustering by Coal Grade – Mercury Emission Factors (lbs/TBtu)

Coal Type by Sulfur Grade	Mercury Emission Factors (lbs/TBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	4.37	4.37	4.37	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	5.75	5.75	5.75	5.27	5.27	5.27	1.82	1.82	1.82	4.05	3.93	4.18	4.70	4.61	4.79	23.03	23.03	23.03	--	--	--
Low Medium Sulfur Bituminous (BD)	7.28	7.28	7.28	5.82	5.67	5.97	21.67	21.67	21.67	5.68	4.38	6.98	8.09	8.09	8.09	10.27	10.27	10.27	--	--	--
Medium Sulfur Bituminous (BE)	12.58	12.58	12.58	6.52	6.52	6.52	5.21	5.21	5.21	8.53	7.93	9.22	15.62	15.62	15.62	18.33	17.95	18.70	10.28	10.28	10.28
High Sulfur Bituminous (BG)	9.06	8.56	9.36	21.54	21.54	21.54	6.73	5.91	7.20	11.99	11.99	11.99	4.09	4.09	4.09	26.07	26.07	26.07	17.59	16.64	18.54
High Sulfur Bituminous (BH)	5.43	5.43	5.43	16.46	16.46	16.46	8.03	7.11	8.82	13.93	13.93	13.93	34.71	34.71	34.71	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	4.94	4.24	5.29	5.61	5.61	5.61	5.61	5.61	5.61	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	2.03	2.03	2.03	6.25	6.25	6.25	4.60	4.60	4.60	4.22	4.22	4.22	6.25	6.06	6.44	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	4.74	4.33	5.35	7.54	7.54	7.54	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	8.65	8.65	8.65	4.41	4.41	4.41	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	7.53	7.53	7.53	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	7.81	7.32	8.30	11.33	11.33	11.33	12.44	12.44	12.44	14.65	14.65	14.65	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	14.88	14.88	14.88	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	30.23	30.23	30.23	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-7 Coal Clustering by Coal Grade – Ash Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	Ash Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	7.39	7.39	7.39	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	9.15	9.15	9.15	7.86	7.86	7.86	5.58	5.58	5.58	8.65	7.83	9.76	6.69	6.41	6.97	58.98	58.98	58.98	--	--	--
Low Medium Sulfur Bituminous (BD)	10.83	10.83	10.83	7.71	7.45	7.97	49.31	49.31	49.31	9.42	8.34	10.50	9.25	9.25	9.25	9.18	9.18	9.18	--	--	--
Medium Sulfur Bituminous (BE)	10.70	10.70	10.70	6.61	6.61	6.61	7.97	7.97	7.97	7.48	5.37	9.89	11.70	11.70	11.70	8.16	7.08	9.23	7.89	7.89	7.89
High Sulfur Bituminous (BG)	7.08	6.48	7.83	9.59	9.59	9.59	8.03	6.39	9.46	10.21	10.21	10.21	8.47	8.47	8.47	13.54	13.54	13.54	12.30	8.00	16.60
High Sulfur Bituminous (BH)	9.06	9.06	9.06	11.56	11.56	11.56	9.49	8.63	10.21	9.13	9.13	9.13	13.89	13.89	13.89	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	4.97	3.98	5.47	5.51	5.51	5.51	7.09	7.09	7.09	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	7.06	7.06	7.06	5.81	5.81	5.81	14.51	14.51	14.51	8.72	8.72	8.72	7.43	6.94	7.92	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	10.58	10.02	11.60	23.09	23.09	23.09	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	23.97	23.97	23.97	5.71	5.71	5.71	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	11.57	11.57	11.57	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	15.00	12.85	17.15	11.69	11.69	11.69	21.51	21.51	21.51	25.65	25.65	25.65	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	25.51	25.51	25.51	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	23.95	23.95	23.95	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-8 Coal Clustering by Coal Grade – HCl Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	HCl Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	0.01	0.01	0.01	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	0.09	0.09	0.09	0.07	0.07	0.07	0.01	0.01	0.01	0.01	0.01	0.02	0.08	0.05	0.11	0.03	0.03	0.03	--	--	--
Low Medium Sulfur Bituminous (BD)	0.03	0.03	0.03	0.06	0.03	0.09	0.07	0.07	0.07	0.06	0.03	0.10	0.10	0.10	0.10	0.10	0.10	0.10	--	--	--
Medium Sulfur Bituminous (BE)	0.03	0.03	0.03	0.21	0.21	0.21	0.04	0.04	0.04	0.07	0.03	0.10	0.07	0.07	0.07	0.09	0.07	0.10	0.09	0.09	0.09
High Sulfur Bituminous (BG)	0.07	0.06	0.08	0.09	0.09	0.09	0.06	0.02	0.11	0.04	0.04	0.04	0.13	0.13	0.13	0.05	0.05	0.05	0.04	0.02	0.07
High Sulfur Bituminous (BH)	0.10	0.10	0.10	0.05	0.05	0.05	0.04	0.02	0.05	0.06	0.06	0.06	0.15	0.15	0.15	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	0.01	0.01	0.01	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	0.01	0.01	0.01	0.01	0.01	0.01	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	0.01	0.01	0.01	0.01	0.01	0.01	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	0.01	0.01	0.01	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	0.04	0.04	0.04	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	0.01	0.01	0.01	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-9 Coal Clustering by Coal Grade – CO_2 Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	CO_2 Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	209.6	209.6	209.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	206.4	206.4	206.4	210.7	207.1	215.5	214.3	214.3	214.3	208.4	204.7	209.6	206.4	206.4	206.4	204.7	204.7	204.7	--	--	--
Low Medium Sulfur Bituminous (BD)	204.7	204.7	204.7	206.4	206.4	206.4	204.7	204.7	204.7	212.9	209.6	216.1	206.4	206.4	206.4	204.7	204.7	204.7	--	--	--
Medium Sulfur Bituminous (BE)	204.7	204.7	204.7	203.1	203.1	203.1	203.1	203.1	203.1	206.7	204.7	209.6	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7
High Sulfur Bituminous (BG)	204.1	202.8	204.7	204.7	204.7	204.7	206.2	203.1	215.5	206.4	206.4	206.4	202.8	202.8	202.8	202.8	202.8	202.8	204.7	204.7	204.7
High Sulfur Bituminous (BH)	203.1	203.1	203.1	204.7	204.7	204.7	203.6	203.1	204.7	204.7	204.7	204.7	204.7	204.7	204.7	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	215.7	215.5	216.1	214.3	214.3	214.3	214.3	214.3	214.3	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	212.8	212.8	212.8	215.5	215.5	215.5	209.2	209.2	209.2	214.3	214.3	214.3	214.9	214.3	215.5	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	215.1	214.3	215.5	209.2	209.2	209.2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	209.2	209.2	209.2	214.3	214.3	214.3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	219.3	219.3	219.3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	216.0	212.6	219.3	219.3	219.3	219.3	217.9	216.5	219.3	212.6	212.6	212.6	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	212.6	212.6	212.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	212.6	212.6	212.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

7.1.5 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 Platform v6 are shown in Table 7-10. 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 7-10 Example of Coal Assignments Made in EPA Platform v6

Plant Name	Unit	Permit Rate (lbs/MMBtu)	Scrubber?	Fuels Allowed
Mt Storm	3	0.15	Yes	BA,BB,BD
Mitchell	1	1.2	Yes	BA,BB,BD,BE,BG,BH
Scherer	1	1.2	Yes	SA,SB, SD,SE
Newton	1	0.5	No	SA, SB, SD, SE
R M Heskett	B2	1.97	Yes	LD, LE, LG, LH, SA, SB, SD, SE
San Miguel	SM-1	1.2	Yes	LD, LE, LG, LH

7.2 Coal Supply Curves

7.2.1 Nature of Supply Curves Developed for EPA Platform v6

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 thermal coal supply curves for EPA Platform v6. EPA utilized Wood Mackenzie 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 through both 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 7.1.1) and 14 coal grades (described above in section 7.1.3). The combined code list is shown in Table 7-11 below with the IPM coal 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 7-11) for forecast years 2021, 2023, 2025, 2030, 2035, 2040, 2045, and 2050.

Table 7-11 Basin-Level Groupings Used in Preparing v6 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	
AL	Appalachia	Southern Appalachia		x	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												

			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**
IL	Interior	East Interior (Illinois Basin)				x	x	x								
IN	Interior	East Interior (Illinois Basin)				x	x	x								
KE	Appalachia	Central Appalachia		x	x	x	x									
KS	Interior	West Interior					x									
KW	Interior	East Interior (Illinois Basin)					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	x	
MS	Gulf	Gulf Lignite Coast								x						
MT	West	Western Montana		x												
ND	West	Dakota Lignite								x						
NS	West	Southwest												x	x	x
OH	Appalachia	Northern Appalachia				x	x	x								
OK	West	West Interior					x									
PC	Appalachia	Northern Appalachia		x	x	x	x	x								
PW	Appalachia	Northern Appalachia				x	x	x								
SK	Canada	Saskatchewan							x	x						
TN	Appalachia	Central Appalachia				x										
TX	Interior	Gulf Lignite								x	x	x				
UT	West	Rocky Mountain	x	x	x	x										
VA	Appalachia	Central Appalachia		x	x	x										
WG	West	Western Wyoming		x										x	x	x
WH	West	Powder River Basin											x			
WL	West	Powder River Basin											x	x		
WN	Appalachia	Northern Appalachia			x	x	x	x								
WS	Appalachia	Central Appalachia		x	x	x	x									

7.2.2 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 for existing mines. For projects, the expansionary capital is spread across the mine life and included into the costs. 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).

<u>Operating cash cost</u>

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 for operating mines. Expansionary capital is included for new greenfield projects. 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 non-production related general and administration overheads that are essential to the production and sale of a mine's coal product. Examples would be mine site staff not related to mining, 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 7-1.

Royalties and Levies

These include, where appropriate, coal royalties, mine safety levies, health levies, industry research levies and other production taxes.

7.2.3 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.

7.2.4 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, some productivity loss may be offset by technology improvements in labor saving equipment.

In order to calculate the amount of employee hours, and therefore the labor cost, of future production Wood Mackenzie uses a multi-step process. First, employee hours associated with coal production for each mine are obtained from MSHA. Total production is then divided by these hours to calculate productivity, measured in short tons per employee hour. Future production levels are divided by this productivity measurement to obtain future employee hours needed to produce that volume of coal. From there, the total staffing level can be determined and the associated cost calculated.

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 variables that can impact underground-mine productivity that are often difficult to quantify and forecast.

7.2.5 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)[73] estimates to ensure that they do not exceed the DRB estimates.

7.2.6 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.

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. These reserves are often the "last step" in a coal supply curve due to the more difficult geologic conditions and have been designated using the above methodology.

In addition to new mines, Wood Mackenzie also identifies extension mines. These are denoted with the letter “A” at the end of an existing mine step name (e.g., E2A). These mine steps reflect the extension of a particular mine operating through a new lease covering tracts not previously recoverable under the existing mine operation. These mine expansions, like new mines, include the capital expansionary component in their cost of production.

7.2.7 Other Notable Procedures

Currency Assumptions

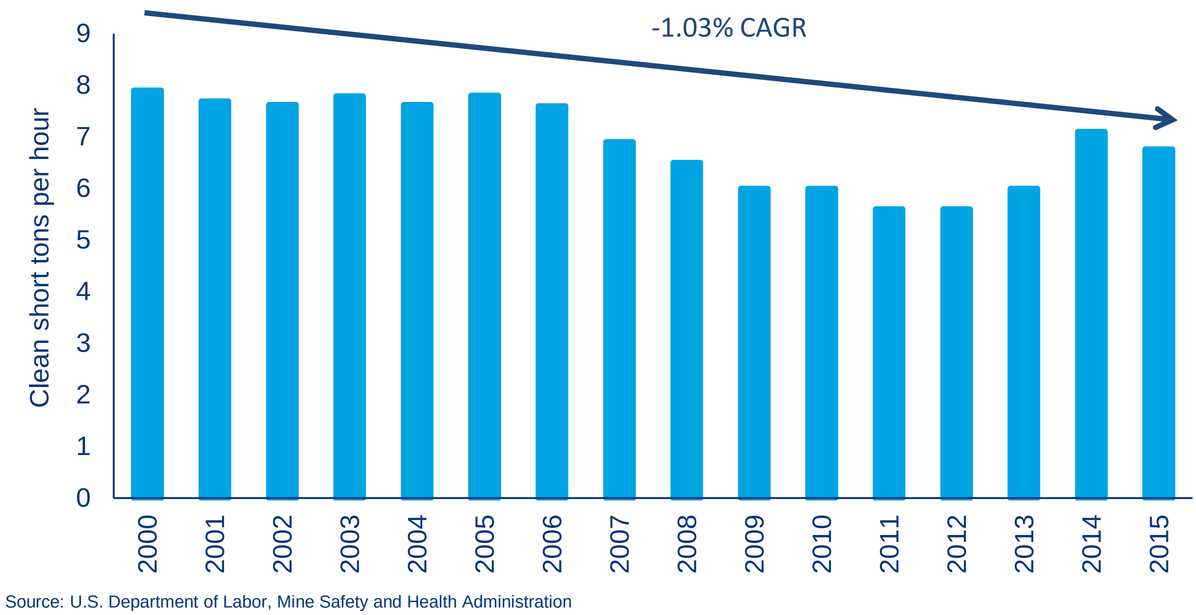
For consistency with the cost basis used in EPA Platform v6, costs are converted to real 2016$.

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 a -1.03% compound annual growth rate (CAGR) from 2000-2015 as shown in Figure 7-2.

[73] Posted by the Energy Information Administration (EIA) in its Coal Production Report.

Figure 7-2 Coal Mine Productivity (2000-2015)



Source: U.S. Department of Labor, Mine Safety and Health Administration

Figure 7-3 Average Annual Cost Growth Assumptions by Region (2021-2050)

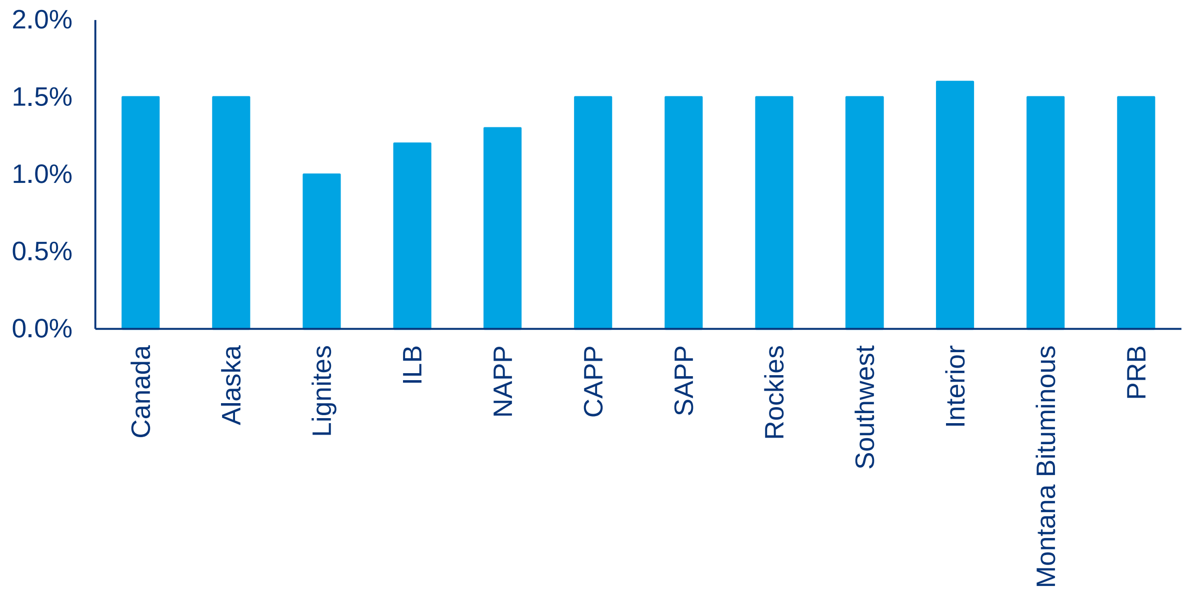


Figure 7-3 shows the compounded average annual growth rate (CAGR) of mining costs by basin over the forecast period. It should be noted that cost increases would ultimately be linked to market demand (as demand grows, the faster the rate of depletion of lower cost reserves). Costs in some supply basins 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 7.2.9.

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 7-4 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 7-4 Maximum Annual Coal Production Capacity per Year (Million Short Tons)

	2021	2023	2025	2030	2035	2040	2045	2050
ILB	180	200	220	240	240	240	240	240
PRB	480	500	520	560	600	600	600	600

7.2.8 Supply Curve Development

The description below describes the development of the coal supply curves. Table 7-26 shows the actual coal supply curves.

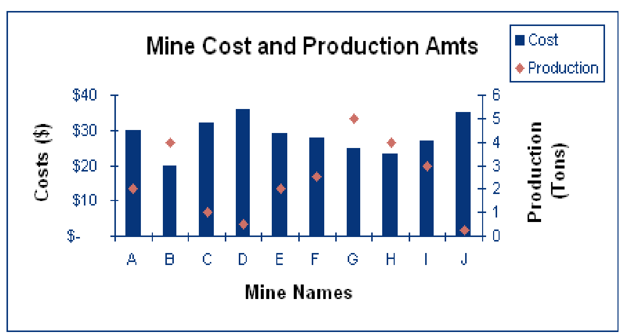
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. 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 7-5 and Figure 7-6 below.

Figure 7-5 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 7-7 for a stepped version of the supply curve example shown in Figure 7-6. 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 7-6 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

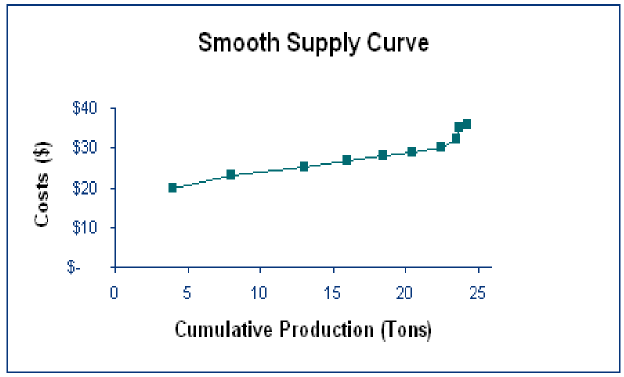
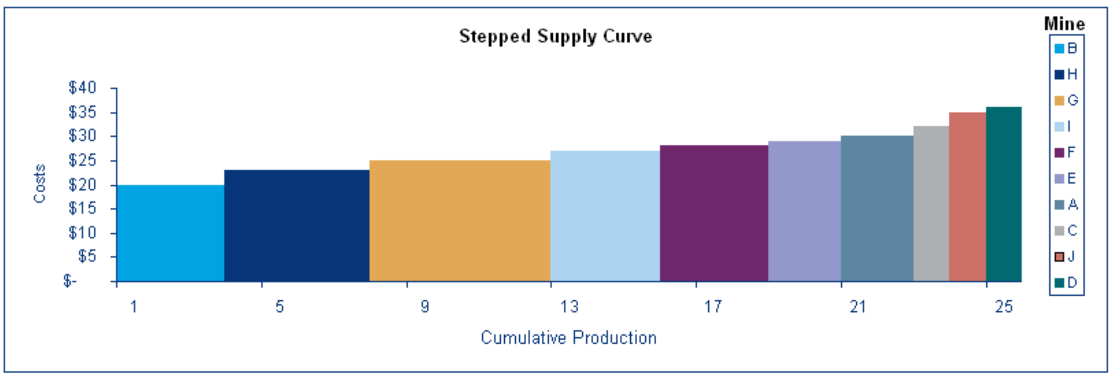


Figure 7-7 Example Coal Supply Curve in Stepped Format



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

7.2.9 EPA Platform v6 Assumptions and Outlooks for Major Supply Basins

Powder River Basin (PRB)

The PRB is somewhat unique to other U.S. 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 westward toward the Joint Line railroad and, at current and forecasted levels of production, around 2023 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. Development of these longwalls has slowed as natural gas prices fell significantly. Many developments have been delayed until prices, and demand, recover. In the long-term, the shape of the ILB supply curve is expected to increase in production capacity and decrease in costs. However, this is not due to a lowering of costs at existing mines. Rather it is caused by new mines being coming online that have lower operating costs than existing mines.

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 U.S. 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.

In the years leading up to 2017, producers have cut back production significantly as coal prices plummeted. Many companies went bankrupt and closed a large proportion of mines. As a result, average costs have fallen substantially as high cost, low productivity mines were closed. In an effort to retain margins, producers implemented a variety of tactics at continuing operations 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.

Out of the possible 17 billion short tons (Bst) of reserves, only 2.2 Bst has been identified – meaning located at an existing mine or a named project. The remainder are reserves that are available for development in the region but no engineering or permitting work has begun.

7.3 Coal Transportation

Table 7-25 presents the coal transportation matrix.

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).

Between 2012 (when the coal transportation rate assumptions for EPA Base Case v.5.13 were finalized), and 2016, coal production in the United States declined by 288 million tons/year, or 28% (from 1.016 billion tons in 2012 to 728 million tons in 2016.)[74] Approximately 46 gigawatts of coal-fired generating capacity (or about 14% of the total coal-fired generating capacity in the United States) retired in the period between 2012 and 2016.[75]

Despite the large decline in coal production, transportation rate levels for most coal movements declined relatively little in real terms between 2012 and 2016, as most providers of coal transportation elected to accept declines in coal volume rather than making large reductions in rates in an attempt to compete more aggressively with natural gas-fired generation.[76] Between 2016 and 2020, rates for all modes of coal transportation are expected to increase in real terms due to increases in fuel prices from the very low 2016 levels. Over the longer term, however, rates for most modes of coal transportation are expected to be flat to declining in real dollars from the 2020 levels, reflecting relatively low levels of expected coal demand throughout the 2021-2050 forecast period used in EPA Platform v6.

[74] The coal production data cited here is U.S. Energy Information Administration (EIA) data. The data is from the quarterly coal report released October 2017, and is available at https://www.eia.gov/coal/production/quarterly/.

[75] Data available at https://www.eia.gov/electricity/data.php#gencapacity.

[76] As will be discussed in more detail later in this section, both BNSF and CSX did introduce some innovative rail contracting structures in an attempt to make the dispatch of selected coal-fired generating plants more competitive with natural gas-fired generation, and the coal transportation rate assumptions in EPA Platform v6 have been modified to account for the effects of these programs. However, these programs only apply to a small number of coal-fired generating units.

The transportation methodology and rates presented below reflect expected long-run equilibrium transportation rates as of December 2016, when the coal transportation rate assumptions for EPA Platform v6 were finalized. The forecasted changes in transportation rates during the 2021-2050 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 of the transportation rates discussed in this document are expected 2020 rates and are shown in 2016 real dollars.

7.3.1 Coal Transportation Matrix Overview

Description

The general structure of the coal transportation matrix in EPA Platform v6 is similar to the structure used in EPA Base Case 5.13. Each of the U.S. and Canadian coal-fired generating plants included in EPA Platform v6 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 on a plant-specific basis. The coal transportation matrix shows the total rate 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 Platform v6 are largely unchanged from the previous version 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 early 2016, 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 Platform v6 (2021-2050.) 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 7-8.

Figure 7-8 Calculation of Multi-Mode Transportation Costs (Example)

Rail Cost ($/ton) = Rail Mill Rate (mills/ton-mile) x Rail Mileage + Transloading Cost ($/ton) + Barge Cost ($/ton) = Loading Cost ($/ton) + Barge Mill Rate (mills/ton-mile) x Barge Mileage

7.3.2 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 usually 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 eight 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 has 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[77] and other industry knowledge available to Hellerworx. Origins for each coal supply region were based on significant mines or other significant 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 December 2016 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. In cases where there are no existing coal plants within a particular IPM Region, the coal supply alternatives and coal transportation costs applicable to that IPM Region were estimated using a methodology similar to that used for the existing coal plants.[78] Using this consistent methodology across all of the IPM regions 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.

7.3.3 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.

As noted earlier in this section, rail rates have declined relatively little in recent years, despite a significant decline in coal demand. However, continued strong competition from natural gas-fired generation and renewables over the duration of the forecast period used in EPA Platform v6 (2021-2050) is expected to limit future coal demand, and to lead to further real declines in rail rates over the long term.

[77] Rail routing and mileage calculations utilize ALK Technologies PC*Miler software.

[78] Since the Canadian government has phased out coal-fired generation in Ontario, and in late 2016 announced plans to phase out coal-fired generation in Alberta by 2030, coal-fired generation was not modeled in the Canadian provinces where it is not currently used.

As of December 2016, 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 2020 fuel price levels.

Overview of Rail Competition Definitions

Within the transportation matrix, rail rates are classified as being either captive or competitive (see Table 7-12) 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 7-12 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 2020 costs in 2016 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 7-13 presents the 2020 eastern rail rates.

Table 7-13 Assumed Eastern Rail Rates for 2020
(2016 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	115	115	90
200-299	77	77	66
300-399	67	67	57
400-649	57	57	49
650+	37	37	35

In an attempt to help coal-fired generating plants located on its system compete more effectively with natural gas-fired generation, CSX recently introduced a new structure for some of its rail contracts that includes both fixed and variable components. Under this contracting structure, about 70% of the total rail rate is a variable component that is charged on a $/ton basis for each ton of coal shipped, and the remaining 30% of the total rail rate is a fixed dollar amount that is paid on a monthly basis. The goal of this contract structure was to reduce dispatch costs (thus improving the utilization of the generating plants using this contract structure), while leaving unchanged or increasing the total amount of revenue CSX earns.

However, many larger generators (whose systems included both CSX-served plants, and plants served by NS or other transportation providers) felt that this contracting structure might tend to favor CSX-served plants at the expense of other plants on their own systems, and/or unnecessarily complicate dispatching. As a result, the contracting structure that includes fixed and variable rail rate components is currently only used by a limited number of smaller generators, which have only CSX-served plants. This rail contracting structure is modeled on a plant-specific basis within EPA Platform v6.

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 7-14 depicts 2020 rail rates in the Midwest.

Table 7-14 Assumed Midwestern Rail Rates for 2020
(2016 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	115	115	90
200-299	77	77	66
300-399	57	57	49
400-649	56	56	48
650+	41	41	35

Rates Applicable to Western Moves

Rail moves within the Western U.S. are handled predominately 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 with 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).

During periods of unusually low natural gas prices, BNSF offered temporary spot rail rate discounts to a few selected generating plants using PRB coal in order to improve the utilization of these plants. Hellerworx believes that these discounts applied only to selected captive generating plants using PRB coal in the Gulf Coast region, were implemented only when natural gas prices reached very low levels, and were implemented primarily in the form of allowing rail rates at selected captive plants to temporarily fall to the rate level applicable to competitively served plants. Since it is Hellerworx's belief that these rate discounts would only apply at very low natural gas prices (likely below $3.00/MMBtu, in 2016$), these rate discounts are not modeled in EPA Platform v6, but could be included in sensitivity analyses involving very low natural gas prices.

Non-PRB Coal Moves

The assumed non-PRB western rail rates for 2020 are shown in Table 7-15.

Table 7-15 Assumed Non-PRB Western Rail Rates for 2020 (2016 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	52	36	36
300+	34	23	23

The assumed PRB western rail rates for 2020 are available in Table 7-16.

PRB Moves Confined to BNSF/UP Rail Lines

Table 7-16 Assumed PRB Western Rail Rates for 2020 (2016 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	30.8	21.2	21.2
300+	24.4	18.0	18.0

PRB Moves Transferring to Eastern Railroads

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 35 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 $2.20 per ton assumption is a minimum rate for short-distance movements of PRB coal on Eastern railroads.)

7.3.4 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 7-17 are expected 2020 rate levels, reflective of current rates as of December 2016, and expected changes in labor costs, fuel prices, and equipment costs.

Table 7-17 Assumed Truck Rates for 2020 (2016 Real Dollars)

Market	Loading Cost ($/ton)	Transport (mills/ton-mile)
All Markets	1.20	110

7.3.5 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 7-18 are expected 2020 rate levels reflective of current rates as of December 2016, and expected changes in labor costs, fuel prices, and equipment costs.

Table 7-18 Assumed Barge Rates for 2020
(2016 Real Dollars)

Type of Barge Movement	Loading Cost ($/ton)	Transport (mills/ton-mile)
Upper Mississippi River, and Downstream on the Ohio River System	4.10	13.5
Upstream on the Ohio River System	3.90	13.0
Lower Mississippi River	3.00	10.1

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.

7.3.6 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 labor, fuel, and equipment costs.

In EPA Platform v6, 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 Table 7-25.

7.3.7 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 7-19.

Table 7-19 Assumed Other Transportation Rates for 2020 (2016 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	2.10
Conveyor	1.00

7.3.8 Long-Term Escalation of Transportation Rates

Overview of Market Drivers

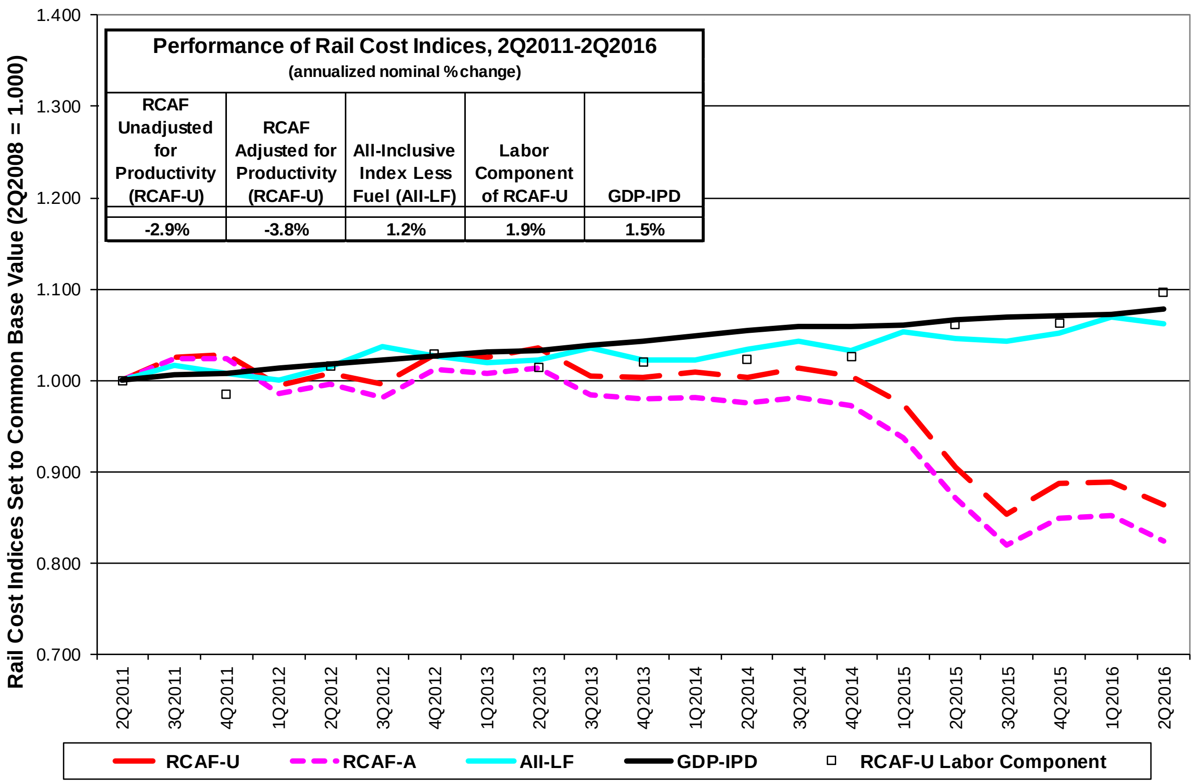
According to data published by the Association of American Railroads (AAR), labor costs accounted for about 32% of the rail industry's operating costs in 2014, and fuel accounted for an additional 21%. The remaining 47% of the rail industry's costs relate primarily to locomotive and railcar ownership and maintenance, and track construction and maintenance.

The performance of various cost indices for the railroad industry over the past five years (2Q2011-2Q2016) is summarized in Figure 7-9. As shown in Figure 7-9, the RCAF[79] Unadjusted for Productivity (RCAF-U), which tracks operating expenses for the rail industry, decreased at an annualized rate of 2.9%/year between the second quarter of 2011 and the second quarter of 2016, largely as a result of the steep decline in fuel prices during 2015 and 2016.

Excluding fuel, the railroad industry's overall input costs (e.g., equipment) decreased by .3% in real terms during the 2Q2011-2Q2016 period. The railroad industry's labor costs increased by an average of 0.4% per year during the same period. During the 2021-2050 forecast period used in EPA Platform v6, Hellerworx expects that labor costs for the railroad industry will continue to increase by approximately 0.5% per year in real terms. The rail industry's equipment and other costs are expected to remain flat.

[79] 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 7-9.

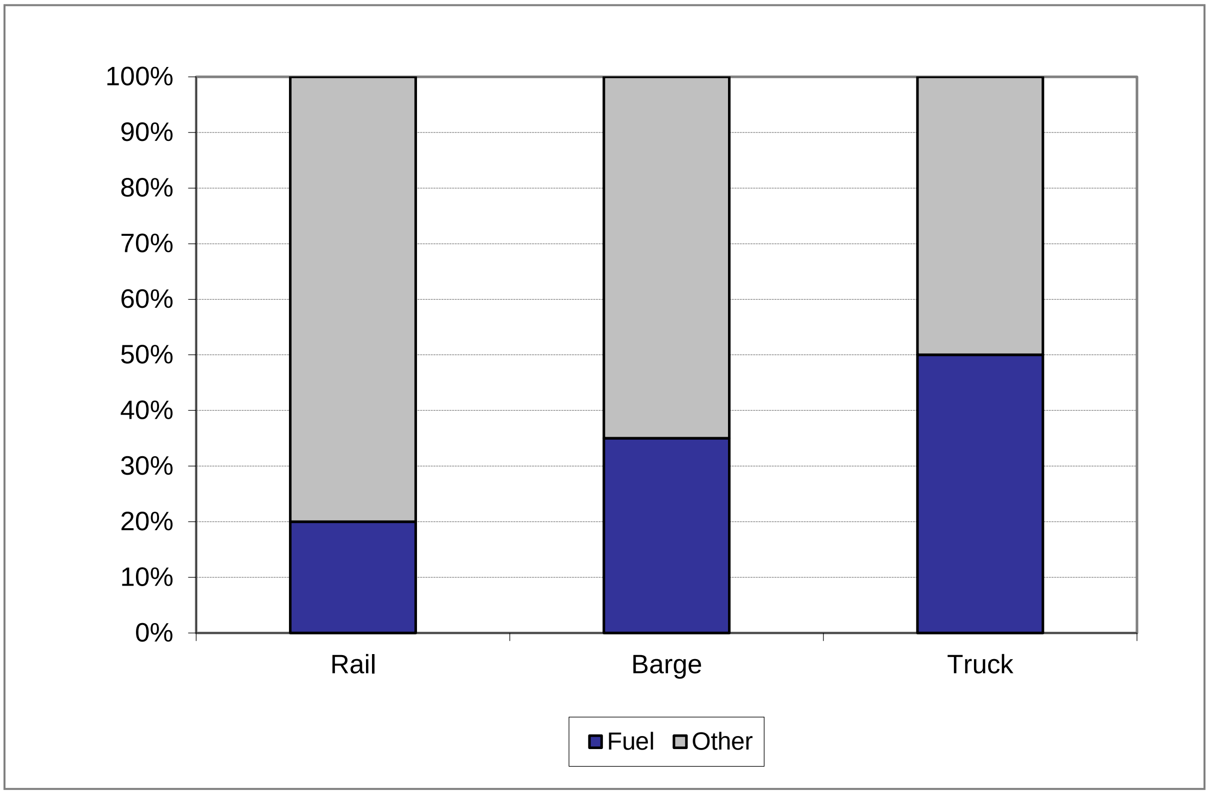
Figure 7-9 Rail Cost Indices Performance (2Q2011-2Q2016)



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 7-10 show that, at 2014[80] 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.

[80] 2014 was used as the reference point for fuel prices in this analysis because a) at the time the coal transportation rate assumptions were finalized, the latest analysis of railroad operating expenses available from the AAR contained 2014 data, and b) the average fuel price forecast by EIA for the 2020-2040 period (in real dollars) was close to the 2014 fuel price level.

Figure 7-10 Long-Run Marginal Cost Breakdown by Transportation Mode



7.3.9 Market Drivers Moving Forward

Diesel Fuel Prices

The Energy Information Administration's (EIA's) Annual Energy Outlook (AEO)[81] forecast of long-term equilibrium prices for diesel fuel used in the transportation sector (see Table 7-20) shows expected prices ranging from about $3.22/gallon in 2020 to about $4.74/gallon in 2040 (2016 real dollars). This represents an average annual real increase in diesel fuel prices of about 2.0%/year during 2020-2040. The coal transportation rate forecast for EPA Platform v6 assumes that this average rate of increase in diesel fuel prices will apply over EPA's entire forecast period (2021-2050).

Table 7-20 EIA AEO Diesel Fuel Forecast, 2020-2040 (2016 Real Dollars)

Year	Rate ($/gallon)
2020	3.22
2025	3.60
2030	3.90
2035	4.31
2040	4.74
Annualized % Change, 2020-2040	2.0%

Source: EIA

[81] As noted at the beginning of this section, the coal transportation rate assumptions for EPA Platform v6 were finalized in December 2016. At that time, the Annual Energy Outlook 2016 forecast was the latest available.

Labor Costs

As noted earlier, labor costs for the rail industry are expected to increase approximately 0.5% faster than overall inflation, on average over the forecast period. Because 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 which was available from the AAR at the time the coal transportation rate assumptions used in EPA Platform v6 were finalized in December 2016 (covering 2010-2014) show that rail industry productivity increased at an annualized rate of approximately 1.4% per year during this period. Since coal-fired generation is expected to continue to face strong competition from natural gas-fired generation and renewables during the entire 2021-2050 forecast period used in EPA Platform v6 (which will significantly limit coal demand), approximately half of the railroad industry's expected productivity gains (0.7% per year) are forecast to be passed through to coal shippers.

The potential for significant productivity gains in the trucking industry is relatively limited since truckload 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 decline at an average rate of 0.1% per year in real terms during 2020-2050. Over the same period, barge and lake vessel rates are expected to increase at an average rate of 0.2% per year, which includes some pass-through of productivity gains in those highly competitive industries. Truck rates are expected to escalate at an average rate of 1.0%%/year during 2020-2050, largely due to increases in fuel costs. 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 7-21.

Table 7-21 Summary of Expected Escalation for Coal Transportation Rates, 2020-2050

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	21%	2.0%		
	Labor	32%	0.5%		
	Equipment	47%	0.0%		
	Total	**100%**	**0.6%**	**0.7%**	**-0.1%**
Barge & Vessel	Fuel	35%	2.0%		
	Labor & Equip.	65%	0.0%		
	Total	**100%**	**0.7%**	**0.5%**	**0.2%**
Truck	Fuel	50%	2.0%		
	Labor & Equip.	50%	0.0%		
	Total	**100%**	**1.0%**	**0.0%**	**1.0%**
Conveyor	**Total**		**0.0%**	**0.0%**	**0.0%**
Transloading Terminals	**Total**		**0.0%**	**0.0%**	**0.0%**

7.3.10 Other Considerations

Estimated Construction Costs for Railcar Unloaders and Rail Spurs at Mine-Mouth Plants

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[82] 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 $25 million installed (in 2016$). 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 $3 million per mile (in 2016$), 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 $3 million per mile (2016$) referenced earlier.

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 2012-2015, and a capital recovery factor of 11.29%.

[82] 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 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.

7.4 Coal Exports, Imports, and Non-Electric Sectors Demand

The coal supply curves used in EPA Platform v6 represent the total steam coal supply in the United States. While the U.S. power sector is the largest consumer of native coal – roughly 91% of mined U.S. coal in 2017 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 be detailed in the modeling of the coal supply available to coal power plants. The projections for imports, exports, and non-electric sector coal demand are based on EIA’s AEO 2017.

In EPA Platform v6, coal exports and coal-serving residential, commercial and industrial demand are designed to correspond as closely as possible to the projections in AEO 2017 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 Platform v6 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 2017. Next, coal for exports and non-electricity demand are constrained by CMM supply region and coal grade to meet the levels projected in AEO 2017. These levels are shown in Table 7-22, Table 7-23 and Table 7-24.

Table 7-22 Coal Exports (Million Short Tons)

Name	2021	2023	2025	2030	2035	2040	2045	2050
Central Appalachia - Bituminous Medium Sulfur	4.46	4.92	5.43	6.93	8.00	10.21	10.69	10.65
East Interior - Bituminous High Sulfur	0.00	0.00	0.00	0.89	1.57	3.32	3.41	2.92
East Interior - Bituminous Medium Sulfur	4.49	4.95	5.46	6.07	6.47	6.94	7.33	7.82
Northern Appalachia - Bituminous High Sulfur	2.39	2.63	2.90	3.71	4.28	5.46	0.00	0.00
Northern Appalachia - Bituminous Medium Sulfur	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Rocky Mountain - Bituminous Low Sulfur	2.78	2.56	2.25	1.79	2.07	2.65	2.77	2.77
Western Montana - Bituminous Low Sulfur	0.00	0.00	0.00	0.00	1.50	1.91	2.00	2.00
Western Montana - Subbituminous Low Sulfur	0.90	0.99	1.10	1.40	0.00	0.00	0.00	0.00
Western Montana - Subbituminous Medium Sulfur	5.26	5.80	6.40	8.17	1.04	0.00	0.00	0.00
Wyoming PRB - Subbituminous Low Sulfur	0.06	0.05	0.03	0.00	8.10	11.62	12.17	12.17

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 Platform v6 than in AEO 2017, the specific regions and coal grades that serve export and non-electric sector demand are not pre-specified but modeled.

Table 7-23 Residential, Commercial, and Industrial Demand (Million Short Tons)

Name	2021	2023	2025	2030	2035	2040	2045	2050
Central Appalachia - Bituminous Low Sulfur	2.60	2.69	2.68	2.55	2.45	2.44	2.41	2.38
Central Appalachia - Bituminous Medium Sulfur	7.83	8.12	8.12	7.73	7.45	7.42	7.37	7.33
East Interior - Bituminous High Sulfur	5.32	5.40	5.33	5.01	4.72	4.55	4.57	4.63
East Interior - Bituminous Medium Sulfur	0.79	0.81	0.81	0.79	0.78	0.78	0.77	0.77
Northern Appalachia - Bituminous High Sulfur	0.47	0.48	0.47	0.44	0.41	0.40	0.40	0.40
Northern Appalachia - Bituminous Medium Sulfur	2.14	2.13	2.06	1.94	1.84	1.81	1.76	1.72
Rocky Mountain - Bituminous Low Sulfur	4.95	5.08	5.07	4.84	4.62	4.56	4.62	4.68
Southern Appalachia - Bituminous Low Sulfur	0.19	0.20	0.20	0.19	0.18	0.18	0.18	0.18
Southern Appalachia - Bituminous Medium Sulfur	1.11	1.16	1.16	1.11	1.09	1.09	1.08	1.07
Wyoming PRB - Subbituminous Low Sulfur	4.28	4.40	4.37	4.12	3.92	3.84	3.83	3.85
Dakota Lignite - Lignite Medium Sulfur	4.87	4.95	4.88	4.57	4.29	4.12	4.14	4.20
West Interior - Bituminous High Sulfur	0.38	0.40	0.40	0.38	0.37	0.37	0.37	0.37
Arizona/New Mexico - Bituminous Low Sulfur	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.14
Arizona/New Mexico - Subbituminous Medium Sulfur	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Western Montana - Subbituminous Low Sulfur	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.07
Western Wyoming - Subbituminous Low Sulfur	2.41	2.46	2.45	2.32	2.20	2.15	2.17	2.20
Western Wyoming - Subbituminous Medium Sulfur	1.12	1.16	1.16	1.12	1.08	1.08	1.10	1.11
Western Montana - Subbituminous Medium Sulfur	0.00	0.08	0.08	0.08	0.08	0.08	0.08	0.00

Imported coal is only available to 25 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 Table 7-25. The total U.S. imports of steam coal are limited to AEO 2017 projections as shown in Table 7-24.

Table 7-24 Coal Import Limits (Million Short Tons)

	2021	2023	2025	2030	2035	2040	2045	2050
Annual Coal Imports Cap	5.76	4.67	3.78	2.23	1.4	1.4	5	5.01

Attachment 7-1 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 cost 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[83] 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.

[83] 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.

List of tables that are uploaded directly to the web:

Table 7-25 Coal Transportation Matrix in EPA Platform v6

Table 7-26 Coal Supply Curves in EPA Platform v6

Table 7-27 Coal Demand Regions in EPA Platform v6

8. Development of Natural Gas Supply Curves for EPA Platform v6

8.1 Introduction

Natural gas supply curves and regional basis are key inputs to IPM and are developed using ICF's Gas Market Model (GMM). ICF develops and maintains the GMM for use by both private and public sector clients. The model has been used to examine strategic issues relating to natural gas supply, pipeline infrastructure, pricing, and demand characteristics.

Like IPM, GMM is a large-scale linear programming model that incorporates a detailed representation of gas supply characteristics, demand characteristics, and an integrating pipeline transportation model to develop forecasts of gas supply, demand, prices, and flows. GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by each scenario. Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand at each node in the model.

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 influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand side, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices. ICF updates GMM model inputs and performs calibration of the model on a monthly basis to ensure the model reliably reflects historical gas market behavior. Figure 8-1 shows the supply side of the calculation in GMM, and Figure 8-2 shows the interaction of IPM and GMM.

Figure 8-1 GMM Gas Quantity and Price Response

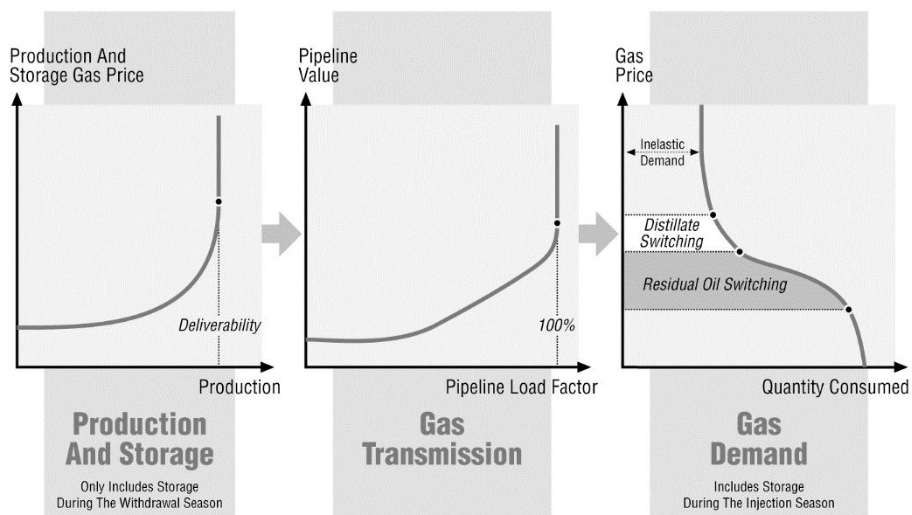
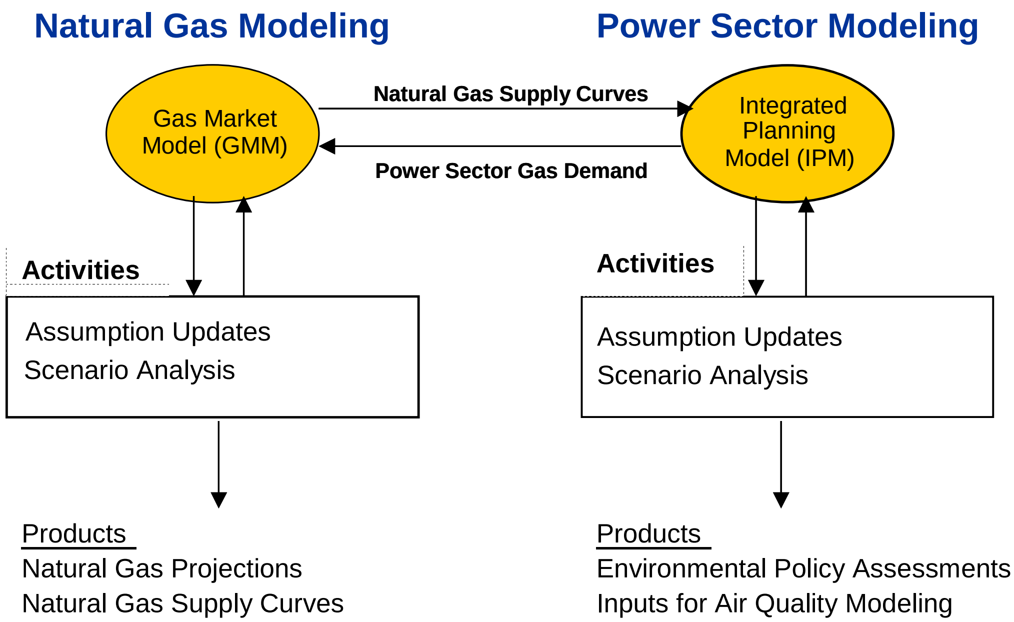


Figure 8-2 IPM/GMM Interaction



To establish gas supply curves in EPA's Platform v6, both GMM and IPM are operated in tandem and are iterated to develop a consistent Henry Hub gas price and total gas demand forecast that informs the derivation of those supply curves. In subsequent analyses using IPM, EPA's Platform v6 will continue to use these originally derived gas supply curves (without necessitating re-modeling in GMM), unless otherwise documented with a given scenario analysis. EPA's Platform v6 uses natural gas market assumptions in power market modeling as follows:

- IPM takes the natural gas supply curves, which are developed based on GMM outputs and specified as a function of Henry Hub prices.
- For each year, three sets of seasonal natural gas transportation differentials (summer, winter, and winter shoulder) are added to the supply curves to generate the final delivered curves by IPM region.
- IPM projects the power sector's demand for natural gas. The natural gas demand is compared to the supply curve to find the market-clearing price for natural gas.
- IPM's linear programming formulation takes into consideration the gas supply curves as well as coal supply curves and detailed power plant modeling in determining electric market equilibrium conditions. Oil usage is modeled as a function of price, which is exogenously supplied to IPM.

This chapter is divided in the following sections. The chapter starts with a brief synopsis of GMM, the primary tool used for generating the natural gas supply curves. This is followed by detailed discussions of modeling methodologies and data used in GMM. The methodologies and data description are grouped in the following five sections:

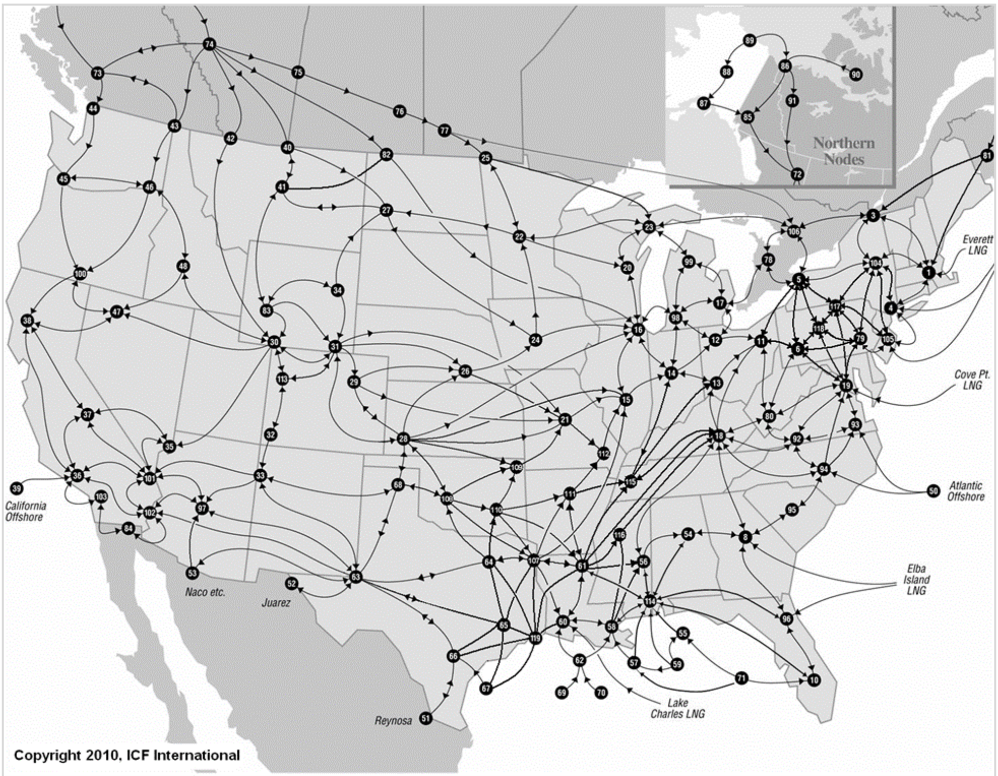
i) Resources data and reservoir description
ii) Treatment of frontier resources and exports
iii) Exploration and production technology characterization
iv) Oil prices
v) Demand assumptions

This is followed by discussion of natural gas assumptions and supply curves used for EPA Platform v6.

8.2 Brief Synopsis of GMM

ICF's integrated natural gas model, GMM, is designed to perform comprehensive assessments of the entire North American gas flow pattern. It is a large-scale, dynamic linear program that models economic decision-making to minimize the overall cost of meeting natural gas demand. GMM is reliable and efficient in analyzing the broad range of natural gas market issues.

Figure 8-3 Geographic Coverage of GMM



Important features of GMM are described below.

Natural Gas Market Prices in GMM are determined by the marginal (or incremental) value of natural gas at 121 regional market centers. Prices are "at the margin", not "average". Marginal prices do not translate directly into pipeline or utility revenues. Prices represent "market center" prices as opposed to delivered prices. Gas prices are determined by the balance of supply and demand in a regional marketplace. Supply is determined considering both availability of natural gas deliverability at the wellhead, the transportation capacity and cost to deliver gas to market centers.

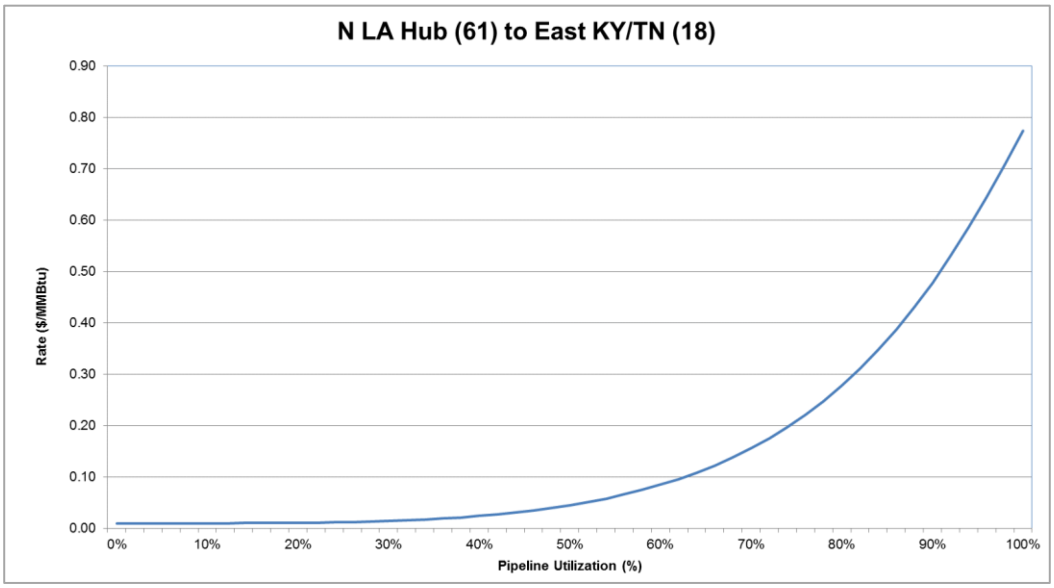
Natural gas production prices are determined from spot gas price curves that yield price as a function of deliverability utilization: Curves reflect price for gas delivered into the transmission system (including gathering cost). Gas storage withdrawal price curves are added to the production price curves during the withdrawal season. Pipeline value curves are then added to yield a total supply curve for a node. The intersection of the supply curve and the demand curve (including net storage injections) yields the marginal price at a node. Price is set by the demand curve when all available supply is utilized.

Demand is modeled for residential, commercial, industrial, and power sectors for each of the 121 nodes. GMM solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. Econometric equations define demand by sector. The industrial and power sectors incorporate fuel competition, dispatch decisions, new power plant builds, economic growth, and weather. GMM solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. GMM iterates with IPM to better capture electric sector demand for natural gas.

Electric generation is modeled regionally with plant dispatch based upon operating cost. Competing power generation technologies are evaluated on a full-cost basis to determine lowest cost capacity additions.

Transportation is modeled by over 423 transportation links between the nodes, balancing seasonal, sectoral, and regional demand and prices, including pipeline tariffs and capacity allocation. Node structure developed to reflect points of change or influence on the pipeline system. These points include: major demand and supply centers, pipeline hubs and market centers, and points of divergence in pipeline corridors. The pipeline network is largely represented as bundles of pipes, though in some regions individual pipes are represented. Gas moves over the network at variable cost. The variable cost as a function of pipeline throughput (i.e., pipeline discount curve) is used to determine the market value of capacity (i.e., the transportation basis) for each period in the forecast for each pipeline link.

Figure 8-4 Example Pipeline Discount Curve



The upper end of discount curve may be shifted by additions of new pipeline capacity. The shift depends on expansion tariff relative to pre-expansion tariff and pricing of expansion (incremental or rolled-in). Curves have been fit to basis observed from actual gas prices and to annual load factors. Pipeline discount curve parameters can also be changed over time to reflect regulatory changes that affect pipeline values.

Pipeline capacity expansions address the physical constraints of transporting gas from supply regions to demand regions. They therefore contribute to determining the supply curves and seasonal basis. For the near–term, pipeline capacity expansions are input to GMM based on identifiable, near-term development plans and ICF's market assessment. For the longer term, new "generic" pipeline capacity is added in GMM when the market value of the added capacity exceeds its cost. Generic pipeline capacity in the model is added starting 2023 and it increases in 2025 and beyond as the natural gas markets grow.

ICF includes projects that satisfy certain criteria in its analysis. The criteria are listed below.

- First Criteria: The project is already under construction;

OR

• Second Criteria: The project has the necessary approvals to proceed from FERC and other relevant regulatory proceedings;

OR

• Third Criteria: The project has been filed with FERC and has the necessary firm shipper commitments;

OR

• Fourth Criteria: The project has been filed with FERC and does not have the necessary shipper commitments, but does appear to have sufficient market support;

OR

• Fifth Criteria: The project has NOT yet been filed with FERC, but appears to have sufficient market support.

For the fourth and fifth criteria, ICF typically considers supply growth directly upstream of the project, market growth for markets that are relevant to the project's delivery point/s, and basis differentials that exceed the per unit cost of pipeline expansion as indicators of market support. If the indicators are all positive, ICF will add the project as a "generic" project and size it based on the level of market support. In the case in which there are multiple generic projects for a single GMM link, the generic projects will be sized in aggregate based on the total level of market support for expansion of the link. Generic projects are classified as such until one of the first three criteria are satisfied.

For certain markets like New York, New Jersey and New England, ICF looks closely at regulatory support for the project which could override the criteria above in determining the pipeline additions in GMM. For example, if a project like Constitution pipeline has been denied water permits even though it has broad market support, ICF does not include it in its base case.

Pipeline cost assumptions used in GMM have been derived by considering data from Oil and Gas Journal (OGJ) surveys of pipeline projects. Using regression analysis of the OGJ data across years, we determined an average U.S. pipeline cost of $183,000 per inch-mile for 2017 (in 2016 dollars) for large gas transmission pipelines. The pipeline cost for future years is kept flat in real terms post 2017. Regional cost multipliers have also been derived from OGJ data as the pipeline costs vary by region. Cost multipliers can be different across regions; for example, costs are relatively high in the Northeast where projects have been very difficult and time consuming to construct.

Supply is modeled by using node-level natural gas deliverability or supply capability, including import and export levels while accounting for gas storage injections and withdrawals at different gas prices. Total supply in the United States comes from three sources: production from natural gas fields located in the lower 48 states, Canadian imports, Alaska, and LNG imports. Natural gas production activity is represented in 82 of the 121 Model nodes where historical production has occurred, or where future production appears likely. The "base trend" for deliverability and gas price are developed from ICF's resource assessment using the Hydrocarbon Supply Model and a long-term "marker price". If the monthly solution price deviates from the "marker price", future exploration and production (E&P) activity is adjusted. Deliverability responds to prices, with a lag of 2 to 18 months.

The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module.

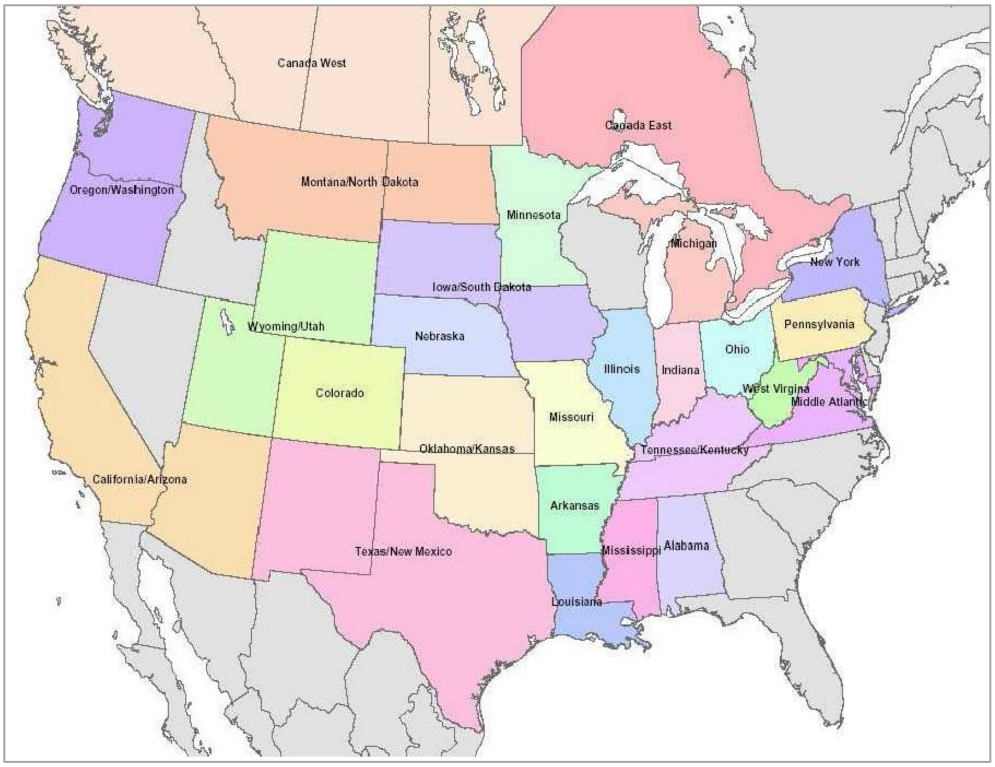
Natural Gas Storage activity is represented for 24 U.S. and two Canadian storage regions, with activity allocated to individual nodes based on historical field level storage capacity. Regional differences in the physical and market characteristics of storage are captured in the storage injection and withdrawal relationships separately estimated for each region:

- Differences between market area storage and supply area storage.

- Differences between regions with primarily depleted field storage and regions with primarily aquifer storage.

Net monthly withdrawals are calculated from a “storage supply curve” that reflects the level of withdrawals relative to gas prices. The curve has been fit to actual historical data. Net monthly injections are calculated from econometrically fit relationships that consider working gas levels, gas prices, and weather (i.e., cooling degree days). The level of gas storage withdrawals and injections are calculated within the supply and demand balance algorithm based on working gas levels, gas prices, and extraction/injection rates and costs.

Figure 8-5 GMM Natural Gas Storage Regions



Storage levels have an impact on GMM’s seasonal basis differentials, which are an important component in constructing the gas supply curves and/or basis differentials that are then input into IPM. The arbitrage value of storage is driven by the seasonal difference in the supply-area gas prices plus the seasonal difference in pipeline transportation value. Storage expansions (or increased utilization of existing storage) decreases seasonal basis differentials in the region surrounding the storage facilities.

8.3 Resources Data and Reservoir Description

This section describes the approach used in GMM and documents the changes to the resource data and reservoir characterization work conducted for EPA Platform v6.

8.3.1 U.S. Resources and Reserves

This section describes the U.S. resource data sources and methodology used in GMM for EPA Platform v6.

Current U.S. and Canada gas production is from over 400 trillion cubic feet (Tcf) of proven gas reserves. ICF assumes that the U.S. and Canada natural gas resource base totals roughly 3,500 Tcf of unproved plus discovered but undeveloped gas resource. This can supply the U.S. and Canada gas markets for over 100 years (at current consumption levels). Shale gas accounts for over 50 percent of remaining recoverable gas resources. No significant restrictions on well permitting and fracturing are assumed beyond restrictions that are currently in place.

Data sources: Conventional resource base assessment is based on data from the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Canadian Gas Potential Committee (CGPC) using ICF's Hydrocarbon Supply Model (HSM).

In the area of unconventional gas, 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 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. 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 Haynesville 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.

Resources 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.

New Fields

Conventional new discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields, and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are oil, sweet nonassociated gas, or sour nonassociated gas.

The methodology uses a modified "Arps-Roberts" equation 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 areal 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. The new equation developed by ICF accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas, 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 discounted cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. The economic decision to develop a field is made using "sunk cost" economics where the discovery cost is ignored and only time-forward development costs and production revenues are considered. However, the model's decision to begin an exploration program includes all exploration and development costs.

Field Appreciation

Field appreciation refers to potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or "probables." The inventories of probables are increased due to expected future appreciation due to many factors that include higher recovery percentages of the gas in-place resulting from infill drilling and application of improved technology and experience gained in the course of developing and operating the field.

Unconventional Gas

The ICF assessment method for shale gas 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 different model 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 based on 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 expected well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data.

To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures. Generally speaking, we find the learning curve effect is roughly 20 percent per doubling of cumulative wells.

Major Unconventional Natural Gas Categories

Definition of Unconventional Gas: *Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.*

Tight Gas is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

Coalbed Methane is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

Shale Gas is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale formations with certain characteristics will produce gas.

Shale Oil with Associated Gas is defined as associated gas from oil shale in horizontal drilling plays such as the Bakken in the Williston Basin. The gas is produced through boreholes along with the oil.

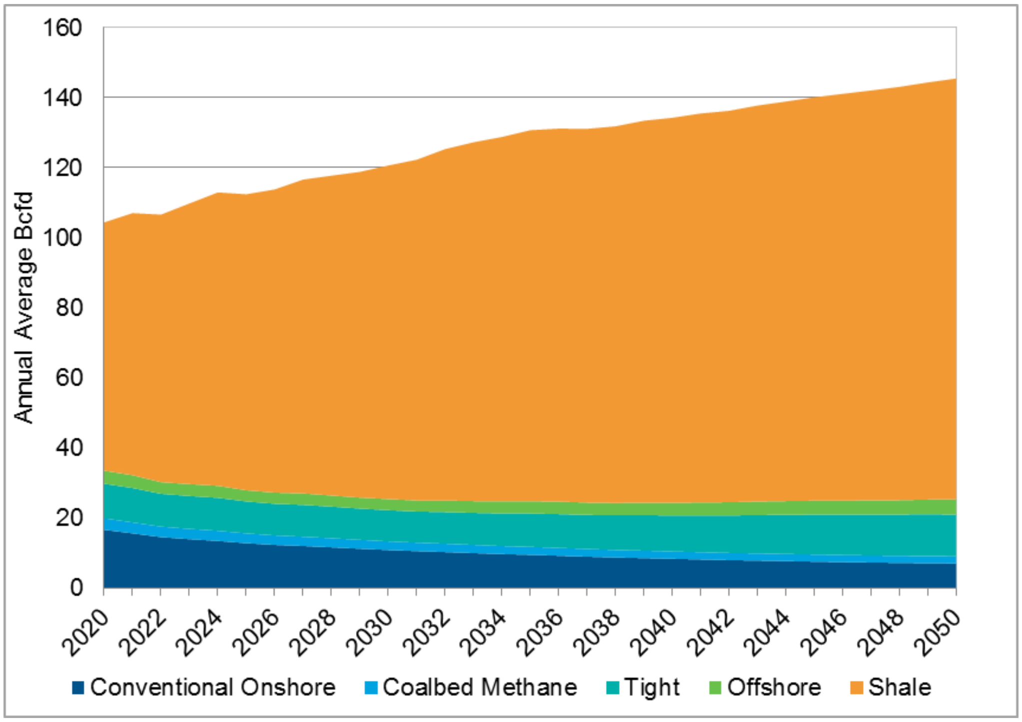
8.3.2 Upstream Cost and Technology Factors

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items.

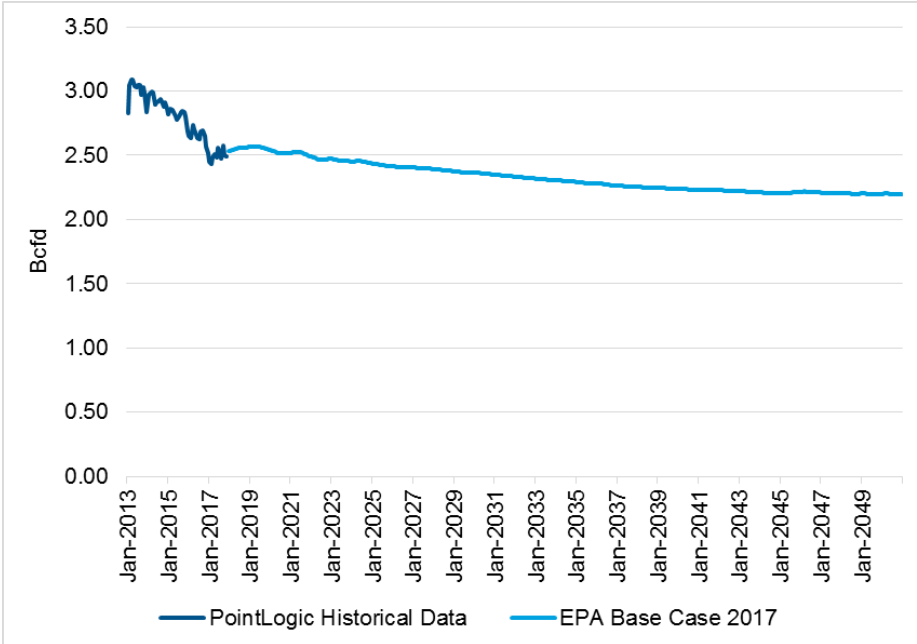
Figure 8-6 GMM U.S. and Canada Projected Gas Production by Source



8.3.3 Historical Gas Production

ICF consistently updates the production and resource data that it used for EPA Platform v6. The historical production data for the model comes from PointLogic. An example comparison of production forecasts for the San Juan and Raton basins is shown in Figure 8-7.

Figure 8-7 Production Comparison for San Juan and Raton Basins



8.3.4 Treatment of Frontier Resources and Exports

Arctic Projects

GMM does not have resources located in frontier regions. Arctic projects (specifically Alaska and Mackenzie Valley gas pipelines) are not included in our projection.

Existing and Potential Liquefied Natural Gas (LNG) Terminals

LNG is natural gas that has been transformed to a liquid by super-cooling it to minus 260 degrees Fahrenheit, reducing its volume by a factor of 600. LNG is then shipped on board special carriers, and the process is reversed at a receiving facility with the re-gasified product delivered via pipeline. Based on current global LNG market conditions, ICF assumes that the six U.S. LNG terminals currently under construction are completed and expanded in future. Those terminals are Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, and Elba Island. By 2020, ICF projects U.S. LNG export capacity will be 10.3 billion cubic feet per day (Bcfd). Given the near-term low oil price expectations, we project that North American export terminal capacity utilization will average about 63% through 2020. U.S. export volumes are projected to approach six Bcfd by 2020. ICF projects that the capacity utilization will increase to over 80% by 2024. In addition to the U.S. trains currently under construction, ICF assumes an additional 5.8 Bcfd of export capacity will come online in North America between 2020 and 2035. ICF assumes that only one export facility will be built in British Columbia: Woodfibre (0.3 Bcfd).

Figure 8-8 Existing and Proposed Marine LNG Terminals as of May 2017

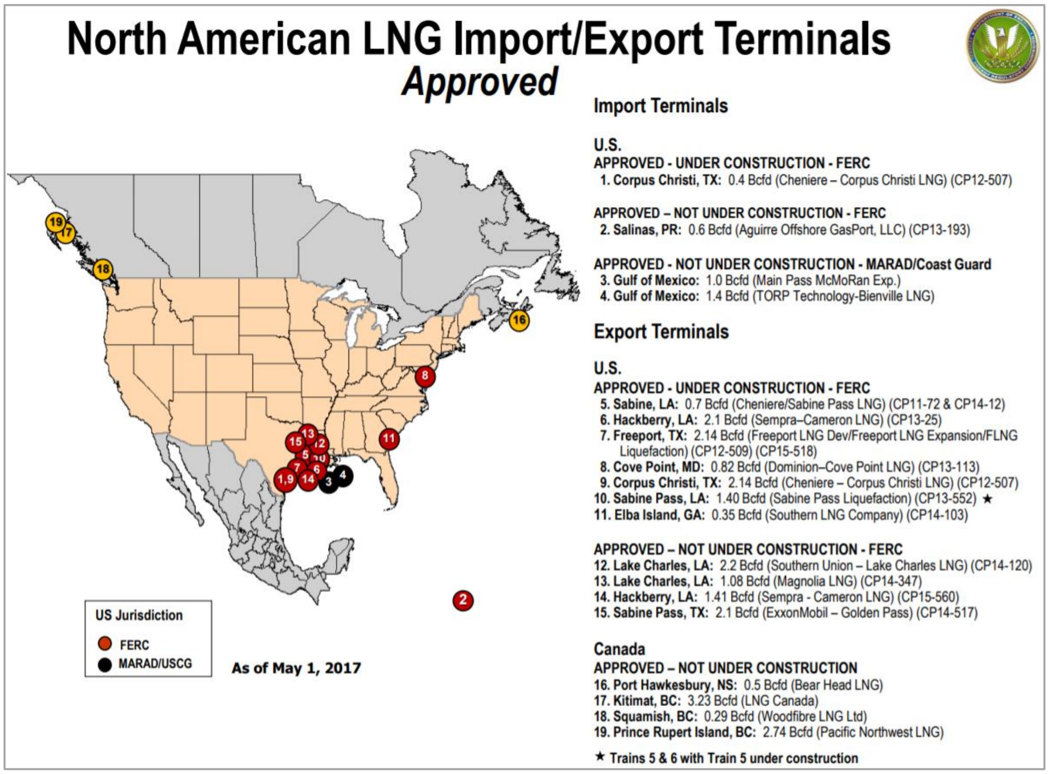
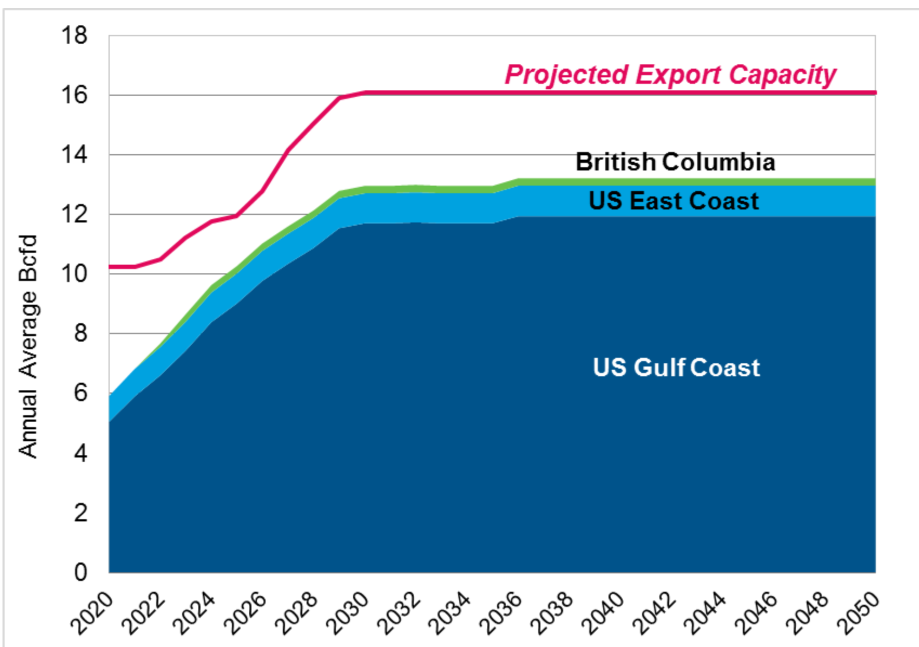


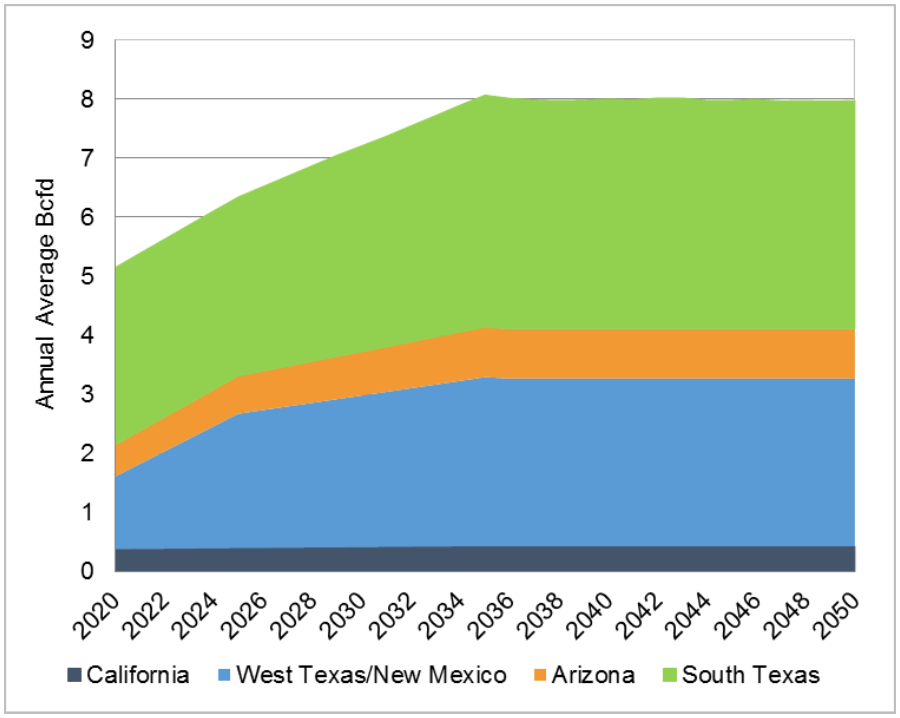
Figure 8-9 LNG Export Volumes versus Capacity



Pipeline Exports to Mexico

Mexico's demand for natural gas continues to rise, while its domestic production has been declining. Since 2010, Mexico's imports of U.S. gas have gone up over 300%, reaching 3.9 Bcfd in 2016. As Mexico continues to add gas-fired generation and sponsor new pipelines from the U.S., exports will continue to grow. ICF projects that exports will reach 8 Bcfd by 2035.

Figure 8-10 U.S. Pipeline Exports to Mexico

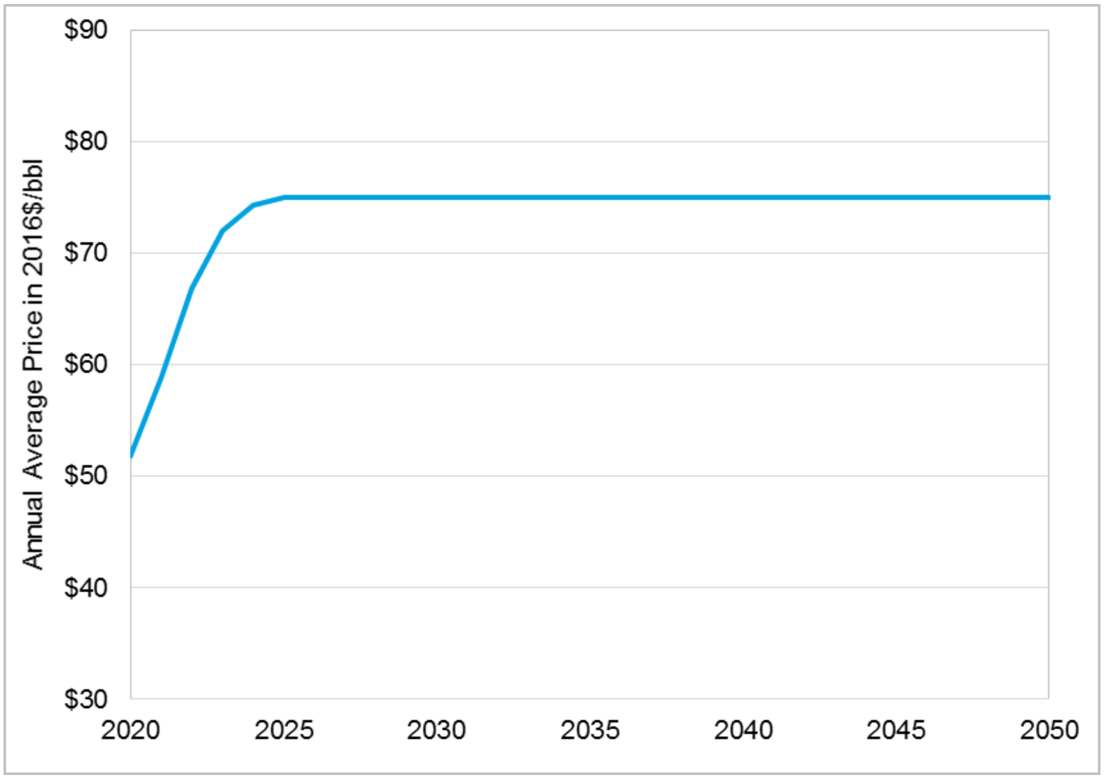


8.4 Oil Prices

Natural gas prices and LNG export levels are forecasted by taking into account oil prices. The following section contains discussions about the crude oil price assumptions used for EPA Platform v6.

ICF uses the Refiner Acquisition Cost of Crude Oil (RACC) price as an oil price input to GMM. The RACC price is a term commonly used in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. For the long-term, ICF projects a slow recovery in oil prices to an equilibrium marginal production cost of $75/bbl (in $2016). The residual oil price averages between 70 and 100 percent of the RACC price on a dollar per Btu basis. This is the price used to determine switching in the industrial sector. Figure 8-11 shows the ICF RACC price projection.

Figure 8-11 Refiners' Acquisition Cost of Crude (RACC)

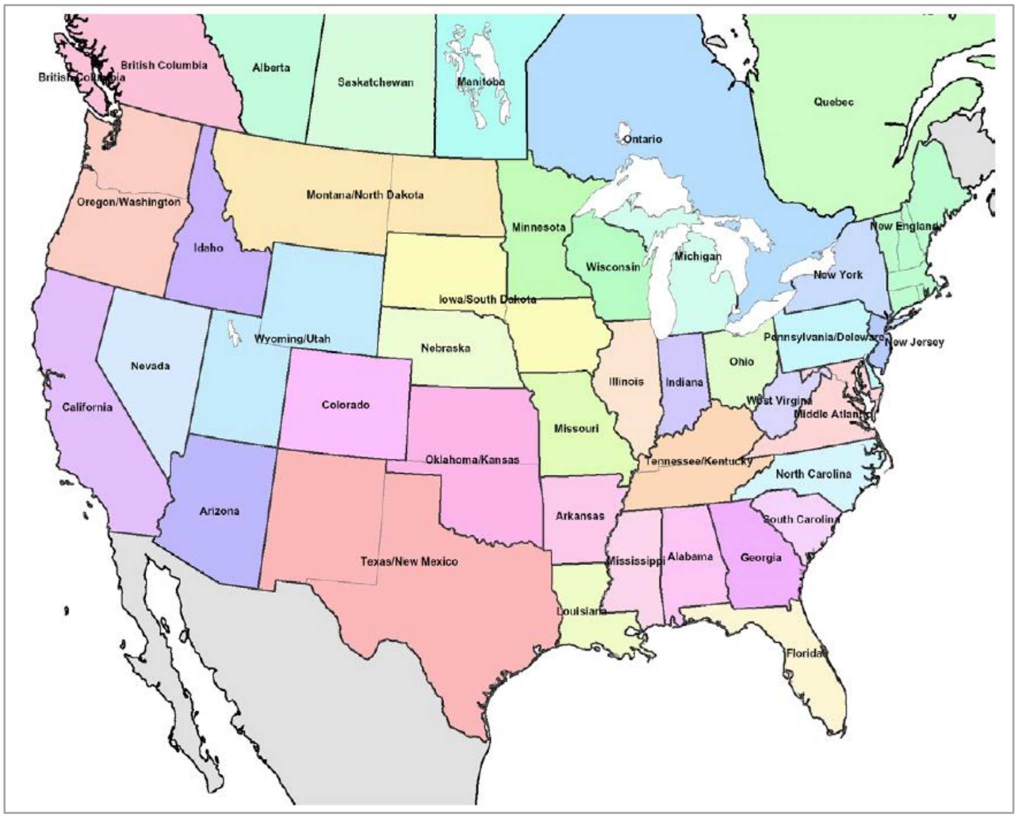


8.5 Demand Assumptions

Gas demand is calculated by sets of algorithms and equations for each sector and region. The model calculates monthly "real-time consumption", not "billed volumes." Demand reported by DOE/EIA represents billed volumes, which is time-lagged. Recent DOE/EIA and Statistics Canada data have been considered in the calibration of the model. However, the historical data represents ICF's backcast of the market. ICF performs market reconnaissance and data analysis each month to support the GMM calibration. GMM models natural gas demand in four end-use sectors: residential, commercial, industrial, and power generation.

Residential/Commercial gas demand calculated from regional equations fit econometrically to weather, economic growth, and price elasticity. The 41 regions for which residential/commercial demand are calculated are shown in Figure 8-12. Regression analysis was separately completed for each sector for 34 Lower-48 and 7 Canadian regions. The seventh Canadian region, Atlantic Provinces, has no historical gas use. An Alaska region is included in the Model, but all Alaska end use gas demand is input exogenously.

Figure 8-12 GMM Residential/Commercial Gas Demand Regions



Industrial gas demand is based on a detailed breakout of industrial activity by census region. The U.S. is divided into 11 regions based on census region boundaries. The model includes ten industry sectors, focusing on gas-intensive industries. Those 10 industries are:

- Food
- Pulp and Paper
- Petroleum Refining
- Chemicals
- Stone, Clay, and Glass
- Iron and Steel
- Primary Aluminum
- Other Primary Metals
- Other Manufacturing
- Non-Manufacturing

Three end-use categories (Process Heat, Boilers, and Other End Uses) are modeled separately for each sector.

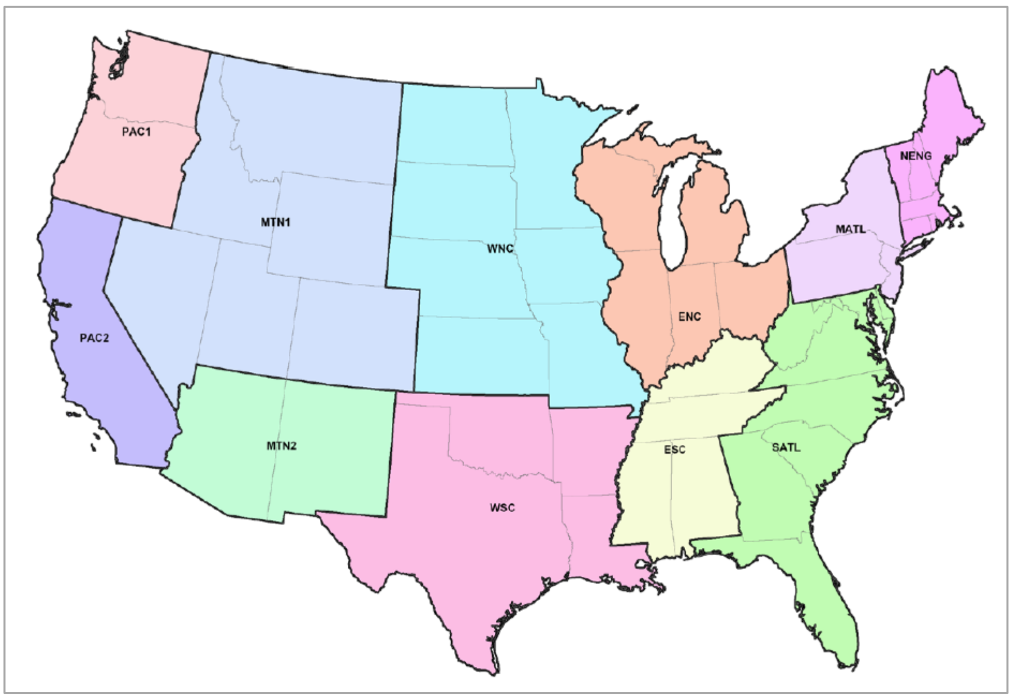
- Process heat: This includes all uses of gas for direct heating as opposed to indirect heating (e.g., steam production). The GMM econometric modeling indicated that forecasts for process heat for each industrial sector are a function of growth in output, the energy intensity trend, and the price elasticity. 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.

The chemicals sector also includes feedstock demands for ammonia, methanol, and non-refinery hydrogen. Canada is divided into 6 regions based on provincial boundaries. The approach for Canada is 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 Atlantic Provinces in Eastern Canada have no historical industrial gas demand.

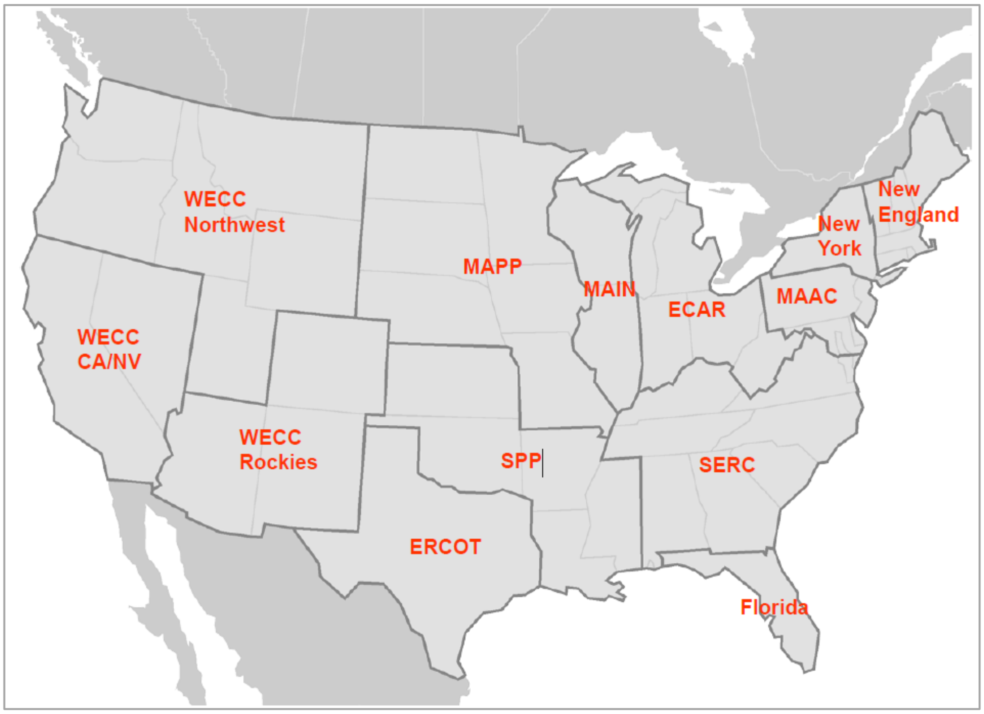
Energy intensity and price elasticity inputs are based on Industrial Sector Technology Use Model (ISTUM-2). Boiler switching curves are defined from work for GRI (now GTI). The GMM captures both near-term price-induced switching and “demand destruction” effects of high gas prices.

Figure 8-13 GMM Industrial Gas Demand Regions



Power generation demand in the GMM is modeled for 13 dispatch regions for the contiguous U.S. All of the power sector inputs in GMM are changed to be consistent with IPM results over time. Most importantly, the total gas use regionally is bench-marked against IPM’s gas use.

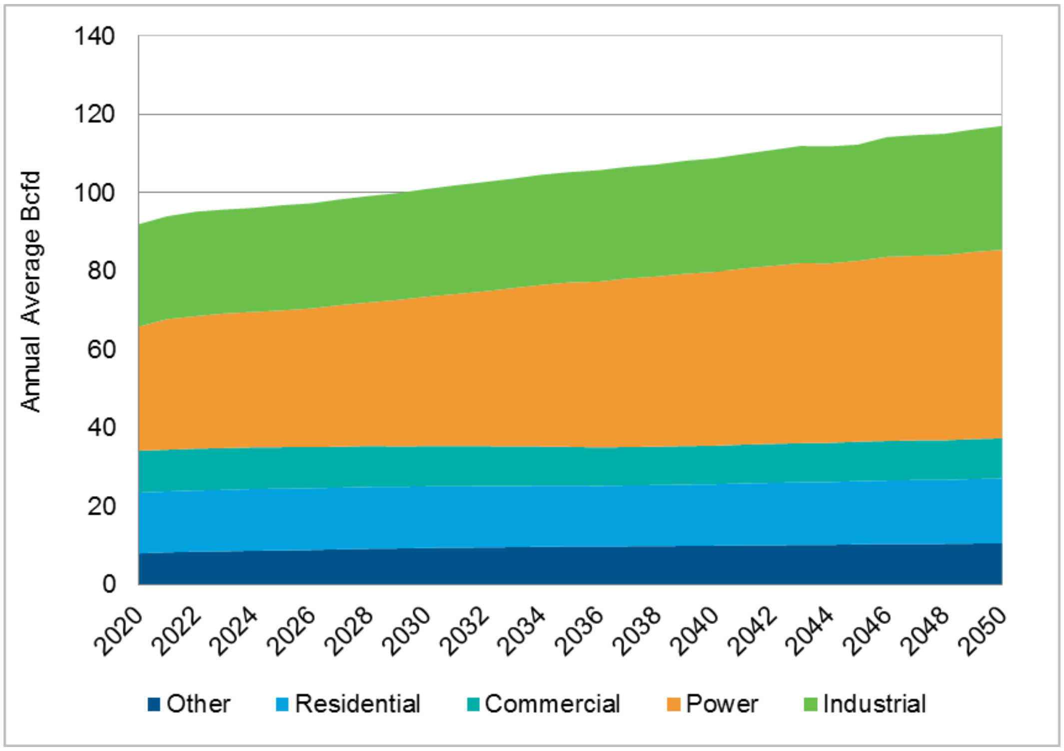
Figure 8-14 GMM Power Generation Gas Demand Regions



Pipeline fuel consumption is the gas consumed in the operation of pipelines, primarily in compressors, as well as pipeline losses. Pipeline gas-use is a function of the fuel rate and the volume of gas moved on each pipeline corridor. Pipeline gas-use is estimated as a percent of natural gas throughput for each link in the pipeline network. Pipeline gas-use is allocated evenly between the upstream and downstream nodes for each link. Historical pipeline gas-use is derived from EIA data on a state by state basis, and then mapped to each link in the pipeline network.

Lease & Plant gas use represents natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and used as fuel in natural gas processing plants. The lease and plant gas-use is forecast based on historical percentages of the dry gas produced at each node. Regional factors determine the share of lease & plant gas use for each supply region.

Figure 8-15 GMM U.S. and Canada Gas Demand Projection



Note: “Other” includes pipeline fuel and lease & plant

There are four key drivers for natural gas demand in GMM. They are:

- **i)** **Macroeconomic parameters:** From 2018 forward, ICF assumes U.S. GDP grows at 2.1% per year, and Canada GDP grows at 2.0% per year.[84]
- **ii)** **Electric Demand Growth:** Electric demand growth rate is assumed to be 0.68% per year consistent with EPA Platform v6.
- **iii)** **Demographics:** Projected demographic trends are consistent with trends over the past 20 years. U.S. population growth averages about 1% per year throughout our projection.
- **iv)** **Weather:** Future weather is assumed consistent with regional and monthly average heating and cooling degree days (HDD/CDD) over the past 20 years (1997 through 2016).

8.6 Discussion of GMM Results Underlying the Natural Gas Supply Curves[85]

In this section, we describe GMM results underlying the natural gas supply curves for EPA Platform v6. A typical GMM run generates the following outputs:

- Natural gas prices
- Natural gas production by region
- Natural gas consumption by region and sector

[84] The U.S. Congressional Budget Office assumes an average annual GDP growth rate of 1.9% between 2018 and 2028, while the 2018 U.S. Energy Information Administration Annual Energy Outlook used an average annual GDP growth rate of 2.0% between 2018 and 2050.

[85] The GMM results presented in this section are illustrative and consistent with a draft version of the EPA Platform v6 November 2018 Reference Case. GMM was not rerun for a final calibration with EPA Platform v6 November 2018 Reference Case using IPM.

Table 8-1 summarizes the supply/demand balance and Henry Hub price for a GMM run underlying the natural gas supply curves. The regional breakout in the supply/demand data is by census region and the mapping to the state and GMM nodes is provided in Figure 8-16 and Figure 8-17. Table 8-3 provides additional results.

Table 8-1 Supply/Demand Balance and Henry Hub Price for a GMM Run Underlying the Natural Gas Supply Curves in EPA Platform v6

Demand (Bcf per year)	**2017**	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
New England	849	939	952	987	1,009	1,034	1,063	1,066	1,092
Mid-Atlantic	3,747	4,471	4,776	4,883	5,286	5,437	5,457	5,645	5,849
East North Central	3,852	4,413	4,442	4,498	4,747	5,160	5,385	5,508	5,723
West North Central	1,782	1,935	1,937	1,948	1,959	2,027	2,034	2,007	2,015
South Atlantic	3,694	4,522	4,536	4,528	4,917	5,294	5,630	5,905	6,192
East South Central	1,705	2,076	2,077	2,115	2,296	2,353	2,427	2,448	2,507
West South Central	6,322	6,974	7,053	7,047	7,334	7,502	7,604	7,641	7,774
Mountain	1,778	1,887	1,947	2,021	2,003	2,167	2,307	2,378	2,451
Pacific (contiguous)	2,888	2,815	2,794	2,758	2,534	2,512	2,559	2,645	2,679
Alaska	347	304	303	301	296	295	295	295	295
Total L-48	**26,619**	**30,033**	**30,514**	**30,785**	**32,084**	**33,486**	**34,465**	**35,242**	**36,281**
Total United States	**26,965**	**30,337**	**30,817**	**31,086**	**32,380**	**33,780**	**34,760**	**35,537**	**36,576**
Exports/Imports (Bcf per year)									
Net LNG Exports from US	593	2,698	3,343	3,990	5,065	5,064	5,164	5,160	5,159
Net Pipeline Exports to Mexico	1,589	1,967	2,142	2,316	2,632	2,945	2,928	2,858	2,911
Net Pipeline Imports from Canada	1,913	1,470	1,481	1,694	2,135	2,371	2,285	2,278	1,942
Supply (Bcf per year)									
New England	0	0	0	0	0	0	0	0	0
Mid-Atlantic	5,229	8,845	9,762	10,225	11,388	12,128	12,608	13,284	13,915
East North Central	1,595	2,780	3,108	3,341	3,812	4,133	4,328	4,520	4,683
West North Central	1,140	1,097	1,047	1,005	942	874	798	758	753
South Atlantic	1,559	2,288	2,534	2,751	3,173	3,433	3,591	3,755	3,890
East South Central	795	861	816	779	753	802	806	866	927
West South Central	11,869	12,406	12,189	12,178	12,536	13,067	13,168	13,732	14,423
Mountain	4,402	4,500	4,389	4,315	4,301	4,649	5,119	5,645	5,838
Pacific (contiguous)	196	174	175	178	181	183	178	170	163
Alaska	311	303	302	307	309	313	303	293	285
Total L-48	**26,788**	**32,951**	**34,020**	**34,772**	**37,087**	**39,269**	**40,596**	**42,731**	**44,593**
Total United States	**27,099**	**33,254**	**34,322**	**35,079**	**37,395**	**39,582**	**40,899**	**43,024**	**44,878**
	2017	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Henry Hub, Nom$/MMBtu	2.82	3.14	3.61	3.77	4.38	4.60	5.76	7.33	8.18

Figure 8-16 Demand Region Definition

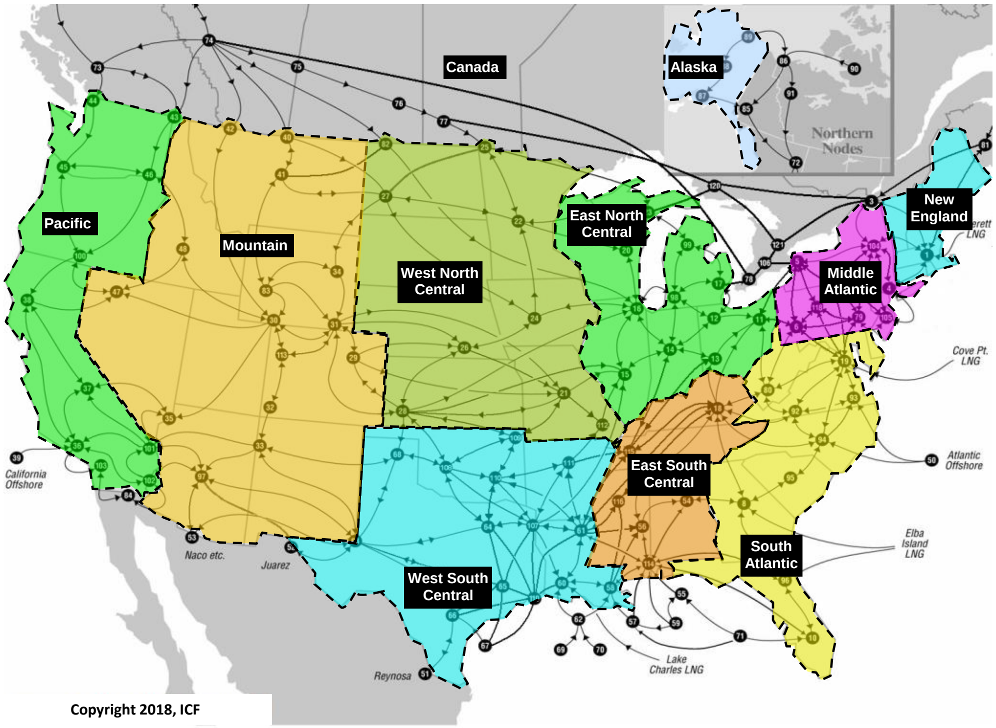
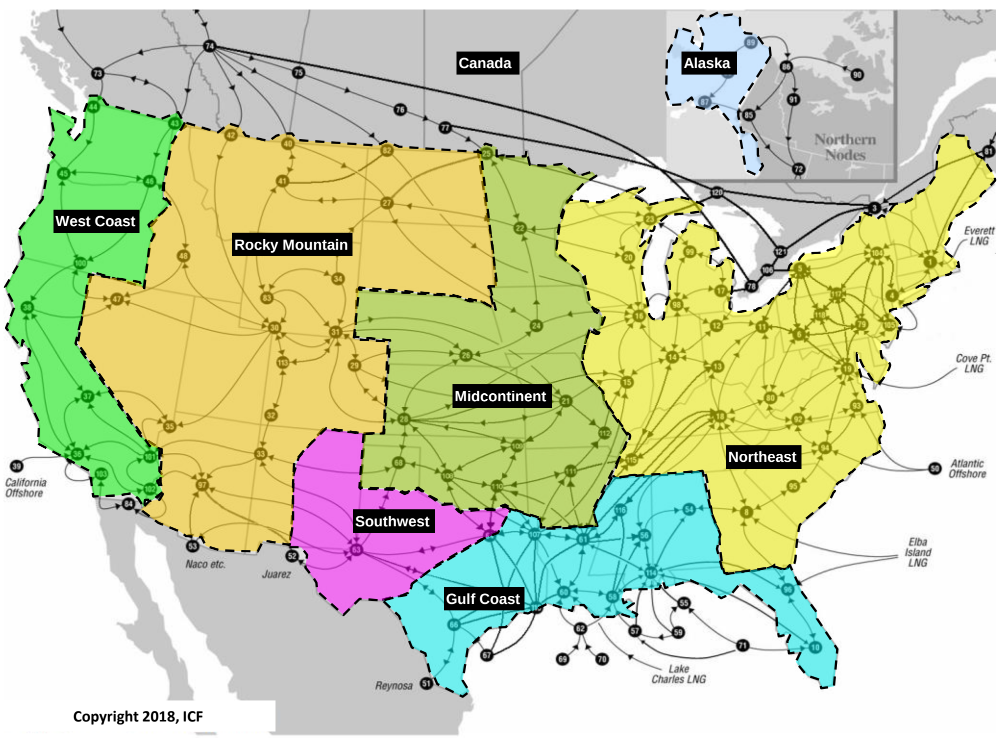


Figure 8-17 Supply Region Definition



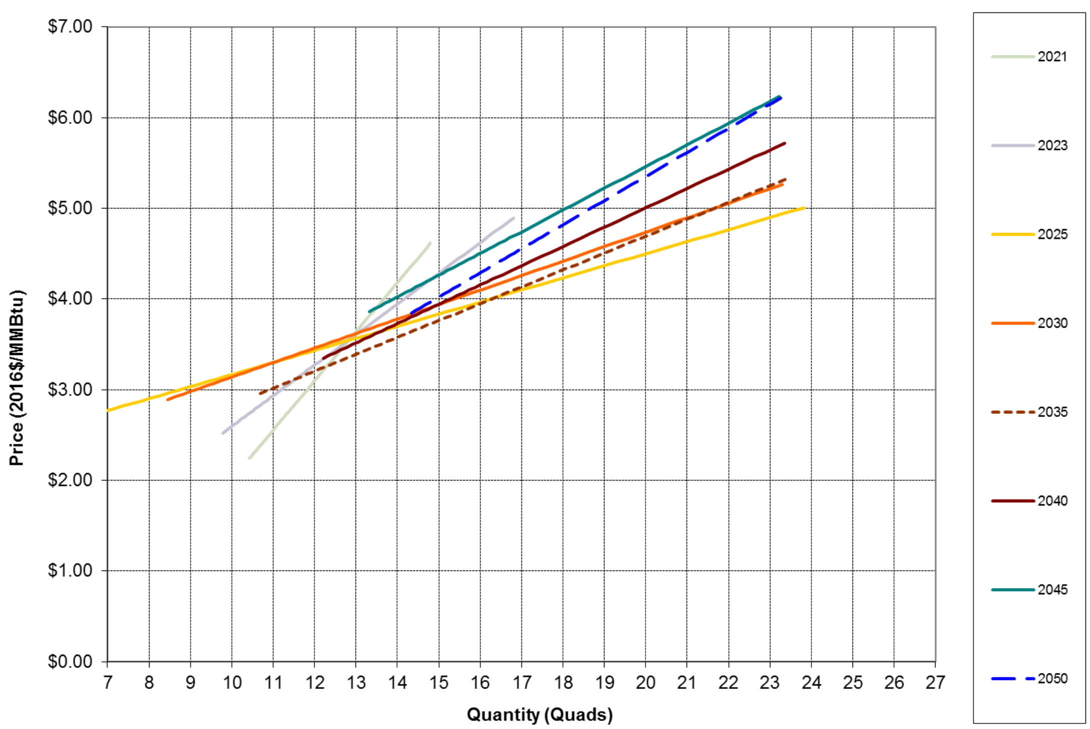
8.6.1 Supply Curves for EPA Platform v6

Henry Hub is a pipeline interchange hub in Louisiana Gulf Coast near Erath, LA, where eight interstate and three intrastate pipelines interconnect. Liquidity at this point is very high and it serves as the primary point of exchange for the New York Mercantile Exchange (NYMEX) active natural gas futures markets. Henry Hub prices are considered as a proxy for U.S. natural gas prices. Natural gas from the Gulf moves through the Henry Hub onto long-haul interstate pipelines serving demand centers. Due to the importance and significance of Henry Hub, GMM generated supply curves are specified at Henry Hub prices.

For IPM modeling, GMM generates a price forecast over a time horizon and a set of time dependent price/supply curves based on that price path for each year in the forecast. For each year, the mid-point price of the supply curve is set equal to the solved Henry Hub price from GMM and the mid-point volume is set equal to the solved gas consumption for the power sector from GMM. Each supply curve's elasticity is set equal to the effective price-elasticity for gas supply in that year. In this manner, even while GMM has itself projected particular levels of gas supply and consumption (and corresponding market-clearing prices) over time, the information included in those projections is input into IPM in the form of gas supply curves that enable IPM to solve for levels of power sector gas consumption and resulting gas prices that respect a least-cost power production future.

The final resulting supply curves developed for years 2021, 2023, 2025, 2030, 2035, 2040, 2045, and 2050 are shown in Figure 8-18 and Table 8-5. In the very short-term, gas supply is price inelastic because there are few years to respond to the market changes. Over time, gas supply becomes more price elastic because producers have more time to respond to the market changes. Thus, the supply curves are much more price elastic by 2025. In the longer term, resource depletion tends to offset elasticity making the curves slightly less elastic than they are between 2025 and 2030.

Figure 8-18 Supply Curves for 2021, 2023, 2025, 2030, 2035, 2040, 2045, and 2050



8.6.2 Basis

Basis is the difference in gas price in a given market from the widely used Henry Hub reference price. Basis reflects the price in a given market based on demand, available supply, and the cost of transporting gas to that location. A negative basis value represents that the gas price in that area is lower than the Henry Hub price. Basis between two nodes in GMM is the difference in prices between the two nodes. The GMM utilizes its network of 121 nodes that comprises 423 gas pipeline corridors to assess the basis between two desired nodes. The pipeline corridors between nodes are represented by pipeline links and can be characterized by their maximum capacity. 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. The basis value is calculated by using the supply/demand balance in two nodes along with the resulting prices in each node and the cost of transporting gas between the two nodes as determined by the discount curve on that link. The discount curve is a function of the pipeline tariffs and the load factor. The discount curves are continuously calibrated to accurately reflect historical basis values. Their parameters can be adjusted to account for regulatory changes that can affect pipeline values.

The GMM solves for basis monthly. Basis pressure (i.e., spiking basis) will generally occur when average monthly load factors rise to above 80%. Since many U.S. markets are winter peaking, the higher basis typically occurs in the winter months when gas use and load factors are highest. The IPM relies on seasonal basis that reflects averages of the monthly basis values solved for in the GMM.

GMM is not only used to estimate the gas supply curves, but also used to estimate the relationship of gas price at Henry Hub to gas prices elsewhere in the country. IPM uses these gas supply curves and regional price relationships (differentials) over time as inputs, based on GMM-projected future of gas supply/demand. While EPA's Platform v6 has the flexibility to re-determine the relationship of power sector gas demand to supply and to accordingly find different gas price futures, EPA's Platform v6 will maintain the future (basis differential) price relationship between Henry Hub and each regional location in a national supply picture as originally determined by these GMM projections. Table 8-4 provides the full set of seasonal basis differentials at the IPM region level.

8.6.3 Delivered Price Adders

As stated in section 8.2, GMM prices are market center prices and not delivered prices. In order to estimate delivered prices at a power plant, an adder is applied to the seasonal basis from GMM. ICF calculated this delivered price adder for each state by comparing its GMM historical prices with historical delivered gas prices to electric power plants based on EIA-176 data. The delivered price adders implemented in EPA Platform v6 are shown in Table 8-2.

Table 8-2 Delivered Price Adders

State	Adder (2016$/MMBtu)	State	Adder (2016$/MMBtu)
Alabama	0.01	Nebraska	0.46
Alaska	0.95	Nevada	0.21
Arizona	0.03	New Hampshire	0.01
Arkansas	0.13	New Jersey	0.26
California	0.16	New Mexico	0.02
Colorado	0.18	New York	0.17
Connecticut	0.05	North Carolina	0.24
Delaware	0.01	North Dakota	0.09
Florida	0.02	Ohio	0.03
Georgia	0.00	Oklahoma	0.03
Idaho	0.05	Oregon	0.01
Illinois	0.16	Pennsylvania	0.04
Indiana	0.14	Rhode Island	0.00
Iowa	0.26	South Carolina	0.17
Kansas	0.13	South Dakota	0.01
Kentucky	0.23	Tennessee	0.05
Louisiana	0.04	Texas	0.19
Maine	0.03	Utah	0.08
Maryland	0.13	Virginia	0.06
Massachusetts	0.03	Washington	0.10
Michigan	0.16	West Virginia	0.13
Minnesota	0.35	Wisconsin	0.09
Mississippi	0.03	Wyoming	0.06
Missouri	0.12	US	0.13
Montana	0.44	Canada	0.13

List of tables that are uploaded directly to the web:

Table 8-3 EIA Style Gas Report for EPA Platform v6

Table 8-4 Natural Gas Basis for EPA Platform v6

Table 8-5 Natural Gas Supply Curves for EPA Platform v6

9. Other Fuels and Fuel Emission Factor Assumptions

Besides coal (Chapter 7) and natural gas (Chapter 8), EPA Platform v6 also includes assumptions for residual fuel oil, distillate fuel oil, biomass, nuclear, and waste fuels. This chapter describes the assumptions pertaining to characteristics, market structures, and prices of these other fuels. As reported in previous chapters, natural gas is represented by an exogenous supply curve along with a basis differential approach informed by a resource fundamentals model. Coal is represented by a robust 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 64% of U.S. electric generation in 2016[86]. 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, nuclear, and waste fuel prices are exogenously determined and entered into IPM during model set-up as constant price points that apply to all levels of supply. The following treats each of these remaining fuels in turn and concludes with a discussion of the emission factors for all the fuels represented in EPA Platform v6.

9.1 Fuel Oil

Two petroleum derived fuels are included in EPA Platform v6. Distillate fuel oil is distilled from crude oil, and residual fuel oil is a residue of the distillation process. The fuel oil prices are from AEO 2017 and are shown in Table 9-1. They are regionally differentiated according to the NEMS (National Energy Modeling System) regions used in AEO 2017. These prices are mapped to their corresponding IPM regions for use in EPA Platform v6.

Table 9-1 Fuel Oil Prices by NEMS Region in EPA Platform v6

Residual Fuel Oil Prices (2016$/MMBtu)								
AEO NEMS Region	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
ERCT	12.86	13.56	14.22	15.34	16.50	17.69	18.02	18.93
FRCC	11.35	12.05	11.26	12.40	13.45	14.48	14.81	15.71
MROE	11.32	11.94	12.60	13.70	14.79	15.79	16.12	16.85
MROW	4.30	5.00	5.65	6.77	7.94	9.13	9.46	10.37
NEWE	11.75	11.94	12.60	13.72	14.88	16.08	16.40	17.31
NYCW	14.19	14.89	15.54	16.66	17.82	19.02	19.35	20.25
NYLI	11.03	11.01	11.67	12.77	13.86	14.86	15.19	15.92
NYUP	9.60	10.30	10.95	12.07	13.23	14.43	14.76	15.66
RFCE	10.47	10.60	11.26	12.36	13.45	14.45	14.87	15.78
RFCM	9.55	10.25	10.90	12.02	13.18	14.38	14.71	15.61
RFCW	10.67	11.37	12.03	13.14	14.31	15.50	15.83	16.74
SRDA	12.16	12.86	13.51	14.63	15.80	16.99	17.32	18.23
SRGW	8.51	9.20	9.86	10.98	12.14	13.34	13.66	14.57
SRSE	9.59	10.28	10.94	12.06	13.22	14.42	14.74	15.65
SRCE	8.58	9.28	9.94	11.05	12.22	13.41	13.74	14.65
SRVC	10.47	10.60	11.26	12.37	13.54	14.73	15.06	15.97
SPNO	8.58	9.28	9.94	11.05	12.22	13.41	13.74	14.65
SPSO	10.83	11.52	12.18	13.30	14.46	15.66	15.99	16.89
AZNM	11.48	12.18	12.84	13.95	15.12	16.31	16.64	17.55

[86] EIA. Detailed EIA-923 monthly and annual survey data back to 1990. Available at https://www.eia.gov/electricity/data.php#generation

Residual Fuel Oil Prices (2016$/MMBtu)								
AEO NEMS Region	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
CAMX	11.26	11.95	12.61	13.73	14.89	16.09	16.41	17.32
NWPP	10.43	11.94	12.60	13.70	14.79	15.79	16.12	16.85
RMPA	7.91	8.61	9.27	10.38	11.55	12.74	13.07	13.98

Distillate Fuel Oil Prices (2016$/MMBtu)								
NEMS Region	**2021**	**2023**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
ERCT	16.57	16.85	17.65	18.96	20.26	21.58	21.95	22.89
FRCC	18.58	19.39	20.17	21.46	22.73	24.12	24.45	25.39
MROE	17.61	18.08	18.88	20.19	21.49	22.81	23.18	24.11
MROW	17.00	17.27	18.07	19.38	20.68	22.00	22.37	23.31
NEWE	16.98	17.38	18.16	19.46	20.72	22.11	22.44	23.38
NYCW	19.92	21.02	21.80	23.09	24.35	25.75	26.07	27.02
NYLI	19.92	21.02	21.80	23.09	24.35	25.75	26.07	27.02
NYUP	19.92	21.02	21.80	23.09	24.35	25.75	26.07	27.02
RFCE	19.57	20.55	21.33	22.59	23.86	25.23	25.56	26.49
RFCM	17.61	18.08	18.88	20.19	21.49	22.81	23.18	24.11
RFCW	17.96	18.54	19.33	20.63	21.92	23.26	23.62	24.56
SRDA	16.57	16.85	17.65	18.96	20.26	21.58	21.95	22.89
SRGW	17.31	17.68	18.48	19.80	21.11	22.48	22.86	23.80
SRSE	17.77	18.37	19.17	20.24	21.53	22.93	23.31	24.23
SRCE	16.65	16.89	17.69	19.00	20.31	21.63	22.00	22.93
SRVC	18.58	19.39	20.17	21.46	22.73	24.12	24.45	25.39
SPNO	16.98	17.26	18.05	19.36	20.66	21.99	22.36	23.29
SPSO	16.61	16.88	17.68	18.99	20.29	21.62	21.99	22.92
AZNM	19.25	20.11	20.90	22.21	23.52	24.84	25.27	26.21
CAMX	19.18	19.95	19.83	21.15	22.45	23.77	24.20	25.14
NWPP	19.18	20.01	20.81	22.22	23.51	24.84	25.27	26.21
RMPA	19.25	20.11	20.90	22.22	23.52	24.84	25.27	26.21

9.2 Biomass Fuel

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 those coal fired plants that have co-fired biomass in the recent past. Section 5.3 provides further details of these selected coal plants.

EPA Platform v6 uses biomass supply curves based on those in the Department of Energy's 2016 Billion-Ton Report (DOE Report). Biomass supply curves at the IPM region and state level are generated by aggregating county level supply curves from the DOE Report. Power plants demand biomass from the supply curve corresponding to the IPM region and state in which they are located. No inter-region 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. The supply component of the curve represents the aggregate supply in each region of agricultural residues, forestry residues, energy crops, waste, and trees. The price component of the curve includes transportation costs of $15 per dry ton. The supply curves represent the IPM region and state-specific delivered biomass fuel cost at the plant gate. A storage cost of $20 per dry ton is added to each step of the agricultural residue supply curves to reflect the limited agricultural growing season[87]. The biomass supply curves are summarized in Table 9-4. The biomass prices are derived endogenously based on the aggregate power sector demand for biomass in each IPM region and state. The results are unique market-clearing prices for each IPM region and state. All plants using biomass from that IPM region and state face the same market-clearing price.

9.3 Nuclear Fuel

The AEO 2018 price for nuclear fuel is used as the nuclear fuel price assumption for 2021-2050 in EPA Platform v6. The 2021, 2023, 2025, 2030, 2035, 2040, 2045, and 2050 prices are 0.64, 0.64, 0.65, 0.65, 0.66, 0.67, 0.68, and 0.69 2016 $/MMBtu, respectively.

9.4 Waste Fuels

The waste fuels include waste coal, petroleum coke, fossil waste, non-fossil waste, tires, and municipal solid waste (MSW). Table 9-2 describes the characteristics of these fuels, the extent to which they are represented in NEEDS, and the assumptions pertaining to their use and pricing. Furthermore, the fuels are provided to only existing and planned committed units. Potential (new) generating units that the model "builds" are not given the option to burn these fuels. In IPM model output, tires, MSW, and non-fossil waste are included under existing non-fossil other, while waste coal and petroleum coke are included under coal.

Table 9-2 Waste Fuels in NEEDS v6 and EPA Platform v6

Modeled Fuel in NEEDS	Number of Units in NEEDS	Total Capacity in NEEDS	Description	Supply and Cost	
				Modeled By	Assumed Price
Waste Coal	22	1,435 MW	"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 unconventional 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." https://www.eia.gov/tools/glossary/index.php?id=W	Supply Curve Based on AEO 2017	AEO 2017
Petroleum Coke	14	1,213 MW	A residual product, high in carbon content and low in hydrogen, from the cracking process used in crude oil refining.	Price Point	$42.60/Ton
Fossil Waste	81	1,049 MW	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

[87] 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

Modeled Fuel in NEEDS	Number of Units in NEEDS	Total Capacity in NEEDS	Description	Supply and Cost	
				Modeled By	Assumed Price
Non-Fossil Waste	221	2,071 MW	Non-fossil waste products that do not 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	52 MW	Discarded vehicle tires.	Price Point	0
Municipal Solid Waste	165	2,123 MW	"Residential solid waste and some nonhazardous commercial, institutional, and industrial wastes." https://www.eia.gov/tools/glossary/index.php?id=M	Price Point	0

9.5 Fuel Emission Factors

Table 9-3 brings together all the fuel emission factor assumptions implemented in EPA Platform v6. For sulfur dioxide, chlorine, and mercury in coal, where emission factors vary widely based on the rank, grade, and supply 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 9-3 because NO_x emissions are a factor of the combustion process, and are not primarily fuel based.

Table 9-3 Fuel Emission Factor Assumptions in EPA Platform v6

Fuel Type		Carbon Dioxide (lbs/MMBtu)	Sulfur Dioxide (lbs/MMBtu)	Mercury (lbs/TBtu)	HCl (lbs/MMBtu)
Coal					
	Bituminous	202.8 - 216.1	0.67 - 7.78	1.82 - 34.71	0.005 - 0.214
	Subbituminous	209.2 - 216.1	0.52 - 2.22	2.03 - 8.65	0.006 - 0.023
	Lignite	212.6 - 219.3	1.51 - 5.67	7.32 - 30.23	0.011 - 0.036
Natural Gas		117.08	0	0.00014	0
Fuel Oil					
	Distillate	161.39	0 - 2.65	0.48	0
	Residual	173.91	1.04	0.48	0
Biomass		195	0.08	0.57	0
Waste Fuels					
	Waste Coal	204.7	8.22	63.9	0.0921
	Petroleum Coke	225.1	7.27	2.66	0.0213
	Fossil Waste	321.1	0.08	0	0
	Non-Fossil Waste	0	0	0	0
	Tires	189.6	1.65	3.58	0
	Municipal Solid Waste	91.9	0.35	71.85	0

Note: Table 7-4 has coal emission factor on a coal supply region level.

List of tables that are uploaded directly to the web:

Table 9-4 Biomass Supply Curves in EPA Platform v6

10. Financial Assumptions

10.1 Introduction and Summary

This chapter presents the financial assumptions used in the EPA Platform v6. EPA Platform v6 models a diverse set of generation and emission control technologies, each of which requires financing[88], and incorporates updates to reflect The Tax Cuts and Jobs Act of 2017.[89] The capital charge rate converts the capital cost for each investment into a stream of levelized annual payments that ensures recovery of all costs associated with a capital investment including recovery of and return on invested capital and income taxes. The discount rate is used to convert all dollars to present values and IPM minimizes the present value of annual system costs. The discount rate is set equal to the weighted average costs of capital. Describing the methodological approach to quantifying the discount and capital charge rates in the EPA Platform v6 is the primary purpose of this chapter.

10.2 Introduction to Risk

The cost of capital is the level of return investors expect to receive for alternative investments of comparable risk. Investors will only provide capital if the return on the investment is equal to or greater than the return available to them for alternative investments of comparable risk. Accordingly, the long-run average return required to secure investment resources is proportional to risk. There are several dimensions to risk that are relevant to power sector operations, including:

- **Market Structure –**The risk of an investment in the power sector is heavily dependent on whether the wholesale power market is regulated or deregulated. The risks are higher in a deregulated market compared to a traditionally regulated utility market. Slightly more than half of U.S. generation capacity is deregulated (operated by Independent Power Producers (IPPs), or 'merchants').[90] IPPs often sell power into spot markets supplemented by near-term hedges. In contrast, regulated plants sell primarily to franchised customers at regulated rates, an arrangement that significantly mitigates uncertainty, and therefore risk.[91]

- **Technology** - 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 peaking combustion turbine is likely to be much riskier than an investment in a combined cycle unit. This is because a combustion turbine operates as a peaking unit and can generate revenues only in times of high demand, or via capacity payments, while a combined cycle unit is able to generate revenues over a much larger number of hours in a year from the energy markets as well as via capacity payments. An investor in a combined cycle unit, therefore, would require a lower return due to a more diversified stream of revenue, and receive a lower risk premium than an investor in a combustion turbine, all else equal.

[88] The capital charge rates discussed here apply to new (potential) units and environmental retrofits that IPM selects. The capital cost of existing and planned/committed generating units (also referred to as 'firm'), and the emission controls already on these units are considered sunk costs and are not represented in the model.

[89] The Tax Cuts and Jobs Act of 2017, Pub.L. 115-97.

[90] 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 2016 about 52% of all operating capacity is merchant and unregulated capacity.

[91] There is a potential third category of risk, where IPPs enter into long-term (e.g., ten years or longer), known-price contracts with credit worthy counterparties (e.g., traditionally regulated utilities). With a guaranteed, longer-term price, the risk profile of this segment of the IPP fleet is similar enough to be treated as regulated plants.

- **Leverage** - There are financial risks related to the extent of leverage. Reliance on debt over equity in financing a project increases the risk of insolvency. This dynamic applies to all industries, power included.[92]

- **Financing Structure** – Lastly, there are also financing structure risks (e.g., corporate vs. project financing), also referred to as non-recourse financing. There is no clear risk implications from the structure alone, but rather this element interacts with other dimensions of risks making considerations of leverage, technology, and market structure more important.

- **Systemic** – Systemic risk is when financial performance correlates with overall market and macro-economic conditions such that investment returns are poor when market and economic conditions are poor, and vice versa. For example, if investors are less likely to earn recovery of and on investments during recessions, then these risks are systemic, and increase required expected rates of return. This emphasis on correlated market risk is based on the Capital Asset Pricing Model (CAPM), which is used to produce key financial assumptions for EPA Platform v6. Other risks are handled in the cash flows and are treated as non-correlated with the market.

10.2.1 Deregulation - Market Structure Risks

As noted, the power sector in North America can be divided into the traditional regulated sector (also known as “cost of service” or “utility” sector) and deregulated merchant sector (also known as “competitive”, “merchant”, “deregulated”[93] or “IPP” sector).

Traditional Regulated

The traditional regulated market structure is typical of the vertically integrated utilities whose investments are approved through a regulatory process and the investment is provided a regulated rate of return, provided the utility’s investments are deemed prudent. In this form of market structure, returns include the return of the original investment plus a return on invested capital 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 equal.

Deregulated Merchant

In a deregulated merchant market structure, investments bear a greater degree of market risk, as the price at which they can sell electricity is dependent on what the short-term commodity and financial hedge 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, 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 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.[94]

Overall, there is ample supporting evidence for the theoretical claim that deregulated investments are more risky than utility investments. For example:

[92] We use the terms debt and leverage interchangeably.

[93] Wholesale generators cannot be economically unregulated; they can be Exempt Wholesale Generator (“EWG”) subject to FERC jurisdiction. The moniker of deregulated is used to convey greater market risk relative to regulated utility plants.

[94] In this documentation, the terms “merchant financing, “deregulated”, “IPP”, “non-utility” and “merchant” refer to this type of market structure.

All three large publicly traded IPPs[95] are rated as sub-investment grade[96] while all utilities are investment grade.

- All major IPPs have gone bankrupt over the last 15 years[97].

- Estimates of beta, a measure of risk using CAPM, leverage, debt costs, and weighted average cost of capital, consistently produce higher risk for deregulated power plants.

10.3 Federal Income Tax Law Changes

EPA Platform v6 incorporates updates to reflect The Tax Cuts and Jobs Act of 2017. The four most significant changes in the federal corporate income tax code are:

- **Rate** – The corporate tax rate is lowered 14 percentage points from 35%[98] to 21%; the 21% rate is in place starting in 2018 and remains in place indefinitely; the lower tax rate decreases capital charges in all periods and all sectors, all else held equal. When state income taxes are included, the average rate decreases 13.1 percentage points, from 39.2% to 26.1%. This applies to all sectors, utility and IPP.
- **Depreciation** – The new tax law expands near-term bonus depreciation (also referred to as expensing) for the IPP sector only until 2027; the utility sector is unaffected.
- **Interest Expense** – The new law lowers tax deductibility of interest expense for the IPP sector, which continues indefinitely; the utility sector is unaffected.
- **Net Operating Losses** – The new law limits the use of Net Operating Losses (NOL) to offset taxable income. This applies to all sectors, utility and IPP.

Other important features of the new tax law include:

- **Annual Variation of Provisions** - The legislation specifies permanent changes (tax rate and NOL usage limit) applying to both sectors, utility and IPP. The legislation also applies temporary changes that vary year-by-year through to 2027 (depreciation and tax deductibility of interest) (See Table 10-1) applying to the IPP sector only. This creates different capital charge rates for each year through 2027. We calculate these parameters for IPM run years 2021, 2023, 2025, and 2030 and thereafter. This set covers a wide range of financing conditions even though we do not estimate every year.

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[95] Dynegy Inc. Calpine Corp. and NRG Energy Inc are the three IPP's whose ratings were B2, Ba3 and Ba3 in 2016.

[96] Below minimum investment grade.

[97] Dynegy, Calpine, and NRG were bankrupt – i.e. the three large public IPPs were bankrupt. Also, Mirant (major IPP), Boston Generating (IPP), EFH (utility with large IPP component), and FES (utility with large IPP component) have been or are bankrupt.

[98] The average state income tax rate is 6.45 percent. State income tax is deductible, and hence, the combined rate is 26.1% (26.1=21+(1-0.21)*6.45).

Table 10-1 Summary Tax Changes

Parameter	Previous	2021[99]	2023	2025	2030 and Later
Marginal Tax Rate - Federal	35	21	21	21	21
Maximum NOL (Net Operating Loss) Carry Forward Usage	No limit. All losses in excess of income are carried forward and usable immediately.	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income
Tax Deductibility of Interest Expense	100%[100]	IPP 30% of EBITDA; Utilities MACRS	30% of EBIT; Utilities MACRS	30% of EBIT; Utilities MACRS	30% of EBIT; Utilities MACRS
Bonus Depreciation[101]	0[102]	IPP 100%; Utilities 0%	IPP 80%[103]; Utilities 0%	IPP 40%[104]; Utilities 0%	0

- **Renewables** - The legislation has minor direct potential impacts on the renewable sector's tax credits via the Base Erosion Anti-Abuse Tax (BEAT). The maximum effect of BEAT could decrease the value of PTC and ITC by up to 20%[105]; estimates of the expected impact are not yet available, but are expected to be less. In addition, the total decrease in corporate income taxes may decrease tax credit appetite accordingly. Nevertheless, as we lack requisite data at this time we do not apply any additional changes to renewable financing beyond the above-mentioned changes, which affect all capacity types.

- **Utilities Versus IPPs** – As noted, the legislation treats utilities and IPPs differently. The new tax code exempts utilities from changes in tax deductibility of interest and accelerated depreciation. The financing assumptions used in IPM modeling are a blend (weighted average) of the utility and IPP average. The weighting is 70% utility and 30% IPP, and hence, the greatest weight is on the least affected sector. This partly mitigates the impacts of the changes.

- **Capital Charge Rates** – In the past, we calculated the blended capital charge rates by taking the weighted average of each input and calculating a single capital charge rate by technology and location. As a result of the legislation, combined with the IPM model's ability to vary capital charge rates by run year, the blended average is calculated for specific run years. In addition, we

[99] IPM run years in the near term are 2021, 2023, 2025, and 2030.

[100] No limit except losses in excess of income can be carried forward. The losses were limited to first few years.

[101] Referred to as expensing. If depreciation exceeds income in first year, it can be carried forward to succeeding years up to 80% of EBITDA.

[102] Bonus depreciation was available but only in the period before IPM runs, and only for new equipment.

[103] For thermal power plants coming on line in 2023, the 100% would apply only to costs incurred through end of 2022. We are hence assuming practically all capital costs are incurred prior to 2023.

[104] Remaining basis depreciated at MACRS schedule.

[105] https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.xml. "Part VII – Base Erosion and Anti-Abuse Tax, Sec 59A, Tax in Base Erosion Payments of Taxpayers with Substantial Gross Receipts, (b), (1), (B), (ii), (II) the portion of the applicable section 38 credits not in excess of 80 percent of the lesser of the amount …"

See also https://www.mwe.com/en/thought-leadership/publications/2017/12/renewable-energy-tax-bill-update-no-change-ptc-itc. A company's regular tax liability reflects certain credits that make it more likely that such a company is subject to the BEAT. However, the Bill provides that only 20 percent of the PTC and ITC be taken into account. Thus, 20 percent of the PTC and ITC might be denied depending on a company's BEAT status and relevant computations in a given year.

have changed the calculation for a given run year. We calculate the capital charge rates for utilities and IPPs, and then take the weighted average of the resulting capital charge rates rather than calculating one blended capital charge rate based on the weighted average inputs. This is because the functional relationship between the inputs and the capital charge rates is now different and it is less accurate to use the prior approach.

- **Discount Rates** – The discount rate equals the weighted average after tax cost of capital (WACC) and is affected by the change in the corporate income tax rate only. The discount rate is invariant over time, sectors, and technologies. Therefore, the calculation methodology for discount rate used in IPM is unchanged.

10.4 Calculation of the Financial Discount Rate

10.4.1 Introduction to Discount Rate Calculations

A discount rate is used to translate future cash flows into current dollars by considering 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.[106]

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. [107]

The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Platform v6 is 4.25%.[108]

10.4.2 Summary of Results

The tables below present a summary of the key financial assumption for the EPA Platform v6. A description of these values and the attendant methodological approaches follow throughout the chapter.

[106] The discount rate is the inverse of compound interest or return rate; the existence of interest, especially compound interest creates an opportunity cost for not having dollars immediately available. Thus, future dollars need to be discounted to be comparable to immediately available dollars.

[107] For a perspective on the legal basis for utilities having the right to have the opportunity to earn such returns under certain conditions such as prudent operations, see *Bluefield Water Works and Improvement Co. v Public Service Comm'n 262 US 679, 692 (1923).* See also *Federal Power Comm'n versus Hope Natural Gas Co., 320 US 591, 603 (1944).*

[108] This rate is equivalent to the real discount rate for a combined cycle plant under hybrid 70:30 utility to merchant ratio assumption. It represents the most common type of thermal generation investment. This is also the hybrid real weighted average after tax cost of capital.

Table 10-2 Financial Assumptions for Utility and Merchant Cases

EPA Platform v6 - Utility WACC using daily beta for 2012-2015	
Parameters	**Value**
Risk-free rate	3.45%[109]
Market premium	6.30%[110]
Equity size premium	0.46%[111]
Levered beta[112]	0.53
Debt/total value[113]	0.51
Cost of debt	4.33%[114]
Debt beta	0.00
Unlevered beta[115]	0.33
Target debt/total value[116]	0.50
Relevered beta	0.52
Cost of equity (with size premium) [117]	7.20%
WACC	5.2%
EPA Platform v6 - Merchant WACC using 55% Target Debt	
Parameters	**Value**
Risk-free rate	3.45%
Market premium	6.30%
Equity size premium	1.21%[118]
Levered beta[119]	1.35
Debt/total value[120]	0.68
Cost of debt[121]	7.20%

[109] Represents 10-year historical average (2007- June 2016) on a 20-year treasury bond. See discussion of risk-free rate and market premium. The five year average (2012- June 2016) on a 20-year treasury bond is 2.70%. The five- (2012- June 2016) and ten-year (2007-June 2016) averages for the 30-year bond are 3.04% and 3.65% respectively.

[110] Represents the 10-year risk premium as of October 1, 2016 (A. Damodaran)

[111] Size premiums according to size groupings taken from Duff & Phelps 2016 Valuation Handbook. Equity size premium is based on weighted average of each company's equity size premium, weighted by each company's equity capitalization level.

[112] Levered betas were calculated using four years (2012-2015).

[113] Debt/total value ratio is the simple average of net debt to equity ratio for the past 5 years.

[114] Cost of debt is based on 5-year weighted average of debt yields for 17 utilities. The weights assigned are the equity share of each utility. The cost of debt using the approach described in the next footnote is 4.45%.

[115] Calculated using Hamada equation.

[116] Target debt/total value for utility case is based on historical 5 years of average D/E for utilities

[117] Cost of equity represents the simple average cost of equity. In the case of utility and merchant ROE, the decrease reflects primarily the lower beta.

[118] Size premiums according to size groupings taken from Duff & Phelps 2016 Valuation Handbook. Equity size premium is based on weighted average of each company's equity size premium, weighted by each company's equity capitalization level.

[119] Levered betas were calculated using five years (2012- June 2016) of historical stock price data. Weekly returns were used in the analysis.

[120] Debt/total value for merchant case is calculated as simple average of the 5-year total debt to total value for each IPP.

[121] Cost of debt is based on historical 5-year weighted average of yields to maturity on outstanding debt. Analyzed merchant companies did not issue long-term debt of 20 year or greater duration in the last five years in this analysis (2012-2016).

Debt beta[122]	0.18
Unlevered beta[123]	0.69
Target debt/ total value[124]	0.55
Relevered beta	1.19
Cost of equity (with size premium) [125]	12.16%
WACC	8.40%

Table 10-3 Weighted Average Cost of Capital

Utility Share	Utility WACC	Merchant Share	Merchant WACC	Weighted Average Nominal WACC	Inflation	Weighted Average Real WACC
70%	5.2%	30%	8.40%	6.16%	1.83%	4.25%

10.5 Discount Rate Components

The discount rate is a function of the following parameters:

- Capital structure (share of equity and debt)
- Post-tax cost of debt
- Post-tax cost of equity

The WACC is used as the discount rate and is calculated as follows:[126]

WACC = [Share of Equity * Cost of Equity]
+ [Share of Preferred Stock * Cost of Preferred Stock]
+ [Share of Debt *After Tax Cost of Debt]

The methodology relies on debt and equity (common stock) because preferred stock is generally a small share of capital structures, especially in the IPP sector. Its intermediate status between debt and equity in terms of access to cash flow also tends not to change the weighted average.[127] Typically, net cash flows are used to fund senior debt before subordinated debt, and all debt before equity. Therefore, the risk of equity is higher than debt, and the rates of return reflect this relationship. Notwithstanding, consistent with our use of utility debt that has recourse to the corporation rather than individual assets, we use IPP debt that has recourse to the corporation rather than individual assets because the data are more robust.

10.6 Market Structure: Utility-Merchant Financing Ratio

With two distinct market structures, EPA Platform v6 establishes appropriate weights for regulated and deregulated financial assumptions to produce a single, hybrid set of utility capital charge rates for new

[122] Debt beta for DYN, CPN, and NRG calculated using the Merton model.

[123] Calculated using Hamada equation. In merchant case, it was modified slightly to include the riskiness of debt.

[124] The capitalization structure (debt to equity (D/E)) for merchant financings is assumed to be 55/45.

[125] Cost of equity represents the simple average cost of equity. In both the utility and merchant cases, the decrease primarily reflects the lower beta.

[126] Sometimes abbreviated as ATWACC. The pretax WACC is higher due to the inclusion of income taxes. Income taxes are included in the capital charges. All references are to the after-tax WACC unless indicated.

[127] Debt generally has first call on cash flows and equity has a residual access.

units. The EPA Platform v6, uses a weighting of 70:30, regulated to deregulated, based on recent capacity addition shares by market type (See Table 10-4).[128]

Table 10-4 Share of Annual Thermal Capacity Additions by Market

Entity	2012	2013	2014	2015	2016	Average
Regulated	70%	88%	60%	58%	64%	68%
Merchant	30%	12%	40%	42%	36%	32%

10.7 Capital Structure: Debt-Equity Share

10.7.1 Introduction and Shares for Utilities and IPPs

The second step in calculating the discount rate is the determination of the capital structure, specifically the debt to equity (D/E) or debt to value (D/V) ratio for utility and merchant investments.[129] This is calculated by determining the total market value of the company, and the market value of its debt and equity. The market value of the company is the sum of the market value of its debt and equity. We also determined the capital structure for the various technology types.

The target capitalization structure for utilities was assumed to be 50:50. This was based on the capitalization over the 2012 to 2016 period. The capitalization structure for merchant financings is assumed to be 55/45, reflecting the greater risk inherent to this market.[130]

10.7.2 Utility and Merchant

For utility financing, the empirical evidence suggests that utility rate of return is based on an average return to the entire rate base. Thus, EPA Platform v6 assumes that the required returns for regulated utilities are independent of technology. In contrast, the merchant debt capacity is based on market risk and varies by technology.

10.7.3 Merchant by Technology

Assigning merchant technology risk is difficult 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.[131] Nevertheless, we assigned merchant technology market risk as follows:

- **Combined Cycles** – The capitalization structure for merchant financing of combined cycles is assumed to be 55/45.

- **Peaking Units** – A peaking unit such as a combustion turbine is estimated to have a capital structure of 40/60. Peaking units have a less diverse, and therefore, more risky revenue stream.

[128] In contrast to new units, existing coal units can be classified as belonging to a merchant or regulated market structure. Hence, for retrofit investments, the EPA Platform v6 assumption is that coal plants owned by a utility get purely utility financing parameters coal plants owned by merchant companies get purely merchant financing parameters.

[129] A project's capital structure is the appropriate debt capacity given a certain level of equity, commonly represented as "D/E." The debt is the sum of all interest bearing short- and long-term liabilities, while equity is the amount that the project sponsors inject as equity capital.

[130] The U.S.-wide average authorized equity ratio during the last 5 years (2012-2016) for 146 utility companies was 50.22%. Debt/total value for merchant case is calculated as simple average of the 5-year total debt to total value for each IPP.

[131] There were only three major IPP companies with traded equity. This is insufficient to conduct statistical analysis.

- **Coal Units** – A new coal unit is estimated to have a capital structure of 40/60, reflecting higher risk than a combined cycle unit. This is reflected in observed higher financing costs at the two IPP companies with coal, NRG and Dynegy, as compared to Calpine, which has no coal, only gas and geothermal. While statistical analysis cannot be performed with such a small sample size, it is supported qualitatively.

- **Fossil Units –** New, non-peaking fossil fuel-fired plants face additional risks associated with a potential cost on future CO_2 emissions, which the EIA handles by increasing the cost of debt and equity for new coal plants.[132] EPA Platform v6 extends this treatment of risk to new combined cycle plants.

- **Nuclear Units** — A new nuclear unit is estimated to have a capital structure of 40/60. There is high risk associated with a new IPP nuclear unit. This is supported by: (1) the financial challenges facing existing nuclear units, (2) the very limited recent new nuclear construction, (3) statements by financial institutions, and (4) the lack of ownership of nuclear power plants by pure play IPP companies. Of the three pure play companies only one has partial ownership of a single nuclear power plant. With this one exception, only utilities and affiliates of utilities own nuclear units.

- **Renewable Units** — A new merchant renewable unit is estimated to have a capital structure of 55/45. This is the highest debt share among the major classes of generation options, and therefore, the lowest cost of capital. This is in part because renewables have access to a third source of financing in tax equity. Tax equity receives the tax benefits such as ITC, PTC, losses available to defray income tax, over time by making a payment upfront. These benefits are not transferable to other companies. There is a risk that the tax credits may become less valuable over time (e.g., the company providing the tax equity does not have sufficient taxable income), or the project may not perform and have inadequate operations to generate expected PTC volumes. This risk is less than typical equity, since the tax credits value is not subject to as much variation as regular equity. These projects are also easier to hedge because they have zero variable costs, and hence, the annual volume of output is less uncertain, all else equal, and often receive support via power purchase agreements and renewable energy credits. Limits of relying on even greater debt include the scheduled lowering of the PTC and ITC over time, and the potential for performance problems.

Table 10-5 Capital Structure Assumptions

Technology	Utility	Merchant
Combustion Turbine	50/50	40/60
Combined Cycle	50/50	55/45
Coal & Nuclear	50/50	40/60
Renewables	50/50	55/45
Retrofits	50/50	40/60

10.8 Cost of Debt

The third step in calculating the discount rate is to assess the cost of debt.[133] The utility and merchant cost of debt is assumed the same across all technologies.

[132] 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

[133] Measured as yield to maturity.

Table 10-6 Nominal Debt Rates

Technology	Utility	Merchant
Combustion Turbine	4.33%	7.20%
Combined Cycle	4.33%	7.20%
Coal & Nuclear	4.33%	7.20%
Renewables	4.33%	7.20%
Retrofits	4.33%	7.20%

10.8.1 Merchant Cost of Debt

The cost of debt for the merchant sector was estimated to be 7.2%. It is calculated by taking a 5-year (2012-2016) 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 (2012-2016), 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.

10.8.2 Utility Cost of Debt

The cost of debt for the utility sector was estimated to be 4.33%. It is calculated based on the 5-year (2012-2016) average of a set of 17 utilities weighted by enterprise value (See Table 10-7).

Table 10-7 Utilities Used to Calculate Cost of Debt

Name
Ameren Corp
American Electric Power Co Inc.
Cleco Corp
CMS Energy Corp
Empire District Electric Co/The
Great Plains Energy Inc.
MGE Energy Inc.
Westar Energy Inc.
WEC Energy Group
Consolidated Edison Inc.
Southern Co/The
UIL Holdings Corp
Avista Corp
IDACORP Inc.
PG&E Corp
Pinnacle West Capital Corp
Xcel Energy Inc.

10.9 Return on Equity (ROE)

10.9.1 Introduction and Beta

The final step in calculating the discount rate is the calculation of the required rate of return on equity (ROE). The ROE is calculated using the formula:

ROE = risk free rate + beta x equity risk premium + size premium

The formula is the key finding of the CAPM and reflects that a premium on return is required as investment risk increases, and that premium is proportional to the systemic risk of the investment.[134] Systemic risk is measured by the impact of market returns on the investment's returns and is measured by beta.[135]

There are several additional aspects of estimating beta:

- **Time Period** – The most common practice is to use five years of historical returns to estimate beta.

- **Returns** – Daily returns are commonly used to estimate beta except for illiquidly traded stocks when weekly returns are used to avoid under estimating beta. The utility estimates presented use daily data and the IPP estimates used weekly estimates.

- **Unlevered Betas** - It is useful to estimate unlevered betas that eliminate the effects of leverage. This facilitates comparison across investments with different leverage levels, and allows recalculation to account for going forward changes in leverage levels. This recalculation involves a technique known as the Hamada[136] equation.

- **Debt Betas** - When a company is facing financial distress, the debt can become the new equity as part of corporate reorganization under the federal bankruptcy code. Hence, during the bankruptcy period, the debt trades like equity. There is a technique to adjust the beta by calculating a debt beta. This technique is employed because one of the three IPP companies, Dynegy, was having significant financial distress especially early in the 2012-2016 period.

10.9.2 Risk-Free Rate and Equity Risk Premium

The risk-free rate of return and equity risk premium are market parameters, and are not company-specific. They also determine the average market-wide level of returns on equity. Therefore, the average return of the market equals the sum of the risk-free rate of return and equity risk premium.

In this analysis, we use the Duff and Phelps 2016 Valuation Handbook, Industry Cost of Capital. Duff and Phelps recommends an estimate of 5.5% for the market risk premium[137]. At the same time, Duff and Phelps recommends a 4% risk-free rate. Thus the total is 9.5%.

The EPA estimates are based on the approach of using long-term averages for both the risk-free rate and the market risk premium. Specifically, EPA estimates the risk-free rate of return and the market risk premium based on 10-year averages. The risk free rate assumption is 3.45% which is the 10-year (2007-2016) average of U.S. Treasury 20 year bond rates. The market risk premium is the ten year average provided by Professor Damodaran of 6.3%[138]. The sum of the two is 9.75%, and is close to Duff and Phelps recommendation of 9.5%.

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[134] The financial literature on CAPM originally did not emphasize the size premium (also referred to as the liquidity premium). It emerged from later findings that the estimated required return was too low for small stocks (i.e., with low equity value).

[135] Beta is the covariance of market and the stock's returns divided by the variance of the market's return.

[136] In corporate finance, Hamada's equation is used to separate the financial risk of a levered firm from its business risk.

[137] Duff and Phelps, 2016 Valuation Handbook, March 2016, see also Client Alert, Duff and Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5% Effective January 31, 2016.

[138] As of October 1, 2016.

10.9.3 Beta

Utility betas average 0.53 during the 2012 to 2015 period on a levered basis (see Table 10-8). This estimate is based on daily returns. This estimate was chosen because it was intermediate between the ten-year average and the 2012-2016 estimate when using partial year 2016 data. For example, the ten-year beta (2007-2016) is even higher at 0.60 daily, and the 2012-2016 partial year estimate is 0.5 because the partial year 2016 data is much lower than the 2012-2015 average.[139]

Table 10-8 Estimated Annual Levered Beta for S15ELUT Utility Index Based on Daily Returns[140]

Year	Levered Beta
2012	0.35
2013	0.70
2014	0.44
2015	0.62
2016 (through June)	0.25
Average (2012-15)	**0.53**

IPP betas average 1.35 based on weekly returns from 2012-June 2016. We did not observe issues with partial year 2016 data. After decreasing leverage from 68% to 55%, and adjusting the beta estimate, the beta decreases to 1.19. Even after correcting for the greater financial risk of IPPs due to higher leverage, the betas of IPPs are higher than utilities. The unlevered betas of utilities is 0.33 and of the IPPs is 0.69[141].

10.9.4 Equity Size Premium

It is observed that long-run returns of smaller, less liquidly traded companies have higher returns than predicted using the market risk premium. Therefore, an equity size of liquidity premium is added. Based on the 2016 Duff and Phelps Valuation Handbook there was a significant equity size premium for IPPs of 1.21% and a smaller premium for utilities at 0.46%.

10.9.5 Nominal ROEs

Utility

The utility ROE is 7.20% in nominal terms. The utility ROE is the single most influential parameter in the estimate of the discount rate because of the 70% weight given to utilities compared to IPPs, and the decrease in interest rates due to the tax shield on debt (debt interest payments are tax deductible).

The estimated utility ROE in EPA Platform v6 is lower than what state and federal commissions have awarded the shareholder-owned electric utilities recently.[142] In some cases, commissions use a different

[139] One-half weight to 2016.

[140] S15ELUT Index comprises of 22 utilities: American Electric Power Co. Inc., Great Plains Energy Inc., Westar Energy Inc., IDACORP Inc., PG&E Corp., Pinnacle West Capital Corp., Xcel Energy Inc., NextEra Energy Inc, Duke Energy Corp, Southern Co, Exelon Corp., Edison International, PPL Corp., Eversource Energy, First Energy Corp., Entergy Corp., Alliant Energy Corp., OGE Energy Corp., Hawaiian Electric Industries Inc., ALETTE Inc., PNM Resources Inc., and El Paso Electric Co.

[141] Unlevered betas are lower than levered betas. Levered beta is directly measured from the company's stock returns with no adjustment made for the debt financing undertaken by the company. The leveraged beta of the market equals one.

[142] SNL-based rate case statistics for 2012-2016 suggest nationwide average ROE rate of 9.93%.The Edison Electric Institute's Financial Update, Rate Case Summary, Q4 2015 reported average approved returns on equity of 9.6% the second lowest in its three decades of data.

approach or assumptions[143]. If it were shown that the existence of higher returns at other utilities prevented utilities receiving the estimated return here while still attracting sufficient capital, this could mean that the estimate here is too low. However, ICF's experience notes that the trend is to lower returns and this is a long-term analysis focused on cost of capital for future investments that can occur 25 years or more in the future.

IPP

The nominal ROE for IPPs is 12.16%. The IPP required ROE is sensitive to the amount of debt and the analysis assumes future delevering. Specifically, the IPP ROE assumes 55% debt rather than 68% debt, which is the 2012-2016 average.

10.9.6 WACC/Discount Rate

The WACCs are 5.2% in nominal terms for utilities and 8.40% in nominal terms for IPPs (see Table 10-3). Using a 70:30 utility/merchant weighting, the weighted average WACC under utility financing and merchant financing is a 6.16% WACC. The real hybrid WACC is 4.25%.

10.10 Calculation of Capital Charge Rate

10.10.1 Introduction to Capital Charge Rate Calculations

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 10-9 to Table 10-11 presents the capital charge rates by technology type used in EPA Platform v6. As discussed in section 10.3, the changes to the Tax Code have caused capital charge rates to vary by run year, therefore the tables below show the rates for the individual run years through 2030. Capital charge rates are a function of underlying discount rate, book and debt life, taxes and insurance costs, and depreciation schedule.

Table 10-9 Real Capital Charge Rate – Blended (%)[144]

New Investment Technology Capital Hybrid (70/30 Utility/Merchant)	2021	2023	2025	2030 and Beyond
Environmental Retrofits - Utility Owned	10.77%	10.77%	10.77%	10.77%
Environmental Retrofits - Merchant Owned	14.05%	14.05%	14.12%	14.54%
Advanced Combined Cycle	8.64%	8.64%	8.66%	8.77%
Advanced Combustion Turbine	9.02%	9.02%	9.02%	9.10%

[143] Some regulatory commissions use what is known as the dividend growth model. This model assumes that the current market price of a company's stock is equal to the discounted value of all expected future cash flows. In this approach, the time period is assumed to be infinite, and the discount rate is a function of the share price, earnings per share and estimated future growth in dividends. The challenge with using this approach is estimating future growth in earnings. Commissions rely on stock analyst forecasts of future growth rates for dividends. In other cases, commissions may allow for other parameters such as flotation costs (costs of issuing stock). We did not use this approach because it is less commonly used. There also appears to be a tendency of allowed rates of return as a group to be too low during periods with high financial costs and too high during periods of low financing costs. This may be to ensure comparability with similar utility companies. There is also a literature that indicates that as betas deviate from 1, the CAPM returns are too low and too high. We did not address these issues directly in part because the results were comparable to other results, with the exception of being lower than allowed returns.

[144] 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 1.83%. The future inflation rate of 1.83% 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 (2012-2016).

New Investment Technology Capital Hybrid (70/30 Utility/Merchant)	2021	2023	2025	2030 and Beyond
Ultra Supercritical Pulverized Coal without Carbon Capture[145]	10.96%	10.96%	11.01%	11.18%
Ultra Supercritical Pulverized Coal with Carbon Capture	8.31%	8.31%	8.32%	8.43%
Nuclear	8.31%	8.31%	8.33%	8.43%
Nuclear without Production Tax Credit	8.31%	8.31%	8.33%	8.43%
Nuclear with Production Tax Credit[146]	7.10%	7.09%	7.10%	7.19%
Biomass	8.14%	8.12%	8.12%	8.12%
Wind, Landfill Gas, Solar and Geothermal	9.79%	9.78%	9.77%	9.77%
Hydro	8.09%	8.09%	8.11%	8.21%

Table 10-10 Real Capital Charge Rate – IPP (%)

New Investment Technology Capital (IPP)	2021	2023	2025	2030 and Beyond
Environmental Retrofits - Merchant Owned	14.05%	14.05%	14.12%	14.54%
Advanced Combined Cycle	10.89%	10.89%	10.97%	11.33%
Advanced Combustion Turbine	11.83%	11.81%	11.81%	12.07%
Ultra Supercritical Pulverized Coal without Carbon Capture	14.05%	14.06%	14.23%	14.78%
Ultra Supercritical Pulverized Coal with Carbon Capture	11.22%	11.22%	11.27%	11.62%
Nuclear without Production Tax Credit	11.22%	11.22%	11.29%	11.62%
Nuclear with Production Tax Credit	9.71%	9.69%	9.71%	10.00%
Biomass	10.60%	10.56%	10.53%	10.53%
Wind, Landfill Gas, Solar and Geothermal	11.77%	11.73%	11.70%	11.70%
Hydro	10.61%	10.61%	10.67%	11.01%

Table 10-11 Real Capital Charge Rate – Utility (%)

New Investment Technology Capital Utility	2021	2023	2025	2030 and Beyond
Environmental Retrofits - Utility Owned	10.77%	10.77%	10.77%	10.77%
Advanced Combined Cycle	7.67%	7.67%	7.67%	7.67%
Advanced Combustion Turbine	7.82%	7.82%	7.82%	7.82%

145 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

146 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 v6 integrates 2,200 MW of new nuclear capacity at Vogtle nuclear power plant. Therefore, in EPA Platform v6 only 3,800 MW of incremental new nuclear capacity will be provided with this tax credit.

New Investment Technology Capital Utility	2021	2023	2025	2030 and Beyond
Ultra Supercritical Pulverized Coal without Carbon Capture	9.63%	9.63%	9.63%	9.63%
Ultra Supercritical Pulverized Coal with Carbon Capture	7.06%	7.06%	7.06%	7.06%
Nuclear without Production Tax Credit	7.06%	7.06%	7.06%	7.06%
Nuclear with Production Tax Credit	5.98%	5.98%	5.98%	5.98%
Biomass	7.08%	7.08%	7.08%	7.08%
Wind, Landfill Gas, Solar and Geothermal	8.94%	8.94%	8.94%	8.94%
Hydro	7.01%	7.01%	7.01%	7.01%

10.10.2 Capital Charge Rate Components

The capital charge rate is a function of the following parameters:

- Capital structure (debt/equity shares of an investment)
- Pre-tax debt rate
- Debt life
- Post-tax return on equity
- Other costs such as property taxes and insurance
- State and federal corporate income taxes
- Depreciation schedule
- Book life

Table 10-12 presents a summary of various assumed book lives, debt lives and the years over which the investment is fully depreciated. The book life or useful life of a plant was estimated based on publicly available financial statements of utility and merchant generation companies.[147]

Table 10-12 Book Life, Debt Life and Depreciation Schedules for EPA Platform v6

Technology	Book Life (Years)	Debt Life (Years)	U.S. MACRS Depreciation Schedule (Years)
Combined 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
Environmental Retrofits	15	15	15

Depreciation Schedule

For the utility sector, the U.S. MACRS depreciation schedules were obtained from IRS Publication 946 that lists the schedules based on asset classes.[148, 149] The document specifies a 5-year depreciation

[147] SEC 10K filings of electric utilities and 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 uses 30 years for power generation facilities.

schedule for wind energy projects and 20 years for electric utility steam production plants. These exclude combustion turbines and nuclear power plants, which each have a separate listing of 15 years. As a result of the tax code changes, the merchant sector is allowed to depreciate assets on an accelerated schedule through 2027. Accelerated depreciation is allowed starting in 2018 with 100% depreciation and phases out at 20% annual between 2023 and 2027.

Taxation and Insurance Costs

The maximum U.S. corporate income tax rate is 21%.[150] State taxes vary but the weighted average state corporate marginal income tax rate is 6.45%. This yields a net effective corporate income tax rate of 26.1%.

U.S. state property taxes are approximately 0.9%, based on a national average basis. This is based on extensive primary and secondary research conducted by EPA using property tax rates obtained from various state agencies.

Insurance costs are approximately 0.3% on a national average basis.

[148] MACRS refers to the Modified Accelerated Cost Recovery System, issued after the release of the Tax Reform Act of 1986.

[149] IRS Publication 946, “How to Depreciate Property,” Table B-2, Class Lives and Recovery Periods.

[150] Internal Revenue Service, Publication 542.