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 and pump 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:

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

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

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

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

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

2.2 Model Structure and Formulation

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

- A linear "objective function,"
- A series of "decision variables," and
- A set of linear "constraints".
- The sections below describe the objective function, key decision variables, and constraints included in IPM for EPA 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 region. Coal decision variables are further differentiated according to coal rank (bituminous, sub-

[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.

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:

Reserve Margin Constraints: Regional reserve margin constraints capture system reliability requirements by defining a minimum margin of reserve capacity (in megawatts) per year beyond the total capacity needed to meet future peak demand that must remain in service to that region. These reserve capacity constraints are derived from reserve margin targets that are assumed for each region based on information from 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.

Demand Constraints: 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.

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

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

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

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

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

2.3 Key Methodological Features of IPM

IPM is a flexible modeling tool for obtaining short- and long-term projections of production activity in the electric generation sector. The projections obtained using IPM are not statements of what will happen, but they are estimates of what might happen given the assumptions and methodologies used. Chapters 3 to 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 initial run and anticipated policy case runs. For EPA Platform v6, IPM employed an aggregation algorithm which allowed 21,742 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 reliability), IPM "builds" one or more of these predefined model plants by raising its generation capacity

[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.

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.

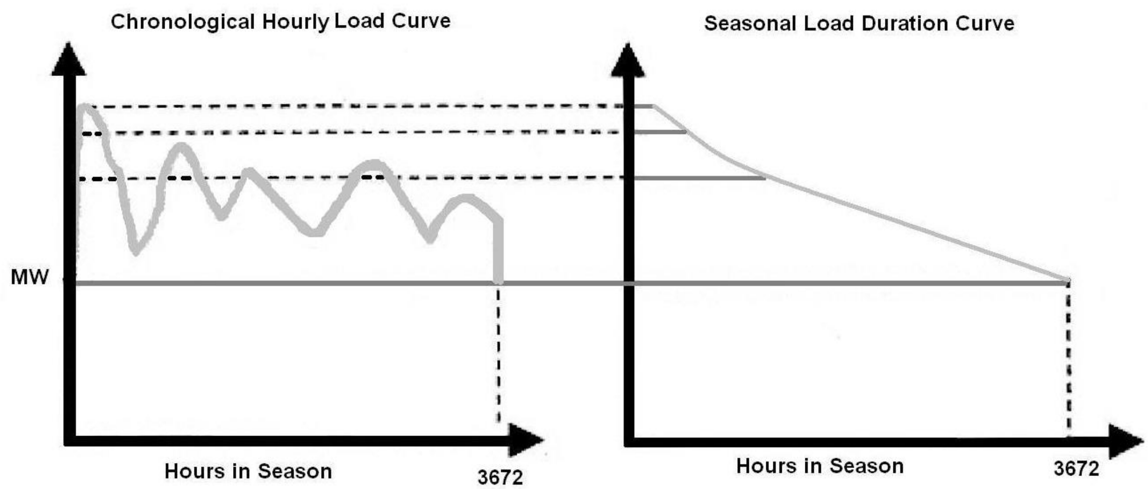
Use of seasonal LDCs rather than annual LDCs allows IPM to capture seasonal differences in the level and patterns of customer demand for electricity. For example, in most regions air conditioner cycling only impacts customer demand patterns during the summer season. The use of seasonal LDCs also allows

[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.

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 2017 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 future variations in electricity consumption patterns.[11]

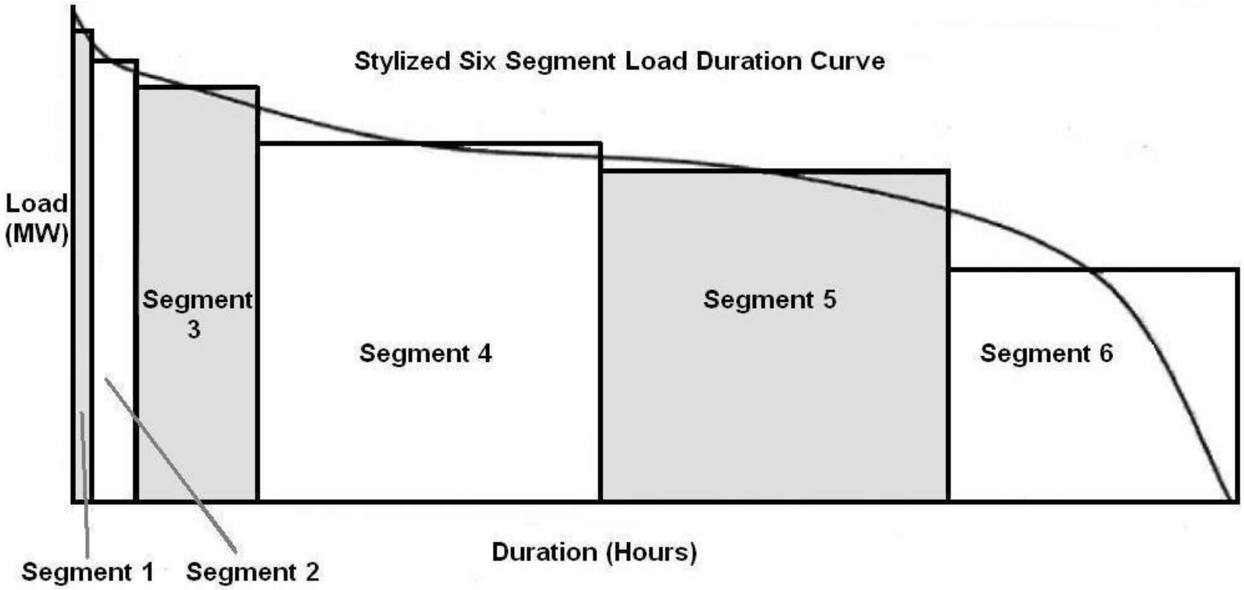
Within IPM, LDCs are represented by a discrete number of load segments, or generation blocks, as illustrated in Figure 2-2. EPA Platform v6 uses 24 load segments in its seasonal LDCs. Figure 2-2 illustrates and the following text describes the 24-segment LDCs used in EPA Platform v6. Length of time and 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 load in all 24 segments of the load duration curve. This is discussed in greater detail in section 2.3.6 below.

[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.

Table 2-2 contains data of the seasonal 2017 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

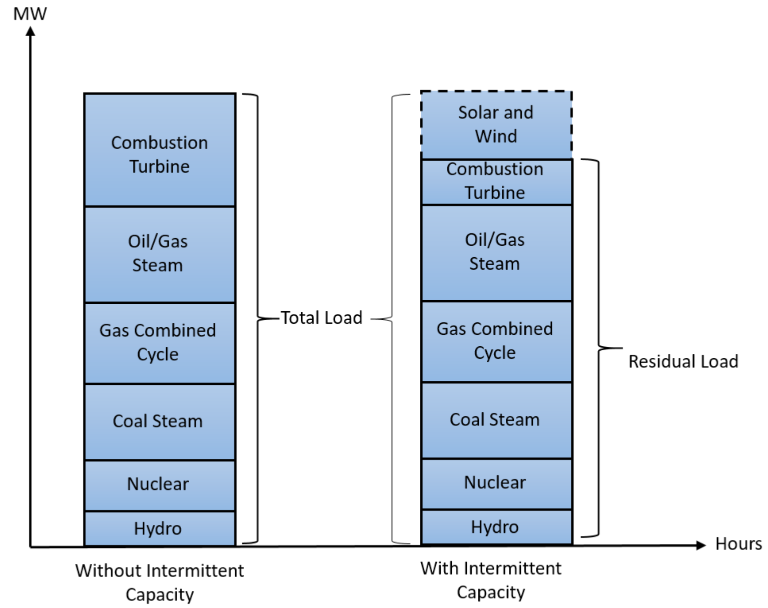


2.3.6 Dispatch Modeling

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 18.6 million decision variables and 1.12 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 3-10contain 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, 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 Profile Characteristics
- 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