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The Electricity Market Module of the National Energy Modeling System

Model Documentation Report

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The Electricity Market Module of the National Energy Modeling System

1. Introduction

The National Energy Modeling System (NEMS) was developed to provide mid-term (20 to 25 years) forecasts and analyses of energy-related activities. The NEMS Electricity Market Module (EMM) provides a major link in the NEMS framework (Figure 1). In each model year, the EMM receives electricity demand from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module and then estimates the actions taken by electric utilities and nonutilities to meet demand in the most economical manner. The EMM then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the integrating module, and capital requirements to the macroeconomic module. The model iterates until a solution is reached for that model year.

The EMM represents the capacity planning, generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and load and demand-side management (Figure 2). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from cogenerators and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 13 supply regions (Figure 3).

Operating (dispatch) decisions are made by choosing the mix of plants that minimizes fuel, variable operating and maintenance (O&M), and environmental costs, subject to meeting electricity demand and environmental constraints. Capacity expansion is determined by the least-cost mix of all costs, including capital, O&M, and fuel. Construction of generating plants with long lead times is selected with planning horizons up to ten periods into the future, although a six-year planning horizon is currently used. Electricity demand is represented by load curves, which vary by region, season, and time of day.

The EMM also represents distributed generation that is owned by electricity suppliers. Consumer-owned distributed generation is determined in the end-use demand modules of the NEMS. The EMM considers construction, operating, and avoided transmission and distribution costs associated with distributed generation to evaluate these options as an alternative to central-station capacity.

The solution to the submodules of the EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be summarized as follows:

1. The load and demand-side management submodule processes electricity demand to construct load curves.

2. The electricity capacity planning submodule projects the construction of new generating plants, the retirement (if appropriate) of existing plants, the level of firm power trades, and the addition of scrubbers and other equipment for environmental compliance.

3. The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in selected regions to be dispatched for another region's needs (economy trade).

4. The electricity finance and pricing submodule calculates total revenue requirements for each utility operation and computes average and marginal-cost based electricity prices.

Electricity Capacity Planning Submodule

The electricity capacity planning (ECP) submodule determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and technology costs. When new capacity is required to meet electricity demand, the timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies and the construction and operating costs of available technologies determine what technology is chosen.

The expected utilization of the capacity is important in the decisionmaking process. A technology with relatively high capital costs but comparatively low operating costs (such as coal-fired technologies) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs (such as a natural-gas fired turbine technology) may be the most economical selection to serve the peak load (i.e., the highest demands on the system), which occurs infrequently. Intermediate or cycling load occupies a middle ground between base and peak load and is best served by plants that are cheaper to build than baseload plants and cheaper to operate than peak load plants (such as a natural-gas fired combined cycle plant).

Figure I. National Energy Modeling System

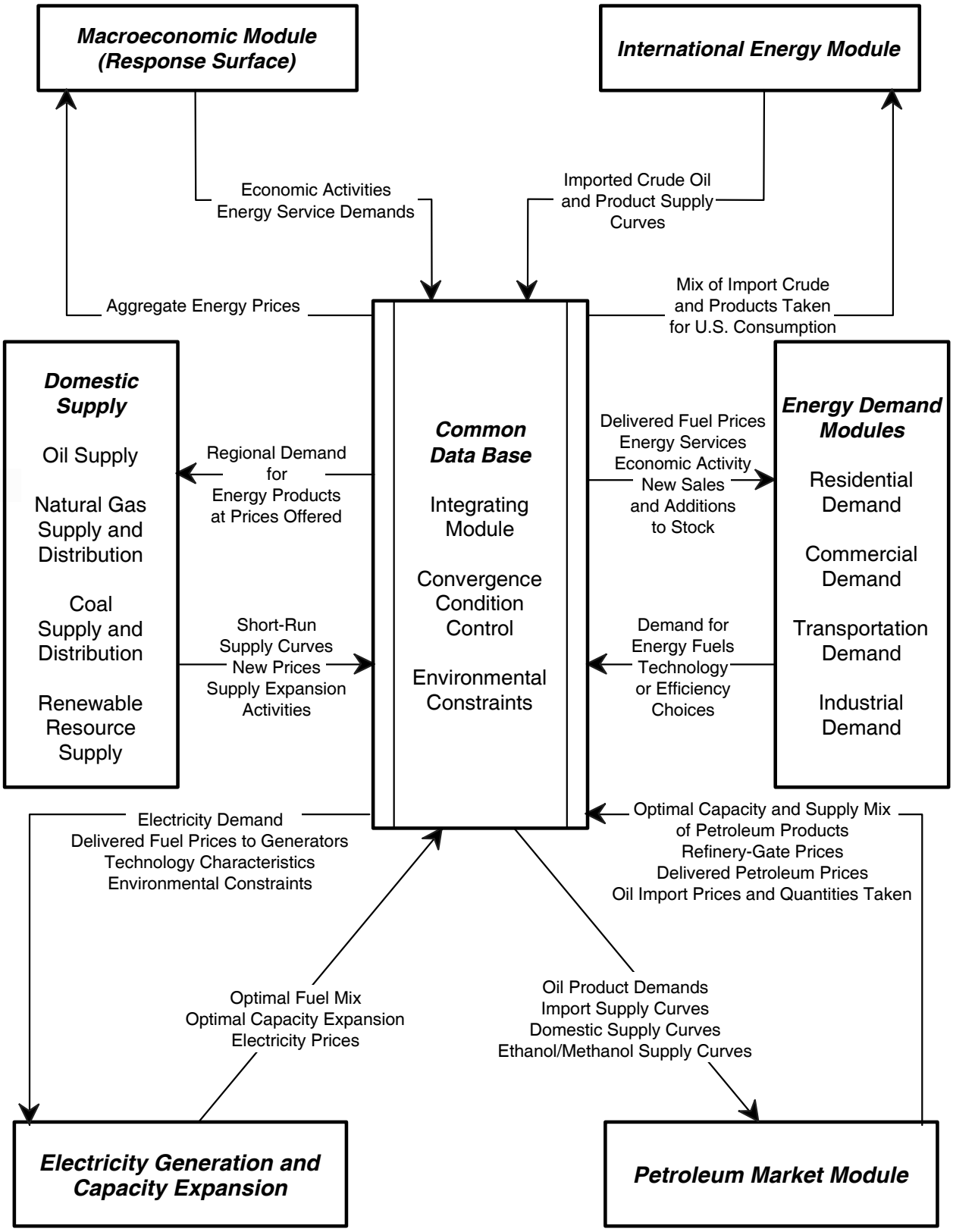
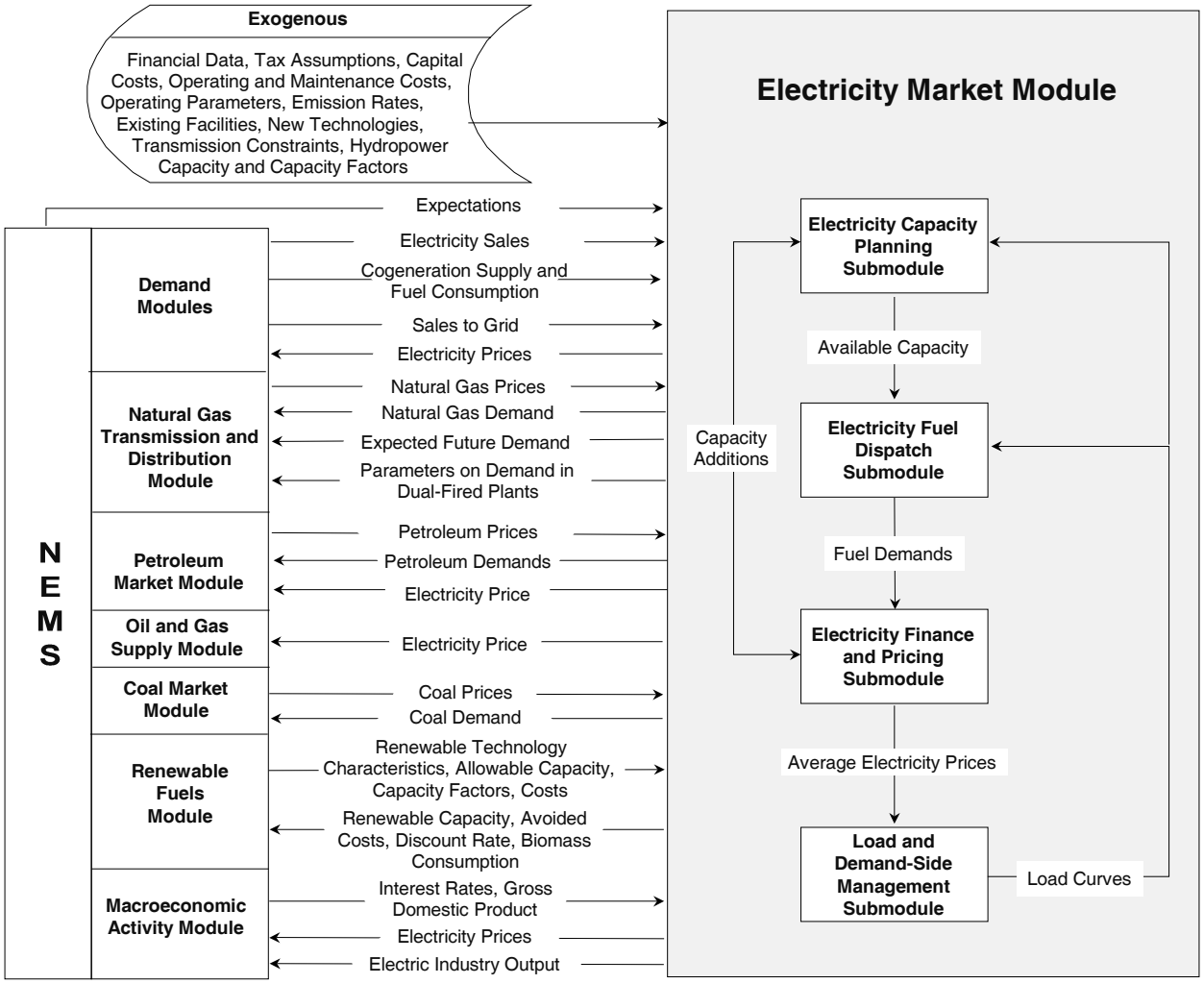


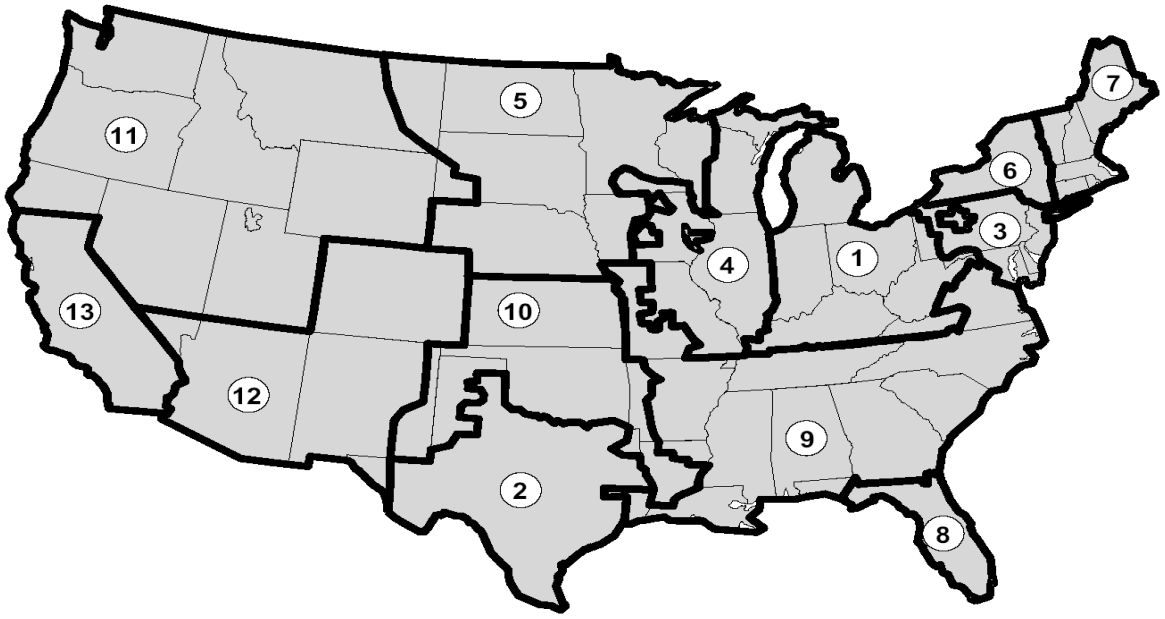
Figure 2. Electricity Market Module Structure



EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components Fuel demands Capacity additions Capital requirements Emissions Renewable capacity Avoided costs	Electricity sales Fuel prices Cogeneration supply and fuel consumption Electricity sales to the grid Renewable technology characteristics, allowable capacity, and costs Renewable capacity factors Gross domestic product Interest rates	Financial data Tax assumptions Capital costs Operation and maintenance costs Operating parameters Emissions rates New technologies Existing facilities Transmission constraints

Figure 3. Electricity Market Model Supply Regions

Technologies are compared on the basis of total capital and operating costs incurred over a 20-



year period. As new technologies become available, they are competed against conventional plant types. Fossil-fuel, nuclear, and renewable generating technologies are represented.

The timing of the demand increase is important, because the construction lead times of technologies differ. A multi-period optimization is performed, capacity choices in each year are made by looking several years into the future rather than the current year only.

Uncertainty about investment costs for new technologies is captured in the ECP using technological optimism and learning factors. "Technological optimism factor" reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.

Learning factors represent reductions in capital costs due to "learning-by-doing." Learning factors are calculated separately for each of the major design components of the technology. For new technologies, cost reductions due to learning also account for international experience in building generating capacity. Base overnight capital costs are assumed to be the current cost per kilowatt for a unit constructed today. Generally, overnight costs for new, untested components are assumed to decrease by 10 percent for each doubling of capacity for the first three doublings,

by 5 percent for each of the next five doublings of capacity, and by 1 percent for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1 percent for each doubling of capacity. Some exceptions to this methodology are made where special circumstances occur, such as for wind.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If a new foreign unit does not satisfy one or more of these requirements, it is given a reduced weight or not included in the learning effects calculation.

Initially, investment decisions are determined in the ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. Therefore, the ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are "competitive" but do not have the lowest average cost.

The ECP submodule also determines whether to contract for new firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After building new capacity, the submodule passes total available capacity to the electricity fuel dispatch submodule and new capacity expenses to the electricity finance and pricing submodule. The following technologies are considered:

<table>
<tr><th>Fossil Fuel Fired</th><th>Nuclear</th></tr>
<tr><td rowspan="3">Existing Coal without FGD
Existing Coal with FGD
New pulverized coal with FGD
Advanced clean coal technology
Advanced clean coal technology with sequestration
Gas/oil steam
Conventional gas/oil combined cycle
Advanced combined cycle
Advanced combined cycle with sequestration
Conventional combustion turbine
Advanced combustion turbine
Fuel cells
Distributed generation
(FGD = flue gas desulfurization)</td><td>Conventional nuclear
Advanced nuclear</td></tr>
<tr><td>Renewables</td></tr>
<tr><td>Conventional hydropower
Geothermal
Solar-thermal
Solar-photovoltaic
Wind
Wood
Municipal solid waste</td></tr>
</table>

Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased-power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. The submodule dispatches utility, independent power producer, and small power producer plants throughout a transmission network until demand is met. A linear programming approach implemented for the *Annual Energy Outlook 2000* (AEO2000) version of the model allows a least cost optimization of plants based on their operating costs and any transmission costs. Limits on emissions of sulfur dioxide and nitrogen oxides from generating units and the engineering characteristics of units serve as constraints. During off-peak periods, the submodule institutes load following, which is the practice of running plants near their minimum operating levels rather than shutting them down and incurring shutoff and startup costs. In addition, to account for scheduled and unscheduled maintenance, the capacity of each plant is derated (lowered) to the expected availability level. Finally, the annual operation of utility and nonutility plants for each region is separated into six time periods to reflect the seasonal variation in electricity demand.

Interregional economy trade is also represented in the EFD. The simultaneous dispatch decision across all regions linked by transmission network allows generation in one region to satisfy

electricity demand in an adjacent region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace energy in an adjacent U.S. region if it results in cost savings. After dispatching, fuel use is reported back to the fuel supply modules and operating expenses and revenues from trade are reported to the electricity finance and pricing submodule.

Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the Electricity Finance and Pricing (EFP) submodule, which then uses these costs to compute both competitive and regulated end-use electricity prices. For those States that still regulate electricity generation, the EFP simulates the cost-of-service method to determine the price of electricity. Using historical costs for existing plants (derived from various sources such as Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees and Others," and Form EIA-412, "Annual Report of Public Electric Utilities"), cost estimates for new plants, fuel prices from the NEMS fuel supply modules, unit operating levels, plant decommissioning costs, plant phase-in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of utility operation—generation, transmission, and distribution. Revenue requirements shared over sales by customer class yield the price of electricity for each class. In addition, the submodule generates detailed financial statements.

For those States that have deregulated or plan to deregulate, their electricity generation markets, the EFP determines "competitive" prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs. Marginal costs are primarily the operating costs of the most expensive plant required to meet demand in a given region during an given time period. The competitive price also includes a "reliability price adjustment," which represents the value consumers place on reliability of service when demands are high and available capacity is limited. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

The delivered price of electricity calculated in the EFP for each EMM region is made available to the end-use demand models in NEMS. The price transmitted is either the cost-of-service price, the competitive price, or a combination of both, depending on whether or not a given EMM region has committed to competitive electricity markets, what percent of the region's sales are in competitive markets, and how long the region has been competitive.

Load and Demand-Side Management Submodule

The load and demand-side management (LDSM) submodule generates load curves representing the demand for electricity. The demand for electricity varies over the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand

varies by geographic area and time of year, the LDSM submodule generates load curves for each region and season for operational purposes.

Emissions

The EMM tracks emission levels for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Facility development, retrofitting, and dispatch are constrained to comply with the requirements of the Clean Air Act Amendments of 1990 (CAAA90) and other pollution constraints. An innovative feature of this legislation is a system of trading emissions allowances. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions level set by CAAA90, but it does tend to minimize the overall cost of compliance. In the EMM, trading is assumed to occur at the regional level, with those regions having a low cost of compliance allowed to sell excess allowances to the higher-cost regions. The EMM also has the ability to track and limit emissions of mercury and carbon.

Because emission standards for mercury have not been established at this time, they are not included in the reference case for the *Annual Energy Outlook*. However, the EMM can be used to analyze policy options for mercury controls that include limits on emissions and investments in emission control technologies.

Appendix 1A. Model Abstract

Description:

The NEMS Electricity Market Module (EMM)provides a major link in the NEMS framework. In each model year, the EMM receives electricity demand from the NEMS demand modules, fuel prices from the NEMS fuel supply modules, expectations from the NEMS system module, and macroeconomic parameters from the NEMS macroeconomic module and then estimates the actions taken by electric utilities and nonutilities to meet demand in the most economical manner. The EMM then outputs electricity prices to the demand modules, fuel consumption to the fuel supply modules, emissions to the system module, and capital requirements to the macroeconomic module. The model is iterated until a solution is reached for that model year. The EMM consists of four submodules: Electricity Capacity Planning (ECP), Electricity Fuel Dispatch (EFD), Electricity Finance and Pricing (EFP), and Load and Demand-Side Management (LDSM).

Electricity Capacity Planning Submodule (ECP):

The purpose of the ECP is to determine how the electric power industry will change its mix of generating capacity over the forecast horizon. It is intended to consider investment decisions for both demand-and supply-side options. However, consumer responses are assumed to be represented in the end-use demand modules, so the structure for demand-side management (DSM)options is not utilized within the ECP. It evaluates retirement decisions for fossil and nuclear plants and captures responses to environmental regulations, such as the CAAA or limits on carbon emissions. It includes traditional and nontraditional sources of supply. The ECP also represents changes in the competitive structure (i.e.,deregulation).Due to competition, no distinction is made between utilities and nonutilities as owners of new capacity.

Electricity Fuel Dispatch Submodule (EFD):

The objective of the EFD is to represent the economic, operational, and environmental considerations in electricity dispatching and trade. The EFD allocates available generating capacity to meet the demand for electricity on a minimum cost basis, subject to engineering constraints and to restrictions on emissions such as SO2, Nox, mercury, and carbon.

Electricity Finance and Pricing Submodule (EFP):

The EFP forecasts financial information for electric utilities on an annual basis given a set of inputs and assumptions concerning forecast capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs of the model include electricity prices by end use sectors for North American Electric Reliability (NERC)and Census regions, financial statements, revenue requirements, and financial ratios for each state of production (generation,transmission

and distribution).

Load and Demand-Side Management Submodule (LDSM):

Broadly speaking, the LDSM submodule has been designed to perform four major functions:
•Translate total electricity consumption forecasts into system load shapes

•Develop utility DSM programs for potential inclusion in future utility capacity expansion plans

•Translate census division demand data into NERC region data,and vice versa

•Report DSM impact on regional system demand.

Emissions

The EMM tracks emission levels for sulfur dioxide (SO_2),nitrogen oxides (NO_x),and mercury (hg).Facility development, retrofitting, and dispatch are constrained to comply with the constraints to the Clean Air Act Amendments of 1990 (CAAA90) and other pollution constraints. An innovative feature of this legislation is a system of trading emissions allowances. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e.,the degree to which its emissions per unit of power generated are below maximum allowable levels)to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions level set by CAAA90, but it does tend to minimize the overall cost of compliance.

2. Load and Demand-Side Management Submodule

This chapter documents the Load and Demand-Side Management (LDSM) submodule of the EMM. The primary purpose of the LDSM submodule is to translate census region annual electricity consumption forecasts from the NEMS demand submodules into the NERC region seasonal and time-of-day load shapes needed to simulate power plant operations and capacity planning decisions in the EMM. A secondary function of LDSM is to give the model the option of explicitly representing utility-sponsored demand side management (DSM) programs.[1]

Broadly speaking, the LDSM submodule has been designed to perform four major functions:

Primary Functions

- Translate census division annual demand data into NERC region annual data, and vice versa
- Translate annual electricity consumption forecasts into seasonal and time-of-day load shapes (load duration curves)

Secondary Functions (not currently utilized)

- Develop utility DSM programs for potential inclusion in future utility capacity expansion plans
- Report DSM program impacts on system demand.

Model Objectives

The primary objective of the LDSM is the preparation of seasonal, time-of-day representations of electricity demand for use in power plant operations and capacity planning decisions. Using historical information on the annual time profile of electricity demand (i.e., system load shapes) at the regional level together with load shape information for individual end-uses (i.e., heating, lighting, air conditioning, etc.) the LDSM constructs seasonal and time of day load shapes for each year of NEMS operation.

A secondary objective of the LDSM is the simulation of utility sponsored demand-side management programs. Using technology data from the residential and commercial demand submodules of NEMS, the LDSM constructs model DSM programs that can be treated as resource options in the Electricity Capacity Planning submodule of the EMM. For example, in

[1]The algorithms within the LDSM representing utility-sponsored DSM programs have not been updated in recent versions of the model, and they would require significant work before they could be used. Utility expenditures on these programs have been declining in recent years, and it is felt that their impact is adequately captured in the efficiency trends seen in the NEMS demand models.

the residential demand model, several different room air conditioner models, with different costs and performance characteristics, are available for consumers to select from. The LDSM constructs a potential DSM option by calculating the cost and impact of providing consumers an incentive to move from a low-cost, lower efficiency unit (referred to as the base or FROM technology in later parts of this documentation), to a higher-cost, higher efficiency unit (referred to as the TO technology). This option is then provided to the electricity capacity planning submodule for competition against other resource options to meet the growing demand for electricity. Details of these processes are given in the sections that follow.

Level of Aggregation

As with all of the EMM, the LDSM operates at a 13 region level. The regions are based on the North American Electric Reliability Council (NERC) Regions and Subregions. Of the 10 NERC Regions, eight are represented in their entirety: ECAR, MAAC, MAIN, MAPP, SPP, ERCOT, SERC and FL. The other region are formed by splitting or combining several of the NERC regions. In the Northeast Power Coordination Council (NPCC), the New England states constitute one region and New York represents another (NY). The Rocky Mountain Power Area (RMPA) and Arizona-New Mexico-Southern Nevada Power Area (AZNMSNV) Subcouncils have been combined into one region. The Northwest Power Pool Area (NWP) and California Power Area (CA) form the other two regions. Because of the topography of the electrical grid in the U.S. using NERC Regions and Subregions allows for a better representation of electricity markets than other options, such as census regions.

Relationship to Other Modules

The LDSM submodule interacts with the ECP, EFD, and EFP submodules within the EMM (Intra-Module linkages) and with the NEMS demand modules (Inter-Module linkages). Figure 4 displays these linkages. Only the LDSM links are shown in the figure.

Intra-Module Data Linkages

Within the EMM the key linkages to the LDSM are with the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) submodules. As mentioned previously, the LDSM submodule supplies system load duration curves to both the ECP and the EFD. The LDSM also develops DSM programs (costs and load shape impacts) for consideration by the ECP submodule, passes information about the DSM options selected by to the Electricity Finance and Pricing (EFP) submodule and adjusts system load curves to reflect DSM program impacts. Table 1 lists the major linkages between the LDSM and the other EMM submodules. The following subsections discuss intra-module linkages in greater detail.

Figure 4. LDSM Linkages With Other Modules

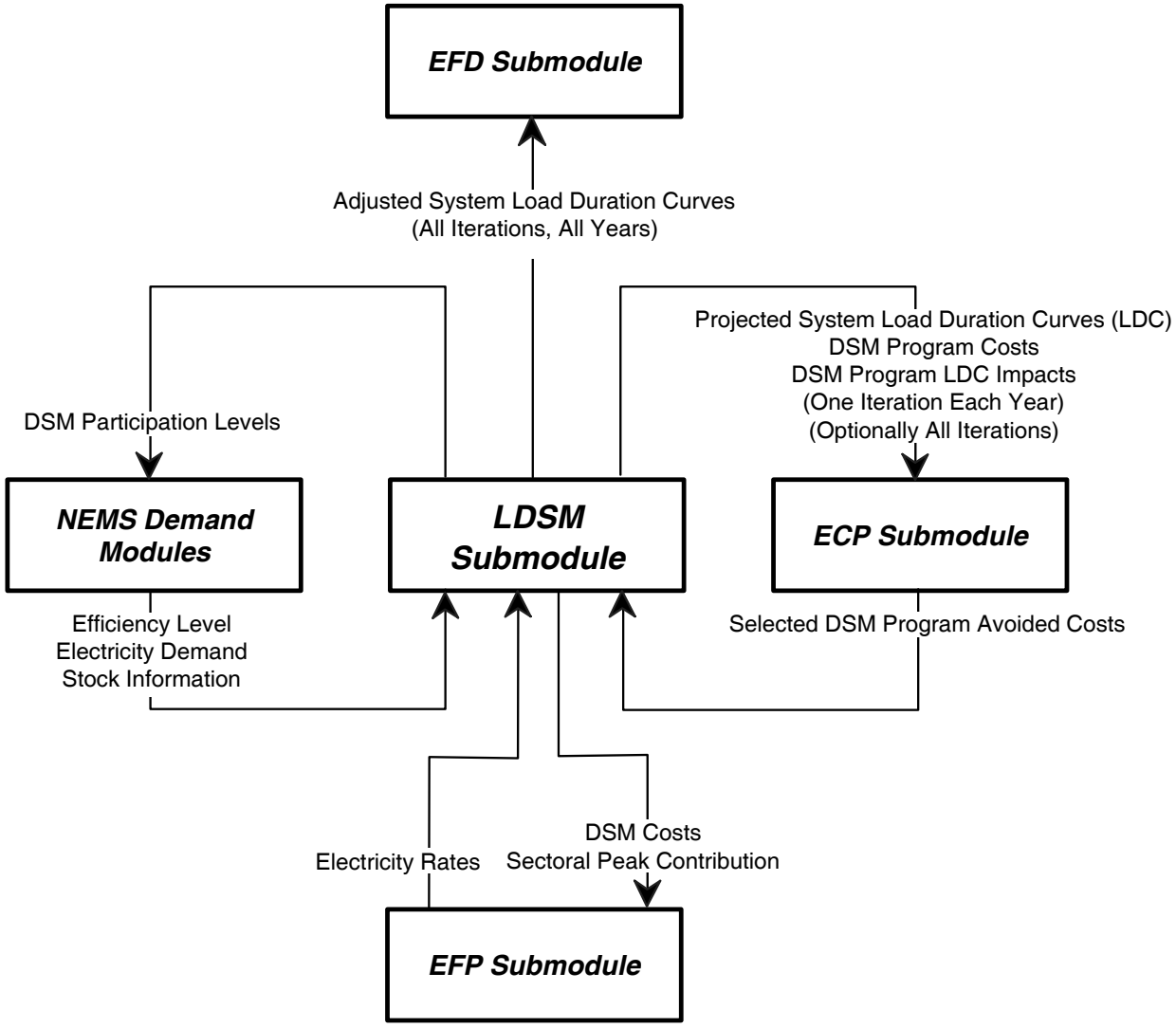


Table 1. LDSM Intra-Module Linkages

EMM Submodule	Inputs to LDSM from Submodule	Outputs from LDSM to Submodule
ECP	• Selected DSM Programs • Fraction of implementation of the selected programs • Avoided Costs	• Projected System Load Duration Curves • DSM Programs • Delta Load Impacts • DSM Costs (Equipment and Program) • Maximum Possible DSM Penetration
EFD		• Yearly Adjusted Regional System Load Duration Curves
EFP	• Electricity Rates	• Utility DSM Investment

Linkages with the Electricity Capacity Planning Submodule

Outputs

The outputs from the LDSM submodule to the ECP include:

- Projected Regional system load duration curves for each year in the ECP planning horizon
- Potential DSM programs, in aggregated form.

In each yearly iteration of NEMS, the LDSM obtains projections of yearly demand data from the NEMS demand modules. The demand modules produce Census Division estimates that the LDSM converts to EMM regions using the "fixed shares" method. In this approach, the percentage of each census division's load allocated to an EMM region remains fixed over time, for each of the sectors in the demand modules. (In other words, the Census division to EMM region mapping matrices do not change over time). Utilizing these forecasts, the LDSM develops system load shapes for each of the 13 EMM regions.

These annual system load data are then converted into seasonal, time of day load duration curves (LDCs), that are input to the ECP submodule. The LDSM allows for vast flexibility in the definition of the LDCs. Both the number of segments and the assignment of hours to segments are inputs to the model. Each LDC segment is discrete, and is associated with a time-of-day and seasonal definition. Individual LDCs are developed for each of the years represented in the ECP's planning horizon while just the current years LDC is used by the EFD.

In each yearly iteration of NEMS, the LDSM also develops DSM program options for each EMM region for possible selection by the ECP submodule. The LDSM actually develops aggregate program options which are combinations of individual options that fall into particular end-use categories. Representing individual options in the ECP would require a dramatic expansion of the model. Examples of aggregate DSM program option categories include space heating, space cooling, and lighting. For example, using the cost and performance of new heating equipment

from the Residential Demand submodule of NEMS the LDSM evaluates the costs and impacts of providing consumers an incentive to purchase more efficient equipment and combines the individual options into a residential heating option.The DSM programs that are passed to the ECP by the LDSM are combinations of individual options that have already passed the prescreening test. The California Total Resource Cost (TRC) test as used by the California Public Utility Commission (CPUC) in 1987, and an alternative test, the Rate Impact Measure (RIM) test are used by the LDSM. The TRC test compares the total customer direct costs of an option to the utility benefits of reduced demand and energy. The RIM test, designed to better represent DSM measures in the competitive market environment, tests options from the perspective of the electric utility. More details on the tests are given in later sections. The ECP selects the least-cost mix of resource options based on data on DSM, supply and renewable options. In effect, the DSM programs become "capacity" resources which are characterized by associated implementation and operating costs and which can be used to satisfy a portion of electricity demand in each load segment.

The specific DSM program data output to the current version of the ECP submodule are the following:

- **Potential DSM Impacts on LDCs.** These load duration curve impacts incorporate market penetration assumptions based on rebate levels, payback acceptance curves, and linear growth from current to maximum penetration levels.
- **DSM Costs.** Total utility DSM costs in present value terms, for each DSM program.[2]

Inputs

The LDSM receives three inputs from the ECP submodule:

- **Regional Avoided Costs**
- **Selected DSM Programs**
- **The Fraction** of the selected DSM programs that the ECP Submodule decides to implement in the next year, expressed as a value between 0 and 1.

These inputs are described below.

Key inputs to the LDSM are forecasts of regional avoided costs derived by the ECP submodule. These avoided costs are used to screen individual program options and from the aggregate DSM programs described above. These avoided costs, are based on the marginal cost of producing more electricity, in case DSM measures are not promoted, and electricity consumption increases as a result. In regions where there is surplus capacity, the marginal costs are only the variable operating costs, mostly fuel cost. However, in regions where new capacity needs to be built in

[2]These present value annual costs are the sum of DSM investment costs (i.e., initial program costs) and annual utility program costs, such as utility rebates and incentives.

order to meet growth in consumption, the avoided costs include the cost of building new capacity. Hence, avoided costs in those regions are larger. Avoided cost projections are needed for each future year and LDC segment.

After the ECP submodule chooses economic aggregate DSM programs, and the amount to be implemented expressed as a function of the maximum possible penetration of the market (if only a small amount of resources are needed the ECP may only partially implement a program), the LDSM processes the selected programs prior to passing participation levels to the NEMS demand modules, and utility DSM costs to the EFP submodule. The key function that the LDSM conducts after the ECP module is executed is to disaggregate the aggregated DSM programs into the more detailed individual DSM options. Tables A1 through A3 in Appendix II-A provide examples of aggregated DSM programs and individual DSM options that can be used in the LDSM submodule.

Linkages with the Electricity Fuel Dispatch Submodule

During each iteration of the NEMS model, the LDSM outputs regional LDCs to the EFD submodule.

Linkages with the Electricity Finance and Pricing Submodule

Outputs

If the ECP chooses to invest in DSM programs, this information is passed to the LDSM submodule. The LDSM translates this information from the aggregate program level to the individual program level and calculates the market impacts of these DSM options. This information is expressed as a fraction of the current market for different technologies, and is passed on to the demand modules by the LDSM. For example, the DSM program chosen may increase the share of market captured by high efficiency room air conditions from 5 percent to 10 percent and this information must be passed to the demand models. Based on current estimates of the market sizes, the demand modules estimate the new mix of technologies in the market, expressed in absolute numbers. These estimates are then returned to the LDSM.

Using this data, the LDSM develops utility costs (e.g., incentives, administration costs) incurred in each NERC region and demand sector. These program costs are output to the EFP submodule to incorporate into utility operating expenses and capital expenditures.

Inputs

In order to estimate of incentives (rebates) needed by consumers to make DSM investments attractive, the LDSM requires forecasts of customer electricity rates. These regional electricity rates are used to calculate the rebate needed to achieve a 2-year customer payback. This 2-year

payback criterion is based on standard utility practice, along with information derived from a survey of utility DSM programs. The survey was conducted by ICF Resources as a part of this project. Its primary function was to get a picture of actual DSM programs offered by utilities, as well as the level of costs incurred and incentives offered. The survey revealed that a 2-year payback criteria is used by many utilities in their DSM planning.

Example

Assume that in the New England EMM region, the LDSM submodule is designing a DSM program offering incentives on the purchase of more efficient refrigerators for existing households in the residential sector. The LDSM acquires the incremental cost and performance characteristics of the more efficient refrigerator from technology data used in the NEMS residential demand submodule. The LDSM then uses the regional electricity rates from the EFP to compute the rebate needed to enable the customer to recover costs over 2 years (i.e., a 2-year payback for the customer). If the program is selected by the ECP, the LDSM makes changes in the system load shapes and the LDCs, to reflect the reduction in refrigerator load as a result of the program, and passes the costs of the program to the EFP submodule, which then includes them as expenses in the appropriate category of the revenue requirements of the region.

Inter-Module Data Linkages

There are three key linkages between the LDSM with the NEMS demand modules. First, the LDSM transforms Census Division electricity demand projections from the demand submodules into EMM regional demand estimates. These estimates are then translated into system load shapes for use by the Electricity Capacity Planning (ECP) and Electricity Fuel Dispatch (EFD) submodules of the EMM module. Second, the demand submodules transfer and share information on technology characteristics (electricity usage and costs) and market size with the LDSM submodule. As electric technologies and usage patterns change over time, the demand modules transfer data conforming to these changes, to the LDSM submodule. The LDSM directly accesses the technology characteristics database for each demand module. Third, if the ECP submodule chooses economic DSM programs, the LDSM submodule translates program information into participation levels for the NEMS demand modules. The demand models transfer and share information about technology characteristics and market size with the LDSM. The LDSM accesses a technology characteristics database in each demand module.

Table 2 lists the linkages between the LDSM and the NEMS demand modules. Examination of this table and Figure 5 shows that the LDSM interacts closely with these other modules during NEMS model runs. Details about theses linkages are not discussed here because the DSM algorithms are not currently being used in NEMS.

Table 2. LDSM Inter-Module Linkages

NEMS Module	Inputs to LDSM from Module	Outputs from LDSM to Module
Residential Demand Module	• Unit energy consumption (UEC) and current stock data, by equipment type • Equipment investment and operating costs • Electric demand by region and end-use	• Participation Shares (share of stock) by Equipment and Efficiency Levels
EFP Commercial Demand Module	• UECs and current stock data, by equipment type • Equipment investment and operating costs • Electric demand by region and end-use	• Participation Shares by Equipment and Efficiency Levels

Model Overview and Rationale

Philosophical and Theoretical Approach

The regional, seasonal and time-of-day pattern of electricity use are critical information needed to properly plan and operate an electricity system. The pattern of usage will impact the types of capacity that can be economically developed and the fuels that will be used to generate electricity. It is for these reasons that the LDSM has primarily been developed to translate the annual electricity demand values generated by the NEMS demand modules into the regional, seasonal, and time-of-day patterns needed by the EMM.

Secondarily, the LDSM was also been developed to allow the EMM to consider demand reduction options when they made economic sense.[3] Over the last 10-20, years many state and local governments, as well as utilities have sought ways to reduce the need for new generation sources, by modifying the ways in which electricity is used in the country. Most state commissions now require that utilities review all possible options, including DSM, in their plans to meet consumer demand. Traditionally, several supply options are competed against each other when planning new generating capacity. However, DSM measures focus on individual end-uses

[3]The algorithms within the LDSM representing utility-sponsored DSM programs have not been updated in recent versions of the model, and they would require significant work before they could be used. Utility expenditures on these programs have been declining in recent years, and it is felt that their impact is adequately captured in the efficiency trends seen in the NEMS demand models.

or appliances, while generating capacity must be planned on the basis of aggregated demand and supply estimates. In order to allow DSM measures to compete against supply options, therefore, both demand and supply-side options must be expressed in terms that are comparable. The LDSM submodule follows such an approach.

Representing DSM Options

To represent demand reduction options, the LDSM has a database of DSM options in the residential and commercial sectors. The option database contains individual DSM options that map a "baseline" technology to a "DSM" technology. The baseline technology consumes more energy or else is characterized by a less economical pattern of energy usage over a 24 hour period, than the DSM technology. The energy savings resulting from the replacement of one unit of "baseline" technology with one unit of DSM technology are represented as delta load duration curves. Each linearly approximated curve consists of a predetermined number of segments representing the different seasons and times-of-day, with each having different avoided costs.

The cost of energy saving is then compared against the LDC block specific avoided costs of electricity production for that region. These avoided costs are obtained from the ECP submodule of the EMM. Using criteria in the form of the Total Resource Cost (TRC) test or alternatively the Rate Impact Measure (RIM) test, all DSM options are pre-screened inside the LDSM submodule. Only those options that pass the test are developed further. Hence it is assumed that only those DSM measures whose cost of energy savings compares favorably with the avoided cost of electricity production, would be promoted by a utility.

For each successful DSM option, the DSM technology must then be "penetrated" into the market depending on the existing market share of the base and DSM technologies in the years over which the DSM program is offered. The market shares for the different technologies prior to implementing DSM programs are obtained from the respective demand modules (residential or commercial) and then revised market shares are passed to the demand modules if the ECP selects DSM programs for implementation.

These options are then aggregated into DSM programs. The energy savings accruing from these programs and the associated program costs on a regional level, are then passed on to the ECP submodule for competing against supply side options. The DSM programs finally chosen as a result of this competition in the ECP submodule are then transferred back to the LDSM submodule where they are disaggregated into individual DSM options. Once this is done, the resulting changes in stock are computed, aggregated to the appropriate census division level, and passed on to the respective demand modules. In this manner, the LDSM submodule uses DSM measure information at the level of individual appliances, and combines it with aggregated demand and avoided cost information, in order to produce DSM programs that can be competed against supply side options. The final choice of DSM programs is made by the ECP submodule, and is then translated into changes in stock, which are executed by the demand modules.

Fundamental Assumptions

There are several implicit assumptions about DSM activities that have been made in the model design. First, the database of technologies used by the LDSM submodule for the residential and commercial sectors assumes that these technologies are available throughout the U.S. at costs that are comparable (See Tables 4 and 5 at the end of this chapter for list of technology options. For cost and performance characteristics of these technologies see the documentation for the Residential and Commercial submodules). The model makes inherent assumptions about the commercial availability of energy efficient appliances in the future. The dates when these appliances will become available, their estimated capital and maintenance costs, as well as efficiencies are assumed inside the joint technology database.

Second, the model chooses the TRC or the RIM test for the pre-screening of DSM options. The general concept of the tests is that only the options with sufficiently high ratios (the actual ratios used can be specified by the user) of economic benefits to costs are accepted. The annual benefits are calculated as the sum of the products of energy savings times the avoided costs of meeting the demand. In the TRC test, the costs include the incremental costs of purchasing of the appliances and the administrative costs of implementing the option. However, using the RIM test, the costs include the revenue losses due to DSM implementation, administrative costs of implementing the option, and the cost of incentives paid to the participants. Both the benefits and the costs are appropriately discounted and summed over the entire technical life of the affected equipment. It is assumed that these tests are the two preferred test criteria used by utilities across the country in assessing the financial viability of their DSM programs, and that only financially viable DSM programs are promoted by utilities. As a possible exception to this rule, in the future, the model may have the provision for hardwiring some DSM programs as "must run" programs mandated by state governments and utility commissions.

The last assumption relates to the aggregation and disaggregation of individual DSM options, into DSM programs. When the ECP submodule chooses a fraction of a DSM program- say 10 percent, it is assumed that 10 percent of each DSM option in the aggregate program is implemented.

Model Structure

The three primary functions of the LDSM submodule are to (a) develop regional system load duration curves from demand estimates for the ECP and EFD modules, (b) screen potential DSM options for analysis by the EMM Capacity Planning module, and © supply the demand modules with feedback from the ECP concerning the shifts in end-use technology resulting from the optimal choice of DSM options. In addition to these three functions, the LDSM also translates the 9 Census division electricity demand estimates into the 13 NERC regions and subregions that the EMM requires.

The LDSM submodule is designed to simulate the DSM planning efforts at electric utilities. Furthermore, the LDSM will provide the bridge between demand forecasting and utility resource planning. For each yearly iteration, the demand models provide the integrating module with the total electricity demand by region for the current year, along with demand by end-use, building type and technology type. This information identifies the size of the potential market for utility-sponsored DSM programs. Naturally occurring customer-driven energy efficiency changes are modeled by the demand models and serve as input into the DSM market penetration estimation procedure. Central to the question of naturally occurring efficiencies versus DSM induced efficiencies, is the issue of free riders, i.e., what proportion of DSM customers would have shifted to more efficient technologies even in the absence of DSM programs. Later sections touch upon this issue in more detail, since assumptions about free ridership play a big role in the cost effectiveness of a DSM program.

The Integrating Module also obtains forecasts of future electricity demand from the demand modules by end-use, building type and technology type. These forecasts are used by LDSM in developing system load shapes for the ECP submodule and for projecting DSM market penetration. The development and screening of DSM programs is conducted by LDSM. Actual choice of DSM programs as part of future utility resource plans is made by the ECP submodule.

Figure 6 displays the sequence of tasks that LDSM conducts during each yearly iteration of the NEMS model. These tasks include:

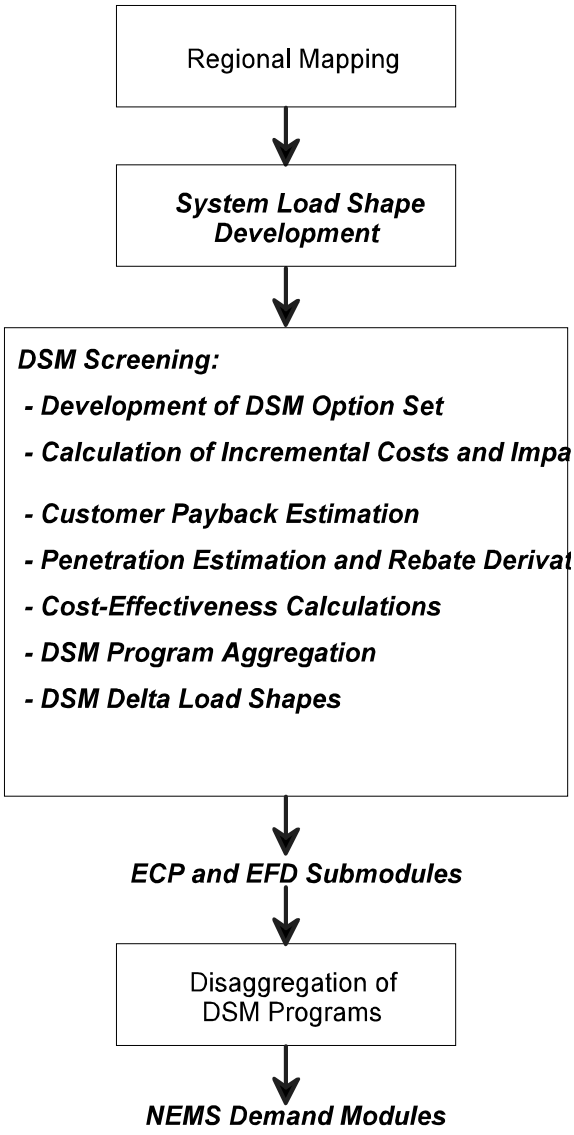
- Mapping of Census Region Demand Estimates into EMM Regions
- Development of System Load Shapes
- Screening of DSM Options
- Computations of the DSM load impact curves and program lifetime costs
- Computation of sectoral peak loads necessary for the ECP module calculations
- Disaggregation of Selected DSM Programs
- Computation of the annual expenditures of utilities on DSM programs

This section summarizes the approaches to accomplish these tasks within the LDSM. The subsections that follow discuss each of these tasks in order.

Mapping of Demand Estimates into EMM Regions

One of the functions of the LDSM submodule is to provide the interface for demand data between the NEMS demand modules and the EMM module. This component conducts two tasks. The first task is the translation of the sectoral demand estimates that are produced by 9 Census divisions within the NEMS demand modules into the 13 EMM Regions. Secondly, the LDSM will need to translate any DSM programs impacts back into the Census Divisions in the form of percentages of available market that has to be subjected to the technology shifts.

Figure 5. LDSM Tasks



Development of System Load Shapes

This section describes the methodology used to construct electric utility load curves in the LDSM. The end result of these calculations is the seasonal and annual load duration curves for each of the 13 EMM regions. The overall methodology can be described as consisting of two steps:

- Step 1: Forecasting regional chronological hourly loads for each hour of the year
- Step 2: Sorting Hourly loads to produce load duration curve representations for ECP and EFD.

Both of these steps are divisible into smaller sub-parts, and these are described in detail below.

Forecasting Regional Chronological Hourly Loads. The LDSM submodule develops 8760 hour system load curves to reflect different appliance usage patterns (e.g., space heating demands may be higher at certain hours, while at other times the water heating load may dominate the LDC). Investments in different utility demand side management programs, will similarly yield nt results that vary by season and time of day. The impact of energy efficiency improvement type DSM options is already incorporated in the analysis, through appliance stock adjustments, accomplished by the demand forecasting modules. In constructing and modifying these curves, the LDSM uses a combination of load shape data from various sources and historical load shape data collected by the North American Electric Reliability Council (NERC).

Many utilities use such chronological hourly load shapes (load profiles) to predict their customers' demand patterns. The hourly system load curves are developed by these utilities from the bottom up by adding together the hourly loads of individual end-uses - i.e., refrigerator, air conditioners, ect - or classes of end-uses. To do this the utilities must have information about the technologies and usage patterns of their customers. At a national level, however, the building of such load shapes can present significant data problems. At present, the end-use load shape data readily available for this effort, are not of sufficient quality to allow for the construction of system load shapes from the ground up. In other words, when the load shapes for each end-use are summed together, the resulting system load curve does not closely replicate the actual curve system for which data is available. This may be because the end-use load curves do not conform to the actual usage pattern in the region or there is significant load diversity (i.e., for example not all refrigerators in an area follow the same usage pattern). Efforts are underway, which will make better quality data available in coming years. One example is the new Central Electric End-use Data (CEED), run by the Electric Power Research Institute (EPRI), whose purpose is to collect, catalogue and disseminate such information. The LDSM will take advantage of such information as it becomes available.

There are two different approaches used within the LDSM model for the forecasting of hourly loads, namely, the Basic Approach and the Delta Approach. In the Basic Approach (that is the more intuitive one), hourly loads for each individual end-use are calculated and then summed to yield the system hourly loads. In the current version of the code, this approach is used for the

development of the DSM Program Load Impact Curves and the demand sector load curves (which are necessary for finding the sectoral peak loads that are required by the EFP model).

In the Delta Approach, the starting point is a historical hourly load curve of the system (or other aggregate of end-use loads) observed in a chosen base year. This curve is then modified using the end-use load shapes in case the contribution of the end-uses has changed since the base year.

Basic Approach: The basic algorithm can be thought of as an end-use building block approach. The system demand is divided into a set of components called end-uses. The hourly loads for each end-use are forecast. Next the hourly loads of each end-use are summed to yield the forecast of system load at the customers' meter (i.e., hourly system sales). The final step is to simulate transmission and distribution losses. The regional hourly loads are calculated as the sum of hourly system sales and transmission and distribution losses. Each of these sub-steps is described below.

Computing End-Use Hourly Loads—In calculating the hourly loads for an end-use, the LDSM requires two major inputs:

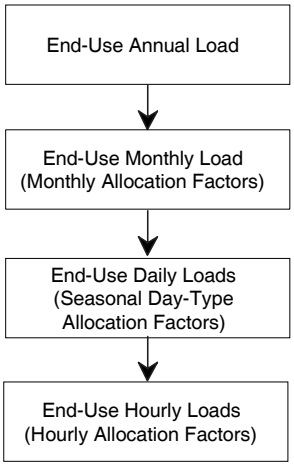
- annual sales forecast
- typical load shapes that allocate end-use annual load to each hour in a year.

The annual sales forecast is determined endogenously in NEMS. The annual sales forecast for each of the base end-uses is passed to the LDSM from the NEMS demand models. The typical load shapes for each end-use are an exogenous input to LDSM. Typical load shapes are input by month and by day-type (peak day, week day, and week end).

The first stage in the development of end-use hourly loads is to prepare, for each end-use, a normalized hourly load profile. This is a one time procedure for the entire NEMS analysis, and so it was put into the LDSM submodule's pre-processor, LSRDBMGR. Computing end-use normalized, hourly load profiles from the end-use inputs is a three step process. Figure II.3 gives a flowchart of the three steps. All three steps utilize data that are supplied on a standardized load shape representation (LSR) file. Each LSR file contains a complete set of data describing a single end-use. The LSRs in the current version of the LDSM come from the RELOAD database.

The first step is to map the annual sales forecast into a set of monthly sales forecasts. This is accomplished based on a set of exogenous input monthly allocation factors. The monthly allocation factors are a set of weights assigned to each month. These weights inform the LDSM submodule of the relative energy usage from month to month. For example, the input data could assign January the weight of 1.0, and if February uses 20 percent more energy then its weight would be 1.2. Similarly, if September's usage was 15 percent less, its weight would be 0.85. In this way the inputs can define the relative energy usage from month to month. Another way of

Figure 6. Steps in the Computation of End-Use Hourly Loads



assigning weights is to define the annual energy usage as 100 percent. Then each month's weight is given by its percentage contribution to the annual load. Thus, if 20 percent of the annual load is used during January, its weight could be 20 and then if September is responsible for only 5 percent of annual energy usage its weight would be 5.

The second step of the conversion is to allocate monthly loads to daily loads. This is done in a similar construct as that by which annual load is assigned to monthly load allocations. It is accomplished with a set of day-type allocation factors which specify the relative energy use for each day type. All days within a month assigned to a given day-type are assumed to have the same load.

The third and final step in the conversion is to divide each day's load into a set of hourly loads for that day. This is done in the same manner as annual load is allocated to monthly load. The only difference is that the hourly allocation factors (sets of these factors are referred to as 24-hour load shapes in the data input file) are provided based upon season and day-type. Thus, instead of providing a set of allocation factors for each day of the forecast year, or only one set that applies for every day in the year, the user can provide a 24-hour load shape for each combination of season and day-type in the forecast year. Therefore, when dividing the daily load into hourly load, the relative energy usage ratios are selected based upon the day-type the day is assigned to and the season to which the month the day falls into is assigned.

It is the complete set of hourly loads that describes the load shape of the end-use. Thus, these computational techniques must be applied to each hour within each day within each month in the forecast year as they are defined in the calendar file. The exact computations performed during each of these three steps is discussed below. The vectors used in the transformation of annual demand in to hourly demand were developed through analysis of historical data.

Allocation of Annual Load to Monthly Load—Allocation of annual load to monthly loads is accomplished in a two step process described below. Since the monthly allocation factors supplied in the LSR files may not be normalized, first, the normalization factor is computed. Second, this normalization factor is applied to each monthly allocation factor. This yields the percentage of annual load assigned to each month.

The normalization factor is computed by summing the monthly allocation factors for each month. Therefore,

(2-1) $$DMNF = \sum_{m=1}^{NM} DMAF_m$$

Where:

DMNF	=	the normalization factor for monthly allocation
NM	=	the number of months in the forecast year
$DMAF_m$	=	the monthly allocation factor for month m (input)

Next this normalization factor is used to normalize the monthly allocation factors. Therefore,

(2-2) $$DNMAF_m = \frac{DMAF_m}{DMNF}$$

Where:

$DNMAF_m$	=	the normalized monthly allocation factor for month m
$DMAF_m$	=	the monthly allocation factor for month m
DMNF	=	the normalization factor for monthly allocation

Allocation of Monthly Load to Daily Load—Allocation of monthly load to daily load is accomplished by performing a weighted normalization on the daily allocation factors. The daily allocation factor set (an allocation factor for each day-type) is selected based upon the season to which the month is assigned. A daily load amount is computed for each day-type. This daily load is the load for every day in the month of that day-type. The allocation factors represent relative energy usage on a typical day of each day-type. The weighted normalization is performed using the number of days assigned to each day-type as weights.

There is a set of daily load allocation factors input for each season of the year. These are computed from the LSRs. Each seasonal set includes an allocation factor for each day-type in that season. The different months are allocated to different seasons, and the corresponding seasonal set is used to allocate the daily load to the different day types in the month. Thus, the set of daily allocation factors used, vary by season though the computations will be performed for each month. Hence, more than one month may use the same set of allocation factors, if they are assigned to the same season.

The weighted normalization of daily allocation factors is accomplished in three computations. First, the weighted daily allocation factors are computed as follows:

(2-3)
$$DWDAF_{mt} = (ND_{mt} \times DDAF_{mt})$$

Where:
$DWDAF_{mt}$ = the weighted daily allocation factor for day-type t in month m
ND_{mt} = the number of days in month m that are assigned to day-type t
$DDAF_{mt}$ = the daily allocation factor for day-type t in month m (input)

Then the normalization factor is computed as the sum of these weighted allocation factors. Therefore,

(2-4)
$$DDNF_m = \sum_{t=1}^{NDT} DWDAF_{mt}$$

Where:
$DDNF_m$ = the normalization factor for daily allocation in month m
NDT = the number of day-types
$DWDAF_{mt}$ = the weighted daily allocation factor for day-type t in month m

Finally, the normalized allocation factor (percent of monthly allocation) for each day-type is computed by dividing each daily allocation factor by the normalization factor. Therefore,

(2-5)
$$DNDAF_{mt} = \frac{DDAF_{mt}}{DDNF_m}$$

Where:
$DNDAF_{mt}$ = the normalized daily allocation factor for day-type t in month m
$DDAF_{mt}$ = the weighted daily allocation factor for day-type t in month m
$DDNF_m$ = the normalization factor for daily allocation in month m

The last step is to combine these normalized daily allocation factors with the monthly allocation factors. This is accomplished by multiplying the daily normalized allocation factors times the monthly normalized allocation factors.

(2-6)
$$DDTL_{mt} = DNDAF_{mt} \times DNMAF_m$$

Where:
$DDTL_{mt}$ = fraction of the annual load allocated to each day assigned to day-type t in month m
$DNDAF_{mt}$ = the normalized daily allocation factor for day-type t in month m
$DNMAF_m$ = the normalized monthly allocation factor for month m

Allocation of Daily Load to Hourly Load—Allocation of daily load to hourly loads is accomplished by normalizing the hourly allocation factors (each set of hourly allocation factors is referred to as a 24-hour load shape) and combining the result with the daily allocation of load. This can be broken down into a three step process. First, the normalization factor is computed. Next, this normalization factor is applied to each hourly allocation factor. This yields the percentage of daily load assigned to each hour. Finally, these hourly allocation percentages are multiplied by fractions of total annual load allocated to each day, thus yielding fractions of annual load allocated to each hour of the year.

A set of hourly load allocation factors (24-hour load shapes) is supplied on an LSR file. There is one set input for each combination of season and day-type, and each set includes 24 hourly allocation factors. The set that is used for each day is the one for the day-type to which the day is assigned and the season to which the month the day falls into is assigned. Note that although the equations presented in this section refer to information that varies by month and day-type, the actual information input by the user varies by season and day-type, respectively.

The normalization factor is computed by summing the hourly allocation factors for each hour of the day. Therefore,

(2-7)
$$DHNF_{mt} = \sum_{h=1}^{24} DHAF_{mth}$$

Where:

$DHNF_{mt}$ = the normalization factor for hourly allocation for day type t in month m

$DHAF_{mth}$ = the hourly allocation factor for hour h of day type t in month m

Next this normalization factor is used to normalize the hourly allocation factors. Therefore,

(2-8)
$$DNHAF_{mth} = \frac{DHAF_{mth}}{DHNF_{mt}}$$

Where:

$DNHAF_{mth}$ = the normalized hourly allocation factor for hour h of day type t in month m

$DHAF_{mth}$ = the hourly allocation factor for hour h of day type t in month m

$DHNF_{mt}$ = the normalization factor for hourly allocation for day type t in month m

Finally, each normalized hourly allocation factor is multiplied by the fraction of annual load, allocated to a given day, yielding a fraction of annual load allocated to each hour. Thus,

(2-9)
$$DHL_{mdh} = DNHAF_{mth} \times DDTL_{mt}$$

Where:

DHL_{mdh} = fraction of annual load allocated to hour h of day d in month m
$DNHAF_{mth}$ = the normalized hourly allocation factor for hour h of day type t in month m
$DDTL_{mt}$ = fraction of the annual load allocated to each day assigned to day-type t in month m

Finally the normalized hourly load profile is given as:

(2-10) $$\{DHL_{mdh} \text{ such that } m = 1,2,...NM;\ d = 1,2,...ND_m;\ h = 1,2,...24\}$$

Where:

DHL_{mdh} = fraction of annual load allocated to hour h of day d in month m
NM = the number of months in the forecast year
ND_m = the number of days in month m of the forecast year

Such a set of values is developed from the LSR files by the LSRDBMGR preprocessor for each end-use, and stored on the direct access file. Each record on the file defines hourly distribution of annual load for one end-use. To speed up computations, the LDSM model refers to the values on each record using the hour-in-the-year index as explained below.

(2-11) $$DistLo = DHL_{mdh}$$

Where:

DistLo(H) = fraction of annual load allocated to hour H of a year
DHL_{mdh} = fraction of annual load allocated to hour h of day d in month

Combining End-Use Load Shapes—The second sub-step of the methodology is to combine the end-use hourly load shapes into one system load shape for the forecast year. The combination of end-use hourly loads is accomplished by an hour-by-hour summation over the forecast year. This procedure is conducted for each EMM region as follows:

(2-12) $$SYLOAD(H) = \sum_{e=1}^{NUSES} DistLo_e(H) \times load_{1e}$$

Where:

SYLOAD(H) = system load in hour H
$load1_e$ = annual load forecast for end-use e (1 stands for base type approach)

Simulating Transmission and Distribution Losses—The system load shape calculated above is the sum of hourly sales for each end-use (i.e., lighting, heating, refrigeration, etc.). Thus, it is the hourly sales for the system. The EFD and ECP require hourly generation requirements, not hourly sales. The final step is to increase the hourly system load requirements by the fraction of generation lost on transmission and distribution which was estimated through analysis of historical data.

In LDSM, this is accomplished by multiplying the hourly load values in the EMM region system load curves by the exogenously defined transmission and distribution loss factor. Since the values are supplied on the input by EMM region and then are applied to the EMM regional loads, no mapping of the multipliers from Census to EMM regions is required.

A transmission and distribution loss factor represents an average of an EMM region's percentage of energy lost during transmission and distribution. The values of those factors are quite stable at a regional level because they reflect the efficiency of a transmission and distribution network as a whole. Unless considerable changes in voltages and distances of transmission take place they do not change significantly. Therefore, those factors are modeled in LDSM as fixed for the entire planning horizon.

Modification to the Basic Methodology: The purpose of this section is to describe and demonstrate an alternative formulation of system load shape forecasting which allows the LDSM to take advantage of the initial system data base, yet still produce reasonable forecasts. This approach is termed the Delta Approach.

The essence of the Delta Approach is to introduce a new end-use into the data base. This end-use is the current utility system load for which actual load data is available. Load shape information for this "end-use" will be historical system hourly loads. The resulting hourly load forecast of this formulation is a shape which in the early forecast years is very similar to current observed shapes. Over time the shape will change in response to changes in end-use mix.

The delta approach is represented by the following formula:

(2-13) $$SYLOAD(H) = DistLo_s(H) \times SystemLoad + \sum_{e=1}^{NUSES} DistLo_e(H) \times load_{2e}$$

Where:

SYLOAD(H)	=	system load in hour H
$load2_e$	=	difference between the end-use e's annual energy consumption in the current year and the base year ("delta" approach — positive or negative value)
SystemLoad	=	base year total system load
$DistLo_e(H)$	=	hourly end-use load shapes
$DistLo_S(H)$	=	historical hourly system load shape
NUSES	=	number of end-uses
s	=	system

Note: If all data on load shapes were perfect this would give same answer as basic approach, but as explained previously the end-use load shape data are not of sufficient quality for this to be true.

While:

(2-14)

$$Load_{2e} = load_{1e} - BaseYrLd(e, RNB)$$

Where:

BaseYrLd(e,RNB) = base year load for end-use e in EMM region RNB

$load1_e$ = current year load for end-use e

$load2_e$ = difference between the end-use's annual energy consumption in the current year and the base year ("delta" approach — positive or negative value)

Development of Load Duration Curves for the ECP and EFD Modules

Load Duration Curves (LDCs), are used by both the ECP and the EFD Modules. An LDC consists of a discrete number of blocks. The height of each block gives the forecasted load, and the width represents the number of hours with that specified load. Summing the widths of all blocks in the LDC gives the total number of hours in the year. However, due to the differing needs of the ECP and EFD modules, the LDCs created for each of these modules, differ. The sections below describe the specific steps used to develop the LDCs.

Load Duration Curves for the ECP Module

Demand for electricity is input to the ECP module by means of approximated LDCs, specified for each of the 13 EMM regions. Both the number of blocks, and the assignment of hours to blocks is specified as input data to the program. The larger the number of blocks used the more accurate the representation of the continuous load curve. However, as the number of blocks is increased the size and execution time of the model increases dramatically. Typically analyst judgement is used to select the minimum number of blocks needed to reasonably represent the load faced by electricity suppliers.

The assignment of hours to blocks is completed in two steps. In each step, a different sorting criteria is followed. In the first step, the 8760 hours that make up a year are assigned to a number of "segments" defined by month, day-type, and time of day, and then, hours within each segment are arranged in descending order of load. In the second step, each segment is divided into a number of "blocks." Each block has a specified percentage of the hours assigned to that segment. Two types of blocks are allowed: "regular" blocks, and "peak" blocks. The height of a regular block is equal to the average load of hours assigned to that block, while the height of a peak block is equal to the highest hourly load for hours assigned to that block.

The width of each block is equal to the number of hours in the block. The area of a regular block represents the energy demand during the hours assigned to it. The area of a peak block slightly overestimates the actual load during the hours assigned to the block. However, for narrow peak blocks, the error in approximation is not very significant. The advantage of this approach is a precise representation of the peak load. To ensure that the total energy represented by the approximated LDC curve equals the regional demand, the excess energy in the peak blocks is evenly subtracted from the regular blocks. In the final step, all of the blocks from the segments are sorted in descending order.

Load Duration Curves for the EFD Module

LDCs for use by the EFD module, are created for each season and for each of the 13 EMM regions. The steps involved in their creation are exactly the same as in the case of the ECP LDCs. The only difference is that the process is performed for each season separately.

DSM Screening

The purpose of this component is to simulate utility DSM planning processes.[4] The design of DSM programs and the evaluation of program cost-effectiveness is a specific and separate electric utility task. Within a utility, forecasting personnel develop estimates of market size and composition and system planning personnel develop future resource plans. The LDSM maintains this separate structure.

The DSM Option Screening component simulates the DSM planning process by conducting the following tasks:

- Development of set of potential DSM options
- Calculation of incremental costs and impacts associated with DSM options,
- Calculation of simple customer payback
- Estimation of market penetration and rebate levels
- Calculation of DSM option cost-effectiveness, and
- Aggregation of cost-effective DSM options into DSM program categories.

The output of this component is a set of DSM programs that are characterized by total utility cost and load shape impact in LDC format. These outputs for each aggregated DSM option are used in the ECP submodule to select future resources. The following sections describe the steps that are performed in the DSM option screening component of the LDSM.

Development of DSM Option Set

The first task in the DSM Option Screening component of LDSM is to identify and specify potential DSM options for each EMM region and for future time periods. The set of options applicable in any particular year are determined jointly by characteristics of standard and efficient electric technologies shared with the demand models, the LDSM and the set of DSM options specified. This set can be adjusted and modified to reflect alternative DSM scenarios.

A DSM option is the most disaggregated unit of a DSM program. An option maps a baseline level technology to a more efficient technology. At a minimum, the following set of information is used to define a DSM option:

- Customer sector
- Baseline technology
- Efficient technology

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[4]The algorithms within the LDSM representing utility-sponsored DSM programs have not been updated in recent versions of the model, and they would require significant work before they could be used. Utility expenditures on these programs have been declining in recent years, and it is felt that their impact is adequately captured in the efficiency trends seen in the NEMS demand models.

- First year option is available
- Ramp-up Period
- Administration costs
- Market: new, existing

The LDSM options database uses the same technologies used in the demand models. For example, a central air conditioner rebate program that promotes high efficiency air conditioners uses the existing stock as the base technology and a higher efficiency unit as the DSM technology.

The first year that the technology is available defines the window of opportunity over which DSM programs can offer options relating to that technology.

Incremental Impacts

The first task in the DSM Option Screening component is the development of the incremental cost and load impacts for each DSM option. These incremental impacts are derived from the base and DSM technologies defined in the end-use technology database. These impacts are used to calculate customer payback, derive rebate levels, and technology penetration levels.

Incremental energy impacts associated with a DSM option is determined on a per unit basis. These energy impacts are referred to as usage indices (UIs). For example, residential impact is measured as a change in unit energy consumption (UEC), measured in kWh/yr., in moving from base technology 1 to efficient technology 2. Commercial impacts are measured in terms of electric usage indices (EUI), in kWh/unit of service demand/yr. This incremental energy impact is calculated as follows:

(2-15)

$$EI_{dir} = UI_{1dr} - UI_{2dr}$$

Where:

EI_{dr} = incremental energy change for option d in region r
UI_{1dr} = usage index for base technology 1 in region r associated with option d
UI_{2dr} = usage index for efficient technology 2 in region r associated with option d

Incremental cost (IC) options are derived by comparing the equipment and maintenance costs associated with the base and DSM technology in the database. If the DSM option is focused on replacing existing equipment, the full costs of the DSM technology are used as the incremental costs. If the DSM option is focused on influencing normal replacement decisions, then the incremental cost is the difference in costs between the base and DSM technologies. Incremental costs have two components, one based on capital costs and the other on maintenance costs per unit (e.g., per refrigerator, or per square foot). Maintenance costs include any ongoing labor or expenditures required to keep equipment operating. The cost of electricity consumed to operate the equipment is not included. Mathematically:

(2-16)

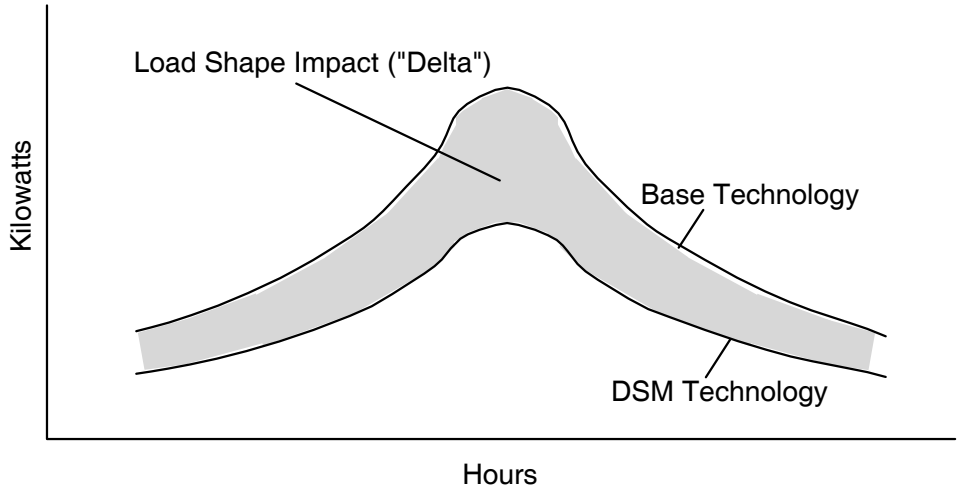
$$ICC_{dr} = TCC_{1r} - TCC_{2r}$$

Where:

ICC_{dr}	=	incremental customer capital costs for DSM option d in region r
ICO_{dr}	=	incremental customer maintenance costs for DSM option d in region r
TCC_{jr}	=	technology capital cost for technology j (= 1 or 2) in each region r
TCO_{jr}	=	technology maintenance cost for technology j (= 1 or 2) in each region r

The incremental demand and energy impacts for options is captured through the use of "delta" load shapes. Delta load shapes represent the difference in electricity consumption by time of day, between use of the base technology and the DSM technology. In this version of the LDSM, load shapes for base and DSM technologies are based on default end-use load shapes and represent unit shapes that can be scaled according to total impact. Though several alternative load shape sources exist, the EPRI RELOAD library, of load shapes forms the basis of the LDSM load shapes. The height and peak impact of each load shape will be derived by scaling the default load shape to the total electricity consumption associated with yearly market penetration. Figure 7 graphically displays the development of delta load shapes for each DSM option.

Figure 7. Development of Delta Load Shapes



Delta LDCs are developed for each DSM option, in a fashion similar to system load duration curves. Thus a delta load duration curve, denoted by LDC_{dlry}, is defined in megawatt equivalents for DSM option d, load segment l, region r, and year y. For example, the value of LDC_{dlry} for efficient central air conditioners for summer daytime may be 100 megawatts for region r in year y.

Payback Estimation

The first step in determining customer acceptance of DSM options and technologies is to calculate simple payback associated with DSM options without any financial incentives from utilities. Simple payback is derived using the following formula:

(2-17)
$$PB_{ydr} = \frac{ICC_{dr}}{(SV_{yrd} \times ER_{yr}) - ICO_{dr}}$$

Where:

PB_{ydr}	=	payback period in years for DSM option d starting in year y in region r.
SV_{yrd}	=	megawatt-hours of savings for option d in region r for program starting in year y
ER_{yr}	=	electricity rates per-megawatt-hour equivalent in region r for year y
ICC_{dr}	=	is incremental customer capital costs for DSM option d in region r
ICO_{dr}	=	is incremental customer maintenance costs for DSM option d in region r

Electricity rates for year y are input from the EFP submodule.

Penetration Estimation and Rebate Derivation

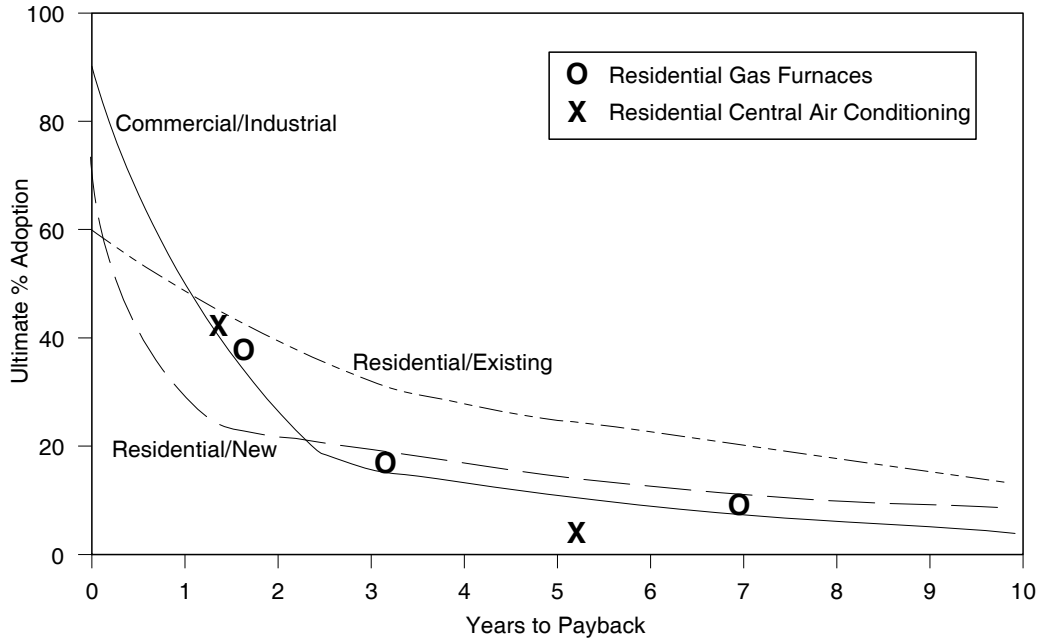
Development of projections of market penetration and customer participation in utility energy efficiency DSM programs requires detailed information on market characteristics, customer response to DSM programs, and forecasts of future penetration of efficient DSM technologies. In addition, market penetration is related to the level of incentives (e.g., financial rebates) offered by utilities. The LDSM simulates the penetration estimation function for each forecasted future year. This portion of the screening task will (a) develop estimates of maximum market penetration achievable for DSM technologies and the annual participation levels expected, and (b) derive rebate levels.

To estimate the maximum penetration of the market by the DSM option, a payback acceptance curve approach is used. This approach has been used by A.D. Little (1990), and has been incorporated into DSM Screening models such as Synergic Resources Corp.'s COMPASS and EPA's EGUMS model. As is shown in Figure 8, this approach derives projections of cumulative market penetration from the calculated payback of a DSM option, and differs by customer sector. For example, review of this figure indicates that a commercial DSM option with a 4 year payback would achieve approximately 10 percent of the commercial market. Through variations in financial incentives and rebates, market penetration can be varied.

During operation, LDSM will follow a four step process. First, LDSM will calculate the rebate level for each DSM option that is necessary to achieve a two (2) year payback. If a DSM option already has less than a two year payback, a rebate is not calculated for the option. The choice of a two year payback level was based on general utility practice. This rebate derivation will be achieved with the following equation:

(2-18)
$$\frac{ICC_{dr} - RB_{dr}}{(SV_{yrd} \times ER_{yr}) - ICO_{dr}} = 2$$

Figure 8. Payback Acceptance Approach



for $0 \leq RB_{dr} \leq ICC_{dr}$

Where:

ICC_{dr}	=	incremental customer capital costs for DSM option d in region r
ICO_{dr}	=	incremental customer maintenance costs for DSM option d in region r
RB_{dr}	=	Rebate level necessary to achieve a 2 year payback in region r for option d
SV_{yrd}	=	megawatt-hours of savings for option d in region r for program starting in year y
ER_{yr}	=	electricity rates per-megawatt-hour equivalent in region r for year y

Second, the maximum market penetration of the DSM technology ("TO" technology), MP_{ydr}, associated with option d in region r that begins in every year y is simply read from the payback acceptance curve.

Third, yearly cumulative participation for each option is calculated as a linear function from current market penetration to maximum market penetration, expressed as a percentage of the available market. Current market penetration of efficient technologies will be derived from the stock data supplied by the demand modules by technology region and year. The participation arithmetic will be conducted with the following set of equations. Total potential market size

TM_{dry} for a DSM option d[5] in region r for program starting in year y is calculated by:

(2-19)
$$TM_{ydr} = (CM_{y1dr} + CM_{y2dr}) \times MP_{ydr} - CM_{y2dr}$$

Where:

TM_{ydr} = total potential market size for DSM option d[6] in region r year y
MP_{ydr} = maximum market penetration of the DSM technology ("TO" technology), associated with option d region r year y
CM_{y2dr} = current market size for region r for efficient technology 2 associated with option d in year y
CM_{y1dr} = current market size for region r for base technology 1 associated with option d in year y

Annual maximum participation level AP_{ydr} in region r for option d for year y will be calculated with the following equations:
during the ramp-up period:

(2-20)
$$AP_{ydr} = TM_{ydr} \times \frac{(y_d - y_0 + 1)}{RU_d}$$

beyond the ramp-up period:

(2-21)
$$AP_{ydr} = TM_{ydr}$$

Where:

AP_{ydr} = annual maximum participation level in region r for option d for year y
TM_{ydr} = total potential market size for DSM option d[7] region r year y
RU_d = ramp-up period for option d
y_0 = the first year of implementation of the DSM option d
y_d = current year for DSM implementation

In the fourth step, the total maximum possible incremental savings TS_{ydr} associated with option d in region r for year y would then be calculated by

(2-22)
$$TS_{ydr} = (UI_{y2dr} - UI_{y1dr}) \times AP_{ydr}$$

Where:

TS_{ydr} = total maximum possible incremental savings associated with option d in region r for year y
AP_{ydr} = annual maximum participation level in region r for option d for year y
UI_{y1dr} = usage index for base technology 1 in region r associated with option d in

[5]The definition of d will determine what category of technologies are applicable.
[6]The definition of d will determine what category of technologies are applicable.
[7]The definition of d will determine what category of technologies are applicable.

year y

UI_{y2dr} = usage index for efficient technology 2 in region r associated with option d in year y

The Free-Ridership Issue and Penetration

In the calculations of program effectiveness, it is important that we include in our consideration the "free riders" issue. Free riders are those customers who would have adopted the program recommended efficiency measures, even in the absence of the DSM program, but who now participate in the program, and, hence, are entitled to the financial incentives of the program. Due to this; energy savings or the load reductions achieved by these customers as a result of DSM programs, do not contribute to net savings, although costs of providing the service to them is a part of program costs.

A study by Marjorie McRae et al, on free riders in the residential sector, conducted a detailed analysis of ten utility DSM programs.[8] The results showed that the net impacts of these residential programs, ranged between 25 to 33% of the utilities' expected values (i.e., 67 to 75% of the participants were free riders). Though the applicability of these numbers to all DSM programs may be questionable, they do indicate that utilities tend to overestimate the impact of their DSM programs. The reason for this is that most utilities do not perform a detailed analysis to estimate the number of free riders in their programs; they do not assume that efficiency improvements may be occurring naturally, and hence by offering DSM programs the utility may be paying for efficiency improvements which may have happened even otherwise.

The current version of the model deals with this problem assuming that the rebates will be paid to a predefined fraction (currently set to 50%) of the customers that apply the efficient (TO) technology. This reflects what is observed in practice, that only a fraction of *potential* free riders will ever apply for rebates. The design and marketing of DSM programs plays a very important role in how many potential free riders may claim rebates. The approach followed in this version of the model lays down the maximum limit of free ridership in any program. This approach is possible, since the restart file gives us information on appliance stocks in the absence of DSM. Thus, the LDSM module uses this information to compute the number of free riders. In the computation of costs of DSM programs by the ECP module, the number of free riders plays an important role. As the number of free riders increase, the program costs go up dramatically, and the program becomes uncompetitive. In this fashion, the present version of the LDSM is able to factor in the role played by naturally occurring efficiency improvements (i.e., the appliance mix in the absence of DSM).

The Targetable Market and Cost Calculations

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[8]Marjorie, McRae, S. George, and M. Koved, "What Are the Net Impacts of Residential Rebate Programs?" *Proceedings of the ACEEE 1988 Summer*
Study on Energy Efficiency in Buildings, page 9.71. Pacific Grove, CA,
August 1988.

The demand modules of NEMS provide the LDSM submodule with forecasts of the expected stock changes over the coming years. The categories into which the stock information is divisible are:

(1) Retiring Stock: This includes stock that is expected to naturally retire over the next year. This segment would be a part of the market for "replacement" type DSM programs. The costs incurred in such programs are therefore the incremental cost of the more efficient appliance over the baseline appliance that would have been purchased in the absence of the program.

(2) New Construction or New Stock: This includes those appliances that are meant for the new customers that are likely to join the grid over the next year as a result of new construction. DSM programs targeted at this segment incur costs that are the incremental costs of the more efficient appliance over the cost of the appliance that was to be bought in the absence of the program.

Information Flows Between the LDSM and Demand Modules

Communication between the LDSM and the Demand Modules follows two paths:
(1) Through the RESTART files created by the Residential and Commercial Modules during the pre-LDSM NEMS runs
(2) Through the COMMON blocks defined in the designated INCLUDE files in the LDSM code

Based on the tasks outlined in the main flow chart of the model Table 3 showing data transfers between the Demand Modules and LDSM submodule has been constructed. The exchange of information between the Demand Modules has the following four objectives:

- The LDSM reads the technology stock information from the RESTART files to forecast LDSM Program impacts and costs for the entire ECP time horizon (this data is always updated according to the foresight assumptions, in the current run, for each of the sectors of electricity demand)

- The LDSM imports the end-use technology data to calculate incremental DSM option costs and the annual energy savings resulting from technological shifts

- The LDSM supplies the Demand Modules with information about the optimal level of DSM penetration, as determined by the ECP model, so that the Demand Modules, in the next run year, can incorporate these changes into their new appliance stock assessment. Thus the demand modules adjust their forecast to incorporate the impacts of DSM.

Table 3. Information Flow Between LDSM and Demand Modules

Specification of Data Item	Restart File or Include File Name	Direction of Transfer	
		Demand Forecasting Models	LDSM
Market shares of end-use technologies in the entire time horizon if no DSM practices are available	RESIDENTIAL RESTART FILE, COMMERCIAL RESTART FILE	FROM	TO
End-use technology data	DSMRETDB, DSMCMTDB	FROM	TO
End-use demand, for each of the EMM regions, for the current year	DSMTFRES, DSMTFCOM	FROM	TO
Technological shifts due to DSM application, for each of the EMM regions, for the current year, expressed in terms of number of appliances for Residential and amount of service demand for Commercial sector (for the first run year — 0)	DSMTFRES, DSMTFCOM	FROM	TO
Level of DSM Utilization determined as optimal by the ECP module, expressed as percentages of the maximum possible technological shifts resulting from each of the DSM Options listed in the DSM option data base, for the next run year, for each of the EMM regions	DSMTFRES, DSMTFCOM	TO	FROM

- The LDSM imports the actual number of appliances (amount of service demand) that are being shifted from the demand modules, to allow for precise calculation of DSM costs. These costs are then passed on to the EFP module.

Cost-Effectiveness Calculations

The primary screening function of the LDSM DSM screening component is to select DSM options based on overall cost-effectiveness. Benefits and costs for each potential DSM option will be calculated. Options for which the benefits are higher than costs pass the screen. The benefits and costs are based on the California Total Resource Cost (TRC) test or the Rate Impact Measure (RIM) test. The general form of the tests is given below. The test must be performed for each of the 13 EMM regions being modeled.

(2-23)

$$TRC = \frac{\text{PV of Avoided System Costs}}{\text{PV of DSM Options Costs}}$$

This can be further expanded in the following form:

(2-24)

$$TRC_{rd} = \sum_{y=1}^{N} \frac{\frac{(MA_{ryl}) \times (LD_{yrdl})}{(1+i)^y}}{(ICC_{dr}) + \sum_{y=1}^{N} \frac{YPC_{yrd}}{(1+i)^y}}$$

Where:

TRC_{rd}	=	Total Resource Costs for region r and option d
MA_{ryl}	=	Marginal electricity costs in region r, year y and conforming to the l segment of the load duration curve
LD_{yrdl}	=	Changes in the load segment l in year y, due to the DSM option d, in region r
ICC_{dr}	=	incremental customer capital costs for DSM option d in region r
YPC_{yrd}	=	Yearly option costs for program d, in year y, in region r
I	=	Discount rate used in the calculations (used for all utility planning decisions)
N	=	Lifetime of appliance in years

The present value (PV) of DSM option costs will be derived by calculating the present value of total incremental customer costs and program costs in each future year associated with program participation. The PV of system avoided costs will be calculated by multiplying regional system avoided costs by load duration curve segment (LD_{yrdl}) times the total load shape impact of the DSM option.

DSM Program Aggregation

The final task in the DSM Screening component of the LDSM submodule is the development of aggregate DSM programs. Aggregation of economic DSM options is necessary because of the computational limitations of the ECP submodule. It was decided that the maximum number of DSM programs that are to compete within the ECP optimization scheme should not exceed 12 per region. This keeps the size of the optimization problem and the computational times of the ECP module within the acceptable limits. The aggregation is accomplished by summing together all costs and LDC impacts for each DSM option within each program.

DSM Program Disaggregation

The final component of the LDSM submodule is the disaggregation of the DSM programs chosen by the ECP submodule for utility investment. The ECP submodule may choose full or less than full implementation of DSM programs. Within LDSM, the scale chosen by ECP is used as the basis for determining the participation levels in percentage terms. For example, if the ECP chooses 50 megawatts of a potential 100 megawatts aggregated DSM option, then all of the individual options within the aggregated option will be scaled down by 50%. In addition, the DSM programs chosen by ECP are based on EMM regions. The LDSM submodule translates these DSM program decisions to the census division level that is used by the Demand Modules of NEMS.

DSM Option Aggregation

Tables 4, 5, 6, and 7 contain the DSM options and programs for the residential and commercial sectors that have been implemented in the current version of the LDSM.

Table 4. Residential DSM Programs in the Current Version of the LDSM

Program Code	Residential Program Description
ResHtoHP	Replace Resistance Heating & CAC/RAC with Heat Pump
HiEff_HP	Replace less efficient Heat Pump with more efficient Heat Pump
HiEffCAC	Replace less efficient CAC with more efficient CAC
HiEffRAC	Replace less efficient RAC with more efficient RAC
HeffRefr	Replace less efficient Refrigerator/Freezer with more efficient Refrigerator/Freezer
HiWaterH	Replace less efficient Water Heater with more efficient Water Heater

Table 5. Commercial DSM Programs in the Current Version of the LDSM

Program Code	Commercial Program Description
HiEffiHP	Replace less efficient Heat Pump with more efficient Heat Pump
HiEffiAC	Replace less efficient CAC with more efficient CAC
HeChillr	Replace less efficient Chiller with more efficient Chiller
HeLights	Replace less efficient Lighting with more efficient Lighting
HeRefrig	Replace less efficient Refrigerator/Freezer with more efficient Refrigerator/Freezer
HeOthrEq	Replace less efficient Other Equipment with more efficient Other Equipment

Table 6. Residential DSM Options in the Current Version of the LDSM

Option Code	Program Code	Residential Option Description
c11sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c11hN	ResHtoHP	Replace Resistance Heating & CAC with HP
r12sN	ResHtoHP	Replace Resistance Heating & RAC with HP
c21sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c22sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c21hN	ResHtoHP	Replace Resistance Heating & CAC with HP
c31sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c32sN	ResHtoHP	Replace Resistance Heating & CAC with HP
c31hN	ResHtoHP	Replace Resistance Heating & CAC with HP
c32hN	ResHtoHP	Replace Resistance Heating & CAC with HP
r31hN	ResHtoHP	Replace Resistance Heating & RAC with HP
H12sN	HiEff_HP	Replace less efficient HP with more efficient HP

Option Code	Program Code	Residential Option Description
H12sE	HiEff_HP	Replace less efficient HP with more efficient HP
H12mN	HiEff_HP	Replace less efficient HP with more efficient HP
H12mE	HiEff_HP	Replace less efficient HP with more efficient HP
H12hN	HiEff_HP	Replace less efficient HP with more efficient HP
H12hE	HiEff_HP	Replace less efficient HP with more efficient HP
H23sN	HiEff_HP	Replace less efficient HP with more efficient HP
H23sE	HiEff_HP	Replace less efficient HP with more efficient HP
H23mN	HiEff_HP	Replace less efficient HP with more efficient HP
H23mE	HiEff_HP	Replace less efficient HP with more efficient HP
H23hN	HiEff_HP	Replace less efficient HP with more efficient HP
H23hE	HiEff_HP	Replace less efficient HP with more efficient HP
C12sN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12sE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12mN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12mE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12hN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C12hE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23sN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23sE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23mN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23mE	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23hN	HiEffCAC	Replace less efficient CAC with more efficient CAC
C23hE	HiEffCAC	Replace less efficient CAC with more efficient CAC
R12sE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12mN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12mE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12hN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R12hE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R13sN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23sN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23sE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23mN	HiEffRAC	Replace less efficient RAC with more efficient RAC

Option Code	Program Code	Residential Option Description
R23mE	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23hN	HiEffRAC	Replace less efficient RAC with more efficient RAC
R23hE	HiEffRAC	Replace less efficient RAC with more efficient RAC
F12sN	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12sE	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12mN	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12mE	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12hN	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
F12hE	HeffRefr	Replace less efficient Refrigerator with more efficient Refrigerator
f12sN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f12mN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f12hN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f23sN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
f23hN	HeffRefr	Replace less efficient Freezer with more efficient Freezer
W13sN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13sE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13mN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13mE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13hN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W13hE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23sN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23sE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23mN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23mE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23hN	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater
W23hE	HiWaterH	Replace less efficient Water Heater with more efficient Water Heater

Table 7. Commercial DSM Options in the Current version of the LDSM

Option Code	Program Code	Commercial Options Description
7CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller

Option Code	Program Code	Commercial Options Description
7CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
7GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
7GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
7LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
7LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
7L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
7L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
7LHmsE	HeLights	Replace mercury lighting with sodium lighting
7LHmsN	HeLights	Replace mercury lighting with sodium lighting
7LHhsE	HeLights	Replace halogen lighting with sodium lighting
7LHhsN	HeLights	Replace halogen lighting with sodium lighting
7RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost refrigerator
7RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost refrigerator
7RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
7RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
1ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
1ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
1A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
1A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
1A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
1A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
1CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
1CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
1GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
1GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
1LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
1LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting

Option Code	Program Code	Commercial Options Description
1L4H0E	HeLights	Replace 4 ft. high efficiency flourescent lighting with electronic ballast fluorescent lighting
1L4H0N	HeLights	Replace 4 ft. high efficiency flourescent lighting with electronic ballast fluorescent lighting
1LHmsE	HeLights	Replace mercury lighting with sodium lighting
1LHmsN	HeLights	Replace mercury lighting with sodium lighting
1LHhsE	HeLights	Replace halogen lighting with sodium lighting
1LHhsN	HeLights	Replace halogen lighting with sodium lighting
1RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
1RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
1RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
1RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
3HPP1E	HiEffiHP	Replace a standard HP with a 1995 HP
3HPP1N	HiEffiHP	Replace a standard HP with a 1995 HP
3HPP2E	HiEffiHP	Replace a 1995 HP with a 2000 HP
3HPP2N	HiEffiHP	Replace a 1995 HP with a 2000 HP
3ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
3ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
3A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
3A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
3A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
3A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
3GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
3GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
3LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
3LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
3LHmsE	HeLights	Replace mercury lighting with sodium lighting
3LHmsN	HeLights	Replace mercury lighting with sodium lighting
3RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
3RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
3RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator

Option Code	Program Code	Commercial Options Description
3RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
4HPP1E	HiEffiHP	Replace a standard HP with a 1995 HP
4HPP1N	HiEffiHP	Replace a standard HP with a 1995 HP
4ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
4ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
4A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
4A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
4A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
4A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
4GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
4GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
4LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
4LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
4L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
4L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
4LHmsE	HeLights	Replace mercury lighting with sodium lighting
4LHmsN	HeLights	Replace mercury lighting with sodium lighting
4RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
4RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
4RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
4RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
5ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
5ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
5A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
5A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
5A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
5A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
5CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller

Option Code	Program Code	Commercial Options Description
5CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
5GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
5GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
5LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
5LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
5L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
5L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent lighting
5LHmsE	HeLights	Replace mercury lighting with sodium lighting
5LHmsN	HeLights	Replace mercury lighting with sodium lighting
5RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
5RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
5RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
5RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
8HPP2E	HiEffiHP	Replace a 1995 HP with a 2000 HP
8HPP2N	HiEffiHP	Replace a 1995 HP with a 2000 HP
8ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
8ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
8A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
8A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
8A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
8A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
8CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
8CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
8GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
8GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
8LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
8LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
8LHmsE	HeLights	Replace mercury lighting with sodium lighting

Option Code	Program Code	Commercial Options Description
8LHmsN	HeLights	Replace mercury lighting with sodium lighting
8RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
8RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
8RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
8RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
9HPP1E	HiEffiHP	Replace a standard HP with a 1995 HP
9HPP1N	HiEffiHP	Replace a standard HP with a 1995 HP
9HPP2E	HiEffiHP	Replace a 1995 HP with a 2000 HP
9HPP2N	HiEffiHP	Replace a 1995 HP with a 2000 HP
9ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
9ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
9A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
9A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
9A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
9A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
9CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
9CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
9GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
9GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
9LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
9LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
9LHmsE	HeLights	Replace mercury lighting with sodium lighting
9LHmsN	HeLights	Replace mercury lighting with sodium lighting
9RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
9RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
9RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
9RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
0ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit

Option Code	Program Code	Commercial Options Description
0ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
0A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
0A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
0A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
0A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
0GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
0GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
0LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
0LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
0LHmsE	HeLights	Replace mercury lighting with sodium lighting
0LHmsN	HeLights	Replace mercury lighting with sodium lighting
0LHhsE	HeLights	Replace halogen lighting with sodium lighting
0LHhsN	HeLights	Replace halogen lighting with sodium lighting
0RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
0RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
0RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
0RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
AASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
AASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
AA58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
AA58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
AA81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
AA81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
AGRRhE	HeOthrEq	Replace standard electric range with high efficiency range
AGRRhN	HeOthrEq	Replace standard electric range with high efficiency range
ALIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
ALIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
AL4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
AL4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light

Option Code	Program Code	Commercial Options Description
ALHmsE	HeLights	Replace mercury lighting with sodium lighting
ALHmsN	HeLights	Replace mercury lighting with sodium lighting
ALHhsE	HeLights	Replace halogen lighting with sodium lighting
ALHhsN	HeLights	Replace halogen lighting with sodium lighting
ARVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
ARVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
ARM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
ARM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
2CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
2CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
2GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
2GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
2LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
2LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
2L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
2L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
2LHmsE	HeLights	Replace mercury lighting with sodium lighting
2LHmsN	HeLights	Replace mercury lighting with sodium lighting
2LHhsE	HeLights	Replace halogen lighting with sodium lighting
2LHhsN	HeLights	Replace halogen lighting with sodium lighting
2RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
2RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
2RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
2RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
6CHVcE	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller
6CHVcN	HeChillr	Replace high efficiency centrifugal chiller with a very high efficient centrifugal chiller

Option Code	Program Code	Commercial Options Description
6GRRhE	HeOthrEq	Replace standard electric range with high efficiency range
6GRRhN	HeOthrEq	Replace standard electric range with high efficiency range
6LIF5E	HeLights	Replace incandescent lighting with compact fluorescent lighting
6LIF5N	HeLights	Replace incandescent lighting with compact fluorescent lighting
6L4H0E	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
6L4H0N	HeLights	Replace 4 ft. high efficiency fluorescent lighting with electronic ballast fluorescent light
6LHmsE	HeLights	Replace mercury lighting with sodium lighting
6LHmsN	HeLights	Replace mercury lighting with sodium lighting
6RVODE	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
6RVODN	HeRefrig	Replace very low temperature open case refrigerator with a gas defrost.refrigerator
6RM2SE	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
6RM2SN	HeRefrig	Replace medium temperature non-CFC refrigerator with a mechanical sub-cooling refrigerator
7ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
7ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
7A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
7A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
7A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
7A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
2ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
2ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
2A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
2A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
2A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
2A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit
6ASE-E	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
6ASE-N	HiEffiAC	Replace a standard A/C unit with a high efficiency unit
6A58-E	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
6A58-N	HiEffiAC	Replace a 1995 A/C unit with a 1998 A/C unit
6A81-E	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit

Option Code	Program Code	Commercial Options Description
6A81-N	HiEffiAC	Replace a 1998 A/C unit with a 2010 A/C unit

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3. Electricity Capacity Planning Submodule

This chapter documents the objectives and analytical approach of the Electricity Capacity Planning Submodule (ECP), which determines investment decisions such as capacity additions and compliance strategies for environmental regulations. It includes the key assumptions, computational methodology, and data requirements of the model.

Model Summary

The ECP considers planning decisions involving changes in capital stock that occur over several years and require a substantial capital investment. It projects how the electric power industry will change its generating capability in response to changes in environmental regulations and increases in demand. The ECP contains a dispatching component so that planning decisions consider the tradeoff between investment and operating costs.

The ECP examines strategies for complying with environmental legislation, such as the Clean Air Act Amendments of 1990 (CAAA). Planning options for achieving the sulfur dioxide (SO_2) emissions restrictions in the CAAA include installing pollution control equipment on existing power plants and building new power plants with low emission rates.[9] These methods for reducing emission are compared to dispatching options such as fuel switching and allowance trading. Environmental regulations also affect capacity expansion decisions. For instance, new plants are not allocated emissions allowances according to the CAAA. Consequently, the decision to build a particular capacity type must consider the cost (if any) of obtaining sufficient allowances. This could involve purchasing allowances or over complying at an existing unit. The ECP also represents restrictions on nitrogen oxide (NO_x), mercury (Hg), and carbon emissions.

Potential options for new generating capacity include central-station plants using fossil-fuel, nuclear, and renewable power (including intermittent technologies such as solar and wind) and distributed generation capacity. The ECP also includes construction of new generation and transmission capacity in Canada for export to a U.S. region and/or in one U.S. region for export to another U.S. region. As new technologies become available, they compete with conventional plant types as sources of supply in the ECP. The ECP contains a technology penetration component, which represents changes in cost and performance characteristics due to learning effects, risk and uncertainty.[10] The ECP also contains a market-sharing algorithm and evaluates plant retirement decisions.

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[9]For a more detailed description of the Clean Air Act Amendments, see Energy Information Administration, *Component Design Report Electricity Fuel Dispatch* (Washington, DC, May 1992).

[10]For a more detailed description, see Energy Information Administration, *NEMS Component Design Report Modeling Technology Penetration* (Washington, DC, March 1993).

Model Purpose

Model Objectives

The purpose of the ECP is to determine how the electric power industry will change its mix of generating capacity over the forecast horizon. It considers investment decisions for new capacity and evaluates retirement decisions for fossil and nuclear plants. It includes traditional and nontraditional sources of supply. The ECP represents changes in the competitive structure (i.e., deregulation). Due to competition, no distinction is made between utilities and nonutilities as owners of new generating capacity. The ECP also captures changes to plants (i.e., pollution control devices) in response to environmental regulations, such as the CAAA. It can represent limits on sulfur dioxide, nitrogen oxide, mercury, and carbon emissions

Technology choices in the ECP include all of the fuel types used by suppliers—coal, natural gas, petroleum, uranium, and renewable. The ECP represents capacity additions of conventional and advanced technologies. Conventional technologies are identified by fuel type (coal, natural gas, petroleum, uranium, and renewable) and prime mover (e.g. steam, combined cycle, combustion turbine, hydraulic turbine, wind turbine). These categories correspond to data collected on Form EIA-860, "Annual Electric Generator Report." Steam turbines use fossil fuel, nuclear, and some renewable energy sources (e.g., geothermal). Combined cycle and combustion turbine units primarily use natural gas and petroleum although some use waste heat. Hydraulic turbines include conventional and pumped storage. New technologies include integrated gasification combined cycle, fuel cells, and advanced nuclear reactors. Renewable technologies include geothermal and biomass (wood). Intermittent renewable capacity (e.g., wind and solar) is also considered. Distributed generation options are represented as generic technologies serving peak and base loads.

In the ECP, planning decisions are represented for 13 electricity supply regions (see Chapter I, Figure 3). Of the 13 regions, 8 correspond to North American Electric Reliability Council (NERC) Regions. These are the East Coast Area Reliability Coordination Agreement (ECAR), Electric Reliability Council of Texas (ERCOT), Mid-Atlantic Area Council (MAAC), Mid-America Interconnected Network (MAIN), Mid-Continent Area Power Pool (MAPP), Southeastern Electric Reliability Council (SERC), Florida Reliability Coordinating Council (FL) and Southwest Power Pool (SPP) Regions. The remaining two NERC Regions are divided into a total of five Subregions to isolate key states or areas. In the Northeast Power Coordinating Council (NPCC), the New England (NE) states constitute one region and New York (NY) represents another. The Western Electric Coordinating Council (WECC) is partitioned into three Subregions. The Rocky Mountain Power Area, and Arizona-New Mexico-Southern Nevada Power Area Subcouncils are combined into one region (RA). The Northwest Power Pool Area (NWP) and California (CA) form the other two electricity supply regions.

The general level of aggregation for the NEMS is Census Divisions, which are collections of states.[11] However, many utilities operate across state boundaries and the NERC Regions and Subregions provide a better representation of electricity operations. This geographic representation also facilitates collection of data and comparisons with industry projections, both of which are generally conducted at the utility- or NERC region-level.

The ECP, as a component of the EMM and the NEMS, is designed to provide forecasts for the *Annual Energy Outlook* and other analyses. For the electric power industry, the model projects planning decisions for each year in the midterm forecast horizon, currently defined as through 2025. It is designed to examine environmental policies such as the CAAA, limits on carbon emissions, and externality costs. It is also intended to examine the economic tradeoffs between the potential suppliers and the available generating technologies in response to different fuel price trajectories, environmental requirements, and macroeconomic conditions. The ECP can examine issues related to international and interregional trade, but it does not represent intra regional trade for the 13 electricity regions. The number and combinations of interregional and international trade opportunities in the ECP are restricted to those areas of the country where bulk power transfers currently exist. These transactions include the electricity supply regions in the West (regions 11, 12 and 13), in the Southeast (8, and 9), and between Canada and the U.S. (regions 1, 4, 5, 6, 7, 11, and 13). Similarly, new generating capacity can be built in selected regions with lower fuel costs to serve demands in other regions if the resulting savings in fuel costs is sufficient to offset the higher transmission costs. These "interregional" capacity additions are also limited to regions with existing relationships.

Relationship to Other Models

In addition to exogenous sources, the ECP requires input data from other modules of the NEMS and other submodules of the EMM (Figure 9). Exogenous inputs include existing operable capacity, planned capacity additions, and announced capacity retirements. Data inputs also include the age of existing units, which will be used in the representation of refurbishment, repowering, and retirement decisions. For each capacity type that is a candidate for capacity expansion, external assumptions include overnight construction cost (i.e., without interest), and construction expenditure profile, operating life, maximum fuel shares, heat rate, and outage rates. Planned additions and retirements are assumed to occur as scheduled. Transmission and trade data inputs are also exogenously specified. Transmission and trade data include the expected level of international and interregional electricity trade based on known contracts, and the costs of constructing new generating units in selected regions to serve loads in a neighboring region.

[11]The demand, conversion, and supply modules of the NEMS use the regional aggregation that is most appropriate for the corresponding energy market. However, the required data flows provided to the Integrating Module for convergence testing and reporting (e.g., energy prices and quantities) are specified for the nine Census Divisions. For additional information, see Energy Information Administration, *NEMS Integration Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

The Integrating Module of the NEMS provides expected fuel prices and expected electricity demands. The end-use demand modules furnish electricity from cogenerators, which decrease the generation requirements from power plants. Cost and performance data for plant types fueled by renewable energy sources are obtained from the Renewable Fuels Module (RFM). For intermittent technologies, the RFM will also provide the capacity credit, which represents the corresponding contribution to reliability requirements.

The Electricity Finance and Pricing (EFP) Submodule supplies the capital structure (debt/equity shares) and the cost of capital. The Load and Demand-Side Management (LDSM) Submodule furnishes the load curves for each year in the planning horizon.

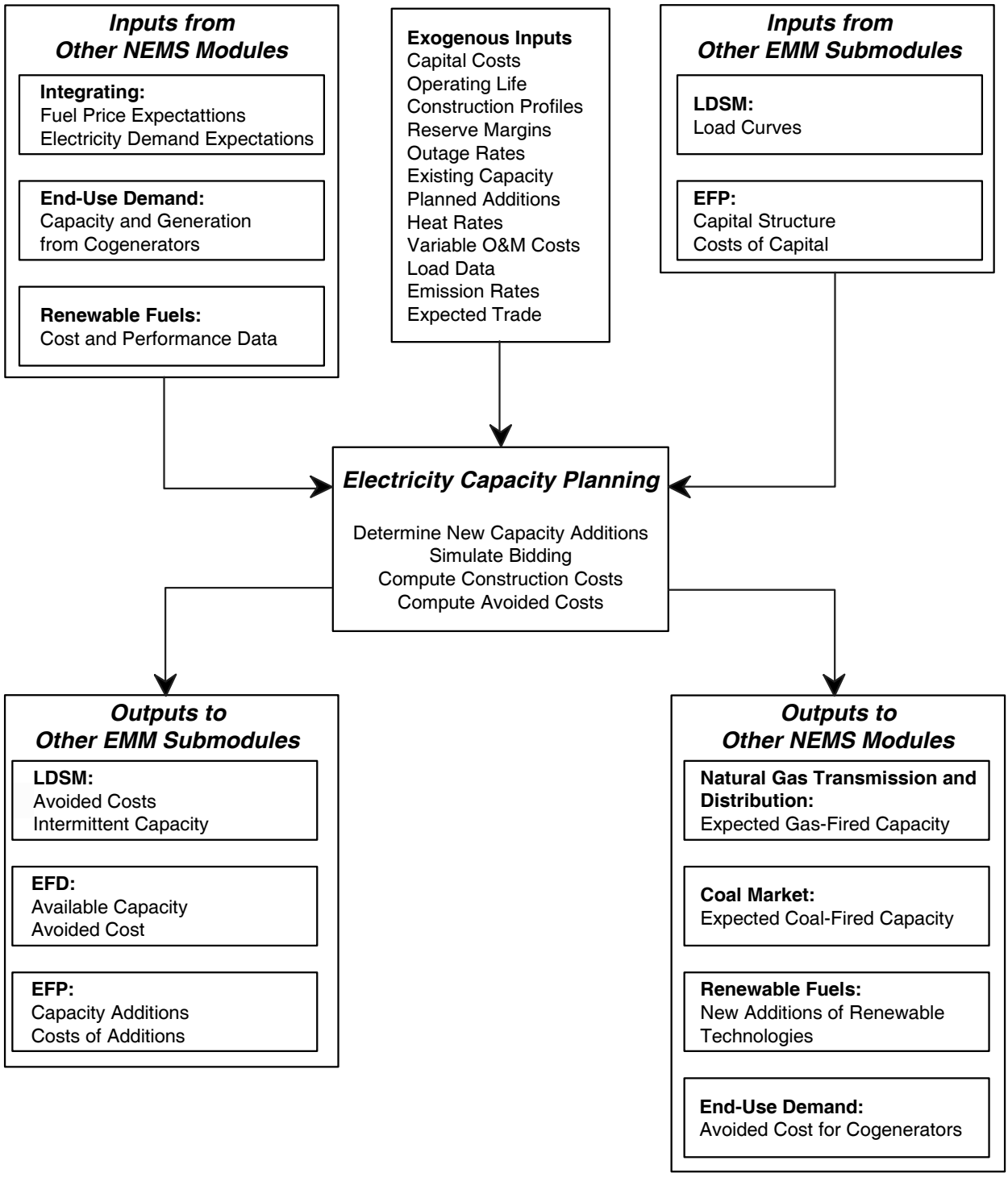
The EFP Submodule requires the capital expenditures for building new capacity and installing pollution control devices on existing units in order to calculate electricity prices. The Electricity Fuel Dispatching (EFD) Submodule uses capacity additions from the ECP to determine available capacity for meeting demand in a given year.

The outputs of the ECP, which are determined by the selection of the least-cost options for meeting expected growth in demand, interact with other modules of the NEMS and Submodules of the EMM. The ECP provides its decision variables to other submodules of the EMM (Figure 9). Capacity additions for coal- and gas-fired generating capacity are provided to the Coal Market Module (CMM) and the Natural Gas Transmission and Distribution Module (NGTDM), which are used for planning decisions in the respective modules. The RFM also receives capacity additions of renewable technologies. In particular, this is required for technologies with resource constraints or limited sites.

The interaction between the ECP and the CMM is particularly important because the electricity and coal markets are closely related. Electricity production accounts for most of the coal consumption in the United States. Coal is the primary input fuel for electricity production and accounts for most of the emissions produced from power generation. Coal supplies vary considerably according to cost (production and transportation) and characteristics (Btu content, sulfur content, and mercury content). Therefore, the ECP includes a detailed representation of the coal supply curves contained in the CMM.[12]

[12]For more information on the description of coal production, transportation and environmental limits in the CMM, see Energy Information Administration, *Coal Market Module of the National Energy Modeling System, Model Documentation 2004*, DOE/EIA-M060(04) (Washington, DC, March 2004).

Figure 9. Input/Output Flows for the Electricity Capacity Planning Submodule



Model Overview and Rationale

Theoretical Approach

The ECP uses a linear programming (LP) formulation to determine planning decisions for the electric power industry. The ECP contains a representation of planning and dispatching in order to examine the tradeoff between capital and operating costs. It simulates least-cost planning and competitive markets by selecting strategies for meeting expected demands and complying with environmental restrictions that minimize the discounted, present value of investment and operating costs. The ECP explicitly incorporates emissions restrictions imposed by the CAAA and provides the flexibility to examine potential regulations such as emissions taxes and carbon stabilization.

The ECP uses multi-year optimization and solves all the years simultaneously. It uses a four-year planning horizon to examine costs over a 20-year period. The final year of the planning horizon actually represents the accumulated costs for the final 17 years of the cost recovery period. The ECP "keeps" only those decisions that must be initiated in the current forecast year and it assumes that these investments are completed once they are started. The available options for capacity expansion and environmental compliance encompass a number of intertemporal issues that need to be addressed using a multi-period planning horizon. For example, generating technologies have different licensing and construction periods. Early in the planning horizon, the options are limited to strategies with shorter lead times, such as construction of peaking units. However, the available options increase over a longer period. Additional capacity requirements could be met by initiating construction of a plant with a longer leadtime or waiting a few years and implementing a shorter-term option.

Furthermore, it may be beneficial to implement a particular option prior to the actual need. Utilities in a given region may have a surplus of capacity to serve a particular load category. Nevertheless, it may be cost-effective to build a new unit to replace or lower the utilization of a less economical existing unit. If the public service commission is willing to allow the new asset to be added to the rate base, then this decision depends on whether or not the resulting fuel savings can offset the investment costs that would be incurred earlier than required.

Emissions banking is another intertemporal issue that needs to be evaluated in a multi-year framework. Depending on the value of allowances, it may be advantageous to reduce emissions beyond required levels in an earlier year in order to under comply in a later year. In the ECP, the value of an allowance is assumed to be the market-clearing price, which is based on the revenue

requirements for the capital and operating expenses associated with compliance.[13] Based on the allowances allocated according to the CAAA, some utilities may have relatively low compliance costs for Phase 1 but incur much higher costs during Phase 2 since the restrictions are much tighter. Banking would lower the overall cost of compliance if the discounted, present value of the compliance costs in a given year is less than the corresponding cost in a later year.

To describe the demands for electric power, the ECP uses a modified load duration curve provided by the LDSM. A typical load duration curve arranges hourly loads in descending order, but does not identify power requirements chronologically. The load requirements are categorized into specific seasonal/time of day segments, which are then reordered to provide a monotonically decreasing curve. Maintaining the chronological identity of the demands for electric power allows the ECP to better represent time-dependent variations in both the demand for and supply of electricity.

In the ECP, the available supply options are characterized by the degree of control they provide the operator of the system. Assuming adequate fuel supplies, fossil-fuel and nuclear units are considered "dispatchable" since they can usually can be operated at any time as long as they are not out-of-service due to planned or forced outages. Some renewable generating capacity, such as geothermal and biomass, are similar to fossil-fired and nuclear plants in that they can be dispatched at the discretion of the operator, subject to limits on the renewable energy source and maintenance schedules. The utilization of hydroelectric plants typically depends on the available water supply, which varies considerably by region and season. Intermittent technologies, such as solar and wind, are less flexible since they can only be operated when the resource occurs (unless accompanied by some storage capability).

In the ECP, a market-sharing algorithm adjusts the solution from the LP model to allow penetration of "competitive" but not "least-cost" alternatives.[14] The LP model evaluates planning decisions on the basis of average (expected) costs and chooses the options that result in the minimum combination of investment and operating costs. However, cost and performance parameters for technologies are typically probabilistic and are more accurately represented by distributions rather than single point estimates such as the means. If the distributions of two or more technologies overlap, then the lowest-cost option is not likely to capture the entire market since some quantity of the selected activity will be more expensive than some quantity of the option(s) that is not selected on the basis of average costs. The market-sharing algorithm determines the "competitiveness" of technologies not selected by the LP and reallocates some of the capacity additions to those that fall within a prespecified level.

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[13]The value of allowances could be affected by several issues, including cost recovery schedules for compliance costs (i.e., capitalized or expensed) and tax treatment (both federal and state). These regulatory decisions have not been determined yet.

[14]For more information see Energy Information Administration, *Component Design Report Electricity Capacity Planning* (Washington, DC, August 1992).

Fundamental Assumptions[15]

It is assumed that capacity additions that have been announced by utilities and nonutilities will be completed as reported.[16] Scheduled retirements of existing units are also assumed to occur. However, a large number of fossil-fired steam generating units are approaching the end of their normal operating lives, but utilities have not indicated any plans to retire them. The ECP evaluates whether it is more effective to continue operating those units or to replace them with new capacity. Thus, the ECP only determines capacity additions and retirements over and above those currently planned that are required to meet new demand, replace retiring capacity, and comply with environmental regulations. It is assumed that a new project is completed once it is initiated. Contributions from cogenerators are determined by the end-use demand modules.

The capacity additions determined by the ECP must be sufficient to satisfy minimum reliability requirements in each of the electricity supply regions. In a region with traditional cost-of-service regulation, it is assumed that the sum of existing capacity (net of retirements) and planned capacity additions, and unplanned additions must be greater than or equal to the expected peak demand by a pre-specified reserve margin. These reserve margins are derived using ten-year projections from the NERC for generating capability and peak demands.[17] However, some States are in various stages of deregulating the electric power industry. In these areas, it is assumed that the optimal reserve margin is represented by the level of capacity that balances the marginal cost of supply and the marginal cost that consumers are willing to pay for capacity (represented by the cost of unserved energy). Firm international and interregional capacity trade contribute to the reliability requirements of the importing region. Similarly, capacity built and operated in one region but serving load in her region is counted towards the reserve margin in the destination region.

The ECP determines planning strategies that are to be implemented to meet electricity demands and environmental requirements in "future" years; therefore, it is necessary to have information about future demands and fuel prices. Adaptive expectations, which assume that future trends can be extrapolated from historical patterns, are used for future demands and prices.[18] Interest rates and inflation rates tend to remain fairly stable over time so the ECP assumes these will remain constant at current levels (i.e., the latest available rates, which correspond to the results from the previous forecast year). Similarly, the capital structure for financing new investments is

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[15]For more detailed information see Energy Information Administration, *Assumptions to the 2004 (AEO2004)*, DOE/EIA-0554(2004) (Washington, DC, February 2004).

[16]Planned capacity additions for electric utilities are reported on Form EIA-860A, "Annual Electric Generator Report–Utility." Scheduled additions for nonutilities are collected on Form EIA-860B, "Annual Electric Generator Report--Nonutility."

[17]These projections are contained in North American Electric Reliability, Electricity Supply & Demand 1992-2001 (Princeton, NJ, June 1992).

[18]For more information on foresight assumptions, see Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

assumed to be the current share of debt and equity. The discount rate is the after-tax, weighted average cost of capital.

The expected demands represent annual electricity sales for the nine Census Divisions. For each year in the planning horizon, the corresponding demands are mapped into the 13 electricity supply regions using constant shares derived from historical data. Chronological variations in the load are captured using a historical distribution of hourly load data from the North American Electric Reliability Council (NERC). The hourly loads are then classified into nine different combinations of season (summer, winter, and spring/fall) and time-of-day (daytime, morning/evening, and night) prior to creating the load duration curves (Table 8). Demands for electric power are typically similar in the spring and fall so the corresponding loads are combined to reduce the size of the model. Morning and evening loads are combined for similar reasons. These categories are also designed to accommodate variations in potential contributions from renewable generating technologies.

Table 8. Definition of Seasonal/Time-of-Day Load Segments

Load Group	Months	Hours
Summer Daytime	June - September	7:00 a.m. - 6:00 p.m.
Summer Morning/Evening	June - September	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00p.m.
Summer Night	June - September	12:00 p.m. - 5:00 a.m.
Winter Daytime	December - March	7:00 a.m. - 6:00 p.m.
Winter Morning/Evening	December - March	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00p.m.
Winter Night	December - March	12:00 p.m. - 5:00 a.m.
Fall/Spring Daytime	April - May, October - November	7:00 a.m. - 6:00 p.m.
Fall/Spring Morning/Evening	April - May, October - November	5:00 a.m. - 7:00 a.m., 6:00 p.m. - 12:00p.m.
Fall/Spring Night	April - May, October - November	12:00 p.m. - 5:00 a.m.

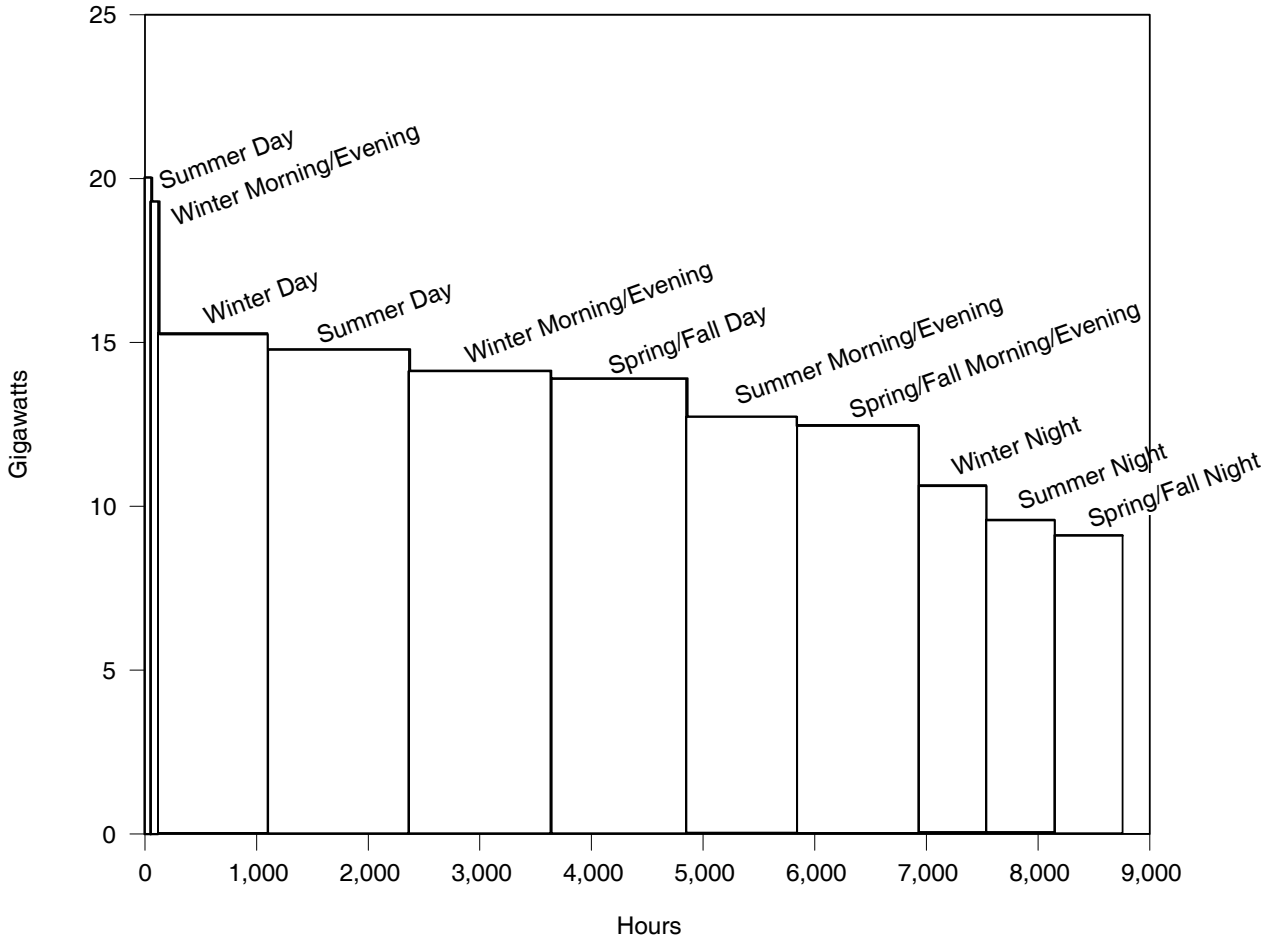
The hourly loads in each of the nine categories, which produce a continuous curve, are approximated by vertical, rectangular blocks (slices) representing the average load during each period. The two seasonal/time-of-day groups containing the peak summer and winter loads are separated into peak and off peak segments. For each region, the resulting 11 blocks are then arranged in descending order to produce the load duration curve (Figure 10).

Planning decisions are determined for each of the 13 Electricity Supply Regions represented in the EMM. Each of the 13 regions is treated as a single "firm" as intra regional electricity trade is not explicitly represented. Within each region, the available capacity is allocated to meet the demand for electricity on the basis of cost minimization, subject to relevant regulatory and environmental constraints. Bulk power purchases between the electricity supply regions are represented with the limits on power flows based on region to region transmission constraints.[19]

[19]Interregional transmission constraints are derived from Department of Energy, Form OE-411, "Coordinated Bulk Power Supply Program Report."

It has been assumed that this initial capability is available throughout the NEMS forecast time horizon. Transmission line capability available for new transactions is calculated by subtracting known contracted capacity from the original transmission line capability. Based on established relationships between selected electricity supply regions, interregional transmission capacity can be added and new plants can be built in one region to serve another region. International trade with Canada is also incorporated, but it is assumed that firm power transactions with Mexico do not occur since there are no existing or planned agreements.

Figure 10. Load Duration Curve with Time-of-Day and Seasonal Load Segmentation



In the ECP, available supply options include fossil-fired, nuclear, and renewable plants (Table 9). Both conventional and advanced technologies are represented. Fossil-fired capacity consumes coal, oil, and natural gas. Renewable technologies include hydroelectric, biomass, geothermal, municipal solid waste, wind, and solar.

Potential options for reducing SO_2 emissions in accordance with the CAAA include installing pollution control equipment at existing units, building new units with lower emission rates, switching to a lower sulfur fuel, and revising the dispatch order to utilize capacity types with lower emission rates more intensively. Allowance trading is represented in the ECP by imposing a national-level limit on emissions. This limit is determined by summing the unit-level emissions allowances allocated in the CAAA.

In addition to the CAAA, it is also assumed that emissions from generating units satisfy state regulations. The total capacity for each technology option is determined from unit-level data and the applicable federal and state standards are identified for each unit prior to aggregation (Table 9). Compliance options are limited to those that violate none of the standards. As a result, an existing coal-fired unit without a scrubber may be limited to the types of coal that can be consumed (e.g., low-sulfur instead of medium- or high-sulfur) by one or more of the standards.

Existing coal capacity is represented by 32 categories that are defined by the types (if any) of particulate, sulfur dioxide, nitrogen oxide, and mercury control devices. These plant types are typically classified as unscrubbed or scrubbed, depending on whether or not they have Flue Gas Desulfurization (FGD) equipment. A given capacity type can include several different configurations since pollutants such as nitrogen oxide can be controlled using multiple devices such as low-NOX burners, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR). Each configuration is characterized by a removal rate for each of these emissions. A given coal capacity type can be converted to another configuration or category by retrofitting pollution control devices in order to comply with specified emissions limits.

Uncertainty about investment costs for new technologies is captured in the ECP using technological optimism and learning factors. These factors are calculated for each of the major design components of a plant type design (Table 10). For modeling purposes, components are identified only if the component is shared between multiple plant types, so that the ECP can reflect the learning that occurs across technologies. The cost adjustment factors are based on the cumulative capacity of a given component. This capacity is calculated by summing the contribution of the component to the capacity of each plant type that contains it (Table 11). It is assumed that for all combined-cycle technologies, the turbine component contributes two-thirds of the capacity and the steam unit one third. All non-capacity components contribute 100% toward component learning. Table 11 only shows components that contribute to multiple plant types, all other components map 100% to their particular technology.

Table 9. Capacity Types Represented in the Electricity Capacity Planning Submodule

Category
Existing Coal Steam
New Scrubbed Coal
Advanced Coal
Advanced Coal with Sequestration
Gas/Oil Steam Turbine
Existing Combustion Turbine
New Conventional Combustion Turbine
New Advanced Combustion Turbine
Existing Gas/Oil Combined Cycle
New Conventional Gas/Oil Combined Cycle
New Advanced Gas/Oil Combined Cycle
New Advanced Combined Cycle with Sequestration
Fuel Cells
Conventional Nuclear
Advanced Nuclear
Biomass (Wood)
Municipal Solid Waste
Geothermal
Hydroelectric
Pumped Storage
Wind
Solar Thermal
Solar Photovoltaic
Distributed Generation - Base load
Distributed Generation - Peak load

Table 10. Design Components Represented in the Electricity Capacity Planning Submodule

Category
Pulverized Coal
Combustion Turbine - conventional
Combustion Turbine - advanced
Heat Recovery Steam Generator (HRSG)
Gasifier
Carbon Capture/Sequestration
Balance of Plant - Integrated Coal Gasification Combined Cycle (IGCC)
Balance of Plant - Turbine
Balance of Plant - Combined Cycle (CC)
Fuel Cell
Advanced Nuclear
Fuel prep - Biomass IGCC
Distributed Generation - Base
Distributed Generation - Peak
Geothermal
Municipal Solid Waste
Wind
Solar Thermal
Solar PV

Table 11. Component Capacity Weights for New Technologies

Technology	Combustion Turbine - conv.	Combustion Turbine-adv.	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant - IGCC	Balance of Plant - Turbine	Balance of Plant - CC	Fuel prep Biomass IGCC
IGCC	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cyc	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cyc	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon seq.	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turb	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turb	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	0%	67%	33%	100%	0%	100%	0%	0%	100%

Model Structure

Introduction

The ECP is executed once each forecast year to determine planning decisions that must be initiated in the current forecast year and completed within the planning horizon. The ECP uses a linear programming (LP) formulation to compete options for meeting future demands for electricity and complying with environmental regulations. It selects the strategies that minimize the total present value of the investment and operating costs over a prespecified period, subject to certain conditions. These conditions include requirements that demands for electricity (accounting for seasonal and daily fluctuations variations and transmission/distributions losses) are met, minimum reliability requirements are satisfied, and emissions limits are not exceeded.

The ECP prepares the input data, solves the LP model, and provides the required outputs to the other submodules of the EMM and modules of the NEMS. The initial matrix and objective function is an input to the ECP. However, most of the coefficients in the model change over time. For instance, the objective function represents the costs of building and operating generating capacity, and installing pollution control equipment and its coefficients include capital expenditures, interest charges, and fuel costs, all of which vary over time. Similarly, coefficients in the constraint matrix, which describes the total capacity needs based on peak demands and reserve margin requirements, the allocation of available capacity to meet demands for electricity, and applicable emissions restrictions, also change during the forecast horizon.

A system of equations has been incorporated in the ECP to simulate the production and tranportation of coal. This formulation, which is based on the corresponding representation in the CMM, is included so that the ECP determines capacity planning, operating, and emissions control decisions using a similar distribution of the availability, costs (production, transportation, and emissions control), BTU contents (bituminous, subbituminous, and lignite), and emissions rates (sulfur, nitrogen oxide, mercury, and carbon) for the coal types in the CMM..

The following section provides a mathematical description of the LP model and specifies the objective function and equations of the constraint matrix. The model uses on the Optimization and Modeling (OML) software, a proprietary mathematical programming package, to create and store coefficients in a database, solve the problem, and retrieve the solution. The OML subroutines are not documented in this report.[20] Capacity planning under competition, the Technology Penetration component, and the methodology for determining nuclear retirement decisions are described in the subsequent sections.

[20]For more information, see Ketron Management Science, *Optimization and Modeling Library (Draft)*, (Arlington, VA, November 1992).

Key Computations and Equations

In the ECP, decision variables include building new generating capacity (conventional and advanced, renewable and nonrenewable technologies), trading firm power (interregional and international), installing pollution control devices at existing units, and banking emissions allowances (i.e., over complying in a particular year and saving the allowances for future use). The LP model determines the appropriate mix of options that meets the environmental regulations and provides reliable and economical supplies of electricity over the planning horizon.

Reliable electricity supplies for each region are represented by a set of constraints that ensure that sufficient generating capability is available to meet the load requirements in each of the load slices and the minimum reliability requirements. Dispatchable capacity types (e.g., fossil-fuel, nuclear, and non-intermittent renewable technologies) can satisfy capacity and energy requirements for any or all of the load segments. Their utilization depends primarily on their availability, fuel constraints (if any), and the relative economics of the potential options. A baseload generating plant type is used in all of the load categories, whereas a peaking plant type is allocated to the first few segments (see Figure 10). A technology may be limited to a particular mode of operation (e.g., nuclear utilized in base load only), if appropriate. Dispatchable plant types receive full credit towards reliability requirements because they can be used during peak loads as long as they are not out-of-service. Contributions from intermittent technologies are limited to the appropriate load segments, depending on the availability of the resource (e.g., wind or sun). Intermittent technologies receive a partial capacity credit depending on their capability to provide electricity when the peak load occurs.

Economical supplies are represented by minimizing the objective function of the LP model, which accumulates the total present value of expenditures associated with investment and operating decisions during the planning horizon. Some of the relevant costs associated with planning horizon are incurred after the end of the planning horizon, so the ECP evaluates each option on the basis of a life-cycle cost. For instance, capital costs (e.g., construction expenditures, interest charges) associated with investment decisions are recovered over the economic life of the asset. The cost coefficient for each investment decision is the sum of the present value of the annual revenue requirements (e.g., depreciation, taxes) over the predefined period. Similarly, operating costs are determined for all years in order to consider factors such as escalating fuel costs. For each operating decision variable in the first 5 years of the model, the cost coefficient is the present value of the corresponding annual fuel and operations and maintenance costs. In the last year of the planning horizon, each cost coefficient represents the sum of the present value of operating costs for the remaining years.

The structure of the ECP is described below.

Dimensions

a	=	Activated Carbon Option
b	=	Canadian Import Project
c	=	Dispatchable Capacity Type
d	=	Fuel Supply Curve Step
e	=	Export Electricity Supply Region
f	=	Fuel Choice
g	=	Import Electricity Supply Region
h	=	International Supply Region
i	=	Intermittent Renewable/Storage Technology
j	=	All Years from Year 1 to Year 4
k	=	Capacity Type Other Than Capacity Type c
l	=	Vertical Load Steps Which Define Total Electricity Load
m	=	Mode of Operation (e.g., “Base,” “Intermediate,” “Peak”)
n	=	Renewable Capacity Type
p	=	Previous Year In Planning Horizon
q	=	Avoided T&D cost supply step for Distributed Generation
r	=	Electricity Supply Region
s	=	Season
t	=	Distributed generation Technology Type (Base, Peak)
u	=	Unit Retrofitted with Pollution Control Devices
v	=	NOX Containment Area
w	=	Next Year In Planning Horizon
x	=	Retirement Group
y	=	Year In the Planning Horizon
z	=	All Years From Year y to the End of the Planning Horizon (z=y,y+1,..,4)
A	=	Cofiring Retrofit Category
B	=	Cofiring Retrofit Level
C	=	Subset of Dispatchable Capacity Types c That Are Coal-Fired
D	=	Subset of Dispatchable Capacity Types c That Are Not Coal-Fired
E	=	Short Term Supply Step
F	=	Subset of Coal Capacity Types C Without Scrubbers
G	=	Subset of Coal Capacity Types C With Scrubbers
H	=	Coal-Fired Configuration Without Scrubbers
I	=	Coal-Fired Configuration With Scrubbers
J	=	Coal Supply Curves
K	=	Subset of Coal Supply Curves J That Are Subbituminous

L	=	Subset of Coal Supply Curves J That Are Lignite
M	=	Supply Curve Steps
N	=	Coal Demand Regions
O	=	Coal Units

Decision Variables

BCF_{yNA}	=	Retrofit Coal-Fired Capacity for Biomass Cofiring by Category A in Coal Region N in Year y (Gigawatts)
BCH_{yhb}	=	Build Canadian Hydro Capacity from Canadian Import Project b in International Region h in Year y (Gigawatts)
BDI_{yecrE}	=	Build Dispatchable Capacity Type c in Export Region e for Import Region r in Year y at Short Term Supply Step E (Gigawatts)
BII_{yeirE}	=	Build/Utilize Intermittent Capacity Type i in region e for region r in Year y at Short Term Supply Step E(Gigawatts)
BLD_{yrcE}	=	Build New Dispatchable Capacity Type c Beginning Operation in Year y in Region r at Short Term Supply Step E (Gigawatts)
BNK_{yw}	=	Bank Allowances for SO_2 From Year y to the Next Year w (Thousands of Tons)
BNK_{py}	=	Allowances Banked for SO_2 In Previous Year p to be Used or Banked In Year y (Thousands of Tons)
BRI_{yenrE}	=	Build Renewable Capacity Type n in region e for region r in Year y at Short Term Supply Step E (Gigawatts)
DGN_{yrqt}	=	Build/Utilize Distributed Generation Type t and avoided cost supply step q Beginning Operation in Year y in Region r (Gigawatts)
ECF_{yNA}	=	Existing Coal-Fired Capacity Retrofitted for Biomass Cofiring by Category A in Coal Region N in Year y (Gigawatts)
ECH_{yhb}	=	Existing Canadian Hydro Capacity from Canadian Import Project b in International Region h in Year y (Gigawatts)
EXC_{yO}	=	Existing Coal-Fired Units O Operated as Current Configuration in Year y (Gigawatts)
EXD_{yrD}	=	Existing Non-Coal Dispatchable Capacity Type D (Announced Retirements) in Year y in Region r (Gigawatts)
$EXDR_{yrDx}$	=	Existing Non-Coal Dispatchable Capacity Type D (Retirement Candidate) in Retirement Group x in Year y in Region r (Gigawatts)
EXH_{yr}	=	Existing Hydro Energy in Year y in Region r (Gigawatthours)
EXI_{yri}	=	Existing Intermittent Capacity Type i in Year y in Region r (Gigawatts)
EXR_{yrn}	=	Existing Renewable Capacity Type n in Year y in Region r (Gigawatts)
GEL_{yr}	=	Total Generation for Region r in Year y (Billion Kilowatthours)

IMP_{yNC}	=	Use Imported Coal in Coal Capacity Type H in Year y in Coal Region N (Trillion Btu)
INT_{yriE}	=	Build/Utilize Intermittent Renewable Type I Beginning Operation in Year y in Region r at Short Term Supply Step E (Gigawatts)
OCH_{yrh}	=	UtilizeAvailable Canadian Hydro Capacity in Year y from International Region h in Region r (Gigawatts)
OPC_{yrNCms}	=	Utilize Unscrubbed Coal Capacity Type C in Mode m in Season s in Year y in EMM Region r and Coal Region N (Gigawatts)
OPD_{yrfms}	=	Utilize Non-Coal Dispatchable Capacity Type D Consuming Fuel f in Mode m in Season s in Year y in Region r (Gigawatts)
OPH_{yrl}	=	Utilize Hydro Capacity in Vertical Load Step l in Year y in Region r (Gigawatts)
OPR_{yrn}	=	Utilize Renewable Capacity Type n in Year y in Region r (Gigawatts)
OTH_{yJ}	=	Other Coal (Nonutility) Demand Satisfied from Supply Curve J in Year y (Trillion Btu)
PMC_{yrcr}	=	Planned Maintenance Scheduled for Capacity Type c in Region r in Season s in Year y (Gigawatts)
QBM_{yNd}	=	Quantity of Biomass Fuel Consumed for Supply Step d in Coal Region N in Year y (Trillion Btu)
$QBMET_{yN}$	=	Quantity of Biomass Fuel Consumed for Ethanol Production in Coal Region N in Year y (Trillion Btu)
$QBMIN_{yN}$	=	Quantity of Biomass Fuel Consumed by the Industrial Sector in Coal Region N in Year y (Trillion Btu)
QCL_{yJM}	=	Quantity of Coal Produced from Supply Curve J and Supply Step M in Year y (Trillion Btu)
QNG_{yd}	=	Quantity of Natural Gas Consumed for Supply Step d in Year y (Trillion Btu)
QOL_{yd}	=	Quantity of Oil Consumed for Supply Step d in Year y (Trillion Btu)
RNW_{yrnE}	=	Build New Renewable Capacity Type n Beginning Operation in Year y in Region r at Short Term Supply Step E (Gigawatts)
STD_{yNC}	=	Use Coal Stocks in Coal Capacity Type C in Coal Region N in Year y (Trillion Btu)
STU_{yNC}	=	Store Coal Stocks in Coal Capacity Type C in Coal Region N in Year y (Trillion Btu)
TBM_{yABNC}	=	Quantity of Biomass Transported to Capacity Type C and Cofiring Category A with Cofiring Level B in Coal Demand Region N in Year y (Trillion Btu)
TCL_{yJNCa}	=	Quantity of Coal Transported from Supply Curve J to Coal Demand Region N Used in Capacity Type C with Activated Carbon Level a in Year y (Trillion Btu)

$TC2_{yJNC}$	=	Quantity of Coal Transported at Additional Coal (Tier 2) Cost from Supply Curve J to Coal Demand Region N Used in Capacity Type C in Year y (Trillion Btu)
TRN_{yecr}	=	Dispatchable Capacity Type c Transferred from Export Region e to Import Region r in Year y (Gigawatts)
$UNIT_{yOH}$	=	Existing Coal-Fired Units O That Operate That Operate as Uncontrolled Configuration Type H in Year y (Gigawatts)
$UNIT_{yOI}$	=	Existing Coal-Fired Units O That Operate That Operate as Controlled Configuration Type I in Year y (Gigawatts)

The operate, or utilize variable for coal-fired units (OPC_{yrNCms}) represent the choices to consume coals from different supply curves. Some coal plants may also have the option of cofiring with biomass (wood and waste products). For non-coal dispatchable technologies, the corresponding decision (OPD_{yrDfms}) considers fuel switching between the available fuel types f. For dual-fired units, this decision involves switching between alternate fuels such as oil and natural gas. The ECP can decide to utilize a dispatchable technology over some or all of the load segments (base, intermediate, and peak).

The available capacity for coal-fired units is represented for by the variables $UNIT_{yOH}$ and $UNIT_{yOI}$. Units with announced retirement dates are available until the scheduled retirement occurs. The remaining units can be retired by the ECP. This capacity is available for the entire planning horizon unless the costs of continuing operation exceed the corresponding revenues and replacement capacity is more economical. Two decision variables are used for existing non-coal dispatchable capacity (EXD_{yrD} and $EXDR_{yrDx}$). The first describes units with announced retirement dates. The second variable represents capacity that can be retired by the ECP if less expensive supplies can be built. Separate variables are also required for the utilization and addition of both the coal and non-coal dispatchable capacity because these capacity types involve decisions about their mode of operation. A similar structure could be used for intermittent technologies, but it is unnecessary because the utilization of the capacity is not a decision variable but is determined by the availability of the renewable resource. Combining the decision variables reduces the size of the model.

The formulation does not explicitly represent intermittent technologies coupled with a back-up source of power, but it effectively determines the appropriate back-up technology. If additional capacity is need to meet reliability requirements and an intermittent technology without a full capacity credit (i.e., contribution to reserve margin determined by its ability to generate power during peak load) is economical, then another capacity type will also have to be built. This structure will allow additions of intermittent technologies when a capacity surplus exists, as long as the resulting fuel savings offsets the capital investment. The model could be modified to include intermittent technologies coupled with a backup power source by creating a composite capacity type that combined cost and operating characteristics of both plant types. This capacity type would receive a full capacity credit and would then be analogous to a dispatchable capacity type. However, this approach would reduce the flexibility of the model to choose the backup technology.

Distributed generation technologies are assumed to be built for two modes of operation–base and peak. The utilization rates for baseload and peaking units are assumed to be fifty and five percent, respectively. Compared to central-station plants, distributed generation capacity typically has higher construction and operating costs, but may be economic because it reduces the need for investment in new transmission and distribution (T&D) equipment. The amount of incremental T&D expenditures avoided by distributed generation varies by region because it depends on the distribution of load. A supply curve is used to describe the quantity and cost of new investment that would be unnecessary because of distributed generation.

Right-Hand Side Values

$AMER_{y}$	=	Mercury Emission Limit for Year y (Million Tons)
$ANOX_{yv}$	=	NOX Emission Limit for NOX Containment Area v and for Year y
$ASO2_{y}$	=	Total SO_2 Limit for Year y (Million Tons)
$CAPL_{yr}$	=	Capacity Addition Limit In Year y and Region r (Gigawatts)
$CHYL_{hb}$	=	Limit for Accelerating Canadian Hydro Capacity for Project b in International Region h
COL_{yrc}	=	Available Coal Capacity Type c for Year y and Region r (Gigawatts)
$CPLIM_{ycE}$	=	Short Term Capacity Limit for Dispatchable Type c for Year y and Supply Step E (Gigawatts)
$CPLIM_{yiE}$	=	Short Term Capacity Limit for Intermittent Type i for Year y and Supply Step E (Gigawatts)
$CPLIM_{yrE}$	=	Short Term Capacity Limit for Renewable Type r for Year y and Supply Step E (Gigawatts)
$DGNL_{yrg}$	=	Amount of new capacity that can be met by distributed generation for supply step q in year y and region r (Gigawatts)
ELC_{yrl}	=	Capacity Requirement In the Vertical Load Step l In Year y and Region r (Gigawatts)
EXP_{yr}	=	Electricity Capacity Export Limit in Year y and Region r (Gigawatts)
$FGDL_{y}$	=	Retrofit Limit for Scrubber Retrofits in Year y (Gigawatts)
$INTL_{ir}$	=	Intermittent Build Limit for Intermittent Technology I and Region r (Gigawatts)
MAX_{yJ}	=	Maximum Production for Coal Supply Curve J in Year y (Trillion Btu)
NUC_{yrc}	=	Available Nuclear Capacity Type c for Year y and Region r (Gigawatts)
RGS_{yr}	=	Regional SO_2 Emissions Limits for Year y and Region r (Million Tons)
RMQ_{yr}	=	Total Capacity Requirement Including a Reserve Margin In Year y and Region r (Gigawatts)
$RNWL_{nr}$	=	Renewable Build Limit for Renewable Capacity Type n and Region r (Gigawatts)

Coefficients

$CAVD_{yrq}$ = Investment Cost for New T&D Equipment Avoided by DG for supply step q in Region r.

$CBCF_{yA}$ = Investment Cost to Retrofit Cofiring Category A in Year y (Millions of Dollars / Gigawatt)

$CBCH_{yhb}$ = Investment Cost to Build Canadian Hydro Capacity from Canadian Project b in International Region h With Initial Online Year y (Millions of Dollars / Gigawatt)

$CBDI_{yecrE}$ = Investment Cost to Build Dispatchable Capacity Type c With Initial Online Year y in Region e for Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

$CBII_{yeirE}$ = Investment and Operating Cost to Build/Operate Intermittent Technology I Starting Operation In Year y in Region e for Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

$CBLD_{yrcE}$ = Investment Cost to Build Capacity Type c With Initial Online Year y in Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

$CBRI_{yenrE}$ = Investment Cost to Build Renewable Capacity Type n With Initial Online Year y in Region e for Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

$CBTU_{yrNCms}$ = Fuel Requirement to Utilize Coal Capacity Type C in Mode m in Season s in Year y in EMM Region r and Coal Region N (Trillion Btu)

$CBT1_{yJUH}$ = Allowable First-Tier Coal Transported from Supply Curve J used, per Unit of Capacity, by Unit U of Unscrubbed Configuration H in Year y (Trillion Btu per Gigawatt)

$CBT1_{yJUI}$ = Allowable First-Tier Coal Transported from Supply Curve J used, per Unit of Capacity, by Unit U of Scrubbed Configuration I in Year y (Trillion Btu per Gigawatt)

$CDGN_{yrt}$ = Investment and Operating Cost to Build/Operate Distributed Generating Technology t Starting Operation in Year y in Region r (Millions of Dollars)

$CDVL_{yOH}$ = Allowable Lignite Consumption per Unit of Capacity by Unit O Operated as Unscrubbed Configuration H in Year y (Trillion Btu per Gigawatt)

$CDVL_{yOI}$ = Allowable Lignite Consumption per Unit of Capacity by Unit O Operated as Scrubbed Configuration I in Year y (Trillion Btu per Gigawatt)

$CDVS_{yOH}$ = Allowable Subbituminous Coal Consumption per Unit of Capacity by Unit O Operated as Unscrubbed Configuration H in Year y (Trillion Btu per Gigawatt)

$CDVS_{yOI}$ = Allowable Subbituminous Coal Consumption per Unit of Capacity by Unit O Operated as Scrubbed Configuration I in Year y (Trillion Btu per Gigawatt)

$CFBTU_{yNA}$ = Average Fuel Use, per Unit of Capacity, for Units of Cofiring Category A in Coal Region N in Year y (Trillion Btu per Gigawatt)

$CFLEV_{AB}$ = Cofiring Level for Cofiring Category A and Utilization Option B (Fraction)

$CFXC_{yrc}$ = Fixed Operating Costs for Dispatchable Capacity Type c (With Announced Retirement Date) in Year y and Region r (Millions of Dollars / Gigawatt)

$CFXCR_{yrcx}$ = Fixed Operating Costs for Dispatchable Capacity Type c (Retirement Candidate) In Retirement Group x in Year y and Region r (Millions of Dollars / Gigawatt)

$CFXF_{yA}$ = Fixed Operating Costs for Cofiring Retrofit Category A in Year y (Millions of Dollars / Gigawatt)

$CFXU_{yOH}$ = Fixed (Including Retrofit) Costs to Operate Coal Unit O as Uncontrolled (e.g., Unscrubbed) Configuration Type H in Planning Year y (Gigawatts)

$CFXU_{yOI}$ = Fixed (Including Retrofit) Costs to Operate Coal Unit O as Controlled (e.g., Scrubbed) Configuration Type I in Planning Year y (Gigawatts)

$CINT_{yriE}$ = Investment and Operating Cost to Build/Operate Intermittent Technology I Starting Operation In Year y and Region r at Short term Supply Step E (Millions of Dollars / Gigawatt)

$CNOX_{vck}$ = Investment Cost to Convert Uncontrolled Coal Capacity Type c to Controlled Plant Group o with NOX Control Technology a

$CONT_{yJOH}$ = Coal Consumed per Unit of Capacity by Unit O Operated as Unscrubbed Configuration H Required to be Satisfied by Coal Supply Curve J in Year y (Trillion Btu per Gigawatt)

$CONT_{yJOI}$ = Coal Consumed per Unit of Capacity by Unit O Operated as Scrubbed Configuration I Required to be Satisfied by Coal Supply Curve J in Year y (Trillion Btu per Gigawatt)

$COPC_{yrNCms}$ = Nonfuel Operating Costs to Utilize Coal Capacity Type C in Mode m in Season s in EMM Region r and Coal Region N in Year y (Million Dollars per Gigawatt)

$COPD_{yrDfms}$ = Variable Operating Cost Including Expected Fuel and Activated Carbon Costs to Operate Non-Coal Dispatchable Capacity Type D Using Fuel f In Mode m in Season s for Year y and Region r (Million Dollars / Gigawatt)

$COPF_{yAB}$ = Incremental Operating Costs to Cofire Coal Capacity Type in Cofiring Category A and Cofiring Level B in year y (Million Dollars per Gigawatt)

$COPH_{yrl}$ = Variable Operating Cost to Operate Hydro Capacity In Load l for Year y and Region r (Million Dollars / Gigawatt)

$COPR_{yrn}$ = Variable Operating Cost to Operate Renewable Capacity Type n for Year y and Region r (Million Dollars / Gigawatt)

$CPMR_{rc}$ = Amount of Time Required for Planned Maintenance for Capacity Type c in Region r (Thousands of Hours)

$CRNW_{yrnE}$ = Investment Cost to Build Renewable Capacity Type n With Initial Online Year y in Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

$CTRN_{yecr}$ = Cost of Transferring Capacity Type c from Region e to Region r in Year y (Millions of Dollars / Gigawatt)

$CTR1_{yJNCa}$ = Tier 1 Transportation and Activated Carbon Cost to Use Coal from Supply Curve J to Coal Demand Region N Used in Capacity Type C with Activated Carbon Level a in Year y (Million Dollars per Trillion Btu)

$CTR2_{yJNC}$ = Incremental Transportation Cost for Tier 2 Coal from Supply Curve J to Coal Demand Region N Used in Capacity Type C in Year y (Million Dollars per Trillion Btu)

ELA_{yrCml} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, and Load Following Rates) for Coal Capacity Type C Allocated to Meet Capacity Requirements In Load Step l In Year y, Region r By Capacity Type c In Mode m (Fraction)

ELA_{yrDml} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, and Load Following Rates) for Non-Coal Dispatchable Capacity Type D Allocated to Meet Capacity Requirements In Load Step l In Year y, Region r By Capacity Type c In Mode m (Fraction)

$ELCH_{yhb}$ = Derating Factor (Availability of Resource) for Canadian Project b in International Region h In Year y (Fraction)

ELD_{yrt} = Derating Factor corresponding to mode of operation (Base, Peak) for Distributed Generation technology type t in Region r in Year y (Fraction)

ELI_{yril} = Derating Factor (Availability of Resource) for Intermittents in Load Step l In Region r By Intermittent Technology Type I Beginning Operation in Year y (Fraction)

ELR_{yrn} = Derating Factor (Adjustment for Forced Outage, Planned Maintenance, Load Following Rates and Availability of Resource) for Renewable Capacity Allocated to Meet Capacity Requirements in Year y, Region r By Capacity Type n (Fraction)

HRD_{yrD} = Heat Rate for Dispatchable Capacity Type D in Region r in Year y(Btu per Kilowatthour)

HRR_{yrn} = Heat Rate for Renewable Capacity Type n in Region r in Year y(Btu per Kilowatthour)

$ISHR_{i}$ = Amount of Generation for Intermittent Capacity Type i That Is Counted Toward Minimum Generation Requirement (Fraction)

$LHRS_{l}$ = Hours in Load Segment l (Thousands of Hours)

$MERC_{yJNCa}$ = Amount of Mercury in Coal from Supply Curve J Used in Coal Capacity in Coal Region N in Coal Capacity Type C With Activated Carbon Option a in year y (Tons / Trillion Btu)

$MERD_{yrDfms}$ = Amount of Mercury Produced Per Unit of Electricity Generated in Region r By Non-Coal Dispatchable Capacity Type D With Fuel f In Mode m in Season s in Year y (Tons / Gigawatt)

$NOXC_{yvNCms}$ = Amount of NOX Produced per Unit of Electricity Generated in Year y for NOX Containment Area v by Coal Capacity Type C in Coal Region N in Mode m and in Season s (Millions of Tons / Gigawatt)

$NOXD_{yvDfms}$ = Amount of NOX Produced per Unit of Electricity Generated in Year y for NOX Containment Area v by Non-Coal Dispatchable Capacity Type D with Fuel f in Mode m and in Season s (Millions of Tons / Gigawatt)

$NOXR_{yvHI}$ = Reduction in Amount of NOX Produced Due to Converting Uncontrolled Existing Coal Configuration H to Controlled Configuration I k by Retrofitting NOX Controls in NOX Containment Area v in Year y (Millions of Tons / Gigawatt)

PBM_{yrd} = Production Cost for Biomass Consumed to Generate Electricity on Supply Step d in Region r in Year y (Dollars per Million Btu)

PCL_{yJM} = Production Cost for Coal from Supply Curve J and Coal Supply Step M in Year y (Trillion Btu)

PNG_{yd} = Production Cost for Natural Gas Consumed to Generate Electricity on Supply Step d in Year y (Dollars per Million Btu)

POL_{yd} = Production Cost for Oil Consumed to Generate Electricity on Supply Step d in Year y (Dollars per Million Btu)

RMC_{yrc} = Contribution Made to Satisfying the Reserve Margin Made By Dispatchable Capacity Build Type c Beginning Operation In Year y for Region r (Fraction)

RMD_{yrt} = Contribution Made to Reserve Margin Made by Distributed Generation Type t in Year y for Region r (Fraction)

RMI_{yri} = Contribution Made to Satisfying the Reserve Margin Made By Intermittent Technology I Beginning Operation In Year y for Region r (Fraction, 0.0 = Resource Never Available at Peak, 1.0 = Resource is Always Available at Peak)

$RMIN_{y}$ = Amount of Total Generation or Sales That Must Be Provided by Renewable Technologies (Fraction)

RMR_{yrn} = Contribution Made to Satisfying the Reserve Margin Made By Renewable Capacity Build Type n Beginning Operation In Year y for Region r (Fraction)

$RSHR_{n}$ = Amount of Generation for Renewable Capacity Type n That Is Counted Toward Minimum Generation Requirement (Fraction)

$SHOURS_{s}$ = Hours in Season s (Thousands of Hours)

$SO2_{yrcfms}$ = Amount of SO_2 Produced Per Unit of Electricity Generated In Year y, Region r By Capacity Type c With Fuel f In Mode m in Season s (Millions of Tons / Gigawatt)

$TLOSS_{yer}$ = 1 - Interregional Transmission Loss Factor from region e to region r in Year y (Fraction)

Objective Function

The objective function of the planning component is to minimize the total, discounted present value of the costs of meeting demand and complying with environmental regulations over the entire planning horizon. All costs are in nominal dollars and the inflation rate is determined using the Gross Domestic Product (GDP) Implicit Price Deflator. The coefficient of each decision variable represents the present value of that particular cost component, discounted to the current forecast year. The total cost includes both investment costs associated with changes in capital stock and variable costs that result from the operation of the available generating capability. Cost components in the objective function include:

- operation (fixed) plus retrofit (if any) costs of existing uncontrolled coal units ($CFXU_{yOH}$ • $UNIT_{yOH}$) and controlled units ($CFXU_{yOI}$ • $UNIT_{yOI}$)
- operation (fixed) of existing non-coal dispatchable capacity types ($CFXD_{yrD}$ • EXD_{yrD} and $CFXDR_{yrDx}$ • $EXDR_{yrDx}$)
- operation (fixed) costs for cofiring with biomass in coal capacity types to cofire with biomass ($CFFX_{yA}$ • ECF_{yNA} and $CFFX_{yA}$ • BCF_{yNA})
- production costs for coal, natural gas, oil, and biomass (PCL_{yJM} • QCL_{yJM}, PNG_{yd} • QNG_{yd}, POL_{yd} • QOL_{yd}, and PBM_{yNd} • QBM_{yNd})
- transportation and activated carbon costs for delivering coal for Tier-1 ($CTR1_{yJNCa}$ • TCL_{yJNCa}) and Tier-2 ($CTR2_{yJNC}$ • $TC2_{yJNC}$) rates
- operation (variable) costs for coal capacity types ($COPC_{yrNCms}$ • OPC_{yrNCms})
- operation (variable) costs, including transportation, for non-coal dispatchable capacity types ($COPD_{yrDfms}$ • OPD_{yrDfms})
- operation (variable) costs for biomass cofiring ($COPF_{yAB}$ • TBM_{yABRH})
- operation of renewable capacity types ($COPR_{yrnm}$ • OPR_{yrnm})
- operation of hydro capacity ($COPH_{yrl}$ • OPH_{yrl})
- construction and operation of intermittent renewable technologies ($CINT_{yriE}$ • INT_{yriE})
- construction of new dispatchable capacity types ($CBLD_{yrcE}$ • BLD_{yrcE})
- construction of new dispatchable capacity types for another region ($CBDI_{yecrE}$ • BDI_{yenrE})
- construction of Canadian Hydro capacity ($CBCH_{yhp}$ • BCH_{yhp})
- construction of new intermittent capacity types for another region ($CBII_{yeirE}$ • BII_{yeirE}).
- construction of new renewable capacity types ($CRNW_{yrnE}$ • RNW_{yrnE}).
- construction of new renewable capacity types for another region ($CBRI_{yenrE}$ • BRI_{yenrE}).
- investment costs to retrofit existing coal capacity to cofire with biomass ($CBCF_{yA}$ • BCF_{yNA})

- transfer of capacity between regions ($CTRN_{yecr} \bullet TRN_{yecr}$)
- construction of new distributed generation capacity, adjusted for avoided transmission and distribution expenditures ($\{CDGN_{yrt} - CAVD_{yrq}\} \bullet DGN_{yrqt}$)

The objective function is expressed as follows:

(3-1)

$$
\begin{aligned}
MIN\ & \sum_{y}\sum_{O}\sum_{H} CFXU_{yOH}\cdot UNIT_{yOH} + \sum_{y}\sum_{O}\sum_{I} CFXU_{yOI}\cdot UNIT_{yOI} + \sum_{y}\sum_{r}\sum_{D} CFXD_{yrD}\cdot EXD_{yrD} \\
&+\sum_{y}\sum_{r}\sum_{D}\sum_{x} CFXDR_{yrDx}\cdot EXDR_{yrDx} + \sum_{y}\sum_{N}\sum_{A} CFXF_{yA}\cdot ECF_{yNA} + \sum_{y}\sum_{N}\sum_{A} CFXF_{yrA}\cdot BCF_{yNA} \\
&+\sum_{y}\sum_{J}\sum_{M} PCL_{yJM}\cdot QCL_{yJM} + \sum_{y}\sum_{d} PNG_{yd}\cdot QNG_{yd} \\
&+\sum_{y}\sum_{d} POL_{yd}\cdot QOL_{yd} + \sum_{y}\sum_{N}\sum_{d} PBM_{yNd}\cdot QBM_{yNd} \\
&+\sum_{y}\sum_{J}\sum_{N}\sum_{C}\sum_{a} CTR1_{yJNCa}\cdot TCL_{yJNCa} + \sum_{y}\sum_{J}\sum_{N}\sum_{C} CTR2_{yJNC}\cdot TC2_{yJNC} \\
&+\sum_{y}\sum_{r}\sum_{N}\sum_{C}\sum_{m}\sum_{s} COPC_{yrNCms}\cdot OPC_{yrNCms} + \sum_{y}\sum_{r}\sum_{D}\sum_{m}\sum_{s}\sum_{f} COPD_{yrDfms}\cdot OPD_{yrDfms} \\
&+\sum_{y}\sum_{A}\sum_{B}\sum_{N}\sum_{C} COPF_{yAB}\cdot TBM_{yABNC} + \sum_{y}\sum_{r}\sum_{n}\sum_{m} COPR_{yrnm}\cdot OPR_{yrnm} \\
&+\sum_{y}\sum_{r}\sum_{l} COPH_{yrl}\cdot OPH_{yrl} + \sum_{y}\sum_{r}\sum_{i}\sum_{E} CINT_{yriE}\cdot INT_{yriE} \\
&+\sum_{y}\sum_{r}\sum_{c}\sum_{E} CBLD_{yrcE}\cdot BLD_{yrcE} + \sum_{y}\sum_{e}\sum_{r}\sum_{c}\sum_{E} CBDI_{yecrE}\cdot BDI_{yecrE} \\
&+\sum_{y}\sum_{h}\sum_{p} CBCH_{yhp}\cdot BCH_{yhp} + \sum_{y}\sum_{e}\sum_{i}\sum_{r}\sum_{E} CBII_{yeirE}\cdot BII_{yeirE} \\
&+\sum_{y}\sum_{r}\sum_{n}\sum_{E} CRNW_{yrnE}\cdot RNW_{yrnE} + \sum_{y}\sum_{e}\sum_{n}\sum_{r}\sum_{E} CBRI_{yenrE}\cdot BRI_{yenrE} \\
&+\sum_{y}\sum_{N}\sum_{A} CBCF_{yA}\cdot BCF_{yNA} + \sum_{y}\sum_{e}\sum_{c}\sum_{r} CTRN_{yecr}\cdot TRN_{yecr} \\
&+\sum_{y}\sum_{r}\sum_{t}\sum_{q} (CDGN_{yrt} - CAVD_{yrq})\cdot DGN_{yrqt}
\end{aligned}
$$

Description of Constraints

Coal Submatrix. The ECP contains a series of equations to represent the production, transportation, and consumption of coal by electric generators. These constraints simulate the costs and characteristics of the different coals described by supply curves in the Coal Market Module (CMM). The ECP determines decisions for operation, capacity expansion, and emissions control in coal-fired capacity based on this representation. Since coal plants can also be modified to cofire with biomass fuels, decisions to retrofit existing capacity to allow cofiring are also included in this structure.

The ECP utilizes the same two-tier pricing system for transportation costs that is incorporated in the CMM. This methodology assumes that the amount of coal that can be delivered at current rates is limited to historical flows. Additional quantities are assumed to require an incremental cost.

Each of the supply curves represents coal from a single Coal Region, characterized by one rank (bituminous, subbituminous, or lignite), emissions content (average), and cost structure. A Coal Region may contain more than one supply curve and the coal produced in a given Coal Region may be able to be transported for use by generators in multiple Electricity Regions. Similarly, coal plants in a particular Electricity Region may be able to obtain fuel supplies from more than one Coal Region.

Production Balance Rows. These rows insure that the coal production from each of the coal supply curves does not exceed the available annual capacity of the mines. For each supply curve J, the following constraints specify that the total annual production of coal over all of the supply steps M (PCL_{yJM}) does not exceed the maximum production level (MAX_{yJ}).

(3-2)
$$\sum_{M} PCL_{yJM} \leq MAX_{yJ}$$

for every coal supply curve J in year y.

Material Balance Rows for Supply. These equations balance the coal produced by a particular supply curve (PCL_{yJM}) and the coal transported to generating plants (TCL_{yJNCa}). Production must also be sufficient to satisfy nonutility coal use (OTH_{yE}). The rows are specified as follows:

(3-3)
$$\sum_{J}\sum_{C}\sum_{a} TCL_{yJNCa} + OTH_{yJ} - \sum_{M} PCL_{yJM} \leq 0$$

for every coal supply curve J in year y.

Material Balance Rows for Demand. These constraints insure that the coal transported from the Coal Regions is sufficient to satisfy the fuel consumption of unscrubbed and scrubbed generating plants in Electricity Regions. The requirements of coal capacity can also be met by imported coal (IMP_{yNC}). The quantity transported also accounts for stock additions (STU_{yNC}) and stock withdrawals (STD_{yNC}). For each capacity type, the fuel requirement is the product of the capacity allocated to produce electricity (OPC_{yrNCms}) and the fuel use per unit of capacity ($CBTU_{yrNCms}$). Coal use is also reduced by biomass fuel used for cofiring (TBM_{yABNC}). The material balance rows insure that the coal transported (TCL_{yJNCa}) is sufficient to satisfy the demand by each coal-fired capacity type, as follows:

(3-4)
$$\sum_{r}\sum_{m}\sum_{s} CBTU_{yrNCms} \cdot OPC_{yrNCms} + \sum_{A}\sum_{B} TBM_{yABNC} + STU_{yNC} - STD_{yNC} - IMP_{yNC} - \sum_{J}\sum_{a} TCL_{yJNCa} \leq 0$$

for every coal plant type C in coal region N in year y.

Contract Flows. These equations require minimum quantities of coal production to satisfy electricity contracts for coal produced by specific coal curves and transported to specific electricity generators. For coal used in unscrubbed plants, the contract flows are represented as follows:

(3-5)
$$\sum_{F}\sum_{a} TCL_{yJNFa} - \sum_{O}\sum_{H} CONT_{yJOH} \cdot UNIT_{yOH} \geq 0$$

for every supply curve J to coal region N in year y.

The coefficient $CONT_{yJOH}$ represents the quantity, per gigawatt of capacity, of the total coal consumed by unscrubbed capacity type J that must be satisfied by coal from supply curve J in coal region N in year y.[21] The product of this coefficient and the capacity variable $UNIT_{yOH}$ provides the corresponding contract flows. Thus, the equation requires that the coal transported from the supply curve J in coal region N to unscrubbed coal plants F (TCL_{yJNFa}) must satisfy the contract amount.

The analogous constraints for contract flows to scrubbed plants are obtained by substituting the scrubbed capacity types G for the unscrubbed capacity types F and the units O with scrubbed configurations I instead of unscrubbed configurations H.

Diversity Requirements. Some coal-fired units are not able to burn subbituminous coal or lignite or can only use limited amounts. These equations impose limits on the quantity of subbituminous and lignite coal that can be used to satisfy coal demands by specified coal capacity types and regions. For subbituminous coal in unscrubbed plants, the diversity constraints are represented as follows:

(3-6)
$$\sum_{K}\sum_{a} TCL_{yKNFa} - \sum_{O}\sum_{H} CDVS_{yOH} \cdot UNIT_{yOH} \leq 0$$

for unscrubbed capacity types F in coal region N in year y.

[21] $CONT_{yJOH}$ is derived by multiplying the total fuel consumed at the unit during the previous year by the fraction of this demand that must be satisfied by the particular contract and then dividing by the total capacity.

The coefficient $CDVS_{yOH}$ represents the maximum quantity, per gigawatt of capacity, of the total coal consumed by coal units O of unscrubbed configuration H that can be satisfied by coal by subbituminous coal in year y.[22] The product of this coefficient and the capacity variable $UNIT_{yOH}$ provides the corresponding contract flows. Thus, the equation states that the sum of subbituminous coal transported from the subbituminous supply curves K unscrubbed coal plants H in coal region N cannot exceed the maximum allowable use of subbituminous coal. Similar constraints are also imposed for subbituminous coal consumption in scrubbed plants by substituting the scrubbed capacity types G for the unscrubbed capacity types H and the scrubbed configurations J for the unscrubbed configurations I. The analogus constraints for lignite use in both unscrubbed and scrubbed capacity are obtained by replacing the subbituminous supply curves K with the lignite supply curves L.

Transportation Rates. Transportation rates are applied using a two-tier system. The first tier rates assume that the current rates are limited to historical flow levels. In order to deliver additional supplies, an incremental cost (second tier rates) is incurred. The constraints on first-tier rates are imposed as follows:

(3-7)
$$\sum_{a} TCL_{yJNFa} - TC2_{yJNF} - \sum_{O}\sum_{H} CBT1_{yJOH} \cdot UNIT_{yOH} \leq 0$$

for every supply curve J to to unscrubbed capacity type F in coal region N in year y.

The coefficient $CBT1_{yJOH}$ represents the maximum quantity, per gigawatt of capacity, of the total coal consumed by coal unit O of unscrubbed capacity configuration H that can be transported from supply curve J at the first-tier rates.[23] The product of this coefficient and the capacity variable $UNIT_{yOH}$ provides the corresponding quantities with these rates. Thus the equation states that the total transportation of coal from supply curve J to unscrubbed plants in Coal Region N in year y is the sum of the first-tier and second-tier flows. The analogous constraints for tier flows to scrubbed plants are obtained by substituting the scrubbed capacity types I for the unscrubbed capacity types H and the units O with scrubbed configurations K instead of unscrubbed configurations J.

Biomass Cofiring Capacity Balance Rows. Coal-fired plants can be retrofitted to cofire coal with biomass fuel. The maximum cofiring shares depend on the type of boiler and the size of the coal fired unit so the available capacity is divided into retrofit categories A to represent the corresponding

[22] $CDVS_{yOH}$ is derived by multiplying the total fuel consumed at the unit during the previous year by the maximum share of this demand that can be satisfied by the subbituminous coal and then dividing by the total capacity. The subsequent coefficients for lignite and scrubbed capacity types are determined similarly.

[23] $CBT1_{yJOH}$ is derived by multiplying the total fuel consumed at the unit O of unscrubbed configuration H during the previous year by the allowable share from supply curve J that is subject to tier-one rates and then dividing by the total capacity. The subsequent coefficients for scrubbed capacity types are determined similarly.

variations in cofiring capability .[24] For each cofiring category, additional cofiring levels B can be achieved by incurring additional transportation costs for incremental biomass supplies.

These equations insure that the use of biomass in coal-fired capacity does not exceed the capability that has been retrofitted to allow cofiring at specified levels. The available cofiring capacity is the sum of the previous retrofit decisions by cofiring category A (ECF_{yrA}) and new retrofit decisions (BCF_{yrA}). The transportation of biomass for cofiring in coal capacity type C in coal region N (TBM_{yABNC}) is converted to the equivalent generating capacity by dividing by the product of the corresponding cofiring level ($CFLEV_{AB}$) and the fuel use per unit of capacity ($CFBTU_{yNA}$).[25] Therefore, Equation 3-8 insures that coal-fired capacity using biomass does not exceed the existing and new retrofitted capacity.

(3-8) $$\sum_{B}\sum_{C} TBM_{yABNC} / (CFBTU_{yNA} \cdot CFLEV_{AB}) - ECF_{yNA} - BCF_{yNA} \leq 0$$

for each cofiring category A in coal region N in year y.

Biomass Cofiring Production Balance Rows. This set of constraints insure that the production (and fuel consumption) from biomass in coal-fired capacity does not exceed the maximum cofiring levels corresponding to the retrofit decisions ($CFLEV_{AB}$). For each coal-fired capacity type C in coal region N in year y, TBM_{yABNC}, describes the consumption of biomass fuels for use in coal plants and TCL_{yJNCa} represents the corresponding transportation of coal. The coefficient of TBM_{yABNC} is the ratio of the coal share to the biomass share. Therefore, Equation 3-9 limits fuel use of biomass relative to coal according to the retrofitted cofiring levels, as follows:

(3-9) $$\sum_{A}\sum_{B} TBM_{yABNC} \cdot (1 - CFLEV_{AB}) / CFLEV_{AB} - \sum_{J}\sum_{a} TCL_{yJNCa} \leq 0$$

for each coal capacity type C in Coal Region N in year y.

Emissions. These constraints limit the emissions produced as a result of electricity generation. The equations below are described for SO_2, NO_X, and mercury emissions, but similar constraints can be included for other emissions such as carbon by substituting the appropriate emissions coefficient[26].

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[24]The assumptions for costs and production levels associated with retrofitting coal-fired units to cofire with biomass were developed in a series of communications between Energy Information Administration staff and analysts from the Electric Power Research Institute (EPRI) and the Antares Group, Incorporated. These inputs are summarized in Appendix 3.D.

[25]The fuel use per unit of capacity depends on the utilization rate. The utilization rate from the previous year is used to determine this value.

[26]Currently, limits on carbon emissions are represented by including the expected carbon fee in the operating cost. This discourages the operation and expansion of carbon-producing technologies.

The ECP can accommodate multiple emissions restrictions simultaneously by incorporating each set of constraints within the model.

According to the CAAA, the allowances for SO_2 emissions may be traded nationwide among utilities and nonutilities so the corresponding limit on emissions in each year is actually national rather than regional or company-level. In each year, the emissions limit is determined by the sum of the allowances ($ASO2_y$). However, the allowances do not have be used in the year that they are allocated—they can be banked for future use. The SO_2 emissions in a given year can exceed the sum of the allowances by using allowances banked in a previous year (BNK_{py}). Conversely, allowances can be banked for use in a subsequent year (BNK_{yw}) by reducing emissions below the specified target. The emissions limit for a given year is adjusted to represent additions or withdrawals from the bank.

Potentially, each capacity type may produce emissions although coal-fired plants produce most of the emissions. The amount of emissions produced depends on the fuel used, pollution control devices installed (if any), and amount of electricity produced. For coal capacity, the decision variable TRC_{yJNCa} describes the coal transported for use in power plants and $SO2_{yJNC}$ represents the corresponding emission rate for SO_2.[27] The product of these two terms gives the SO_2 emissions from coal. Similarly, the product of the decision variable $OPD_{yrcfams}$ and the coefficient $SO2_{yrcfms}$ represents the corresponding emissions from non-coal capacity types.

A national level constraint is represented as follows:

(3-10)
$$\sum_{y}\sum_{J}\sum_{N}\sum_{C}\sum_{a} SO2C_{yJNC} \cdot TRC_{yJNCa} + \sum_{y}\sum_{r}\sum_{D}\sum_{f}\sum_{m}\sum_{s} SO2D_{yrDfms} \cdot OPD_{yrDfms} + BNK_{yw} - BNK_{py} \leq ASO2_{y}$$

for every year y in the planning horizon.

Recent proposed legislation has also contained limits on mercury emissions[28]. The mercury constraint is similar to the SO_2 structure except mercury in coal plants can also be reduced by injecting activated carbon. The mercury constraint is specified as follows:

(3-11)
$$\sum_{J}\sum_{N}\sum_{C}\sum_{a} MERC_{yJNCa} \cdot TRC_{yJNCa} + \sum_{r}\sum_{D}\sum_{f}\sum_{m}\sum_{s} MERD_{yrDfms} \cdot OPD_{yrDfms} \leq AMER_{y}$$

[27]The use of activated carbon only affects mercury emissions so it is not reflected in the SO_2 emissions coefficient.

[28]Most of the proposed mercury regulations do not include banking. If banking is included, the constraint would be specified in a similar manner as the SO2 formulation.

for every year y in the planning horizon.

Selected states are also subject to limitations on nitrogen oxide (NO_X) emissions. As with SO_2 and mercury, coal-fired capacity accounts for virtually all of the Nox emissions resulting from power generation. However, the NO_x content does not really vary between different types of coal so the corresponding emissions cannot be reduced by switching coals, so the available compliance options only involve installing pollution control equipment. Therefore, the formulation of NO_x limits differs from the corresponding constraints for SO_2 and mercury emissions. The product of the NO_X emission rate ($NOXC_{yvNCms}$) and the utilization variable (OPD_{yvNCms}) describes the emissions from coal plants in NO_X containment region v. Similarly, the second term provides the NO_X emissions from non-coal capacity. The third term represents the reduction in emissions that result from retrofitting uncontrolled coal-fired units with NO_x pollution control devices. The NO_x limits are represented as follows:

(3-12)

$$\sum_N \sum_C \sum_m \sum_s NOXC_{yvNCms} \cdot OPC_{yvNCms} + \sum_D \sum_f \sum_m \sum_s NOX_{yvDfms} \cdot OPD_{yrDfms} - \sum_O \sum_H \sum_I NOXR_{yOHI} \cdot UNIT_{yOH} \leq ANOX_{yv}$$

for each NOX containment region v in year y.

The first two terms represent the NO_x emissions resulting from the utilization of coal and non-coal capacity, respectively. The last term on the left-hand side of the equation accounts for the reduction in emissions that results from converting a coal-fired unit from an uncontrolled to a controlled configuration by installing NO_x control equipment.

National Short-Term Supply Cost Adjustments. The ECP includes short-term supply cost adjustment factors for the installation of new electricity generating technologies. The factors reflect the expectation that rapid expansions in the supply of installations using new generating technologies will incur shortages of critical input resources. Shortages could reflect manufacturing bottlenecks, as well as delays in regulation, licensing and public approval, and constraints incurred from shortages of construction and operation personnel and equipment.

In the ECP, U.S. generating capacities of new technologies are permitted to increase by a prespecified amount without including cost increases, but above some threshold rate of increase, costs are assumed increase. In AEO2004, capacity builds in a given year can be up to 20% above a base amount ($CPBAS_{yc}$) in a given year without a cost adjustment. The base amount is equal to the greatest amount of capacity brought on line in a single year over the last ten years, for each technology. If no existing capacity is online, then an off-line assumption is used for the base amount, which is set based on the newness of the technology.

The short-term cost adjustment factors are based on the percentage change of national installed capacity of a technology, using an exponential cost function relating an increase in capacity to a cost multiplier. The function is divided into three distinct points to establish a three step supply curve for the installation of new capacity. For AEO2004, the capacity assumed for the steps ($CPSTP_{cE}$) is 120% of the base amount for the first step, 80% of the base amount for the second step and 100% of the base amount for the third step. The first step has a cost multiplier of 1.0. The cost multiplier for the second and third steps are calculated from the following function:

(3-13)
$$CST_{ycE} = \left(\frac{C_2}{C_1} - a_{thresh}\right)^{\frac{\ln(1+a_2)}{\ln(1+a_1)}}$$

where:

CST_{ycE}= cost multiplier for year y, capacity type c, and short term supply step E

C_1 = capacity at current step

C_2 = capacity at midpoint of subsequent step

a_{thresh} = threshold above which elasticity is active, defined as percent increase based on current installed capacity (i.e. 20% for AEO2004)

a_1 = increase in capital cost for every a_2 increase in capacity, fraction

a_2 = increase in capacity, fraction

The midpoint of the step is used to linearly approximate the log linear supply equation. The cost multiplier represents the average cost increase over the full range of the capacity step, rather than a direct response for each increment of new capacity. The number of steps was chosen to limit the number of new decision variables in the ECP while still accurately portraying the relationship between rapid capacity increases and cost increases. The user specifies the capacity limit for each step, and by changing this value the cost multipliers will respond accordingly. For example, by making the second step larger, allowing for more capacity additions, the cost multiplier will go up.

The short-term expansion constraint for dispatchable technologies is as follows:

(3-14)
$$\sum_r BLD_{yrcE} + \sum_r \sum_e BDI_{yecrE} \le CPLIM_{ycE}$$

for every capacity type, c, year y and supply step E.

where $CPLIM_{ycE}$ = $CPSTP_{cE}$ * $CPBAS_{yc}$

Analogous constraints exist for intermittent and renewable builds. The objective function coefficients for the appropriate build vectors ($CBLD_{yrcE}$, $CBDI_{yecrE}$, $CRNW_{yrnE}$, $CBRI_{yenrE}$, $CINT_{yriE}$,

$CBII_{yeirE}$) represent the overnight cost multiplied by the cost multiplier for each supply step, as calculated in (3-13).

Planned Maintenance Constraints. The Planned Maintenance constraints ensure that the total of the seasonal planned maintenance scheduled for each dispatchable technology satisfies the annual maintenance requirements for that technology. For coal-fired capacity, these constraints are defined as:

$$\sum_{s} SHOURS_{s} \cdot PMC_{yrDs} - 8.76 \cdot CPMR_{rD} \cdot EXD_{yrD} - 8.76 \cdot \sum_{x} CPMR_{rD} \cdot EXDR_{rDx} - 8.76 \cdot \sum_{j=1}^{y} \sum_{E} CPMR_{rD} \cdot BLD_{jrDE} \geq 0 \quad \text{(3-16)}$$

for every coal capacity type C in year y and region r.

In the first term, $SHOURS_s$ represents the number of hours in season s (in thousands of hours) and PMC_{yrCs} is the decision variable that determines the amount of capacity undergoing planned maintenance in that season. The product of these two quantities summed over the season specifies the total number of hours each coal capacity type is undergoing maintenance in each region and year. The terms $8.76 \cdot CPMR_{rC} \cdot UNIT_{yOH}$ and $8.76 \cdot CPMR_{rC} \cdot UNIT_{yOI}$ define the annual maintenance requirements (in thousand of hours) for uncontrolled and controlled coal plants, respectively. Similarly, the term $8.76 \cdot CPMR_{rC} \cdot BLD_{jrCE}$ describes maintenance for new capacity. Therefore, Planned Maintenance rows require that the total allocation of capacity type C for planned maintenance over all seasons equals or exceeds the annual requirements for that capacity type.

The analogous rows for non-coal capacity types have a similar form. The corresponding capacity variables (EXD_{yrD} and $EXDR_{yrD}$) are substituted into the equation, as follows:

$$\sum_{s} SHOURS_{s} \cdot PMC_{yrCs} - 8.76 \cdot CPMR_{rC} \cdot \sum_{O} \sum_{H} UNIT_{yOH} - 8.76 \cdot CPMR_{rC} \cdot \sum_{O} \sum_{I} UNIT_{yOI} - 8.76 \cdot \sum_{j=1}^{y} \sum_{E} CPMR_{rC} \cdot BLD_{jrCE} \geq 0 \quad \text{(3-15)}$$

for every non-coal dispatchable capacity type D in year y and region r.

Electricity Load Requirements. These constraints are specified by vertical load segment, region and year. Each load segment has a specific capacity (height) and energy (height times width) requirement. Since the load segment represents a fixed time slice, the capacity and energy requirements are directly proportional and can be measured in either capacity or energy units. That

is, the energy requirement for a given load segment can be obtained by multiplying the capacity requirement (gigawatts) by the duration (hours) of that time period.

The load segments are defined by a combination of capacity requirements, time of day, and seasonal variations. The objective for the segment definitions is to be able to clearly map intermittent technologies (i.e., solar and wind) to the appropriate load segments while maintaining the overall regional load characteristics. For each segment of the load duration curve, the capacity requirement (ELC_{yrl}) corresponds to its height.

The energy requirements for each vertical segment can be satisfied by a number of different alternatives. First, the energy may be produced by operating dispatchable technologies in one or more capacity factor modes. For example, conventional steam capacity can be operated in base or intermediate modes. In base mode, one unit of capacity would contribute energy to all load segments. If the same capacity is operated in intermediate mode it would not contribute to those load segments with lower capacity requirements. The contribution of a dispatchable capacity type towards meeting the requirements for a given load segment is the product of the capacity assigned to that mode of operation for coal plants (OPC_{yrNCms}) and noncoal capacity (OPD_{yrDfms}) and the respective derating factors (ELA_{yrCml} and ELA_{yrDml}).

Second, capacity using renewable energy sources (excluding intermittent technologies) such as geothermal, biomass or municipal waste contribute to load. These technologies are used to their full capability subject to energy resource constraints. There are two dispatch modes. First, the total capacity can be used over as of the peak most load slices as possible until all the renewable energy is used. Second, the capacity can be operated at the average capacity factor uniformly over all the load segments. In either case the contribution to load is the product of the capacity (OPR_{yrn}) and the corresponding derate capacity factor (ELR_{yrn}). For hydroelectric plants, the capacity constraint is converted to an energy constraint and capacity utilization (OPH_{yrl}) is determined independently for each load segment. Each operate vector is bounded at the existing capacity and thus precluding the addition of new unplanned capacity.

Also, generating capacity with intermittent energy sources (Existing - EXI_{yri}, New - INT_{yri}, New Import -BII_{yeir}) can be used to satisfy energy requirements in those load segments for which input energy is fully or partially available. For example, solar capacity can be used during those load segments in which the sun is shining. Finally, load can be met from Canadian hydroelectric power (OCH_{yrh}).

$$\sum_{N}\sum_{C}\sum_{m} ELA_{yrCml} \cdot OPC_{yrNCms} + \sum_{D}\sum_{f}\sum_{m} ELA_{yrDml} \cdot OPD_{yrDfms} + \sum_{n} ELR_{yrnl} \cdot OPR_{yrn}$$

$$+ \sum_{i}\sum_{z=1}^{y} ELI_{zril} \cdot INT_{zri} + ELH_{yrl} \cdot OPH_{yrl} + \sum_{i} ELI_{yril} + \sum_{i}\sum_{e}\sum_{z=1}^{y} ELI_{zril} \cdot TLOSS_{zer} \cdot BII_{zeir} \quad (3\text{-}17)$$

$$+ \sum_{h} OCH_{yrh} \geq ELC_{yrl}$$

for every load step l in season s in year y and region r.

Production Balance Rows. For each non-coal capacity type, region, year, and season, these equations limit production of electricity by the available generating capability, which includes existing and new units.[29] Existing capacity includes units that have announced retirement dates (EXD_{yrD}) and units that can be retired if new capacity is more economical ($EXDR_{rDx}$). It also accounts for capacity that is unavailable due to scheduled maintenance. These constraints are specified for all available conventional and advanced plant types.

In the Production Rows, negative terms define the available capacity while positive terms represent the disposition of capacity. Each operate vector (OPD_{yrDfms}) will consume/use capacity in order to produce electricity. The available generating capability for capacity type D in each year is the sum of the existing capacity (EXD_{yrD} and $EXDR_{rDx}$) and the cumulative new capacity (BLD_{yrDE} or BDI_{yeDrE}) that has been placed into service, adjusted for planned maintenance (PMC_{yrsD}). The amount of existing capacity is also affected by decisions to export or import existing capacity. Exports (TRN_{yrDg}) reduce the supply to meet use of native capacity, while imports (TRN_{yeDr}) add to the available capacity.

For oil and gas plants, these rows also determine retirements.[30] The objective function coefficient of the decision variable $EXDR_{rDx}$ contains the costs of continuing to operate that capacity (fixed operating and maintenance, capital expenditures for equipment, etc.). If the ECP determines that it is not cost effective to continue using this capacity, the solution value for $EXDR_{rDx}$ will be less than the available capacity. The difference between the available capacity and the solution represents the "retired" capacity.

Renewable capacity is represented in much the same way as dispatchable technologies. However, the utilization of renewable plants is typically determined by the availability of the energy source so

[29]For coal capacity type, the corresponding constraints are described in the earlier discussion of the coal submatrix.

[30]Coal and nuclear capacity have an additional set of constraints (Capacity Balance Rows) which determine retirements. Nuclear plants are assumed to operate only as baseload capacity so they do not have production balance rows since there is only one mode of operation. The constraints for these plant types are discussed in the following section.

there is only one "operate" decision. For hydroelectric capacity, the utilization rates are determined from historical generation, which is assumed to account for any restrictions on water usage.

There is also a set of production balance rows that allocate capacity obtained through the early development of international generation projects. Power from a particular foreign project is derated to describe the current availability of power. More than one U.S. region can buy power from an international region, and the utilization shares between the multiple regions can change from one planning year or cycle to the next. Domestic utilities are required to commit to the purchase of all output from a project between an accelerated project start date and the project start date announced by the foreign utility. Further, all project start dates must conform to a reasonable lead time requirement. For example, if a Canadian hydro project is scheduled to start generation in 2010 to serve Canadian needs, then domestic utilities can accelerate the project start date by committing to purchase all the output of the project from the current year plus a lead time until 2010. In 2010, this capacity is assumed to be fully committed to the Canadian needs and is no longer available to the U.S. utilities, except through economy trades determined by the Electricity Fuel Dispatch (EFD).

Non-Coal Dispatchable Capacity Production Balance Row

(3-18)

$$\sum_{f}\sum_{m}\sum_{s} OPD_{yrDfms} - \sum_{j=1}^{y}\sum_{E} BLD_{jrDE} + \sum_{g} TRN_{yrDg} - \sum_{e} TRN_{yeDr} \cdot TLOSS_{yer}$$
$$-\sum_{e}\sum_{j=1}^{y}\sum_{E} BDI_{jeDcrE} \cdot TLOSS_{jer} - PMC_{ysrD} - EXD_{yrD} - \sum_{x} EXDR_{yrDx} \leq 0$$

For every non-coal dispatchable capacity type D (except nuclear) in year y in region r.

Renewable Capacity Production Balance Row

(3-19)

$$OPR_{yrn} - \sum_{j=1}^{y}\sum_{E} RNW_{jrnE} - \sum_{e}\sum_{j=1}^{y}\sum_{E} BRI_{jenrE} \cdot TLOSS_{jer} + \sum_{g} TRN_{yrng}$$
$$-\sum_{e} TRN_{yenr} \cdot TLOSS_{yer} - EXR_{yrn} \leq 0$$

for every renewable capacity type n in year y in region r.

Hydro Energy Production Balance Row

(3-20)

$$\sum_{l} \mathrm{OPH}_{yrl} \cdot \mathrm{ELR}_{yrl} - \mathrm{EXH}_{yr} \leq 0.0$$

for every year y in region r.

Canadian Hydro Capacity Production Balance Row

$$\sum_{r} OCH_{yrh} - \sum_{p} ELCH_{yhp} \cdot ECH_{yhp} - \sum_{p} \sum_{j=1}^{y} ELCH_{jhp} \cdot BCH_{jhp} \leq 0 \quad (3\text{-}21)$$

for every international region h in year y.

Nuclear Capacity Balance Row. For nuclear capacity, these rows determine the retirement and continue-to-operate decisions. The value of $EXDR_{yrD}$ describes the amount of capacity that the ECP determines is economic to operate. That is, if the decision variable is activated, then the operating costs are incurred. The difference between $EXDR_{yrD}$ and the available capacity, NUC_{yrD}, represents the retired capacity. The capacity balance row for nuclear is given by

$$\mathbf{EXDR_{yrD} \leq NUC_{yrD}} \quad (3\text{-}22)$$

for nuclear capacity type D in year y in region r.

Fuel Supply/Demand Curves. Like the fuel curves described in the coal submatix, these equations describe the price/quantity relationships associated with the demand for oil, natural gas, and biomass fuels used in electricity generation. Rather than assuming that unlimited quantities of fuel are available at a given price, these constraints accumulate total fuel use so that the fuel price can vary directly with the amount required. For oil- and gas-fired capacity type D and fuel type f, the generation for mode of operation m and load segment l is the product of the capacity assigned to the mode of operation (OPD_{yrDfms}), the derating factor or utilization rate (ELA_{yrDfml}), and the hours in a load segment ($LHRS_l$). Multiplying the generation by the heatrate (HRD_{yrD}), divided by 1000, describes the fuel use corresponding to the allocation of capacity. Equations 3-23 and 3-24 describe total fuel consumption using a series of decision variables for oil and gas (QNG_{yd} and QOL_{yd}), respectively.

$$\sum_{r} \sum_{D} \sum_{m} \sum_{l} \sum_{s} ELA_{yrDml} \cdot OPD_{yrDfms} \cdot LHRS_l \cdot (HRD_{yrD}/1000) - \sum_{d} QNG_{yd} \leq 0 \quad (3\text{-}23)$$

for every capacity type c using fuel type f (natural gas) in year y.

$$\sum_{r} \sum_{D} \sum_{m} \sum_{l} \sum_{s} ELA_{yrDml} \cdot OPD_{yrDfms} \cdot LHRS_l \cdot (HRD_{yrD}/1000) - \sum_{d} QOL_{yd} \leq 0 \quad (3\text{-}24)$$

for every capacity type c using fuel type f (oil) in year y.

There are also regional fuel curves for biomass consumed in dedicated biomass plants and cofiring in coal-fired steam plants. Fuel use in dedicated biomass capacity type n is the product of the capacity allocated (OPR_{yrn}), the annual utilization rate (ELR_{yrn}), the heatrate (HRR_{yrn}) divided by 1000, and the hours per year divided by 1000. Biomass fuel used for cofiring in capacity types c is described by the decision variable TBM_{yABNC}. Equation 3-25 describes total biomass fuel use for electricity generation using a series of decision variables (QBM_{yd}). Biomass consumed in the industrial sector ($QBMIN_{yr}$) and used for ethanol production ($QBMET_{yr}$), both of which are determined in the end-use demand models, represent competing demands for the available biomass supplies.

$$ELR_{yNn} \cdot OPR_{yNn} \cdot (HRR_{yNn}/1000) \cdot 8.76 + \sum_{A} \sum_{B} \sum_{C} TBM_{yABNC} + QBMIN_{yN} + QBMET_{yN} - \sum_{d} QBM_{yd} \leq 0 \quad (3\text{-}25)$$

for every coal region N in year y.

Reserve Margin Requirement. The reserve margin constraints ensure that the planning decisions that increase supply by adding new generating capability are sufficient to satisfy regional reliability requirements. In this section, reliability requirements are described for cost-of-service regulation and are based on prespecified reserve margins. Under competition, it is assumed that the optimal reliability level will be market based. Capacity planning under competition is discussed later.

Planning decisions will have to be implemented if the total capacity requirement (RMQ_{yr}) exceeds the existing capacity ($\sum_c EXC_{yrc} + \sum_c EXCR_{yrcx} + \sum_n EXR_{yrn} + \sum_i EXI_{yri}$). Available capacity can be increased by building new capacity—either dispatchable (BLD_{yrcE} , BDI_{yecrE}), renewable (RNW_{yrnE} , BRI_{yenrE}) or intermittent (INT_{yriE} , BII_{yeirE}). For an intermittent technology, its capacity credit (RMI_{yri}) will depend on its ability to provide electricity when the peak demand occurs. In addition, the amount of capacity is affected by imports and exports (TRN_{yrcg} / TRN_{yecr}) and by Canadian hydroelectric imports (BCH_{yrp}). Distributed generation technologies (DGN_{yrt}) operate during peak load and also contribute to reliability.

For regulated regions, the reserve margin constraint is formulated as follows:

(3-26)

$$\sum_{c}\sum_{j=1}^{v}\sum_{E} BLD_{jrcE} + \sum_{i}\sum_{j=1}^{v}\sum_{E} INT_{jriE} \cdot RMI_{jri} + \sum_{n}\sum_{j=1}^{v}\sum_{E} RMR_{jrn} \cdot RNW_{jrnE} + \sum_{d}\sum_{j=1}^{v} RMD_{jyrd} \cdot DSM_{yrd}$$
$$+ \sum_{c}\sum_{e}\sum_{j=1}^{v}\sum_{E} BDI_{jecrE} \cdot TLOSS_{jer} + \sum_{n}\sum_{e}\sum_{j=1}^{v}\sum_{E} RMR_{jrn} \cdot TLOSS_{jer} \cdot BRI_{jenrE}$$
$$+ \sum_{i}\sum_{e}\sum_{j=1}^{v}\sum_{E} BII_{jeirE} \cdot TLOSS_{jer} \cdot RMI_{jri} + \sum_{C} EXC_{yrC} + \sum_{D} EXD_{yrD} + \sum_{D}\sum_{x} EXDR_{yrDx}$$
$$+ \sum_{n} EXR_{yrn} \cdot RMR_{yrn} + \sum_{p}\sum_{j=1}^{v} BCH_{yhp} + \sum_{g}\sum_{c} TRN_{yrcg} - \sum_{e}\sum_{c} TRN_{yecr} \geq RMQ_{yr}$$

for every year y and region r.

Electricity Export Constraint. The export constraint limits the interregional flow of electricity out of a region in accordance with existing transmission capability.

(3-27)

$$\sum_{c}\sum_{g} \mathrm{TRN}_{yrcg} \leq \mathrm{EXP}_{yr}$$

for every year y and region r.

International Firm Power Imports Limit. The firm power imports constraints limit the development of foreign generation projects by the available supply.

(3-28)

$$\sum_{y} BCH_{yhb} \leq CHYL_{hb}$$

for every project b in international region h.

Dispatchable Capacity Build Limit. The dispatchable capacity build limit simulates disincentives for overbuilding such as the disallowance by public utility commissions of capital additions to the rate base for new plants that are excess capacity. This constraint also incorporates contributions to the reserve margin requirement of Canadian hydroelectric projects and plants built in one region to serve another.

(3-29)

$$\sum_{c}\sum_{j=1}^{v}\sum_{E} BLD_{jrcE} + \sum_{c}\sum_{e}\sum_{j=1}^{v}\sum_{E} BDI_{jecrE} \cdot TLOSS_{jer} + \sum_{b} BCH_{yhb} + \sum_{n}\sum_{j=1}^{v}\sum_{E} RNW_{jrnE}$$
$$+ \sum_{n}\sum_{e}\sum_{j=1}^{v}\sum_{E} BRI_{jenrE} \cdot TLOSS_{jer} \leq MAX\ (RMQ_{yr} - \sum_{c} EXC_{yrc} - \sum_{n} EXR_{yrn},\ 0.0)$$

for every year y and region r.

Intermittent Build Limit. The limits on new intermittent capacity result from a combination of resource constraints and new technology penetration limits.

(3-30) $$\sum_{j=1}^{y} \sum_{B} INT_{jriB} + \sum_{e} \sum_{j=1}^{y} \sum_{B} BII_{jeirB} \leq INTL_{ir}$$

for every intermittent technology i and region r.

Renewable Build Limit. The limit on new renewable capacity result from a combination of resource constraints and new technology penetration limits.

(3-31) $$\sum_{j=1}^{y} \sum_{B} RNW_{jmB} + \sum_{e} \sum_{j=1}^{y} \sum_{B} BRI_{jenrB} \leq RNWL_{nr}$$

for every renewable capacity type n and region r.

Distributed Generation Build Limit. These build limits represent the supply curves for avoiding transmission and distribution expenditures by adding distributed generation rather than central-station generating capacity. Depending on the location of different load centers, the cost of adding T&D equipment can vary considerably. These constraints describe the amount of distribution generation that could be added in year y, region r, and supply step q, which corresponds to a specific level of avoided T&D costs.

(3-32) $$\sum_{t} DGN_{yrtq} \leq DGNL_{yrq}$$

for every supply step q in region r in year y.

FGD Retrofit Limit. This national-level row limits annual FGD retrofits, which convert unscrubbed capacity type C to scrubbed capacity type k, to reflect industry constraints on the amount of scrubber capacity that can be installed. If $UNIT_{yOI}$ represents the subset of coal-fired units O currently without scrubbers that are retrofitted to a controlled configuration I in year y, then the limit is defined as follows:

(3-33) $$\sum_{O} \sum_{I} UNIT_{yOI} \leq FGDL_{y}$$

For every year y.

Intermittent Generation Limits. These constraints, which limit the amount of generation produced by intermittent renewable technologies in order to maintain stability in the transmission system, are described below.

(3-34)
$$\sum_i \sum_l ELI_{yril} \cdot EXI_{yri} + \sum_i \sum_{j=1}^{y} \sum_l \sum_E ELI_{yril} \cdot INT_{jriE} + \sum_i \sum_e \sum_{j=1}^{y} \sum_l \sum_E ELI_{yril} \cdot BII_{jeirE} - PINT \cdot GEL_{yr} \leq 0$$

for every region r and year y.

Renewable Portfolio Constraint. Renewable Portfolio Standards (RPS) are included in many of the Federal and State proposals for deregulating the electric power industry. A RPS specifies that electricity suppliers must produce a minimum level of generation using renewable technologies. Producers with insufficient renewable generating capacity can either build new plants of purchase "credits" from other suppliers with excess renewable generation.

The RPS proposals differ according to their respective definitions of renewable technologies. Solar, wind, biomass, and geothermal are typically included, but some proposals exclude generation from hydroelectric and/or municipal solid waste plants. The required level of renewable generation also varies as well as the formula for computing the percentage of renewable generation. In some cases, the minimum requirement specifies the level of renewable sales relative to total sales. Alternative proposals consider renewable generation as a percentage of total sales or as a percentage of total nonhydroelectric sales.

In the ECP, the RPS is represented by adding a set of constraints that specify the minimum level of renewable generation for a given year. Since renewable generation credits can be traded, the lower bound is actually national rather than regional or utility-level. Thus, the following rows are required for each year of the planning region, but not each region.

(3-35)
$$\sum_r \sum_i \sum_l ISHR_i \cdot ELI_{yril} \cdot LHRS_l \cdot (EXI_{yri} + \sum_{z=1}^{y} \sum_E INT_{zriE}) + \sum_r \sum_n \sum_l RSHR_n \cdot ELR_{yrn} \cdot LHRS_l \cdot (EXR_{yrn} + \sum_{z=1}^{y} \sum_E RNW_{zrnE}) + \sum_A \sum_B \sum_N \sum_C RSHR_n \cdot TBM_{yABNC} \cdot 1000 / HRD_{yNC} - \sum_r RBND_y \cdot GEL_{yr} \geq 0$$

For every year y.

The first term of the equation accounts for generation from existing and new intermittent technologies. For each load segment l, the derating factor (ELI_{yril}) describes the fraction of total

capacity that is utilized in that segment (i.e., adjusted for forced outages and load following). The product of this utilization rate and the hours in load segment l ($LHRS_l$) yields the generation per unit of capacity. Summing over all load segments and then multiplying by the available capacity ($EXI_{yri} + \sum\sum INT_{zriE}$) and the fraction of generation credited towards the RPS ($ISHR_i$) gives the intermittent generation that satisfies the minimum renewable requirement. Similarly, the second term describes the generation from dispatchable renewable capacity. The third term represents renewable generation from cofiring biomass with coal. Dividing the biomass fuel consumption from cofiring (TBM_{yABNC}) by the heatrate yields the corresponding generation. Multiplying this quantity by the RPS credit for biomass ($RSHR_n$) provides the qualifying renewable generation from biomass cofiring. The fourth term (GEL_{yr}) represents the total regional generation produced from all sources. Multiplying this quantity by the RPS fraction ($RBND_y$) provides the minimum renewable generation requirement.

The renewable credit price is based on the marginal cost of complying with the renewable generation requirement, which is represented by the dual value (shadow price) of the RPS constraint. The objective function of the ECP minimizes the present value of investment and operating costs, in nominal dollars, for the planning horizon. Therefore, the dual value of the RPS constraint for a given year provides the present value of the marginal cost of compliance in that year.

The renewable credit price is assumed to be the levelized cost of compliance over the operating period for renewable additions. The levelized cost is the annuity (i.e., constant amount of dollars in each year) that provides the same total present value as the actual stream of costs over the time horizon and is determined for the period beginning in planning year (MAXLT + 1), which is the initial operating date for new renewable capacity. That is,

(3-36)
$$EPRPSCR_y \cdot \sum_{z=MAXLT+1}^{ECP\$XPH} [(1 + UPGNPD_z)/(1 + AVGDCR)^z] = \sum_{z=MAXLT+1}^{ECP\$XPH} EPRENEW_z$$

for every year y.

where: ECP$XPH = Number of Years in Planning Horizon (Years)

MAXLT = Lead Time When All Renewable Capacity Types Can Compete to Meet RPS (Years)

$EPRPSCR_y$ = Levelized Cost for Period Beginning in Year z=MAXLT + 1 (Real Dollars)

$UPGNPD_z$ = Cumulative Inflation Factor for Year z (Scalar)

AVGDCR = Average Discount Rate (Fraction)

$EPRENEW_z$ = Discounted, Annual Compliance Cost (dual value) in Year z (Mills per Kilowatthour in Nominal Dollars)\

Rearranging Equation (3-36) to solve for the levelized compliance cost yields Equation (3-37).

(3-37) $$EPRPSCR_y = \sum_{z=MAXLT+1}^{ECPSXPH} EPRENEW_z \Big/ \sum_{z=MAXLT+1}^{ECPSXPH} [(1 + UPGNPD_z)/(1 + AVGDCR)^z]$$

Capacity Planning Under Competition

Under deregulation it is assumed that reserve margins will be determined by competitive markets rather than set at a prespecified level. The economically optimal level occurs when the marginal cost of capacity equals the consumer's willingness to pay for capacity, which is represented by the value of unserved energy.

Optimal reserve margins are calculated from the relationship:

(3-38) $$(\partial UE/\partial G) \cdot V(UE) = A_t \quad ,$$

where:

A_t = annual carrying cost (dollars per kilowatt per year) of the least expensive generating capacity (combustion turbine), and

$(\partial UE/\partial G) \cdot V(UE)$ = Marginal cost of unserved energy (dollars per kilowatt per year).

This is expressed by a constraint row[31]

(3-39) $$\sum_{dsp}\sum_{j} delemuedsp(dsp,j)*X_{dsp} + \sum_{rnw}\sum_{j} delemuernw(rnw,j)*X_{rnw} + \sum_{int} delemueint(int)*X_{int} \sum_{dgn} delemuedgn(dgn)*X_{dgn} \le delemuerhs$$

where:

delemuedsp = change in unserved energy per unit of dispatchable capacity dsp, season j,

X_{dsp} = Available Dispatchable Capacity Type dsp

delemuernw = change in unserved energy per unit of renewable capacity rnw, season j,

[31]The coefficients representing the change in unserved energy are negative because the unserved energy decreases as capacity increases.

X_{rnw}	=	Available Renewable Capacity Type rnw
delemueint	=	change in unserved energy per unit of intermittent capacity int, and
X_{int}	=	Available Intermittent Capacity Type int
delemuedgn	=	change in unserved energy per unit of distributed generation capacity dgn
X_{dgn}	=	Available Distributed Generation Capacity Type dgn
delemuerhs	=	change in marginal unserved energy.

These coefficients are described in greater detail in Appendix III.C.

Technology Penetration

The ECP contains a component that represents changes in cost and performance characteristics for different capacity types, particularly new technologies. It addresses initial cost estimates (technological optimism), cost reductions as commercialization occurs (learning), uncertainty associated with capacity expansion (risk), and efficiency improvements.[32] This component also contains a market-sharing algorithm, which reallocates capacity expansion decisions from the LP model based on the "competitiveness" of technologies that were not selected.

Technological Optimism. Cost assumptions for technologies that are already in commercial operation are based on available cost data. Therefore, the inputs for these plant types include only the traditional project contingency factor, which typically ranges from 5 to 10 percent.[33]

However, there are no data on realized costs for new technologies. As a result, capital costs for new generating technologies are based on engineering estimates. The ECP incorporates a technological optimism factor, which is an additional contingency rate that represents the tendency to underestimate costs for new technologies.[34] The accuracy of cost estimates is directly related to a technology's stage of development. These estimates become better as a technology progresses toward commercialization.

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[32]For greater detail on the methodology for technological optimism, learning, and risk, see Energy Information Administration, *NEMS Component Design Report, Modeling Technology Penetration* (Washington, DC, March 1993). The inputs for these factors are contained in Energy Information Administration, *Assumptions to the Annual Energy Outlook 2004*, DOE/EIA-0554(2004) (Washington, DC, February 2004).

[33]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements if costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur".

[34]For more information on technological optimism, see Independent Project Analysis, Incorporated, "An Analysis of the Potential for Cost Improvement in Emerging Power Generation Technologies" (Reston, Va., June 1993).

The technological optimism factor is calculated for each major design component of new technologies (Table 10). Often a new technology design incorporates parts of existing designs, which will have less uncertainty in the cost estimates. By calculating the optimism factor by component, only the new, untested parts of the design will have the cost adjustment over time. Multiple technologies may share components, and in those cases new capacity built of one plant type will contribute to lowering the technological optimism for another plant type. Some plant types have not been explicitly modeled as having components where there are no large opportunities for cross-technology learning.

Technological optimism is assumed to occur for a specified number of units. The initial technological optimism factor applied to the 1st-of-a-kind cost is also an input (e.g., a 10 percent technological optimism factor equals 1.10). It is assumed that this factor decreases linearly until the actual costs and estimates are the same (e.g., the factor equals 1.00).

The number of units currently operational is estimated by dividing the available capacity by the typical unit size. The total capacity for each component is the sum of the capacity for all plant types that include that component, weighted by the share that the component contributes to the total capacity of the plant type (Table 11). The slope of the line that describes the decrease in the technological optimism factor is given by

(3-40) $$SLOPE_D = (1 - OPTFAC0_D)/(UNITL_D - UNITB_D)$$

where:

$OPTFAC0_D$ = Initial Technological Optimism Factor for Design Component D

$UNITL_D$ = Number of Units of Capacity with Component Type D Completed When Technological Optimism is No Longer Observed

$UNITB_D$ = Number of Units of Capacity with Component Type D Completed When Technological Optimism Factor is First Applied (i.e. 0)

The technological optimism factor $OPTFAC_{yD}$ for component type D in year y is then given by

(3-41) $$OPTFAC_{yD} = OPTFAC_0 + SLOPE_D \cdot UNITS_{yD} \quad \text{for } UNITS_{yD} < UNITL_D$$

where:

$UNITS_{yD}$ = Number of Units of Capacity with Component Type D Completed by Year y

For a given component, the factor is set to 1.0 once the number of units in operation reaches the level in which technological optimism is no longer observed.

The technological optimism factor $OPTFAC_{yc}$ for a given technology is calculated from a weighted average of the factors for each design component.

(3-42)
$$OPTFAC_{yc} = \sum_{D} CSTWT_{cD} \cdot OPTFAC_{yD}$$

where:

$CSTWT_{cD}$ = Share of Initial Cost Estimate of Capacity Type c contributed to by Design Component D

Learning Methodology. The ECP uses a learning curve approach to model the commercialization of generating technologies. The learning methodology represents "learning-by-doing effects", which indicate that costs fall as experience increases. Experience is measured using cumulative capacity. An assumed rate of cost reduction is applied to each doubling of capacity. For simplicity, this rate of cost reduction is called the slope of the learning curve. As for the technological optimism factor, the learning factor is first calculated by design component. A final component by plant type is calculated as a weighted average of the individual component factors, using the contribution of each component to the overall technology cost estimate as the weight.

A 3-step learning curve is utilized for all design components. Typically, the greatest amount of learning occurs during the initial stages of development and the rate of cost reductions declines as commercialization progresses. Each step of the curve is characterized by the learning rate and the number of doublings of capacity in which this rate is applied. Depending on the stage of development for a particular component, some of the learning may already be incorporated in the initial cost estimate.

Mathematically, the cost for capacity level N can be expressed as follows:[35]

(3-43)
$$C_N = C_I \cdot \left(\frac{N}{I}\right)^b$$

where:

C_N = Cost at current capacity level (Dollars per Kilowatt)
C_I = Initial Cost estimate (Dollars per Kilowatt)
N = Current capacity
I = Initial capacity (set to typical unit size if no units online)

[35]The methodology for determining learning factors is discussed in greater detail in Independent Project Analysis, Incorporated, "An Analysis of the Potential for Cost Improvement in Emerging Power Generation Technologies" (Reston, Va., June 1993).

Rearranging Equation (3-43), the exponent for each step s (b_s) can be determined by letting (N/I) equal 2 (i.e., considering a doubling of capacity). That is,

(3-44) $$b_s = \ln(1 - LCR_s)/\ln(2)$$

where:

LCR_s = cost reduction for every doubling of capacity in step s (Fraction)

Note that b_s is negative so that as (N/I) increases the corresponding cost decreases. That is,

(3-45) $$C_2 = C_1 \cdot 2^b;\ C_4 = C_1 \cdot 4^b;\ C_8 = C_1 \cdot 8^b;\ \ldots$$

The cost reductions continue until the number of doublings completed reaches a prespecified level, when learning-by-doing effects are assumed to be no longer observed. Capital cost input data used in the ECP represent initial cost estimates as of the most recent historical year (C_I), so the learning factor associated at capacity level N, LF_N, is expressed as a multiplier of C_I. That is, LF_N describes the decrease in capital costs between the initial estimate and the Nth-of-a-kind units.

(3-46) $$C_N = C_I \cdot LF_N$$

Solving equation (3-43) for both C_N and C_{n0} and substituting the results into equation (3-46) yields

(3-47) $$LF_N = \left(\frac{N}{I}\right)^b$$

A learning factor for each component is calculated each year, $LRNFAC_{yD}$. Just as with the technological optimism factor, a learning factor, $LRNFAC_{yc}$, for each plant type c is calculated from the learning factors by component.

(3-48) $$LRNFAC_{yc} = \sum_D CSTWT_{cD} \cdot LRNFAC_{yD}$$

Technological Improvements in Heatrates. The ECP also includes improvements in heatrates, which describe the amount of fuel input required to produce a kilowatthour of electricity. For each of technology, it is assumed that the annual reduction in the heatrate is constant and occurs over a prespecified time period. The heat rate for technology type c in a particular year is given by

$$EPPHRT_{yc} = EPPHRT0_c + (EPPHRTN_c - EPPHRT0_c) \cdot \left(\frac{y - UPDHRY0_c}{UPDHRYN_c - UPDHRY0_c}\right)$$

(3-49) for $UPDHRY0_c \le y \le UPDHRYN_c$

$EPPHRT_{yc} = EPPHRT0_c$ for $y<1995$

$EPPHRT_{yc} = EPPHRTN_c$ for $y>2010$

where:

$EPPHRT_{yc}$	=	heatrate for technology type c in year y
$EPPHRT0_c$	=	initial heatrate for technology type c
$EPPHRTN_c$	=	final heatrate for technology type c
$UPDHRY0_c$	=	last year for initial heatrate for technology type c (i.e., year before heatrate improvements begin)
$UPDHRYN_c$	=	last year of learning for heatrate for technology type c

Market-Sharing Algorithm. The ECP contains a market-sharing algorithm, which revises the capacity expansion decisions from the LP model for each of the electricity supply regions. For a given region r, the total "market" ($TOTBAS_r$) is represented by the sum of the capacity expansion decisions that were selected (basic vectors). The market-sharing algorithm then reallocates some of this market to options that were not selected (nonbasic vectors), based on the following logit function:[36]

$$MS_i = MC_i^a / \sum_j MC_j^a \quad (3\text{-}50)$$

where:

MS_i	=	Market Share for the ith Technology
MC_i	=	Marginal Cost for the ith Technology
a	=	Exponent of Logit Function

In Equation (3-50), market shares are determined on the basis of marginal costs. In the ECP, the competitiveness of the different technologies is compared using the *reduced cost* from the LP model,

[36]For more information on the function used in the market-sharing algorithm of the ECP, see Energy Information Administration, *NEMS Component Design Report Modeling Technology Penetration* (Washington, DC, March 1993).

which describes the marginal cost reduction required for a particular option to be selected.[37] In this algorithm, MC_i is represented using the following ratio:

(3-51) $$CSTRATIO_{yrc} = (CBLD_{yrcE} - RC_{yrcE}) / CBLD_{yrcE}$$

where:

$CSTRATIO_{yrcE}$= Ratio of Required Cost to Actual Cost for Building Capacity Type c Beginning Operation in Year y in Region r at Short Term Supply Step E (Scalar)

$CBLD_{yrcE}$ = Investment Cost to Build Capacity Type c With Initial Online Year y in Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

RC_{yrcE} = Reduced Cost to Build Capacity Type c With Initial Online Year y in Region r at Short Term Supply Step E (Millions of Dollars / Gigawatt)

Since RC_{yrcE} is greater than or equal to zero, $CSTRATIO_{yrcE}$ is less than or equal to one. A prespecified tolerance level, EPMSTOL, is used to eliminate options that are considered noncompetitive because the cost reduction required for penetration is too large. That is, $CSTRATIO_{yrcE}$ is set to 0 if $CSTRATIO_{yrcE}$ is less than (1 - EPMSTOL), so that the corresponding market share will be 0. After $CSTRATIO_{yrcE}$ has been determined for all options evaluated by the market-sharing algorithm, this ratio is incorporated into Equation (3-50) to determine the individual market shares for each technology choice. That is,

(3-52) $$MS_{yrcE} = (CSTRATIO_{yrcE})^a / (\sum_y \sum_c CSTRATIO_{yrcE})^a$$

A "less-competitive" technology has a comparatively high reduced cost relative to its actual cost, thereby resulting in a lower value for $CSTRATIO_{yrcE}$. When the exponent a is applied, the numerator in Equation (3-52) declines rapidly resulting in a lower market share compared to other technologies with higher values for $CSTRATIO_{yrcE}$.

These market shares are then used to reallocate the capacity additions determined by the LP model ($TOTBAS_r$) so that the same total capacity is added. The "revised" build decisions (BMS_{yrcE}) for those capacity types not selected by the LP model are given by

(3-53) $$BMS_{yrcE} = MS_{yrcE} \cdot TOTBAS_r$$

[37] An option selected by the LP model has a reduced cost of 0.

Finally, the capacity expansion decisions that were selected by the LP model (BLP_{yrcE}) must be decreased to account for the new capacity that was reallocated ($TOTNBS_r$). This is accomplished by Equation (3-54) and Equation (3-55), which reduce each of the original decisions in proportion to their share of the total market.

(3-54) $$TOTNBS_r = \sum_y \sum_c \sum_E BMS_{yrcE}$$

where:

BLD'_{yrcE} = Market-Sharing Build Decisions for Capacity Type c Beginning Operation in Year y in Region r at Short Term Supply Step E (Gigawatts)

(3-55) $$BLP'_{yrcE} = BLP_{yrcE} - TOTNBS_r \cdot (BLP_{yrcE} / TOTBAS_r)$$

where:

BLP'_{yrcE} = Revised LP Build Decisions for Capacity Type c Beginning Operation in Year y in Region r at Supply Step E (Gigawatts)

Demand Expectations

The EMM can determine demand expectations using an alternative method to the original approach used by the Integrating Module.[38] This methodology relies on a "smoothing" technique to limit the impact of extreme changes in demand that could occur in a given year. This procedure, which is implemented by specifying the initial year (GRW_XYR), is described below.

(3-56) $$GDEM_{sry} = DEM\text{–}WGHT_{sr} * GDEM_{srl} + (1 - DEM\text{–}WGHT_{sr}) * DEM\text{–}GRW_{sr}$$

where:

$GDEM_{sry}$ = expected annual growth rate for electricity demand in sector s in region r in year y (scalar)

[38]For more information on the methodology to determine adaptive expectations, see Energy Information Administration, *NEMS Integrating Module Documentation Report*, DOE/EIA-M057(98) (Washington, DC, December 1998).

DEM_WGHT_s = weighting factor used to smooth original and new expected demand growth rate (scalar)

$GDEM_{srl}$ = previous expected annual growth rate for electricity demand in sector s in region r in year l = y-1 (scalar)

DEM_GRW_{sr} = initial expected demand growth rate (scalar)

Appendix 3.A. ECP Data Flows

The subroutine *ELECP* initializes variables and calls *ECPOML*, which controls the setup and solution of the LP model. *ECPOML* initializes the LP database and sets up the starting matrix using OML subroutines. It then executes a series of FORTRAN subroutines that control the revision of coefficients for the ECP. The modified coefficients include costs in the objective function, constraint matrix (row/column intersections and right-hand sides) and bounds (lower and upper limits) on decision variables. Once the matrix revisions are completed, the LP model is solved and the solution retrieved using OML subroutines.

Matrix Revisions

EP$ALLOW sets up the right-hand side of the emissions constraints for each year of the planning horizon. For SO_2, the right-hand side represents the limit corresponding to the sum of the emissions allowances allocated in accordance with the Clean Air Act Amendments of 1991 or other proposed limits. Restrictions on SO_2 emissions are implemented as national constraints since allowances can be traded. If emissions allowances have been banked by over complying in previous years (i.e., emitting less sulfur dioxide than the sum of the allowances), then the right-hand side is adjusted accordingly. *EP$ALLOW* calls *GETSO2*, which is a data processing routine that obtains the SO_2 allowances from an EMM input file. *EP$ALLOW* similarly represents limits on nitrogen oxide (NOX) and mercury emissions.

EP$ETT imposes interregional transmission constraints and incorporates limits on imports from new Canadian hydroelectric projects. The corresponding contributions to reserve margin requirements are also included. *EP$ETT* calls *GETEIJ*, which is a data processing routine that obtains transmission and trade data from an EMM input file.

EP$COAL creates the model structure for retirement and retrofit decisions for existing coal capacity. It represents the costs of retiring plants, continuing to operate in its present configuration, and installing control devices to reduce emissions of SO_2, NOX, and mercury, including scrubbers, low-NOX burners, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), spray dryers, and fabric filters.

EP$CSUPPLY creates the coal supply curves that are used to represent the delivery of coal to electric generating plants. It uses information from the Coal Market Module (CMM) to describe production and transportation costs, available supplies, and coal characteristic such as Btu content and emissions rates for SO_2, NOX, mercury, and carbon. This subroutine also sets up the decision variables to retrofit and operate coal-fired capacity to cofire with biomass. These decisions can reduce emissions and/or contribute to the requirements specified in a renewable portfolio standard.

EP$RET sets up a national level constraint that represents infrastructure limits on the amount of scrubber retrofits that can be completed annually. This limit is relaxed over time as additional retrofits are required.

EP$BLD simulates disincentives for overbuilding generating capacity such as the disallowance by public utility commissions of capital additions to the rate base for new plants that are excess capacity. Electric utilities must have sufficient generating capacity to satisfy minimum reliability requirements, which is defined as the peak demand plus an assumed amount of reserve capacity in case of unexpected demands or unavailable supply (e.g., unplanned maintenance). *EP$BLD* revises the coefficients for constraints that limit capacity additions in excess of the minimum reliability requirements. It also uses *GETEIJ* in order to incorporate contributions to the reserve margin requirement of Canadian hydroelectric projects and plants built in one region to serve another.

For each of the electricity supply regions, the data processing routine *GETBLD* reads a file that stores input data required to generate coefficients in the LP model. These data are initially used in the subroutines *EPFLPRC,* which determines the expected fuel prices. These fuel prices are used to determine the coefficients for the discounted present value of fuel costs over the 20-year period in which project expenditures are evaluated.[39]

EPPMLF determines the planned maintenance and load following requirements. The planned maintenance constraints ensure that capacity is removed from service in order to perform annual maintenance. The load following structure simulates reductions in utilization rates that can occur during periods of low demand. Load following can prevent shutdowns of units that are difficult or costly to restart.

EXCUM and *EMUE* revise the coefficients of the constraints that represent capacity planning under competition. These equations determine the optimal capacity level by equilibrating the marginal cost of capacity and the marginal cost of unserved energy.

EP$MRM computes the total capacity needed to meet the reserve margin requirement. In contrast to *EP$BLD*, which places an upper limit on the amount of capacity, *EP$MRM* determines minimum capacity for insuring reliable supplies. *EP$LOAD* establishes the required allocation of capacity to meet the demand for electric power in each seasonal/time-of-day load segments in the ECP. The calculations in *EP$MRM* and *EP$LOAD* represent the respective right-hand sides of the reserve margin rows and electricity load requirement rows in the LP model.

EP$RPS sets up the constraints that represent renewable portfolio standards, which impose a minimum generation requirement for qualifying renewable technologies. This subroutine also can

[39]The planning horizon for the ECP is 6 years, so the cost coefficients for the last year actually represent the total present value of expenditures incurred in years 6 through 20.

specify a maximum credit price that can be that can be incurred if the cost of building additional renewable capacity becomes too expensive.

EP$LINT imposes a limit on the amount of generation that can be provided by intermittent capacity (i.e., wind and solar). This represents reliability concerns that can result if too much of the available supply is provided by technologies with energy sources that vary hourly or seasonally.

EP$RFS creates fuel supply curves to represent the costs and quantities of biomass fuel. This fuel is used in dedicated biomass plants and coal capacity that cofire with biomass.

The remaining revisions primarily involve updating coefficients for the decision variables in the ECP. These coefficients describe cost and performance characteristics for building and operating fossil, nuclear, and renewable technologies. The primary function of *EP$BDSP* is to calculate the objective function coefficient for decision variables to build new fossil-fuel and nuclear units (referred to as "build vectors"). This coefficient corresponds to the discounted present value of construction expenditures and fixed operations and maintenance costs for building new generating capacity and the associated transmission equipment. *EP$BRNW* updates the corresponding objective function value for new renewable capacity (e.g., geothermal, hydroelectric, biomass), excluding intermittent technologies (e.g., wind and solar). For some renewable technologies, the Energy Policy Act of 1992 (EPACT) established cost credits, which are subtracted from the corresponding capital costs. *EP$BRNW* also imposes limits (upper bounds) on capacity additions for renewable technologies due to resource constraints, if appropriate. *EP$BDGN* determines the objective function coefficients and maximum capacity additions for each step of the distributed generation supply curves.

EP$ODSP modifies the coefficients for decision variables that describe the allocation of fossil-fuel and nuclear to meet the demand for electricity (referred to as "operate vectors"). It determines the cost of operating fossil-fuel and nuclear capacity types, based on the discounted, present value of operating expenses (fuel and variable operating and maintenance costs). These capacity types are considered "dispatchable" since they are generally available to generate electricity except for planned and unplanned outages. One of the decisions evaluated by the ECP is the mode of operation for these capacity types, which ranges from "baseload" (continuous operation except for outages) to "peaking" (operated only during periods when demand is high). The total variable cost depends on the utilization rate and the per-unit operating costs. *EP$ODSP* calls *EPDRATE*, which calculates the derating factors for dispatchable capacity types across all load slices. The derating factor is a function of the forced outage rate, planned maintenance rate, and load following rate of the capacity type and of the load shape.

EP$ORNW is similar to *EP$ODSP* except it determines the operating cost and performance coefficients for renewable capacity types, excluding intermittent technologies. If appropriate, the variable costs for renewable technologies are reduced to account for subsidies specified in EPACT. The renewable capacity types described in *EP$ORNW* are similar to fossil-fuel and nuclear units in

that they are generally dispatchable but they may be subject to an energy constraint (e.g., steam for geothermal and water for hydroelectric) that imposes a maximum utilization rate.

EP$INT revises the cost and performance coefficients for intermittent technologies. Unlike the dispatchable capacity types, which have separate decision variables for the construction and operation on capacity, a single variable is used for intermittent technologies. The ECP essentially determines whether or not to build these capacity types because they will be operated if available since they have relatively low operating costs. However, the utilization of these technologies varies according to the season and time-of-day depending on the availability of the resource (e.g., sun and wind). The objective function coefficient is the present value of building and operating intermittent technologies. As with the other renewable technologies, the capital and operating costs are decreased to reflect subsidies from EPACT. The coefficients in the constraint matrix describe the variations in utilization rates across the seasonal and time-of-day load segments.

The subroutines that calculate the costs of building new capacity (EP$BDSP, EP$BRNW, EP$BDGN, and EP$INT) call a couple of subroutines that determine costs associated with new plant construction. *EPINCST* computes the installed cost of new capacity, accounting for construction expenditures, interest, and inflation. It provides the tax basis and book value for a unit of each technology type. EPCNBLD then determines the corresponding annual capital recovery payment.

EP$NUC creates the decision variables to represent retirements of existing nuclear capacity. These variables determine whether it is economic to continue operating existing plants as opposed to retiring them and replacing them with other types of capacity.

Once the computations to revise the coefficients for the LP model are completed, *ECPOML* executes several OML routines to process the data, load the matrix, and solve the model. *ECPOML* then calls a series of subroutines to obtain solution values that are provided to other components of the EMM..

Solution Retrievals

EPO$BANK retrieves and stores the allowances banked in the current year. The banked allowances are provided to the Electricity Fuel Dispatching (EFD) Submodule so that the emissions limit for the current forecast year can be increased by the corresponding amount. *EPO$RPS* obtains the dual values of the renewable portfolio standard constraints, if any, and computes the levelized credit price. *EPO$TBLD* identifies national-level build limits to insure that these restrictions are not violated when the capacity decisions are reallocated by the market-sharing algorithm. *EPO$ETT* captures the decision to purchase electric power from new Canadian hydroelectric projects. This information is used to increase firm Canadian imports when evaluating subsequent dispatching and planning decisions.

EPO$COAL obtains the planning decisions to retire existing coal capacity or retrofit plants with pollution control devices. *EPO$NUC* stores retirement decisions for existing nuclear capacity.

Prior to getting the remaining planning decisions, the data processing routine *GETBLD* retrieves input data such as capital costs and the cost of capital in order to calculate the required expenditures. For each electricity supply region, *EPO$AVOID* obtains the avoided cost of electricity (the cost of producing an additional unit of electricity). This value is determined so that the Load and Demand-Side Management Submodule will be able to pre-screen candidates and eliminate programs that are not competitive with supply options. *EPO$BILD* retrieves capacity expansion decisions and provides them to the EFD in order to adjust the available capacity for future dispatching decisions. *EPO$BILD* also provides investment costs for new capacity to the Electricity Finance and Pricing Submodule (EFP) to include in the revenue requirements. *EPO$BILD* also stores the retirement decisions for noncoal fossil capacity.

EPO$PM and *EPO$COF* capture the planned maintenance and cofiring decisions from the ECP, respectively. These results can be passed to the EFD if this option is specified by the user. The information from the LP solution is made available to the other submodules using *STRBOUT* and *STRPCNTL*, which store the data on direct access files.

Appendix 3.B. Data Sources

This appendix provides a list of the data sources in the ECP. Each data source is accompanied by a brief description.

SURVEY FORMS

Form EIA-860A

The Form EIA-860A is a mandatory, annual census of electric utilities in the United States that operate power plants or plan to operate a power plant within 10 years of the reporting year. The survey collects data from the electric utilities on existing power plants, and on 10 year plans for constructing new plants, and modifying and retiring existing plants. Data is collected at the generating unit level and includes capacity and fuel source information, along with ownership and location data.

*Form EIA-860*B

The Form EIA-860B is a mandatory, annual survey of all existing and planned nonutility electric generating facilities in the United States with a total generator nameplate capacity of 1 or more megawatts. The form is used to collect data on the installed capacity, energy consumption, generation and electric energy sales to electric utilities and other nonutilities by facility. Additionally, the form is used to collect data on the quality of fuels burned and the types of environmental equipment used by the respondent. Planned generators are defined as a proposal by a company to install electric generating equipment at an existing or planned facility. The proposal is based on the owner having obtained (1) all environmental and regulatory approvals, (2) a contract for the electric energy, or (3) financial closure on the facility.

Form EIA-767

The Form EIA-767 is a mandatory, annual, restricted-universe census of all electric power plants with a total existing or planned organic- or nuclear-fueled steam electric generator nameplate rating of 10 or more megawatts. The entire form is filed by approximately 700 power plants with a nameplate capacity of 100 or more megawatts. An additional 200 power plants with a nameplate capacity between 10 and 100 megawatts submit information only on fuel consumption/quality, boiler/generator configuration, and flue-gas desulfurization equipment, if applicable. The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data).

Form EIA-759

The Form EIA-759 is a mandatory, annual census of all operators of electric utility plants producing electric power for public use. The Form-EIA 759 is used to collect monthly data on net generation,

consumption of coal, petroleum, and natural gas; and end-of-the-month stocks of petroleum and coal for each plant by prime mover and fuel type combination.

FERC Form 1

The FERC Form 1 is a mandatory, annual census of major investor-owned electric utilities that meet specified criteria for sales. The form collects data on income and earnings, taxes, depreciation and amortization, salaries and wages, operating revenues, and operating and maintenance costs.

Quality of EIA Survey Data

The Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF) is responsible for routine data improvements, and quality assurance activities of EIA survey data. Data improvement efforts include verification of data-keyed input by automatic computerized methods, editing by subject matter specialists, and follow up on nonrespondents. Manual edit checks include spot checking information stored on computer tapes against the survey forms, and computer edits include both deterministic checks, in which records are checked for the presence of required fields and their validity; and statistical checks, in which estimation techniques are used to validate data according to their behavior in the past and in comparison to other current fields. Data values that fall outside of prescribed ranges are verified by telephoning respondents to resolve any discrepancies.

Office of Integrated Analysis and Forecasting, "Cost and Performance Database for New Generating Technologies"

A database of current costs and performance characteristics for a wide range of conventional and advanced generating technologies was derived from reports and discussions with sources from industry, government and Department of Energy National Laboratories.

NERC regional publications of the "Coordinated Bulk Power Supply Program Report"

A annual compilation of load and resource data that allows the ten North American Electric Reliability Councils (NERC) to assess the adequacy and reliability of bulk power supply in the NERC regions. The report contains information in three categories: 1) Peak Load/Resource and Energy/Fossil Fuel Information, 2) Existing Generation, and 3) Generation Additions. This information is filed with the Department of Energy, Office of Emergency Planning and Operations (OE) as part of the FORM OE-411 response. FORM OE-411 is described below.

FORM OE-411

The Form OE-411 is filed annually on April 1 by the ten NERC regions. The information reported includes: (1) actual energy and peak demand for the preceding year and 10 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) assessment of adequacy; (6) generating

capacity unavailability; (7) bulk power system maps; (8) near term transmission adequacy; (9) future critical bulk power facilities that may not be in service when required; and, (10) system evaluation criteria.

Environmental Protection Agency "Emissions Characteristics and Costs"

- Allowance Tracking System (ATS) -- database for sulfur dioxide allowances under the Acid Rain Program specified by the Clean Air Act
- NO_X Allowance Tracking System (NATS) -- data on nitrogen oxide allowances under the Ozone Transport Commission (OTC) and State Implementation Program (SIP) Call Programs
- "Analyzing Electric Power Generators Under the CAAA, Appendix 5" (Washington, DC, March 1998) -- costs for pollution control equipment

Distributed Utility Associates "Cost and Performance Characteristics for Distributed Generation"

- "Assessing Market Acceptance and Penetration for Distributed Generation in the United States" (June 1999)

Appendix 3.C. Derivation of Coefficients for Capacity Planning Under Competition

SUBROUTINE: SHAVEL

Description: Computes the Shavel/Sanghvi approximation to the cumulative distribution at a point z given its first four cumulants. This is based on first few terms of the Gram-Charlier expansion of a distribution as an infinite series of its cumulants.

Parameters:

z	=	z-value (input)
cum1	=	first cumulant of marginal capacity function
cum2	=	second cumulant of marginal capacity function
cum3	=	third cumulant of marginal capacity function
cum4	=	fourth cumulant of marginal capacity function
cum	=	cumulative distribution (output)

Called by: ELREL, EMUE

Calls: NORM

Equations:

$$g1 = \frac{cum3}{cum2^{1.5}}$$

$$g2 = \frac{cum4}{cum2^{2}}$$

$$norm0 = pinorm * \exp^{-\frac{z^2}{2}}$$

call norm(z1,norm0,normx1)

$$cum = normx1 - \frac{g1 * norm0 * (z^2 - 1)}{6!} + \frac{g2 * norm0 * (3z - z^3))}{4!} + \frac{g1^2 * 10 * norm0 * (10z^3 - 5z - z^5)}{6!}$$

where:

for	=	forced outage rate,
cap	=	size of the unit (Gigawatts),
cum1	=	first cumulant of marginal capacity function,
cum2	=	second cumulant of marginal capacity function,

cum3 = third cumulant of marginal capacity function, and
cum4 = fourth cumulant of marginal capacity function.

FUNCTION: DELEUE

Description: Develops the contribution of a unit of capacity of a particular ECP type to the reduction in marginal expected unserved energy.

Called by: DELEUE

Calls: Shavel.

Equations:

Determine loss of load probability (LOLP)
CALL Shavel(cum1,cum2,cum3,cum4,LOLP)

$$G1 = \left(\frac{cum3}{cum2}\right)^{3/2}$$

$$DELEUE = 0 + DZ1(for,cap,cum1,cum2) * LOLP - DG1(for,cap,cum2,cum3) + \frac{N2(z14)}{3!} + \frac{DG2(for,cap,cum2,cum4) * N3(z14)}{4!} + \frac{2 * G1 * DG1(for,cap,cum2,cum3) * 10 * N5(z14)}{6!}$$

where
for = forced outage rate,
cap = size of the unit (Gigawatts),
cum1 = first cumulant of marginal capacity function,
cum2 = second cumulant of marginal capacity function,
cum3 = third cumulant of marginal capacity function, and
cum4 = fourth cumulant of marginal capacity function.

FUNCTION: DZ1

Description: DZ1 creates the coefficient for the third order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$DZ1 = -for * \sqrt{cum2} - .5 * (-1 * cum1) * for * (1 - for) * cap * cum2^{-3/2}$$

where:

for = forced outage rate,
cap = size of the unit (Gigawatts),
cum1 = first order cumulant of marginal capacity function, and
cum2 = second cumulant of marginal capacity function.

FUNCTION: NORM

Description: NORM finds the cumulative normal probability distribution for any value z1.

Called by: DELEUE

Calls: None.

Parameters: dens = normal density evaluated at z1

Equations:
data a/0.2316419/
data b/0.31938153,-0.356563782,1.781477937,-1.821255978,1.330274429/

$$val3 = \sum_{i=1}^{5} b_i * \left(\frac{1.0}{1.0 + a * z1}\right)^i$$

where:

val3 = intermediate value,
b = constant, and
a = constant.

$$cum = 1.0 - dens * val3$$

where:

cum = cumulative distribution evaluated at z1, and
dens = normal density evaluated at z1.

FUNCTION: DG2

Description: DG2 creates the coefficient for the fourth order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$DG2 = for * cap^3 * (1 - 7 * for + 12 * for^2 - 6 * for^3) * cum2^{-2} - 2 * cum4 * for * cap * (1 - for) * cum2^{-3}$$

where:

for = forced outage rate,
cap = size of the unit (Gigawatts),
cum2 = second cumulant of the marginal capacity function, and
cum4 = fourth order cumulant of the marginal capacity function.

FUNCTION: DG1

Description: DG1 creates the coefficient for the second order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$DG1 = for * cap^2 * (1 - 3 * for + 2 * for^2) * cum2^{3/2} - 1.5 * cum3 * for * cap * (1 - for) * cum2^{-5/2}$$

where:

for = forced outage rate,
z3 = mean of the marginal capacity function,
cap = size of the unit (Gigawatts),
cum2 = second cumulant of marginal capacity function, and
cum3 = third cumulant of marginal capacity function.

FUNCTION: N2

Description: N2 creates the coefficient for the second order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N2 = -1 * (z2^2 - 1.0) * pinorm * Exp\frac{-z2^2}{2}$$

where:

pinorm	=	0.39894228040, and
z2	=	mean of the marginal capacity function.

FUNCTION: N3

Description: N3 creates the coefficient for the third order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N3 = -1 * (z3^3 - 3 * z3) * pinorm * Exp(\frac{-z3^2}{2})$$

where:

pinorm	=	0.39894228040, and
z3	=	mean of the marginal capacity function.

FUNCTION: N5

Description: N5 creates the coefficient for the fifth order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N5 = -1 * (z5^5 - 10 * z5^3 + 15 * z5) * pinorm * Exp(\frac{-z5^2}{2})$$

where:

pinorm = 0.39894228040, and

z5 = mean of the marginal capacity function.

SUBROUTINE: EMUE

Description: This subroutine calculates the coefficients for the reserve margin row. Reserve margins are calculated from the relationship

$$(\partial UE / \partial G) \cdot V(UE) = A_t \quad ,$$

where:

A_t = annual carrying cost (dollars per kilowatt per year) of the least expensive generating capacity (combustion turbine), and

$(\partial UE/\partial G) \cdot V(UE)$ = Marginal cost of unserved energy (dollars per kilowatt per year).

Substituting the Taylor series expansion of the Gram-Charlier approximation to the expression for expected unserved energy, we get

$$EUE^J = EUE^1 + \sum_i (\partial UE / \partial X_i) * (X_i^j - X_i^1) + (\partial UE / \partial L^j) * (L^j - L^1)$$

where:

EUE^J = expected unserved energy in forecast year J,

L^J = load in forecast year I, and

X_I^J = capacity of type I.

If we approximate $(\partial UE/\partial G)$ by $\Delta UE/\Delta G$ and note

$$\Delta G = \sum_i (X_i^j - X_i^1) + (L^j - L^1)$$

after some algebraic manipulation, we get

$$\sum_i (\partial UE / \partial X_i - A_t / V(UE)) * (X_i^j - X_i^1) + (\partial UE / \partial L_i - A_t / V(UE)) * (L_i - L_1) = 0$$

where:

$(\partial EUE/\partial X_i)$ = partial derivative of unserved energy for each capacity type, and
$(\partial UE/\partial L_i)$ = partial derivative of unserved energy for changes in load.

Called by: REVECP

Calls: Shavel, Deleue

Parameters: NERC = NERC region, YEAR = Forecast year

Equations:

We calculate capacity cumulants by ECP season and demand cumulants by ECP slice. These are used to calculate loss of load probability (LOLP) in each slice, and also the contribution of each capacity to the reduction of marginal unserved energy in each slice.

$$xcap = \frac{(ECUMDSP(ISP,IP,NERC) - PMDSP(ISP,IP,NERC)}{ECUNIT(IP,1)}$$

where:
xcap = average size of unit capacity type IP,
ECUMDSP = dispatchable capacity (GW) of type IP in season ISP, region NERC,
PMDSP = planned maintenance of capacity IP in season ISP, region NERC.

For each ECP capacity type in each season:

$$vex1 = (1 - UPFORT) * xcap$$
$$vex2 = (1 - UPFORT) * xcap^2$$
$$vex3 = (1 - UPFORT) * xcap^3$$
$$vex4 = (1 - UPFORT) * xcap^4$$

where:
UPFORT = forced outage rate of ECP capacity type j,
xcap = average size of unit of capacity type j in season I
vexk = moment k around 0 of capacity type j, and

$$vmom(1) = vex1$$
$$vmom(2) = vex2 - vex1^2$$
$$vmom(3) = vex3 - 2 * vex1 * vex2 + vex1^3$$
$$vmom(4) = vex4 - 4 * vex3 * vex1 + 6 vex1^2 * vex2 - 3 vex1^4 - 2 * vmom(2)^2$$

where:
vmom(k) = cumulant k of a unit of type J, season I.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$ecapcum(ISP,IMOM) = ecapcum(ISP,IMOM) + vmom(IMOM) * ECUNIT(IP,YEAR)$$

where:

ecapcum(ISP,IMOM) = total capacity cumulant IMOM, season ISP, and

Ecunit = number of plants of type L.

The cumulants of the rest of the ECP capacity types are calculated similarly. For conventional and reversible hydropower:

$$xcap = \frac{EPECAP(J,YEAR) * RNWFAC}{ECUNIT(J,YEAR)}$$

where:

EPECAP = capacity of renewable type J, season ISP

ECUNIT(J) = number of units of type J,

RNWFAC = capacity factor for renewable,

xcap = average size of unit of capacity type j in season I,

while for all other renewable capacity types

$$xcap = EPECAP(J,ISP) * EHHYCF(J,ISP)/ECUNIT(J)$$

where:

EPECAP = capacity of renewable type J, season ISP, year YEAR,

EHHYCF(J,ISP) = capacity factor for renewable J season ISP, and

xcap = average size of unit of capacity type J in season ISP.

$$vex1 = (1 - RENFOR) * xcap$$
$$vex2 = (1 - RENFOR) * xcap^2$$
$$vex3 = (1 - RENFOR) * xcap^3$$
$$vex4 = (1 - RENFOR) * xcap^4$$

where:

RENFOR = forced outage rate of EFD capacity type J,

vexk = moment k around 0 of capacity type J.

$$vmom(1) = vex1$$
$$vmom(2) = vex2 - vex1^2$$
$$vmom(3) = vex3 - 2 * vex1 * vex2 + vex1^3$$
$$vmom(4) = vex4 - 4 * vex3 * vex1 + 6 vex1^2 * vex2 - 3 vex1^4 - 2 * vmom(2)^2$$

where:

vmom(k) = cumulant k of a unit of type J, season ISP.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$ecapcum(ISP,IMOM) = ecapcum(ISP,IMOM) + vmom(IMOM) * ECUNIT(IP,YEAR)$$

where:

ecapcum(ISP,IMOM) = total capacity cumulant IMOM season ISP.

Ecunit = number of plants of type L

For each slice we calculate

$$dem = EPHGHT(VLS,YEAR) + UEITAJ(IGRP,NERC)$$

$$\begin{aligned} cum(1) &= ecapcum(ISP,1) - dem \\ cum(2) &= ecapcum(ISP,2) + (dem * loadecpu)^2 \\ cum(3) &= ecapcum(ISP,3) \\ cum(4) &= ecapcum(ISP,4) \end{aligned}$$

where:

cum(I) = cumulant of order I,

Ecapcum (ISP,IMOM)= capacity cumulant in season ISP of order IMOM, and

Loadecpu = fraction used to calculate load standard deviation.

We get the LOLP for this slice from calling the subroutine

$$Shavel(z1,cum(1),cum(2),cum(3),cum(4),LOLP)$$

where:

LOLP = loss of load probability in slice VLS.

The contribution to reduction of marginal energy is calculated for each capacity type. For dispatchable capacity

$$\begin{aligned} FOR &= 1 - UPFORT(IP) \\ PMR &= 1.0 - UPPMRT(IP) * FOR \end{aligned}$$

where:

PMR = effective planned maintenance rate,

UPFORT = forced outage rate of capacity type IP,

FOR = availability rate,

UPPMRT(IP) = planned maintenance rate, and

$$DELEMUEDSP(ISP,IP,NERC) = \sum_{VLS} \left(DELEUE(z1,cum(1),cum(2),cum(3),cum(4),xcap,FOR,LOLP) - \frac{CCOSTTURB}{(8760 * ECPVOLL)} \right) * EPWIDTH(VLS) * PWR$$

where:

DELEUE = contribution to reduction in marginal unserved energy from capacity IP in slice VLS,

COSTTURB = cost of a turbine ($/kWh),

ECPVOLL = value of unserved energy ($),

EPWIDTH = width in hours of slice VLS,

while for conventional hydroelectric sources

$$DELEMUERNW(ISP,IP,NERC)=\sum_{VLS}\left(DELEUE(z1,cum(1),cum(2),cum(3),cum(4),xcap,FOR,LOLP)-\frac{CCOSTTURB}{(8760*ECPVOLL)}\right)*EPWIDTH(VLS)*RNWFAC$$

where:

RNWFAC = capacity factor for hydro renewables and EPIRCCR for non-hydro renewables.

The contribution from all existing capacity is then

$$EXMUE(NERC)=\sum_{ip} delemue(ip)*epecap(ip,YEAR)$$

where:

delemue = contribution to reduction in marginal unserved energy of capacity type ip.

The contribution for demand is

$$LMUE(YEAR)=\sum_{VLS}(LOLP*(LCUM(VLSA,NERC,YEAR)-LCUM(VLS,NERC,1))*(1.0+ADJ)-\frac{CCOSTTURB}{8760.0*ECPVOLL(NERC)})*EPWDTH(VLS,YEAR)$$

where:

LMUE = contribution to marginal unserved energy by load increase,

LCUM = load in slice VLS region NERC forecast year YEAR,

ADJ = adjustment factor for revenue reconciliation,

and

$$ADJ=(DGAPOLD(NERC)-1.0)*MEFAC(NERC)$$

where:

DGAPOLD = revenue gap in region NERC,

MEFAC = scaling factor for region NERC.

The right hand side is then

$$DELEMUERHS(YEAR,NERC)=EXMUE(YEAR)+LCUM(NERC).$$

Appendix 3.D Assumptions for Biomass Cofiring

Biomass cofiring characteristics depend on the type of coal-fired boiler. Cofiring costs and levels differ for cyclone and other pulverized coal units. The size of the unit also affects cofiring capability. The ECP utilizes five retrofit categories for cofiring in coal-fired capacity: (1) Cyclone boilers greater than 500 megawatts, (2) Cyclone boilers less than or equal to 500 megawatts, (3) Other pulverized coal boilers greater than 500 megawatts, (4) Other pulverized coal boilers greater than or equal to 200 megawatts and less than or equal to 500 megawatts, and (5) Other pulverized coal boilers less than 200 megawatts.

Table 12 describes the cost assumptions for the biomass cofiring categories. Table 13 contains the assumed cofiring levels. Within each category, different levels can be achieved by incurring higher transportation cost. Table 14 displays the incremental transportation costs associated with the delivery of sufficient biomass fuel to support the specified cofiring level.

Table 12. Biomass Cofiring Costs by Retrofit Category (2000 Dollars)

Retrofit Category	Capital Cost (Dollars / Kw)	Fixed O&M Cost (Dollars / Kw)
1	100	7.0
2	100	7.0
3	100	7.0
4	200	7.0
5	230	7.0

Table 13. Biomass Cofiring Levels by Retrofit Category (Percent)

Retrofit Category	Cofiring Level					
	1	2	3	4	5	6
1	2.5	5.0	7.5	10.0	12.5	15.0
2	5.0	10.0	15.0	NA	NA	NA
3	2.0	4.0	6.0	8.0	12.0	15.0
4	10.0	15.0	NA	NA	NA	NA
5	15.0	NA	NA	NA	NA	NA

NA = Not Available

Table 14. Incremental Biomass Transportation Costs by Retrofit Category and Cofiring Level (2000 Dollars per Million Btu)

Retrofit Category	Cofiring Level					
	1	2	3	4	5	6
1	0.00	0.24	0.43	0.58	0.72	0.84
2	0.00	0.24	0.43	NA	NA	NA
3	0.00	0.24	0.43	0.58	0.84	1.01
4	0.00	0.13	NA	NA	NA	NA
5	0.00	NA	NA	NA	NA	NA

NA = Not Available

Appendix 3.E. Cost of Capital

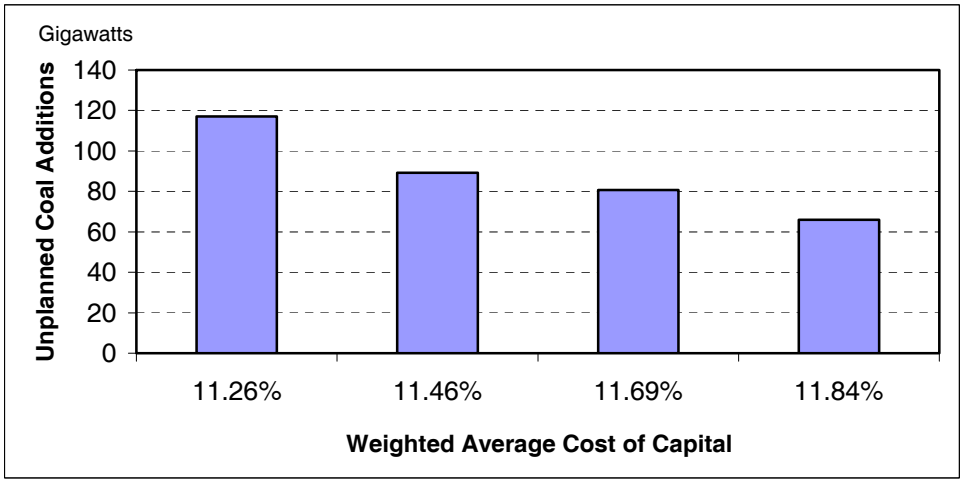
Introduction

This document describes the assumptions, methodology, and estimating techniques used to calculate the discount rate for capital budgeting in the Electricity Capacity Planning (ECP) submodule of the National Energy Modeling System (NEMS).

The expected construction of new electric power plants is needed to prepare the 20-year projections of energy production, consumption and prices. The specific generating technologies that will be chosen and the fuels that they will use is part of this effort. The ECP chooses the mix of plants that will minimize the total system costs of meeting consumers' electricity needs. The model performs a discounted cash flow analysis of the costs of building and operating power plants over the next 20 years and chooses the least cost mix of options. The ECP assumes that building power plants will take place in a competitive environment rather than in a rate base or regulated environment.

Each year, the assumptions and parameters for discount rates and the weighted average cost of capital (WACC)[1] are reviewed to reflect the changing nature of the power industry and to incorporate new capital market information. For example, for the AEO 2004, we have increased the equity portion of project financing and the return required on equity to reflect the greater risk associated with investments in a deregulated market. The discount rate (WACC) is a very important component because the rate reflects the riskiness of the investment and affects mix of capacity additions. For instance, Figure 11 shows the sensitivity of unplanned capacity additions to discount rates; small changes in the weighted average cost capital lead to huge changes in capital intensive capacity additions.

Figure 11



Source: *The National Energy Modeling System: AEO 2004 Run Review*, EIA

[1] We are implicitly assuming that the project will be financed by both debt and equity and will return the expected interest payments to creditors and the expected dividends to shareholders.

This report explains the models, assumptions and parameters for the WACC. The report is organized as follows: The following section describes theoretical approaches, assumptions and parameters of the model. The subsequent section provides the model structure and computations.

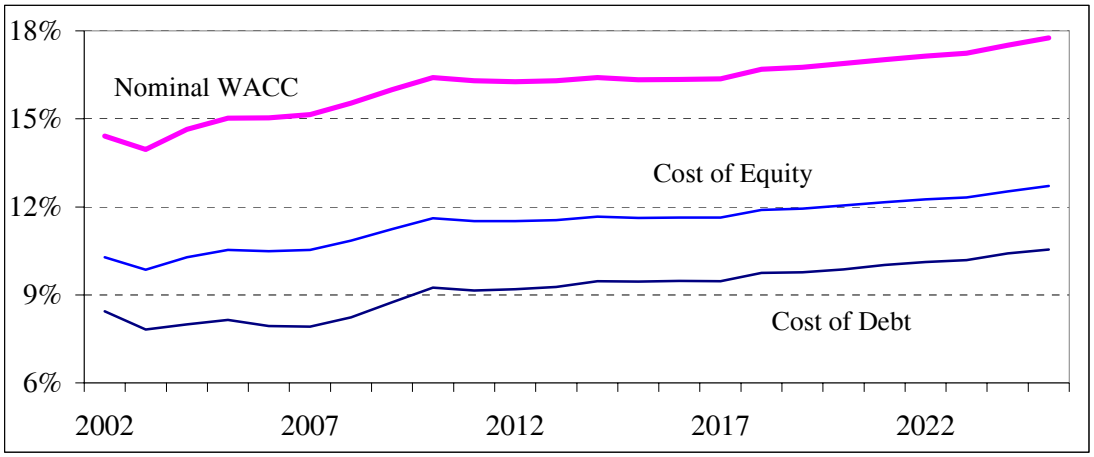
Discount Rate Assumptions and Parameters

Investment Assumptions in the ECP

In the ECP, a traditional net present value (NPV) capital budgeting methodology is employed to perform investment feasibility. In order to do so, the following assumptions are made:

1) Power generating industry is competitive. Thus, investments for power plants are made in competitive environment that includes certain risks.
2) Different generating technologies have the same risk treatment in investment for capital budgeting purposes. That is the required rate of return (WACC) on investment is the same for all projects.
3) The discount rate (WACC) is different for each year[2], and it is shown in Figure 12.

Figure 12
Derived Nominal WACC



[2] A fixed discount rate of net present value (NPV) methodology over the life of the project for capital budgeting is simplified computations and overly restricted. Since several parameters for the cost of debt and equity in the NEMS are endogenously determined, the different WACC for each is derived by the NEMS and is used for capital budgeting. This approach is more realistic and accurate to forecast next 20 years.

The WACC Overview

The WACC equation is as follow:

$$WACC = \left(\frac{Debt}{Total\ Capital}\right) k_d\ (1-t) \quad + \quad \left(\frac{Equity}{Total\ Capital}\right) k_s$$

$$= (w_d)\,(k_d)\,(1-t) \quad + \quad (w_s)\,(k_s)$$

where w_d: weight of debt proportion to total capital
w_s: weight of equity proportion to total capital
k_d: cost of debt
k_s: cost of equity
t: corporate tax rate

In order to calculate the discount rate (WACC) for capital budgeting, we need to identify at least seven different parameters, two endogenous[3] and five exogenous inputs. The fundamental assumptions and parameters of the variables are shown in Table 15.

Table 15
Financial Parameters and Assumptions

	Variables	Parameters		
1.	Debt fraction	45%	Exogenous	Fixed
	Cost of debt: Utility AA Rate + Premium		Endogenous	Varied
2.	Utility AA bond rate		Endogenous	Varied
3.	Debt Premium	1.25%	Exogenous	Fixed
	Cost of equity: Capital Asset Pricing Model		Endogenous	Varied
4.	Risk-free rate: 10 year T-note rate		Endogenous	Varied
5.	Market risk premium	7%	Exogenous	Fixed
6.	Equity beta	1.4	Exogenous	Fixed
7.	Corporate tax rates	38%	Exogenous	Fixed
	Nominal WACC		Endogenous	Varied

It is assumed that projects will be financed by both debt and equity and will return the expected interest payments to creditors and the expected dividends to shareholders. Therefore, the after-tax weighted average cost of capital is an appropriate discount rate for evaluating investment opportunities.

[3] These parameters, utility AA bond rate and 10-year T-note rate, are forecasted and generated by the macroeconomic module in the NEMS.

Assumptions and Derivations of the Parameters

Capital structure: Debt and equity proportions to total capital

The decision about capital structure to fund an investment project is based on the financial health of the industry outlook and capital market information. For example, an investment in an industry with a healthy outlook could use a larger debt proportion for the investment while a riskier investment project would require more equity relative to total capital. However, the capital structure will be constant over the project life.

Table 16 is the capital structure assumptions for the AEO 2003 and AEO 2004.

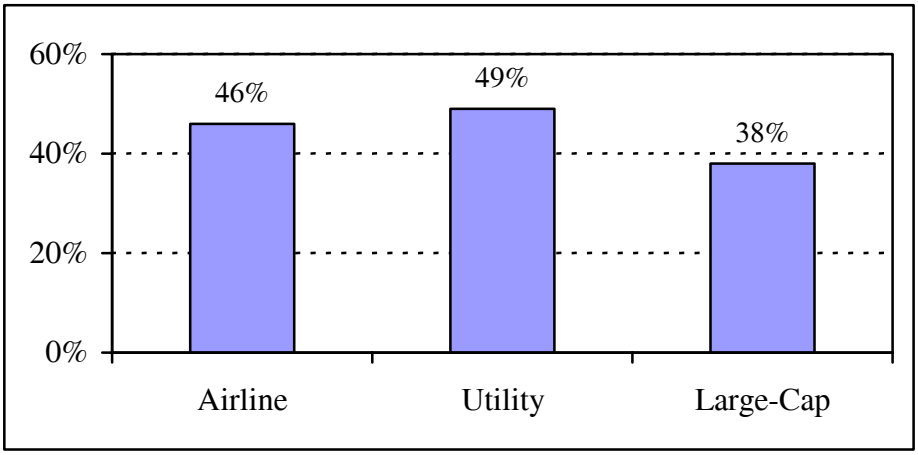
Table 16
Capital Structure

	AEO	
	2003	2004
Debt fraction	55%	45%
Equity fraction	45%	55%

The capital structure, debt and equity proportions for investment capital, decision is made by a feasible target capital structure using a "pure-play" analysis. For the AEO 2004, the capital structure is composed by 45 percent of debt fraction and 55 percent of equity fraction. The decision is based on our conversations with and survey data by utility practitioners suggest to us that less than 50 percent of debt finance will be feasible due to risks associate with industry over capacity and post Enron climate. We also look at last five years average debt structures of airline and utility industries, as well as large-cap firms for pure-play purpose.[4]

[4] Large-cap firms have equity capitalizations greater than $5,013,000,000. For more information on the methodology to determine the large-cap, see Ibbotson Associations, *Cost of Capital: 2003 Yearbook*, Chicago, IL, 2003.

Figure 13
Debt Fraction of Total Capital
Industry Composite: 5-year Average (3/1998 through 3/2003)



Source: Ibbotson Associates, "Cost of Capital: 2003 Yearbook."

Cost of debt

The cost of debt (k_d) is determined by the utility AA bond rate plus a debt premium.

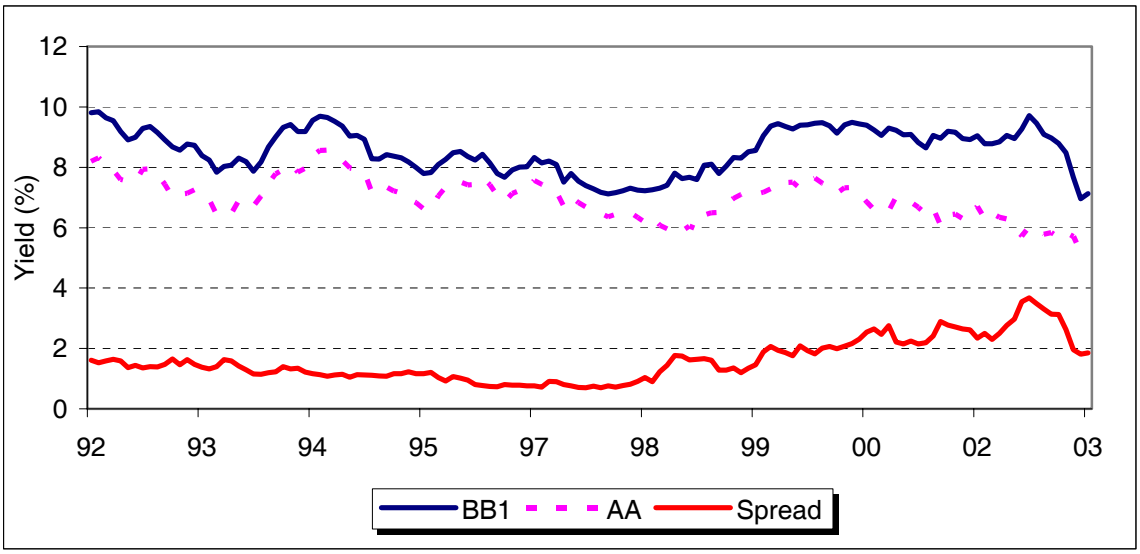
$$\text{Cost of debt}_t \equiv k_{dt} = \text{Utility AA bond rate}_t + \text{Debt premium} \qquad (3.E.1)$$

where
k_{dt} = Cost of debt in year t
AA bond rate$_t$ = Utility AA bond rate in year t
Debt Premium = Spread between corporate AA rate and BBB rate

Since the Macroeconomic module endogenously determines the utility AA bond rates for the forecasting period, rates (cost of debt) are different for each year. The debt premium is an exogenous variable and is assumed to be constant over the forecasting period. Given BB1 to BBB1 debt ratings on utility projects for recent years,[5] 1.25 percent debt premium over utility AA bond rates is added to get the cost of debt for the AEO 2004. It is assumed that an average debt rating for a utility project is BBB. Therefore, the debt premium is determined by an average historical spread between the corporate 10-year AA bond rate and BBB rate.[6]

[5] See Moody's, S&P, and Fitch for the recent projects and firms' debt ratings. The range of the debt ratings is also consistent with recent structured financing for power investments by investment banks, i.e., Morgan Stanley, Dean Witer, Merrill Lynch and Lehman Brothers.
[6] The monthly data is the index of corporate 10-year bond rates over the period of March 1992 through June 2003, and the data is from Bloomberg database.

Figure 14
Corporate Bond Rate Spread: AA Rates vs. BB1 Rates
3/1992 through 6/2003



Source: Bloomberg database.

Cost of equity

The Capital Asset Pricing Model (CAPM) was used to compute a cost of equity, which is an implied investor's opportunity cost or the required rate of return of any risky investment. The model is:

$$k_{st} = k_{RFt} + (EMRP)\,\beta_{Equity} \qquad \text{(3.E.2)}$$

where
k_{st} = cost of equity at year t
k_{RFt} = risk-free rate at year t
$EMRP$ = expected market risk premium (constant)
β_{Equity} = equity beta (constant)

The model requires that three variables be specified including risk-free rates, a market risk premium, and a systematic risk coefficient relative to market (beta). Since the CAPM assumes all investors have the same one-period time investment horizon such as one month, six months, or one year, using Treasury bill rates as risk-free rates is not appropriate. As a result, a risk-free rate (k_{RF}) is based on 10-year Treasury note rates. The future spot 10-year Treasury note rates in

the Macroeconomic module are used as estimates of expected risk-free rates in future time periods.

The expected market risk premium (*EMRP*), which is 7 percent,[7] is the expected return on market (S&P 500) over the rate of 10-year Treasury note (risk-free rate). Monte Carlo simulation is used to estimate the expected market return. There have been a number of studies to estimate the expected equity risk premium utilizing a variety of approaches. These studies can be categorized into four groups based on the approach and methodology. The first group of studies derives the equity risk premium from the historical returns between stocks and bonds. The second group uses supply side models, incorporating fundamental information such as earnings, dividends, or overall productivity. A third group adopts demand side models that derive the expected return of equity based on the payoff required by equity investors for bearing the additional risk. The opinions of financial professionals and industry practitioners based on a survey are used by the fourth group. The EIA approach estimates the expected market risk premium using the historical market risk premium methodology with arithmetic mean of returns on both S&P 500 and government bonds.

The arithmetic mean is used to estimate historical returns instead of the geometric mean, which is backward-looking and measures the change in value over more than one period. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending values. This makes the arithmetic mean return appropriate for forecasting the cost of capital.

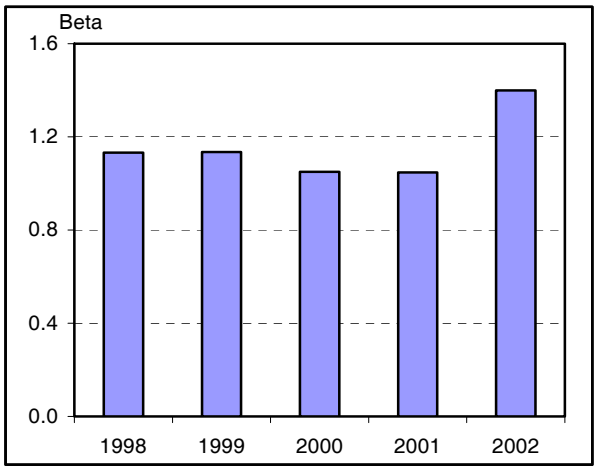
An industry composite equity beta of the utility industry is determined by a pure play analysis with the airline and telecommunication industries. The estimated utility industry equity beta for the AEO 2004 is 1.40. Since the industry is restructuring markets, historical utility data are no longer useful to analyze statistical inferences, especially going forward. The structure and size of the both airline and telecommunication industries are an appropriate guide to the current and future utility industries. A trend of the benchmark industry betas is shown in Figure 15 and Figure 16.

The year-average beta is calculated by an average of monthly fundamental betas for each year in both figures 15 and 16. The monthly fundamental beta is a measurement of the sensitivity of a company's stock price to the overall fluctuation in the S&P 500 index price, and it is calculated for a 5 year (60 month) time period.

Under regulated utility regimes, both equity and debt investment returns are guaranteed by a cost recovery system over time. Thus, the risk for equity or debt holders is the same. However, the investment risk for equity holders is greater than that of debt holders under unregulated utility regimes, since the power producer faces greater uncertain outcomes due to input factors and out prices as well as returns.

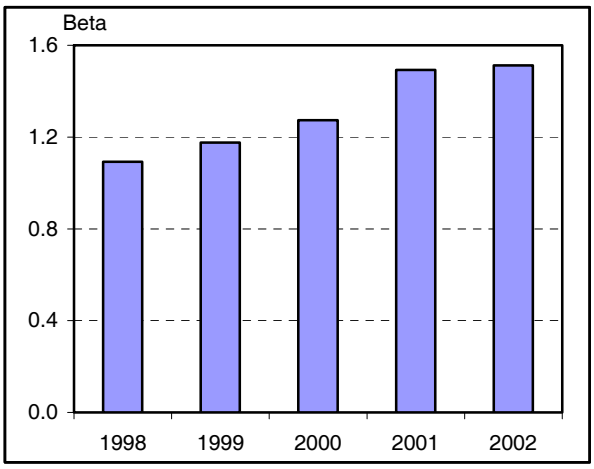
[7] This expected risk premium is coincidently the same as the equity risk premium that is estimated by Ibbotson Associates, SBBI 2003 Yearbook, page 177.

Figure 15
Airline Year-average Beta
(11/1997 through 10/2002)



Source: Compustat®

Figure 16
Telecommunication Year-average Beta
(11/1997 through 10/2002)



Source: Compustat®

As a result, the risk and return assessment must be estimated for the equity holders.[8] Equity holders now face with not only business risk but also financial risk so that the cost of equity should include financial risk premium.[9]

We proceed by not only obtaining betas for similar publicly traded firms to get an industry composite beta (pure play) but also obtaining an asset beta for the utility industry and then "lever it up or down" to make it consistent with the project or target firm's risk level, capital structure and tax rate. The result is an estimate of the target industry's beta, given (1) its business risk as measured by the asset beta of the business, and (2) its financial risk as measured by its own capital structure and tax rate.

In addition to the benchmark industry equity beta, the utility industry composite equity beta is computed using the Hamada model, which combines the Capital Asset Pricing Model (CAPM) with the Modigliani-Miller (MM) after-tax model to obtain the cost of equity to a leveraged firm.[10] This model captures not only business risk but also financial risk for equity holders.

[8] In an event of bankruptcy, Chapter 11, in general, the equity holder bears all the costs and is at risk of losing all of their investment.
[9] Business risk is associated with the operating conditions faced by and the operating decisions made by a firm, while financial risk is the additional risk placed on the equity holders as a result of the decision to finance with debt.
[10] Conceptually, equity holders face a certain amount of risk which is inherent in a firm's operations even if there is no debt in its capital structure. If a firm uses debt (financial leverage), the equity holders will face more risk due to financial leverage. As a result, the cost of equity of a firm that has financial leverage in its capital structure (levered firm) is higher than the cost of equity of a firm that has no financial leverage (unlevered firm).

4. Electricity Fuel Dispatch Submodule

Model Summary

The Electricity Fuel Dispatch Submodule (EFD) determines the annual allocation of available capacity (as determined in the Electricity Capacity Planning Submodule) to meet demand on a least-cost (merit-order) basis subject to current environmental regulations. Available capacity is determined according to season of year, time of day, planned maintenance, outage rates, reserve margin and variable fuel costs. A transmission network is constructed allowing electricity to be traded regionally. The dispatch and network configuration is similar to real-time capacity allocation. Units are dispatched for each time slice using available capacity and optimized on minimum costs until demand is satisfied and environmental and load constraints are honored. (The Electricity Capacity Planning Submodule determines the capacity needed in each year to meet demand; demand is determined in the demand modules, with seasonal and hourly demands determined in the Load and Demand Side Management Submodule.) Emissions of nitrogen oxide (NO_x) are accounted for by plant type and are determined based on the boiler type, control equipment (if any), and the utilization of capacity.

Fuel consumption is provided to the fuel supply modules while fuel and variable operations and maintenance (O&M) costs are used to determine electricity prices in the Electricity Finance and Pricing (EFP) Submodule. Fixed and variable O&M costs are assumed to decline over time, reflecting recent historical trends. Electricity prices are provided to the demand models to determine electricity demand.

The EFD dispatches new nonutility capacity together with utility fossil-fueled and nuclear generating capacity. The EFD also incorporates the dispatch of geothermal and biomass units as well as other fossil-fueled nonutility (excluding traditional cogenerators) supply endogenously. Other renewable supply, demand-side management programs, and DSM impacts are incorporated by adjusting the demand for capacity prior to the dispatching decision, i.e. the load curve is revised[40]. Traditional cogeneration and generation from intermittent renewable technologies are determined in the demand models and renewable models, respectively, with the demand curve adjusted to incorporate their contribution to load. Existing nonutility capacity and nontraditional cogenerators are considered "must run" units which are dispatched first. Interregional and international economy sales are also represented in the EFD. Utilities have the option to purchase electricity from another region in place of generating the power themselves.

Beginning with AEO2000, the EFD is a linear programming (LP) algorithm that incorporates the previous Electricity Transmission and Trade Submodule into the transmission system for the LP. The LP algorithm is a flexible approach to model electric generator dispatch in a realistic

[40]Renewables included in this adjustment are municipal solid waste, wind, hydroelectric, and solar generation.

manner. It provides an optimal solution for unit dispatch and electricity trade across all regions simultaneously.

In former versions the EFD did not incorporate interregional trade within the unit dispatching decision. It used a heuristic approach to provide a least-cost solution to allocating capacity in a region. Previously, the least-cost algorithm was solved for one region at a time based on a merit-order allocation of capacity. The regions had the option to purchase or sell energy to neighboring regions after the dispatch allocation if it was economic to do so. Regions could only purchase or sell energy to neighboring regions based on the remaining capacity after dispatch decisions were made. This methodology proved to be suboptimal as far as a national forecast was concerned. By formulating the LP as a national model, the solution is significantly more robust.

Another benefit of these changes is the ability to calculate the true marginal cost for each region explicitly. The marginal unit for the region can be traced to its components even if it happens to be from another region. The commercial software used for solving the linear program is used by other modules in NEMS, and there are also improved data handling capabilities and structural improvements are easier to implement.

An example of the flexibility of the LP algorithm is the ability to analyze proposed Renewable Portfolio Standards (RPS) within the dispatch decision. This constraint could not have been included during the actual dispatch decision in the previous representation of the EFD, but could only be estimated through the capacity planning portion of the model. Because of this enhancement, the model is a useful tool for studying the alternative proposals being considered.

The new representation permits geothermal and biomass units to be dispatched, and includes co-firing of coal plants with biomass. The co-firing share is determined in the ECP.

Since AEO2001, distributed generation is included as a potential supply option. Available distributed generation capacity is operated according to pre-specified utilization rates depending on the type (base or peak). Contributions from these technologies is predetermined by the ECP because decisions to build and use this capacity considers avoided transmission and distribution costs, which are not included in dispatch decisions.

Model Purpose

Model Objectives

The purpose of the EFD is to represent the economic, operational and environmental considerations in electricity dispatching and trade. The EFD allocates available generating capacity to meet the demand for electricity on a minimum cost basis, subject to engineering constraints and to restrictions on emissions such as SO_2, NO_x, mercury and carbon. The primary use of the EFD, as a component of the EMM and NEMS, is to develop projections for the Energy Information Administration's *Annual Energy Outlook* and other analyses. For the electric power industry, the model projects fuel consumption, and both average and marginal fuel and operating costs, for each year in the forecast horizon. Intermediate projections of SO_2 and mercury emissions are calculated (final values come from the CMM), as well as the projections for NO_x and carbon emissions.

The EFD addresses utility and nonutility supplies endogenously; i.e. the EFD dispatches new nonutility sources[41] together with utility fossil-fuel, geothermal, biomass, and nuclear generating capacity. However, existing nonutility supply, along with nontraditional cogenerators, are considered "must run" units and are placed such that they are always dispatched. Most of these facilities have contracts with utilities to purchase power, so this treatment ensures that the model output reflects actual usage. Traditional cogeneration and intermittent renewable technologies are represented exogenously with the load curve adjusted prior to dispatching other generating technologies.

The EFD represents the dispatch and trade decision at the regional level. These regions, referred to as NEMS electricity supply regions, are North American Electric Reliability Council (NERC) regions and subregions (Table 15 see also Figure 11). The primary inputs from other NEMS modules are the demands for electricity and fuel prices. The resulting fuel consumption is passed to the respective fuel supply models. The fuel supply modules and end-use demand modules use other regional aggregations (Census regions and divisions, coal and gas supply regions, etc.). The interaction between the EFD and other modules of the NEMS and other regional issues, including the required transformations between different regional structures, are described later in this section.

[41]In this document, the term "nonutilities" refers to independent and small power producers, exempt wholesale generators and nontraditional cogenerators. Traditional cogenerators will be referred to specifically.

Table 17. NEMS Electricity Supply Regions

NERC Region/ Subregion	Acronym
East Central Areal Reliability Coordination Agreement	ECAR
Electric Reliability Council of Texas	ERCOT
Mid-Atlantic Area Council	MAAC
Mid-America Interconnected Network	MAIN
Mid-Continent Area Power Pool	MAPP
Northeast Power Coordinating Council/New England	NPCC/NE
Northeast Power Coordinating Council/New York	NPCC/NY
Southeastern Electric Reliability Council	SERC
Florida Reliability Coordinating Council	FL
Southwest Power Pool	SPP
Western Electric Coordinating Council/Northwest Power Pool Area	WECC/NWP
Western Electric Coordinating Council/ Rocky Mountain Area, Arizona, New Mexico, Southern Nevada	WECC/RA
Western Electric Coordinating Council/California	WECC/CA

The EFD only incorporates current regulatory strategies to comply with the Clean Air Act Amendments (CAAA) that can be implemented during dispatching, i.e. fuel switching. (Retrofitting units with scrubbers is represented in the ECP).

Another feature of the EFD is the ability to engage in interregional economy transactions. Utilities are allowed to purchase power from utilities in neighboring regions if it is economic to do so and transmission capacity is available. In a contiguous time slice simultaneous dispatch and trade occurs by dispatching power in the exporting region instead of in the importing region. Least cost units are fully utilized if there is demand and transmission capacity. Transmission capacity for Canadian Provinces is represented for trade with the United States. Information on how much excess electricity supply is available by season and time slice from each Canadian Province is provided.

Relationship to Other Modules

The EFD requires input data from exogenous sources, other modules of the NEMS, and other submodules of the Electricity Market Module. This section contains an overview of the data flows within the EFD. Figure 4.1 contains an overview of the data flows both into and out of the EFD submodule.

Exogenous Inputs

The EFD requires cost and performance data for both existing and future units to complete the dispatch decision. This information is obtained for existing units from various EIA and Federal Energy Regulatory Commission (FERC) survey forms. Cost and performance data for future generating units are provided to the Office of Integrated Analysis and Forecasting from discussions

with various sources — industry, government and the National Laboratories[42]. Transmission constraints and trade relationships are also input to incorporate firm and economy trade. Firm trade contracts are culled from NERC's Electricity Supply and Demand Database. Transmission characteristics are from NERC and WECC summer and winter reliability assessments.

Sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury (HG), carbon dioxide (CO_2), carbon, carbon monoxide (CO) and volatile organic compounds (VOC) emission rates and ash retention rates are also provided to determine annual emissions. A full listing of the data sources for exogenous inputs can be found in Appendix 4.C.

Inputs from Other Modules [43]

The demand modules provide electricity demand by sector. These demands are aggregated and mapped to a load duration curve in the Load and Demand Side Management submodule prior to the dispatch decision.

The commercial and industrial demand modules represent traditional cogeneration and other electricity production at their facilities. The generation provided by these modules is converted to capacity (assuming a 100 percent capacity factor) with the resulting capacity subtracted from the load curve. Likewise, generation from intermittent renewable sources is subtracted from the load duration curve prior to the dispatch decision using capacity factors provided by the Renewable Fuels Module.

Fossil fuel prices are provided by the fuel supply modules of NEMS. These prices are used in determining variable costs for each plant type and arranging the plants in merit order. The Coal Market Module, in addition to providing coal prices, also provides a "penalty cost" proportional to the sulfur content of each coal type. In analyses where mercury emissions are constrained, an additional penalty cost is passed related to the mercury content of the coal types. These costs are used by the EMM to minimize the cost of meeting sulfur and/or mercury constraints.

The Electricity Capacity Planning (ECP) submodule provides the annual available capacity to be used in the dispatch decision as well as the share of biomass co-firing that is allowed from coal fired plants. It also provides the utilization rates for distributed generation capacity. The ECP determines any penalty costs necessary to meet constraints on NO_x emissions, and this is passed to the EFD for use in dispatching decisions.

Outputs

The EFD determines the allocation of generating capacity to meet electricity demand. The output of this decision is needed to determine the price of electricity and to account for: 1) the utilization of

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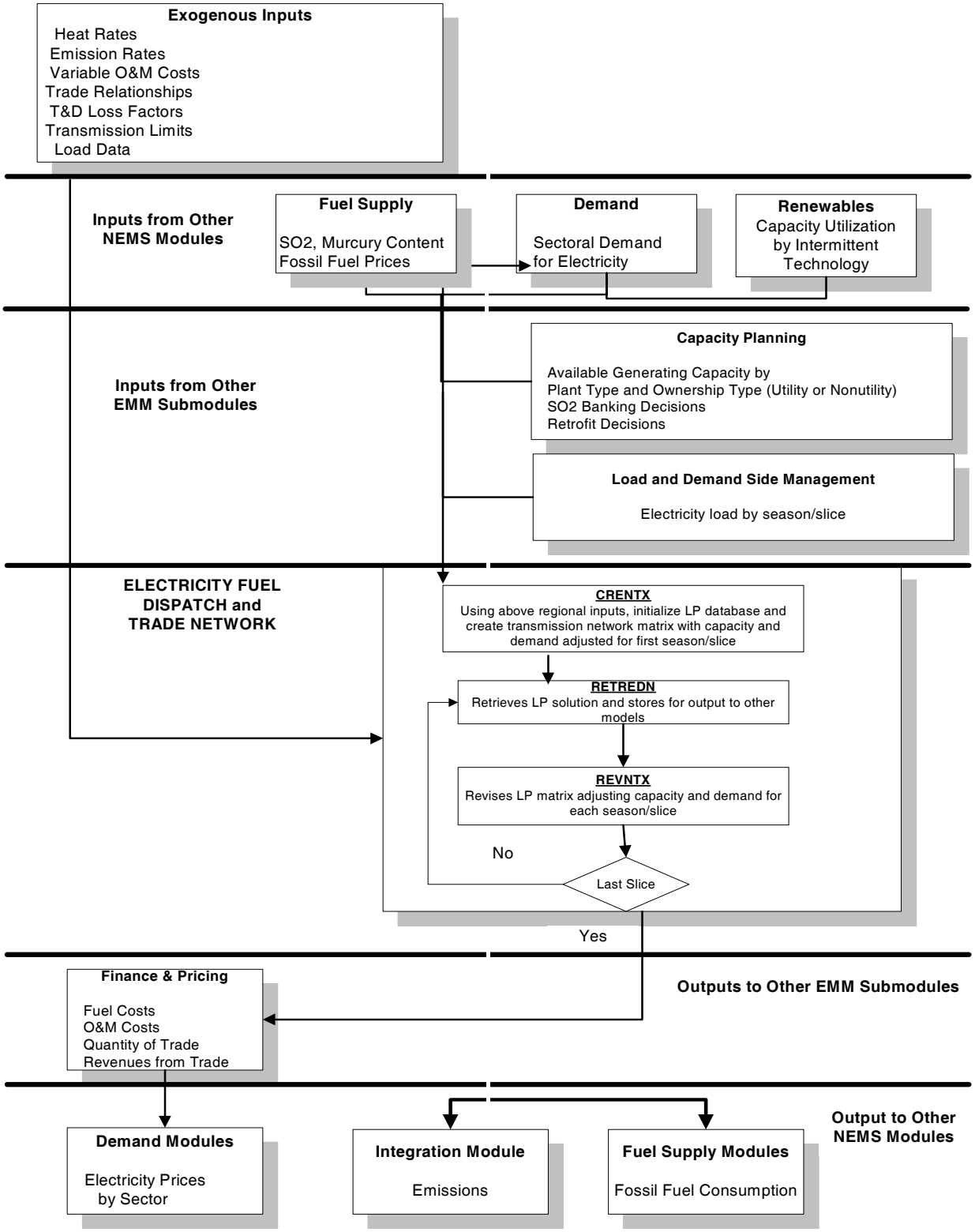
[42]See *Assumptions for the AEO2004* for specific technologies and sources.

[43]A synopsis of NEMS, the model components, and the interrelationships of the modules is presented in *The National Energy Modeling System: An Overview*. Detailed documentation of the modeling system and any of the modules is available in a series of documentation reports available on the A. CD-ROM. For ordering information, contact the National Energy Information Center (202/586-8800) or E-mail: infoctr@eia.doe.gov.

the fuel inputs; 2) renewable generation; and, 3) emissions. In particular, the EFP requires fuel and variable O&M costs to determine the price of electricity. For competitive pricing, the marginal unit for each region and its cost can be easily determined. The Renewable Fuels Modules is passed generation from renewable sources determined by EMM so that total generation and fuel consumption from all renewable sources can be calculated. The fuel supply modules require the quantity of fuel consumed for the pricing of those fuels and for calculating "total" fuel use by all sectors. The EFD provides regional SO_2 and mercury removal rates to the CMM, and the final SO_2 and mercury emissions are computed in the CMM and passed to the integrating module. Emissions of NO_x are calculated in the EFD, based on NO_x emission rates determined by plant and boiler type.

Output reports provide projections of generation and fuel consumption by plant and fuel type, for both electric generators and nontraditional cogenerators and for interregional and for international economy trade. Reports include emissions. These reports contain both national and regional projections. National projections are published each year in the *Annual Energy Outlook* and regional projections are provided on EIA's Internet site (http://www.eia.doe.gov) in the *Supplement to the Annual Energy Outlook*.

Figure 17. EFD Data Inputs and Outputs



Model Rationale

Theoretical Approach

Basic Model Approach. The EFD uses a linear programming (LP) approach to provide a minimum cost solution to allocating (dispatching) capacity to meet demand. Dispatching involves deciding what generating capacity should be operated to meet the demand for electricity, which is subject to seasonal, daily, and hourly fluctuations. The objective of the EFD is to provide an economic/environmental dispatching solution. In an economic (least-cost) dispatch, the marginal source of electricity is selected to react to each change in load.[44] In environmental dispatching, the demand for electricity must be satisfied without violating certain emissions restrictions. The EFD integrates the cost-minimizing solution with environmental compliance options to produce the least-cost solution that satisfies electricity demand and restricts emissions to be within specified limits.

Early in the NEMS development process, models from other organizations were reviewed as possible methodologies for modeling the dispatch decision in NEMS (including trade and nonutility supply). Although an LP approach was considered at the time, LP models required considerable execution time and storage which was prohibitive even five years ago. A Lagrangian approach[45] was chosen because of its quick execution time and ability to manage many intervals for approximating the load duration curves. A full description of this heuristic modeling approach and the alternative approaches considered are reviewed in more detail in the original version of the EMM documentation.[46]

Environmental issues that are incorporated in the EMM-NEMS include compliance with SO_2 and NO_x restrictions specified in the Clean Air Act (New Source Performance Standards — NSPS, Revised New Source Performance Standards — RNSPS, and Clean Air Act Amendments — CAAA). The implications of Title IV of the CAAA in the EFD decision-making process are discussed later in this chapter in the "Assumptions" section while the specifics of the CAAA are outlined in Appendix 4.A.

Demand can be characterized by a load curve, which is a plot of power demand (load) versus time (Figure 12). The highest point on the curve, the peak point, defines the capacity requirement. The capacity allocated to meet this last increment of demand is used infrequently

during the entire period. On the other hand, the capacity assigned to satisfy demand at the base, or minimum point of the curve is required on a continuous basis. The percent of time capacity is required

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[44]If load is increasing then the cheapest available source of electricity is brought on-line. Similarly, if demand is decreasing then the most expensive source of electricity currently operating is shut down.

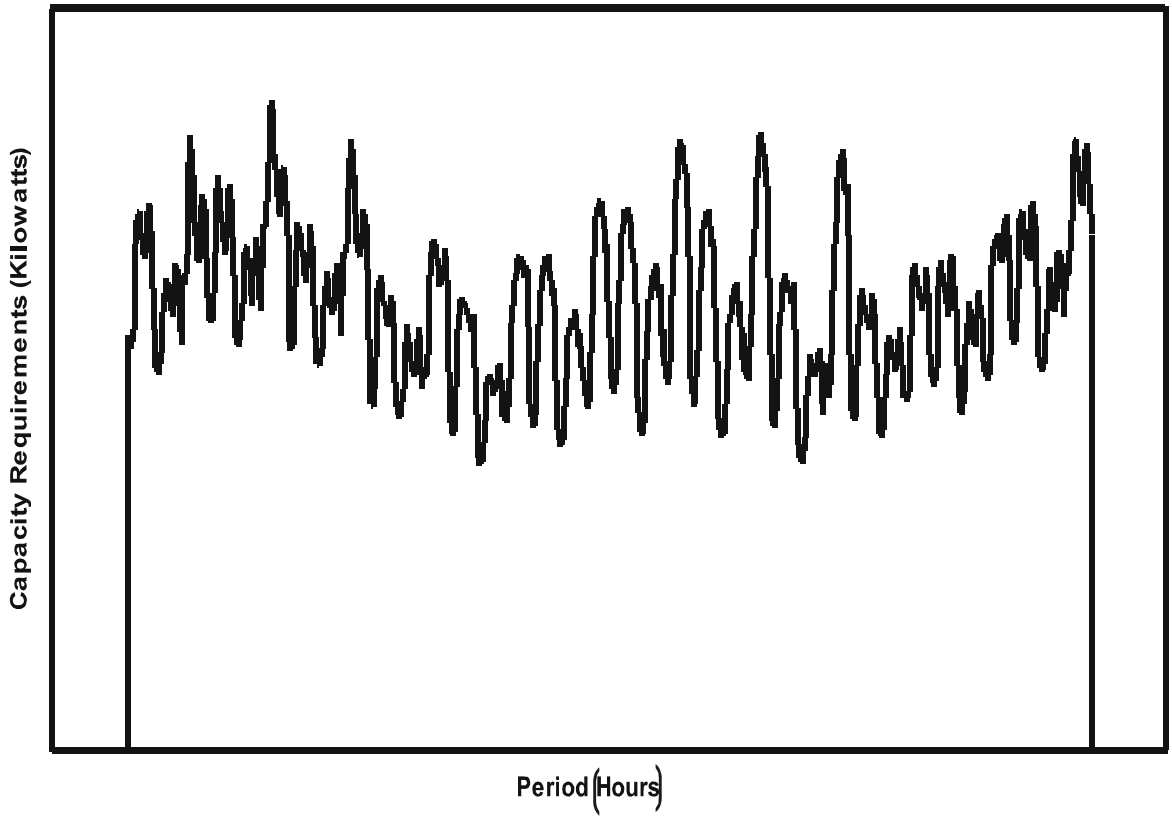
[45]For a discussion of the Lagrangian approach see *Cost and Optimization Engineering*, F.C. Jelen, McGraw Hill, 1970, pages 249 - 261.

[46]Energy Information Administration, *Model Documentation: Electricity Market Module Electricity Fuel Dispatch Submodule,* DOE/EIA-M068-D (Washington, DC, March 1994)

at each slice of load is called a capacity factor (utilization rate). The capacity factor for the load at the base of the curve is 100 percent and it approaches 0 percent at the peak of the load curve.

The relationship between capacity requirements and capacity utilization can also be illustrated by a load duration curve, which is obtained by reordering the demands for power in descending order rather than chronologically (Figure 19). This curve shows the capacity utilization requirements for

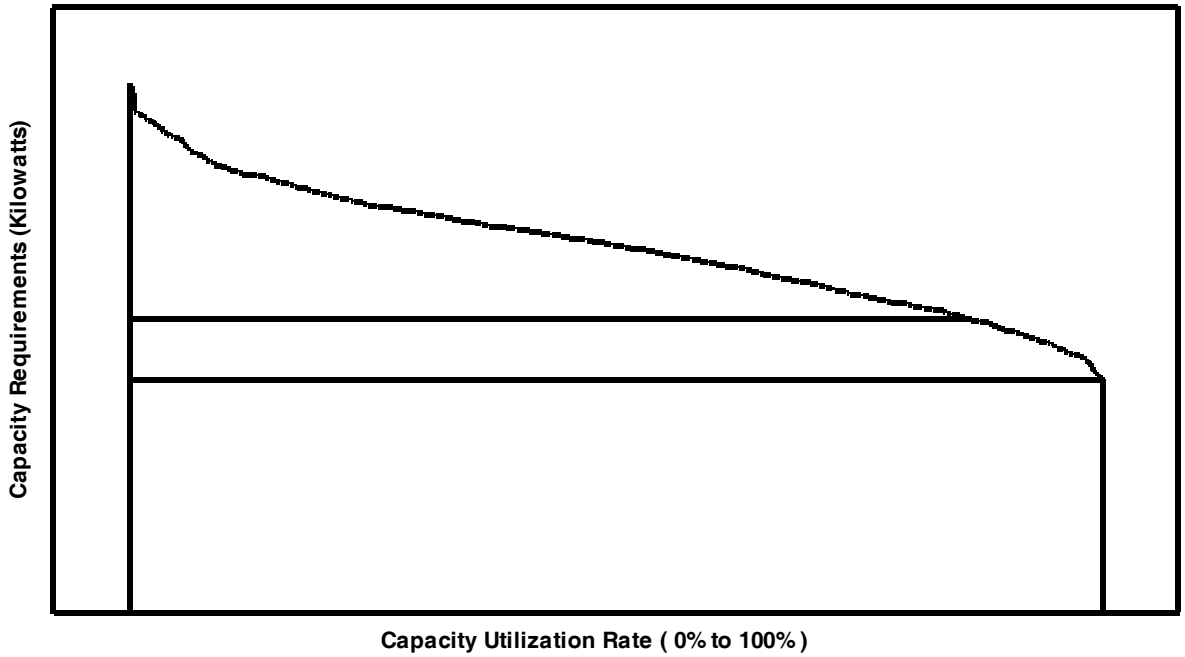
Figure 18. Typical Load Curve



each increment of load. The height of each slice is a measure of capacity, and the width of each slice is a measure of the utilization rate or capacity factor. The product of the two is a measure of electrical energy (e.g. kilowatthours). The problem is to determine which capacity types to assign to each of these slices of load, and what fuels to use in each of these capacity types (in order to represent switching in multi-fuel units).

In the EFD, there are four seasonal load curves for each region with each load curve representing three months. Each load curve contains nine vertical slices, categorizing the load by magnitude (height) and time. The EFD dispatches available capacity to meet load in each of these slices. (Note, although the load curve re-orders the load segments, the chronology is maintained to represent maintenance scheduling for capacity and to model economy trade.)

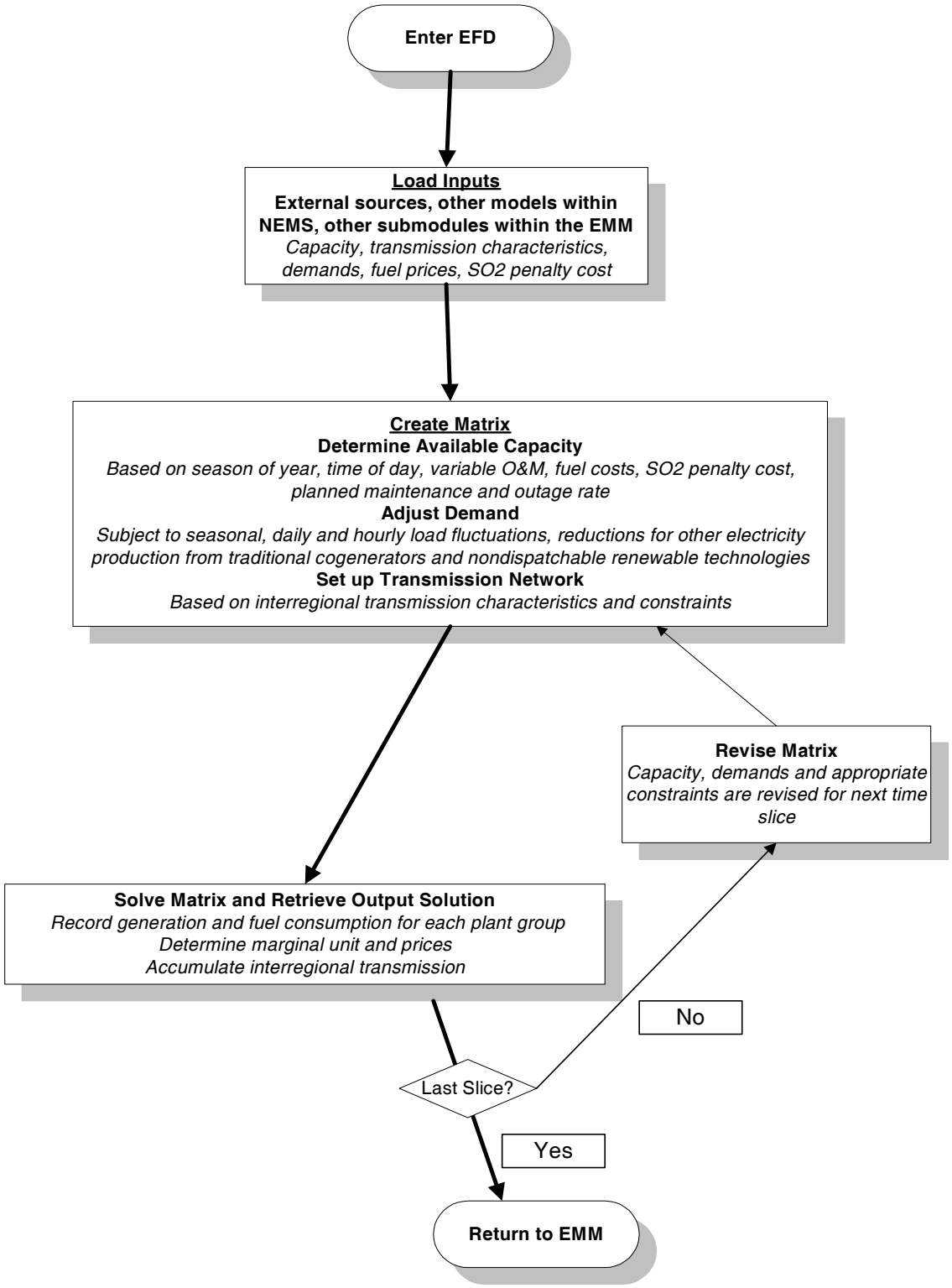
Figure 19. Typical Load Duration Curve



The algorithm used for the dispatch decision is a straightforward LP formulation. It simulates the electric transmission network on the NERC region level and simultaneously dispatches capacity[47] regionally by time slice until demand for the year is met. Figure 14 shows a flow diagram of the solution process. Capacity costs for each time slice are based on fuel and variable O&M costs. Capacity is then allocated (in a cost minimization LP) for each time slice for the entire United States under certain considerations / constraints (i.e., engineering considerations limit the range of operation for certain capacity types and are incorporated using minimum and maximum capacity factors) until demand is satisfied. Next, generation and fuel usage is determined in each area for which the capacity has been allocated. Each of the 36 time slices represents an area under the load curve to allocate specific kinds of capacity based on costs and engineering considerations. Generators are permitted to meet demand in either the region where they are located or in a neighboring region if transmission capacity is available. Excess production that is cheaper would be available for export to displace more expensive capacity in importing regions.

[47]Note, traditional cogeneration and non dispatchable renewable capacity is removed from the load duration curve prior to the dispatch decision.

Figure 20. Electricity Fuel Dispatch & Transmission Network Process Flow



Assumptions

The assumptions of the EFD include the representation of the Clean Air Act Amendments of 1990 (CAAA)[48] and aggregation issues related to electricity supply and demand. Details on specific cost and performance assumptions used in the EMM are published on EIA's Internet site, in the *Assumptions to the Annual Energy Outlook*.

While the marketable allowance program in the CAAA is economically attractive it is difficult to model. (See Appendix 4.A for a summary of the relevant provisions of the CAAA.) The CAAA does not set plant specific emission rate limits. Rather, the CAAA sets national limits on the emissions of SO_2. Utilities are free to choose from a wide array of options to reduce their SO_2 emissions to the level of allowances allotted to them. Among the major options available to utilities are switching to the use of lower sulfur fuels, reducing the utilization of their relatively high emission units while increasing the utilization of their low emission units, adding emissions reduction equipment at some generating facilities, purchasing additional allowances from others or purchasing power from utilities in neighboring regions which have lower emissions. Thus, representing utility efforts to minimize their costs of complying with the CAAA requires a complex nationwide analysis.

The Coal Market Module (CMM) and the EFD work together to ensure that emissions of sulfur dioxide do not exceed limits set by the Clean Air Act Amendments of 1990 (CAAA). The EFD determines the total coal demand for each plant type, without regard to rank and sulfur content. The plant types are defined according to vintage. The older units (pre-1965) have a more limited flexibility to switch between coal ranks. Given these constraints, the CMM satisfies the coal demand optimally for each plant type with respect to rank and sulfur. Defined regional supply patterns in the CMM also limit ranks that can be selected to prevent, for instance, lignite from being burned in an exclusively bituminous plant. The coal module determines the least cost sulfur penalty as well as the mix of coals necessary to meet the EMM demand; the EFD determines the total demand (in Btu) for each plant type. Banking decisions for sulfur dioxide allowances are exogenous inputs to the EMM.

The EFD includes operating options for reducing emissions, which are based on short-term, operating (fuel and variable O&M) costs. During dispatching, emissions can be reduced by switching from fuels with "high" emission rates to fuels with "low" emission rates. This includes only interfuel switching, since switching within coal sulfur types is accomplished within the CMM. For example, required reductions in SO_2 emissions can be accomplished by decreasing utilization of coal- or oil-fired units with comparatively high emission rates by increasing the utilization of capacity types that emit little or no SO_2 (gas-fired, nuclear, and renewable plants). This "fuel-switching" option is also

[48]The Clean Air Act and its subsequent amendments contain Federal regulations for SO_2 and NO_x emissions by electric utilities. The most recent amendments to the CAA in 1990 set up a system of marketable allowances to emit SO_2. Each allowance entitles the holder to emit one ton of SO_2. Allowances may be traded among utilities and nonutilities, so the limit on total emissions is a national rather than a unit level limit.

available through interregional economy trade; i.e., a utility may lower its emissions by purchasing surplus power from a utility in a neighboring region which has lower emissions.

For each of the 13 electricity supply regions, the EFD also represents trading of SO_2 allowances. That is, utilities with relatively low costs of reducing emissions may over comply (i.e. reduce emissions beyond their required level) and sell their excess allowances to utilities with comparatively high reduction costs. This trading of allowances assumes that the market for allowance trading is "perfect," i.e., is based only on a cost saving. However there are other factors involved in allowance trading which are not currently incorporated, such as local pressure for utilities to reduce emissions in place of purchasing allowances. On a national level, allowance trading does not lower total emissions but it reduces the overall cost of achieving the specified emissions target.

There are also assumptions regarding both the supply and demand for electricity in the EFD, particularly related to aggregation issues. Forced outages are assumed to occur randomly. The capacity that is out-of-service at any given time is the expected value. Also, utilities in each of the 13 electricity supply regions are operated as a "tight" power pool, meaning that all generators can service load anywhere within a region. Because this aggregation of generating capacity does not address transmission and other engineering constraints that may limit dispatching of particular plants, the effect is that intra-regional trade is not represented. On the demand side, the load duration curve aggregates loads from many utilities to 18 points per season and region. Although this may not fully represent load variations, the aggregation is necessary due to computer time and resource constraints.

Model Structure

Introduction

The EFD is executed for each year in the planning horizon to determine the amount of capacity dispatched, fuels used, electricity trade, and costs to meet the yearly level of demand. Within each year, the EFD is executed once for each of four seasons with nine time slices, a total of 36 times. The EFD uses a linear programming (LP) formulation to compete generating capacity and transmission capacity on the supply side with the demand side options for meeting load. It dispatches a mix of capacity that minimizes costs on a national basis subject to certain conditions and constraints such as complying with environmental regulations. The capacity mix includes restrictions on the type of capacity that is allowed to operate in certain load slices based on engineering constraints. Seasonal and daily fluctuations and transmission and distribution losses are accounted for. There are also constraints on emissions.

The EFD prepares input data, solves the LP model, and provides the required outputs to the other submodules of the EMM and the modules of NEMS. The initial matrix is created for the first iteration of season/slice demand. It is solved, modified, and then resolved for the subsequent 35 iterations representing a full year of demand. The initial matrix and objective function are created for the first peak slice and then revised for the rest of the time slices. The objective function represents the costs of generation and transmission. The coefficients describe the available capacity for base, intermediate and peak load slices, demands, and constraints, most of which are specific to each of the time slices. For each time slice, the capacity level is scaled to account for planned maintenance, forced outages and load following.

The following section provides a mathematical description of the subroutines and LP model and specifies the objective function and equations of the constraint matrix. The LP model uses the Optimization and Modeling Library (OML) software, a proprietary mathematical programming package, to create and store coefficients in a database, solve the problem, and retrieve the solution. The OML subroutines are not documented in this report.[49]

Key Computations and Equations

This section provides the mathematical specification of the EFD. The EFD uses a linear programming algorithm which incorporates trade as well as dispatch in the cost minimization decision. The EFD ranks available capacity in a least-cost manner, but only uses this list to keep track of plant costs. The dispatch and trading of capacity is solved simultaneously to meet regional demands over the entire United States (subject to certain operating and engineering constraints, discussed in detail in the solution algorithm constraints section).

The objective of the EFD is to provide an economic and environmental dispatch and electricity trade procedure. In the LP optimization, the costs of generation, trade, and transmission are minimized for the entire United States. The decision variables include operating a dispatchable generating unit and transmission network. The marginal source of electricity is selected for each time slice and reacts to changes in load.[50] The demand for electricity must also be satisfied without violating certain engineering and emissions restrictions. There are environmental, load-related, capacity, and renewable portfolio constraints placed on the dispatch decisions. The EFD integrates the least cost solution with environmental compliance and engineering constraints. Environmental issues incorporated into the NEMS include compliance with SO_2 restrictions specified in the CAAA, as discussed above in "Assumptions."

[49]For more information, see Ketron Management Science, Optimization and Modeling Library (Draft), (Arlington, VA, November 1992).

[50]If load is increasing, then the cheapest available source of electricity is brought on-line. Similarly, if demand is decreasing, then the expensive source of electricity currently operating is shut down.

The EFD forecasts domestic economy trade by including the option of "dispatching" (i.e. purchasing) capacity in one region to serve a different region's demand. The load representation preserves additional chronological information to allow for energy purchases from extra regional utilities within physical limits of the transmission system (the requirement is to be able to match the blocks of energy available in the exporting region to the simultaneous need for power in the importing region).[51] Limits on total energy available during each demand slice and transmission line constraints are applied to control trade. Additional transmission costs and energy losses associated with trade are assigned to the exported power.

Initial operating costs (fuel and operations and maintenance expenses) are accumulated by plant groups. A merit order is calculated by ranking the groups in ascending order of the total variable costs in order to determine the marginal plant in an efficient manner.

In computing available capacity for a time slice, engineering considerations that may limit the range of operation for a given capacity type are incorporated. Minimum and maximum capacity factors are used to prevent base load plants from operating only in the peak slices. For instance, nuclear units are not allowed to operate as peaking capacity because they cannot be started or stopped quickly. The operating range is represented by a set of trigger points that identify the point(s) that corresponds to the capacity factor limits. A subroutine checks to insure that the corresponding trigger points are not violated.

For each plant type, fuel consumption is computed by multiplying generation by the fuel share and heat rate for each fuel. SO_2 and mercury emissions are calculated in the EFD, but reported values are derived in the CMM. NO_x emissions are calculated in the EFD based on boiler and fuel type.

The following provides the mathematical specification of the EFD's solution algorithm.

Dimensions:

d = EMM electricity demand region
f = Fuel type
h = Vertical load slice
p = Dispatchable plant group
r = EMM electricity supply region
s = Season

[51]Note that it is possible for electrical energy to flow in one direction during a season and in the opposite direction during another season.

Input Requirements

Electricity Demand

D_h = Height of Load Slice h (megawatts)

W_h = Width of Load Slice h (hours)

Fuel Specific Information

EP = SO_2 Allowance Price ($ per ton) - calculated in the CMM and passed to EFD

P_{frs} = Price of Fuel f in Supply Region r in Season s ($ per million Btu)

SO_{fr} = Quantity of Sulfur Dioxide per Unit of Fuel in Supply Region r (pounds per million Btu)

Plant Specific Information by Capacity Grouping

B_{pr} = Scrubber Emissions Reduction factor for Plant Group p and Supply Region r (fraction)

CP_{pr} = Nameplate Capacity for Plant Group p and Supply Region r (megawatts)

FS_{fpr} = Maximum Allowable Fuel Share for Fuel f in Plant Group p and Supply Region r (fraction)

H_{fpr} = Heat rate for Fuel f used in Plant Group p and Supply Region r (Btu per kilowatthour)

OM_{fpr}= Variable Operations and Maintenance Cost using Fuel f in Plant Group p and Supply Region r (mills per kilowatthour)

R_{pr} = Planned Maintenance Requirement for Plant Group p and Supply Region r (megawatts)

Transmission Specific Information

TC_{dr} = Transmission costs for energy transmitted to Demand Region d from Supply Region r (mills per kilowatthour)

TL_{dr} = Transmission loss factor for energy transmitted to Demand Region d from Supply Region r (fraction)

TN_{drs}= Transmission limits for energy trade in Season s to Demand Region d from Supply Region r (megawatts)

Derived Variables required

CST_{prs}= Operating Costs (variable O&M and fuel) for Plant Group p and Supply Region r in Season s (mills per kilowatthour)

$$CST_{prs} = \text{Min} \sum_f (OM_{fpr} + H_{fpr} \cdot S_{fpr} \cdot P_{fr}/1000 + EC_{fpr})$$

The fuel shares S_{fpr} specify the fraction of time alternative fuels are used in multi-fuel units. This accounts for fuel switching due to changes in the relative fuel prices or

seasonal availability of fuels. For example, utility consumption of natural gas is limited in some regions during the winter because residential customers have priority over available supplies. Even though the price of gas may be less than the price of residual fuel oil, utilities may be unable to burn gas exclusively in dual-fired oil/gas plants. The variable cost is minimized by using the least expensive fuel as much as possible.

EC_{fpr} = Emissions Costs for Fuel Type f in Plant Group p and Supply Region r

$$EC_{fpr} = H_{fpr} \cdot S_{fpr} \cdot SO_{fpr} \cdot (1 - B_{pr}) \cdot EP$$

The representation of emissions restrictions, such as those specified for SO_2 in the CAAA, require additional information. Emissions cannot exceed allowable limits placed on SO_2 emissions. According to the CAAA, there are two classes of compliance groups — "affected" and "unaffected" units. Affected units are allocated allowances or permits to emit SO_2. Since allowances can be traded among affected units, the CAAA implies that the collective emissions from all affected units cannot exceed the sum of allowances. For each fuel f, the quantity ($H_{fpr} \cdot S_{fpr} \cdot SO_{fr}/2 \cdot (1-B_{pr})$) describes the SO_2 emission rate, accounting for the conversion from pounds to tons and reductions due to pollution control equipment. It is summed over the applicable fuels to provide the total tons of SO_2 per billion kilowatthour emitted by plant type p.

M_{prs} = Capacity Out of Service in Season s for Planned Maintenance for Plant p in Supply Region r (megawatts)

Planned maintenance is represented as an average yearly input by capacity grouping. The total for the year is distributed over the seasons establishing a maintenance schedule for the units. The scheduled is based on the amount of time needed for each unit and the seasonal reserve margin. Planned maintenance must be performed for each plant type.

$$\Sigma_s M_{prs} \geq R_{pr} \qquad \forall \text{ r and p}$$

S_{fpr} = Fuel Share of Fuel f for Plant p in Supply Region r (fraction)

The fuel share for capacity that can use more than one fuel is calculated by using the cheapest fuel up to its maximum share, followed by the next least costly, etc., until all capacity has been allocated a fuel. Maximum fuel shares for multifuel plant types cannot be exceeded.

$$S_{fpr} \leq FS_{fpr} \qquad \forall \text{ r, f and p}$$

Each plant type consumes fuel to produce electricity and the fuel shares must sum to one.

$$\Sigma_f S_{fpr} = 1 \qquad \forall \text{ r and p}$$

SD_{hrs} = Adjusted load in Supply Region r, accounting for extraneous generation and firm power contracts by Season s and Load Slice h. The load for each season and slice is deducted by the amount of generation from traditional cogeneration (industrial and commercial)

facilities and nondispatchable renewable units. Some of this capacity, i.e. hydroelectric, may change by season due to the intermittent nature of the plant and is removed accordingly from the appropriate time slices. The load is also incremented or decremented for exports or imports of firm power trade.

X_{hprs} = Derate Factors for Plant p in Supply Region r by Season s and Load Slice h

Calculates unit specific expected outage rates allocated by season and slice.

Load following is determined after allocating units in the first or peak slice. During off-peak periods operating levels are scaled down to reflect the practice of running plants at their minimum operating levels to prevent incurring shutoff and startup costs.

Decision Variables within the LP:

O_{hprs} = Utilized Dispatchable and Distributed Generation Capacity of Plant Group p in Season s and Supply Region r to Load Slice h (megawatts)

T_{dhrs} = Utilized Transmission Capacity between Supply Region r and Demand Region d in Season s and Load Slice h.

Existing and planned transmission capacity limits are bounded (using NERC data).

Objective Function

The objective function of the dispatching algorithm minimizes total operating (fuel and variable O&M) costs and transmission costs while complying with environmental regulations. In mathematical terms, the objective function is expressed:

Minimize: $\Sigma_p\Sigma_r(CST_{prs} \cdot O_{hprs}) + \Sigma_d\Sigma_r (TC_{dr} \cdot T_{dhrs})$ $\forall$ s, h

Multiplying per unit variable costs by O_{hprs} produces an average operating cost per hour. Multiplying by the width of the slice, W_h in hours, corresponds to the area (energy) for load slice h. This result represents the total cost of generation for that slice.

Constraints

The objective function is subject to the following conditions and constraints:

Each load slice must have capacity assigned to completely satisfy its energy requirements. That is, a region's energy requirement is met by the amount of domestic capacity assigned to meet load plus the amount of energy assigned for sale to region r from all regions d ($d \neq r$), less the amount of energy sold from region r to all regions d ($d \neq r$). The amount imported must be adjusted for losses occurring in the transmission of power between regions.

4.1 $\Sigma_p O_{hprs} + \Sigma_{d \neq r} T_{dhrs} \cdot (1-TL_{dr}) - \Sigma_{d \neq r} T_{dhrs} = SD_{hrs} \quad \forall$ h, r and s

Transmission constraint: The amount of capacity that can be assigned in region d to meet demand in region r is constrained by the interregional transmission capacity limit.

4.2 $T_{dhr} \leq TN_{drs} \quad \forall$ d, h, r, and s

Allocated capacity cannot exceed available capacity, accounting for planned maintenance, forced outages and load following.

4.3 $O_{hprs} \leq (CP_{pr} - M_{prs}) \cdot X_{hprs} \quad \forall$ h, p, r and s

Modeling Renewable Portfolio Standards

The EFD determines the annual allocation of available capacity to satisfy electricity demand, given current environmental regulations.[52] Capacity is dispatched on a least-cost (merit-order) basis so that the most economical capacity types are utilized to the greatest extent. For each EMM region, the EFD determines the trades of renewable credits by computing the renewable generation and comparing it to the total generation (or total sales depending on the specific RPS). If the corresponding fraction exceeds the minimum RPS level, then the surplus represents the renewable credits sold. Alternatively, if the regional renewable generation is less than the required amount, then the difference represents the renewable credits bought.

The regional, total generation requirements (net imports are included since they replace domestic supplies) are computed using Equation 4.4:

4.4
$$TOTGEN_r = [\sum_c \sum_o EQPGN_{cor} + \sum_i UPRNWSHR_i \cdot \sum_o EQHGN_{ior} + \sum_n UPRNWSHR_n \cdot \sum_n EQHGN_{nor} + (ETIMPF_r + ETIMPE_r - ETEXPF_r - ETEXPE_r] \cdot 0.001$$

where:

$TOTGEN_r$ = Total Generation Requirement in Supply Region r

[52]For more information, see Energy Information Administration, *Model Documentation: Electricity Market Module, Electricity Fuel Dispatch Submodule,* DOE/EIA-M068-D (Washington, DC, March 1994).

$EQPGN_{cor}$ = Generation by Nonrenewable Capacity Type c and Owner Type o in Supply Region r

$UPRNWSHR_i$ = Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum Requirement (Fraction)

$EQHGN_{ior}$ = Generation by Intermittent Type i and Owner Type o in Supply Region r

$UPRNWSHR_n$ = Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)

$EQHGN_{nor}$ = Generation by Dispatchable Renewable Type n and Owner Type o in Supply Region r

$ETIMPF_r$ = Firm Power Imports in Supply Region r

$ETIMPE_r$ = Economy Power Imports in Supply Region r

$ETEXPF_r$ = Firm Power Exports in Supply Region r

$ETEXPE_r$ = Economy Power Exports in Supply Region r

Next, the regional, renewable generation credited towards the RPS requirement is determined using Equation 4.5:

4.5 $$RENGEN_r = [\sum_i UPRNWSHR_i \cdot \sum_o EQHGN_{ior} + \sum_n UPRNWSHR_n \cdot \sum_o EQHGN_{nor}] \cdot 0.001$$

where:

$RENGEN_r$ = Total Renewable Generation for RPS in Region r

$UPRNWSHR_i$ = Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum Requirement (Fraction)

$EQHGN_{ior}$ = Generation by Intermittent Type i and Owner Type o in Region r

$UPRNWSHR_n$ = Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)

$EQHGN_{nor}$ = Generation by Dispatchable Renewable Type n and Owner Type o in Region r

Both the renewable and total generation amounts are then adjusted to include sales-to-the-grid ($SALGRD_r$) but not own-use ($OWNUSE_r$) from cogenerators. Total renewable cogeneration by region ($RENCOG_r$) is determined by summing over all sectors and renewable energy sources. The ratio of sales-to-the-grid to total cogeneration is then applied to renewable cogeneration to obtain sales-to-the-grid from renewables. That is,

4.6 $$RENCOG_{ry} = \sum_s \sum_f COGEN_{frsy} \cdot SALGRD_{ry} / (SALGRD_{yr} + OWNUSE_{ry})$$

where:

$RENCOG_{ry}$ = Renewable Sales-to-Grid in Year y in Supply Region r (billion kilowatthours)

$COGEN_{ersy}$ = Cogeneration in Year y in Supply Region r in Sector s by Renewable Energy Source e

For each region, the achieved renewable generation fraction is determined as follows:[53]

4.7 $$URPSPCT_r = (RENGEN_r + RENCOG_r) / (TOTGEN_r + SALGRD_r)$$

where:

$URPSPCT_r$ = Achieved Renewable Generation Level in Supply Region r (Fraction)

$RENGEN_r$ = Total Renewable Generation for RPS in Supply Region r

$RENCOG_r$ = Total Renewable Sales-to-Grid for RPS in Supply Region r

$TOTGEN_r$ = Total Generation for RPS in Supply Region r

$SALGRD_r$ = Total Sales-to-Grid for RPS in Supply Region r

The renewable generation in each region is then compared to the required level specified by the RPS (RENPCT) to ascertain the trading of credits ($URPSCRD_r$). A surplus of renewable generation (i.e., $URPSCRD_r$ greater than 0) implies that suppliers in region r are net sellers of credits. Conversely, a deficit corresponds to a net purchase. Regional trades of renewable credits are determined as follows:

4.8 $$URPSCRD_r = (RENGEN_r + RENCOG_r) - RENPCT \cdot (TOTGEN_r + SALGRD_r)$$

In a given year, the applicable credit price is assumed to be the quantity-weighted average of the levelized credit prices associated with each increment of renewable generation, as expressed in Equation 4.9.

4.9 $$RENEWCR_y = (\sum_{z=syr}^{y} (URPSRGN_z - URPSRGL_z) \cdot EPRPSPR_z) \; / \; URPSRGN_y$$

where:

$RENEWCR_y$ = average renewable credit price in year y (mills per kilowatthour)

syr = initial year of the RPS program

$URPSRGN_z$ = renewable generation in year z (billion kilowatthours)

$URPSRGL_z$ = renewable generation in year prior to year z (billion kilowatthours)

$EPRPSCR_z$ = levelized credit price for incremental renewable generation in year z (mills per kilowatthour)[54]

[53] If the RPS considers renewable generation as a fraction of sales instead of total generation, then the denominator is total regional electricity sales, in billion kilowatthours ($QELASN_r \cdot 0.001$).

[54] For existing renewable generation (i.e., the amount of generation prior to the initial year of the RPS), the credit price is assumed to be the levelized price for the current year. In effect, this corresponds to a spot price for existing generation, whereas the levelized price for incremental generation represents a long-term contract price.

The revenues associated with renewable credit trade (ERRPS) is the product of the credits traded ($URPSCRD_r$) and the average credit price ($RENEWCR_y$). In the EFD, Subroutine *ELRPSCR* determines the renewable credit trades. It also computes the regional revenue adjustments associated with the sale or purchase of credits.

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Appendix 4.A. Summary of Title IV to the Clean Air Act Amendments of 1990

Unlike the previous New Source Performance Standards (NSPS) and Revised New Source Performance Standards (RNSPS) programs which set plant and unit specific emission rate limits, the CAAA program employs a unique, market-based approach to SO_2 emission reductions, while relying on more traditional methods for NO_x reductions. Under the market-based approach, utilities receive a limited number of marketable emission permits or "allowances" each year.[55] Each allowance permits the emission of 1 ton of SO_2 for that year or any year thereafter. In the EMM-NEMS these SO_2 allowances are treated as emission constraints on utility and nonutility planning and operations.

The acid deposition provisions of the CAAA are instituted in two phases. In Phase I, 1995 through 1999, allowances are allocated to large, electric-utility steam generating units fired by fossil fuels in an effort to limit their average SO_2 emissions to 2.5 pounds per million Btu of heat input.[56] No additional control is required at other units.

In Phase II, beginning in 2000, "basic" allowances are allocated to all electric-utility steam units greater than 25 megawatts in existence between 1985 and 1995.[57] New utility and nonutility units that begin operating after 1995 are required to have allowances beginning in 2000, which they must acquire through the market or in some other manner. In general, the amount of allowances allocated to a particular unit is determined by its size, primary fuel, 1985 emission rate, average fuel consumption from 1985 through 1987, and the year it began operation. The annual "basic" allowance allocation is limited to 8.95 million tons. In addition, almost 0.5 million "bonus" allowances are distributed each year for the first 10 years of Phase II.

In both phases, 2.8 percent of the "basic" allowances intended to be allocated each year will be placed in a special reserve, a portion of which may be sold directly, the remainder to be auctioned. The auction is intended to stimulate the market and to give new entrants, such as independent power producers, access to allowances. The direct sale is intended to be a market of last resort for anyone needing but unable to acquire allowances. Proceeds from both the auction and the direct sale are returned to the original owners of the allowances. These auctions and direct sales of allowances are not explicitly represented in the EMM-NEMS because of their small impact on the allowance market. However, they are included in the original allocation of allowances, and, thus captured in trading.

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[55]Electricity generators must still meet the emission standards in existence before the passage of the CAAA.

[56]Phase I affects electric utility steam generating units with a nameplate capacity of 100 megawatts or greater and an actual 1985 SO_2 emission rate of 2.5 pounds per million Btu or greater. The names of the units and their Phase I allowances are listed in the CAAA.

[57]Units less than or equal to 25 megawatts, combustion turbines, solar units, wind turbines, geothermal units, and hydroelectric units are not subject to the requirements of the CAAA.

The CAAA establishes incentives (e.g., extra allowances and compliance-deadline extensions) for installing scrubbers during Phase I, instituting energy conservation, using new renewable energy sources, and using clean coal technologies. Presently the Environmental Protection Agency is finalizing procedures for a utility to take advantage of these incentives. When these procedures are finalized the EMM-NEMS allowance constraints will be modified to reflect the distribution of these incentive allowances.

Allowances can also be banked (saved) for future use. Because fewer emissions are allowed after 1999, allowances will increase in value beginning in 2000. A utility may find it advantageous to overcomply from 1995 through 1999, saving allowances for use in Phase II. Because banking decisions are dependent on unit and utility specific information (including each utility's assumptions about future allowance costs), banking algorithms is not endogenized within EMM-NEMS. Analysis will be done exogenous to the model to access the economics of banking and the EMM-NEMS allowances constraints will be adjusted to reflect the estimated levels of banking in future versions of NEMS.

Utilities must also submit compliance plans for and install continuous emission-monitoring devices at all affected units. A utility that does not comply (emits SO_2 in excess of the allowances it holds) must pay $2,000 for each ton of SO_2 it emits in excess of its allowances and must offset those emissions the following year.

The CAAA also requires the Environmental Protection Agency (EPA) to set new NO_x emission standards for existing and new utility boilers. For existing tangentially-fired boilers[58] the maximum emission rate the EPA can set is 0.45 pounds of NO_x per million Btu of heat input; for existing dry-bottom wall-fired boilers[59] (excluding cell-burner technology[60]) the maximum is 0.50 pounds per million Btu. These new standards must be met by 1995. For cyclones,[61] wet-bottom wall-fired boilers,[62] cell-burner technology, and other utility boilers, the EPA has until 1997 to set new standards, taking into account available technology and environmental considerations. In addition, by 1993, the EPA must revise the performance standards for NO_x emissions from new units to account for improved emission-reduction methods since the 1979 revision.

[58]Tangentially-fired boilers are fired from the corners of the furnace; the fireball can be directed upward or downward.

[59]Wall-fired boilers have burners mounted on their front and back walls. Dry-bottom wall-fired boilers use coal with high ash-fusion temperatures. Most of the fly ash is removed just ahead of the stack.

[60]Cell-burner technology is used in dry-bottom wall-fired boilers. The burners are arranged in clusters on the firing wall to reduce NO_x emissions.

[61]In a cyclone boiler, combustion occurs in water-cooled horizontal cylinders connected to the furnace walls. High-velocity air is fed tangentially to the cylinders, and the combustion gases exit into the furnace.

[62]Wet-bottom wall-fired boilers use coal with low-ash fusion temperatures, where the slag tends to cling to the walls and bottom of the furnace. In a wet-bottom furnace, the slag drops into a tank of water.

The SO_2 emission allowance program established in the CAAA offer a more economical approach to emissions control compared with the NSPS and RNSPS programs established in the original Clean Air Act and its earlier amendments. By establishing a market for emission permits, utilities with relatively high cost emissions reduction options will be able to purchase allowances from other utilities with lower cost options. These allowance trades among utilities are expected to continue until there are no gains or savings to be made, resulting in the most cost-effective solution.

Appendix 4.B EFD Data Flows

The EFD runs every year and iteration of the NEMS, as long as the EMM model is being run. The EMM often makes use of direct access files (DAFs) to store data that is passed back and forth between submodules, or accessed several times during a run. Many of the subroutine calls in the EFD simply involve retrieving or storing variables that are needed at different times during the simulation. The control module of the EFD is the subroutine *ELEFD*. Subroutine *ELEFD* initializes variables and reads in necessary data, and then calls *ELDISP*, which adjusts the load curve for trade and non-dispatchable renewable generation, and schedules maintenance. *ELEFD* next calls *EDN*, which creates the initial LP matrix, updates coefficients for each time slice, solves the LP and retrieves the solutions, making use of OML subroutines for the LP management. Fuel consumption, generation and emissions are accumulated during the solution retrieval subroutine. *ELEFD* then calls subroutine *ELRPSCR*, where the costs of renewable credits for each region are calculated when there is a renewable portfolio standard in place. The final subroutine call is simply to create reports used in analysis. The remainder of this section will go into more detail in each of the major subroutines.

The EFD begins by reading information on firm trades and the transmission constraints for economy interregional trade. The height of the demand segments are adjusted to account for firm trades. Subroutine *ELDISP* is then called, which initializes variables and then calls a number of subroutines. The first call is to *ELMRIT*, which determines a merit order by listing the plant groups in order of increasing operating costs. Since the implementation of the LP, this step is not necessary, but is still useful to create an ordered list of plants. Before determining the merit order, the fuel shares used by each plant are determined. Subroutine *ELFSHR* calculates the fuel shares for dual-fired units based on the relative costs of the fuels. Each unit is assumed to have a maximum allowed share for each fuel type (where the sum of the maximum shares could be greater than one). The model then determines the cheapest fuel, and assigns the maximum share to that fuel, and then loops through the remaining fuel types until the capacity is fully allocated. When the prices between two fuels are close, some sharing is done between fuels. Once fuel shares are set, *ELMRIT* calculates operating costs for each plant, based on the fuel shares and fuel prices, variable operations and maintenance costs and any penalty costs related to emissions. Then the plants are sorted in ascending order of operating costs.

ELDISP then calls *ELPLNM* to determine the maintenance schedule for the plants. The maintenance is scheduled in a manner to maintain a constant reserve margin across the seasons. The total time required for planned maintenance is calculated for the year, and the maximum possible reserve margin is derived based on the total capacity less planned maintenance, divided by the demand. Then the time available for maintenance in each season is calculated, based on the peak load in the season, the capacity and the reserve margin. Maintenance is scheduled for each season, starting with the season that has the most available time.

For each season, a series of subroutines are called to calculate unit level costs for dispatchable capacity types, and to calculate generation from non-dispatchable renewable plant types. *ELMRIT* is called again to reorder the plants based on the available capacity after planned maintenance, as well

as to take account of any seasonal variations in fuel prices or costs. A similar subroutine, *ELDGNI*, orders the distributed generation plants. Processing of the renewable plants is then done in subroutine *ELRNEW*. Subroutine *ELRNEW* dispatches the hydroelectric and intermittent renewable capacity and calculates the resulting generation from these plant types. Since these plant types have low variable costs, a traditional dispatch would choose these plants first to maximize their utilization. However, they cannot be operated as baseload capacity because their output is constrained by the availability of the power source. Hydroelectric generating capacity is dispatched using an average utilization rate which specifies the fraction of time water is available to operate these plants. The total energy that could be produced by the available hydroelectric capacity is calculated, and removed from the load curve, starting with the peak slice. Wind and solar plants are assumed to have different capacity factors for each load slice, since the power is dependent on time-of-day, and their contributing energy is also removed from the load curve in the appropriate time slices.

The final subroutine called by *ELDISP*, within the seasonal loop, is *ELFACT*, which determines the load factors needed to calculate unit specific derate factors. After the peak slice, units need to lower operating levels to simulate off-peak times and avoid shutting off and restarting plants. Load following factors are determined by first calculating the area on top of the load curve. Plants are assigned factors depending on unit size, type of capacity and proportion of time left in declining slices.

Once *ELDISP* is completed, the model calls the subroutine to process the LP, *EDN*. Within the subroutine *EDN* is a loop over all time slices for the year. For the first time slice, the LP must be created from scratch, in the subroutine *CRENTX*. Each plant group is a column in the LP, with an upper bound set based on the maximum available capacity in the time slice, accounting for planned maintenance and derate factors calculated earlier. The cost of each plant is accumulated in the COST row, which is the objective function. The available capacity columns intersect with the electricity supply row. The transmission network columns are set up, enabling the electricity supply rows to meet electricity demand rows. Flows across the network are constrained by regional transmission limits. Assumed costs are added to transactions, and additional transmission losses are accumulated for these transactions. The final action in *CRENTX* is to call the OML subroutine to solve the model.

Subroutine *RETREDN* is then called to retrieve the optimized solution of the LP for the first slice. These results are stored for reporting and for use in other models. Using OML subroutines, the model retrieves the marginal cost of generation for the time slice in each region, and determines the plant type and region that provided that generation. The subroutine also determines which plant groups were operating in the time slice, and their generation, fuel and operating costs and emissions. The subroutine *ELCOST* is called to aggregate these variables by fuel type, plant type and/or owner. Subroutine *ELDGNO* aggregates the information for distributed generation plants.

After the first slice, the subroutine *REVNTX* is called to revise the LP structure. The necessary coefficients and bounds are reset, based on the new load slice. The model then solves the LP, and

calls *RETREDN* to retrieve and process the results. These two subroutines are called for each remaining time slice, until the total demand for the year has been met.

Once the model returns from the *EDN* subroutine, *ELRPSCR* is called to do the renewable credit trading. This is only necessary when a renewable portfolio standard (RPS) is in place, which is not in the current Reference case. If there is an RPS, then this subroutine calculates the renewable share (as defined in the particular standard) for each region, and determines how many credits it has either bought or sold. These costs or revenues are stored for use in the regulated pricing of electricity.

The final subroutine of the EFD, *DEBUG*, is simply used to create reports and fill in the EMM database.

Appendix 4.C. Data Sources

This appendix provides a list of the data sources in the EFD. Each data source is accompanied by a brief description.

Survey Forms

Form EIA-860

The Form EIA-860 is a mandatory census of electric generators that operate power plants or plan to operate a power plant within five years of the reporting year. Separate surveys collect data from both utilities (EIA-860A) and nonutilities (EIA-860B). The survey collects data on existing power plants, and on five year plans for constructing new plants, and modifying and retiring existing plants. Data is collected at the generating unit level and includes capacity and fuel source information, along with ownership and location data.

Form EIA-767

The Form EIA-767 is a mandatory census of all steam-electric power plants with generating capacity of 100 megawatts or greater. A subset of the data is provided from plants with capacity between 10 and 100 megawatts. The form is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data). This data is used to calculate capacity factors and heatrates for existing steam units for use in the EFD.

Form EIA-759

The Form EIA-759 collects monthly data from all electric utilities with at least one plant with a nameplate capacity of 25 megawatts or more. It also includes all nuclear units and all renewable units using fuel other than hydroelectric. The form is used to collect data on net generation, consumption of coal, petroleum, and natural gas, and fuel stocks for each plant. This data is used to calculate historical fuel shares for existing plants, and used to project potential for fuel switching in dual-fired plants.

Form EIA-412

The Form EIA-412 is designed to collect accounting, financial and operating data from publicly-owned electric power entities. Data collected include balance sheets, income statements, sales of electricity for resale, electric operations and maintenance expenses, purchase power and power exchanges. The average historical operations and maintenance expenses are calculated by plant, and used in the EFD as part of the calculation of total operating costs.

FERC Form 1

The Federal Energy Regulatory Commission Form 1 is a mandatory, annual census of major investor-owned electric utilities that meet specified criteria for sales. The form collects data on income and earnings, taxes, depreciation and amortization, salaries and wages, operating revenues, and operations and maintenance expenses.

Environmental Protection Agency - Emissions Monitoring

The EPA uses the Continuous Emissions Monitoring System (CEMS) to ensure that the mandated reductions of SO_2 and NO_x under the Acid Rain Program are achieved. CEMS is the continuous measurement of pollutants emitted into the atmosphere in exhaust gases from combustion or industrial processes. Annual emissions for each unit are reported, and average emission rates are be calculated for each plant for use in the EFD.

North American Electric Reliability Council - Transmission and Trade Data

Electricity Supply and Demand Database

The NERC ES&D database collects annual data and ten year projections of electricity demand, generating and transmission capacity, and capacity purchases and sales, by NERC region, and in some cases, by utility. The historical and projected interregional trade contracts are used as input to the EFD to capture firm power transactions.

Reliability Assessment Reports

NERC publishes summer and winter reliability assessment reports each year, to assess expected demand and available resources to meet demand, as well as to address transmission reliability issues. The report includes details on interregional transmission capability, which is used as input to the EFD to limit interregional trade to what can be transferred across existing lines.

5. Electricity Finance and Pricing Submodule

Model Purpose

The Electricity Finance and Pricing Submodule (EFP) is a component of the Electricity Market Module (EMM), which is part of the National Energy Modeling System (NEMS). As a component of NEMS, the EFP forecasts financial information for electric utilities on an annual basis given a set of inputs and assumptions concerning forecast capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs of the model include electricity prices by end use sectors for North American Electric Reliability (NERC) and Census regions, financial statements, revenue requirements,[63] and financial ratios for each stage of production (generation, transmission and distribution).

Electricity prices are forecasted for regulated, competitive and mixed regions. Regulated prices are determined by allocating projected revenue requirements to each customer class and dividing by the corresponding sales. Because the EFP is an aggregated model, the revenue requirements are allocated according to a representative rate structure for an entire region. The EFP simulates the traditional original-cost or rate-of-return regulatory method where electric utilities have their rates set by local, State, and Federal regulatory commissions. Utilities have rates set so as to allow them to recover their operating costs and earn a rate of return equal to their cost of capital.

The EFP determines the revenues that the aggregated utility requires in order to operate and earn its allowed profit using an average cost based algorithm. Revenues required for wholesale trades, including generation that is provided by nonutilities,[64] are determined in separate submodules of the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS)[65] and transferred to the EFP as expense items.

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[63]Revenue requirements are the costs that a ratemaking authority allows a regulated utility to recover from ratepayers.

[64]Nonutility generators are companies that generate electric power to be sold at wholesale rates to utilities who will in turn sell the power to ultimate consumers. Nonutility generators are nonregulated in that ratemaking commissions generally do not use the exhaustive cost based determination of electricity rates that are used for traditional regulated utilities. Instead, alternate methods for setting their rates have been developed such as a utility avoided cost method for cogenerators, and competitive bidding for independent power producers (IPPs).

[65]**The electricity capacity planning submodule projects the level of firm power trades for sales from utility and nonutility generators. As described in Chapter 3, The Electricity Capacity Planning Submodule, subroutine *EP$PCL* establishes limits on the amount of capacity purchased from nonutilities so that the interest coverage ratio for utilities does not fall below a prespecified level. The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility generators.**

When calculating regulated prices,there are three exceptions to the use of traditional rate of return regulation for determining revenue requirements in the EFP. These exceptions--sales-leaseback transactions,[66] phase-in plans for new generating units,[67] and disallowances[68]-- are modeled by exogenously adjusting the forecasted revenue requirements to comply with known information. The revenue that the aggregated utility will actually receive is modeled by adjusting the revenue requirement by a function to simulate regulatory lag.[69] The model solves for internal cash flow and determines the need for external financing in order to meet capital expenditures.

Competitive prices are forecasted by calculating the marginal cost of the generation dispatched for each of the36 time slices in the EFD.

Revenue requirements are allocated to each of four customer classes: residential, commercial, industrial, and transportation. The allocation process is carried out in three steps. First, all costs are functionalized. That is, they are sorted by stage of production into generation, transmission, and distribution. Second, the functionalized costs are classified according to the service characteristics to which they are related. The four service characteristics are fuel costs, variable operation and maintenance (O&M) costs, fixed O&M costs, and capital related costs.[70] Third, these functionalized and classified costs are allocated to the four customer classes and the average revenue for each customer class in each region is determined. In addition to determining customer average revenues on a regional basis, the EFP builds financial statements and ratios using accounting methods that simulate standard industry accounting practice.

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[66]A sales-leaseback transaction in the electric power industry generally involves the sale by the utility of a newly completed power plant to a group of investors with the understanding that the utility will then operate the plant through a lease arrangement. The advantage to the utility of such an arrangement is that rate shock can be avoided because there is a quick recovery of the costs of building the plant (through the sale proceeds). Payments by the utility for the use of the plant may then be levelized by the lease payments.

[67]A phase-in plan also serves to reduce rate shock caused by a new plant entering service. A new plant is introduced into rates in phases to raise rates gradually over time. In many cases, the ratemaking authority will allow the utility to earn a compounded return on the unrecovered portion of the plant, but recovery of these returns is deferred until a later date as part of the phase-in plan.

[68]A disallowance occurs when a ratemaking authority refuses to allow a utility to recover the costs of building a plant or a portion of a plant through the rates it charges consumers. Grounds for a disallowance could be that the utility has built more generating capacity than it needs, or the ratemaking authority judges that the utility's management was imprudent in some aspect of the manner in which the building project was undertaken.

[69]Regulatory lag is the effect that is caused by any time-related deviation in the assumptions that underlie the calculations of electricity prices, such as the differences between forecasted electricity sales and actual sales. The time variable in the EFP controls the period of time that passes before the realization of the change in assumptions.

[70]Capital related costs include all costs of production other than operation and maintenance (O&M, including fuel) and all wholesale trade expenses. The return on the ratebase, annual depreciation expenses, and all taxes are three examples of capital related costs.

In recent years restructuring has occurred in many regions of the country. Prices in the generation sector of those regions now reflect a competitive market rather than traditional rate-of-return regulation. Alternative algorithms that incorporate such changes have been added to the EFP.

Alternative regulatory and financial treatments that can be simulated in the EFP are flow-through versus normalized accounting,[71] construction work in progress (CWIP) versus allowance for funds used during construction (AFUDC),[72] alternate levels of allowed rates of return, and varying periods of regulatory lag.

The type of ownership (investor-owned or public) is specified to allow for more precise historic data inputs, varying regulatory, financial, and accounting conditions between ownership types as well as to allow for enhanced analysis flexibilities and capabilities.

Relationship to Other Models

Inputs

The EFP is a submodule of the NEMS. As such, there are several inputs to the EFP which come from other NEMS components (Figure 15). The capacity expansion plan is provided by the Electricity Capacity Planning (ECP) submodule. This includes the year the plant enters service, capacity (megawatts), and cost (dollars per kilowatt). The EFP uses this information to calculate the cost of construction as well as when and how these construction costs are incorporated into electricity rates.

The fuel, and operation and maintenance (O&M) costs come from the Electricity Fuel Dispatch (EFD) submodule. The EFP uses these data to calculate the revenues that are needed by electric utilities. The revenue requirements are used to calculate electricity prices to be charged to consumers. Each customer class's contribution to peak load comes from the Load and Demand Side Management (LDSM) submodule. The EFP uses these data to allocate costs to customer classes for pricing retail electricity.

Electricity demand comes from the end-use sector demand modules. The EFP uses electricity demand forecasts in its average revenue calculations.[73]

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[71]In flow-through accounting the tax advantages of accelerated depreciation and investment tax credits are passed on directly to ratepayers by way of a reduction in the regulated utility's revenue requirements. In normalized accounting, these tax advantages are amortized over a period of time — usually the useful life of the asset that generated the tax advantage.

[72]In the CWIP scenario, construction costs are added to the ratebase for an immediate return on investment as they are accrued. In the AFUDC scenario, construction costs are not added to the utility's ratebase until construction is completed and the new asset is operational. Financing costs are accrued in the AFUDC accounts and amortized over the life of the asset.

[73]In order to calculate average revenues the EFP will calculate revenue requirements and divide the result by total sales in kilowatthours.

The amount of power purchased from industrial and commercial cogeneration facilities and refineries (kilowatthours) and the amount paid by utilities is passed from the Electricity Fuel Dispatch (EFD) submodule. The EFP includes this information in its average revenue calculations.

Information on firm interregional and international power transfers comes from the Electricity Capacity Planning (ECP) submodule.

Interest rates on bonds rated AA are passed to the EFP from the Macroeconomic Activity Module. These interest rates are used to determine the forecasted costs of capital in the EFP.

Outputs

There are also several outputs from the EFP which are passed to other NEMS components. Electricity price forecasts by customer class are passed to the electricity demand modules. The demand modules use this price information to calculate changes in the demand for electricity.

The utility cost of capital is used by the ECP submodule in its capital budgeting algorithm.

Model Overview and Rationale

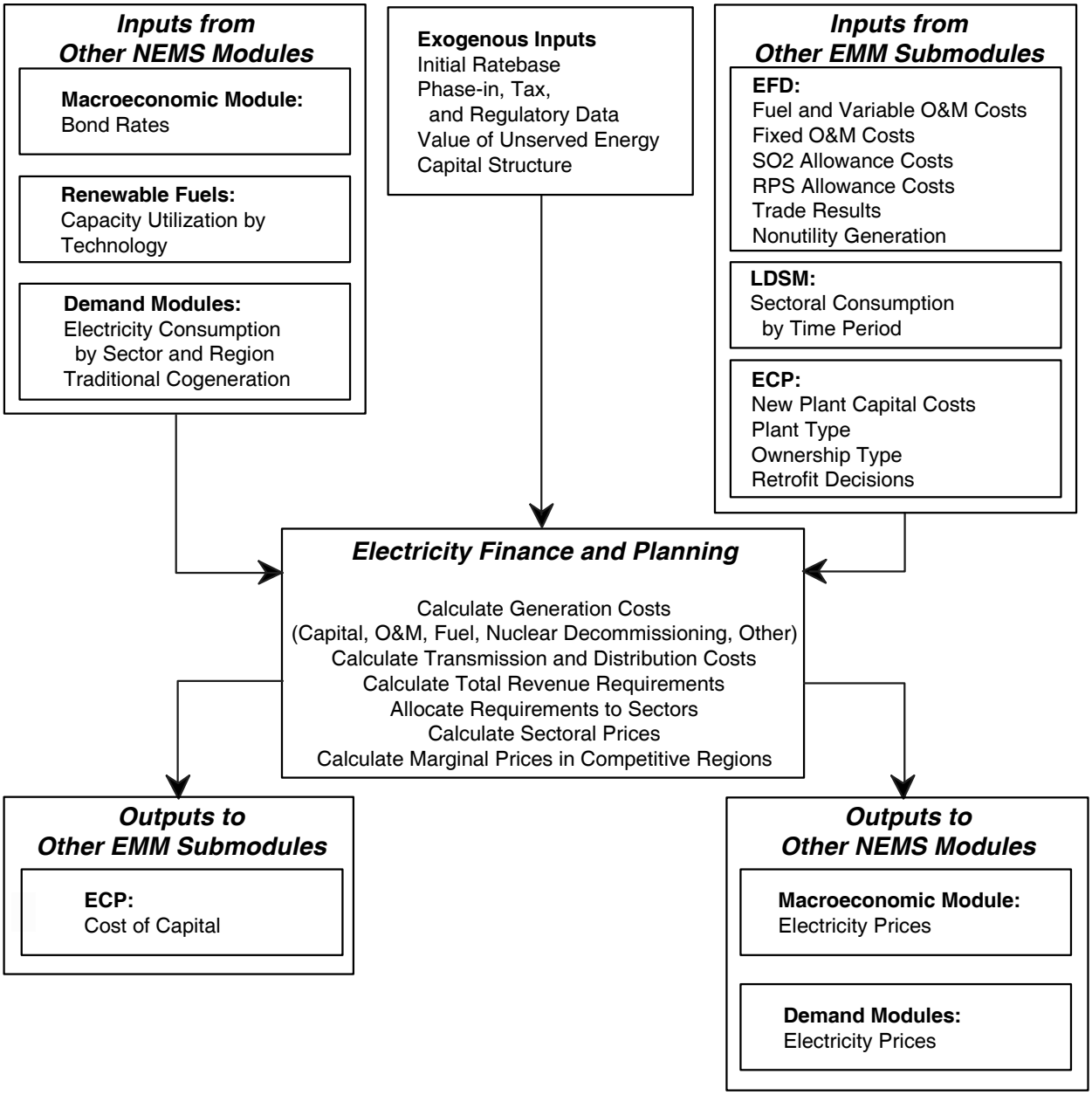
Theoretical Approach

The EFP has four functions:

1. Electricity pricing;
2. Accounting;
3. Determining the cost of capital for electric utilities; and
4. Determining the costs of transmission and distribution services.

The EFP is an accounting system that models regulatory practice and is completely deterministic. It has solution algorithms for the generation, transmission, and distribution stages of production. Pricing mechanisms are implemented for the generation and transmission stages of production to enhance the model's flexibility in simulating emerging pricing techniques used in the electric power industry. There are many pricing mechanisms that could be used for this purpose. The one that has been included initially in this submodule is the traditional cost of service method. The modular design of this submodule will allow the user to plug in additional pricing methods as they are needed in the future.

Figure 21. Input/Output Flows for the Electricity Finance and Pricing Submodule



In those parts of the country where restructuring has occurred, alternative algorithms are needed to determine electricity prices. Algorithms to determine the generation component of price for such regions have been developed. Both transmission and distribution (T&D) are considered to remain under rate of return regulation. Revenue requirements are determined as before. However, the allocation of costs between sectors has been modified for the competitive regions **(see Section 5C, Remaining Algorithms, Price of Electricity, Sectoral Pricing Under A Competitive Generation Scenario).**

The first step in calculating generation and transmission transfer prices and distribution average revenues is the determination of the revenue requirement. The revenue requirement, the costs that a ratemaking authority allows a regulated utility to recover from ratepayers, is the sum of the fixed and variable costs of production. The fixed costs include the return on the ratebase, fixed operation and maintenance (O&M) costs, and the annual depreciation expense (the recovery of invested capital). Revenue requirements are determined for generation, transmission, and distribution independently for each region. In the case of generation and transmission, the term revenue requirement is used loosely and is not meant to infer that, in the future, these stages are assumed to be regulated under a cost of service arrangement.

Fixed Costs

The ratebase is the total value (original cost less accumulated straight line depreciation and excluded tax deferrals) of all capitalized assets on which the regulated utility is allowed by a ratemaking authority to earn a return. The ratebase for the first modeled year is based on historical data from the previous year with additions or deletions determined by the modeled costs of capacity additions. Additions to the generation ratebase are determined in the Electricity Capacity Planning submodule. Transmission ratebase additions are determined in the EFP as a function of generation capacity expansion. Additions to the distribution ratebase are determined in the EFP as a function of sales. The EFP also determines the fixed O&M for the three stages of production.

The forecasted rate of return is a function of the interest rate on AA rated utility bonds. This rate of return is the weighted average cost of capital for each region. In the first year of the simulation, the long-term debt rate for each region is the weighted average of the actual long-term debt rates for electric utilities in that region. After that, it is a function of the national utility long-term debt rate (from the Macroeconomic Activity Module). The regional cost of equity is a function of the previous year's regional return on equity and debt, and the current year's regional debt rate. The cost of preferred stock is a function of the average of the regional debt rates.

Variable Costs

Fuel costs and variable operation and maintenance costs (O&M) for generation are determined by the Electricity Fuel Dispatch (EFD) submodule. Transmission and distribution related variable O&M

costs are determined in the EFP based on historic data as is the rest of the data for the calculation of the revenue requirements.

Cost Allocation and Retail Average Revenues

After the revenue requirements for all three stages of production have been aggregated, costs are allocated to the four customer classes. Costs are summed into four groups — capital related, fixed operation and maintenance (O&M), variable O&M, and fuel — for each stage of production for the purpose of allocation to customer classes. Several methods for allocating costs are available in the EFP. The choice as to which method to use for which type of costs (capital, fixed O&M, variable O&M, and fuel) for each stage of production is a user option.

The selection of the method used for the allocation of each type of cost (in each stage of production) should result in costs being allocated according to which customer class is responsible for the cost of service. For example, some costs, such as variable O&M, can be confidently allocated on the basis of the level of electricity sales to each customer class. Others, such as fuel costs, are allocated on the basis of each customer class's contribution to the system peak load at the time of peak load (coincident peak method). The justification for this is that, for the purposes of allocating costs, it is assumed that electric utilities burn more expensive fuel as demand on the system increases. Therefore, the customer class most responsible for the system peak is most responsible for the burning of the most expensive fuels. Allocating fuel costs on the basis of the customer class's contribution to the peak load (using the coincident peak or probability of contribution to peak method) provides a method that is consistent with that assumption. Other costs, such as the cost of building new generating plants, are incurred to meet peak load requirements as well as for fuel diversity and other reasons. Allocation methods that recognize the multiple reasons for these costs have been developed in the utility industry and are available in the EFP (two versions of the average and excess demand method).

Following are the cost allocation methods available in the EFP:

Sales method. Costs are allocated on the basis of the proportion of electricity sales, in kilowatthours, to each of the four customer classes. This method will be used most frequently to allocate variable O&M costs for all three stages of production (generation, transmission, and distribution).

Coincident peak method. Costs are allocated on the basis of each customer class's contribution to the system peak at the time of the system peak.[74]

[74]The system, or coincident peak, is the highest point on the system load curve. That is where the greatest demand on the system exists. Non-coincident peaks, on the other hand, are where individual customer class demands are greatest.

Probability of contribution to peak (PCP) method. The proportion of each class's load in each of the highest twenty peaking hours of each year (from the Load and Demand Side Management — LDSM — submodule) is determined. Each customer class's proportions are averaged for each year and used as the weight for allocating costs. That is, costs are allocated on the basis of system peak data to time periods and customer classes.

Non-coincident peak (NCP) method. The residential, commercial, industrial, and transportation peaks are summed. Costs are allocated on the basis of the proportion of each customer class's individual peak load to the sum of the individual peak loads. This method will be used most frequently to allocate distribution fixed O&M and capital costs, and will be used with the average and excess demand using probability of contribution to peak (AED-PCP) method (discussed below) to allocate transmission fixed O&M and capital costs.

Average and excess demand method using the probability of contribution to peak (AED-PCP) or coincident peak (AED-CP). This cost allocation method recognizes that capital additions are not made solely for peak demands. Sometimes capital additions are needed for fuel cost savings or other sales oriented reasons. Customer class peaks and system load factors are both used in allocating costs. In this method costs are first divided into those that will be allocated on the basis of average demand and those that will be allocated on the basis of "excess" or peak load demand. Those costs to be allocated on the basis of average demand are allocated first. This is done by calculating the ratio of the class average demand to the sums of the class average demands. Then, the remaining costs are allocated on the basis of the demand in excess of the system load factor. This is done by calculating each customer class's contribution to the system peak using either the probability of contribution to peak method or the coincident peak method.

Retail electricity average revenues are calculated for each ownership type (investor owned and public utilities) and across ownership categories (investor owned and public utilities combined) for each NERC region and selected subregions. That is, each region will have an average revenue calculation for investor owned utilities, public utilities, and a combination of the two. The calculation of average revenues for a given region and customer class is the revenue requirement that has been allocated to that customer class divided by the total sales (kilowatthours) to that customer class, or:

$$\text{Average Revenue}_{ijy} = \text{Total Revenue}_{ijy} / \text{Sales}_{ijy}$$

where:

$\text{Average Revenue}_{ijy}$ = average revenue (retail price) of electricity for customer class i, in region j for year y.

$\text{Total Revenue}_{iiv}$ = revenue requirement allocated to customer class i and region j, for year y

Sales_{ijy} = sales to customer class i in region j, for year y.

Stage of production and industry-wide financial statements are generated for each region and nationally. Financial statements are standard accounting statements such as Balance Sheets and Income Statements. The industry-wide financial statements aggregate the three stages of production into a single set of financial statements to represent a vertically integrated industry.

Cost Allocation Under Competition

The emergence of competitive markets for generation in the electricity industry has created the potential of a new distribution of costs and benefits among classes of utility customers. Traditionally, rates were set by regulators based on "embedded costs," the average cost of producing electricity and serving the customer, including both short-run costs such as fuel and long-run costs such as plant and capital recovery. Since rates were set so as to cover all costs, including return on capital invested, this was referred to as rate-of-return regulation. Rates were generally set to reflect average costs rather than the more volatile fluctuations in marginal costs. Historically, given the large transaction costs associated with real-time pricing, average cost pricing was seen as a way of ensuring revenues covered total cost.

The changing nature of the electric power industry will undoubtedly modify the pattern of allocations of costs between customer classes. Market forces will have a more dominant role. While all customers are expected to eventually benefit by the introduction of competition in the generation function, the rate and degree of such benefits may vary by customer class. The EFP has been changed to reflect the changing environment. The primary assumption is that the generation component of price is determined in a fully competitive market, while transmission and distribution remain under regulation. Under the new market structure, some consumers may have the ability to bypass the distribution system at relatively low cost by connecting directly to the transmission system or building an on-site generation. Therefore some redistribution of fixed costs may be necessary to retain these customers.

Most analyses of this issue begin and end with Ramsey's model of socially optimal pricing when the firm is faced with the constraint that it must recoup its costs under the condition that the marginal cost is less than the average cost.[75] In this model of pricing, the decision maker is assumed to maximize the sum of consumer surpluses over all customer classes subject to the constraint that the firm recovers its costs. The optimal solution is given by the inverse-elasticities rule under which the markup of price above marginal cost is inversely related to that sector's price elasticity of demand. While this result offers some useful insights, it ignores the possibility that regulators may weigh the economic interests of industrial customers more or less heavily than the economic interests of commercial or residential customers. This of course affects the pattern of sectoral prices that is observed under regulation.

[75]Such an approach was found to be economically optimal by Ramsey some 70 years ago. See F.P. Ramsey, "A Contribution to the Theory of Taxation," *Economic Journal*, Vol. 37 (March 1927).

For the restructured regions, a modified Ramsey pricing scheme was implemented. The economic principles underlying the valuation are described in detail later in this chapter.

Modeling Renewable Portfolio Standards

One element of modeling the renewable portfolio standard (RPS) is calculating a credit price; that is, the marginal value of each kilowatthour of renewable generation. The credit price is calculated as follows. A levelized credit price, representing the marginal cost of compliance with the renewable portfolio standard, is calculated using output from the Electricity Capacity Planning Module for each of the planning years of the solution, derived as described above. Each such levelized credit price is weighted by the incremental change in renewable generation since the imposition of the portfolio standard, to produce the annual credit price. It is assumed that the revenues (regional generation from qualified renewables multiplied by the credit price) from renewable credit trades are included in the revenue requirements. Credit sales reduce the revenue requirements and the resulting prices of electricity, whereas purchases increase revenue requirements and prices. In the competitive regions, the credit price is multiplied by the appropriate RPS fraction (e.g. 0.15 if the standard is set such that 15% of generation must be of the appropriate renewable type) and added to the marginal energy cost.

The rationale is as follows. Assume that the RPS is set at 15%, and that every generator must present 0.15 credits per kilowatt-hour of power sold, where a qualified renewable generator receives one credit for each kilowatt-hour sold. In this way, exactly 15% of the generation will be from the qualified renewable sources. The cost of purchasing 0.15 of a credit is variable cost, and is then added directly to the marginal cost of generation.

Alternative Approaches and Reasons for Selection

The EFP, as the financial and electricity pricing component of EIA's intermediate-term energy modeling system, accounts for two broad-based changes in the industry that are occurring or could occur in the next decade: (1) industry structural changes, and (2) capital investment changes.

Changes Related to Industry Structure

The structure of the regulated electric power industry , in which vertically integrated franchise monopolies[76] dominate, was influenced in large part by the Public Utility Holding Company Act of 1935 (PUHCA). This act was passed by Congress as part of the New Deal legislation to break up the large monopoly holding companies that dominated the electric power industry. These holding companies were structured in such a way as to impede regulatory oversight.

[76]In a franchise monopoly, an electric utility (investor-owned or public) operates in a defined service territory at the exclusion of all other electric utilities.

This vertical integration of the electric power industry has been breaking down as a result of efforts to increase competition in the power generation arena. In states allowing retail competition, generation, transmission and distribution rates have been unbundled and generation rates for retail electricity customers are determined by an agreement between the customer and the competitive electricity supplier[77] other than the traditional cost of service approach. FERC's Order 888 has allowed the formation of competitive electricity markets from which utilities and competitive electricity suppliers purchase at least some of their wholesale power. Thus, the three primary stages of production of the industry: generation, transmission, and distribution[78] are modeled separately. Transfer prices are calculated for generation and transmission. The purpose of these prices is to transfer the costs of each of these stages to the distribution stage so that total costs for all of these stages can be included in the calculation of average revenues. In the case of a vertically integrated electric utility, the generation and transmission transfer prices represent the flow of costs (as between divisions within a corporation) that become components of the retail pricing mechanism (which calculates average revenues for distribution). This technique facilitates an analysis of industry structural change, allows for independent assumptions for each of the three stages of production with regard to regulatory and tax treatment, and allows the analyst to use a variety of costing mechanisms with varying underlying economic assumptions for these stages of production.

Separate financial statements are provided for each stage of production on a regional and national basis so that an independent analysis of each will be feasible. (Financial statements are provided on an industry-wide basis as well. In these reports, the three stages of production are combined at the regional and national levels to represent a regional vertically integrated utility.)

The pricing technique used for retail distribution continues to be the average cost based method. Average revenues are calculated for the four customer classes: residential, commercial, industrial, and transportation. An improved cost allocation algorithm has been implemented so that these customer class average revenues are more meaningful in terms of the actual forecasted cost of service. That is, cost allocation methods in the EFP may use peak load data generated by the Load and Demand Side Management submodule (LDSM) as the basis for the allocation of some costs of service so that costs may be more accurately allocated to the customer class responsible for those costs.

Changes Related to Capital Expenditures

The second broad based change has to do with investment emphasis. In the 1970's and 1980's, most capital expenditures were for construction projects. Throughout the 1990's a sizable amount of capital expenditures were for purposes other than for new construction. They include demand side management (DSM) costs, nuclear decommissioning costs, life extension costs, post operational

[77]A competitive supplier can be a generator, power marketer, or power broker that agrees to either directly provide, or arrange the provision of, power for the customer.

[78]Within each stage of production — generation, transmission, and distribution — representations are made of the various ownership categories, regulatory considerations, and economic assumptions that exist now or are likely to exist in the future.

capital expenditures, and costs and revenues associated with the Clean Air Act Amendments of 1990 (CAA). Since many of the accounting and rate-making issues dealing with these expenditures will be different in the future, the EFP is designed so that an accurate representation of these issues can be made.

Solution Algorithm and Key Computations

Overview

The purpose of this section is to describe the solution algorithm used within EFP. The discussion is organized into three parts, Sections 5A, 5B and 5C . Section 5A, Forecasting Revenue Requirements, describes the method used to forecast annual revenue requirements. In order to forecast the revenue requirement, one must first forecast the components of the rate base and the expenses. This part describes the algorithms used to calculate and forecast these items. Section 5B, Competitive Pricing Algorithm, describes how to calculate and forecast competitive generation prices. With all of these items forecast, one has nearly all the necessary components to forecast the financial statements and ratios. Section 5C, Remaining Algorithms, describes the process of using these items to yield forecasts of electric revenue, prices, taxes (both actual and for financial purposes), and financial ratios.

5A. Forecasting Revenue Requirements

The EFP method of forecasting revenue requirements simulates the outcomes of the regulatory process. The EFP forecast of revenue requirements in any given year is that which allows the utilities to earn a rate of return equal to the cost of capital and also recover their operating costs. Formally, the forecast for revenue requirements in any given year is:

(5A)

$$ERRVRQ = (ERRB \cdot ESRR) + ERTFLN + ERTOMN + ERBDE + GENREG + STAREG + FEDREG - EROFFS + ESLLPN - EPIND + ERNDFPMT$$

where:[79]

[79]The variable names used in this description are the same as those found in the computer code of EFP. There are some conventions used in variable naming, as follows. A prefix of ER denotes variables containing results aggregated to the total system level. A prefix of ES denotes a ratio or fraction. A prefix of EO denotes variables related to assets existing before the first forecast year. Finally, a prefix of EB denotes a variable related to an individual plant build.

ERRVRQ = revenue requirement[80]
ERRB = rate base
ESRR = rate of return
ERTFLN = fuel costs
ERTOMN = operation and maintenance expenses, excluding fuel costs
ERBDE = book depreciation expense
GENREG = general taxes (gross receipts, property, sales) for regulatory purposes
STAREG = State income taxes for regulatory purposes
FEDREG = Federal income taxes for regulatory purposes
EROFFS = allowance for funds used during construction (AFUDC) offset
ESLLPN = net lease payment associated with sales/leaseback transactions
EPIND = net deferred phase-in revenues for year.
ERNDFPMT = nuclear decommissioning fund annual payment

Note that, except where specifically stated, the variables are calculated in nominal dollars. Nominal dollars, rather than real dollars, are required to simulate the regulatory process effectively. Once nominal electricity prices are determined, they are reported in both nominal and real dollars. Each of the eleven variables on the right-hand side of the revenue requirement equation above is discussed in separate sections below. More detailed and involved discussions, beyond general explanations of a specific variable, are found in Appendix sections below, when needed to fully describe the solution algorithms.

Calculation of Rate Base (ERRB):

The formula used to calculate the rate base is:

(5A.1)

$$ERRB = ERTUP + ERRCWP + ERWC + ERNFSN - ERABDE - ERPRDF - (ERCNBV - ERCNAD) - ESLNDG - EDISNT$$

where:
ERRB = rate base
ERTUP = total utility plant
ERRCWP = Construction work in progress (CWIP) allowed in rate base
ERWC = working capital
ERNFSN = nuclear fuel stock

[80]For accounts that describe `flows' (e.g., fuel expense, depreciation expense), the value refers to the period January 1 to December 31 of the given year. For accounts that describe `stocks' (e.g., rate base, utility plant), except when otherwise stated, the value refers to the end of the given year value, i.e., value on December 31 of the given year.

ERABDE = accumulated book depreciation
ERPRDF = provision for deferred income taxes
ERCNBV = book value of canceled projects whose unamortized balance is not allowed in rate base
ERCNAD = accumulated depreciation (or amortization) of canceled projects whose unamortized balance is not allowed in rate base
ESLNDG = net deferred gain from sale/leaseback transactions
EDISNT = net disallowed plant.

As calculated above, ERRB is the year-end rate base. Another option in EFP is to calculate revenue requirements using the average value of the rate base over the year. The analyst may choose either option. The formulas used to calculate the average rate base are:

(5A.1a) $$ERRBA = (ERRB + ERRBB)/2.0$$

(5A.1b) $$ERRBB = ERRB_{y-1} + ERDLRB$$

where:
ERRBA = average year rate base
ERRB = end of year rate base
ERRBB = beginning year rate base
$ERRB_{y-1}$ = end of year rate base from proceeding year
ERDLRB = book value of new plants that come on line this year.

The average-year rate base is calculated as the simple average of the beginning-and end-of-year rate base. The beginning-of-year rate base is calculated as the rate base at the end of the previous year plus the book value of any new plants that come on line in the given year. (The calculation of the book value of new assets is described below.)

When the end-of-year rate base option is chosen, an additional adjustment to the calculation of rate base is made. When plants come on line in the middle of a given year, they continue to accrue allowance for funds used during construction (AFUDC) for those months until the plant is actually in service. To avoid earning an excess return (AFUDC plus a full-year cash return) on such plants, the end-of-year rate base is lowered so that the total return (AFUDC plus cash return) on the plant is appropriate. Further discussion of AFUDC is found in Appendix 5.A, Construction Work in Progress.

Total Utility Plant (ERTUP):

Total Utility Plant (ERTUP) is calculated as:

(5A.1.1)

$$ERTUP = \sum_{all\ k} (EOBKVL_k) + \sum_{all\ k} (ERBVYE_k) - ERBTIR$$

where:

ERTUP = total utility plant

(5A.1.2)

$$WP_v = EBRCWP_v + ERRCV$$

$EOBKVL_k$ = book value of assets existing in the base year (old assets) of type $_k$ (i.e., distribution)

$ERBVYE_k$ = book value of assets completed in the forecast horizon (new assets) of type $_k$ which are completed as of the year of forecast

ERBTIR = book value of all assets which have been retired during the forecast horizon as of the year of forecast.

The book value of existing assets in the base year is an input that can be derived from historical financial statements such as the FERC Form 1 or Form EIA-412. $ERBVYE_k$ is calculated by summing the book values of each individual new asset of type $_k$ which is completed as of the year of forecast. Retired assets are all assets. The calculation of the book value of individual new assets is also discussed below.

Construction work in progress (CWIP) allowed in rate base (ERRCWP):

where:

$ERRCWP_y$ = CWIP allowed in rate base

$EBRCWP_y$ = CWIP allowed in rate base by new build, year y

$ERRCWP_{(y-1)}$ = CWIP allowed in this year's rate base from previous year's build based on last year's output.

For a more detailed discussion of CWIP, see Appendix 5A, Construction Work in Progress.

Working Capital (ERWC):

Working capital is calculated within EFP using what is known as the 1/8 method. In general, this method arrives at working capital by summing the following: materials and supplies excluding fuel stocks; a percentage of operating and maintenance expenses, usually 1/8, representing a 45-day net lag in revenues and expenses; and other adjustments unique to a jurisdiction. The 1/8 method is based on the assumption that an average monthly billing utility has a net lag of 45 days between the payment of expenses and collection of revenues. This method of estimating working capital does have some drawbacks. The implicit assumption behind the 1/8 method is that there is a positive working capital need. The 1/8 method does not give any recognition to the availability of working capital resulting

from the accrual of interest or tax expenses prior to the time of their payment. Items such as these constitute sources of working capital that are not considered using the 1/8 method. In addition, under circumstances of unusually fast receipt of customer payments and extended delay in paying suppliers, there can actually be a negative working capital requirement for a utility. The 1/8 method also assumes that all utilities have the same experience with regard to receipt of payment from customers and employ the same payment policies.

The calculation for working capital is:

(5A.1.3) $$ERWC = 0.125 \cdot (ERTOMN + ERTFLN)$$

where:
ERWC = working capital
ERTOMN = operation and maintenance costs, excluding fuel
ERTFLN = fuel costs

The calculation of ERTOMN and ERTFLN is discussed below.

Nuclear Fuel Stock (ERNFSN):

The nuclear fuel stock in any given year is calculated as a function of the amount of fuel actually used in the year.

(5A.1.4) $$ERNFSN = 3.5 \cdot EFPNUC \cdot ESGNPD$$

where:
ERNFSN = Nuclear fuel stock
EFPNUC = Real dollar nuclear fuel expense
ESGNPD = inflation index to convert real dollars to nominal

Accumulated Book Depreciation for All Public and Private Utility Assets (ERABDE)

(5A.1.5) $$ERABDE = ERABDL + ERBDE - ERBTIR$$

where:
ERABDE = accumulated book depreciation, all assets
ERABDL = accumulated book depreciation expense for last year
ERBDE = book depreciation for all assets

ERBTIR = book value of all retirements

The book depreciation is a function of the book value and takes into account the plant type for each build, the year which plant comes on line, the percent of year plant is in service during the first year, the book life for new assets by plant type, the book depreciation rate for old assets by plant type, the book life for old assets by plant type, the accumulated book depreciation expense for the previous year, the booked value of existing assets, the value of existing assets net of AFUDC, the share of public and private generation and the number of vintage years.

Provision for Deferred Income Taxes (ERPRDF):

The provision for deferred income taxes is the sum of the values of all deferred income taxes or deferred tax savings (excluding investment tax credits). For purposes of EFP, this includes the deferred taxes from accelerated depreciation and the deferred tax savings from the debt portion of AFUDC on assets not affected by the TRA of 1986.

(5A.1.6) $$ERPRDF = DAD + DAFDC - EREDTF$$

where:

ERPRDF = provision for deferred income taxes
DAD = deferred income taxes due to accelerated depreciation
DAFDC = deferred tax savings from the debt portion of AFUDC
EREDTF = excess deferred taxes flowed back to ratepayers

Book Value of Canceled Projects Not in Rate Base (ERCNBV) and Accumulated Depreciation of Canceled Projects Not in Rate Base (ERCNAD):

After the Three Mile Island nuclear plant incident, many regulations were put into place requiring added safety features in nuclear plants that greatly increased the cost of building such plants. Nuclear plants that were under construction at the time of the incident became subject to these new regulations. In some cases, the projected added costs to complete the plant build with the added safety enhancements rendered the project too expensive, thus it was cancelled. The values of ERCNBV and ERCNAD–the book value and accumulated depreciation of canceled projects whose unamortized balance is not allowed in the rate base–were calculated by summing the costs of all canceled projects. They contributed to electricity prices in historical years but have been paid off and thus do not contribute to current electricity prices. Thus the values for ERCNBV and ERCNAD are now zero.

(5A.1.7) $$ERCNBV = \sum ERBVYE_{eican}$$

where:

ERCNBV = Book value of canceled projects not in rate base

$ERBVYE_{eican}$ = Book value of new canceled plant assets at the end of the year

(5A.1.8) $$ERCNAD = ERCNAD + EBABDE + BDE$$

where:

ERCNAD = Accumulated depreciation of canceled projects not in rate base

EBABDE = Accumulated book depreciation all assets by build

BDE = Book depreciation computations

For more information on depreciation, see Appendix 5B.

Net Deferred Gain From Sale/Leaseback Transactions (ESLNDG)

The sale and leaseback of an electric plant by a utility allows the utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position. It was an attractive means for mitigating cost increases to ratepayers of plant builds with high capital costs (such as nuclear plants), allowing costs to be stretched out over the lease period of 25 or 30 years. The net deferred gain from the sale of the plant is subtracted from the rate base.

(5A.1.9) $$ESLNDG = ESLNDG + SLGAIN - AMOR * YRSL$$

where:

ESLNDG = total regional net deferred gain

SLGAIN = net of tax gain over book value from sale

AMOR = amortized amount of tax gain

YRSL = year of sale/leaseback plan

For a detailed discussion of Sale/Leaseback Transactions see Appendix 5.D.

Net Disallowed Plant (EDISNT)

Disallowed plant refers to plant builds with capital costs that were higher than considered "prudent" by regulators. These generally refer to nuclear plant cost overruns. This subject, as well as the derivation of the following calculation of EDISNT, is discussed further in Appendix 5.E, Rate Phase-Ins:

(5A.1.10)

$$EDISNT_y = PIBKVL \cdot DISPER \cdot (1.0 - y/PIBKLF)$$
$$\text{for } y = 1, PIBKLF$$

where:

$EDISNT_y$ = net disallowed plant, year y
PIBKVL = book value of phase-in plant (input)
DISPER = fraction of phase-in plant disallowed (input)
PIBKLF = book life of phase-in plant (input).

Rate of Return (ESRR):

The rate of return is calculated as a weighted average of the cost of long term debt, short term debt, common equity, and preferred stock. The equation is:

(5A.2) $$ESRR = ESPRLT \cdot ESEMDT + ESPRST \cdot ESRTST + ESPRCE \cdot ESRTCE + ESPRPS \cdot ESEMPS$$

where:

ESRR = rate of return
ESPRLT = fraction of capital structure made up by long term debt
ESEMDT = embedded cost of long term debt (explanation below on page 155)
ESPRST = fraction of capital structure made up by short term debt
ESRTST = cost of short term debt
ESPRCE = fraction of capital structure made up by common equity
ESRTCE = cost of common equity (explanation below on page 156)
ESPRPS = fraction of capital structure made up by preferred stock
ESEMPS = embedded cost of preferred stock (explanation below on page 157)

With the exception of ESEMDT, ESRTCE, and ESEMPS, all of the above values are inputs into EFP.

Embedded Cost of Long-Term Debt (ESEMDT):

The embedded cost of long-term debt in any year is a function of several quantities including the cost of new debt, the cost of existing debt, and the timing and quantity of retirements and issues of new debt:

(5A.2.1) $$ESEMDT = \frac{(ESEMDL \cdot ERBNDL - ESEMDB \cdot RETIRE + ESRTLT \cdot (ERBOND - ERBNDL + RETIRE))}{ERBOND}$$

where:

ESEMDT = embedded cost of long term debt

ESEMDL = embedded cost of long-term debt in previous year

ERBNDL = total long-term debit outstanding from previous year

ESEMDB = embedded cost of long-term debt in the year previous to the first forecast year

RETIRE = amount of debt that is retired in current year, as determined by calculating the maximum of: ESPRLT * ERBDE; and EROBL, where ESPRLT = fraction of capital structure made up by long-term debt, ERBDE = book depreciation expense, and EROBL = long-term debt outstanding in previous year that was issued before the first year of the forecast period

ESRTLT = Cost of new long term debt as determined by the national yield on new AA corporate bonds

ERBOND = total long-term debt outstanding in current year, as determined by ERAMD * ESPRLT, where ERAMD = assets minus deferrals–the amount that must be financed, and ESPRLT = fraction of capital structure made up by long-term debt)

The algorithm calculates the embedded cost of debt as a weighted average of: i) the embedded cost in the previous year (ESEMDL); ii) the embedded cost in the base year (ESEMDB); and iii) the cost of new long-term debt issued in the current year (ESRTNB). Only debt issued before the forecast period is assumed to be retired. This is appropriate, given the mid-range forecast period over which EFP forecasts.

To better represent the risks facing developers of new generating plants in the restructured environment, the cost of capital has been re-evaluated. The yield on debt represents that of an AA corporate bond rather than that of utilities. For a more detailed discussion of the cost of capital in NEMS please see Appendix 5F. Cost of Capital

Cost of Common Equity (ESRTCE):

The cost of equity algorithm is based on the Capital Asset Pricing Model (CAPM). CAPM states that, given specific assumptions,[81] the cost of equity for a particular corporation is equal to a risk-free rate of return plus a premium equal to the difference between the market rate of return and that risk-free rate times a beta coefficient. Beta is a measure of an asset's sensitivity to market movements.[82] A corporation with a beta equal to 1.5 means that the return on that company's stock is 1.5 times as volatile as the return on the stock market in general. More volatility means that a company's stock is more risky. More risk commands a higher rate of return for investors. A higher required rate of return for investors means that the corporation has a higher cost of equity.

The mathematical specification of the CAPM is as follows:

(5A.2.2)

$$R_E = R_F + \beta (R_M - R_F)$$

where:

R_E	=	the required return on the company's common stock
R_F	=	the risk-free rate of return (generally the return on 90-day Treasury bills)
β	=	the beta coefficient
R_M	=	the return on the market.

For the purposes of the EFP, the risk-free rate of return is the real Treasury bill (T-bill) rate from the NEMS Macroeconomic Activity Module (MAM) plus an exogenous inflation rate.[83] The return on the market is also an exogenous input.[84] This means that the beta coefficient provides the dynamic properties of the cost of equity to electric utilities in NEMS. Through the beta coefficient, the EFP translates the forecasts of operational and financial conditions into the cost of equity for utilities. This, in turn, affects the pricing of electricity in the EFP, as well as capacity planning decisions in the ECP. The value of β was determined exogenously based on historical values of unregulated industries with characterics similar to the restructured electricity generation sector.

[81]For a detailed description of CAPM, see Energy Information Administration, *Investor Perceptions of Nuclear Power*, DOE/EIA-0446 (Washington, DC, May 1984).

[82]Beta is the covariance of rates of returns between the company and the market. The market rate of return is measured by some index, such as the S&P 500.

[83]The inflation rate used may be exogenous or may be the inflation rate from the MAM. The decision as to which inflation rate to use will depend on the range of inflation rates across NEMS cases. An inflation rate that is unrealistically high or low given other economic conditions may generate perverse results in the ECP submodule.

[84]It is beyond the scope of NEMS to forecast a return on the stock market.

Embedded Cost of Preferred Stock (ESEMPS):

The embedded cost of preferred stock is calculated in an algorithm similar to that used for the embedded cost of long-term debt above.

(5A.2.3) $$ESEMPS = \frac{(ESEMPL \cdot ERPRFL - ESEMPB \cdot RETIRE + ESRTPS \cdot (ERPREF - ERPRFL + RETIRE))}{ERPREF}$$

Where:

ESEMPS	=	embedded cost of preferred stock
ERPRFL	=	total preferred stock from previous year
ESEMPB	=	embedded cost of preferred stock from the year previous to the first forecast year
RETIRE	=	amount of preferred stock that is retired in current year--maximum of: ESPRPS * ERBDE; AND ERPFL (ESPRPS = fraction of capital structure made up by preferred stock, ERBDE = book depreciation expense, and ERPFL = preferred stock outstanding in previous year that was issued before the first year of the forecast period)
ESRTPS	=	PSRCF1 + (PSRCF2 * ESRTDA) where PSRCF1 and PSRCF2 are regression coefficients for preferred stock and ESRTDA is the average of all regional new long-term utility debt
ERPREF	=	total preferred stock in current year-- ERAMD * ESPRPS (ERAMD = assets minus deferrals and ESPRPS = fraction of capital structure made up by preferred stock)
ERBDE	=	book depreciation expense preferred stock outstanding in previous year that was issued before the first year of the forecast period

The values of ESEMPB and ERPFL (for the first forecast year) are input into EFP. These values can be derived from historical financial statements such as the FERC Form 1.

Fuel Costs (ERTFLN):

Fuel costs in each forecast year are derived from the results of the dispatch exercise.

(5A.3) $$ERTFLN = (EFPFL + BLKSUM) \cdot ESGNPD$$

where:

ERTFLN	=	nominal dollar fuel cost
EFPFL	=	real dollar fuel costs as determined by the dispatch model
BLKSUM	=	real dollar wholesale electricity purchase costs (includes imports, exports, purchases from NUGs and inter-regional transfers), as determined by the dispatch model
ESGNPD	=	inflation index to convert real dollars to nominal dollars

Operation and Maintenance (O&M), Excluding Fuel (ERTOMN):

As with fuel costs, operation and maintenance costs are input to EFP from other modules being used to drive EFP. Again, if necessary, these costs are inflated each year by a user-defined inflation rate. Operation and maintenance costs are calculated differently for generation, transmission, and distribution.

Generation O&M:

(5A.4.1)

$$ERTOMN(ISECT=1) = (ERTOM + OVERPR + ERTOMF + OMLE) \cdot ESGNPD$$

where:

ERTOMN	=	operation and maintenance costs, excluding fuel cost, in nominal dollars
ISECT=1	=	sector is generation
ERTOM	=	real dollar production related variable operation and maintenance expenses
OVERPR	=	real dollar production and maintenance expenses allocated to the production function (e.g., general and administrative)
ERTOMF	=	real dollar production related fixed O & M expenses
OMLE	=	real dollar O & M expenses associated with the life extension of the generating units
ESGNPD	=	inflation index to convert real dollars to nominal dollars

Transmission O&M:

(5A.4.2)

$$ERTOMN(ISECT=2) = (ERTOMT + OVERTR) \cdot ESGNPD$$

where:

ERTOMN	=	operation and maintenance costs, excluding fuel cost, in nominal dollars
ISECT=2	=	sector is transmission
ERTOMT	=	real dollar transmission operation and maintenance expenses

OVERTR	=	real dollar overhead-related O & M expenses allocated to transmission (e.g., general administration)
ESGNPD	=	inflation index to convert real dollars to nominal dollars

Distribution O&M:

Operation and maintenance costs are input to EFP from the distribution model being used to drive EFP. If necessary, these costs are inflated each year by a user-defined inflation rate.

(5A.4.3)

$$ERTOMN(ISECT=3) = (ERTOMD + OVERDS) \cdot ESGNPD$$

where:

ERTOMN	=	operation and maintenance costs, excluding fuel cost, in nominal dollars
ISECT=3	=	sector is distribution
ERTOMD	=	real dollar operation and maintenance expenses associated with distribution
ESGNPD	=	inflation index to convert real dollars to nominal dollars
OVERDS	=	real dollar overhead related O & M expenses allowed to distribution (e.g., general administration).

Depreciation for Financial Purposes (ERBDE):

Book depreciation is calculated using the straight-line method (net book value divided by remaining life):

(5A.5a)

$$ERBDE_y = (EBBKVL - EBABDE_{y-1})/(ESBKLF - (YEAR - EBSYR))$$

and

(5A.5b)

$$EBABDE_y = \sum_{i=EBSYR}^{y} ERBDE_i$$

for $y = EBSYR$ to $EBSYR + ESBKLF - 1$ (i.e., over service life of asset)

where:

$ERBDE_y$	=	book depreciation, year y
EBBKVL	=	book value of plant (includes any AFUDC).
$EBABDE_{y-1}$	=	accumulated book depreciation, previous year to year y
ESBKLF	=	book life of plant
YEAR	=	current year

EBSYR = year plant comes on line

$EBABDE_y$ = accumulated book depreciation, year y

The derivation of EBBKVL is discussed in Appendix 5A, Construction Work in Progress, (see Equation App5.A.7). When the plant retires (year EBSYR + ESBKLF), its book value is added to account ERBTIR and subtracted from EBABDE. This has the effect of removing the plant from the books. Further discussion of depreciation is provided below in Appendix 5B.

General Taxes for Regulatory Purposes (GENREG):

General taxes encompass all taxes except State and Federal income taxes. Among these taxes are gross receipts, FICA, payroll, property, and sales. It is assumed that these taxes each year will be a constant percentage of revenue requirements.

(5A.6) $$GENREG = EGTXRT \cdot ERRVRQ + ERPRTX + ERSLTX$$

where:

GENREG = general taxes for regulatory purposes

EGTXRT = gross receipts tax rate

ERRVRQ = revenue requirement

ERPRTX = property taxes

ERSLTX = sales tax

The gross receipts tax rate is an input which is calculated from base-year data (e.g., FERC Form 1, Form EIA-412). Including ERRVRQ on the right-hand side of the equation appears to make this discussion circular (i.e., ERRVRQ is a function of GENREG and GENREG is a function of ERRVRQ). However, the equations for ERRVRQ and GENREG (along with STAREG and FEDREG, discussed next) are part of a system of four linear equations with four unknowns. Using the method known as algebraic substitution, one can solve for the value of ERRVRQ. Discussion of this takes place below in the "Resolution of ERRVRQ "Circular" Argument" section. ERPRTX is modeled as an input fraction of book value, and ERSLTX is modeled as an input fraction of construction expenditures.

State Income Taxes for Regulatory Purposes (STAREG):

STAREG is equal to State taxable income for regulatory purposes multiplied by the State income tax rate:

(5A.7) $$STAREG = (ERRVRQ - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR$$

where:

STAREG	=	state income taxes for regulatory purposes
ERRVRQ	=	revenue requirement
ERTFLN	=	fuel expense
ERTOMN	=	operation and maintenance expense, excluding fuel costs
ERTDWO	=	depreciation for tax purposes, without acceleration
ERTIEX	=	interest expense
ESLLP	=	lease payment associated with sale/leaseback transactions
ESSTXR	=	State income tax rate

Interest Expenses (ERTIEX):

The total interest expense depends on the cost of debt and on the average amount of debt outstanding during the year.

(5A.7.1a)

$$ERTIEX = ERSIEX + ERLIEX$$

(5A.7.1b)

$$ERSIEX = ESRTST \cdot ESPRST \cdot \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

(5A.7.1c)

$$ERLIEX = ESEMDT \cdot ESPRLT \cdot \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

where:

ERTIEX	=	total interest expense
ERSIEX	=	short-term interest expense
ERLIEX	=	long-term interest expense
ESRTST	=	cost of short-term debt
ESPRST	=	fraction of capital structure made up by short-term debt
ERAMD	=	assets minus deferrals (equals amount that must be financed through debt or equity)
ERAMDL	=	assets minus deferrals from previous year
ESLPRC	=	net of tax sales proceeds from sale/leaseback transactions

ESEMDT	=	embedded cost of long-term debt
ESPRLT	=	fraction of capital structure made up by long-term debt

ESRTST, ESPRST, and ESPRLT are user inputs. ESEMDT is discussed above (See section above on *Embedded Cost of Long-Term Debt* and Equation 5A.2.1). ERAMDL for a given year is equal to ERAMD from the previous year. ERAMD is discussed in the next section and ESLPRC is discussed in Appendix 5D, Sale-Leaseback Transactions, below.

Assets Minus Deferrals (ERAMD):

ERAMD is the amount that must be financed by debt or equity.

(5A.7.2)

$$ERAMD = ERTUP + ERBCWP + ERWC + ERNFSN + EPIDEF - ERABDE - ERPRDF - ERDITC - EDISNT - ESLNDG$$

where:

ERTUP	=	total utility plant (see Equation 5A.1.1)
ERBCWP	=	booked construction work in progress (see Appendix 5A: Construction Work in Progress for further discussion)
ERWC	=	working capital (see Equation 5A.1.3)
ERNFSN	=	nuclear fuel stock (see Equation 5A.1.4)
EPIDEF	=	cumulative deferred phase-in revenues (see Appendix 5.E: Rate Phase-in Plans)
ERABDE	=	accumulated book depreciation (see Appendix 5.C: Depreciation)
ERPRDF	=	provision for deferred income taxes (see Appendix 5.B: Taxes)
ERDITC	=	deferred investment tax credits (see Appendix 5.B: Taxes)
EDISNT	=	net disallowed plant (see Appendix 5.E: Rate Phase-in Plans)
ESLNDG	=	net deferred gain from sale/leaseback transactions (see Appendix 5.D: Sale and Leaseback Transactions)

Federal Income Taxes for Regulatory Purposes (FEDREG):

FEDREG is equal to Federal taxable income (for regulatory purposes) multiplied by the Federal income tax rate, adjusted by several accounts reflecting timing differences between actual income taxes paid and regulatory income taxes:

(5A.8)

$$FEDREG = (ERRVRQ - ERTFLN - ERTOMN - GENREG - STAREG - ERTDRG - ERTIEX + ERCIDC - ESLLP) \cdot ESFTXR - ERFITC - ERAITC - ERFFDC - ERAFDC - EREDTF$$

where:

FEDREG	=	federal income taxes for regulatory purposes
ERRVRQ	=	revenue requirement
ERTFLN	=	fuel expense
ERTOMN	=	operation and maintenance expense, excluding fuel costs
GENREG	=	general taxes for regulatory purposes
STAREG	=	State income taxes for regulatory purposes
ERTDRG	=	tax depreciation expense for regulatory purposes
ERTIEX	=	interest expenses
ERCIDC	=	interest expenses capitalized for purposes of calculating Federal income taxes for regulatory purposes
ESLLP	=	lease payment associated with sale/leaseback transactions
ESFTXR	=	Federal income tax rate
ERFITC	=	generated investment tax credits (ITC) that are flowed through
ERAITC	=	amortization of deferred ITC
ERFFDC	=	generated tax savings from the debt portion of AFUDC that is flowed through
ERAFDC	=	amortization of deferred tax savings from the debt portion of AFUDC
EREDTF	=	excess deferred taxes flowed back to ratepayers

ERRVRQ on the right side of the equation is discussed below in the section: Resolution of ERRVRQ "Circular" Argument: ESFTXR is a user-supplied input. FEDREG includes the effects of the ITC or the tax savings due to the debt portion of AFUDC. These effects are captured with the variables ERFITC, ERAITC, ERFEDC, and ERAFDC.

Allowance for Funds Used During Construction (AFUDC) Offset (EROFFS):

When construction work in progress (CWIP) is allowed in rate base, the utility is allowed to earn a current cash return on all construction outlays. If CWIP is not allowed in rate base (i.e., AFUDC is capitalized) the utility is allowed to include an annual estimate of the net cost, for the period of construction, of funds used for construction purposes. These "allowances" are accumulated over the construction period of the project and are brought into the rate base as an addition to the value of the completed investment once the investment becomes operational. The third alternative of dealing with construction work in progress is the capitalized AFUDC offset method. For this procedure, CWIP is allowed in rate base and AFUDC is capitalized, but there is a corresponding offset to the return on rate base equal to the amount of the capitalized AFUDC.

The AFUDC offset is calculated as:

(5A.9) $$EROFFS_y = AFUDC_y \cdot ESRBAF$$

where:

$EROFFS_y$	=	AFUDC offset, year y.
$AFUDC_y$	=	AFUDC year y
ESRBAF	=	Percent of AFUDC/CWIP which receives offset treatment

See Appendix 5.A: Construction Work in Progress below for further discussion.

Net Lease Payments Associated with Sale/Leaseback Transactions (ESLLPN):

The sale and leaseback of an electric plant by a utility is a creative way for the utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position, benefitting both investors and ratepayers. Regulators treat the rental payment as operating expenses, and the utility's revenue requirement no longer includes the return on capital or depreciation expense associated with the plant. The result is a flat revenue requirement over time, lower than conventional cost recovery in the short term, and higher toward the end of the lease.

(5A.10) $$ESLLPN = ESLLP - ESLAGN$$

where:

ESLLPN	=	net lease payment
ESLLP	=	annual lease payment
ESLAGN	=	amortization of gain

See Appendix 5.D: Sale and Leaseback Transactions for further discussion.

Net Deferred Phase-in Costs (EPIND):

Under tradition cost-of-service, rate-of-return regulation, the rate impacts of the capital costs of a new asset coming on line are greatest in its first year of service and decline thereafter over the life of the asset. Historically, the large increase in capital costs associated with a new plant were substantially, if not totally, offset by the lower operating costs obtained by utilizing the new unit.

Sometimes, however, the costs of building a new power plant are not offset by lower operating costs. This has occurred when energy commodity prices are low, new power generation technologies are not much more efficient than previous technologies, a utility has overbuilt capacity, and/or the cost to finish a plant build is higher than expected, such as with many nuclear facilities. To decrease the impact of such new plant builds to the ratepayer, some of the early capital costs are deferred and phased-in more evenly over the life of the asset.

(5A.11) $$EPIND = EPIND + DEFCST$$

where:

EPIND	=	net (pre-tax) deferred costs
DEFCST	=	deferred (after tax) costs

See Appendix 5.E: Rate Phase-In Plans below for a more detailed description of rate phase-in plans and derivation of EPIND and DEFCST.

Nuclear Decommissioning:

The data required for each nuclear plant consists of eleven fields. Each data record describes a nuclear unit or a plant containing more than one unit (only if unit parameters are similar and utility-owner did not specify data by unit). The database is input into NEMS in the phasein input data file.

After the data is input, the nuclear decommissioning methodology consists of three steps:

1. calculate estimates of missing data
2. initialize all data to start year of NEMS (1990)
3. perform annual calculations

Each of the steps is discussed below.

Calculate Estimates of Missing Data:

The input database for each nuclear unit includes the balance of the fund as well as the most recent annual payment into the fund. As described above, for some nuclear units, this information was not available. For units where the information is not available, the values must be estimated. This information is estimated in this step under the assumption that the payment patterns for these units is similar to the average pattern observed for all units for which data is available.

Initialize All Data to Start Year of NEMS (1990):

The total estimated decommissioning costs, fund balances, and fund payments for each nuclear unit are derived from the most recent data available. The purpose of this step is to adjust these inputs to reflect values applicable to 1990 (beginning of the year). This adjustment includes the impact of escalation and inflation which occurs between the beginning of 1990 and the date for which input values actually apply.

Perform Annual Calculations

For each forecast year, the fund balance for each unit is calculated as:

(5A.12) $$Balance_y = Balance_{y-1} + Earnings_y - Tax_y - (Administrative\ Cost)_y + Payment_y$$

where the fund payment is calculated in one of two ways:

1) For years before the early retirement year (if applicable) and before the input "catch up" year, the payment is calculated as the input payment adjusted for inflation.

2) For all other years, the payment is calculated as the annuity payment necessary over the remaining period of collection (i.e., through the year of retirement plus any input maintenance period) to result in a fund balance sufficient to pay the current estimated decommissioning costs. Note that this calculation does not take into account any future real escalation in decommissioning costs nor any early retirement of the unit. As this escalation occurs in each subsequent year, the payment will rise accordingly. Only when the year of retirement is reached does the fund payment rise to reflect the shorter collection period.

Within the model, each annual fund payment can be covered by one of three sources of funds within the model: (1) the ratepayers, (2) the equity holders, or (3) the government. The methodology assumes that the total fund payment will continue to be collected from the ratepayers until the earlier of "catch up" year or an early retirement year. The increase in payment that occurs in either of these years is shared between the three sources according to the input shares. Any monitoring costs are assumed to be recovered from the ratepayers as they are incurred.

Resolution of ERRVRQ "Circular" Argument:

The following four equations have been presented:

(1) ERRVRQ = . . . + GENREG + STAREG + FEDREG + . . . (see Equation 5A)
(2) GENREG = EGTXRT * ERRVRQ + . . . (see Equation 5A.6)
(3) STAREG = (ERRVRQ - . . .) * ESSTXR (see Equation 5A.7)
(4) FEDREG = (ERRVRQ - . . . - STAREG - GENREG) * ESFTXR (see Equation 5A.8)

In the somewhat linear presentation above, these equations seem to present a circular argument. (ERRVRQ is a function of GENREG, STAREG, and FEDREG, but also the later variables depend on ERRVRQ.) This specification, of course, is not really a problem. The above is just a system of four linear equations with four unknowns. Using the method known as algebraic substitution, one can solve for the value of ERRVRQ, as follows:

First, the above equations (5A.6), (5A.7), and (5A.8) can be substituted into equation (5A) to yield:

(5Aa)
$$\begin{aligned} ERRVRQ = \ & \ldots + ERRVRQ \cdot EGTXRT + (ERRVRQ - \ldots) \cdot ESSTXR \\ & + (ERRVRQ - \ldots - STAREG - GENREG) \cdot ESFTXR \end{aligned}$$

Next, substituting equations (5A.6) and (5A.7) into the above equation and gathering like terms yields:

(5Ab)

$$ERRVRQ = \ldots + ERRVRQ \cdot EGTXRT \cdot (1 - ESFTXR) + (ERRVRQ - \ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (ERRVRQ - \ldots) \cdot ESFTXR$$

Next, moving all terms on the right hand side of the equation that contain the variable ERRVRQ to the left hand side yields:

(5Ac)

$$ERRVRQ \cdot (1 - EFTXRT \cdot (1 - ESFTXR) - ESSTXR \cdot (1 - ESFTXR) - ESFTXR) = \ldots + (- \ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (- \ldots) \cdot ESFTXR$$

Finally, dividing the equation on both sides by the constant on the left hand side yields:

(5Ad)

$$ERRVRQ = \frac{\ldots + (- \ldots) \cdot ESSTXR \cdot (1 - ESFTXR) + (- \ldots) \cdot ESFTXR}{1 - EGTXRT \cdot (1 - ESFTXR) - ESSTXR \cdot (1 - ESFTXR) - ESFTXR}$$

This equation yields a unique value for ERRVRQ. This value can then be substituted back into equations (5A.6), (5A.7), and (5A.8) to yield values for the remaining variables.

5B. Competitive Pricing Algorithm

As proposed by W. Vickrey in 1971, spot or responsive pricing allows for economically optimal behavior by each customer and avoids system overload without having to resort to rationing because the price of electricity increases or decreases as system conditions change.[85] True spot prices are set and communicated by suppliers of electricity services (or other services) instantaneously. Different prices can be set for each customer location at each moment or a day ahead.

This section documents the modifications necessary to allow the calculation of spot prices for generation. The prices do not indicate the locational variations that one would expect from true spot prices, which would result from localized network congestion and other phenomena.

It is well known that the optimal spot price is equal to the marginal cost of electricity. In this model, the costs of generation to be covered comprise (1) the marginal operating costs, including maintenance and marginal general and administrative (G&A) costs, (2) taxes, and (3) a reliability

[85]R.E. Bohn, M.C. Caramanis, and F.C. Schweppe, "Optimal Pricing in Electrical Networks Over Space and Time," *Rand Journal of Economics* (Autumn 1984).

price adjustment equal to the marginal cost of unserved energy. Since transmission and distribution are assumed to remain regulated, the total price is the sum of the generation costs and no changes were made in the calculation of the average transmission and distribution costs. There is no explicit representation of capital recovery in the competitive price of electricity generation, as capital and all other costs must be recovered from the difference between the market clearing price and the operating cost of each unit. The following is a description of three components of the competitive spot prices calculated in this model.

In summary, the spot price of electricity under competition is represented as:

(5B)

$$Pcomp_{ryt} = E_{ryt} + C_{ryt} + GA_{ry} + Tax_{ryt} + TD_{ry}$$

where:

$Pcomp_{ryt}$ = the competitive price of delivered electricity in region r, year y, period t (cents per kilowatthour),

E_{ryt} = the marginal short-run operating cost in region r, year y, period t (variable operating costs of the last plant dispatched in period t, in cents per kilowatthour),

C_{ryt} = the reliability adjustment of price in region r, year y, period t (cents per kilowatthour),

GA_{r} = general and administrative costs related to generation in period t for region r, year y (cents per kilowatthour),

Tax_{ryt} = recovery of Federal income taxes and all other taxes in region r, year y, period t (cents per kilowatthour), and

TD_{ry} = average transmission and distribution costs in region r, year y (cents per kilowatthour).

The marginal production costs are based on estimates of the marginal costs of generation. Some costs, including fuel, other consumables, and some maintenance vary directly with the hour by hour level of output of a plant. The competitive price then includes the marginal short-run operating costs; that is the operating cost of the last plant dispatched (assumed to be the most expensive plant running) in each of the 36 time periods used in the EFD submodule.

The marginal production costs include more than just the operating costs listed above. Over the mid-term, these costs—primarily maintenance costs and overhead expenses—do change with the level of output and are therefore variable. Since the G&A (or overhead) costs are avoidable over the mid-term, they must be recovered over the course of the year or it would not pay to keep the plant running. All taxes other than Federal income taxes (i.e., State income taxes, sales taxes, and property taxes) are aggregated and treated as a gross receipts tax (revenue tax).

The reliability price adjustment reflects the cost of maintaining a margin of safety for generation to meet electricity demand. Such a cost can be quantified in several ways.[86] This model evaluates the reliability price adjustment on the basis of estimates of the marginal cost of expected unserved energy. It is assumed that consumers will curtail electricity usage when the spot price of electricity exceeds their cost of unserved energy. The cost of unserved energy may be revealed through energy service contracting mechanisms, where consumers are offered varying levels of reliability (greater or lower probability of a service interruption) for varying contract prices, and through behavioral responses to spot prices by spot market participants.

Marginal unserved energy is the quantity of unserved energy satisfied by the last (or marginal) unit of generating capacity. Unserved energy is the difference between supply and demand during periods when, at a given price, demand exceeds supply. Expected unserved energy is a derived quantity based on the expectation of the joint stochastic distribution of supply and demand. Expected unserved energy does not imply a system failure. Rather, it is an expected value calculated from an uncertain amount of generating capacity and an uncertain level of demand for each pricing period.[87]

In this model, the expected amount of unserved energy for each region for each dispatching period is calculated from the following inputs:

1. The capacity of each generating plant in each region for each season of the year (total capacity adjusted by planned outages)
2. An estimate of the probability of a forced outage for each plant
3. Stochastic hourly load data (projections of demands with an uncertainty factor that creates probability distributions from the deterministic values for demand).

The cost of unserved energy (or value of unserved energy) is an input assumption, because the value of unserved energy is difficult to estimate. The costs for consumers can vary widely. Estimates range from $2 to $25 per kilowatthour and are affected by the type of consumer, the timing of service curtailment, the length of the interruption, and the amount of warning before curtailment begins. For example, an outage without warning during the dinner hour is much more expensive for a restaurant owner than it is for most residential consumers. Hence, a restaurant owner (and commercial consumers in general) would be willing to pay more for reliable electric power than would most residential consumers. Further, a disruption is more costly if it lasts for a longer period of time and creates costs associated with food spoilage, prolonged loss of residential heating and cooling, and the like.

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[86]See F.C.Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic Publishers, 1988), p. 136. Another method to quantify this component is to use a market-clearing approach, also described in Chapter 6 of Schweppe et al.

[87]Expected unserved energy calculations are performed for the system in its current state and for the system augmented by a small amount of capacity (perhaps equal to a small turbine). These calculations yield the reduction in unserved energy for each kilowatt of additional capacity that is brought into service or, stated another way, the change in unserved energy relative to a change in capacity (marginal unserved energy).

As mentioned above, competitors may have the means to determine the value of unserved energy through the price discovery role of competitive markets. If the revealed cost to consumers of an outage is actually lower than the assumed value that system planners have traditionally used, it means that reserve margins may fall. Lower reserve margins could have important implications for system operating costs and electricity prices.[88]

Mathematically, the reliability adjustment of price is represented as:

(5B.1)

$$C_{ryt} = \left(\frac{\partial UE}{\partial G} \right)_{ryt} \cdot V(UE) \quad ,$$

where:

C_{ryt} = reliability adjustment of price, year y, pricing period t for region r (cents per kilowatthour),

$\left(\frac{\partial UE}{\partial G} \right)_{ryt}$ = change in unserved energy with respect to a change in generating capacity (reduction in unserved energy that results from an increase in capacity) in region r, year y, dispatch period t (kilowatthours per kilowatt per hour), and

V(UE) = assumed value of a kilowatthour of unserved energy (cost to consumers of a kilowatthour of electricity during a blackout, in cents per kilowatthour).

The reliability adjustment of spot prices for each pricing period, region, and year of the projection is calculated by multiplying the change in unserved energy per kilowatt of additional generating capacity (marginal unserved energy), calculated as described in the previous paragraphs, multiplied by the assumed value of unserved energy.

Modifications to three submodules were needed to calculate competitive prices. The capacity cumulants are calculated in subroutines ELEFD and ELRNEW of the fuel dispatch module; demand cumulants are calculated in subroutine DSMEFD of the load and DSM submodule. The reliability component is a function of the capacity and demand cumulants in each slice. All of the subsequent calculations were performed in the electricity pricing submodule. The calculation of the reliability component for each slice is performed in subroutine ELREL . This calculation is described in detail in Appendix 5.F, Functional Description Calculation of the Reliability Component. The total price for each slice is summed in subroutine COMPPRC. Annual prices for each of the end-use service are calculated in subroutine RATES2. These prices were modified to reflect the transition to full competition, sectoral adjustments and converted to Census division level in the subroutine ELSET. Furthermore, subroutine REVGAP was added to summarize the relationship between revenues and total costs for each region. Finally, subroutine RATES was modified to include the transition price

[88]Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996), p. 30.

freezes and reductions in competitive regions, as well as the large amount of California load effected through 2010 by long-term contract prices as negotiated by the California Department of Water Resources in 2001. The changes in rates are described in greater detail below in the following sections: Remaining Algorithms, Price of Electricity: *Electricity Pricing During the Transition to Competition* and *Modifications for California*

5C. Remaining Algorithms

Section 5A of this section described the EFP algorithms used to forecast the major components of revenue requirements to forecast regulated electricity prices based on average cost calculations, while Section 5B of this section described how to calculate competitive prices. This section describes the remaining algorithms which are used to yield forecasts of electric revenues, allocation of costs to customer classes, the regulated price of electricity, taxes (both current and for financial purposes), financial ratios, and other miscellaneous items.

Electric Revenues:

Electric revenues are a function of revenue requirements and the regulatory lag. Regulatory lag can result from the situation where electric utility rates (and thus revenues) are based on costs from a historical test year rather than on costs from the period during which the rates are in effect. EFP calculates electric revenues under five different assumptions: i) no lag, ii) 1-year lag, iii) one-quarter-year lag, iv) one-half-year lag, and v) three-quarter-year lag.

In a no-lag scenario, rates are based on current year experiences and rate base so that electric revenues are equal to the revenue requirements calculated in part 1 above:

(5C.1)

$$ERRVLG = ERRVRQ$$

where:
ERRVLG = electric revenues
ERRVRQ = revenue requirements

In a 1-year lag scenario, electric revenues are calculated as follows:

(5C.2)

$$ERRVLG_y = [(ERRB'_{y-1} \cdot ESRR_y) + ERTOMN_{y-1} + ERBDE_{y-1} + GENREG_{y-1} + STAREG_{y-1} + FEDREG_{y-1} - EROFFS_{y-1} + ESLLPN_{y-1} - EPIND_{y-1}] \cdot EQTLSL_y / EQTLSL_{y-1} + ERTFLN_y$$

where variables are same as in part 1 above, except:
$ERRB'_{y-1}$ = $ERRB_{y-1} + (EBRCWP_y - EBRCWP_{y-1})$
$EQTLSL_y$ = total sales of electricity, year y.

This equation is similar to the equation for revenue requirements presented in 5C.1 above. However, the variables are lagged by 1 year, with some exceptions. First, the rate base differs from the previous year's rate base by the difference in the amount of CWIP allowed in rate base. This reflects the fact that the amount of CWIP in rate base is determined by order in each rate case and does not reflect a historically observed value. Similarly, the rate of return on rate base is not the previous year's value,

but instead reflects the regulatory commission's current finding on the appropriate return. Next, a factor equal to the ratio of current-year sales to previous-year sales is present because the rates are based on historical expenses and sales, but will be collected on the current year sales. Finally, fuel costs are not lagged, but instead recovered as they are incurred. The overall approach is that the price of electricity is comprised of two parts — a fuel cost (recovered through an instantaneously adjusting fuel adjustment clause) and base rates set in rate hearings.

Weighted averages of the revenues under the no-lag and 1-year lag cases are used in the other scenarios (e.g., one-half-year lag).

Forecast sales of electricity are passed to EFP from the dispatch module (EFD).

Allocation of Costs to Customer Classes:

Costs are functionalized by stage of production and classified as capital related, fixed O&M, variable O&M, or fuel for each modeled region. Each of these categories may be allocated to the various customer classes using any of the following methods (depending on which method is generally used for the particular cost category):

Sales Method:

Costs are allocated on the basis of the proportion of total sales to the class as follows:

(5C.3a) $$DEMFAC1_j = SALCLS_j / SALTOT$$

where:

$DEMFAC_n$ = the factor for allocating costs to customer class j

SALCLS = the total sales of electricity to class j

SALTOT = the total sales of electricity to all classes

Coincident Peak Method:

Costs are allocated on the basis of each customer class's contribution to the system peak load:

(5C.3b) $$DEMFAC5_j = SECANNUALPEAK1_j / TOTAL$$

where:

$SECANNUALPEAK1_j$ = the load attributable to customer class j at the time of the system peak

TOTAL = the total load on the system at the time of system peak

Probability of Contribution to Peak:

Costs are allocated on the basis of the average contribution to system peak of the customer class over a number of previous model years:

(5C.3c) $$DEMFAC6_j = SECANNPEAAVPCP_j / TOTAL$$

where:

$SECANNPEAAVPCP_j$ = the average contribution to the system peak of customer class j over a number of previous model years

TOTAL = the sum of the average contributions to the system peaks of all customer classes over a number of previous model years

Non-Coincident Peak Method:

In this method, costs are allocated on the basis of the proportion of the load of each customer class at the time of the customer class peak, divided by the sum of the customer class peaks:

(5C.3d) $$DEMFAC7_j = SECANNUALPEAK2_j / TOTAL$$

where:

$SECANNUALPEAK2_j$ = the load of customer class j at the time of the peak load of customer class j

TOTAL = the sum of the customer class loads at the time of the peak for each individual customer class (non-coincident peak)

Average and Excess Demand Using Coincident Peak:

Costs are allocated using a combination of the sales method (average demand) and the coincident peak (excess demand). The proportion of costs equal to the level of the system load factor is allocated on the basis of the sales method. The remaining costs are allocated on the basis of the coincident peak method:

(5C.3e) $$DEMFAC8_j = (SYSTEMLF \cdot DEMFAC1) + [(1 - SYSTEMLF) \cdot DEMFAC5]$$

where:

SYSTEMLF = the system load factor

Average and Excess Demand Using Probability of Contribution to Peak:

This method is the same as that described above except that the proportion of costs in excess of the system load factor is allocated on the basis of the probability of contribution to peak instead of the coincident peak method:

(5C.3f) $$DEMFAC9_j = (SYSTEMLF \cdot DEMFAC1) + [(1 - SYSTEMLF) \cdot DEMFAC6]$$

Allocation of Costs to Customer Classes:

Finally, all of the methods used for allocating each cost category (each cost type—capital, fuel, etc.—by stage of production) are summed for each of those cost categories:

(5C.3.1) $$COSTFC_{kjl} = \sum DEMFAC_{nj} \cdot TECFAC_{nkl}$$

where:

$COSTFC_{kjl}$= the sum of all allocation proportions for cost type k, customer class j, and stage of production l

$DEMFAC_{nj}$ = allocation proportion using method n for customer class j

$TECFAC_{kjl}$= the proportion of cost type k to be allocated using method n for stage of production l

and revenues are allocated to the class:

(5C.3.2) $$REV_{jl} = COSTFC_{kjl} \cdot COST_{kl}$$

where:

REV_{jl} = the revenues allocated to customer class j for stage of production l

$COST_{kl}$ = the cost type k (classified cost) for stage of production l (functionalized cost)

Price of Electricity:

With electric revenues forecast and allocated, the forecast price of electricity is straightforward:

Price Calculation:

(5C.4) $$EPRICE_{jl} = REV_{jl} / SALCLS_j$$

where:

$EPRICE_{jl}$ = the price of electricity for customer class j and stage of production l

REV_{jl} = electric revenues allocated to customer

SALCLS = sales to customer

Benchmark/Subsidization Calculation:

Once the price of electricity has been calculated for each customer class and region at the distribution stage of production, the computed prices for the residential, commercial, and industrial sectors are compared to historic prices for benchmarking and subsidy calculation.[89] The prices for transportation are not benchmarked because (1) there is no relevant historic price for off-peak electric vehicles, and (2) the proportion of costs allocated to this class is very small. Differences in the modeled prices and historic prices may be due to differences between the modeled allocation techniques and those being used in practice, and they may be due to customer class cross-subsidization where one customer class's cost allocation is increased or decreased for the purpose of accommodating another class. This benchmarking/subsidization routine is as follows:

First, the historic and modeled proportions of revenues to each of the three classes are determined. Historic proportions are:

(5C.4.1a) $$REVHPCT_{jy} = REVH_{jy}/REVHRCI_{y}$$

where:

$REVHPCT_{jy}$ = the actual proportion of revenues allocated to customer class j in year y

$REVH_{jy}$ = the actual revenues allocated to customer class j in year y

$REVHRCI_{y}$ = the actual total revenues allocated to all three classes in year y

The modeled proportions are:

(5C.4.1b) $$REVPCT_{jy} = REV_{jy}/REVRCI_{y}$$

where:

$REVPCT_{jy}$ = the modeled proportion of revenues allocated to customer class j in year y

REV_{jy} = the modeled revenues allocated to customer class j in year y

[89]This benchmarking/subsidization technique is not used for the generation or transmission transfer price calculations.

$REVRCI_y$ = the modeled total revenues allocated to all three classes in year y

The historic proportion of sales attributable to each customer class is:

(5C.4.2a) $$SLSHPCT_{jy} = SALY_j / SLSHRCI_y$$

where:

$SLSHPCT_{jy}$ = the actual proportion of sales to customer class j

$SALH_{jy}$ = the actual sales to customer class j in year y

$SLSHRCI_y$ = the actual sales to all three classes in year y

The modeled proportion of sales is:

(5C.4.2b) $$SLSPCT_{jy} = SALCLS_{jy} / SLSRCI_y$$

where:

$SLSPCT_{jy}$ = the modeled proportion of sales to customer class j in year y

$SALCLS_{jy}$ = the modeled sales to customer class j in year y

$SLSRCI_y$ = the modeled sales to all three classes in year y

These ratios are then used to calculate the implied subsidy to be used to benchmark/subsidize customer class prices while controlling for differences in the level of actual sales to each customer class and modeled sales to each customer class:

(5C.4.3) $$SUBPCT_j = (REVHPCT_j - SLSHPCT_j) - (REVPCT_j - SLSPCT_j)$$

where:

$SUBPCT_j$ = the implied percent of subsidy for customer class j

$REVHPCT_j$ = the actual proportion of revenues allocated to customer class j

$SLSHPCT_j$ = the actual proportion of sales to customer class j

$REVPCT_j$ = the modeled proportion of revenues allocated to customer class j

$SLSPCT_j$ = the modeled proportion of sales to customer class j

Calculation of Prices with Benchmarking and Subsidization:

After the benchmarking/subsidization proportion has been calculated, it is multiplied times the total revenues allocated to the three benchmarked/subsidized customer classes to determine the revised

allocation to each class. This revised allocation is again divided by sales to the class to determine the revised price:

(5C.4.4)

$$EPRICE_j = (REV_j + (REVRCI \cdot SUBPCT_j))/(SALCLS_j)$$

where:

$EPRICE_j$ = the benchmarked/subsidized price of electricity to customer class j

REV_j = the costs (revenues) allocated to customer class j before the benchmarking/subsidization routine

REVRCI = total costs allocated to the three customer classes

$SUBPCT_j$ = benchmarking/subsidy percent for customer class j

$SALCLS_j$ = electricity sales to customer class j

Sectoral Pricing Under A Competitive Generation Scenario:

It is assumed that in a competitive generation market, prices will be divided among customer classes (sectors) differently than under a regulated market. **Specifically, large customers are expected to have more opportunities to leave the grid than previously. If firms with large loads leave the grid, the price of distribution will be increased for those customers who must continue to buy on-grid electricity. It is assumed that regulators of distribution utilities will thus be more likely to offer these large customers lower distribution prices to entice them to continue to buy on-grid energy.** For restructured regions, a modified Ramsey pricing scheme is implemented. The economic principles underlying the valuation are described below.

Suppose that the regulator sets prices for the firm so it maximizes a weighted sum of consumer surpluses over the customer classes served by the firm. For simplicity, we model two customer classes. Specifically, assume there are two customer classes and the decision maker maximizes the function $\theta_1 CS_1 + \theta_2 CS_2$, where CS_i is the consumer surplus of customer class I and θ_i is the weight that the decision maker attaches to I's level of welfare. The case where the decision maker is indifferent to the welfare of I is represented by $\theta_i = 0$. The case where the economic interests of I are twice as important as those of j can represented as by $\theta_i = 4/3$ and $\theta_j = 2/3$ while the case where I's interests are three times more "important" than j's would be represented by $\theta_i = 1.5$ and $\theta_j = .5$.

Our model is then:

(5C.4.5a)

$$Max \quad \theta_1 CS_1 + \theta_2 CS_2$$

such that:

(5C.4.5b) $$P_1X_1+P_2X_2-C(X_1,X_2) = 0.$$

This merely states that the regulator attempts to maximize the weighted consumer surplus subject to the constraint that the revenues for the regulated utility must equal its costs. This maximization problem may be solved through the application of Lagrange multipliers. The solution is:

(5C.4.5c) $$\frac{P_i-C_i'}{P_i}=\frac{1-\theta_i/\lambda}{|\varepsilon_i|},$$

where ε_i is sector I's price elasticity of demand, λ is a scalar to preserve feasibility of the solution, and $C_i' = \partial C(X_1, X_2)/\partial X_i$ is the marginal cost of production. Inspection of 5C.4.5c reveals that the price-cost margin varies inversely with the absolute value of the price elasticity of demand. It also indicates that regulatory preferences will affect the margin between price and marginal cost. Specifically, if the decision-maker attaches zero weight to the interests of customer class I, then θ_i is zero in which case the price cost margin reduces to $1/|\varepsilon_i|$, a level equivalent to the unconstrained monopoly solution.

Now assume that the electricity is distributed by a regulated natural monopolist. We have three sectors: residential, commercial and industrial. Each sector purchases X_i (where X_i equals $\sum x_{f,i}$) from the generating industry at the price PG_i per unit. Assume the total cost of distribution is related to the amount of power distributed to each sector, i.e. the total cost of distribution is $C^D(X_1^S, X_2^S, X_3^S)$ where X_i^S is the amount of power that the distributor delivers to sector I through its system. The industrial and commercial sectors are assumed to have the threat of by-pass; that is, the ability to leave the system through self-generation or other means. We let $X_I^S = X_I - X_I^B$. Let η represent the elasticity of nongrid supply, i.e. $\eta = (\partial X_2^B/\partial P_2)(P_2/X_2^B)$, and S_I^D be the share of total generation purchased by the industrial sector that uses the distribution system, i.e., $S_2^D = X_2^S/X_2$. In contrast, the residential sector must purchase all of its power through the local distribution system. Assume that the amount of power bypassed is positively related to the end use price of electricity, i.e. $\partial X_2^B/\partial P_2 > 0$ where P_2 is the total end use price. Finally, assume that the end-use price is the sum of the generation price (PG_I) and the distribution charge (PD_I).

Based on the above discussion, the decision maker is assumed to maximize the function:

(5C.4.6a) $$L=\theta_R CS_R + \theta_C CS_C + \theta_I CS_I + \lambda[PD_R X_R^S + PD_C X_C^S + PD_I X_I^S - CD(X_R^S, X_C^S, X_I^S)]$$

For the customers in the residential sector , $X_j^S = X_j$, and thus the following result can be obtained:

(5C.4.6b)

$$PD_j = \frac{CD_j' |\epsilon_j| + PG_j(1-\theta_j/\lambda)}{|\epsilon_j| - (1-\theta_j/\lambda)}$$

Customers in the industrial and commercial sectors are assumed to have the option to bypass the distribution system and thus, for instance, $X_I^S = X_I - X_I^B$. Let η represent the elasticity of nongrid supply, i.e. $\eta = (\partial X_I^B / \partial P_I)(P_I/X_I^B)$, and S_I^D be the share of total generation purchased by sector I that uses the distribution system, i.e., $S_I^D = X_I^S/X_I$.

Assuming that the regulator sets the price of distribution under the belief that price of generation does not change as a result of his action, one can solve the constrained system to find:

(5C.4.6c)

$$PD_I = \frac{\frac{CD_I'}{S_D}[|\epsilon_I| + \eta(1-S_D)] + PG_I(1 - \theta_I/\lambda)}{\frac{1}{S_D}[|\epsilon_I| + \eta(1-S_D)] - (1 - \theta_I/\lambda)}$$

It is known that revenues must equal costs. Therefore:

(5C.4.7a)

$$REV = \sum_1^3 \left(\frac{\frac{CD_I'}{S_D}[|\epsilon_I| + \eta(1-S_D)] + PG_I(1 - \theta_I/\lambda)}{\frac{1}{S_D}[|\epsilon_I| + \eta(1-S_D)] - (1 - \theta_I/\lambda)} \right) Q(I)$$

where:

REV = total revenues required for transmission and distribution,

Q(I) = total consumption in sector I, and

S_D, CDI', ϵ_I, η, and θ_i are all known.

This is cubic in λ. The model then expresses λ as the polynomial equation:

5C.4.7b)

$$coff(1)*\lambda^3 + coff(2)*\lambda^2 + coff(3)*\lambda + coff(4) = 0.$$

Defining:

(5C.4.7c)

$$\alpha(i) = newtd/Sdval** + (eps(I) + nuval*(1-Sdval)) + PG(I)$$
$$\beta(i) = -1*pg(I)*\theta(I,NERC)$$
$$\gamma(I) = (eps(i) + nuval*(1-Sdval))/Sdval - 1$$

Where:

newtd = marginal cost of T&D,

Sdval = fraction of consumption available for bypass,

Eps(I) = Elasticity of consumption for sector I,

Nuval = Elasticity of bypass for sector I,

PG(I) = Generation price to sector I,

NERC = NERC region.

(5C.4.7d)

$$\begin{aligned} COFF(1) = {} & totrev * \theta(1,NERC) * \theta(2,NERC) * \theta(3,NERC) \\ & - \beta(1) * (Q(1) + transal) * \theta(2,NERC) * \theta(3,NERC) \\ & - \beta(2) * Q(2) * \theta(1,NERC) * \theta(3,NERC) \\ & - \beta(3) * (Q(3)) * \theta(2,NERC) * \theta(1,NERC) \end{aligned}$$

where:

totrev = total revenues required for T&D,

Q(I) = consumption of electricity in sector I, and

Transal= consumption of electricity in transportation sector.

(5C.4.7e)

$$\begin{aligned} COFF(2) = {} & totrev * (\theta(1,NERC) * \theta(3,NERC) * \gamma(2) \\ & + \gamma(1) * \theta(2,NERC) * \theta(3,NERC) + \theta(1,NERC) * \theta(2,NERC) * \gamma(3)) \\ & - (Q(1) + transal) * (\alpha(1) * \theta(2,NERC) * \theta(3,NERC) \\ & + \beta(1) * \gamma(3) * \theta(2,NERC) + \beta(1) * \gamma(2) * \theta(3,NERC)) \\ & - Q(2) * (\alpha(2) * \theta(1,NERC) * \theta(3,NERC) + \beta(2) * \gamma(3) \\ & * \theta(1,NERC) + \beta(2) * \gamma(1) * \theta(3,NERC) \end{aligned}$$

(5C.4.7f)

$$\begin{aligned} COFF(3) = {} & totrev * (\theta(1,NERC) * \gamma(2) * \gamma(3) + \theta(2,NERC) * \gamma(1) * \gamma(3) \\ & + \theta(3,NERC) * \gamma(1) * \gamma(2)) - (Q(1) + transal) * (\alpha(1) * \gamma(3) * \theta(2,NERC) \\ & + \alpha(1) * \gamma(2) * \theta(3,NERC) + \beta(1) * \gamma(2) * \gamma(3)) \\ & - Q(2) * (\alpha(2) * \gamma(3) * \theta(1,NERC) + \alpha(2) * \gamma(1) * \theta(3,NERC) + \beta(2) * \gamma(1) * \gamma(3)) \\ & - (Q(3)) * (\alpha(3) * \gamma(2) * \theta(1,NERC) + \alpha(3) * \gamma(1) * \theta(2,NERC) + \beta(3) * \gamma(1) * \gamma(2)) \end{aligned}$$

(5C.4.7g)

$$\begin{aligned} COFF(4) = {} & totrev * \gamma(1) * \gamma(2) * \gamma(3) - \alpha(1) * (Q(1) + transal) * \gamma(2) * \gamma(3) \\ & - \alpha(2) * Q(2) * \gamma(1) * \gamma(3) - \alpha(3) * Q(3) * \gamma(1) * \gamma(2) \end{aligned}$$

A Newton-Raphson iterative method is used to solve for λ. Given λ, Equation 5C.4.7.e may be solved directly. This gives the T&D price for each sector.

This equation represents the optimal pricing strategy by the regulator. As long as the price of distribution is above marginal cost, it is worthwhile to continue to supply service. As the share of non-grid service decreases, the price approaches that which might be set if no by-pass were available. This model gives a framework for analysis given a regulated distribution system and customers with different elasticities and abilities to avoid the distribution system.

Given λ, equations of the form of 5C.4.7g are then solved for the T&D cost for each sector, which is added to the generation price to produce the total regional price.

The generation price PG_I, the total consumption by sector, and total revenue requirement for T&D are all calculated endogenously by region. Only the initial and final projection value of the national level of bypass are exogenous. Calculation of SDVAL, the fraction of load available for bypass in each region for each year of the projection is described below.

Calculation of Annual Bypass:

Only the national bypass fraction is an exogenous input. Shares of bypass are then calculated. At the national level, the share of bypass in year y for sector j is projected to be equal to its share in 2020 multiplied times a logistical market penetration factor:

(5C.4.8a)
$$Nationalshr(j,t) = Nationalshr(j,2020) * \frac{(\exp(y - midyear))}{(1 + \exp(y - midyear))}$$

where:

midyear = midpoint of forecast, and

Nationalshr(j,y) = share of bypass in sector j year y.

The regional share of bypass must then be determined. There are two essential factors that will shape the regional distribution of self-generation: the price of electricity from the grid relative to its marginal cost and the average level of consumption per customer. These parameters are used to calculate the regional share of the total national bypass by:

(5C.4.8b)
$$allocationweight(j,r) = \frac{\ln(Markup(j,r) + \ln(Consfactor(j,r)}{\sum_r [\ln(Markup(j,r) + \ln(Consfactor(j,r)]}$$

where:

Markup(j,r) = markup of the generation price over marginal cost for sector j in region r

Consfactor(j,r) = ratio of average consumption per customer in sector j in region r relative to the average consumption for sector j over all regions.

Furthermore, all of the regional shares must sum to the national share of consumption that may use bypass. A normalization factor is then calculated by:

(5C.4.8c)

$$Normalizationfactor(j,t) = \frac{Nationalshr(j,t)}{\sum_r conshr(j,r,y) * allocationweight(j,r)}$$

where:

conshr(j,r,y) = share of sector j's national consumption in region r, year y.

This aggregate projection for the sector is used to calculate a factor for the region based on the region's consumption and its allocation weight:

It follows that the bypass share will be:

(5C.4.8d)

$$bypassshr(j,t) = Normalizationfactor(j,t) * allocationweight(j,r)$$

The resulting regional shares are used to calculate sectoral prices by region in Equations 5C.4.6c-5C.4.7g above.

Electricity Pricing During the Transition to Competition

When all or a majority of electricity sales within an electricity supply region come from deregulated states, this region is assumed to be fully or partially competitive. It is assumed that there is a gradual 10-year transition to fully competitive pricing from the inception of deregulation in competitive regions. This is the estimated amount of time needed to complete collection of stranded costs, consumer education concerning electricity choices, and resolution of market imperfections. It also accounts for the time needed for an adequate number of suppliers to enter the market and learn to be cost-efficient enough to stay in the market and keep it competitive. Thus, the competitive proportion of sales in a deregulated region for the first 10 years of the inception of retail deregulation is calculated as:

(5C.4.9a)

$$compSLSHPCT_{ry} = totcompSLSHPCT_{ry} * (10\% * compyear_r)$$

where:

$compSLSHPCT_{ry}$ = the actual competitive proportion of sales in region r in year y

$totcompSLSHPCT_{ry}$ = the total proportion of sales within competitive states in region r in year y

$compyear_r$ = the number of years the market has been deregulated in region r (the first year of deregulation equals 1)

The exception to this rule is in the Mid-Atlantic region, where research has shown it to be more competitive than other regions. Thus, for this region only, we assume it to be 40 percent competitive at the start of competition, increasing its competitiveness by 10 percent each year. Thus, NEMS calculates a fully competitive price by the seventh year after the start date of competition instead of the 10^{th} year as for the other competitive regions.

Within a competitive region, it is assumed that the same percentages of competitive and regulated pricing as the percentages of electricity sales in the deregulated and regulated states in that region, respectively. For supply regions with more than half of their electricity sales in competitive states:

(5C.4.9b)

$$EPRICE_{jry} = (regEPRICE_{jry} * \%\ regSLSHPCT_{jry}) + (compEPRICE_{jry} * \%\ compSLSHPCT_{jry})$$

where:

$EPRICE_{jry}$ = the nominal electricity price of customer class j in region r in year y

$regEPRICE_{jry}$ = the nominal regulated electricity price of customer class j in region r in year y

$regSLSHPCT_{jry}$ = the regulated proportion of sales to customer class j in region r in year y

$compEPRICE_{jry}$ = the nominal competitive electricity price of customer class j in region r in year y

$compSLSHPCT_{jry}$ = the actual competitive proportion of sales to customer class j in region r in year y

For supply regions with less than half of their electricity sales in competitive states, the EFP assumes regulated prices.

Each state with approved electricity deregulation plans has mandated electricity price reductions or freezes for a specified period of time. The extent of the mandates often differs by customer class (i.e. residential, commercial, industrial). The EFP has incorporated these mandates for each competitive region. With a mandated price reduction, the regulated electricity price (EPRICE) for the affected regions, years, and customer classes is decreased by the price reduction for those affected regions, years and customer classes, which has been weighted by the percentage of electricity sales affected by the price reduction With a price freeze, the electricity price for the affected regions, years and

customer classes remains the same as it was at the time of the freeze for the specified number of months or years of the freeze. If the EFP picing algorithm calculates higher regional prices in the affected years for the affected customer class, this freeze amounts to a price reduction. Weighted electricity price reductions for areas affected by price reductions and/or price freezes are calculated exogenous to the EMM and subtracted from the electricity price calculated by the EFP pricing algorithm for the affected region, year and customer class:

(5C.4.9c) $EPRICE_{jry} = EPRICE_{jry} - weighted\ price\ reduction_{jry}$

where:

$EPRICE_{jry}$ = the nominal electricity price of customer class j in region r in year y

$weighted\ price\ reduction_{jry}$ = the electricity price reductions for customer class j in region r in year y as a result of price reductions and/or price freezes and as weighted by the percentage of kilowatt-hour electricity sales affected by the price reductions and/or price freezes -- calculated exogenous to the EMM.

Modifications for California:

As a result of the 2000-2001 electricity shortage, skyrocketing wholesale electricity prices, and the loss of credit by the major investor-owned utilities, the State of California started purchasing large amounts of electricity for the utilities through long-term contracts. The bulk of these contracts are to last 10 years. California also ended its retail competition program. Thus, starting in 2002 and throughout the forecast period, NEMS assumes that California electricity supply region will be regulated. An actual electricity price for the portion of California's load covered by long-term contracts was calculated through 2010. This calculation was based on the latest published average contract prices by customer class, year and percent of forecasted demand to be covered by contract prices. For most years this price was higher than the NEMS-forecasted regulated price. The difference between actual and forecast prices for the affected load amount was added or subtracted to the NEMS forecast price through 2010 so that:

(5C.4.9d) $EPRICE_{jCAy} = EPRICE_{jCAy} + (CPRICE_{jCAy} - EPRICE_{jCAy}) * percent\ of\ CA\ load\ under\ contract$

where:

$EPRICE_{jCAy}$ = the nominal electricity price of customer class j in the California region in year y

$CPRICE_{jCAy}$ = the nominal average long-term contract electricity price of customer class j in the California region in year y

Taxes:

EFP calculates two categories of taxes: general taxes and income taxes.

General Taxes:

General taxes encompass all taxes except the State and Federal income taxes. Among these taxes are gross receipts, FICA, capitalized payroll, property and sales. The assumption is made that these taxes each year will be a constant percentage of revenues.

(5C.4.10a) $$GENTAX = EGTXRT \cdot ERRVLG + ERPRTX + ERSLTX$$

where:

GENTAX = actual general taxes

EGTXRT = general tax rate (user input)

ERRVLG = electric revenues

ERPRTX = property taxes

ERSLTX = sales tax

ERPRTX is modeled as an input fraction of the book value of property, and ERSLTX is modeled as an input fraction of the construction expenditures.

Income Taxes:

Current income taxes are those actually paid by the utility in a given year. Because of the regulatory and financial treatment of certain tax savings (e.g., investment tax credits, accelerated depreciation), this is not, in general, what is booked on the income statement as income tax expense.

(5C.4.10b)

$$CITAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - GENTAX - (ERTIEX - AVDINT) - ESLLP) \cdot ESFTXR + STTAX - (ERFITC + XITCD) - (ERATSF + ERATSD)$$

where:

CITAX = current income taxes

ERRVLG = electric revenues

ERTFLN = fuel costs

ERTOMN = operation and maintenance expenses, excluding fuel

ERTDWO = depreciation for tax purposes, without acceleration

GENTAX = actual general taxes

ERTIEX = interest expenses

AVDINT = interest capitalized on assets during construction

ESLLP= annual lease payment associated with sale/leaseback transactions

ESFTXR = Federal income tax rate (user input)

STTAX = State income taxes, including Federal income tax benefits (see Equation 5C.4.10d below)

ERFITC = generated ITC which is flowed through

XITCD = generated ITC that is deferred

ERATSF = tax savings from accelerated depreciation that is flowed through

ERATSD = tax savings from accelerated depreciation that is deferred

Now, booked income tax expense is current taxes, plus deferrals, minus amortizations:

(5C.4.10c) $$BKITAX = CITAX + (XITCD - ERAITC) + (ERXFDC - ERAFDC) + ERATSD - EREDTF$$

where:

BKITAX = booked income tax expense

ERAITC = amortization of deferred ITC

ERXFDC = generated tax savings from debt portion of AFUDC that is deferred

ERAFDC = amortization of deferred tax savings from the debt portion of AFUDC

EREDTF = excess deferred taxes flowed back to rate payers.

The only remaining tax variable to be explained is STTAX (State income taxes including Federal income tax benefits):

(5C.4.10d)

$$STTAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) \cdot ESSTXR \cdot (1 - ESFTXR)$$

where:

ESSTXR = State income tax rate (user input).

State income taxes are deductible in calculating Federal taxable income so the net effect of State income taxes upon total income taxes is STTAX.

Financial Ratios:

The output of EFP includes the forecasted values of several financial ratios. These ratios are standard indicators of a utility company's financial health. However, financial analysts disagree over the exact formula to be used in some cases. For EFP, the following definitions are used:

1) Interest Coverage. Interest coverage is calculated and printed for four alternative formulas. In all formulas, the denominator is total interest expenses. For pre-tax interest coverage, less AFUDC, the numerator is operating income plus booked income taxes. For pre-tax interest coverage, with AFUDC, the numerator is operating income, plus booked income taxes, plus AFUDC. For post-tax interest coverage, less AFUDC, the numerator is operating income. For post-tax interest coverage, with AFUDC, the numerator is operating income plus AFUDC.

2) Actual Return on Common Equity. This ratio is calculated as earnings available for common equity divided by the year-average book value of common equity (common stock plus retained earnings).

3) AFUDC as a Percentage of Earnings Available for Common. This ratio is calculated AFUDC divided by earnings available for common equity.

4) Internal Cash Flow as a Percent of Construction Expenditures. This ratio is calculated as total internally generated funds divided by construction expenditures (excluding AFUDC).

5) Construction Work in Progress (CWIP) as a Percentage of Net Plant. This ratio is calculated as total CWIP divided by net plant. Net plant includes both plant in service and CWIP.

6) Effective Tax Rate. This rate is calculated as booked income taxes divided by booked pre-tax income. Pre-tax income is the sum of operating income and booked income taxes.

7) Safety Margin. This ratio is calculated as net income plus booked income taxes, minus AFUDC, all divided by electric revenues.

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Data Sources

Utility Expenses

Utility costs and tax data come from four separate survey forms, depending on the type of utility. Data for investor-owned electric utilities come from the Federal Energy Regulatory Commission Form FERC 1, "Electric Utility Annual Report." Data for Federal power projects and municipal power authorities (publicly-owned) come from the Energy Information Administration Form EIA- 412, "Annual Electric Industry Financial Report". Data for rural cooperatives (publicly-owned) come from the Department of Agriculture, Rural Electrification Administration (REA) Form REA-7, "Financial Statistical Report" and Form REA-12, "Operating Report." In the *Annual Energy Outlook (AEO),* the latest available survey data were used to forecast electricity prices.

Percent of Regional Load in States with Competitive Pricing

Information on which states have legislation or regulations in place to allow competitive retail markets can be found on the Energy Information Administration (EIA) website "Status of State Electric Industry Restructuring Activity" at the following sites:
http://www.eia.doe.gov/cneaf/electricity/chg_str/regmap.html,
http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html and
http://www.eia.doe.gov/cneaf/electricity/chg_str/retail.html.

The amount of electricity sales within each of the NERC electricity regions used by EFP is found on Form EIA-861, "Annual Electric Power Industry Report." The latest available survey data were used to forecast electricity prices in the AEO.

Information to Calculate Frozen and Reduced Electricity Prices in Regions with a Transition-to-Competition Pricing Structure

This information was collected from legislation and regulatory commission orders in relevant states as well as the EIA web site "Status of State Electric Industry Restructuring Activity" cited above.

Appendix 5.A
Construction Work in Progress

For regulatory purposes, EFP simulates three alternative treatments of construction work in progress (CWIP): 1) CWIP in rate base; 2) CWIP not in rate base; or 3) the offset method. When CWIP is allowed in rate base for ratemaking purposes, the utility is allowed to earn a current cash return on all construction outlays. If CWIP is not allowed in rate base (i.e., AFUDC is capitalized), the utility is allowed to include an annual estimate of the net cost, for the period of construction, of funds used for construction purposes. These "allowances" are accumulated over the construction period of the project and are brought into the rate base as an addition to the value of the completed investment once the investment becomes operational. The third alternative of dealing with construction work in progress is the capitalized AFUDC offset method. For this procedure, CWIP is allowed in rate base and AFUDC is capitalized, but there is a corresponding offset to the return on rate base equal to the amount of the capitalized AFUDC. If the AFUDC rate is equal to the allowed rate of return on rate base and if the utility is allowed to compound the effects of AFUDC, then this method is essentially equivalent to not allowing CWIP in rate base.

The regulatory treatment of CWIP is decided upon a case-by-case basis by most public utility commissions. In general, at the multi-utility aggregation level at which EFP is run, all of the treatments are used to some degree. To account for this, EFP allows the analyst to input the percentage of CWIP that is to be allowed in rate base. The remainder of the CWIP is then assumed either not to be in rate base or to be handled under the offset method (depending on another user input).

The treatment of CWIP affects several variables. The following discussion assumes only one plant is being built for ease in presentation. For the algorithms, the following values are input to EFP:

Variable	Description	Source
EBPCAP	Capacity of build	Capacity Planning Model
EBPCST	Real dollar cost per unit of capacity (real dollars/ capacity), not including any financing costs incurred during construction	Capacity Planning Model
EBSYR	Year plant comes on line	Capacity Planning Model
ESLCP	Length (in years) of construction period (including first year of operation)	User

Variable	Description	Source
$ESCPRF_y$	Direct (i.e., not including financing charges) construction expenditures (in real dollars) in year y as a fraction of total direct construction costs (in real dollars)	User
$ESGNPD_y$	Inflation escalation index used to convert real dollars to current year y dollars, expressed as the ratio of current year y dollars to real dollars	User
$CWPPER_y$	Percentage (expressed as a fraction) of CWIP allowed in rate base, year y	User
ESRBAF	Percent of AFUDC/CWIP which receives offset treatment 0 Remainder of CWIP (i.e., 1.0 - CWPPER) is not in rate base 1 Remainder of CWIP is receives AFUDC offset treatment	User
ESCGRW	Annual escalation rate used to escalate costs over and above the inflation rate	User
ESBKLF	Book life of plant	User

The algorithms to calculate the CWIP related variables in EFP are executed in five basic steps:

1) Calculate the AFUDC (allowance for funds used during construction) rate
2) Calculate annual direct construction expenditures in current year dollars
3) Calculate year by year CWIP accounts and the resulting book value of the new plant
4) Calculate tax basis of plant
5) Calculate several AFUDC related accounts

Each step is discussed in detail below.

Step 1:

Step 1 is to calculate the AFUDC rate. EFP simulates a pre-tax AFUDC rate. EFP calculates the pre-tax AFUDC rate as:

(App5.A.1) $$ESAFDC = TEMPD + TEMPE$$

where:

ESAFDC = pre-tax AFUDC rate

TEMPD	=	ESPRLT * ESEMDL + ESPRST * ESRTST
TEMPE	=	ESPRCE * ESRTCE + ESPRPS * ESEMPL

All of the right-hand variables above have been discussed in the preceding sections. An additional value used below is the fraction of AFUDC representing debt costs.

(App5.A.2)

$$ESWACD = TEMPD / ESAFDC$$

where:

ESWACD	=	fraction of AFUDC representing debt costs.

Step 2:

Step 2 is to calculate direct construction expenditures by year, in nominal dollars. This is done for each year y, where y ranges from the first year of construction (i.e., EBSYR - ESLCP + 1) to the first year of operation (i.e., EBSYR).

(App5.A.3)

$$EBYCWP_y = EBPCAP \cdot EBPCST \cdot ESCPRF_y \cdot ESGNPD_y \cdot CAPESC_y$$
$$\text{for } y = (EBSYR - ESLCP + 1) \text{ to } EBSYR$$

Where:

$EBYCWP_y$	=	nominal dollar direct construction expenditures, year y
EBPCAP	=	capacity of build
EBPCST	=	real dollar cost per unit of capacity
$ESCPRF_y$	=	real dollar direct construction expenditures, in year y, as a fraction of total direct construction expenditures
$ESGNPD_y$	=	inflation index to convert real dollars to current year y dollars
$CAPESC_y$	=	escalation index to escalate construction costs over and above inflation
EBSYR	=	year plant comes on line
ESLCP	=	length (in years) of construction period (including first year of operation).

EBPCAP, EBPCST, ESCPRF, ESGNPD, EBSYR, and ESLCP are inputs to EFP. CAPESC is calculated from the input values of ESCGRW (see description above of user inputs).

Step 3:

This step includes calculation of the major CWIP-related accounts for each year y during the construction period. includes year by year: CWIP allowed in rate base, booked CWIP, booked AFUDC, and the AFUDC offset. Also calculated is the book value of the new plant.

CWIP allowed in rate base is calculated as:

(App5.A.4)

$$EBRCWP_y = (EBBCWP_y + EBYCWP_y) \cdot [CWPPER_y + ESRBAF \cdot (1.0 - CWPPER_y)]$$

where:

$EBRCWP_y$	=	CWIP allowed in rate base by build, year y
$EBBCWP_{y-1}$	=	booked CWIP, year y-1
$EBYCWP_y$	=	nominal dollar direct construction expenditures, year y
$CWPPER_y$	=	percentage of CWIP allowed in rate base, year y
ESRBAF	=	Percent of AFUDC/CWIP which receives offset treatment: 0 if no AFUDC offset, and 1 if AFUDC offset.

Booked AFUDC in year j is calculated as:

(App5.A.5)

$$AFUDC_y = (EBBCWP_{y-1} + 0.5 \cdot EBYCWP_y) \cdot (1 - CWPPER_y) \cdot ESAFDC_y$$

where:

$AFUDC_y$	=	booked AFUDC, year y
$EBBCWP_{y-1}$	=	booked CWIP, year y-1
$EBYCWP_y$	=	nominal dollar direct construction expenditures, year y
$CWPPER_y$	=	percentage of CWIP allowed in rate base, year y
$ESAFDC_y$	=	AFUDC rate, year y

Note that in the calculation of AFUDC the average level of CWIP over the calendar year is used. This is why $EBYCWP_j$ is multiplied by one-half (the construction takes place evenly over the year so the average balance should include only half of this amount). The calculation of CWIP in rate base, however, uses an end-of-year CWIP balance. Adjustments to this value to make it an average level over the year are made only if the user requests an average-year rate base.

ESAFDC and EBYCWP were calculated above in Steps 1 and 2, respectively. The calculation of EBBCWP is shown below.

Booked CWIP in year y is calculated as:

(App5.A.6)

$$EBBCWP_y = 0$$
for $y = EBSYR - ESLCP$ (i.e., year before construction begins)

$$= EBBCWP_{y-1} + EBYCWP_y + AFUDC_y$$
for $y = (EBSYR - ESLCP + 1)$ to $EBSYR$ (i.e., construction period)

where:

$EBBCWP_y$	=	booked CWIP, year y
$EBYCWP_y$	=	nominal dollar direct construction expenditures, year y
$AFUDC_y$	=	booked AFUDC, year y

The AFUDC offset is calculated as:

(App5.A.7)

$$EROFFS_y = AFUDC_y \cdot ESRBAF$$

where:

$EROFFS_y$	=	AFUDC offset, year y.

The book value of the new plant when it comes on line is:

(App5.A.8)

$$EBBKVL = EBBCWP_y$$

where:

EBBKVL	=	book value of new plant
y	=	EBSYR (the first year of operation)
$EBBCWP_y$	=	booked CWIP, year y

This equation assumes that the new plant comes on line January 1 of year EBBSYR. EFP can also simulate plants coming on line after January 1, using similar equations.

Step 4:

The fourth step is to calculate the tax basis for the investment. Previous to the Tax Reform Act (TRA) of 1986, the tax basis was the sum over all years of the nominal dollar direct construction expenditures (EBYCWP) calculated in Step 2 (adjusted for investment tax credits, as described below). However, any asset coming on line after 1986 that is not grand-fathered under the provision must capitalize interest during construction.

(App5.A.9)

$$EBASVL_y = 0$$
$$\text{for } y = EBSYR - ESLCP \text{ (i.e., year before construction begins)}$$
$$= EBASVL_{y-1} + EBYCWP_y + AVDINT_y$$
$$\text{for } y = (EBSYR - ESLCP + 1) \text{ to } EBSYR \text{ (i.e., construction period)}$$
$$= EBASVL_{EBSYR}$$
$$\text{for } y = EBSYR \text{ to } (EBSRY + ESBKLF) \text{ (i.e., during service life)}$$

where:

EBASVL	=	tax basis, year y
$EBYCWP_y$	=	nominal dollar direct construction expenditures, year y
$AVDINT_y$	=	interest capitalized for tax basis (avoided interest), year y

No interest is capitalized for the tax basis unless the plant is covered under the TRA. The applicability of the TRA to a given plant is determined by a user-defined test based on the year the plant came on line and first year of construction. When the new tax law does apply, the capitalized interest is calculated as:

(App5.A.10)

$$AVDINT_y = (EBASVL_{y-1} + 0.5 \cdot EBYCWP_y) \cdot ESRTNB_y$$

where:

$AVDINT_y$	=	interest capitalized for tax basis (avoided interest), year y
$EBASVL_{y-1}$	=	tax basis, year y-1
$EBYCWP_y$	=	nominal dollar direct construction expenditure, year y
$ESRTNB_y$	=	cost of new debt, year y.

Step 5:

The fifth step is to calculate several accounts related to AFUDC. It is important to separate AFUDC into that financed by debt and that financed by equity:

(App5.A.11)

$$ERFDCD_y = ESWACD_y \cdot AFUDC_y$$
$$ERFDCE_y = (1 - ESWACD_y) \cdot AFUDC_y$$

where:

$ERFDCD_y$	=	debt financed portion of AFUDC, year y
$ERFDCE_y$	=	equity financed portion of AFUDC, year y
$ESWACD_y$	=	fraction of AFUDC representing debt costs, year y (see step 1)

While a plant is under construction, various interest expenses associated with construction of the plant accrue. For those plants not covered under the TRA, this interest expense provides a tax savings to the utility because interest is a deductible expense. The regulatory process attempts to

capture this savings for ratemaking purposes and either flow it through immediately to ratepayers or defer it to a later period when the asset is in service. This is done by using the concept of the tax savings due to the debt portion of AFUDC.

(App5.A.12)

$$ERFFDC_y = ERFDCD_y \cdot ESFTXR \cdot ESFPDB$$
$$ERXFDC_y = ERFDCDsubyj \cdot ESFTXR \cdot (1 - ESFPDB)$$
$$DAFDC_y = \sum_{i=k}^{y} ERXFDC_i$$

for $y = K$ to $EBSYR$
where $K = EBSYR - ESLCP + 1$

where:

$ERFFDC_y$	=	generated tax savings from the debt portion of AFUDC that is flowed through, year y
$ERFXFDC_y$	=	generated tax savings from the debt portion of AFUDC that is deferred (normalized), year y
$DAFDC_y$	=	deferred tax savings from the debt portion of AFUDC, year y
$ERFDCD_y$	=	debt-financed portion of AFUDC, year y, (see above)
ESFTXR	=	Federal tax rate (user input)
ESFPDB	=	flow through percentage (expressed as a fraction) for AFUDC tax savings.

ESFPDB reflects the regulatory policy towards the tax savings and is a user input. The tax savings is generated while the plant is under construction. When the plant begins service, the deferred taxes, if any, are amortized over the service life of the plant.

(App5.A.13)

$$EBAFDC = DAFDC_{EBSYR}/ESBKLF$$
$$DAFDC_y = DAFDC_{y-1} - EBAFDC$$
for $y = EBSYR$ to $(EBSYR + ESBKLF - 1)$ (i.e., over service life of plant)

where:

EBAFDC	=	annual amortization of deferred savings from the debt portion of AFUDC
$DAFDC_y$	=	deferred tax savings from the debt portion of AFUDC, year y
ESBKLF	=	book life of plant

Again, the calculations above pertaining to the tax savings from the debt portion of AFUDC relate only to plants not covered under the TRA of 1986. For plants covered under the TRA of 1986, there is no tax savings because interest must be capitalized for tax purposes. The interest capitalized for the purposes of calculating Federal income taxes for regulatory purposes is therefore:

(App5.A.14)

$$ERCIDC_y = ERXFDC_y + AVDINT_y$$

where:

$ERCIDC_y$ = interest capitalized for the purposes of calculating Federal income taxes for regulatory purposes, year y

$ERXFDC_y$ = generated tax savings from the debt portion of AFUDC that is deferred, year y

$AVDINT_y$ = interest capitalized for tax basis, year y (see Step 4 above on p. 193).

Appendix 5.B
Depreciation

Depreciation expenses are calculated separately for financial (or book) and for tax purposes . Financial and tax depreciation differ for several reasons. First, book depreciation is calculated using the straight-line method while tax depreciation uses an accelerated method. The accelerated method yields higher depreciation in the early years of an asset's life followed by lower depreciation in later years than does the straight-line method (assuming all else equal). Second, capitalized AFUDC is depreciated for book purposes but not for tax purposes. Similarly, interest capitalized during construction for tax purposes is not depreciated for book purposes, but is for tax purposes. Finally, the depreciation base for tax purposes must be lowered by one-half of the total investment tax credit earned during construction of the plant. The depreciation base for book purposes is not adjusted in this way.

ESDEPR = depreciation rate for financial purposes (usually 1/ESBKLF)

The methodology presented here is easily expanded to the "n" plant case and to existing plants.

Depreciation for Financial Purposes (ERBDE):

Book depreciation is calculated using the straight-line method (net book value divided by remaining life):

(App5.B.1a) *ERBDEy - (ERBKVL - EBABDEy-1)/(ESBKLF - (YEAR-EBSYR))*

and

(App5.B.1b)

$$EBABDE_y = \sum_{i=EBSYR}^{y} ERBDE_i$$

for y = *EBSYR* to *EBSYR* + *ESBKLF* − 1 (i.e., over service life of asset)

where:

$ERBDE_y$ = book depreciation, year y
EBBKVL = book value of plant (includes any AFUDC).
$EBABDE_{y-1}$ = accumulated book depreciation, previous year to year y
ESBKLF = book life of plant
YEAR = current year

EBSYR = year plant comes on line
$EBABDE_y$ = accumulated book depreciation, year y

The derivation of EBBKVL is discussed above in Appendix 5.A, Construction Work in Progress. When the plant retires (year EBSYR + ESBKLF), its book value is added to account ERBTIR and subtracted from EBABDE. This has the effect of removing the plant from the books.

Depreciation for Tax Purposes:

For tax purposes, depreciation is accelerated (i.e., allowed to be greater in early life of plant and less in later life) by two forces. First, utilities may depreciate the plant over a shorter period of time than the service life used for financial purposes. Second, an accelerated depreciation rate is used instead of a straight-line constant rate. The effect of accelerated depreciation is to lower tax liability in the earlier years of the plant life and raise them in the later years, compared to the straight-line method.

There are three different options in EFP when determining tax depreciation rates: i) use those prescribed in the Tax Reform Act (TRA) of 1986; ii) use those prescribed in the 1981 Economic Recovery Tax Act (ERTA); or iii) use the sum-of-years digit method. The method used for a particular asset is based on a user-specified test, which is a function of the year the construction of asset begins and the year the asset comes on line. The sum-of-years digit method is used for any asset that comes on line before 1981. Because the first two methods are the most applicable approaches, they are discussed below.[90]

Under ERTA and TRA, tax depreciation schedules (now more properly called tax recovery schedules) are specified. The tax base, as modified under the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA), is reduced by one half of the investment tax credit (discussed below) earned during the construction of the asset. For a given asset, the relevant recovery schedule is based on when the asset comes on line and on what service life class the asset belongs. Most assets in EFP are depreciated over 15 years (some 10) under ERTA, and 20 years (some 15) under TRA. Then, for the remaining years of the book life, tax depreciation is zero.

(App5.B.2a)

$$ERTDE_y = EXTXRS_y \cdot (EBASVL - 0.5 \cdot EBDITC)$$
$$\text{for } y = EBSYR \text{ to } EBSYR + ESBKLF - 1 \text{ (i.e., during the service life of the plant)}$$

where:
$ERTDE_y$ = depreciation expense for tax purposes, year y
EBASVL = tax basis of asset

[90] The approach for the sum-of-years digit method is identical to that described except that the tax base is not reduced by one-half the investment tax credit.

$EXTXRS_y$ = depreciation rate prescribed by ERTA or TRA, year y
EBDITC = investment tax credits generated.

EBASVL is discussed above. EBDITC is described below.

Absent accelerated depreciation, tax depreciation would be:

(App5.B.2b)

$$ERTDWO_y = ESDEPR \cdot (EBASVL - 0.5 \cdot EBDITC)$$
for y = $EBSYR$ to $EBSYR + ESBKLF - 1$ (i.e., during the service life of the plant)

where:
$ERTDWO_y$ = depreciation for tax purposes, without acceleration, year y
ESDEPR = straight-line depreciation rate.

The difference between $ERTDWO_y$ and $ERTDE_y$ leads to tax savings in the early years of service followed by increased taxes in the later years. The regulatory authority determines the treatment of this difference for ratemaking purposes.

(App5.B.2c)

$$ERTDRG_y = ERTDWO_y \cdot (1 - ESFLPR) + ERTDE_y \cdot (ESFLPR)$$
for y = $EBSYR$ to $EBSYR + ESBKLF - 1$ (i.e., during the service life of the plant)

where:
$ERTDRG_y$ = tax depreciation expense for regulatory purposes, year y
ESFLPR = percentage of tax savings due to acceleration depreciation that is flowed through

When the tax effects of accelerated depreciation are flowed through for regulatory purposes (ESFLPR = 1.0), ERTDRG is equal to ERTDE. In this case, revenue requirements directly show the effects of the acceleration. However, when the tax effects are normalized (ESFLPR = 0.0), then ERTDRG is equal to ERTDWO and thus the revenue requirements show no effects of the acceleration. Thus, in a flow-through scenario, revenue requirements are lower in the early years of the plant's service and higher in the later years, compared to revenue requirements in a normalized scenario (all else equal). This effect comes about because ERTDRG affects Federal income taxes for regulatory purposes, which in turn affects revenue requirements.

Other useful quantities relating to this tax effect are:

(App5.B.2d)

$$ERATSF_y = ESFTXR \cdot (ERTDE_{yj} - ERTDWO_y) \cdot ESFLPR$$
$$ERATSD_y = ESFTXR \cdot (ERTDE_y - ERTDWO_{yj}) \cdot (1 - ESFLPR)$$
$$DAD_y = \sum_{i=EBSYR}^{y} ERATSD_i \text{ for } y = EBSYR \text{ to} EBSYR + ESBKLF - 1$$

where:

$ERATSF_y$ = tax savings resulting from accelerated depreciation that are flowed through, year y

$ERATSD_y$ = tax savings resulting from accelerated depreciation that are deferred, year y

DAD_y = provision for deferred taxes due to accelerated tax depreciation, year y

ESFTXR = Federal income tax rate.

Appendix 5.C
Tax Issues

Excess Deferred Income Taxes Flowed Back to Ratepayers (EREDTF):

The 1986 Tax Reform Act (TRA) lowered the marginal Federal income tax rate from 46 percent to 40 percent in 1987 and to 34 percent thereafter. One effect of the decrease in the marginal tax rate is to lower future reductions in deferred income taxes that will occur as assets complete their service lives.

As described in the preceding section, accelerated depreciation allowed for tax purposes leads to deferred income taxes for regulated utilities. Over the life of an individual asset the level of deferred income taxes will increase in its early years and finally decrease to zero at the end of its service life. A complication arises, however, when the marginal tax rate decreases during the service life of an asset. The deferred taxes have been booked at the higher marginal tax rate, but will now be paid at the lower tax rate. The difference between deferred income taxes now booked (under the 46-percent marginal tax rate) and what will ultimately be paid under the 34-percent marginal rate is referred as excess deferred income taxes.

(App5.C.1a)

$$EXCESS = \sum_{y=EBSYR}^{IYREDT} (ERTDE_y - ERTDWO_y) \cdot (ESFTXR_y - ESFTXR_{IYREDT})$$

These excess deferred taxes should be flowed through to the ratepayers. EFP can flow back these taxes over the remaining lives of the assets or over any user-defined schedule of years.

The first step is to calculate the amount of deferred taxes that have accrued:

where:

EXCESS = total excess deferred income taxes
$ERTDE_y$ = depreciation expense for tax purposes, year y
ERTDWO = depreciation for tax purposes, without acceleration, year y
$ESFTXR_y$ = Federal income tax rate, year y (user input)
EBSYR = first year of service
IYREDT = year in which excess taxes are to be calculated (user input)

Now the amount of excess deferred income taxes flowed back to ratepayers in each year can be calculated:

(App5.C.1b)

$$EREDTF_y = 0.0 \quad \text{if } y < IYREDT$$
$$= EXCESS/REMLIF \quad \text{if } y \geq IYREDT$$

where:

$EREDTF_y$ = excess deferred taxes flowed back to ratepayers, year y

EXCESS = total excess deferred income taxes

REMLIF = remaining years of life for asset (ESBKLF - (IYREDT-EBSYR)).

The above equation flows back the excess deferred income taxes over the remaining life of the investment. Within EFP, it can also be flowed back over any user-defined schedule of years.

Provision for Deferred Income Taxes (ERPRDF):

The provision for deferred income taxes is the sum of the values of all deferred income taxes or deferred tax savings (excluding investment tax credits). For purposes of EFP, this includes the deferred taxes from accelerated depreciation and the deferred tax savings from the debt portion of AFUDC on assets not affected by the TRA of 1986.

(App5.C.2)

$$ERPRDF = DAD + DAFDC - EREDTF$$

where:

ERPRDF = provision for deferred income taxes

DAD = deferred income taxes due to accelerated depreciation

DAFDC = deferred tax savings from the debt portion of AFUDC

EREDTF = excess deferred taxes flowed back to ratepayers

Investment Tax Credit:

The investment tax credit was established by Congress to encourage certain kinds of investments. The effect of the investment tax credit is to reduce the Federal tax liability by the amount of the credit. The credit is generated during each year of the construction period for the plant. Previous to the Tax Reform Act of 1986 (TRA), the value of the credit each year was a percentage of construction expenses (excluding AFUDC) for that year. The investment tax credit was repealed under TRA. However, many assets currently under construction when the TRA was passed were grand-fathered under the provision and will continue to receive the credit. For these assets, the effective investment tax credit rate will decrease over time. Within EFP, assets that receive the credit are determined by a user-specified test that is a function of the year in which the construction of the asset began and the year in which the asset enters service (i.e., any asset for which construction began before a user-specified year and which enters service before a user-specified

year, will continue to receive the credit). This test allows the capability to examine alternative assumptions regarding grand-fathering.

The regulatory treatment of this tax savings is decided by the new regulatory commission. The credit can be flowed through immediately to lower the revenue requirement in the year it was generated or deferred and then amortized over the life of the plant. EFP handles any combination of these two treatments.

(App5.C.3)

$$ERFITC_y = EBYCWP_y \cdot ESRITC_y \cdot ESFLPR$$
$$XITCD_y = EBYCWP_y \cdot ESRITC_y \cdot (1 - ESFLPR)$$
$$EBDITC_y = \sum_{i=K}^{y} XITCD_i \quad \text{for } y = K \text{ to } EBSYR, \text{ where } K = EBSYR - ESLCP + 1$$

where:

$ERFITC_y$ = generated ITC that is flowed through, year y
$XITCD_y$ = generated ITC that is deferred, year y
$EBDITC_y$ = deferred ITC, year y
$EBYCWP_y$ = construction expenses, net of AFUDC, year y
$ESRITC_y$ = investment tax credit rate, year y
ESFLPR = percentage of tax savings flowed through
ESLCP = length (in years) of construction period (including first year of operation)

When the plant begins service, any deferred ITC is amortized over the life of the plant.

(App5.C.4)

$$ERAITC = EBDITC_{EBSYR} / ESBKLF$$
$$EBDITC_y = EBDITC_{y-1} - ERAITC$$
$$\text{for } y = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

where:

ERAITC = amortization of deferred investment tax credit
$EBDITC_y$ = deferred ITC, year y,
ESBKLF = service life of plant (user input).

Note that the investment tax credit is generated only on the direct construction expense, not on capitalized AFUDC.

Appendix 5.D
Sale/Leaseback Transactions

The sale and leaseback of an electric power plant is essentially a financial transaction that affects

the timing of cost recovery, and frequently the capital cost, associated with the plant. It generally does not change the utility's responsibilities for operating and maintaining the plant or for selling the electricity it generates. Attractive for a variety of reasons, the sale/leaseback may be a creative way for a utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position, benefitting both investors and ratepayers.

In the simplest form of a sale or leaseback, the utility sells a power plant to an institutional investor, then leases the plant back from the investor for equal semiannual rents over a term that is typically between 25 and 30 years. Regulators treat the rental payment as operating expenses, and the utility's revenue requirement no longer includes the return on capital or depreciation expense associated with the plant. The result is a flat revenue requirement over time, lower than conventional cost recovery in the short term, and higher toward the end of the lease.

For the algorithm presented below, the following values are input in EFP for each sale/leaseback transaction to be modeled:

Variable	Description
IBYRSL	Year transaction is completed
SLPROC	Gross proceeds from transaction
BKGAIN	Gross gain on book value
SLTAXS	Utility income taxes on transaction
SLLP	Annual lease payment
SLTERM	Lease term

The methodology presented here applies to one transaction and is easily expanded to the “n” transaction case.

The first step is to calculate the book value of the plant sold, the net gain from the transaction, and the tax basis of the plant sold:

(App5.D.1)

$$SLBKVL = SLPROC - BKGAIN$$
$$SLGAIN = BKGAIN - SLTAXS$$
$$SLASVL = SLPROC - SLTAXS/ESFTXR$$

where:

SLBKVL = book value of plant sold
SLPROC = gross proceeds from transaction (input)
BKGAIN = gross gain on book value (input)
SLGAIN = net gain on book value
SLTAXS = utility income taxes on transaction (input)

SLASVL = tax basis of plant sold
ESFTXR = federal income tax rate (input).

The book value of the plant is removed from utility plant in service and the tax basis is removed from the utility tax accounts. This is done within the EFP by creating an asset with a negative book value and tax basis equal in absolute value to that calculated above. This has the effect of removing the plant from utility books.

The remaining quantities are now calculated:

(App5.D.2)

$$
\begin{aligned}
ESLPRC &= SLPROC - SLTAXS \\
ESLLP &= SLLP \\
ESLAGN &= SLGAIN / SLTERM \\
ESLNDG_j &= SLGAIN - j \cdot ESLAGN \text{ for } j = 1, SLTERM \\
ESLLPN &= ESLLP - ESLAGN
\end{aligned}
$$

where:
ESLPRC = net of tax sales proceeds
ESLLP = annual lease payment
ESLAGN = amortization of gain
ESLNDG = net deferred gain from transaction
ESLLPN = net lease payment
SLPROC = gross proceeds from transaction (input)
SLTAXS = utility income taxes on transaction (input)
SLLP = annual lease payment (input)
SLGAIN = net gain on book value
SLTERM = lease term.

Appendix 5.E
Rate Phase-in Plans

Almost all electric utilities in the United States have their electricity rates set by regulatory commissions at the local, State, or Federal level (or any combination of these three). The most common method used by regulators to determine the appropriate rates is often referred to as original-cost, rate-of-return regulation. Under this methodology, the utility is able to charge rates that allow it to recover its operating and capital costs. Under this scheme, the rate impacts of the capital costs of a new asset coming on line are greatest in its first year of service and decline thereafter over the life of the asset. Historically, the large increase in capital costs associated with a new plant were substantially, if not totally, offset by the lower operating costs obtained by utilizing the new unit.

Throughout the 1980's and early 1990's, however, many situations have arisen where, under traditional regulation, substantial rate increases would occur as new plants come on line. This was caused by two major forces. First, the costs of new power plants rose substantially. This widely discussed phenomenon caused the capital costs of the plant to be substantially higher. Second, the savings derived from lower operating costs of the new plants had not been very great. This is due to lower energy commodity prices as well as the power generation technologies leveling out in terms of efficiency. Additionally, many areas of the country were over-built with capacity, again lowering the savings derived from the new plants. In many cases, a single utility brought on line a new plant whose total costs made up a large fraction of its total assets, thus amplifying the two forces just described.

Given this pressure for dramatic increases in rates, alternative regulatory approaches were necessary. Even if a regulatory commission were to allow the large rate increases, the potential reaction of customers, particularly large customers, forbids such rate increases. The prospect of these customers leaving the service territory or bypassing the local utility through cogeneration or transmission wheeling is very real. Any exit of these customers requires the rates of remaining customers to increase even more, and ever-increasing rates and ever-declining sales become a possibility. In the interests of both the utilities and the ratepayers, a common approach to deal with this problem emerged and was referred to as rate phase-in plans.

The idea of a rate phase-in plan is straightforward. For a number of years, rates are to be set at a level lower than would have been the case under traditional ratemaking. This is followed by a number of years in which rates are higher than they would have been in order to allow the company to make up for the early years. After 2000,. EFP forecasts are no longer affected by these plans, however the capacity to model them, EFP is still available should phase-ins be used by regulated regions in the future.

For the algorithm presented below, the following values are input for each rate phase-in plan to be modeled:

IBYRPI = Year rate phase-in plan begins
PIBKVL = Book value of phase-in plant
DISPER = Fraction of phase-in plant disallowed
LPI = Length of phase-in plan
$PIDFS_y$ = Cumulative fraction of total cost to be phased-in in year y
$PIRCS_y$ = Fraction of remaining deferred revenues to be recovered in year y
IRDPI = Logical variable indicating whether capitalized return is earned on deferred costs
PIBKLF = Book life of phase-in plant
PITXBS = Tax basis as a fraction of book basis for phase-in plant

The methodology presented here applies to one rate phase-in plan and is easily expanded to the "n" plan case.

The first step is to calculate the total revenue requirement associated with the phase-in plant under traditional regulation for each year of the phase-in plan:

(App5.E.1)

$$RR_y = \frac{PIBKVL \cdot (1.0 - DISPER) \cdot (1.0 - y/PIBKLF) \cdot ESPR/(1.0 - ESFTXR) + PIBKVL}{PIBKLF \cdot (1.0 + (1.0 - PITXBS) \cdot ESFTXR/(1.0 - ESFTXR)))}$$

$$\text{for } y = 1, LPI$$

where:
RR_j = traditional revenue requirement of phase-in plant, year y
PIBKVL = book value of phase-in plant (input)
DISPER = fraction of phase-in plant disallowed (input)
PIBKLF = book life of phase-in plant (input)
ESRR = rate of return
ESFTXR = federal income tax rate (input)
PITXBS = tax basis as a fraction of book basis for phase-in plant (input)
LPI = length of phase-in plan (input)

Next, the costs to be deferred in each year are calculated:

(App5.E.2)

$$EPIND_y = RR_y \cdot (1.0 - PIDFS_y) \cdot (1.0 - ESFTXR) - PIRCSy \cdot EPIDEF_{y-1}$$
$$\text{for } y = 1, LPI$$

where:
$EPIND_y$ = pre-tax deferred costs, year y
RR_y = traditional revenue requirement of phase-in plant, year y

$PIDFS_y$ = cumulative fraction of total cost to be phased-in in year y (input)
ESFTXR = federal income tax rate (input)
$PIRCS_y$ = fraction of remaining deferred revenues to be recovered in year y (input)
$EPIDEF_{y-1}$ = cumulative deferred costs, year y-1 (see below).

Note that $EPIND_y$, calculated above, will be positive during the initial period of the phase-in and will be negative during the final period of the phase-in. A negative value represents recovery from rate payers of deferred costs.

Next, the capitalized deferred return is calculated, if necessary (depends on value of IRDPI, an input described above):

(App5.E.3)

$$EPIRET_y = (EPIDEF_{y-1} + 0.5 \cdot EPIND_y) \cdot ESAFDC$$
$$\text{for } y = 1, LPI$$

where:
$EPIRET_y$ = capitalized return on deferred costs, year y
$EPIDEF_{y-1}$ = cumulative deferred costs, year y-1 (see below)
$EPIND_y$ = pre-tax deferred costs, year y
ESAFDC = AFUDC rate

Next, cumulative deferred costs are calculated:

(App5.E.4)

$$EPIDEF_y = EPIDEF_{y-1} + EPIND_y + EPIRET_y$$
$$\text{for } y = 1, LPI$$

where:
$EPIDEF_y$ = cumulative deferred costs, year y
$EPIND_y$ = pre-tax deferred costs, year y
$EPIRET_y$ = capitalized return on deferred costs, year y

EPIDEF begins year 1 with a value of 0.0.

Finally, the net value of disallowed plant is calculated:

(App5.E.5)

$$EDISNT_y = PIBKVL \cdot DISPER \cdot (1.0 - y/PIBKLF)$$
$$\text{for } y = 1, PIBKLF$$

where:
$EDISNT_y$ = net disallowed plant, year y
PIBKVL = book value of phase-in plant (input)

DISPER = fraction of phase-in plant disallowed (input)
PIBKLF = book life of phase-in plant (input).

Appendix 5.F

Functional Description Calculation of the Reliability Component

Subroutine: ELREL

Description: This subroutine calculates the reliability component of marginal cost. The basic idea is from "Incorporating Explicit Loss-of-Load Probability Constraints in Mathematical Programming Models for Power System Capacity Planning," by Sanghvi and Shavel. We describe the capacity and load distributions by means of their first four cumulants, and form the marginal capacity function from the sum of the cumulants. See "Kendall's Advanced Theory of Statistics," Fifth Addition, Kendall, Stuart and Ord. By taking the derivative of each of the cumulants, we then derive the marginal change in unserved energy.

Called by: COMPPRC

Calls: DELEUE, SHAVEL

Equations: There are 6 seasons, and 18 slices per season. We calculate marginal expected unserved energy for each slice independently. Rather than calculate the derivative of expected unserved energy, we approximate it by a differential.

We define the marginal capacity function as the stochastic function

(App5.F.1)
$$M = G - L$$

where: $L(l)$ = density function for load (demand), and

$G(g)$ = density function for generating capacity.

We define unserved energy as the stochastic variable

(App5.F.2)
$$UE = \begin{cases} m, m<0 \\ 0, otherwise \end{cases}$$

and expected unserved energy

(App5.F.3)
$$EUE = \int_0^{Z1} m M_x(m)\,dm$$

where:

$$Z1 = \frac{[E(L) - E(G)]}{sdev}$$

the normalized mean of the marginal capacity function. Since M_x cannot be integrated analytically, it is approximated numerically from its first four cumulants using the Gram-Charlier expansion.

First, we calculate the cumulants of the marginal capacity function:

(App5.F.4a)
$$tdcum1(icm) = capcum(ise, icmRNB, 1) + dcum(sblkicm, RNB) * (-1)^{icm}$$

where:

tdcum1 = marginal capacity cumulant icm for the slice,

capcum1 = capacity cumulant icm for season ise, region RNB,

dcum = demand cumulant icm for slice sblk and region RNB, and

(App5F.4b)
$$tdcum2(icm) = capcum(ise, icmRNB, 2) + dcum(sblkicm, RNB) * (-1)^{icm}$$

where:

tdcum2 = marginal capacity cumulant icm for the slice,

capcum2 = capacity cumulant (with increment) icm for season ise, region RNB, and

dcum = demand cumulant icm for slice sblk and region RNB.

Next we calculate the standard deviation of the distributions

(App5F.5a)
$$sdev1 = \sqrt{tdcum1(2)}$$

(App5.F.5b)
$$sdev2 = \sqrt{tdcum2(2)}$$

and the normalized mean of the marginal capacity function. The subroutine DELEUE finds the change in margin unserved energy from these quantities.

Subroutine: SHAVEL

Description: Computes the Shavel/Sanghvi approximation to the cumulative distribution at a point z given its first four cumulants. This is based on first few terms of the Gram-Charlier expression of a distribution as an infinite series of its cumulants.

Parameters:

z = z-value (input)

cum1 = first cumulant of marginal capacity function

cum2 = second cumulant of marginal capacity function

cum3 = third cumulant of marginal capacity function

cum4 = fourth cumulant of marginal capacity function

cum = cumulative distribution (output)

Called by: ELREL, EMUE

Calls: NORM

Equations:

(App5.F.6a)
$$g1 = \frac{cum3}{cum2^{1.5}}$$

(App5.F.6b)

$$g2 = \frac{cum4}{cum2^2}$$

(App5.F.7)

$$norm0 = pinorm * \exp^{-\frac{z^2}{2}}$$

(App5.F.8)

$$call\ norm(z1,\ norm0,\ normx1)$$

(App5.F.9)

$$cum = normx1 - \frac{g1 * norm0 * (z^2 - 1)}{6!} + \frac{g2 * norm0 * (3z - z^3))}{4!} + \frac{g1^2 * 10 * norm0 * (10z^3 - 5z - z^5)}{6!}$$

where:

for = forced outage rate,
cap = size of the unit (Gigawatts),
cum1 = first cumulant of marginal capacity function,
cum2 = second cumulant of marginal capacity function,
cum3 = third cumulant of marginal capacity function, and
cum4 = fourth cumulant of marginal capacity function.

Function: NORM
Description: NORM finds the cumulative normal probability distribution for any value z1.
Called by: DELEUE
Calls: None.
Parameters: dens = normal density evaluated at z1
Equations: data a/0.2316419/
data b/0.31938153,-0.356563782,1.781477937,-1.821255978,1.330274429/

(App5.F.10a)

$$val3 = \sum_{i=1}^{5} b_i * (\frac{1.0}{1.0 + a * z1})^i$$

where:

val3 = intermediate value,
b = constant, and
a = constant.

(App5.F.10b)

$$cum = 1.0 - dens * val3$$

where:

cum = cumulative distribution evaluated at z1, and
dens = normal density evaluated at z1.

Function: DELEUE

Description: Develops the contribution of a unit of capacity of a particular ECP type to the reduction in marginal expected unserved energy.

Called by: DELEUE

Calls: Shavel.

Equations: Determine loss of load probability (LOLP)

CALL Shavel(cum1,cum2,cum3,cum4,LOLP)

(App5.F.11)

$$G1 = \left(\frac{cum3}{cum2}\right)^{3/2}$$

(App5.F.12)

$$DELEUE = 0 + DZ1(for,cap,cum1,cum2) * LOLP - DG1(for,cap,cum2,cum3) + \frac{N2(z14)}{3!} + \frac{DG2(for,cap,cum2,cum4) * N3(z14)}{4!} + \frac{2 * G1 * DG1(for,cap,cum2,cum3) * 10 * N5(z14)}{6!}$$

where:

for = forced outage rate,

cap = size of the unit (Gigawatts),

cum1 = first cumulant of marginal capacity function,

cum2 = second cumulant of marginal capacity function,

cum3 = third cumulant of marginal capacity function, and

cum4 = fourth cumulant of marginal capacity function.

Function: DZ1

Description: DZ1 creates the coefficient for the third order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

(App5.F.13a)

$$DZ1 = -for * \sqrt{cum2} - .5 * (-1 * cum1) * for * (1 - for) * cap * cum2^{-3/2}$$

where:

for = forced outage rate,

cap = size of the unit (Gigawatts),

cum1 = first order cumulant of marginal capacity function, and

cum2 = second cumulant of marginal capacity function.

Function: DG2

Description: DG2 creates the coefficient for the fourth order term of the approximation of marginal

unserved energy function for the ECP.

(App5.F.13c)

$$DG1 = for * cap^2 * (1 - 3 * for + 2 * for^2) * cum2^{3/2} - 1.5 * cum3 * for * cap * (1 - for) * cum2^{-5/2}$$

Called by: DELEUE

Calls: None.

Equation:

(App5.F.13b)

$$DG2 = for * cap^3 * (1 - 7 * for + 12 * for^2 - 6 * for^3) * cum2^{-2} - 2 * cum4 * for * cap * (1 - for) * cum2^{-3}$$

where:

for = forced outage rate,

cap = size of the unit (Gigawatts),

cum2 = second cumulant of the marginal capacity function, and

cum4 = fourth order cumulant of the marginal capacity function.

Function: DG1

Description: DG1 creates the coefficient for the second order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

where:

for = forced outage rate,

z3 = mean of the marginal capacity function,

cap = size of the unit (Gigawatts),

cum2 = second cumulant of marginal capacity function, and

cum3 = third cumulant of marginal capacity function.

Function: N2

Description: N2 creates the coefficient for the second order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

(App5.F.13d) $$N2 = -1 * (z2^2 - 1.0) * pinorm * Exp\frac{-z2^2}{2}$$

where:

pinorm = 0.39894228040, and

z2 = mean of the marginal capacity function.

Function: N3

Description: N3 creates the coefficient for the third order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

(App5.F.13e) $$N3 = -1 * (z3^3 - 3 * z3) * pinorm * Exp(\frac{-z3^2}{2})$$

where:

pinorm = 0.39894228040, and

z3 = mean of the marginal capacity function.

Function: N5

Description: N5 creates the coefficient for the fifth order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

(App5.F.13f) $$N5 = -1 * (z5^5 - 10 * z5^3 + 15 * z5) * pinorm * Exp(\frac{-z5^2}{2})$$

where:

pinorm = 0.39894228040, and

z5 = mean of the marginal capacity function.