The electricity market module (EMM) represents the generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation from renewable fuels; 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 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from combined heat and power (CHP) 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 15 supply regions (Figure 10), and fuel consumption is allocated to the 9 Census divisions.

The EMM determines airborne emissions produced by the generation of electricity. It represents limits for sulfur dioxide and nitrogen oxides specified in the Clean Air Act Amendments of 1990. The EMM can also examine potential legislation that requires more stringent restrictions on sulfur dioxide and nitrogen oxides as well as limits on mercury and carbon dioxide.

Operating (dispatch) decisions are provided by the cost–minimizing mix of fuel and variable operating and maintenance (O&M) costs, subject to environmental costs. Capacity expansion is determined by the least–cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region, season, and time of day. The solution to the submodules of 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 viewed as follows:

- The load and demand–side management submodule processes electricity demand to construct load curves
- The electricity capacity planning submodule projects the construction of new utility and nonutility plants, the level of firm power trades, and the addition of scrubbers for environmental compliance
- The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in select regions to be dispatched for another regions needs (economy trade)
- The electricity finance and pricing submodule calculates total revenue requirements for each operation and computes average and marginal–cost based electricity prices.

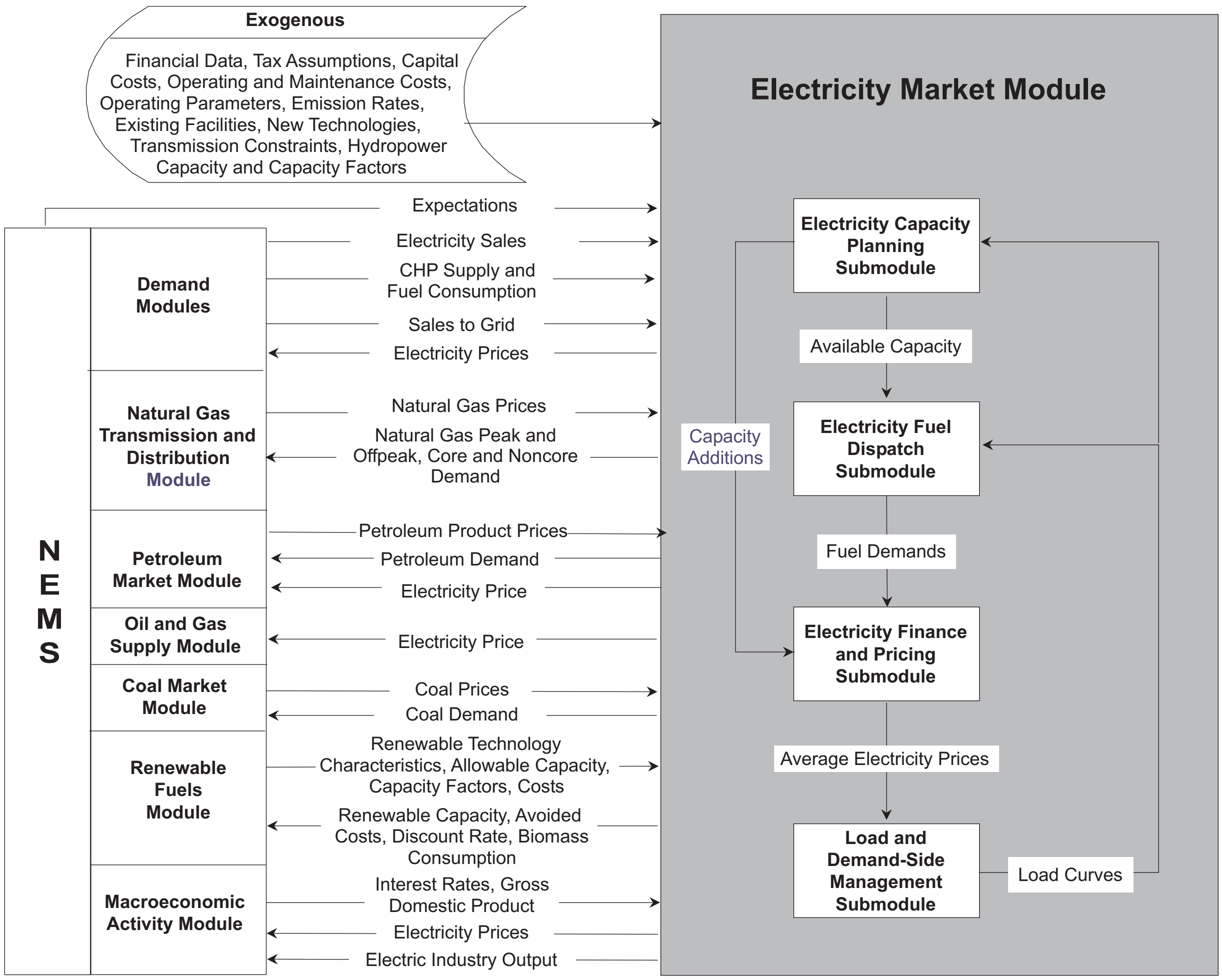
Electricity Capacity Planning Submodule

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 costs for utility and nonutility technologies. When new capacity is required to meet growth in electricity demand, the technology choosen is determined by 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.

The expected utilization of the capacity is important in the decision–making process. A technology with

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

Figure 9. Electricity Market Module Structure



relatively high capital costs but comparatively low operating costs (primarily fuel costs) 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 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.

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 central–station generating technologies are represented, as listed on page 46. The EMM also considers two distributed generation technologies–baseload and peak.

Uncertainty about investment costs for new technologies is captured in ECP using technological optimism and learning factors. The 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. For new technologies, cost reductions due to learning also account for international experience in building generating capacity.

he decrease in overnight capital costs due to learning depends on the stage of technological development. The cost for a revolutionary technology is assumed to decrease by 10 percent for the first three doublings of capacity constructed, 5 percent for the next five

Figure 10. Electricity Market Module Supply Regions

doublings, and 1 percent for every doubling thereafter. The cost for an evolutionary technology is assumed to decrease by 5 percent for the first five doublings and 1 percent for every doubling thereafter. The cost for a conventional technology is assumed to decrease by 1 percent for every doubling of capacity constructed.

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 the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the learning effects calculation. Capital costs, heat rates, and first year of availability from the Annual Energy Outlook 2003 reference case are shown on page 46; capital costs represent the costs of building new plants beginning in 2002. For renewable technologies, the capital costs are for California, which is representative of the United States. Additional information about costs and performance characteristics can be found on page 73 of the *Assumptions to the Annual Energy Outlook 2003*.[27]

Initially, investment decisions are determined in 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, ECP uses a market–sharing algorithm to adjust the initial solu-

[27] Energy Informtion Administration, *Assumptions to the Annual Energy Outlook 2003*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf (January 2003).

tion and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

Fossil–fired steam and nuclear plant retirements are calculated endogenously within the model. Plants are retired if the market price of electricity is not sufficient to support continued operation. The expected revenues from these plants are compared to the annual going–forward costs, which are mainly fuel and operations and maintenance costs. A plant is retired if these costs exceed the revenues and the overall cost of electricity can be reduced by building replacement capacity.

The ECP submodule also determines whether to contract for unplanned 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 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.

Central–Station Generating Technologies

Fossil
Existing coal steam plants (with or without environmental controls)
New pulvberized coal with environmental controls
Advanced clean coal technology
Advanced clean coal technology with sequestration
Oil/Gas steam
Conventional combined cycle
Advanced combined cycle
Advanced combined cycle with sequestration
Conventional combustion turbine
Advanced combustion turbine
Fuel Cells
Nuclear
Conventional nuclear
Advanced nuclear
Renewables
Conventional hydropower
Pumped storage
Geothermal
Solar-thermal
Solar-photovoltaic
Wind
Wood
Municipal solid waste
Environmental controls include flue gas desulfurization (FGD), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), fabric filters, spray cooling, activated carbon injection (ACI), and particulate removal equipment.

2002 Overnight Capital Costs (including Contingencies), 2002 Heat Rates, and Online Year by Technology for the AEO2003 Reference Case

Technology	Capital Costs[1/] (2001$/Kwhr)	2002 Heat Rates (Btu/Kwhr)	Online Year[2/]
Advanced Combustion Turbine	460	8,550	2004
Conventional Combustion Turbine	409	10,450	2004
Advanced Gas/Oil Combined Cycle	608	7,000	2005
Conventional Gas/Oil Combined Cycle	536	7,500	2005
Scrubbed Coal New	1,154	9,000	2006
Integrated Gas Combined Cycle	1,367	8,000	2006
Fuel Cells	2,137	7,500	2005
Advanced Nuclear	2,117	10,400	2007
Biomass	1,763	8,911	2006
Solar Thermal	2,594	10,280	2005
Solar Photovoltaic	3,915	10,280	2004
Wind	1,003	10,280	2005

[1/]Overnight capital cost include contingency factors, and exclude regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2002.
[2/]Online year represents the first year that a new unit could be completed, given an order date of 2002.

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 uses merit order dispatching; that is, utility, independent power producer, and small power producer plants are dispatched until demand is met in a sequence based on their operating costs, with least–cost plants being operated first. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics of units serve as constraints. Coal–fired capacity can cofire with biomass in order to lower operating costs and/or emissions.

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 operation of utility and nonutility plants for each region is simulated over six seasons to reflect the seasonal variation in electricity demand.

Interregional economy trade is also represented in the EFD submodule by allowing surplus generation in one region to satisfy electricity demand in an importing 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 importing region if it results in a 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 simulates both competitive electricity pricing and the cost–of–service method often used by State regulators to determine the price of electricity. While there is considerable near–term uncertainty, twenty–two States and the District of Columbia either had or were still planning to initiate competitive retail pricing of electricity at the time the AEO2003 was prepared. In these States, it is assumed that such programs are in effect as of the date established by each State's legislation and/or regulations. The remaining States are assumed to continue traditional cost-of-service regulation through 2025.

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 operation—generation, transmission, and distribution—for pricing of electricity in the fully regulated States. Revenue requirements shared over sales by customer class yield the price of electricity for each class. Electricity prices are returned to the demand modules. In addition, the submodule generates detailed financial statements.

For those States for which it is applicable, EFP also 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. 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.

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.

Emissions

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 pollution constraints 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 addition to SO_2 and NO_X, the EMM also determines mercury and carbon dioxide emissions. It represents control options to reduce emissions of these four gases, either individually or in any combination. Fuel switching from coal to natural gas, renewables, or nuclear can reduce all of these emissions. Flue gas desulfurization equipment can decrease SO_2 and mercury emissions. Selective catalytic reduction can reduce NO_X and mercury emissions. Selective non-catalytic reduction and low–NO_X burners can lower NO_X emissions. Fabric filters, spray cooling, and activated carbon injection can reduce mercury emissions. Lower emissions resulting from demand reductions are determined in the end-use demand modules.