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Electricity Market Module

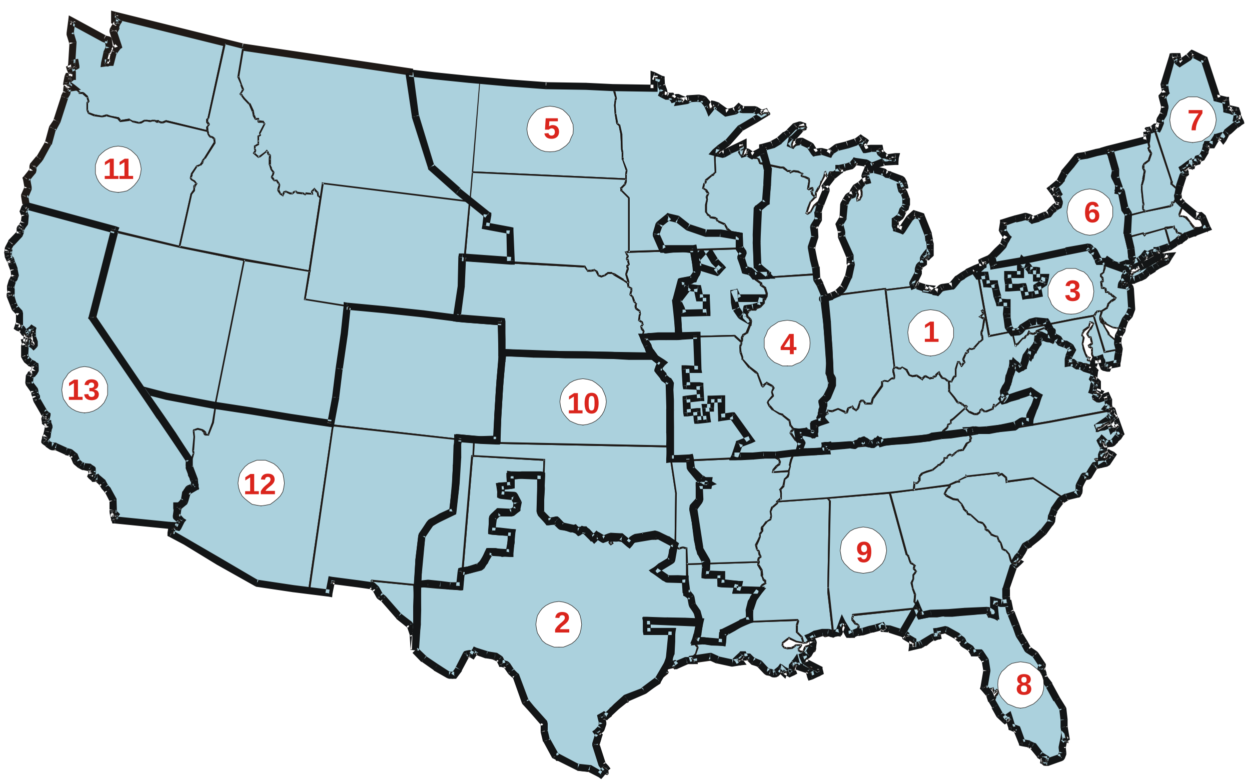
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand electricity, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *Electricity Market Module of the National Energy Modeling System 2009*, DOE/EIA-M068(2009).

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM Regions

The supply regions used in EMM are based on the North American Electric Reliability Council regions and subregions shown in Figure 6 (region definitions as of 2004).

Figure 6. Electricity Market Model Supply Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8 Florida Reliability Coordinating Council (FL)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13 California (CA)

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. Generating Capacity Types Represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Advanced Coal with carbon sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Integrated Gasification Combined-Cycle
Solar Thermal - Central Receiver
Solar Photovoltaic - Single Axis Flat Plate
Wind
Wind Offshore

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of No_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

New Generating Plant Characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies are assumed to decline linearly through 2025.

The overnight costs shown in Table 8.2 are the cost estimates to build a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers that represent variations in the cost of labor. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

The base overnight costs for *AEO2009* were updated to reflect current costs and capture some of the rapid increases due to rising comodity costs. A new cost adjustment factor was also implemented based on the producer price index for metals and metal products, allowing the overnight costs to fall in the future if this index drops, or rise further if it increases.

Table 8.2. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtime (Years)	Base Overnight Cost in 2008 ($2007/kW)	Contingency Factors		Total Overnight Cost in 2008[4] (2007 $/kW)	Variable O&M[5] ($2007 mills/kWh)	Fixed O&M[5] ($2007/kW)	Heatrate[6] in 2008 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
					Project Contingency Factor[2]	Technological Optimism Factor[3]					
Scrubbed Coal New[7]	2012	600	4	1,923	1.07	1.00	2,058	4.59	27.53	9,200	8,740
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2012	550	4	2,223	1.07	1.00	2,378	2.92	38.67	8,765	7,450
IGCC with Carbon Sequestration	2016	380	4	3,172	1.07	1.03	3,496	4.44	46.12	10,781	8,307
Conv Gas/Oil Comb Cycle	2011	250	3	917	1.05	1.00	962	2.07	12.48	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2011	400	3	877	1.08	1.00	948	2.00	11.70	6,752	6,333
ADV CC with Carbon Sequestration	2016	400	3	1,683	1.08	1.04	1,890	2.94	19.90	8,613	7,493
Conv Combustion Turbine[8]	2010	160	2	638	1.05	1.00	670	3.57	12.11	10,810	10,450
Adv Combustion Turbine	2010	230	2	604	1.05	1.00	634	3.17	10.53	9,289	8,550
Fuel Cells	2011	10	3	4,640	1.05	1.10	5,360	47.92	5.65	7,930	6,960
Advanced Nuclear	2016	1350	6	2,873	1.10	1.05	3,318	0.49	90.02	10,434	10,434
Distributed Generation -Base	2011	2	3	1,305	1.05	1.00	1,370	7.12	16.03	9,050	8,900
Distributed Generation -Peak	2010	1	2	1,566	1.05	1.00	1,645	7.12	16.03	10,069	9,880
Biomass	2012	80	4	3,339	1.07	1.05	3,766	6.71	64.45	9,646	7,765
MSW - Landfill Gas	2010	30	3	2,377	1.07	1.00	2,543	0.01	114.25	13,648	13,648
Geothermal [7,9]	2010	50	4	1,630	1.05	1.00	1,711	0.00	164.64	34,633	30,301
Conventional Hydropower[9]	2012	500	4	2,038	1.10	1.00	2,242	2.43	13.63	9,919	9,919
Wind	2009	50	3	1,797	1.07	1.00	1,923	0.00	30.30	9,919	9,919
Wind Offshore	2012	100	4	3,416	1.10	1.03	3,851	0.00	89.48	9,919	9,919
Solar Thermal[7]	2012	100	3	4,693	1.07	1.00	5,021	0.00	56.78	9,919	9,919
Photovoltaic[7]	2011	5	2	5,750	1.05	1.00	6,038	0.00	11.68	9,919	9,919

[1]Online year represents the first year that a new unit could be completed, given an order date of 2008. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit in 2009 for wind and 2010 for the others.

[2]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."

[3]The technological optimism factor is applied to the first four units of a new, unproven design. It reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2008.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2007. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

[7]Capital costs are shown before investment tax credits are applied.

[8]Combustion turbine units can be built by the model prior to 2010 if necessary to meet a given region's reserve margin.

[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are not based on any specific technology model, but rather, are meant to represent the cost and performance of typical plants under normal operating conditions for each plant type. Key sources reviewed are listed in the 'Notes and Sources' section at the end of the chapter.

Technological Optimism and Learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 8.3). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function has the nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 8.3. Learning Parameters for New Generating Technology Components

Technology Component	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2025
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	20%	10%	1%	3	5	20%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass IGCC	20%	10%	1%	3	5	20%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	1%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

[1]HRSG = Heat Recovery Steam Generator

Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

The progress ratio (*pr*) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (f) is an exogenous parameter input for each component (Table 8.3). Consequently, the progress ratio and *f* are related by:

$$pr = 2^{-b} = (1 - f)$$

The parameter "b" is calculated by (b =-(ln(1-*f*)/ln(2)). The parameter "a" can be found from initial conditions. That is,

$$a = OC(C0)/C0^{-b}$$

where C0 is the cumulative initial capacity. Thus, once the rates of learning (f) and the cumulative capacity (C0) are known for each interval, the corresponding parameters (a and b) of the nonlinear function are known. Three learning steps were developed, to reflect different stages of learning as a new design is introduced to the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. All design components receive a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rate by component is calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 8.4). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component. These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning.

Table 8.4. Component Cost Weights for New Technologies

Technology	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep Biomass IGCC
Integrated Coal_Gasification Comb Cycle (IGCC)	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	0%	12%	16%	25%	0%	20%	0%	0%	27%

Note: All unlisted technologies have a 100% weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.

HRSG = Heat Recovery Steam Generator.

Source: Market Based Advanced Coal Power Systems, May 1999, DOE/FE-0400

Table 8.5 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning. All non-capacity components, such as the balance of plant category, contribute 100 percent toward the component learning.

International Learning. In *AEO2009*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new

Table 8.5. Component Capacity Weights for New Technologies

Technology	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuelprep Biomass IGCC
Integrated Coal_Gasification Comb Cycle (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 Cycle	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	0%	67%	33%	100%	0%	100%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

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 U.S. market, 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 domestic learning effects calculation.

AEO2009 includes 5,000 megawatts of advanced coal gasification combined-cycle capacity, 5,244 megawatts of advanced combined-cycle natural gas capacity, 11 megawatts of biomass capacity and 47 megawatts each of traditional wind and offshore wind capacity to be built outside the United States from 2000 through 2003. The learning function also includes 7,200 megawatts of advanced nuclear capacity, representing two completed units and four additional units under construction in Asia.

Distributed Generation

Distributed generation is modeled in the end-use sectors as well as in the EMM, which is described in the appropriate chapters. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Representation of Electricity Demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Council regions and subregions) using historical hourly load data. The load duration curve in the EMM is made up of 9 time slices. First, the load data is split into three seasons, (winter - December through March, summer - June through September, and fall/spring). Within each season the load data is sorted from high to low, and three load segments are created - a peak segment representing the top 1 percent of the load, and then two off-peak segments representing the next 49 percent and 50 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an iterative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted each model cycle until the two costs converge. The resulting reserve margins from the *AEO2009* reference case range from 10 to 15 percent.

Fossil Fuel-Fired and Nuclear Steam Plant Retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the expected revenues from these plants are not sufficient to cover the annual going forward costs, the plant is assumed to retire if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant specific based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $17 per kW for coal plants and $21 per kW for nuclear plants (in 2007 dollars). These costs are added to existing plants regardless of their age. Beyond 30 years of age an additional $6 per kW capital charge for fossil plants, and $31 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

Biomass Co-firing

Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $119 to $273 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional supply.

Nuclear Uprates

The AEO2009 nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modifications, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the AEO projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2009* assumes that all of those uprates approved, pending or expected by the NRC will be implemented, for a capacity increase of 3.4 gigawatts between 2008 and 2030. Table 8.6 provides a summary of projected uprate capacity additions by region. In cases where the NRC did not specifically identify the unit expected to uprate, EIA assumed the units with the lowest operating costs would be the next likely candidates for power increases.

Table 8.6. Nuclear Uprates by EMM Region
(gigawatts)

Region	
East Central Area Reliability Coordination Agreement	0.1
Electric Reliability Council of Texas	0.4
Mid-Atlantic Area Council	0.7
Mid-America Interconnected Network	0.2
Mid-Continent Area Power Pool	0.0
New York	0.1
New England	0.1
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	1.5
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.3
California	0.1
Total	3.4

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on Nuclear Regulatory Commission survey, http://www.nrc.gov/reactors/operating/licensing/power-uprates.html

Interregional Electricity Trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the National Electric Reliability Council and Western Electric Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's *Electricity Supply and Demand Database 2007*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2016 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2016, they are assumed to be phased out by 2025. In addition, in certain regions where data show an established commitment to build plants to serve another region, new plants are permitted to be built to serve the other region's needs. This option is available to compete with other resource options.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are allowed to exchange power.

International Electricity Trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Existing and planned transactions are obtained from the North American Electric Reliability Council's *Electricity Supply and Demand Database 2007*. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report *Northern Lights: The Economic and Practical Potential of Imported Power from Canada*, (DOE/PE-0079).

International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity Pricing

The reference case assumes a transition to full competitive pricing in New York, Mid-Atlantic Area Council, and Texas, and a 95 percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998. In addition electricity prices in the East Central Area Reliability Council, the Mid-American Interconnected Network, the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a mix of both competitive and regulated prices. Since some States in each of these regions have not taken action to deregulate their pricing of electricity, prices in those States are assumed to continue to be based on traditional cost-of-service pricing. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, with the weight based on the percent of electricity load in the region that has taken action to deregulate. The reference case assumes that State-mandated price freezes or reductions during a specified transition period will occur based on the terms of the legislation. In general, the transition period is assumed to occur over a ten-year period from the effective date of restructuring, with a gradual shift to marginal cost pricing. In regions where none of the states in the region have introduced competition—Florida Reliability Coordinating Council and Mid-Continent Area Power Pool—electricity prices are assumed to remain regulated and the cost-of-service calculation is used to determine electricity prices.

The price of electricity to the consumer is comprised of the price of generation, transmission, and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the *AEO*; that is, the price of transmission and distribution is based on the average cost. In competitive regions, an algorithm in place allows customers to compete for better rates among rate classes as long as the overall average cost is met. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The marginal cost includes fuel, operation and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. The price of electricity in the regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution.

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2009*. Both General and Administrative (G&A) expenses and Operations and Maintenance (O&M) expenses have shown declines in recent years. The O&M declines show variation based on the plant type. A regression analysis of recent data was done to determine the trend, and the resulting function was used to project declines throughout the projection. The analysis of G&A costs used data from 1992 through 2001, which had a 15 percent overall decline in G&A costs, and a 1.8 percent average annual decline rate. The *AEO2009* projection assumes a further decline of 18 percent by 2025 based on the results of the regression analysis. The O&M cost data was available from 1990 through 2001, and showed average annual declines of 2.1 percent for all steam units, 1.8 percent for combined cycle and 1.5 percent for nuclear. The *AEO2009* assumes further declines in O&M expenses for these plant types, for a total decline through 2025 of 17 percent for combined cycle, 15 percent for steam and 8 percent for nuclear.

There have been ongoing changes to pricing structures for ratepayers in competitive States since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various States, and surcharges in California relating to the 2000-2001 energy crisis there. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were now explicitly added to the distribution portion, and sometimes the transmission portion of the customer bill regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, State regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee. For *AEO2009*, typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include: transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion.

Transmission costs for the AEO are traditionally projected based on regressions of historical spending per non-coincident peak time electricity use to ensure that the model builds enough transmission infrastructure to accommodate growth in peak electricity demand. However, since spending decreased throughout the 1990s we have had to add in extra spending on transmission. Our additions were based on several large studies, such as the Department of Energy's National Transmission Grid Study, which set out to document how much spending would be needed to keep the national grid operating efficiently. Transmission spending has in fact been increasing very recently. We will be monitoring transmission spending closely over the next several years and updates will be made as new information becomes available.

Fuel Price Expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 20-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas and oil are derived using rational expectations, or 'perfect foresight'. In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the projection horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Legislation and Regulations

Clean Air Act Amendments of 1990 (CAAA90) and Clean Air Interstate Rule (CAIR)

The Clean Air Interstate Rule is a cap-and-trade program promulgated by the EPA in 2005 to reduce SO2 and NOx emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter, and to further emissions reductions already achieved through earlier programs. On July 11, 2008 the U.S. District Court of Appeals overturned CAIR, and the program is not included in the AEO2009, and allowance prices for SO2 and NOx are not modeled. However, on December 23, 2008, the Court of Appeals issued a new ruling that allowed CAIR to remain in effect while EPA determines the appropriate modifications to address the original objections. This December ruling came after the cutoff date for AEO2009, so CAIR remains out of the model. Nonetheless, States are still required to meet their NAAQS, which will require emissions reductions and are projected to do so through the addition of emission control equipment and the elimination of higher sulfur coal consumption at unscrubbed electricity plants after 2014.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NO_x) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired, and tangential fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet their Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NO_x limits are incorporated in EMM.

In addition, the EPA has issued rules to limit the emissions of NOx, specifically calling for capping emissions during the summer season in 22 Eastern and Midwestern states. After an initial challenge, these rules have been upheld, and emissions limits have been finalized for 19 states and the District of Columbia (Table 8.7). Within EMM, electric generators in these 19 states must comply with the limit either by reducing their own emissions or purchasing allowances from others who have more than they need.

The costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NO_x) are given below for 300, 500, and

Table 8.7. Summer Season NO_x Emissions Budgets for 2004 and Beyond
(Thousand tons per season)

State	Emissions Cap
Alabama	29.02
Connecticut	2.65
Delaware	5.25
District of Columbia	0.21
Illinois	32.37
Indiana	47.73
Kentucky	36.50
Maryland	14.66
Massachusetts	15.15
Michigan	32.23
New Jersey	10.25
New York	31.04
North Carolina	31.82
Ohio	48.99
Pennsylvania	47.47
Rhode Island	1.00
South Carolina	16.77
Tennessee	25.81
Virginia	17.19
West Virginia	26.86

Source: U.S. Environmental Protection Agency, Federal Register, Vol. 65, number 42 (March 2, 2002) pages 11222-11231.

700-megawatt coal plants. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NO_x. The costs per megawatt of capacity decline with plant size and are shown in Table 8.8.

Table 8.8. Coal Plant Retrofit Costs
(2007 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	310	128
500	237	111
700	195	101

Note: The model was run for each individual plant assuming a 1.3 retrofit factor for FGDs and 1.6 factor for SCRs.

Source: CUECOST3.xls model (as updated 2/9/2000) developed for the Environmental Protection Agency by Raytheon Engineers and Constructors, Inc. EPA Contract number 68-D7-0001.

Mercury Regulation

The Clean Air Mercury Rule set up a national cap-and-trade program with emission limits set to begin in 2010. This rule was vacated in February, 2008 and therefore is not included in the AEO2009. However, many States had already begun adopting more stringent regulations calling for the application of the best available control technology on all electricity generating units of a certain capacity. After the court's decision, more States imposed their own regulations. Because State laws differ, a rough estimate was created that generalized the various State programs into a format that could be used in NEMS. The EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NO_x or an SO_2 scrubber. They can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $5 (2007 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $65 per kilowatt of capacity.[1] The amount of activated carbon required to meet a given percentage removal target is given by the following equations.[2]

For a unit with a CSE, using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 – (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 – (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 – (28.049 / (ACI + 0.428))

For a unit with a HSE/Other, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 – (43.068 / (ACI + 0.421))

ACI = activated carbon injected in pounds per million actual cubic feet.

Power Plant Mercury Emissions Assumptions

The Electricity Market Module (EMM) of the National Energy Modeling System (NEMS) represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide (SO_2) control devices, nitrogen oxide (NO_x) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40 percent of the mercury that was in the fuel is removed by various parts of the plant. Table 8.9 provides the assumed EMFs for existing coal plant configurations without mercury specific controls.

Table 8.9. Mercury Emission Modification Factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NO_x Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	—	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	—-	0.05	0.75	0.75	0.05	0.75	1.00
None	CSE	—-	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	—-	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	—-	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	—-	0.60	0.85	0.85	0.60	0.85	1.00

Notes: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction, — = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations.

Sources: EPA, EMFs. http://www.epa.gov/clearskies/technical.html EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO_2 Scrubber and NO_x Control Equipment Additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, 31.5 gigawatts of capacity are assumed to add these controls (Table 8.10). The greatest number of retrofits is expected to occur in the Midwestern States, where there is a large base of coal capacity impacted by the SO_2 limit in CAIR, as well as in the Southeastern Electric Reliability Council because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 8.10. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Gigawatts)
East Central Area Reliability Coordination Agreement	15.3
Electric Reliability Council of Texas	0.0
Mid-Atlantic Area Council	3.5
Mid-America Interconnected Network	1.1
Mid-Continent Area Power Pool	0.6
New York	0.0
New England	0.0
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	10.3
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.7
California	0.0
Total	31.5

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on public announcements and reports to Form EIA-767, "Annual Steam-Electric Plant Operation and Design Data".

Companies are also announcing plans to retrofit units with controls to reduce NOx emissions to comply with emission limits in certain states. In the reference case planned post-combustion control equipment amounts to 18.7 gigawatts of selective catalytic reduction (SCR) and just 0.3 gigawatts of selective non-catalytic reduction (SNCR) equipment.

Energy Policy Acts of 1992 (EPACT92) and 2005 (EPACT05)

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million (per gigawatt) annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. In the *AEO2009* Reference case it is projected that 3 gigawatts of new nuclear capacity will be built by 2020, each receiving the full credit worth 1.8 cents per kilowatthour. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Energy Improvement and Extension Act 2008 (EIEA2008)

EIEA2008 extended the PTC to qualifying wind facilities entering service by December 31, 2009. Other facilities eligible to receive the PTC, such as geothermal, hydroelectric, and biomass, were extended through December 31, 2010.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make it economic to do so.

Electricity Alternative Cases

Fossil Cost Cases

The *high fossil cost case* assumes that the costs of all fossil generating technologies will remain at current costs during the projection period, that is, no learning reductions are applied to the cost. (Table 8.11) Capital costs of non-fossil generating technologies are the same as those assumed in the reference case.

In the *low fossil cost case*, capital costs, and operating costs for the fossil technologies are assumed to be 25 percent lower than Reference case levels in 2030. Since learning occurs in the Reference case, costs and performance in the high case are reduced from initial levels by more than 25 percent. Capital costs are reduced by 40 percent to 47 percent between 2009 and 2030.

The *low and high fossil cost cases* are fully-integrated runs, allowing feedback from the end-use demand and fuel supply modules.

Nuclear Cost Cases

For nuclear power plants, two nuclear cost cases analyze the sensitivity of the projections to lower and higher costs for new plants. The cost assumptions for the *low nuclear cost case* reflect a 25 percent reduction in the capital and operating cost for the advanced nuclear technology in 2030, relative to the reference case. Since the reference case assumes some learning occurs regardless of new orders and construction, the reference case already projects a 29 percent reduction in capital costs between 2009 and 2030. The *low nuclear cost case* assumes a 46 percent reduction between 2009 and 2030. The *high nuclear cost case* assumes that capital costs for the advanced nuclear technology do not decline from 2009 levels (Table 8.12). The *high nuclear cost case* also assumes that all existing nuclear plants will retire after 55 years, rather than allowing operation to 60 years. This results in a total of 31 GW of retirements by 2030. Cost and performance characteristics for all other technologies are as assumed in the reference case.

Electricity Plant Capital Cost Cases

The costs to build new power plants have risen dramatically in the past few years, driven primarily by significant increases in the costs of construction related materials, such as cement, iron, steel and copper. For the *AEO2009* reference case, initial overnight costs for all technologies were updated to be consistent with costs estimates in the early part of 2008. A cost adjustment factor based on the projected producer price index for metals and metal products was also implemented, allowing the overnight costs to change over time following the index. Although there is significant correlation between commodity prices and power plant costs, there may be other factors that influence future costs that raise the uncertainties surrounding the future costs of building new power plants. For the *AEO2009*, three additional cost cases were run which focus on the uncertainties of future plant construction costs (Table 8.13). These cases use exogenous assumptions for the annual adjustment factors, rather than linking to the metals price index. The cases are discussed in the Issues in Focus article, “Electricity Plant Cost Uncertainties.”

The *frozen plant capital costs case* assumes that base overnight costs for all new electric generating technologies are frozen at 2013 levels. Cost decreases due to learning can still occur. In this case, costs do decline slightly over the projection, but by 2030 are roughly 20 percent above reference case costs for the same year.

The *high plant capital costs case* assumes that base overnight costs for all new electric generating technologies continue increasing throughout the projection, by assuming the cost factor increases 25 percentage points between 2013 and 2030. Cost decreases due to learning can still occur and may partially offset these increases, but for most technologies, costs in 2030 are above current costs. Relative to the reference case, costs in 2030 are about 50 percent higher.

Table 8.11. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2008 (Reference) (2007 $/kW)	Total Overnight Cost[1] Reference (2007 $/kW)	High Fossil Cost (2007 $/kW)	Low FossilCost (2007 $/kW)
Pulverized Coal	2058			
2015		2029	2058	1825
2020		1900	2058	1629
2025		1726	2058	1434
2030		1654	2058	1240
Advanced Coal	2378			
2015		2321	2378	2086
2020		2143	2378	1841
2025		1909	2378	1597
2030		1804	2378	1354
Advanced Coal withSequestration	3496			
2015		3366	3496	3040
2020		3076	3496	2660
2025		2714	3496	2280
2030		2533	3496	1900
Conventional Combined Cycle	962			
2015		949	962	852
2020		889	962	761
2025		807	962	670
2030		773	962	577
Advanced Gas	948			
2015		929	948	829
2020		857	948	732
2025		759	948	633
2030		717	948	536
Advanced Gas with Sequestration	1890			
2015		1816	1890	1637
2020		1651	1890	1427
2025		1444	1890	1216
2030		1340	1890	1004
Conventional CombustionTurbine	670			
2015		661	670	595
2020		619	670	531
2025		562	670	467
2030		539	670	404
Advanced CombustionTurbine	634			
2015		619	634	552
2020		565	634	483
2025		492	634	414
2030		460	634	345

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: AEO2009 National Energy Modeling System runs: AEO2009.D120908A, HCFOSS09.D121108A, LCFOSS09.D121608A.

The *falling plant capital costs case* assumes that base overnight costs for all new electric generating technologies fall more rapidly than in the reference case, starting in 2013. In 2030, the cost factor is assumed to be 25 percentage points below the reference case value.

Table 8.12. Cost Characteristics for Advanced Nuclear Technology: Three Cases

		Total Overnight Cost[1]		
Advanced Nuclear Technology	Overnight Cost in 2008 (Reference) (2007$/kW)	Reference Case (2007$/kW)	High Nuclear Cost (2007$/KW)	Low Nuclear Cost (2007$/kW)
	3318			
2015		3213	3318	2879
2020		2954	3318	2512
2025		2535	3318	2146
2030		2372	3318	1779

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.

Source: AEO2009 National Energy Modeling System runs: AEO2009.D120908A, HCNUC09.D121108A, LCNUC09.D121108A.

Table 8.13. Cost Characteristics for Electric Generating Technologies, Four Cases

	2008	Reference		Frozen Costs		Rising Costs		Falling Costs	
		2015	2030	2015	2030	2015	2030	2015	2030
Scrubbed Coal New	2058	2029	1654	2056	1964	2117	2456	1959	1170
Integrated Coal-Gasification Comb	2378	2321	1804	2352	2141	2421	2668	2239	1276
IGCC with carbon sequestration	3496	3366	2533	3411	3006	3511	3746	3248	1791
Conv Gas/Oil Comb Cycle	962	949	773	962	918	990	1144	916	547
Adv Gas/Oil Comb Cycle (CC)	948	929	717	941	851	969	1060	895	507
Adv CC with carbon sequestration	1890	1816	1340	1840	1590	1894	1981	1751	947
Conv Comb Turbine	670	661	539	670	640	689	797	638	381
Adv Comb Turbine	634	619	460	628	545	646	680	596	325
Fuel Cells	5360	5000	3456	5066	4104	5215	5113	4827	2445
Adv Nuclear	3318	3213	2372	3255	2951	3351	3676	3101	1653
Distributed Generation - Base	1370	1326	1028	1344	1221	1384	1521	1280	728
Distributed Generation - Peak	1645	1593	1235	1614	1466	1661	1826	1537	851
Bioimass	3766	3634	2488	3682	3012	3790	3834	3506	1735
MSW - Landfill Gas	2543	2508	2043	2541	2426	2616	3023	2421	1446
Geothermal	1711	4398	3942	4456	4661	4588	5825	4246	2678
Conventional Hydropower	2242	2318	1920	2348	2157	2418	2690	2192	1179
Wind	1923	1910	1615	1935	1918	1992	2389	1844	1143
Wind Offshore	3851	3709	2859	3758	3395	3869	4230	3581	2023
Solar Thermal	5021	4604	3082	4665	3660	4803	4560	4445	2181
Photovoltaic	6038	5633	3823	5707	4539	5875	5655	5437	2705

Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: *AEO2009* National Energy Modeling System runs: AEO2009.D120908A, FRZCST09.D121108A, INCCST09.D121208A, DECCST09.D121108A.

Notes and Sources

[1] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[2] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

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