Report #:DOE/EIA-0554(2006)
Release date: March 2006
Next release date: March 2007

Electricity Market Module

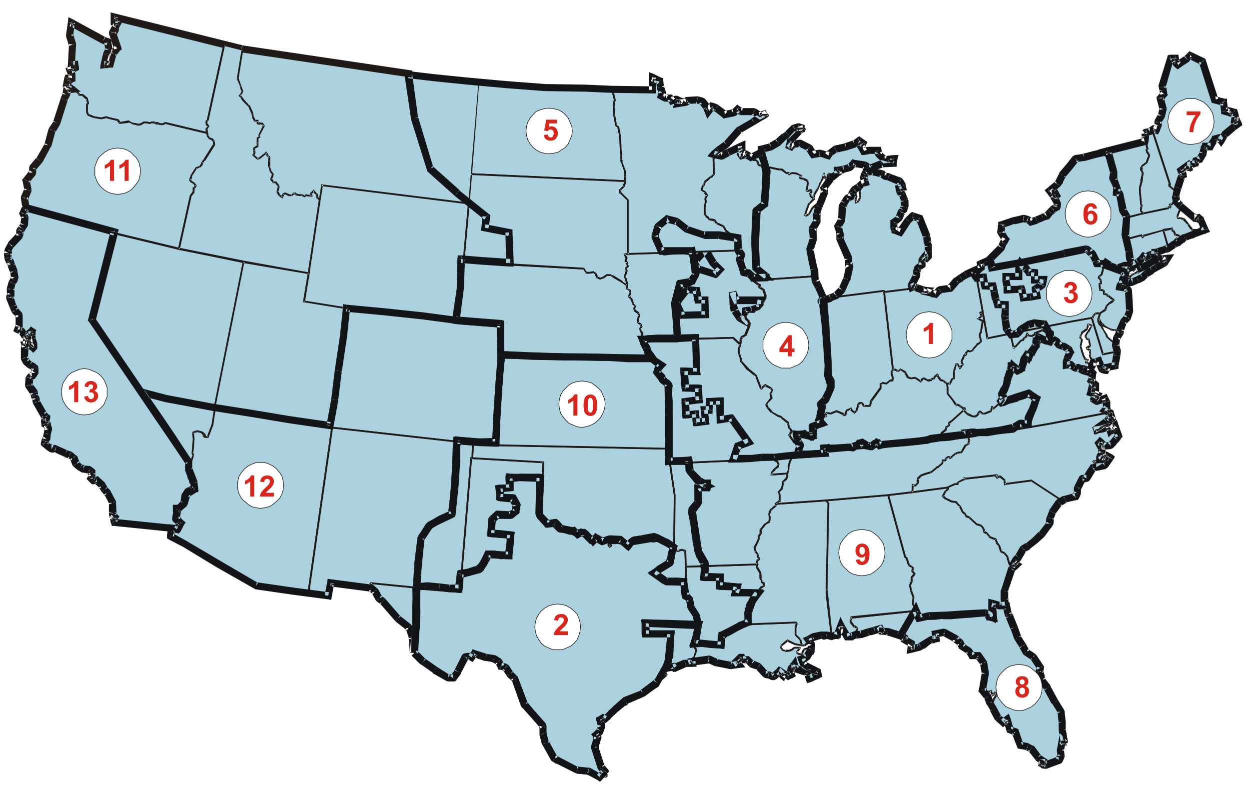
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand electricity, and electricity finance and pricing. It includes nonutility capacity 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 2006*, DOE/EIA-M068(2006).

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.

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 37.

Table 37. 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

[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 38). 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 2015.

The overnight costs shown in Table 38 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.

Table 38. Cost and Performance Characteristics of New Central Station Electricity Generating Technologies

Technology	Online Year[1]	Size (mW)	Leadtimes (Years)	Base Overnight Costs in 2005 ($2004/kW)	Contingency Factors: Project Contingency Factor	Contingency Factors: Technological Optimism Factor[2]	Total Overnight Cost in 2005[3] (2004 $/kW)	Variable O&M[5] ($2004 mills/kWh)	Fixed O&M[5] ($2004/kW)	Heatrate in 2005 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
Scrubbed Coal New[7]	2009	600	4	1,167	1.07	1.00	1,249	4.18	25.07	8,844	8,600
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2009	550	4	1,349	1.07	1.00	1,443	2.65	35.21	8,309	7,200
IGCC with Carbon Sequestration	2010	380	4	1,873	1.07	1.03	2,065	4.04	41.44	9,713	7,920
Conv Gas/Oil Comb Cycle	2008	250	3	556	1.05	1.00	584	1.88	11.37	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2008	400	3	532	1.08	1.00	575	1.82	10.65	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,021	1.08	1.04	1,147	2.68	18.12	8,613	7,493
Conv Combustion Turbine[5]	2007	160	2	388	1.05	1.00	407	3.25	11.03	10,842	10,450
Adv Combustion Turbine	2007	230	2	367	1.05	1.00	385	2.89	9.59	9,227	8,550
Fuel Cells	2008	10	3	3,787	1.05	1.10	4,374	43.64	5.15	7,930	6,960
Advanced Nuclear	2013	1000	6	1,744	1.10	1.05	2,014	0.45	61.82	10,400	10,400
Distributed Generation -Base	2008	2	3	791	1.05	1.00	831	6.49	14.60	9,650	8,900
Distributed Generation -Peak	2007	1	2	951	1.05	1.00	998	6.49	14.60	10,823	9,880
Biomass	2009	80	4	1,659	1.07	1.02	1,809	3.13	48.56	8,911	8,911
MSW - Landfill Gas	2008	30	3	1,443	1.07	1.00	1,544	0.01	104.03	13,648	13,648
Geothermal[6,7]	2009	50	4	2,100	1.05	1.00	2,205	0.00	75.00	32,173	35,460
Conventional Hydropower[6]	2009	500	4	1,320	1.10	1.00	1,452	3.20	12.72	10,338	10,338
Wind	2008	50	3	1,091	1.07	1.00	1,167	0.00	27.59	10,280	10,280
Solar Thermal[7]	2008	100	3	2,589	1.07	1.10	3,047	0.00	51.70	10,280	10,280
Photovoltaic[7]	2007	5	2	3,981	1.05	1.10	4,598	0.00	10.64	10,280	10,280

[1]Online year represents the first year that a new unit could be completed, given an order date of 2005.

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

[3]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 2005.

[4]O&M = Operations and maintenance.

[5]Combustion turbine units can be built by the model prior to 2007 if necessary to meet a given region's reserve margin.

[6]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.

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

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 39). 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 39. 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	10%	5%	1%	3	5	10%
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%
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 39). 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 40). 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 40. 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%	33%	0%	20%	0%	0%	19%

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 41 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.

Table 41. 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.

International Learning. In *AEO2006*, 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 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.

AEO2006 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 of 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 38 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. However, unlike traditional load duration curves where the demands for an entire period would be ordered from highest to lowest, losing their chronological order, the load duration curves in the EMM are segmented into the 9 time periods shown in Table 42. The summer and winter peak periods are represented in the model by 2 vertical slices each (a peak slice and an off-peak slice) while the remaining 7 periods are represented by 1 vertical slice each, resulting in a total of 11 vertical slices.

Table 42. Load Segments in the Electricity Market Module

Season	Months	Period	Hours
Summer	June-September	Daytime	0700-1800
		Morning/Evening	0500-0700 and 1800-2400
		Night	0000-0500
Winter	December-March	Daytime	0800-1600
		Morning/Evening	0500-0800 and 1600-2400
		Night	0000-0500
Off-peak	April-May	Daytime	0700-1700
	October-November	Morning/Evening	0500-0700 and 1700-2400
		Night	0000-0500

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

The time periods shown were chosen to accommodate intermittent generating technologies (i.e., solar and wind facilities) and demand-side management programs.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are currently assumed for all EMM regions. Target reserve margins range from 9 to 17 percent, and were set based on an off-line analysis comparing the marginal cost of capacity and the cost of unserved energy.

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 $11 per kilowatt (kW) for oil and gas steam plants, $6 per kW for combined-cycle plants, and combustion turbines, $15 per kW for coal plants and $18 per kW for nuclear plants (in 2004 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 $28 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 $108 to $248 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.

New Nuclear Plant Orders

A new nuclear technology competes with other fossil-fired and renewable technologies as new generating capacity is needed to meet increasing demand, or replace retiring capacity, throughout the forecast period. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide. The capital cost assumptions in the reference case represent the expense of building a new single unit nuclear plant of approximately 1,000 megawatts at a new "Greenfield" site. Since no new nuclear plants have been built in the US in many years, there is a great deal of uncertainty about the true costs of a new unit. The estimate used for *AEO2006* is an average of the construction costs incurred in completed advanced reactor builds in Asia, adjusting for expected learning from other units still under construction.

Nuclear Uprates

The AEO2006 nuclear power forecast also 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 forecasts 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. The NRC approved 8 applications for power uprates in 2003, and another 12 were approved or pending in 2004. *AEO2006* assumes that all of those uprates will be implemented, as well as others expected by the NRC over the next 15 years, for a capacity increase of 3.2 gigawatts between 2005 and 2030. Table 43 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.

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 Electriic Reliability Council and

Table 43. Nuclear Upratres by EMM Region
(gigawatts)

Region	
East Central Area Reliability Coordination Agreement	0.2
Electric Reliability Council of Texas	0.4
Mid-Atlantic Area Council	0.3
Mid-America Interconnected Network	0.2
Mid-Continent Area Power Pool	0.0
New York	0.1
New England	0.2
Florida Reliability Coordinating Council	0.1
Southeastern Electric Reliability Council	1.6
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.1
California	0.0
Total	3.2

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

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 2004*. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2013 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2013, they are assumed to be phased out by 2022. 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 2004*. 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 as reported in the Canadian National Energy Board report *Energy Supply and Demand to 2025.*

Electricity Pricing

The reference case assumes a transition to full competitive pricing in New York, New England, Mid-Atlantic Area Council, and Texas. California returned to return 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 (Illinois, plus parts of Missouri, Michigan and Wisconsin), the Southeastern Electric Reliability Council, the Southwest Power Pool, the Northwest Power Pool, and the Rocky Mountain Power Area/Arizona are a weighted average 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 the region is a weighted average of the competitive price and the regulated price, with the weight based on the percent of 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, electricity prices are assumed to remain regulated. The cost-of-service calculation is used to determine electricity prices in regulated regions.

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 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, operating and maintenance, taxes, and a reliability price adjustment, which represents the value of capacity in periods of high demand. Therefore, the price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. The price of electricity in the four regions with a competitive generation market consists of the marginal cost of generation summed with the average costs of transmission and distribution. In the seven partially competitive regions the price is a combination of cost-of-service pricing and marginal pricing weighted by the share of sales.

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 *AEO2006*.

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 forecast.

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 *AEO2006* forecast 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 *AEO2006* 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.

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 forecast 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)

It is assumed that electricity producers comply with the CAIR, which mandates limits on sulfur dioxide (SO_2) and /or nitrogen oxide (NO_x) in 28 eastern states and the District of Columbia. The annual limits for SO_2 emissions are 3.6 million tons beginning in 2010 and 2.5 million tons starting in 2015. The corresponding limits of NO_x emissions are 1.5 million tons in 2009 and 1.3 million tons in 2015

Prior to the implementation of these targets, generators are still required to comply with the SO_2 and NO_x limits specified by the CAAA90. The western states not covered by the CAIR are assumed to comply with the CAAA90 throughout the forecast period. by 2010, the CAAA90 assigns an annual limit of 1.7 million tons for SO_2 in these areas. Utilities are assumed to satisfy the limits on sulfur emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. It is assumed that the market for trading emission allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal too be used.

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 44). 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 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 45.

Table 44. 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.

Clean Air Mercury Rule (CAMR)

The CAMR establishes a cap-and-trade program with a two-phase implementation. The regulation specifies a limit of 38 tons beginning in 2010 and 15 tons starting in 2018. To reduce mercury, power companies can change their fuels, redispatch their units, change the configuration of their units or add mercury specific controls. To represent this, 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 $4 (2004 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 $60 per kilowatt of capacity.[82] The amount of activated carbon required to meet a given percentage removal target is given by the following equations.[83]

Table 45. Coal Plant Retrofit Costs
(2004 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	282	116
500	215	101
700	179	92

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.

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 46 provides the assumed EMFs for existing coal plant configurations without mercury specific controls.

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, 22.1 gigawatts of capacity are assumed to add these controls (Table 47). The greatest number of retrofits is expected to occur in the Southeastern Electric Reliability Council because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 46. 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.

Table 47. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Gigawatts)
East Central Area Reliability Coordination Agreement	4.2
Electric Reliability Council of Texas	0.0
Mid-Atlantic Area Council	1.3
Mid-America Interconnected Network	0.0
Mid-Continent Area Power Pool	0.6
New York	0.0
New England	0.8
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	15.3
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.0
California	0.0
Total	22.1

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 11.0 gigawatts of selective catalytic reduction (SCR) and another 2.7 gigawatts of selective non-catalytic reduction (SNCR) equipment. These plants are located in thirteen States (Alabama, Georgia, Indiana, Kentucky, Michigan, Minnesota, North Carolina, New Jersey, Ohio, South Carolina, Tennessee, Texas and West Virginia) primarily in response to EPA rules.

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 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. 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).

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 and Technology Cases

Low and High, Fossil Technology Cases

The *low fossil case* assumes that the costs of advanced fossil generating technologies (integrated coal-gasification combined-cycle, advanced natural gas combined-cycle and turbines) will remain at current costs during the projection period, that is, no learning reductions are applied to the cost. Operating efficiencies for advanced technologies are assumed to be constant at 2005 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 48).

In the *high fossil case*, capital costs, heat rates and operating costs for the advanced coal and gas technologies are assumed to be ten 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 ten percent. Heat rates for advanced fossil technologies, in the high fossil case, fall to 16 to 22 percent below initial levels, while capital costs are reduced by 22 percent to 26 percent between 2005 and 2030.

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

Table 48. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2004 Reference (2004 $/kW)	Total Overnight Cost[1]			Heatrate in 2005 (Reference) Btu/kWhr	Heat Rate		
		Reference (2004 $/kW)	High Fossil (2004 $/kW)	Low Fossil (2004 $/kW)		Reference BTU/kWhr	High Fossil Btu/kWhr	Low Fossil Btu/kWhr
Pulverized Coal	1249				8844			
2010		1233	1233	1233		8763	8763	8763
2015		1217	1217	1217		8661	8661	8661
2020		1199	1202	1191		8600	8600	8600
2025		1184	1186	1176		8600	8600	8600
2030		1171	1171	1163		8600	8600	8600
Advanced Coal	1444				8309			
2010		1415	1376	1437		7939	7699	8309
2015		1386	1300	1437		7477	6937	8309
2020		1340	1223	1437		7200	6480	8309
2025		1265	1147	1437		7200	6480	8309
2030		1190	1070	1437		7200	6480	8309
Conventional Combined Cycle	584				7196			
2010		576	576	576		7031	7031	7031
2015		569	569	569		6866	6866	6866
2020		562	562	562		6800	6800	6800
2025		555	555	556		6800	6800	6800
2030		547	547	547		6800	6800	6800
Advanced Gas Technology	575				6752			
2010		565	552	573		6577	6314	6717
2015		555	528	573		6403	5875	6717
2020		532	502	573		6333	5700	6717
2025		517	476	573		6333	5700	6717
2030		502	452	573		6333	5700	6717
Conventional CombustionTurbine	407				10842			
2010		402	402	402		10664	10664	10664
2015		397	397	397		10486	10486	10486
2020		392	392	392		10450	10450	10450
2025		387	387	388		10450	10450	10450
2030		381	381	381		10450	10450	10450
Advanced CombustionTurbine	385				9227			
2010		378	368	383		8920	8492	9166
2015		369	347	383		8612	7828	9166
2020		347	329	383		8550	7695	9166
2025		333	308	383		8550	7695	9166
2030		320	288	383		8550	7695	9166

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

Source: AEO2006 National Energy Modeling System runs: AEO2006.D111905A, HFOSS06.D120105B, LFOSS06.D120105A.

Advanced Nuclear Cost Cases

For nuclear power plants, two advanced nuclear cost cases analyze the sensitivity of the projections to lower costs for new plants. The cost assumptions for the *advanced nuclear cost case* reflect a twenty 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 14 percent reduction in capital costs between 2005 and 2030. The advanced nuclear case therefore assumes a 31 percent reduction between 2005 and 2030. The *Nuclear vendor estimate case* assumptions are consistent with estimates from British Nuclear Fuel Limited (BNFL) for the manufacture of their

Advanced Pressurized Water Reactor (AP1000), as provided to DOE's Office of Nuclear Energy's Near-Term Deployment Working Group. In this case, the overnight capital cost of a new advanced nuclear unit is assumed to be $1,659 per kilowatt initially, declining to $1,136 per kilowatt for plants coming on line in 2030 (in year 2004 dollars)—18 percent lower initially than assumed in the reference case and 44 percent lower in 2030 (Table 49). Cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 49. Cost Characteristics for Advanced Nuclear Technology: Two Cases

		Total Overnight Cost[1]		
Advanced Nuclear	Overnight Cost in 2005 (Reference) (2004$/kW)	Reference Case (2004$/kW)	Advanced Nuclear (2004$/KW)	Nuclear Vendor Estimate (2004$/kW)
	2014			
2010		1964	1902	1659
2015		1913	1772	1528
2020		1832	1644	1310
2025		1782	1515	1136
2030		1733	1387	1136

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

Source: AEO2006 National Energy Modeling System runs: AEO2005.D111905A, ADVNUC20.D120105A, ADVNUC5A.D120105A.

Notes and Sources

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

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

Sources referenced in Table 38

Fossil technology cost and performance characteristics were developed utilizing reviews performed by A2H Energy Services and Booz Allen Hamilton (BAH) in May 2004. A2H and BAH reviewd the parameters utilized in the Annual Energy Outlook 2004 (AEO2004) and provided recommended changes where needed. The averages of the AE2004 values and the recommended values were used.

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