Electricity Market Module

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The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules— electricity load and demand, electricity capacity planning, electricity fuel dispatching, 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 2014, DOE/EIA-M068(2014).

Based on fuel prices and electricity demands provided by the other modules of 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 the EMM. It includes a discussion of legislation and regulations that are incorporated in the EMM, as well as information about the climate change action plan. The various electricity side cases are also described.

EMM regions

The supply regions used in the EMM are based on the North American Electric Reliability Corporation regions and subregions shown in Figure 6.

Figure 6. Electricity Market Model Supply Regions

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 (IGCC)
IGCC 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 - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic - Fixed Tilt
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 and carbon.
Source: U.S. Energy Information Administration.

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 new fossil-fueled technologies are assumed to decline linearly through 2025.

For AEO2013, EIA commissioned an external consultant to update current cost estimates for utility-scale electric generating plants [1]. This report used a consistent methodology, similar to the one used to develop the estimates for AEO2011 and AEO2012, but accounted for more recent data and experience. Because the costs from the report were assumed to be consistent with plants that would be ordered in 2012, for AEO2014 the initial costs were adjusted to account for learning from capacity built during 2012. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2 represent the estimated cost of building a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers. Regional multipliers by technology are also based on regional cost estimates developed by the consultant. The regional variations account for multiple

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (MW)	Lead time (years)	Base Overnight Cost in 2013 (2012 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2013[4] (2012 $/kW)	Variable O&M[5] (2012 $/mWh)	Fixed O&M (2012$/kW/yr.)	Heatrate[6] in 2013 (Btu/kWh)	nth-of-a-kind Heatrate (Btu/kWh
Scrubbed Coal New	2017	1300	4	2,734	1.07	1.00	2,925	4.47	31.18	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)	2017	1200	4	3,525	1.07	1.00	3,771	7.22	51.39	8,700	7,450
IGCC with Carbon sequestion	2017	520	4	5,958	1.07	1.03	6,567	8.45	72.84	10,700	8,307
Conv Gas/Oil Comb Cycle	2016	620	3	871	1.05	1.00	915	3.60	13.17	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2016	400	3	945	1.08	1.00	1,021	3.27	15.37	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,856	1.08	1.04	2,084	6.78	31.79	7,525	7,493
Conv Comb Turbine[8]	2015	85	2	924	1.05	1.00	971	15.45	7.34	10,817	10,450
Adv Comb Turbine	2015	210	2	641	1.05	1.00	673	10.37	7.04	9,750	8,550
Fuel Cells	2016	10	3	6,099	1.05	1.10	7,044	42.99	0.00	9,500	6,960
Adv Nuclear	2019	2234	6	4,763	1.10	1.05	5,501	2.14	93.28	10,464	10,464
Distributed Generation - Base	2016	2	3	1,414	1.05	1.00	1,485	7.76	17.45	9,027	8,900
Distributed Generation - Peak	2015	1	2	1,698	1.05	1.00	1,783	7.76	17.45	10,029	9,880
Biomass	2017	50	4	3,590	1.07	1.02	3,919	5.26	105.64	13,500	13,500
Geothermal[7,9]	2016	50	4	2,375	1.05	1.00	2,494	0.00	112.92	9,716	9,716
Muncipal Solid Waste	2014	50	3	7,751	1.07	1.00	8,294	8.75	392.81	18,000	18,000
Conventional Hydropower[9]	2017	500	4	2,213	1.10	1.00	2,435	2.65	14.83	9,716	9,716
Wind	2014	100	3	2,061	1.07	1.00	2,205	0.00	39.55	9,716	9,716
Wind Offshore	2017	400	4	4,503	1.10	1.25	6,192	0.00	74.00	9,716	9,716
Solar Thermal[7]	2016	100	3	4,715	1.07	1.00	5,045	0.00	67.26	9,716	9,716
Photovoltaic[7,10]	2015	150	2	3,394	1.05	1.00	3,564	0.00	24.69	9,716	9,716

[1] Online year represents the first year that a new unit could be completed, given an order date of 2013. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge both market activity already occurring as well as the incentive for certain types of projects to develop at an accelerated rate in order to qualify for the Production Tax Credit.

[2] A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of 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 2013.

[5] O&M = Operations and maintenance.

[6] For hydro, wind, solar and geothermal technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2012. 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 2015 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.

[10] Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.

Sources: For the AEO2014 cycle, EIA continues to use the previously developed cost estimates for utility-scale electric generating plants, updated by external consultants for AEO2013. This report can be found at http://www.eia.gov/forecasts/capitalcost/. The costs were assumed to be consistent with plants that would be ordered in 2012, and learning from capacity built in 2012 has been applied in the initial costs above. Site-specific costs for geothermal were provided by the National Renewable Energy Laboratory, "Updated U.S. Geothermal Supply Curve," February 2010.

factors, such as differences in terrain, weather, population, and labor wages. 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.

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 four 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, OC, 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 (LR1)	Period 2 Learning Rate (LR2)	Period 3 Learning Rate (LR3)	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2035
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	-	10%	1%	-	5	10%
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%	-	-	5%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	10%
Solar PV - Module	-	10%	1%	-	5	10%
Balance of Plant - Solar PV	-	10%	1%	-	5	10%

[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: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

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 (LR) is an exogenous parameter input for each component (Table 8.3). The progress ratio and LR are related by:

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

The parameter "b" is calculated from the second equality above (b =-(ln(1-LR)/ln(2))). The parameter "a" is computed from initial conditions, i.e.

$a = OC(C_0)/C_o^{-b}$

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. Three learning steps were developed to reflect different stages of learning as a new design is introduced into 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. Costs of all design components are adjusted to reflect 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 rates by component are 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. In the case of the solar PV technology, it is assumed that the module component accounts for 50% of the cost, and that the balance of system components accounts for the remaining 50%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors.

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 (GW) toward turbine learning, and 0.33 GW toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100% capacity credit for any capacity built with that component. For example, when calculating capacity for the "Balance of plant - CC" component, all combined cycle capacity would be counted 100%, both conventional and advanced.

Table 8.4. Component cost weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCCwith carbon sequestration	0%	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%

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. Component capacity weights for new technologies

Technology	Pulverized Coal	Combus-tion Turbine-conven-tional	Combus-tion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Seques-tration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with Carbon sequestration	0%	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) as well as in the EMM. 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.

Demand storage

The EMM includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. This plant type is limited to operating only in the peak load slices, and for *AEO2014*, it is assumed that this capacity is limited to 3.5% of peak demand on average in 2040, with limits varying from 2.2% to 6.8% of peak across the regions.

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 Corporation 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% of the load, and then two off-peak segments representing the next 49% and 50%, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity in excess of peak demand required to adequately maintain reliability during unforeseeable outages—are established for each region by its governing body – public utility commission, NERC region or Independent System Operators (ISOs)/Regional Transmission Operators (RTOs). The reserve margin values from the *AEO2014* Reference case are set based on these regional Reference Margins reported to NERC and range from 14% to 17% [2].

Operating reserves

In addition to the planning reserve margin requirement, system operators typically require a specific level of operating reserves – generators available within a short period of time to meet demand in case a generator goes down or there is another disruption to supply. These reserves can be provided through plants that are already operating but not at full capacity (spinning reserves) as well as through capacity not currently operating but that can be brought online quickly (non-spinning reserves). This is particularly important as more intermittent generators are added to the grid, because technologies like wind and solar have uncertain availability that can be difficult to predict. For *AEO2014*, the capacity and dispatch submodules of the EMM were both updated to include explicit constraints requiring spinning reserves in each load slice. The amount of spinning reserves required is computed as a percentage of the load height of the slice plus a percentage of the distance between the load of the slice and the seasonal peak. An additional requirement is calculated that is a percentage of the intermittent capacity available in that time period to reflect the greater uncertainty associated with the availability of intermittent resources. All technologies except for storage, intermittents and distributed generation can be used to meet spinning reserves. Different operating modes are developed for each technology type to allow the model to choose between operating a plant to maximize generation versus contributing to spinning reserves, or a combination of both. Minimum levels of generation are required if a plant is contributing to spinning reserves, and vary by plant type, with plant types typically associated with baseload operation having higher minimums than those that can more operate more flexibly to meet intermediate or peak demand.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Generating units 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 plant generators. A generating unit is assumed to retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and 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 unit-specific and 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 $22 per kW for nuclear plants (in 2012 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $7 per kW capital charge for fossil plants and $33 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging.

EIA assumes all retirements reported as planned during the next ten years on the Form EIA-860 will occur. Additionally, the *AEO2014* nuclear projection assumes a decrease of 5.7 GW by 2020 in several regions where existing nuclear units appear at risk of early closure due to a combination of high operating costs and low electricity prices.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $285 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15% of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The *AEO2014* 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%) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20%, requiring significant modifications. Recently, several companies have canceled previously planned extended uprates due to lower demand projections and low electricity prices [3]. *AEO2014* assumes that only those uprates reported to EIA as planned modifications on the Form EIA-860 will take place in the Reference case, representing 0.7 GW of additional capacity. In the High Nuclear case (discussed in more detail later in this chapter), it is assumed that most plants with remaining uprate potential will implement uprates, with a total of 6.0 GW throughout the projection.

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 NERC and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America, as well as information obtained from the Open Access Same-Time Information System (OASIS). Known firm power contracts are compiled from NERC's Electricity Supply and Demand Database as well as information provided in the 2013 Summer and Winter Assessments and individual ISO reports. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2018 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2018, they are assumed to be phased out linearly over 10 years. The EMM includes an option to add interregional transmission capacity. In some cases it may be more economical to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred as well. Explicitly expanding the interregional transmission capacity may also make the transmission line available for additional economy trade.

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 assumed 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. Data on existing and planned transactions are compiled from NERC's Electricity Supply and Demand Database and Canada's National Energy Board. 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 was determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity pricing

Electricity pricing is projected for 22 electricity market regions in *AEO2014* for fully competitive, partially competitive and fully regulated supply regions. The price of electricity to the consumer comprises 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 to build, operate and maintain these systems using a cost of service regulation model. 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 energy component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The competitive generation price includes the marginal cost (fuel and variable operations and maintenance costs), taxes, and a capacity payment. The capacity payment is calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity calculated within the EMM. The capacity payment is calculated for all competitive regions and should be viewed as a proxy for additional capital recovery that must be procured from customers rather than the representation of a specific market. The capacity payment also includes the costs associated with meeting the spinning reserves requirement discussed earlier. The total cost for meeting both constraints in a given region is calculated within the EMM, and allocated to the sectors based on their contribution to overall peak demand. The price of electricity in the regions with a competitive generation market consists of the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions reflects a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region subject to deregulation. In competitively supplied regions, a transition period is assumed to occur (usually over a 10-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the ReliabilityFirst Corporation/East region, and a 97% transition to competitive pricing in New England (Vermont being the only fully-regulated state in that region). Six regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, three of the SERC Reliability Corporation subregions - Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC) - Southwest Power Pool Regional Entity/North (SPNO), and the Western Electricity Coordinating Council/Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, is now only 88% competitive, since many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998, with only 7% competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/California region. All other regions reflect a mix of both competitive and regulated prices.

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 in the state. 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 *AEO2014*, 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. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the projection. Regions found to have these added costs include the Northeast Power Coordinating Council/New England and New York regions, the ReliabilityFirst Corporation/East and West regions, and the WECC/California region.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 30-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.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis which determines the delivered price to generators in mills per kilowatthour. To produce reactor-grade uranium, the uranium (U_30_8) must first be mined, and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of U-235, typically 3-5% for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The one mill per kilowatthour charge that is assessed on nuclear generation to go to DOE's Nuclear Waste Fund is also included in the final nuclear price. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

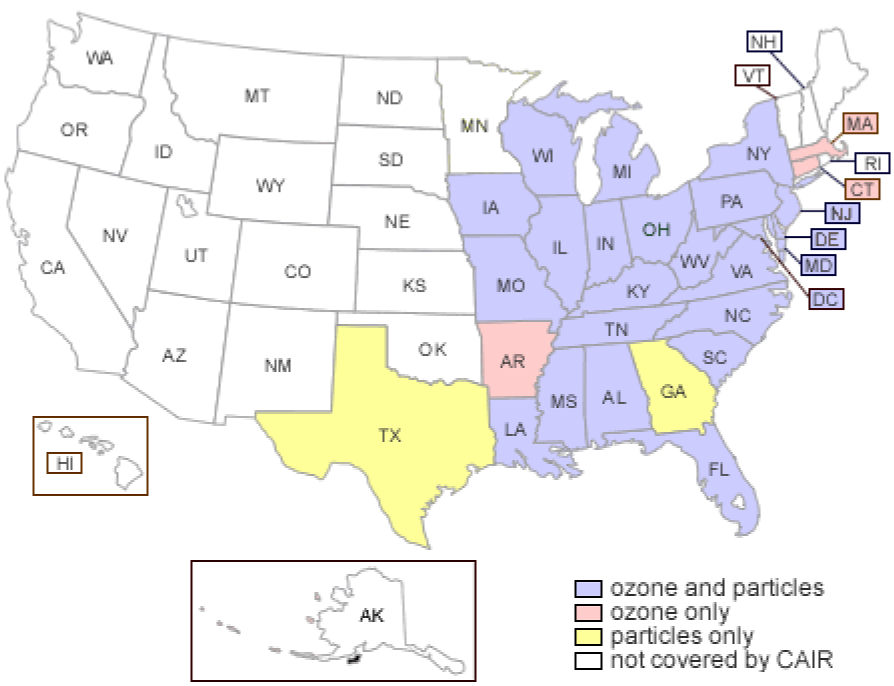
Clean Air Act Amendments of 1990 (CAAA90) and Clean Air Interstate Rule (CAIR)

Currently, regulation of SO_2 and NO_X emissions is administered under the Clean Air Interstate Rule (CAIR), and AEO2014 assumes that CAIR remains a binding regulation throughout the projection period. CAIR was initially promulgated in 2005, but has been challenged in court several times. The Cross-State Air Pollution Rule (CSAPR) was released by EPA in July 2011 and was intended to replace CAIR, but it was vacated by the U.S. Court of Appeals for the District of Columbia Circuit, and CAIR was reinstated.

CAIR covers all fossil-fueled power plants greater than 25 megawatts in 27 states and the District of Columbia. There are annual emissions caps for SO_2 and NO_X and different states fall under each cap, as shown in the map in Figure 7, although all are in the eastern half of the United States. The caps for SO_2 and NO_X were set to allow states to achieve their National Ambient Air Quality Standards (NAAQS) for particulate matter (impacted by SO_2 levels) and ground level ozone (impacted by NO_X). Allowances can be traded among all participants in the CAAA90 Title IV program, not just those in CAIR states; however allowances are traded at a discount in non-CAIR states. *AEO2014* represents emissions trading in both the CAIR and non-CAIR regions, as specified by the regulation, and includes banking of allowances consistent with CAIR's provisions.

As specified in CAAA90, EPA 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, are referred to as Group 1 Boilers, and 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% to meet the Phase I limits and further reductions to meet the Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have instituted additional NO_x regulations. All new fossil units are required to meet current 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.

Figure 7. States covered by the Clean Air Interstate Rule



Source: U.S. Environmental Protection Agency, Clean Air Interstate Rule—Where You Live (Washington, DC, July 31, 2012), website http://www.epa.gov/cair/where.html.

Table 8.6 shows the average capital costs for environmental control equipment utilized by NEMS for existing coal plants as retrofit options in order to remove sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and/or hydrogen chloride (HCl). In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. The table reflects the capacity-weighted averages of all plants falling into each size category. FGD units are assumed to remove 95% of the SO_2, while SCR units are assumed to remove 90% of the NO_x. The EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70% of the SO_2. However, the DSI option is only available under the mercury and air toxics rule discussed in the next section, as its primary benefit is for reducing hydrogen chloride (HCl).

Mercury regulation

The Mercury and Air Toxics Standards (MATS) were finalized in December 2011 to fulfill EPA's requirement to regulate mercury emissions from power plants. MATS also regulates other hazardous air pollutants (HAPS) such as hydrogen chloride (HCl) and fine particulate matter (PM2.5). MATS applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 megawatts. The standards are scheduled to take effect in 2015, but allow for a one-year waiver to comply, and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For *AEO2014*, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2016, due to the large number of plants requesting the one-year extension. All power plants are required to reduce their mercury emissions to 90% below their uncontrolled emissions levels.

Because the EMM does not explicitly model HCl or PM2.5, specific control technologies are assumed to be used to achieve compliance. In order to meet the HCl requirement, units must have either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems in order to continue operating. A full fabric filter (FF) is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. When plants alter their configuration by adding equipment such as an SCR to remove NO_x or an SO_2 scrubber, removal of mercury is often a resulting cobenefit. The EMM considers all combinations of controls and may choose to add NO_X or SO_2 controls purely to lower mercury if it is economic to do so. Plants 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 $6 (2012 dollars) per kilowatt of capacity [4]. The costs of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) are calculated by unit, with average costs shown in Table 8.6. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [5].

For a unit with a cold side electrostatic precipitator (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 hot side electrostatic precipitator (HSE) or other particulate control, and a supplemental fabric filter with activated carbon injection:

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

ACI = activated carbon injection rate in pounds per million actual cubic feet of flue gas.

Table 8.6. Coal plant retrofit costs
2012 dollars per kW

Coal Plant Size (MW)	FGD Capital Costs ($/kW)	SCR Capital Costs ($/kW)	DSI Capital Costs ($/kW)	FF Capital Costs
<100	896	417	189	258
100 - 299	635	270	94	192
300 - 499	502	217	50	163
500 - 699	444	200	37	147
>=700	399	183	31	135

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018, Appendices to Chapter 5.

Power plant mercury emissions assumptions

The EMM 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% of the mercury that was in the fuel is removed by various parts of the plant. Table 8.7 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 8.7. 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	0.50	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. 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

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For *AEO2014*, this includes 16.9 GW of planned SO_2 scrubbers (Table 8.8) and 10.2 GW of planned selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a federal greenhouse gas program is not assumed in the *AEO2014* Reference case, the EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). This option is important when considering alternate scenarios that do constrain carbon emissions. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[6] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heatrate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90% of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30% and reduced efficiency of 43% at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs averaging $1,635 per kilowatt, and ranging from $1,193 to $2,255 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heat rates below 12,000 Btu per kilowatthour would be considered for CCS retrofits.

State air emissions regulation

AEO2014 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants over 25 megawatts in the Northeastern United States. The State of New Jersey withdrew from the program at the end of 2011, leaving nine states in the accord. The rule caps CO_2 emissions from covered electricity generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. Because the baseline and projected emissions were calculated before the economic recession that began in 2008, the actual emissions in the first years of the program have been less than the cap, leading to excess allowances and allowance prices at the floor price. As a result, in February 2013 program officials announced a tightening of the cap starting in 2014. AEO2014 applies these revised targets, which reflect a cap that is 45% of the original target for 2014.

The California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013 for the electric power sector and industrial facilities. Fuel providers must comply starting in 2015. The AB32 cap-and-trade provisions are incorporated in AEO2014 through an emission constraint in the EMM that also accounts for the emissions determined by the other sectors. Within the power sector, emissions from plants owned by California utilities but located out of state as well as emissions from electricity imports into California count toward the emission cap, and estimates of these emissions are included in the EMM constraint. An allowance price is calculated and added to fuel prices for the affected sectors. Limited banking and borrowing of allowances as well as an allowance reserve and offsets have been modeled, as specified in the Bill, providing some compliance flexibility and cost containment.

Table 8.8. Planned SO_2 scrubber additions by EMM region
Gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	1.5
Midwest Reliability Council - West	2.2
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Coordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	0.0
ReliabilityFirst Corporation/East	0.0
ReliabilityFirst Corporation/Michigan	2.8
ReliabilityFirst Corporation/West	3.7
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	2.2
SERC Reliability Corporation/Southeastern	3.6
SERC Reliability Corporation/Central	0.0
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	1.0
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.0
Total	16.9

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

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

The provisions of EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). EPACT92 also implemented a permanent 10% investment tax credit for geothermal and solar facilities, and introduced a production tax credit for eligible renewable technologies (subsequently extended and expanded). EPACT05 provides a 20% investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15% investment tax credit for other advanced coal technologies. These credits are limited to 3 GW in both cases. These credits have been fully allocated and are not assumed to be available for new, unplanned capacity built within the EMM. EPACT05 also contains a production tax credit (PTC) of 1.8 cents (nominal) per kWh for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million annually, and is limited to 6 GW of new capacity. However, this credit may be shared to additional units if more than 6 GW are under construction by January 1, 2014. 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 investment tax credit of 30% through 2016 for solar and fuel cell facilities. After 2016, the tax credit for solar facilities reverts back to the 10% level set by EPACT92.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA extended the expiration date for the PTC to January 1, 2013, for wind and January 1, 2014, for all other eligible renewable resources. In addition, ARRA allows companies to choose an investment tax credit (ITC) of 30% in lieu of the PTC and allows for a grant in lieu of this credit to be funded by the U.S. Treasury. For some technologies, such as wind, the full PTC would appear to be more valuable than the 30% ITC; however, the difference can be small. Qualitative factors, such as the lack of partners with sufficient tax liability, may cause companies to favor the ITC grant option. AEO2014 generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them.

Loan guarantees for renewables

ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. While most renewable projects which started construction prior to September 30, 2011 are potentially eligible for these loan guarantees, the application and approval of guarantees for specific projects is a highly discretionary process, and has thus far been limited. While AEO2014 includes projects that have received loan guarantees under this authority, it does not assume automatic award of the loans to potentially eligible technologies.

Support for CCS

ARRA provided $3.4 billion for additional research and development on fossil energy technologies. A portion of this funding is expected to be used to fund projects under the Clean Coal Power Initiative program, focusing on projects that capture and sequester greenhouse gases. To reflect the impact of this provision, AEO2014 Reference case assumes that an additional 1 GW of coal capacity with CCS will be stimulated by 2018.

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from the generator to the consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment than would otherwise occur.

Several changes were made throughout NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. In *AEO2014*, it is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand from what they otherwise would be, with the amount of total peak load reduction growing from 2.2% initially to 3.5% by 2040, although the shifts vary by region. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

American Taxpayer Relief Act of 2012 (ATRA)

Passed in January 2012, the impacts of ATRA were included in a side case of AEO2013 and are now reflected in the Reference case of AEO2014. ATRA extended the expiration date of the wind production tax credit by one year, and redefined the criteria for all qualifying projects to be based on ‘under construction’ by December 31, 2013 rather than placed in service by that same date, effectively extending the credit for the length of the typical construction period.

FERC Orders 888 and 889

FERC 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. As a result, utilities have functionally or physically unbundled 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 such transactions economical.

Electricity alternative cases

Accelerated Retirement cases

For *AEO2014*, three alternate cases were run to examine the impacts of potentially large amounts of retirements of baseload coal and nuclear plants on the electric power sector. In recent years, a combination of low natural gas prices, high retrofit or repair costs and uncertain environmental legislation have led to an increase in announced retirements of coal and nuclear plants.

These scenarios are discussed in an Issues in Focus article in the full *AEO2014* report.

- The Accelerated Nuclear Retirement case assumes that reactors will not receive a second license renewal, therefore all existing plants are retired within 60 years of operation. Non-fuel operating costs at existing nuclear plants are assumed to increase by 3% per year after 2013. The 4.8 GW of announced retirements remain as in the Reference case, along with the decrease of 5.7 GW of nuclear capacity by 2020 to reflect plants at risk of early closure in specific regions. In this case an additional 37.4 GW of nuclear capacity is retired by 2040, relative to the Reference case. The Accelerated Nuclear Retirement case also assumes that no new nuclear capacity will be added throughout the projection, with the exception of capacity already under construction.
- The Accelerated Coal Retirement case includes the assumptions used for the High Coal Cost case, including lower productivity and higher costs associated with mining and transportation rates. (This case is described in more detail in the Coal chapter of this report). By 2040, delivered coal prices are more than 60% higher in the Accelerated Coal Retirement case than the Reference case. This case also assumes that non-fuel operating costs at existing coal plants increase by 3% per year after 2013.
- The Accelerated Coal and Nuclear Retirement case combines the assumptions of the Accelerated Coal Retirement and Accelerated Nuclear Retirement cases.

Nuclear Alternative cases

For AEO2014, two alternate cases were run for nuclear power plants to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants.

- The Low Nuclear case combines the Accelerated Nuclear Retirement case with the High Oil and Gas Resource case and the No Sunset case. (All case descriptions can be found in Table 1.1 of this report). This combines more pessimistic assumptions regarding nuclear costs and lifetimes with more favorable conditions for natural gas-fired and renewable technologies, so that the impacts on the power sector can be viewed under an outlook where output from nuclear power is greatly reduced.
- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding 4.8 GW of announced retirements). In the Reference case, beyond the announced retirements an additional decrease of 5.7 GW of nuclear capacity is assumed to be retired by 2020. The High Nuclear case was run to provide a more optimistic outlook where all licenses are renewed and all plants are assumed to find it economic to continue operating beyond 60 years. The High Nuclear case also assumes additional planned nuclear capacity is completed based on combined license (COL) applications with the NRC and whether an Atomic Safety and Licensing Board hearing has been scheduled for a COL. The High Nuclear case assumes 12.6 GW of planned capacity additions, as compared with the 5.5 GW of planned capacity additions in the Reference case. Finally, the High Nuclear case assumes a total of 6.0 GW of uprates at existing plants, reflecting an assumption that most plants with remaining uprate potential will elect to perform such uprates.

Flat Electricity Demand case

For AEO2014, a case was developed combining technology and efficiency improvements across the end use demand sectors to create a case that projects retail sales to the grid to be relatively flat at current levels. This case was developed to analyze the impacts on the power sector capacity and generation requirements under an extreme scenario of no demand growth. The Flat Electricity Demand case uses the assumptions in the Best Available Technology case for the residential and commercial sectors.

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