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Assumptions to the Annual Energy Outlook 2008

With Projections for 2030

Energy Information Administration

Contents

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Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook 2008*[1] (*AEO2008*), including general features of the model structure, assumptions concerning energy markets, and the key input data and parameters that are the most significant in formulating the model results. Detailed documentation of the modeling system is available in a series of documentation reports.[2]

The National Energy Modeling System

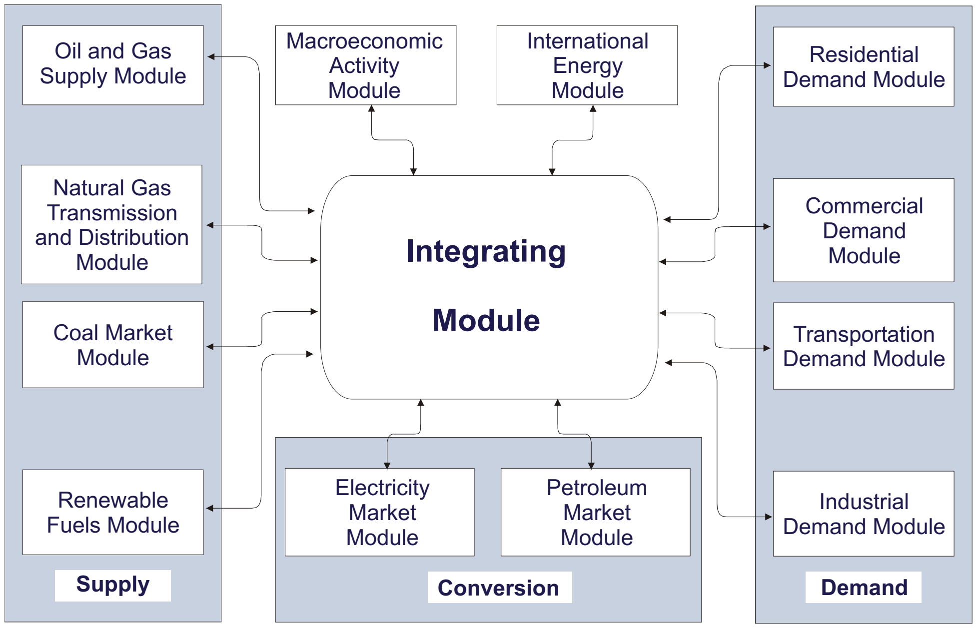
The projections in the *AEO2008* were produced with the NEMS, which is developed and maintained by the Office of Integrated Analysis and Forecasting of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the long term and perform policy analyses requested by decisionmakers in the White House, U.S. Congress, offices within the Department of Energy, including DOE Program Offices, and other government agencies. The *AEO* projections are also used by analysts and planners in other government agencies and outside organizations.

The time horizon of NEMS is approximately 25 years, the period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, natural gas, and coal supply and distribution, the North American Electric Reliability Council (NERC) regions and subregions for electricity, and the Petroleum Administration for Defense Districts (PADDs) for refineries. Maps illustrating the regional formats used in each module are included in this report. Only selected regional results are presented in the *AEO2008,* which predominately focuses on the national results. Complete regional and detailed results are available on the EIA Forecasts and Analyses Home Page. (http://www.eia.doe.gov/oiaf/aeo/index.html)

For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes a macroeconomic and an international module. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production, and international petroleum supply availability.

The integrating module of NEMS controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data storage location. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consumming sectors. Solution is reached annually through the projection horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Figure 1. National Energy Modeling System



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

Each NEMS component also represents the impact and cost of Federal legislation and regulation that affect the sector and reports key emissions. NEMS generally reflects all current legislation and regulation that are defined sufficiently to be modeled as of December 31, 2008, such as the Energy Independence and Security Act of 2007, the Energy Policy Act of 2005, the Working Families Tax Relief Act of 2004, and the America Jobs Creation Act of 2004, and the costs of compliance with regulations such as the Mobile Source Air Toxics rule released by the Environmental Protection Agency on February 9, 2007 that establishes controls on gasoline, passenger vehicles, and portable fuel containers designed to significantly reduce emissions of benzene and other hazardous air pollutants. The NEMS components also reflect selected State legislation and regulations where implementing regulations are clear. The potential impacts of pending or proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. A list of the specific Federal and selected State legislation and regulations included in the *AEO*, including how they are incorporated, is provided in Appendix A.

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption. This section provides brief summaries of each of the modules.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules, and there is a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, new light-duty vehicle sales, interest rates, and employment. The module uses the following models from Global Insight, Inc. (GII): Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Module

The International Module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are a set of crude oil and product supply curves that are available to U.S. markets for each case/scenario analyzed. The petroleum import supply curves are made available to U.S. markets through the Petroleum Market Module (PMM) of NEMS in the form of 5 categories of imported crude oil and 17 international petroleum products, including supply curves for oxygenates and unfinished oils. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced form models of international liquids supply and demand (new to *AEO2008*), current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies and the effects of both building shell and appliance standards, including the recently enacted provisions of the EISA2007. The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to “normal” heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects that the average square footage of both new construction and existing structures increase based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 21 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the Macroeconomic Activity Module, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the 8 energy-intensive industries, 7 are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. A generalized representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the PMM, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments. Fleet vehicles are represented separately to allow analysis of the Energy Policy Act of 1992 (EPACT1992) and other legislation and legislative proposals. EPACT2005 is used to assess the impact of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. The module also includes a component to assess the penetration of alternative-fuel vehicles. The CAFE and biofuel representation in the module reflect the provisions in the EISA2007.

The air transportation component explicitly represents air travel in domestic and non U.S. markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs and the movement of aircraft from passenger to cargo markets as aircraft ages.[3] For air freight shipments, the model represents regional fuel use in narrow-body and wide-body aircraft. An infrastructure constraint limits overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module (EMM) represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs; macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are modeled in the planning and dispatching submodules. The levelized cost of uranium fuel for nuclear generation is incorporated directly in the EMM.

All specifically identified CAAA90 compliance options that have been promulgated by the EPA are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, regulations are represented in *AEO2008*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in EPACT1992 and EPACT2005. EPACT1992 provides a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power; those credits have no expiration date. EPACT2005 increases the tax credit to 30 percent for solar energy systems installed before January 1, 2009.

Production tax credits for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are also represented. They provide a tax credit of up to 1.9 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2008*, new plants coming on line before January 1, 2009, are eligible to receive the credit.

Oil and Gas Supply Module

The Oil and Gas Supply Module (OGSM) represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and unconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and gas production functions are computed for 12 supply regions, including 3 offshore and 3 Alaskan regions. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

Crude oil production quantities are input to the Petroleum Market Module (PMM) in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module (NGTDM) for use in determining natural gas prices and quantities. International LNG supply sources and options for construction of new regasification terminals in Canada, Mexico, and the United States as well as expansions of existing U.S. regasification terminals are represented, based on the projected regional costs associated with international natural gas supply, liquefaction, transportation, and regasification and world natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module (NGTDM) represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and biofuels (ethanol, biodiesel, biobutanol, etc.). The module represents refining activities in the five PADDs. It explicitly models the requirements of the EISA2007, the CAAA90, and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes biofuels production for blending in gasoline and diesel

AEO2008 represents regulations that limit the sulfur content of all non-road and locomotive/marine diesel to 15 ppm by mid-2012. The module also reflects the renewable fuels standard (RFS) in the EISA2007 that requires the use of 36 billion gallons per year of biofuels by 2022 with corn ethanol limited to 15 billon gallons per year. Demand growth and regulatory changes necessitate capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing product marketing and distribution costs and State and Federal taxes.[4] Refinery capacity expansion at existing sites is permitted in all five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume or less (E10), as well as E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and may also be produced from cellulosic material, such as switchgrass and poplar, in the future. Biodiesel is produced from seed oil, imported palm oil, animal fats, or yellow grease (primarily, recycled cooking oil).

Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled from two feedstocks: corn and cellulosic materials. Corn-based ethanol plants are numerous (more than 100 in operation, producing more than 5 billion gallons annually) and are based on a well-known technology that converts sugar into ethanol. Ethanol from cellulosic sources is a new technology with no pilot plants in operation. However, the U.S. Department of Energy has awarded grants (up to $385 million) in 2007 to construct capacity totaling 147 million gallons per year. *AEO2008* assumes that this capacity will be operational in 2012. Imported ethanol may be produced from cane sugar or bagasse, the cellulosic byproduct of sugar milling. The sources of ethanol are modeled to compete on an economic basis and to meet the EISA2007 renewable fuels mandate.

Fuels produced by gasification and Fischer-Tropsch synthesis are modeled in the PMM, based on their economics relative to competing feedstocks and products. The three processes modeled are coal-to-liquids (CTL), gas-to-liquids (GTL), and biomass-to-liquids (BTL). CTL facilities are likely to be built at locations close to coal supply and water sources, where liquid products and surplus electricity could also be distributed to nearby demand regions. GTL facilities may be built in Alaska but would compete with the Alaska Natural Gas Transportation System for available natural gas resources. BTL facilities are likely to be built where there are large supplies of biomass such as crop residue and forestry waste. Since the BTL process uses cellulosic feedstocks, it is also modeled as a choice to meet the EISA2007 cellulosic biofuels requirement.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by

40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur and mercury allowance costs. Over the projection horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the cost of rail transportation equipment and diesel fuel.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports, in the context of world coal trade. The CMM determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export and 20 import regions. U.S. coal production and distribution are computed for 14 supply and 14 demand regions.

Cases for the *Annual Energy Outlook 2008*

In preparing projections for the *AEO2008*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between now and 2030. Besides the reference case, the *AEO2008* presents detailed results for four alternative cases that differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. These alternative cases include the following:

- **Economic Growth** - In the *reference case*, real GDP grows at an average annual rate of 2.4 percent from 2006 through 2030, supported by a 1.9 percent per year growth in productivity in nonfarm business and a 0.9 percent per year growth in nonfarm employment. In the *high economic growth case,* real GDP is projected to increase by 3.0 percent per year, with productivity and nonfarm employment growing at 2.4 percent and 1.2 percent per year, respectively. In the *low economic growth case*, the average annual growth in GDP, productivity and nonfarm employment is 1.8, 1.5 and 0.5 percent, respectively.

- **Price Cases** – For purposes of the *AEO2008*, the world oil price is defined by the price of light, low-sulfur crude oil delivered in Cushing, Oklahoma. In the reference case, world oil prices decline gradually from current levels to $57 per barrel in 2016 ($68 per barrel in nominal terms), as expanded investment in exploration and development brings new supplies to world markets. After 2016, real prices begin to rise as demand continues to grow and higher cost supplies are brought to market. In 2030, the average real price of crude oil is $70 per barrel in 2006 dollars, or about $113 per barrel in nominal dollars. The reference case represents EIA's current judgment about the most likely behavior of key OPEC members in the mid term. In the projection, OPEC countries increase production at a rate that keeps their market share of world liquids production at approximately 40 percent through 2030. The low and high price cases define a wide range of potential price paths, which in 2030 span from $43 to $117 per barrel in real dollars. These cases reflect differences in the assumptions about world energy resource availability, production costs, and changes in OPEC behavior. The low price case assumes greater world crude oil and natural gas resources that are less expensive to produce and a future market where all oil and natural gas production becomes more competitive and plentiful than the reference case. The high price cases assumes that world crude oil and natural gas resources, including OPEC's, are lower and require greater cost to produce than assumed in the reference case.

In addition to these four cases, and the reference case, 31 additional alternative cases presented in Table 1 that explore the impact of changing key assumptions on individual sectors.

Many of the side cases were designed to examine the impacts of varying key assumptions for individual modules or a subset of the NEMS modules, and thus the full market consequences, such as the consumption or price impacts, are not captured. In a fully integrated run, the impacts would tend to narrow the range of the differences from the reference case. For example, the best available technology side case in the residential demand assumes that all future equipment purchases are made from a selection of the most efficient technologies available in a particular year. In a fully integrated NEMS run, the lower resulting fuel consumption would have the effect of lowering the market prices of those fuels with the concomitant impact of increasing economic growth, thus stimulating some additional consumption. The results of single model or partially integrated cases should be considered the maximum range of the impacts that could occur with the assumptions defined for the case.

Table 1. Summary of *AEO2008* Cases

Case name	Description	Integration mode
Reference	Baseline economic growth (2.4 percent per year from 2006-2030), world oil price, and technology assumptions.	Fully integrated
Early Release Reference	Released in 12/2007, excludes EISA2007 and other changes in reference case.	Fully integrated
Low Economic Growth	Gross domestic product grows at an average annual rate of 1.8 percent from 2006 through 2030. Other assumptions are the same as in the reference case.	Fully integrated
High Economic Growth	Gross domestic product grows at an average annual rate of 3.0 percent from 2006 through 2030. Other assumptions are the same as in the reference case.	Fully integrated
Low Price	More optimistic assumptions for worldwide crude oil and natural gas resources than in the reference case. World light, sweet crude oil prices are $43 per barrel in 2030, compared with $72 per barrel in the reference case (2006 dollars). Other assumptions are the same as in the reference case.	Fully integrated
High Price	More pessimistic assumptions for worldwide crude oil and natural gas resources than in the reference case. World light, sweet crude oil prices are about $117 per barrel (2006 dollars) in 2030. Other assumptions are the same as in the reference case.	Fully integrated
Residential: 2008 Technology	Future equipment purchases based on equipment available in 2008. Existing building shell efficiencies fixed at 2008 levels.	With commercial
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new construction meet ENERGY STAR requirements after 2016.	With commercial
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available by fuel. Building shell efficiencies for new construction meet the criteria for most efficient components after 2008.	With commercial
Commercial: 2008 Technology	Future equipment purchases based on equipment available in 2008. Building shell efficiencies fixed at 2008 levels.	With residential
Commercial: HighTechnology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 2003 values by 2030.	With residential
Commercial Best Available Technology	Future equipment purchases based on most efficient technologies available by fuel. Building shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 2003 values by 2030.	With residential
Industrial: 2008 Technology	Efficiency of plant and equipment fixed at 2008 levels.	Standalone
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone
Transportation: High Technology	Reduced costs and improved efficiencies assumed for advanced technologies.	Standalone

Table 1. Summary of *AEO2008* Cases (cont.)

Case name	Description	Integration mode
Electricity: Low Nuclear Cost	New nuclear capacity assumed to have 10 percent lower capital and operating costs in 2030 than in the reference case.	Fully Integrated
Electricity: High Nuclear Cost	Costs for new nuclear technology are assumed not to improve over time from 2006 levels in the reference case.	Fully Integrated
Electricity: Low Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2030 from reference case values.	Fully Integrated
Electricity: High Fossil Cost	New advanced fossil generating technologies assumed not to improve over time from 2008.	Fully Integrated
Renewable Fuels: High Renewable Cost	New renewable generating technologies assumed not to improve over time from 2008.	Fully integrated
Renewable Fuels: Low Renewable Cost	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2030 from reference case values.	Fully integrated
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case.	Fully integrated
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case.	Fully integrated
Oil and Gas: High LNG Supply	LNG imports exogenously set to a factor times the reference case levels from 2010 forward, with remaining assumptions from the reference case. The factor starts at 1.0 in 2010 and linearly increases to 3.0 by 2030.	Fully Integrated
Oil and Gas: Low LNG Supply	LNG imports help constant at 2009 levels, with remaining assumptions from the reference case.	Fully Integrated
Oil and Gas: ANWR	The Arctic National Wildlife Refuge in Alaska is opened to Federal oil and natural gas leasing, with remaining assumptions from the reference case.	Fully Integrated
Coal: Low Coal Cost	Productivity for coal mining and coal transportation assumed to increase more rapidly than in the reference case. Coal mining wages, mine equipment, and coal transportation equipment costs assumed to be lower than in the reference case.	Fully Integrated
Coal: High Coal Cost	Productivity for coal mining and coal transportation assumed to increase more slowly than in the reference case. Coal mining wages, mine equipment, and coal transportation equipment costs assumed to be higher than in the reference case.	Fully integrated
Integrated 2008 Technology	Combination of the residential, commercial, and industrial 2008 technology cases, electricity high fossil cost case, high renewable cost case, and high nuclear cost case.	Fully integrated
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity low fossil cost case, low renewable cost case, and low nuclear cost case.	Fully integrated
Integrated Alternative Weather Case	Assumes future weather resembles 30-year average, as opposed to 10-year average.	Fully integrated
Low Energy Project Cost	Recent cost increases are assumed to revert back to lower levels of a few years ago. Base costs for new electric generating capacity decreases by 15 percent over ten years, then remain flat. Capital costs for oil and natural gas exploration and production fall back toward their pre-2003 levels over time. Refining costs are set to 2004 levels.	Fully integrated

Table 1. Summary of *AEO2008* Cases (cont.)

Case name	Description	Integration mode
High Energy Project Cost	Recent cost increases are assumed to continue. Base costs for new electric generating capacity increase throughout the projection. Capital costs for oil and natural gas exploration and production activities remain at increased levels as experienced since 2003. Refining costs increase from current costs.	Fully integrated
Limited Electricity Generation Supply	New coal plants are not built unless they include sequestration. Other non-natural gas capacity sources are restricted to reference case levels or assumed to have higher costs. Existing nuclear units are assumed to have lower output than in the reference.	Fully integrated
Limited Natural Gas Supply	No Arctic natural gas pipelines are in operation by 2030. LNG import values are held constant at 2009 levels from 2010 forward. Oil and natural gas resources are 15 percent lower, and the technological progress is set to half the rate of the reference case.	Fully integrated
Combined Limited	This case combines all the assumptions of the Limited Electricity Generation Supply and Limited Natural Natural Gas Supply cases.	Fully integrated

Carbon Dioxide Emissions

Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor for each fossil fuel. The emissions factors are expressed in millions of metric tons carbon dioxide emitted per quadrillion Btu of energy use, or equivalently, in kilograms carbon dioxide per million Btu. The adjusted emissions factors are multiplied by the energy consumption of the fossil fuel to arrive at the carbon dioxide emissions projections.

For fuel uses of energy, the combustion fractions are assumed to be 1.00 in keeping with international conventions.[5] Previously, a small fraction of the carbon content of the fuel was assumed to remain unoxidized. The carbon dioxide in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. For energy categories that are mixes of fuel and nonfuel uses, the combustion fractions are based on the proportion of fuel use. Any carbon dioxide emitted by biogenic renewable sources, such as biomass and alcohols, is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from biogenic renewable sources are taken as zero, and no emission coefficient is reported. In calculating carbon dioxide emissions for motor gasoline, the direct emissions from renewable blending stock (ethanol) is omitted. Similarly, direct emissions from biodiesel are omitted from reported carbon dioxide emissions. Table 2 presents the assumed carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2008*.

Table 2. Carbon Dioxide Emission Factors
(million metric tons carbon dioxide equivalent per quadrillion Btu)

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emissions Factor
Petroleum			
Motor Gasoline (net of ethanol)	70.88	1.000	70.88
Liquefied Petroleum Gas			
Used as Fuel	63.03	1.000	62.72
Used as Feedstock	61.64	0.200	12.31
Jet Fuel	70.88	1.000	70.88
Distillate Fuel (net of biodiesel)	73.15	1.000	73.15
Residual Fuel	78.80	1.000	78.80
Asphalt and Road Oil	75.61	0.000	0.00
Lubricants	74.21	0.500	37.11
Petrochemical Feedstocks	69.85	0.381	26.59
Kerosene	72.31	1.000	72.31
Petroleum Coke	102.12	0.860	87.82
Petroleum Still Gas	64.20	1.000	64.20
Other Industrial	74.43	1.000	74.43
Coal			
Residential and Commercial	95.35	1.000	95.35
Metallurgical	93.71	1.000	93.71
Industrial Other	93.98	1.000	93.98
Electric Utility[1]	94.66	1.000	94.66
Natural Gas			
Used as Fuel	53.06	1.000	53.06
Used as Feedstocks	53.06	0.517	27.44

[1]Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average carbon dioxide contents for coal varies throughout the projection. The 2006 average is 94.66.

Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006, DOE/EIA-0573(2006),* (Washington, DC, November 2006).

Notes and Sources

[1] Energy Information Administration, *Annual Energy Outlook 2008* (*AEO2008*), DOE/EIA-0383(2008), (Washington, DC, April 2008).

[2] NEMS documentation reports are available on the EIA Homepage (http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation).

[3] Jet Information Services, Inc., *World Jet Inventory Year-End 2006* (Utica, NY, March 2007); and personal communication from Stuart Miller (Jet Information Services).

[4] For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be available through 2010. It is assumed to expire after 2010 under current law.

[5] The Intergovernmental Panel on Climate Change 2006, 2006 IPCC Guidelines For National Greenhouse Gas Inventories, prepared by the National Greenhouse Gas Inventories Program, published: IGES, Japan, 2006.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) represents the interaction between the U.S. economy as a whole and energy markets. The rate of growth of the economy, measured by the growth in gross domestic product (GDP) is a key determinant of the growth in demand for energy. Associated economic factors, such as interest rates and disposable income, strongly influence various elements of the supply and demand for energy. At the same time, reactions to energy markets by the aggregate economy, such as a slowdown in economic growth resulting from increasing energy prices, are also reflected in this module. A detailed description of the MAM is provided in the EIA publication, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System*, DOE/EIA-M065(2007), (Washington, DC, January 2007).

Key Assumptions

The output of the U.S. economy, measured by GDP, is expected to increase by 2.4 percent between 2006 and 2030 in the reference case. Two key factors help explain the growth in GDP: the growth rate of nonfarm employment and the rate of productivity change associated with employment. As Table 3 indicates, for the Reference Case GDP growth slows from 2.5 percent between 2010 and 2020, to 2.4 percent between 2020 and 2030. In the near term from 2006 through 2010, the growth in nonfarm employment is low at 1.1 percent compared with 2.4 percent in the second half of the 1990s, while the economy is expected to experiencing productivity growth of 1.7 percent. Over the projection period, nonfarm employment is expected to grow by 0.9 percent per year. Nonfarm employment, a measure of demand for nonfarm labor, is generally more volatile than the labor force, a measure of labor supply. The latter depends upon the projection of population and labor force participation rate. The Census Bureau's middle series population projection is used as a basis for population growth for the AEO2008. Total population is expected to grow by 0.8 percent per year between 2006 and 2030, and the share of population over 65 is expected to increase over time. However, the share of the labor force in the population over 65 is also projected to increase in the projection period.

Table 3. Growth in Gross Domestic Product, Nonfarm Employmemt and Productivity
(Percent per Year)

Assumptions	2006-2010	2010-2020	2020-2030	2006-2010
GDP (Billion Chain-Weighted $2000)				
High Growth	3.1	3.0	2.9	3.0
Reference	2.4	2.5	2.4	2.4
Low Growth	1.7	2.0	1.7	1.8
Nonfarm Employment				
High Growth	2.0	1.2	1.0	1.2
Reference	1.1	0.8	0.8	0.9
Low Growth	0.2	0.4	0.6	0.5
Productivity				
High Growth	2.1	2.4	2.4	2.4
Reference	1.7	2.0	1.9	1.9
Low Growth	1.5	1.6	1.4	1.5

Source: Energy Information Administration, *AEO20068 National Energy Modeling System runs: AEO2008.d030208f; hm2008.d031608a; and lm2008.d031608a.*

To achieve the reference case's long-run 2.4 percent economic growth, there is an anticipated steady growth in labor productivity. The improvement in labor productivity reflects the positive effects of a growing capital stock as well as technological change over time. Nonfarm labor productivity is expected to remain between 1.9 and 2.0 percent for the remainder of the projection period from 2006 through 2030. Business fixed investment as a share of nominal GDP is expected to grow over the last 10 years of the projection. The resulting growth in the capital stock and the technology base of that capital stock helps to sustain productivity growth of 1.9 percent from the 2005 to 2030.

To reflect the uncertainty in projection of economic growth, the *AEO2007* uses high and low economic growth cases along with the reference case to project the possible impacts on energy markets. The high economic growth case incorporates higher population, labor force and productivity growth rates than the reference case. Due to the higher productivity gains, inflation and interest rates are lower compared to the reference case. Investment, disposable income, and industrial production are increased. Economic output is projected to increase by 3.0 percent per year between 2006 and 2030. The low economic growth case assumes lower population, labor force, and productivity gains, with resulting higher prices and interest rates and lower industrial output growth. In the low economic growth case, economic output is expected to increase by 1.8 percent per year over the projection horizon.

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International Energy Module

The International Energy Module (IEM) performs two tasks in all NEMS runs. First, the module reads exogenously global and U.S.A. petroleum liquids supply and demand curves (1 curve per year; 2008-2030; approximated, isoelastic fit to previous NEMS results). These quantities are not modeled directly in NEMS. Previous versions of the IEM adjusted these quantities after reading in initial values. In an attempt to more closely integrate the *AEO2008* with *IEO2007* and the STEO some functionality was removed from IEM while a new algorithm was implemented. Based on the difference between U.S. total petroleum liquids production (consumption) and the expected U.S. total liquids production (consumption) at the current WTI price, curves for global petroleum liquids consumption (production) were adjusted for each year. According to previous operations, a new WTI price path was generated. An exogenous oil supply module, Generate World Oil Balances (GWOB), was also used in IEM to provide annual regional (country) level production detail for conventional and unconventional liquids.

The second task of the IEM is to interact with the PMM module during runs to determine changes in the WTI price and the supply prices of crude oils and petroleum products for import to the United States in response to changes in U.S. import requirements. As a result of the interaction with PMM, this module also determines new values for oil production in the Middle East OPEC region, along with a report for crude oil, light and heavy refined products imports by source.

Key Assumptions

The level of oil production by countries in the Organization of Petroleum Exporting Countries (OPEC) is a key factor influencing the world oil price projections incorporated into *AEO2008*. Non-OPEC production, worldwide regional economic growth rates and the associated regional demand for oil are additional factors affecting the world oil price.

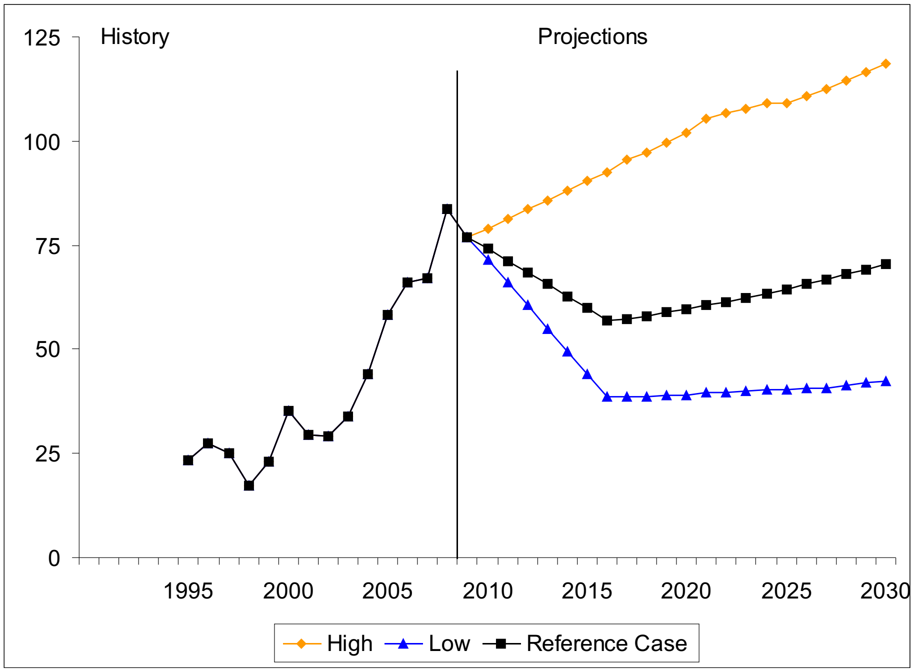
The world oil price is the annual average U.S. cost of imported low-sulfur light crude oil in PADD2. For the low, reference, and high oil price cases, prices reach $42, $70 and $118 per barrel in 2030, respectively, in 2006 dollars. The reference case assumes that OPEC producers will continue to demonstrate a disciplined production approach. The low oil price case reflects a market where all oil production becomes more competitive and plentiful. The high oil price case could result from a more cohesive and market-assertive OPEC whose long-term goal might be to maintain a constant market share. The three price scenarios are shown in Figure 2.

OPEC oil production is assumed to increase throughout the reference case projection, making OPEC the primary source for satisfying the worldwide increase in oil consumption expected over the projection period (Figure 3). OPEC is assumed to be the source of additional production because its member nations hold a major portion of the world's total reserves—exceeding 927 billion barrels, about 70 percent of the world's estimated total, at the end of 2006.[1]

The reference case values for OPEC production are shown in Figure 3. Ecuador is not included in OPEC in AEO2008 because of the late announcement. Iraq oil production is assumed to not return to pre-conflict volumes until 2010. By 2030, Iraq is expected to increase production capacity to more than 4.6 million barrels per day with likely investment help from foreign sources. Non-OPEC liquids production is expected to increase by 1.1 percent per year over the projection period, as advances in both exploration and extraction technologies result in an upward trend. The non-OPEC production path for the reference case is shown in Figure 4.

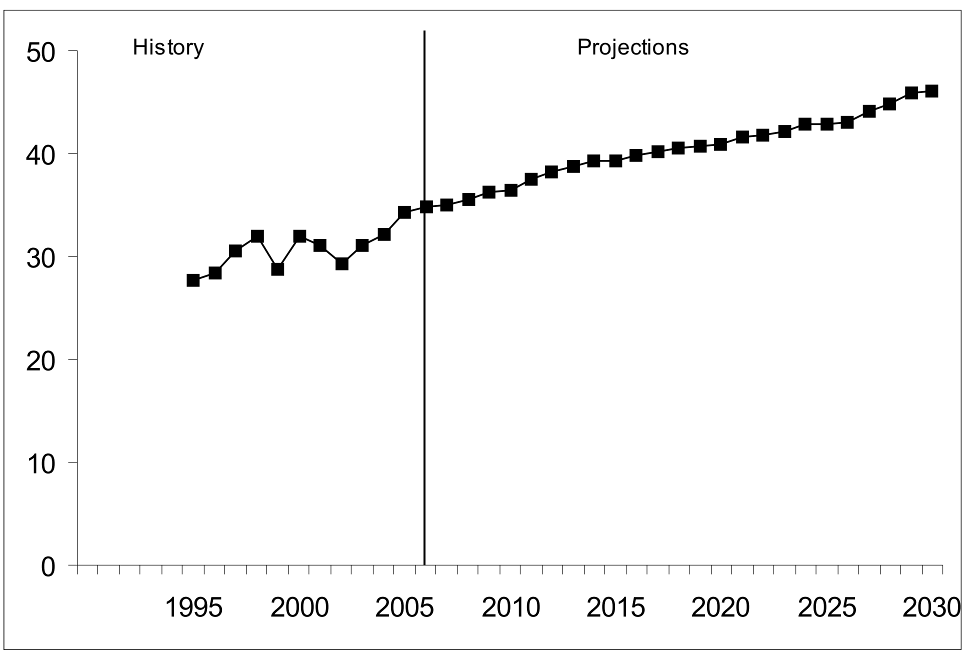
The non-U.S. oil production projections in the *AEO2008* begin with country-level assumptions regarding oil resources. These resource estimates are taken in part from the USGS World Petroleum Assessment of 2000 as well as from PennWell Publishing Company Oil and Gas Journal, summary of which is shown in Table 4.

Figure 2. World Oil Prices in Three Cases, 1995-2030
2006 Dollars per Barrel



Source: AEO2008 National Energy Modeling System runs AEO2008.D030208F, LP2008.D031608A, and HP2008.D031808A.

Figure 3. OPEC Total Liquids Production in the Reference Case, 1995-2030
Millions barrels per Day

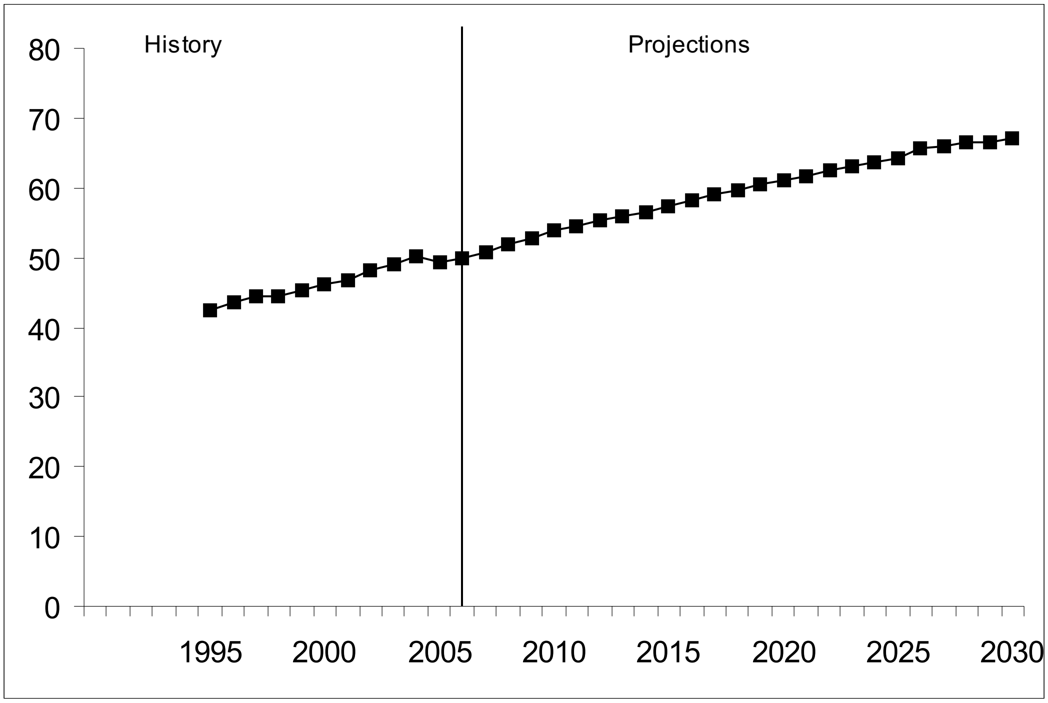


OPEC = Organization of Petroleum Exporting Countries.

Source: Energy Information Administration. AEO2008 National Energy Modeling System run AEO2008.D030208F.

Figure 4. Non-OPEC Total Liquids Production in the Reference Case, 1995-2030

Millions barrels per Day



OPEC = Organization of Petroleum Exporting Countries.

Source: Energy Information Administration. AEO2008 National Energy Modeling System run AEO2008.D030208F.

The reference case growth rates for GDP for various regions in the world are shown in Table 5. Except for the United States, the GDP growth rate assumptions for non U.S. country/regions are taken from IEO2007.

The values for growth in oil demand in the International Energy Module, which depend upon the oil price levels as well as GDP growth rates, are shown in Table 6 for the reference case by regions.

Petroleum products imports are represented in the projections through a series of curves for each of the five Petroleum Administration for Defense Districts (PADDs). Curves are provided for seventeen products: traditional gasoline (including aviation), reformulated gasoline, conventional and reformulated gasoline blending stocks for oxygenated blending (CBOB, RBOB), traditional distillate fuel, low-sulfur heating oil, ultra low-sulfur diesel fuel, high and low-sulfur residual fuel, jet fuel (including naphtha jet), liquefied petroleum gases, petrochemical feedstocks, unfinished oils (resid, naphtha, heavy gas oil), methanol, MTBE, and other petroleum products. The curves are derived from *AEO2007* curves and analysis of price differential between marker crude oils and refined petroleum productions imported into the U.S.

Table 4. Worldwide Oil Reserves as of January 1, 2008
(Billion Barrels)

Region	Proved Oil Reserves
Western Hemisphere	321.1
Western'Europe	13.2
Asia-Pacific	34.3
Eastern Europe and F.S.U.	100
Middle East	748.3
Africa	114.8
Total World	1331.7
Total OPEC	927.5

Source: PennWell Corporation, Oil and Gas Journal, Vol 103, No 47 (Dec 19, 2005).

Table 5. Average Annual Real Gross Domestic Product Rates, 2004-2030 (2000 Purchasing PowerParity Weights and Prices)

Region	Average Annual Percentage Change
OECD	2.3
OECD North America	2.6
OECD Europe	2.3
OECD Asia	1.9
Non-OECD	5.3
Non-OECD Europe and Eurasia	4.3
Non-OECD Asia	5.8
Middle East	4.2
Africa	4.9
Central and South America	3.9
Total World	4.0

Source: For the U.S., Energy Informatin Administration, National Energy Modeling System run AEO2008.D030208F; for other countries, Global Insight, Inc., World Overview (Lexington, MA, January 2007)

Table 6. Average Annual Growth Rates for Total Liquids Demand in the Reference Case, 2004-2030
(Percent per Year)

Region	Oil Demand Growth
OECD	0.3%
OECD North America	0.4%
OECD Europe	0.1%
OECD Asia	0.4%
Non-OECD	2.3%
Non-OECD Europe and Eurasia	1.1%
Non-OECD Asia	2.8%
Middle East	2.2%
Africa	2.2%
Central and South America	2.3%
Total World	1.2%

Source: Energy Information Administration, *AEO2008* National Energy Modeling System run: AEO2008.D030208F; and IEO2007 System for the Analysis of Global Energy Markets (2007).

Notes and Sources

[1] PennWell Corporation, Oil and Gas Journal, Vol. 103, No. 47 (December 19, 2005).

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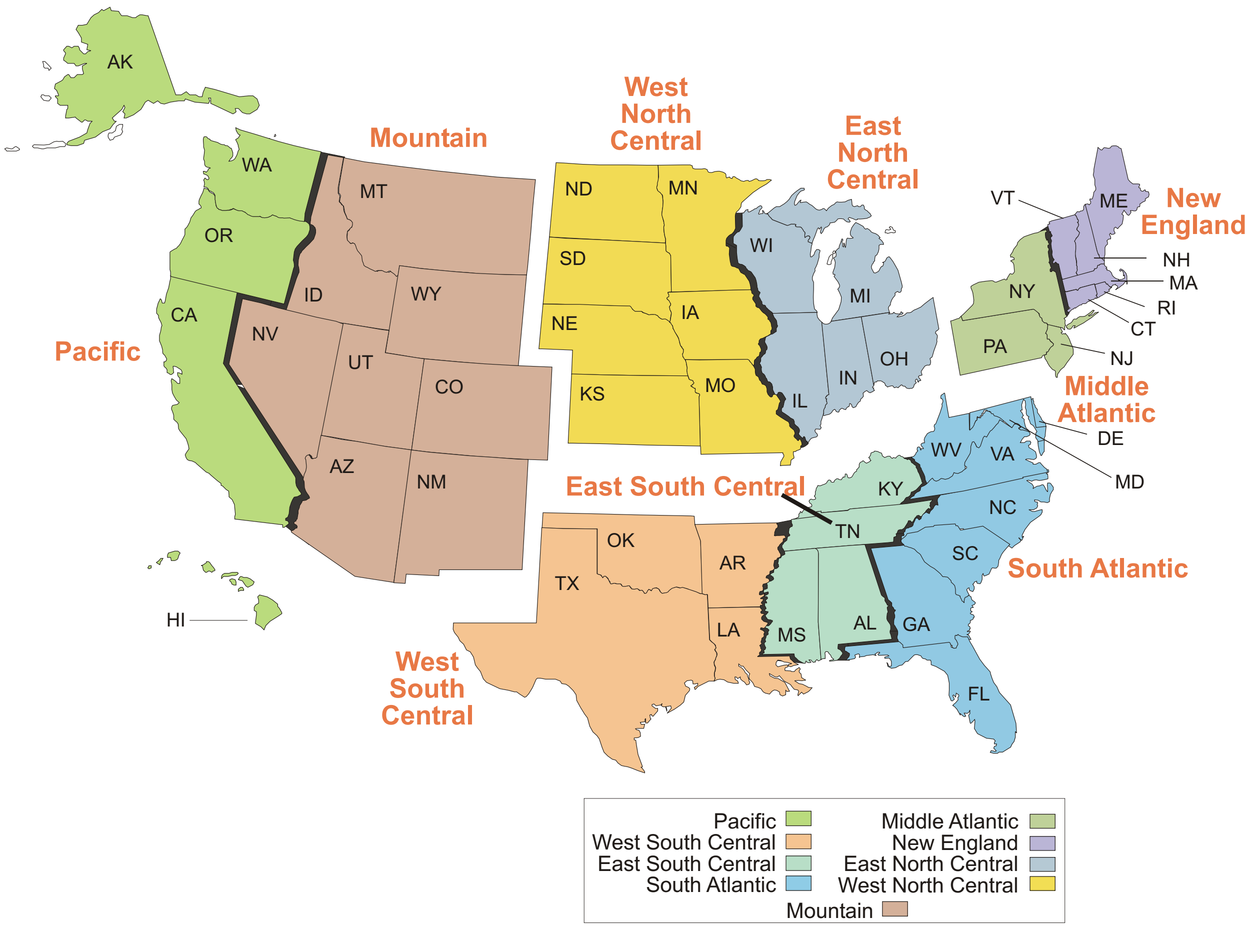
Residential Demand Module

The NEMS Residential Demand Module projects future residential sector energy requirements based on projections of the number of households and the stock, efficiency, and intensity of use of energy-consuming equipment. The Residential Demand Module projections begin with a base year estimate of the housing stock, the types and numbers of energy-consuming appliances servicing the stock, and the "unit energy consumption" by appliance (or UEC—in million Btu per household per year). The projection process adds new housing units to the stock, determines the equipment installed in new units, retires existing housing units, and retires and replaces appliances. The primary exogenous drivers for the module are housing starts by type (single-family, multifamily and mobile homes) and Census Division and prices for each energy source for each of the nine Census Divisions (see Figure 5). The Residential Demand Module also requires projections of available equipment and their installed costs over the projection horizon. Over time,

Figure 5. United States Census Divisions



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

equipment efficiency tends to increase because of general technological advances and also because of Federal and/or state efficiency standards. As energy prices and available equipment changes over the projection horizon, the module includes projected changes to the type and efficiency of equipment purchased as well as projected changes in the usage intensity of the equipment stock.

The end-use services for which equipment stocks are modeled include space conditioning (heating and cooling), water heating, refrigeration, freezers, dishwashers, clothes washers, lighting, furnace fans, color televisions, personal computers, cooking, clothes drying, ceiling fans, coffee makers, spas, home security systems, microwave ovens, set-top boxes, home audio equipment, rechargeable electronics, and VCR/DVDs. In addition to the major equipment-driven end-uses, the average energy consumption per household is projected for other electric and nonelectric appliances. The module's output includes number of households, equipment stock, average equipment efficiencies, and energy consumed by service, fuel, and geographic location. The fuels represented are distillate fuel oil, liquefied petroleum gas, natural gas, kerosene, electricity, wood, geothermal, coal, and solar energy.

One of the implicit assumptions embodied in the Residential Demand Module is that, through 2030, there will be no radical changes in technology or consumer behavior. No new regulations of efficiency beyond those currently embodied in law or new government programs fostering efficiency improvements are assumed. Technologies which have not gained widespread acceptance today will generally not achieve significant penetration by 2030. Currently available technologies will evolve in both efficiency and cost. In general, at the same efficiency level, future technologies will be less expensive than those available today in real dollar terms. When choosing new or replacement technologies, consumers will behave similarly to the way they now behave. The intensity of end-uses will change moderately in response to price changes. Electric end uses will continue to expand, but at a decreasing rate.[1]

Key Assumptions

Housing Stock Submodule

An important determinant of future energy consumption is the projected number of households. Base year estimates for 2005 are derived from the Energy Information Administration's (EIA) *Residential Energy Consumption Survey* (RECS) (Table 7). The projection for occupied households is done separately for each Census Division. It is based on the combination of the previous year's surviving stock with projected housing starts provided by the NEMS Macroeconomic Activity Module. The housing stock submodule assumes a constant survival rate (the percentage of households which are present in the current projection year, which were also present in the preceding year) for each type of housing unit; 99.6 percent for single-family units, 99.9 percent for multifamily units, and 97.6 percent for mobile home units. Projected fuel consumption is dependent not only on the projected number of housing units, but also on the type and geographic distribution of the houses. The intensity of space heating energy use varies greatly across the various climate zones in the United States. Also, fuel prevalence varies across the country—oil (distillate) is more frequently used as a heating fuel in the New England and Middle Atlantic Census Divisions than in the rest of the country, while natural gas dominates in the Midwest. An example of differences by housing type is the more prevalent use of liquefied petroleum gas in mobile homes relative to other housing types.

Table 7. 2005 Households

Census Division	Single-family Units	Multiple family Units	Mobile Home	Total Units
New England	3,392,944	1,899,981	173,072	5,465,996
Mid Atlantic	10,077,231	4,784,686	254,610	15,116,527
East North Central	14,091,216	3,233,929	424,271	17,749,416
West North Central	6,107,582	1,406,214	340,759	7,854,555
South Atlantic	14,823,560	4,910,592	1,962,563	21,696,715
East South Central	5,438,660	729,591	724,503	6,892,754
West South Central	8,892,255	2,120,675	1,109,901	12,122,831
Mountain	5,680,398	951,482	922,976	7,554,856
Pacific	11,150,078	4,456,348	1,030,541	16,636,967
United States	79,653.923	24,493,498	6,943,196	111,090,617

Source: U.S. Department of Energy, Energy Information Administration, *2005 Residential Energy Consumption Survey* (preliminary data).

Technology Choice Submodule

The key inputs for the Technology Choice Submodule are fuel prices by Census Division and characteristics of available equipment (installed cost, maintenance cost, efficiency, and equipment life). Fuel prices are determined by an equilibrium process which considers energy supplies and demands and are passed to this submodule from the integrating module of NEMS. Energy price, combined with equipment UEC (which is a function of efficiency), determines the operating costs of equipment. Equipment characteristics are exogenous to the model and are modified to reflect both Federal standards and anticipated changes in the market place. Table 8 lists capital cost and efficiency for selected residential appliances for the years 2007 and 2020.

Table 8. Installed Cost and Efficiency Ratings of Selected Equipment

Equipment Type	Relative Performance[1]	2007 Installed Cost ($2007)[2]	Efficiency[3]	2020 Installed Cost ($2004)[2]	Efficiency[3]	Approximate Hurdle Rate
Electric Heat Pump	Minimum	$3,800	13.0	$3,800	13.0	15%
	Best	$7,500	17.0	$6,700	20.0	
Natural Gas Furnace	Minimum	$1,500	0.80	$1,500	0.80	15%
	Best	$3,050	0.96	$2,700	0.96	
Room Air Conditioner	Minimum	$310	9.8	$310	9.8	140%
	Best	$925	11.7	$875	12.0	
Central Air Conditioner	Minimum	$3,000	13.0	$3,000	13.0	15%
	Best	$5,700	21.0	$5,750	23.0	
Refrigerator (23.9 cubic ft in adjusted volume)	Minimum	$550	510	$550	510	19%
	Best	$950	417	$1000	417	
Electric Water Heater	Minimum	$400	0.90	$400	0.90	30%
	Best	$1,530	2.4	$1,700	2.4	
Solar Water Heater	N/A	$3,500	2.0	$4,500	2.0	30%

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.

[2]Installed costs are given in 2007 dollars in the original source document.

[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).

Source: Navigant Consulting, *EIA Technology Forecast Updates*, Reference Number 20070831.1September 2007.

Table 9 provides the cost and performance parameters for representative distributed generation technologies. The *AEO2008* model also incorporates endogenous "learning" for the residential distributed generation technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, learning parameter assumptions for the *AEO2008* reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles.

The Residential Demand Module projects equipment purchases based on a nested choice methodology. The first stage of the choice methodology determines the fuel and technology to be used, the second stage determines the efficiency of the selected equipment type. The equipment choices for cooling, water heating, and cooking are linked to the space heating choice for new construction. Technology and fuel choice for replacement equipment uses a nested methodology similar to that for new construction, but includes (in addition to the capital and installation costs of the equipment) explicit costs for technology switching (e.g., costs for installing gas lines if switching from electricity or oil to gas, or costs for adding ductwork if switching from electric resistance heat to central heating types). Also, for replacements, there is no linking of fuel choice for water heating and cooking as is done for new construction. Technology switching upon replacement is allowed for space heating, air conditioning, water heating, cooking and clothes drying.

Once the fuel and technology choice for a particular end use is determined, the second stage of the choice methodology determines efficiency. In any given year, there are several available prototypes of varying efficiency (minimum standard, medium low, medium high and highest efficiency). Efficiency choice is based on a functional form and coefficients which give greater or lesser importance to the installed capital cost (first cost) versus the operating cost. Generally, within a technology class, the higher the first cost, the lower the operating cost. For new construction, efficiency choices are made based on the costs of both the heating and cooling equipment and the building shell characteristics.

The parameters for the second stage efficiency choice are calibrated to the most recently available shipment data for the major residential appliances. Shipment efficiency data are obtained from industry associations which monitor shipments such as the Association of Home Appliance Manufacturers. Because of this calibration procedure, the model allows the relative importance of first cost versus operating cost to vary by general technology and fuel type (e.g., natural gas furnace, electric heat pump, electric central air conditioner, etc.). Once the model is calibrated, it is possible to calculate (approximately) the apparent

Table 9. Capital Cost and Performance Parameters of Selected Residential Distributed Generation Technologies

Technology Type	Year of Introduction	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec. + Thermal)	Installed Capital Cost ($2005 per KW of Capacity)[1]	Service Life Years
Solar Photovoltaic						
	2007	2.0	0.16	N/A	$6,924	30
	2010	2.5	0.18	N/A	$6,944	30
	2015	3.0	0.20	N/A	$5,310	30
	2020	3.0	0.22	N/A	$4,627	30
	2030	4.0	0.25	N/A	$3,840	30
Fuel Cell	2007	10	0.308	0.697	$8,897	20
	2010	10	0.320	0.699	$7,802	20
	2015	10	0.335	0.705	$6,160	20
	2020	10	0.350	0.712	$4,517	20
	2030	10	0.360	0.723	$2,669	20

[1]Installed costs are given in 2005 dollars in the original source document.

Source: Solar Technology Specifications: Solar Energy Industries Association, *Our Solar Power Future - The U.S. Photovoltaic Industry Roadmap through 2030 and Beyond* (SEIA, September 2004). Fuel cells: Discovery Insights, *LLC, "Installed Costs for Small CHP Systems - Estimates and Projections"* (April 2005).

discount rates based on the relative weight given to the operating cost savings versus the weight given to the higher cost of more efficient equipment. Hurdle rates in excess of 30 percent are common in the Residential Demand Module. The prevalence of such high apparent hurdle rates by consumers has led to the notion of the "efficiency gap" that is, there are many investments that could be made that provide rates of return in excess of residential borrowing rates (15 to 20 percent for example). There are several studies which document instances of apparent high discount rates.[2] Once equipment efficiencies for a technology and fuel are determined, the installed efficiency for its entire stock is calculated.

Appliance Stock Submodule

The Appliance Stock Submodule is an accounting framework which tracks the quantity and average efficiency of equipment by end use, technology, and fuel. It separately tracks equipment requirements for new construction and existing housing units. For existing units, this module calculates equipment which survives from previous years, allows certain end uses to further penetrate into the existing housing stock and calculates the total number of units required for replacement and further penetration. Air conditioning and clothes drying are the two end uses not considered to be "fully penetrated."

Once a piece of equipment enters into the stock, an accounting of its remaining life is begun. It is assumed that all appliances survive a minimum number of years after installation. A fraction of appliances are removed from the stock once they have survived for the minimum number of years. Between the minimum and maximum life expectancy, all appliances retire based on a linear decay function. For example, if an appliance has a minimum life of 5 years and a maximum life of 15 years, one tenth of the units (1 divided by 15 minus 5) are retired in each of years 6 through 15. It is further assumed that, when a house is retired from the stock, all of the equipment contained in that house retires as well; i.e., there is no secondhand market for this equipment. The assumptions concerning equipment lives are given in Table 10.

Table 10. Minimum and Maximum Life Expectancies of Equipment

Equipment	Minimum Life	Maximum Life
Heat Pumps	7	21
Central Forced-Air Furnaces	10	25
Hydronic Space Heaters	20	30
Room Air Conditioners	8	16
Central Air Conditioners	7	21
Gas Water Heaters	4	14
Electric Water Heaters	5	22
Cooking Stoves	16	21
Clothes Dryers	11	20
Refrigerators	7	26
Freezers	11	31

Source: Lawrence Berkeley Laboratory, *Baseline Data for the Residential Sector and Development of a Residential Forecasting Database*, May 1994, and analysis of RECS 2001 data.

Fuel Consumption Submodule

Energy consumption is calculated by multiplying the vintage equipment stocks by their respective UECs. The UECs include adjustments for the average efficiency of the stock vintages, short term price elasticity of demand and "rebound" effects on usage (see discussion below), the size of new construction relative to the existing stock, people per household and shell efficiency and weather effects (space heating and cooling). The various levels of aggregated consumption (consumption by fuel, by service, etc.) are derived from these detailed equipment-specific calculations.

Equipment Efficiency

The average energy consumption of a particular technology is initially based on estimates derived from RECS 2001. Appliance efficiency is either derived from a long history of shipment data (e.g., the efficiency of conventional air-source heat pumps) or assumed based on engineering information concerning typical installed equipment (e.g., the efficiency of ground-source heat pumps). When the average efficiency is computed from shipment data, shipments going back as far as 20 to 30 years are combined with assumptions concerning equipment lifetimes. This allows for not only an average efficiency to be calculated, but also for equipment retirements to be vintaged—older equipment tends to be lower in efficiency and also tends to get retired before newer, more efficient equipment. Once equipment is retired, the Appliance Stock and Technology Choice Modules determine the efficiency of the replacement equipment. It is often the case that the retired equipment is replaced by substantially more efficient equipment.

As the stock efficiency changes over the simulation interval, energy consumption decreases in inverse proportion to efficiency. Also, as efficiency increases, the efficiency rebound effect (discussed below) will offset some of the reductions in energy consumption by increased demand for the end-use service. For example, if the stock average for electric heat pumps is now 10 percent more efficient than in 2001, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would average about only 9 percent less.

Adjusting for the Size of Housing Units

Information derived from RECS 2001 indicates that new construction (post-1990) is on average roughly 26 percent larger than the existing stock of housing. Estimates for the size of each new home built in the projection period vary by type and region, and are determined by a log-trend projection based on historical data from the Bureau of the Census.[3] For existing structures, it is assumed that about 1 percent of households that existed in 2005 add about 600 square feet to the heated floor space in each year of the projection period.[4] The energy consumption for space heating, air conditioning, and lighting is assumed to increase with the square footage of the structure. This results in an increase in the average size of the housing stock from 1,802 to 2,046 square feet from 2005 through 2030.

Adjusting for Weather and Climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid inadvertently projecting abnormal weather conditions into the future. In the residential module, adjustments are made to space heating and air conditioning UECs by Census Division by their respective heating and cooling degree-days (HDD and CDD). A 10 percent increase in HDD would increase space heating consumption by 18 percent over what it would have otherwise been. Over the projection period, the residential module uses a 10-year average for heating and cooling degree - days by Census Division, adjusted by projections in state population shifts.

Short-Term Price Effect and Efficiency Rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an opposite, but less than proportional, effect on fuel consumption. The current value for the short-term elasticity parameter is -0.15.[5] This value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of -0.15 percent. Another way of affecting the marginal cost of providing a service is through altered equipment efficiency. For example, a 10 percent increase in efficiency will reduce the cost of providing the end-use service by 10 percent. Based on the short-term efficiency rebound parameter, the demand for the service will rise by 1.5 percent (-10 percent multiplied by -0.15). Only space heating and cooling are assumed to be affected by both elasticities and the efficiency rebound effect.

Shell Efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling load for each type of household. In the NEMS Residential Demand Module, the shell integrity is represented by an index, which changes over time to reflect improvements in the building shell. The shell integrity index is dimensioned by vintage of house, type of house, fuel type, service (heating and cooling), and Census Division. The age, type, location, and type of heating fuel are important factors in determining the level of shell integrity. Housing units which heat with electricity tend to have less air infiltration rates than homes that use other fuels. The age of homes are classified by new (post-2005) and existing. Existing homes are characterized by the RECS 2005 survey and are assigned a shell index value based on the mix of homes that exist in the base year (2005). The improvement over time in the shell integrity of these homes is a function of two factors—an assumed annual efficiency improvement and improvements made when real fuel prices increase (no price-related adjustment is made when fuel prices fall). For new construction, building shell efficiency is determined by the relative costs and energy bill savings for several levels of heating and cooling equipment, in conjunction with the building shell attributes. The packages represented in NEMS range from homes that meet the International Energy Conservation Code (IECC)[6] to homes that exceed the IECC by 50 percent. Shell efficiency in new homes would increase over time if energy prices rise, or the cost of more efficient equipment falls.

Legislation and Regulations

Energy Independence and Security Act of 2007 (EISA 2007)

EISA 2007 contains several provisions that impact projections of residential energy use. Standards for general service incandescent light bulbs are phased-in over 2012-2014, with a more restrictive standard specified in 2020. It is estimated that these standards require 29 percent less watts per bulb in the first phase-in, increasing to 67 percent in 2020. EISA also updates the dehumidifier standard specified in EPACT 2005, resulting in 7 percent increase in electricity savings, relative to the EPACT 2005 requirement. New efficiency standards for external power supplies are set for July 1, 2008, reducing electricity use in both the active and no-load modes. Standards are also set for boilers (September 2012) and dishwashers (January 2010). Lastly, DOE is instructed to create standards for manufactured housing, requiring compliance to the latest International Energy Conservation Code (IECC) by the end of 2011.

Energy Policy Act of 2005 (EPACT05)

The passage of the EPACT05 in August 2005 provides additional minimum efficiency standards for residential equipment and provides tax credits to producers and purchasers of energy efficient equipment and builders of energy efficient homes. The standards contained in EPACT05 include: 190 watt maximum for torchiere lamps in 2006; Dehumidifier standards for 2007 and 2012; and ceiling fan light kit standards in 2007. Manufactured homes that are 30 percent better than the latest code, a $1000 tax credit can be claimed in 2006 and 2007. Likewise, builders of homes that are 50 percent better than code can claim a $2000 credit over the same period. The builder tax credits and production tax credits are assumed to be passed through to the consumer in the form of lower purchase cost. EPACT05 includes production tax credits for energy efficient refrigerators, dishwashers, and clothes washers in 2006 and 2007, with dollar amounts varying by type of appliance and level of efficiency met, subject to annual caps. Consumers can claim a 10 percent tax credit in 2006 and 2007 for several types of appliances specified by EPACT05, including: Energy efficient gas, propane, or oil furnaces or boilers, energy efficient central air conditioners, air and ground source heat pumps, hot water heaters, and windows. Lastly, consumers can claim a 30 percent tax credit in 2006 and 2007 for purchases of solar PV, solar water heaters, and fuel cells, subject to a cap.

National Appliance Energy Conservation Act of 1987

The Technology Choice Submodule incorporates equipment standards established by the National Appliance Energy Conservation Act of 1987 (NAECA). Some of the NAECA standards implemented in the module include: a Seasonal Energy Efficiency Rating (SEER) of 13.0 for central air conditioners and heat pumps; an Annual Fuel Utilization Efficiency (energy output over energy input) of 0.78 for oil and gas furnaces; an Efficiency Factor of 0.90 for electric water heaters; and refrigerator standards that set consumption limits to 510 kilowatt-hours per year in 2002.

Residential Alternative Cases

Technology Cases

In addition to the *AEO2008* reference case, three side cases were developed to examine the effect of equipment and building standards on residential energy use—a *2008 technology case,* a *best available technology case*, and a *high technology case*. These side cases were analyzed in stand-alone (not integrated with the supply modules) NEMS runs and thus do not include supply-responses to the altered residential consumption patterns of the two cases. *AEO2008* also analyzed *integrated 2008 technology* and *high technology cases*. The *integrated 2008 technology case* combines the *2008 technology cases* of the four end-use demand sectors, the *electricity low fossil technology case*, and the assumption of renewable technologies fixed at 2008 levels. The *integrated high technology case* uses the same approach, but for high technology.

The 2008 technology case assumes that all future equipment purchases are made based only on equipment available in 2008. This case further assumes that existing building shell efficiencies will not improve beyond 2008 levels.

The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies.[7] In the *high technology case*. All new construction is assumed to meet Energy Star specifications after 2016.

The *best available technology case* assumes that all equipment purchases from 2009 forward are based on the highest available efficiency in the *high technology case* in a particular simulation year, disregarding the economic costs of such a case. This case is designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. In this case, all new construction is built to the most efficient specifications after 2008.

Residential "Normal" Weather Sensitivity Case

The projections presented in *AEO2008* assume that future “normal” weather is represented by the average of the last 10 years (1997-2006). Prior to *AEO2008*, “normal” weather, in the form of heating and cooling degree-days, was represented as the average of the past 30 years, as published by the National Oceanic and Atmospheric Administration (NOAA). In order to gauge the importance of this change, a weather sensitivity case was created using the NOAA 30-year average heating and cooling degree-days as a proxy for future “normal” weather. Because the 10-year average weather assumed in the *AEO2008* reference case is warmer in both summer and winter relative to the 30-year average, the sensitivity case reduces future needs for air conditioning, and increases the need for space heating, relative to the *AEO2008* reference case.

Notes and Sources

[1] The Model Documentation Report contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Residential Sector Demand Module of the National Energy Modeling System, DOE/EIA-M065(2006), (March 2007).

[2] Among the explanations often mentioned for observed high average implicit discount rates are: market failures, (i.e., cases where incentives are not properly aligned for markets to result in purchases based on energy economics alone); unmeasured technology costs (i.e., extra costs of adoption which are not included or difficult to measure like employee down-time); characteristics of efficient technologies viewed as less desirable than their less efficient alternatives (such as equipment noise levels or lighting quality characteristics); and the risk inherent in making irreversible investment decisions. Examples of market failures/barriers include: decision makers having less than complete information, cases where energy equipment decisions are made by parties not responsible for energy bills (e.g., landlord/tenants, builders/home buyers), discount horizons which are truncated (which might be caused by mean occupancy times that are less than the simple payback time and that could possibly be classified as an information failure), and lack of appropriate credit vehicles for making efficiency investments, to name a few. The use of high implicit discount rates in NEMS merely recognizes that such rates are typically found to apply to energy-efficiency investments.

[3] U.S. Bureau of Census, Series C25 Data from various years of publications.

[4] Sources: U.S. Bureau of Census, Annual Housing Survey 2001 and Professional Remodler, 2002 Home Remodeling Study.

[5] See DAHL, CAROL, *A Survey of Energy Demand Elasticities in Support of the Development of the NEMS*, October 1993.

[6] The IECC established guidelines for builders to meet specific targets concerning energy efficiency with respect to heating and cooling load.

[7] The high technology assumptions are based on Energy Information Administration, Technology Forecast Updates-Residential and Commercial Building technologies-Advanced Adoption Case (Navigant Consulting, September 2007).

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Commercial Demand Module

The NEMS Commercial Sector Demand Module generates projections of commercial sector energy demand through 2030. The definition of the commercial sector is consistent with EIA's State Energy Data System (SEDS). That is, the commercial sector includes business establishments that are not engaged in transportation or in manufacturing or other types of industrial activity (e.g., agriculture, mining or construction). The bulk of commercial sector energy is consumed within buildings; however, street lights, pumps, bridges, and public services are also included if the establishment operating them is considered commercial. Since most of commercial energy consumption occurs in buildings, the commercial module relies on the data from the EIA Commercial Buildings Energy Consumption Survey (CBECS) for characterizing the commercial sector activity mix as well as the equipment stock and fuels consumed to provide end use services.[1]

The commercial module projects consumption by fuel[2] at the Census division level using prices from the NEMS energy supply modules, and macroeconomic variables from the NEMS Macroeconomic Activity Module (MAM), as well as external data sources (technology characterizations, for example). Energy demands are projected for ten end-use services[3] for eleven building categories[4] in each of the nine Census divisions (see Figure 5). The model begins by developing projections of floorspace for the 99 building category and Census division combinations. Next, the ten end-use service demands required for the projected floorspace are developed. The electricity generation and water and space heating supplied by distributed generation and combined heat and power technologies are projected. Technologies are then chosen to meet the projected service demands for the seven major end uses.[5] Once technologies are chosen, the energy consumed by the equipment stock (both existing and purchased equipment) is developed to meet the projected end-use service demands.[6]

Key Assumptions

The key assumptions made by the commercial module are presented in terms of the flow of the calculations described above. The sections below summarize the assumptions in each of the commercial module submodules: floorspace, service demand, distributed generation, technology choice, and end-use consumption. The submodules are executed sequentially in the order presented, and the outputs of each submodule become the inputs to subsequently executed submodules. As a result, key projection drivers for the floorspace submodule are also key drivers for the service demand submodule, and so on.

Floorspace Submodule

Floorspace is projected by starting with the previous year's stock of floorspace and eliminating a portion to represent the age-related removal of buildings. Total floorspace is the sum of the surviving floorspace plus new additions to the stock derived from the MAM floorspace growth projection.[7]

Existing Floorspace and Attrition

Existing floorspace is based on the estimated floorspace reported in the 2003 *Commercial Buildings Energy Consumption Survey* (Table 11). Over time, the 2003 stock is projected to decline as buildings are removed from service (floorspace attrition). Floorspace attrition is estimated by a logistic decay function, the shape of which is dependent upon the values of two parameters: average building lifetime and *gamma*. The average building lifetime refers to the median expected lifetime of a particular building type. The *gamma* parameter corresponds to the rate at which buildings retire near their median expected lifetime. The current values for the average building lifetime and *gamma* vary by building type as presented in Table 12.[8]

Table 11. 2003 Total Floorspace by Census Division and Principal Building Activity
(Millions of Square Feet)

	Assem-bly	Educa-tion	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other	Total
New England	431	299	75	45	48	374	282	320	819	411	351	3,452
Middle Atlantic	1,243	1,384	163	127	310	797	1,523	1,065	1,641	1,112	1,177	10,543
East North Central	1,355	1,990	218	248	316	549	1,297	1,129	2,148	2,023	1,152	12,424
West North Central	772	552	102	206	123	595	219	704	1,045	994	369	5,680
South Atlantic	1,161	2,445	223	433	469	939	1,173	1,065	3,391	1,836	865	13,999
East South Central	546	341	67	99	134	368	195	371	985	390	223	3,719
West South Central	965	1,198	197	232	235	387	916	501	2,076	1,740	575	9,022
Mountain	411	640	64	32	94	438	230	535	1,087	506	168	4,207
Pacific	809	1,027	146	232	176	649	1,028	915	2,051	1,066	515	8,613
United States	7,693	9,874	1,255	1,654	1,905	5,096	6,861	6,605	15,242	10,078	5,395	71,658

Note: Totals may not equal sum of components due to independent rounding.

Source: Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey Public Use Data

Table 12. Floorspace Attrition Parameters

	Assem-bly	Educa-tion	Food Sales	Food Service	Health Care	Lodging	Large Office	Small Office	Merc/ Service	Ware-house	Other
Median Expected Lifetime (years)	80	80	65	65	65	69	73	73	65	80	75
gamma	1.8	2.6	2.5	2.5	2.3	2.0	2.0	2.0	1.8	1.6	2.5

Sources: Energy Information Administration, Commercial Buildings Energy Consumption Survey 1999, 1995, 1992, and 1989 Public Use Data, 1986 Nonresidential Buildings Energy Consumption Survey, McGraw-Hill Construction Dodge Annual Starts - non residential building starts, and Journal of Business and Economic Statistics, April 1986, Vol. 4, No. 2.

New Construction Additions to Floorspace

The commercial module develops estimates of projected commercial floorspace additions by combining the surviving floorspace estimates with the total floorspace projection from MAM. A total NEMS floorspace projection is calculated by applying the MAM assumed floorspace growth rate within each Census division and MAM building type to the corresponding NEMS Commercial Demand Module's building types based on the CBECS building type shares. The NEMS surviving floorspace from the previous year is then subtracted from the total NEMS floorspace projection for the current year to yield new floorspace additions.[9]

Service Demand Submodule

Once the building stock is projected, the Commercial Demand module develops a projection of demand for energy-consuming services required for the projected floorspace. The module projects service demands for the following explicit end-use services: space heating, space cooling, ventilation, water heating, lighting, cooking, refrigeration, personal computer office equipment, and other office equipment.[10] The service demand intensity (SDI) is measured in thousand Btu of end-use service demand per square foot and differs across service, Census division and building type. The SDIs are based on a hybrid engineering and statistical approach of CBECS consumption data.[11] Projected service demand is the product of square feet and SDI for all end uses across the eleven building categories with adjustments for changes in shell efficiency for space heating and cooling.

Shell Efficiency

The shell integrity of the building envelope is an important determinant of the heating and cooling loads for each type of building. In the NEMS Commercial Demand Module, the shell efficiency is represented by an index, which changes over time to reflect improvements in the building shell. This index is dimensioned by building type and Census division and applies directly to heating. For cooling, the effects are computed from the index, but differ from heating effects, because of different marginal effects of shell integrity and because of internal building loads. In the *AEO2008* reference case, shell improvements for new buildings are up to 21 percent more efficient than the 2003 stock of similar buildings. Over the projection horizon, new building shells improve in efficiency by 7 percent relative to their efficiency in 2003. For existing buildings, efficiency is assumed to increase by 5 percent over the 2003 stock average. The shell efficiency index affects the space heating and cooling service demand intensities causing changes in fuel consumed for these services as the shell integrity improves.

Distributed Generation and Combined Heat and Power

Nonutility power production applications within the commercial sector are currently concentrated in education, health care, office and warehouse buildings. Program driven installations of solar photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs as well as DOE and industry news releases and the National Renewable Energy Laboratory's Renewable Electric Plant Information System. Historical data from Form EIA-860, *Annual Electric Generator Report*, are used to derive electricity generation for 2004 through 2006 by Census division, building type and fuel. A projection of distributed generation and combined heat and power (CHP) of electricity is developed based on the economic returns projected for distributed generation and CHP technologies. The model uses a detailed cash-flow approach to estimate the internal rate of return for an investment. Penetration assumptions for distributed generation and CHP technologies are a function of the estimated internall rate of return relative to purchased electricity. Table 13 provides the cost and performance parameters for representative distributed generation and CHP technologies.

The model also incorporates endogenous "learning" for new distributed generation and CHP technologies, allowing for declining technology costs as shipments increase. For fuel cell and photovoltaic systems, parameter assumptions for the *AEO2005* reference case result in a 13 percent reduction in capital costs each time the number of units shipped to the buildings sectors (residential and commercial) doubles. Doubling the number of microturbines shipped results in a 10 percent reduction in capital costs and doubling the number of distributed wind systems shipped results in a 3 percent reduction.

Technology Choice Submodule

The technology choice submodule develops projections of the results of the capital purchase decisions for equipment fueled by the three major fuels (electricity, natural gas, and distillate fuel). Capital purchase decisions are driven by assumptions concerning behavioral rule proportions and time preferences, described below, as well as projected fuel prices, average utilization of equipment (the capacity factors), relative technology capital costs, and operating and maintenance (O&M) costs.

Decision Types

In each projection year, equipment is potentially purchased for three "decision types". Equipment must be purchased for newly added floorspace and to replace the portion of equipment in existing floorspace that is projected to wear out.[12] Equipment is also potentially purchased for retrofitting equipment that has become economically obsolete. The purchase of retrofit equipment occurs only if the annual operating costs of a current technology exceed the annualized capital and operating costs of a technology available as a retrofit candidate.

Behavioral Rules

The commercial module allows the use of three alternate assumptions about equipment choice behavior. These assumptions constrain the equipment selections to three choice sets, which are progressively more restrictive. The choice sets vary by decision type and building type:

Table 13. Capital Cost and Performance Parameters of Selected Commercial Distributed Generation Technologies

Technology Type	Year	Average Generating Capacity (kW)	Electrical Efficiency	Combined Efficiency (Elec.+Thermal)	Installed Capital Cost ($2005 per kW of Capacity)*	Service Life (Years)
Solar Photovoltaic	2005	30	0.16	N/A	$6,115	30
	2010	32	0.18	N/A	$4,458	30
	2015	35	0.20	N/A	$4,292	30
	2020	40	0.22	N/A	$3,856	30
	2025	40	0.22	N/A	$3,528	30
	2030	45	0.25	N/A	$3,200	30
Fuel Cell	2005	200	0.36	0.72	$7,162	20
	2010	200	0.44	0.66	$6,219	20
	2015	200	0.45	0.67	$5,203	20
	2020	200	0.47	0.69	$4,187	20
	2025	200	0.48	0.70	$3,647	20
	2030	200	0.49	0.72	$3,108	20
Natural Gas Engine	2005	300	0.31	0.77	$2,132	20
	2010	300	0.32	0.78	$1,878	20
	2015	300	0.32	0.78	$1,714	20
	2020	300	0.33	0.78	$1,551	20
	2025	300	0.33	0.79	$1,343	20
	2030	300	0.34	0.80	$1,134	20
Oil-Fired Engine	2005	300	0.34	0.73	$2,575	20
	2010	300	0.34	0.74	$2,268	20
	2015	300	0.35	0.74	$2.071	20
	2020	300	0.35	0.74	$1,873	20
	2025	300	0.36	0.78	$1,622	20
	2030	300	0.36	0.82	$1,370	20
Natural Gas Turbine	2005	1000	0.22	0.68	$2,000	20
	2010	1000	0.23	0.68	$1,775	20
	2015	1000	0.24	0.68	$1,684	20
	2020	1000	0.24	0.69	$1,593	20
	2025	1000	0.25	0.69	$1,511	20
	2030	1000	0.26	0.70	$1,429	20
Natural Gas Micro Turbine	2005	200	0.29	0.60	$2,856	20
	2010	200	0.29	0.60	$2,328	20
	2015	200	0.31	0.61	$1,981	20
	2020	200	0.33	0.61	$1,634	20
	2025	200	0.34	0.62	$1,343	20
	2030	200	0.36	0.63	$1,052	20
Wind	2005	30	0.13	N/A	$4,000	30
	2010	32	0.13	N/A	$3,735	30
	2015	35	0.13	N/A	$3,720	30
	2020	40	0.13	N/A	$3,609	30
	2025	40	0.13	N/A	$3,497	30
	2030	50	0.13	N/A	$3,417	30

*Installed costs are given in 2005 dollars in the original source document. Costs for solar photovoltaic, fuel cell, microturbine, and wind technologies include learning effects.

Sources: Energy Information Administration, *Commercial and Industrial CHP Technology Cost and Performance Data Analysis for EIA's NEMS,* Decision Analysis Corporation and Discovery Insights LLC., February 2006, National Renewable Energy Laboratory, *Gas-Fired Distributed Energy Resource Technology Characterizations: Reference Number NREL/TP-620-34783,* November 2003, Discovery Insights, *LLC, "Installed Costs for Small CHP Systems - Estimates and Projections"* (April 2005), *and* Solar Energy Industries Association, *Our Solar Power Future - The U.S. Photovoltaic Industry Roadmap through 2030 and Beyond,* (SEIA, September 2004).

- **Unrestricted Choice Behavior -** This rule assumes that commercial consumers consider *all* types of equipment that meet a given service, across all fuels, when faced with a capital purchase decision.

- **Same Fuel Behavior -** This rule restricts the capital purchase decision to the set of technologies that consume the *same fuel* that currently meets the decision maker's service demand.

- **Same Technology Behavior -** Under this rule, commercial consumers consider only the available models of the *same technology and fuel* that currently meet service demand, when facing a capital stock decision.

Under any of the above three behavior rules, equipment that meets the service at the lowest annualized lifecycle cost is chosen. Table 14 illustrates the proportions of floorspace subject to the different behavior rules for space heating technology choices in large office buildings.

Table 14. Assumed Behavior Rules for Choosing Space Heating Equipment in Large Office Buildings
(Percent)

	Unrestricted	Same Fuel	Same Technology	Total
New Equipment Decision	21	30	49	100
Replacement Decision	8	35	57	100
Retrofit Decision	0	5	95	100

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2008) (June 2008).

Time Preferences

Commercial building owners' time preferences regarding current versus future expenditures are assumed to be distributed among seven alternate time preference premiums (Table 15). Adding the risk-adjusted time preference premiums to the 10-year Treasury Bill rate from MAM results in implicit discount rates, also known as hurdle rates, applicable to the assumed proportions of commercial floorspace. The effect of the use of this distribution of discount rates is to prevent a single technology from dominating purchase decisions in the lifecycle cost comparisons. The distribution used for *AEO2008* assigns some floorspace a very high discount or hurdle rate to simulate floorspace which will never retrofit existing equipment and which will only purchase equipment with the lowest capital cost. Discount rates for the remaining six segments of the distribution get progressively lower, simulating increased sensitivity to the fuel costs of the equipment that is purchased. The proportion of floorspace assumed for the 0.0 time preference premium represents an estimate of the Federally owned commercial floorspace that is subject to purchase decisions in a given year. The Federal sector is expected to purchase energy-efficient equipment to meet the Federal buildings performance standards of the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 whenever cost effective. For Federal purchase decisions relating to energy conservation, cost effectiveness is determined using a discount rate based on long-term Treasury bond rates, approximated in the commercial module by the 10-year Treasury Bill rate. For lighting, the proportion of floorspace assumed for the 0.0 time preference premium is increased to include all Federal floorspace starting in 2009 to represent the EISA 2007 provision that all Federal buildings be equipped with energy efficient lighting fixtures and bulbs to the maximum extent feasible, including when replacing bulbs in existing fixtures.

Table 15. Assumed Distribution of Risk-adjusted Time Preference Premiums
(Percent)

Proportion of Floorspace-All Services (Except Lighting 2009 and later)	Proportion of Floorspace-Lighting (2009 and later)	Time Preference Premium
27.0	27.0	1000.0
25.4	25.4	152.9
20.4	20.4	55.4
16.2	16.2	30.9
10.0	7.9	19.9
0.8	0.6	13.6
0.2	2.5	0.0
100.0	100.0	--

Source: Energy Information Administration, *Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M066(2008) (June 2008).

The distribution of hurdle rates used in the commercial module is also affected by changes in fuel prices. If a fuel's price rises relative to its price in the base year (2003), the nonfinancial portion of each hurdle rate in the distribution decreases to reflect an increase in the relative importance of fuel costs, expected in an environment of rising prices. Parameter assumptions for *AEO2008* result in a 30 percent reduction in the nonfinancial portion of a hurdle rate if the fuel price doubles. If the risk-adjusted time preference premium input by the model user results in a hurdle rate below the assumed financial discount rate for the commercial sector, 15 percent, with base year fuel prices (such as the rate given in Table 15 for the Federal sector), no response to increasing fuel prices is assumed.

Technology Characterization Database

The technology characterization database organizes all relevant technology data by end use, fuel, and Census division. Equipment is identified in the database by a technology index as well as a vintage index, the index of the fuel it consumes, the index of the service it provides, its initial market share, the Census division index for which the entry under consideration applies, its efficiency (or coefficient of performance or efficacy in the case of lighting equipment), installed capital cost per unit of service demand satisfied, operating and maintenance cost per unit of service demand satisfied, average service life, year of initial availability, and last year available for purchase. Equipment may only be selected to satisfy service demand if the year in which the decision is made falls within the window of availability. Equipment acquired prior to the lapse of its availability continues to be treated as part of the existing stock and is subject to replacement or retrofitting. This flexibility in limiting equipment availability allows the direct modeling of equipment efficiency standards. Table 16 provides a sample of the technology data for space heating in the New England Census division.

An option to allow endogenous price-induced technological change has been included in the determination of equipment costs and availability for the menu of equipment. This concept allows future technologies faster diffusion into the market place if fuel prices increase markedly for a sustained period of time. The option was not exercised for the *AEO2008* model runs.

End-Use Consumption Submodule

The end-use consumption submodule calculates the consumption of each of the three major fuels for the ten end-use services plus fuel consumption for combined heat and power and district services. For the ten end-use services, energy consumption is calculated as the end-use service demand met by a particular type of equipment divided by its efficiency and summed over all existing equipment types. This calculation includes dimensions for Census division, building type, and fuel. Consumption of the five minor fuels is projected based on historical trends.

Equipment Efficiency

The average energy consumption of a particular appliance is based initially on estimates derived from the 2003 CBECS. As the stock efficiency changes over the model simulation, energy consumption decreases nearly, but not quite proportionally to the efficiency increase. The difference is due to the calculation of efficiency using the harmonic average and also the efficiency rebound effect discussed below. For example, if on average, electric heat pumps are now 10 percent more efficient than in 2003, then all else constant (weather, real energy prices, shell efficiency, etc.), energy consumption per heat pump would now average about 9 percent less. The Service Demand and Technology Choice Submodules together determine the average efficiency of the stocks used in adjusting the initial average energy consumption.

Adjusting for Weather and Climate

Weather in any given year always includes short-term deviations from the expected longer-term average (or climate). Recognition of the effect of weather on space heating and air conditioning is necessary to avoid projecting abnormal weather conditions into the future. In the commercial module, proportionate adjustments are made to space heating and air conditioning demand by Census division. These adjustments are based on National Oceanic and Atmospheric Administration (NOAA) data for Heating Degree Days (HDD) and Cooling Degree Days (CDD). A 10 percent increase in HDD would increase space heating consumption by 10 percent over what it would have been otherwise. The commercial module uses a 10-year average for HDD and CDD by Census division, adjusted over the projection period by projections for state population shifts.

Table 16. Capital Cost and Efficiency Ratings of Selected Commercial Space Heating Equipment[1]

Equipment Type	Vintage	Efficiency[2]	Capital Cost ($2007 per Mbtu/hour) [3]	Maintenance Cost ($2007 per Mbtu/hour) [3]	Service Life (Years)
Electric Rooftop Heat Pump	2007- typical	3.2	$72.78	$1.39	15
	2007- high efficiency	3.4	$96.67	$1.39	15
	2010 - typical (standard)	3.3	$76.67	$1.39	15
	2010 - high efficiency	3.4	$96.67	$1.39	15
	2020 - typical	3.3	$76.67	$1.39	15
	2020 - high efficiency	3.4	$96.67	$1.39	15
Ground-Source Heat Pump	2007- typical	3.5	$140.00	$16.80	20
	2007- high efficiency	4.9	$170.00	$16.80	20
	2010- typical	3.5	$140.00	$16.80	20
	2010 - high efficiency	4.9	$170.00	$16.80	20
	2020 - typical	4.0	$140.00	$16.80	20
	2020 - high efficiency	4.9	$170.00	$16.80	20
Electric Boiler	Current typical	0.98	$17.53	$0.58	21
Packaged Electric	Typical	0.96	$16.87	$3.95	18
Natural Gas Furnace	Current Standard	0.80	$9.35	$0.97	20
	2007 - high efficiency	0.82	$9.90	$0.94	20
	2020 - typical	0.81	$9.23	$0.96	20
	2020 - high efficiency	0.90	$11.57	$0.86	20
	2030 - typical	0.82	$9.12	$0.94	20
	2030 - high efficiency	0.91	$11.44	$0.85	20
Natural Gas Boiler	Current Standard	0.80	$22.42	$0.50	25
	2007 - mid efficiency	0.85	$25.57	$0.47	25
	2007 - high efficiency	0.96	$39.96	$0.52	25
	2020 - typical	0.82	$21.84	$0.49	25
Natural Gas Heat Pump	2007 - absorption	1.4	$158.33	$2.50	15
	2010 - absorption	1.4	$158.33	$2.50	15
	2020 - absorption	1.4	$158.33	$2.50	15
Distillate Oil Furnace	Current Standard	0.81	$11.14	$0.96	20
	2020 - typical	0.81	$11.14	$0.96	20
Distillate Oil Boiler	Current Standard	0.83	$17.63	$0.15	20
	2007 - high efficiency	0.89	$19.84	$0.14	20
	2020 - typical	0.83	$17.63	$015	20

[1]Equipment listed is for the New England Census division, but is also representative of the technology data for the rest of the U.S. See the source referenced below for the complete set of technology data.

[2]Efficiency measurements vary by equipment type. Electric rooftop air-source heat pumps, ground source and natural gas heat pumps are rated for heating performance using coefficient of performance; natural gas and distillate furnaces are based on Thermal Efficiency; and boilers are based on combustion efficiency.

[3]Capital and maintenance costs are given in 2007 dollars.

Source: Energy Information Administration, “EIA - Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case Second Edition (Revised)”, Navigant Consulting, Inc., Reference Number 20070831.1, September 2007.

Short-Term Price Effect and Efficiency Rebound

It is assumed that energy consumption for a given end-use service is affected by the marginal cost of providing that service. That is, all else equal, a change in the price of a fuel will have an inverse, but less than proportional, effect on fuel consumption. The current value for the short-term price elasticity parameter is -0.25 for all major end uses except refrigeration. A value of -0.1 is currently used for commercial refrigeration. A value of -0.05 is currently used for PC and non-PC office equipment and other minor uses of electricity. For example, for lighting this value implies that for a 1 percent increase in the price of a fuel, there will be a corresponding decrease in energy consumption of 0.25 percent. Another way of affecting the marginal cost of providing a service is through equipment efficiency. As equipment efficiency changes overtime, so will the marginal cost of providing the end-use service. For example, a 10 percent increase in efficiency will reduce the cost of providing the service by 10 percent. The short-term elasticity parameter for efficiency rebound effects is -0.15 for affected end uses; therefore, the demand for the service will rise by 1.5 percent (-10 percent x -0.15). Currently, all services are affected by the short-term price effect and services affected by efficiency rebound are space heating and cooling, water heating, ventilation and lighting.

Legislation and Regulations

Energy Independence and Security Act of 2007 (EISA07)

The EISA07 legislation passed in December 2007 provides standards for the following explicitly modeled commercial equipment. The EISA07 requires specific energy efficiency measures in commercial walk-in coolers and walk-in freezers effective January 1, 2009. Incandescent and halogen lamps must meet standards for maximum allowable wattage based on lumen output starting in 2012 and metal halide lamp fixtures using lamps between 150 and 500 watts are required to have a minimum ballast efficiency ranging from 88 to 94 percent, depending on ballast type, effective January 1, 2009.

The EISA07 requirement for Federal buildings to use energy efficient lighting fixtures and bulbs to the maximum extent possible is represented by adjusting the proportion of the commercial sector assumed to use the 10-year Treasury Bill rate as an implicit discount or hurdle rate for lighting.

Energy Policy Act of 2005 (EPACT05)

The passage of the EPACT05 in August 2005 provides additional minimum efficiency standards for commercial equipment. Some of the standards for explicitly modeled equipment, effective January 1, 2010, include: an Energy Efficiency Rating (EER) ranging from 10.8 to 11.2 for small package air conditioning and heating equipment; daily electricity consumption limits by volume for commercial refrigerators, freezers, and refrigerator-freezers; and electricity consumption limits per 100 pounds of ice produced based on equipment type and capacity for automatic ice makers. The EPACT05 adds standards for medium base compact fluorescent lamps effective January 1, 2006, for ballasts for Energy Saver fluorescent lamps effective in 2009 and 2010, and bans the manufacture or import of mercury vapor lamp ballasts effective January 1, 2008.

Several efficiency standards in the EPACT05 pertain to equipment not explicitly represented in the NEMS Commercial Demand Module. For low voltage dry-type transformers, effects of the standard are included in estimating the share of projected miscellaneous electricity use attributable to transformer losses. For illuminated exit signs, traffic signals, and commercial prerinse spray valves, assumed energy reductions are calculated based on per-unit savings relative to a baseline unit and the estimated share of installed units and sales that already meet the standard. Total projected reductions are phased in over time to account for stock turnover. Under the EPACT05 standards, illuminated exit signs and traffic signal modules must meet ENERGY STAR program requirements as of January 1, 2006. The requirements limit input power demand to 5 watts or less per face for exit signs. Nominal wattages for traffic signal modules are limited to 8 to 15 watts, based on module type. Effective January 1, 2007, low voltage dry-type distribution transformers are required to meet the National Electrical Manufacturers Association Class I Efficiency Levels with minimum efficiency levels ranging from 97 percent to 98.9 percent based on output. Commercial prerinse spray valves[13] must have a maximum flow rate of 1.6 gallons per minute, effective January 1, 2006 with energy reductions attributed to hot water use.

The EPACT05 expands the Business Investment Tax Credit to 30 percent for solar property installed in 2006 and 2007. Business Investment Tax Credits of 30 percent for fuel cells and 10 percent for microturbine power plants are also available for property installed in 2006 and 2007. The EPACT05 tax credit provisions were extended in December 2006 to cover equipment installed in 2008. These credits are directly incorporated into the cash-flow approach for distributed generation systems and factored into the installed capital cost assumptions for solar hot water heaters.

Energy Policy Act of 1992 (EPACT92)

A key assumption incorporated in the technology selection process is that the equipment efficiency standards described in the EPACT92 constrain minimum equipment efficiencies. The effects of standards are modeled by modifying the technology database to eliminate equipment that no longer meets minimum efficiency requirements. For standards effective January 1, 1994, affected equipment includes electric heat pumps—minimum heating system performance factor of 6.8, gas and oil-fired boilers—minimum combustion efficiency of 0.8 and 0.83, respectively, gas and oil-fired furnaces—minimum thermal efficiency of 0.8 and 0.81, respectively, fluorescent lighting—minimum efficacy of 75 lumens per watt, incandescent lighting—minimum efficacy of 16.9 lumens per watt, air-cooled air conditioners—minimum energy efficiency ratio of 8.9, electric water heaters—minimum energy factor of 0.85, and gas and oil water heaters—minimum thermal efficiency of 0.78. Updated standards are effective October 29, 2003 for gas water heaters—minimum thermal efficiency of 0.8. An additional standard affecting fluorescent lamp ballasts is effective April 1, 2005. The standard mandates electronic ballasts with a minimum ballast efficacy factor of 1.17 for 4-foot, 2-lamp ballasts and 0.63 for 8-foot, 2-lamp ballasts.

The 10 percent Business Investment Tax Credit for solar energy property included in EPACT92 is directly incorporated into the cash-flow approach for projecting distributed generation by commercial photovoltaic systems. For solar hot water heaters, the tax credit is factored into the installed capital cost assumptions used in the technology choice submodule.

Energy Efficiency Programs

Several energy efficiency programs affect the commercial sector. These programs are designed to stimulate investment in more efficient building shells and equipment for heating, cooling, lighting, and other end uses. The commercial module includes several features that allow projected efficiency to increase in response to voluntary programs (e.g., the distribution of risk-adjusted time preference premiums and shell efficiency parameters). Retrofits of equipment for space heating, air conditioning and lighting are incorporated in the distribution of premiums given in Table 14. Also the shell efficiency of new and existing buildings is assumed to increase from 2003 through 2030. Shells for new buildings increase in efficiency by 7 percent over this period, while shells for existing buildings increase in efficiency by 5 percent.

Commercial Alternative Cases

Technology Cases

In addition to the *AEO2008* reference case, three side cases were developed to examine the effect of equipment and building standards on commercial energy use—a *2008 technology case*, a *high technology case*, and a *best available technology case*. These side cases were analyzed in stand-alone (not integrated with the NEMS demand and supply modules) buildings (residential and commercial) modules runs and thus do not include supply-responses to the altered commercial consumption patterns of the three cases. *AEO2008* also analyzed an *integrated high technology case*, which combines the *high technology cases* of the four end-use demand sectors, the *electricity high fossil technology case,* the *low nuclear cost case*, and the *low renewable cost case*, and an *integrated 2008 technology case*, which combines the *2008 technology cases* of the end-use demand sectors, the *electricity low fossil technology case*, and the *high renewable cost case*.

The *2008 technology case* assumes that all future equipment purchases are made based only on equipment available in 2008. This case assumes building shell efficiency to be fixed at 2008 levels. In the reference case, existing building shells are allowed to increase in efficiency by 5 percent over 2003 levels, and new building shells improve by 7 percent by 2030 relative to new buildings in 2003.

The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case. Equipment assumptions were developed by engineering technology experts, considering the potential impact on technology given increased research and development into more advanced technologies. In the *high technology case*, building shell efficiencies are assumed to improve 25 percent more than in the reference case after 2008. Existing building shells, therefore, increase by 6.25 percent relative to 2003 levels and new building shells by 8.75 percent relative to their efficiency in 2003 by 2030.

The *best available technology case* assumes that all equipment purchases after 2008 are based on the highest available efficiency in the high technology case in a particular simulation year, disregarding the economic costs of such a case. It is designed to show how much the choice of the highest-efficiency equipment could affect energy consumption. Shell efficiencies in this case are assumed to improve 50 percent more than in the reference case after 2008, i.e., existing shells increase by 7.5 percent relative to 2003 levels and new building shells by 10.5 percent relative to their efficiency in 2003 by 2030.

Fuel shares, where appropriate for a given end use, are allowed to change in the technology cases as the available technologies from each technology type compete to serve certain segments of the commercial floorspace market. For example, in the *best available technology case*, the most efficient gas furnace technology competes with the most efficient electric heat pump technology. This contrasts with the reference case, in which, a greater number of technologies for each fuel with varying efficiencies all compete to serve the heating end use. In general, the fuel choice will be affected as the available choices are constrained or expanded, and will thus differ across the cases.

Two sensitivities that focus on electricity generation incorporate alternative assumptions for non-hydro renewable energy technologies in the power sector, the industrial sector, and the buildings sectors, including residential and commercial photovoltaic systems. In each of these cases, assumptions regarding non-renewable technologies are not changed from the reference case.

The *high renewable cost case* assumes that the cost and performance characteristics for residential and commercial photovoltaic systems remain fixed at 2008 levels through the projection horizon.

The *low renewable cost case* assumes that costs for residential and commercial photovoltaic systems are 10 percent lower than reference case cost estimates by 2030.

Notes and Sources

[1] Energy Information Administration, 2003 Commercial Buildings Energy Consumption Survey (CBECS) Public Use Files, web site www.eia.doe.gov/emeu/cbecs/cbecs2003/public_use_2003/cbecs_pubdata 2003. html.

[2] The fuels accounted for by the commercial module are electricity, natural gas, distillate fuel oil, residual fuel oil, liquefied petroleum gas (LPG), coal, motor gasoline, and kerosene. Current commercial use of biomass (wood, Municipal solid waste) is also included. In addition to these fuels the use of solar energy is projected based on an exogenous estimate of projected solar photovoltaic system installations under the Million Solar Roofs program, State and local incentive programs, and the potential endogenous penetration of solar photovoltaic systems and solar thermal water heaters.

[3] The end-use services in the commercial module are heating, cooling, water heating, ventilation, cooking, lighting, refrigeration, PC and non-PC office equipment and a category denoted other to account for all other minor end uses.

[4] The 11 building categories are assembly, education, food sales, food services, health care, lodging, large offices, small offices, mercantile/services, warehouse and other.

[5] Minor end uses are modeled based on penetration rates and efficiency trends.

[6] The detailed documentation of the commercial module contains additional details concerning model structure and operation. Refer to Energy Information Administration, Model Documentation Report: Commercial Sector Demand Module of the National Energy Modeling System, DOE/EIA M066(2008), (June 2008).

[7] The commercial floorspace equations of the Macroeconomic Activity Model are estimated using the F.W. Dodge Statistics and Forecasts Group database of historical floorspace estimates. The F.W. Dodge estimate for commercial floorspace in the U.S. is approximately 16 percent lower than the estimate obtained from the CBECS used for the Commercial module. See F.W. Dodge, Building Stock Database Methodology and 1991 Results, Construction Statistics and Forecasts, F.W. Dodge, McGraw-Hill.

[8] The commercial module performs attrition for 9 vintages of floorspace developed using stock estimates from the previous 5 CBECS and historical floorspace additions data from F.W. Dodge data.

[9] In the event that the computation of additions produce a negative value for a specific building type, it is assumed to be zero.

[10] “Other office equipment” includes copiers, fax machines, typewriters, cash registers, server computers, and other miscellaneous office equipment. A tenth category denoted other includes equipment such as elevators, medical, and other laboratory equipment, communications equipment, security equipment, transformers and miscellaneous electrical appliances. Commercial energy consumed outside of buildings and for combined heat and power is also included in the “other” category.

[11] Based on updated estimates using 2003 CBECS building-level consumption data and CBECS 1995 end-use-level consumption data and the methodology described in Estimation of Energy End-Use Intensities, web site www.eia.doe.gov/emeu/cbecs/tech_end_use.html.

[12] The proportion of equipment retiring is inversely related to the equipment life.

[13] Commercial prerinse spray valves are handheld devices used to remove food residue from dishes and flatware before cleaning.

Industrial Demand Module

The NEMS Industrial Demand Module estimates energy consumption by energy source (fuels and feedstocks) for 21 manufacturing and 6 nonmanufacturing industries. The manufacturing industries are further subdivided into the energy-intensive manufacturing industries and nonenergy-intensive manufacturing industries. The manufacturing industries are modeled through the use of a detailed process flow or end use accounting procedure, whereas the nonmanufacturing industries are modeled with substantially less detail (Table 17). The Industrial Demand Module projects energy consumption at the four Census region level (see Figure 5); energy consumption at the Census Division level is estimated by allocating the Census region projection using the SEDS[1] data.

Table 17. Industry Categories

Energy-Intensive Manufacturing		Nonenergy-Intensive Manufacturing		Nonmanufacturing Industries	
Food Products	(NAICS 311)	Metal-Based Durables		Agricultural Production -Crops	(NAICS 111)
		Fabricated Metal Products	(NAICS 332)		
		Machinery	(NAICS 333)		
		Computer and Electronic Products	(NAICS 334)		
		Electrical Equipment	(NAICS 335)		
		Transportation Equipment	(NAICS 336)		
Paper and Allied Products	(NAICS 322)	Other Non-Intensive Manufacturing		Other Agriculture Including Livestock	(NAICS 112-115)
		Wood Products	(NAICS 321)		
		Plastic Products	(NAICS 326)		
		Balance of Manufacturing	(all remaining NAICS)		
Bulk Chemicals				Coal Mining	(NAICS 2121)
Inorganic	(NAICS 32512 to 32518)				
Organic	(NAICS 32511, 32519)				
Resins	(NAICS 3252)				
Agricultural	(NAICS 3253				
Glass and Glass Products	(NAICS 3272)			Oil and Gas Extraction	(NAICS 211)
Cement	(NAICS 32731)			Metal and Other Nonmetallic Mining	(NAICS 2122-2123)
Iron and Steel	(NAICS 3311-3312)			Construction	(NAICS 233-235)
Aluminum	(NAICS 3313)				

NAICS = North American Industry Classification System.

Source: Office of Management and Budget, North American Industry Classification System (NAICS) - United States (Springfield, VA, National Technical Information Service).

The energy-intensive industries (food products, paper and allied products, bulk chemicals, glass and glass products, cement, iron and steel, and aluminum) are modeled in considerable detail. Each industry is modeled as three separate but interrelated components consisting of the Process Assembly (PA) Component, the Buildings Component (BLD), and the Boiler/Steam/Cogeneration (BSC) Component. The BSC Component satisfies the steam demand from the PA and BLD Components. In some industries, the PA

Component produces byproducts that are consumed in the BSC Component. For the manufacturing industries, the PA Component is separated into the major production processes or end uses.

Petroleum refining (North American Industry Classification System 32411) is modeled in detail in the Petroleum Market Module of NEMS, and the projected energy consumption is included in the manufacturing total. projections of refining energy use, and lease and plant fuel and fuels consumed in cogeneration in the oil and gas extraction industry (North American Industry Classification System 211) are exogenous to the Industrial Demand Module, but endogenous to the NEMS modeling system.

Key Assumptions

The NEMS Industrial Demand Module primarily uses a bottom-up process modeling approach. An energy accounting framework traces energy flows from fuels to the industry's output. An important assumption in the development of this system is the use of 2002 baseline Unit Energy Consumption (UEC) estimates based on analysis of the Manufacturing Energy Consumption Survey (MECS) 2002.[2] The UECs represent the energy required to produce one unit of the industry's output. The output may be defined in terms of physical units (e.g., tons of steel) or in terms of the dollar value of shipments.

The module depicts the manufacturing industries (apart from petroleum refining, which is modeled in the Petroleum Market Module of NEMS) with a detailed process flow or end use approach. The dominant process technologies are characterized by a combination of unit energy consumption estimates and "technology possibility curves." The technology possibility curves indicate the energy intensity of new and existing stock relative to the 2002 stock over time. Rates of energy efficiency improvement assumed for new and existing plants vary by industry and process. These assumed rates were developed using professional engineering judgments regarding the energy characteristics, year of availability, and rate of market adoption of new process technologies.

Process/Assembly Component

The PA Component models each major manufacturing production step or end use for the manufacturing industries. The throughput production for each process step is computed as well as the energy required to produce it.

Within this component, the UECs are adjusted based on the technology possibility curves for each step. For example, state-of-the-art additions to waste fiber pulping capacity in 2002 are assumed to require only 94 percent as much energy as does the average existing plant (Table 18). The technology possibility curve is a means of embodying assumptions regarding new technology adoption in the manufacturing industry and the associated increased energy efficiency of capital without characterizing individual technologies. To some extent, all industries will increase the energy efficiency of their process and assembly steps. The reasons for the increased efficiency are not likely to be directly attributable to changing energy prices but due to other exogenous factors. Since the exact nature of the technology improvement is too uncertain to model in detail, the module employs a technology possibility curve to characterize the bundle of technologies available for each process step.

Byproducts produced in the PA Component serve as fuels for the BSC Component. In the industrial module, byproducts are assumed to be consumed before purchased fuel.

Table 18. Coefficients for Technology Possibility Curve

Industry/Process Unit	Existing Facilities		New Facilities		
	REI 2030[1]	TPC[2]	REI 2002[3]	REI 2030[4]	TPC[2]
Food Products					
Process Heating	0.900	-0.0038	0.900	0.800	-0.0042
Process Cooling	0.875	-0.0048	0.850	0.750	-0.0045
Other	0.914	-0.0032	0.915	0.810	-0.0043
Paper & Allied Products					
Wood Preparation	0.792	-0.0083	0.882	0.701	-0.0082
Waste Pulping	0.936	-0.0024	0.936	0.936	-0.0000
Mechanical Pulping	0.816	-0.0072	0.931	0.701	-0.0101
Semi-chemical	0.954	-0.0017	0.971	0.937	-0.0013
Kraft, Sulfite, misc. Chemicals	0.870	-0.0049	0.914	0.827	-0.0036
Bleaching	0.798	-0.0080	0.878	0.719	-0.0071
Paper Making	0.869	-0.0050	0.885	0.852	-0.0014
Bulk Chemicals					
Process Heating	0.900	-0.0038	0.900	0.800	-0.0042
Process Cooling	0.875	-0.0048	0.850	0.750	-0.0045
Electro-Chemical	0.980	-0.0007	0.950	0.850	-0.0040
Other	0.914	-0.0032	0.915	0.810	-0.0043
Glass & Glass Products[5]					
Batch Preparation	0.941	-0.0022	0.882	0.882	0.0000
Melting/Refining	0.934	-0.0024	0.900	0.868	-0.0013
Forming	0.984	-0.0006	0.982	0.968	-0.0005
Post-Forming	0.978	-0.0008	0.968	0.955	-0.0005
Cement					
Dry Process	0.905	-0.0036	0.900	0.810	-0.0038
Wet Process[6]	0.951	-0.0018	NA	NA	NA
Finish Grinding	0.975	-0.0009	0.950	0.950	0.0000
Iron and Steel					
Coke Oven[6]	0.935	-0.0024	0.902	0.869	-0.0013
BF/BOF	0.994	-0.0002	0.987	0.987	0.0000
EAF	0.955	-0.0028	0.990	0.849	0.0055
Ingot Casting/Primary Rolling[6]	1.000	0.0000	NA	NA	NA
Continuous Casting[7]	1.000	0.0000	1.000	1.000	0.0000
Hot Rolling[7]	0.826	-0.0068	0.800	0.652	-0.0073
Cold Rolling[7]	0.737	-0.0108	0.924	0.474	-0.0236
Aluminum					
Alumina Refining	0.930	-0.0026	0.900	0.860	-0.0016
Primary Smelting	0.900	-0.0038	0.950	0.800	-0.0061
Secondary	0.875	-0.0048	0.850	0.750	-0.0045
Semi-Fabrication, Sheet	0.900	-0.0038	0.900	0.800	-0.0042
Semi-Fabrication, Other	0.925	-0.0028	0.950	0.850	-0.0040
Metal-Based Durables					
Fabricated Metals					
Process Heating	0.728	-0.0113	0.675	0.420	-0.0168
Process Cooling	0.669	-0.0143	0.638	0.385	-0.0178
Other	0.763	-0.0096	0.686	0.420	-0.0174

Table 18. Coefficients for Technology Possiblity Curves (Continued)

Industry/Process Unit	Existing Facilities		New Facilities		
	REI 2030[1]	TPC[2]	REI 2002[3]	REI 2030[4]	TPC[2]
Machinery					
Process Heating	0.728	-0.0113	0.675	0.330	-0.0252
Process Cooling	0.669	-0.0143	0.638	0.298	-0.0268
Other	0.763	-0.0096	0.686	0.328	-0.0261
Computers and Electronics					
Process Heating	0.900	-0.0075	0.720	0.569	-0.0084
Process Cooling	0.875	-0.0095	0.880	0.529	-0.0089
Other	0.914	-0.0064	0.732	0.573	-0.0087
Electrical Equipment					
Process Heating	0.900	-0.0075	0.720	0.569	-0.0084
Process Cooling	0.875	-0.0085	0.880	0.529	-0.0089
Other	0.914	-0.0064	0.732	0.573	-0.0087
Transportation Equipment					
Process Heating	0.863	-0.0053	0.765	0.633	-0.0067
Process Cooling	0.829	-0.0067	0.723	0.591	-0.0071
Other	0.882	-0.0045	0.778	0.640	-0.0069
Other Non-Intensive Manufacturing					
Wood Products					
Process Heating	0.728	-0.0113	0.630	0.392	-0.0168
Process Cooling	0.669	-0.0143	0.595	0.359	-0.0178
Other	0.763	-0.0096	0.641	0.392	-0.0174
Plastic Products					
Process Heating	0.854	-0.0075	0.675	0.533	-0.0084
Process Cooling	0.818	-0.0095	0.638	0.496	-0.0089
Other	0.874	-0.0064	0.686	0.538	-0.0084
Balance of Manufacturing					
Process Heating	0.728	-0.0131	0.675	0.373	-0.0210
Process Cooling	0.669	-0.0167	0.638	0.339	-0.0143
Other	0.763	-0.0112	0.686	0.371	-0.0217

[1]REI 2030 Existing Facilities = Ratio of 2030 energy intensity to average 2002 energy intensity for existing facilities.

[2]TPC = annual rate of change between 2002 and 2030.

[3]REI 2002 New Facilities = For new facilities, the ratio of state-of-the-art energy intensity to average 2002 energy intensity for existing facilities.

[4]REI 2030 New Facilities = Ratio of 2030 energy intensity for a new state-of-the-art facility to the average 2002 intensity for existing facilities.

[5]REIs and TPCs apply to virgin and recycled materials.

[6]No new plants are likely to be built with these technologies.

[7]Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.

NA = Not applicable.

BF = Blast furnace.

BOF = Basic oxygen furnace.

EAF = Electric arc furnace.

Source: Energy Information Administration, *Model Documentation Report*, *Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2008) (Washington, DC, 2008).

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the projection horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When an old motor fails, an economic choice is made on whether to repair or replace the motor. When a new motor is added, either to accommodate growth or as a replacement, the motor must meet the premium efficiency standard minimum for efficiency or a premium efficiency motor. Table 19 provides the beginning stock efficiency for seven motor size groups in each of the four industries, as well as efficiencies for EPACT minimum and premium motors. [3] As the motor stock changes over the projection horizon, the overall efficiency of the motor population changes as well.

Table 19. Cost and Performance Parameters for Industrial Motor Choice Model

Industrial Sector Horsepower Range	2002 Stock Efficiency (%)	Premium Efficiency (%)	Premium Cost (2002$)
Food			
1 - 5 hp	81.3	89.2	607
6 - 20 hp	87.1	92.5	1,352
21 - 50 hp	90.1	93.8	2,612
51 - 100 hp	92.7	95.3	6,354
101 - 200 hp	93.5	95.2	11,548
201 - 500 hp	93.8	95.4	30,299
> 500 hp	93.0	96.2	36,187
Bulk Chemicals			
1 - 5 hp	82.0	89.4	607
6 - 20 hp	87.4	92.6	1,352
21 - 50 hp	90.4	93.9	2,612
51 - 100 hp	92.4	95.4	6,354
101 - 200 hp	93.5	95.3	11,548
201 - 500 hp	93.3	95.5	30,299
> 500 hp	93.2	96.2	36,187
Metal-Based Durables[1]			
1 - 5 hp	81.9	89.2	607
6 - 20 hp	89.9	92.5	1,352
21 - 50 hp	89.9	93.9	2,612
51 - 100 hp	92.0	95.3	6,354
101 - 200 hp	93.5	95.2	11,548
201 - 500 hp	93.7	95.4	30,299
> 500 hp	93.0	96.2	36,187
Other Non-Intensive Manufacturing[2]			
1 - 5 hp	83.0	89.2	607
6 - 20 hp	88.3	92.5	1,352
21 - 50 hp	90.3	93.9	2,612
51 - 100 hp	92.7	95.3	6,354
101 - 200 hp	94.3	95.2	11,548
201 - 500 hp	94.3	95.4	30,299
> 500 hp	92.9	96.2	36,187

[1] The Metal-Based Durables group includes five sectors that are modeled separately: Fabricated Metal Products; Machinery; Computer and Electronic Products; Electrical Equipment, Appliances, and Components; and Transportation Equipment

[2] The Other Non-Intensive Manufacturing group includes three sectors that are modeled separately: Wood Products; Plastics and Rubber Products; and Balance of Manufacturing.

Source: Energy Information Administration, *Model Documentation Report, Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2008) (Washington, DC, 2008).

Note: The efficiencies listed in this table are operating efficiencies based on average part-loads. Because the average part-load is not the same for all industries, the listed efficiencies for the different motor sizes vary across industries.

Buildings Component

The total buildings energy demand by industry for each region is a function of regional industrial employment and output. Building energy consumption was estimated for building lighting, hvac (heating,ventilation, and air conditioning), facility support, and onsite transportation. Space heating was further divided to estimate the amount provided by direct combustion of fossil fuels and that provided by steam (Table 20). Energy consumption in the BLD Component for an industry is estimated based on regional employment and output growth for that industry.

Boiler/Steam/Combined Heat and Power Component

The steam demand and byproducts from the PA and BLD Components are passed to the BSC Component, which applies a heat rate and a fuel share equation (Table 21) to the boiler steam requirements to compute the required energy consumption.

The boiler fuel shares apply only to the fuels that are used in non-combined heat and power (CHP) boilers. The portion of the steam demand that is met with cogenerated steam reduces the amount of boiler fuel that would otherwise be required. The non-CHP boiler fuel shares are calculated using a logit formulation. The equation is calibrated to 2002 so that the actual boiler fuel shares are produced for the relative prices that prevailed in 2002.

The byproduct fuels are consumed before the quantity of purchased fuels is estimated. The boiler fuel shares are based on the 2002 MECS.[4]

Combined Heat and Power

Combined heat and power (CHP) plants, which are designed to produce electricity and useful heat, have been used in the industrial sector for many years. The CHP estimates in the module are based on the assumption that the historical relationship between industrial steam demand and CHP will continue in the future.

The energy intensity of the new capital stock relative to 2002 capital stock is reflected in the parameter of the technology possibility curve estimated for the major production steps for each of the energy-intensive industries. These curves are based on engineering judgment of the likely future path of energy intensity changes (Table 20). The energy intensity of the existing capital stock also is assumed to decrease over time, but not as rapidly as new capital stock. The net effect is that over time the amount of energy required to produce a unit of output declines. Although total energy consumption in the industrial sector is projected to increase, overall energy intensity is projected to decrease.

Table 20. 2002 Building Component Energy Consumption (Trillion Btu)

Industry	Region	Building Use and Energy Source: Lighting Electricity Consumption	HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumptiion	Onsite Transportation Total Consumption
Food Products	1	1.6	1.7	4.0	2.0	0.6	0.9
	2	7.2	7.7	16.9	4.4	2.2	0.8
	3	5.8	6.2	12.1	6.0	1.6	1.8
	4	2.5	2.7	7.5	3.7	1.0	1.6
Paper & Allied Products	1	1.9	2.0	3.6	0.0	0.2	0.8
	2	3.5	3.7	6.4	0.0	0.2	1.1
	3	7.1	7.5	14.0	0.0	0.5	2.5
	4	2.9	3.1	3.4	0.0	0.1	0.7
Bulk Chemicals	1	1.4	1.7	1.3	0.0	0.3	0.8
	2	3.1	3.7	2.3	0.0	0.5	0.8
	3	13.0	15.7	16.4	0.0	3.3	5.3
	4	0.9	1.1	1.1	0.0	0.2	0.1
Glass & Glass Products	1	0.3	0.5	2.2	0.0	0.5	0.5
	2	0.6	0.9	2.1	0.0	0.1	0.1
	3	0.8	1.3	3.3	0.0	0.8	0.8
	4	0.2	0.4	0.9	0.0	0.1	0.1
Cement	1	0.1	0.1	0.1	0.0	0.1	0.7
	2	0.2	0.2	0.4	0.0	0.1	1.4
	3	0.4	0.4	0.6	0.0	0.2	1.4
	4	0.2	0.2	0.3	0.0	0.1	1.4
Iron & Steel	1	0.6	0.7	3.4	0.0	0.5	0.8
	2	2.1	2.6	8.1	0.0	1.1	6.4
	3	2.0	2.5	3.2	0.0	0.5	0.8
	4	0.4	0.4	0.3	0.0	0.0	0.0
Aluminum	1	0.3	0.4	0.7	0.0	0.1	0.1
	2	0.8	1.1	1.6	0.0	0.3	0.1
	3	1.5	2.1	3.7	0.0	0.7	1.1
	4	0.3	0.4	0.5	0.0	0.1	0.0
Metal-Based Durables							
Fabricated Metal Products	1	2.2	2.4	7.4	2.1	0.2	0.1
	2	7.3	7.8	25.1	7.1	0.6	0.8
	3	5.2	5.6	15.2	4.3	0.4	1.3
	4	1.4	1.5	3.4	1.0	0.1	0.0
Machinery	1	1.9	2.6	4.7	2.4	0.2	0.0
	2	5.8	7.7	18.7	9.4	0.7	0.7
	3	3.7	5.0	6.9	3.5	0.2	0.3
	4	1.0	1.4	2.3	1.2	0.1	0.0
Computers & Electronic Products	1	5.2	11.3	7.1	8.9	0.5	0.1
	2	2.5	5.3	4.1	5.1	0.3	0.2
	3	4.2	9.2	2.7	3.3	0.1	0.0
	4	5.9	12.8	8.0	10.0	0.4	0.1

Table 20. 2002 Building Component Energy Consumption (cont.)
(Trillion Btu)

Industry	Region	Lighting Electricity Consumption	Building Use and Energy Source: HVAC Electricity Consumption	HVAC Natural Gas Consumption	HVAC Steam Consumption	Facility Support Total Consumptiion	Onsite Transportation Total Consumption
Electrical Equipmentt	1	0.9	1.2	3.0	1.3	0.1	0.1
	2	2.3	3.0	5.7	2.4	0.1	0.1
	3	2.8	3.7	5.5	2.3	0.2	0.8
	4	0.4	0.5	1.6	0.7	0.1	0.1
Transportation Equipment	1	2.2	2.8	6.6	0.9	0.4	0.0
	2	14.6	18.6	36.9	5.2	1.4	1.0
	3	7.5	9.5	14.5	2.0	0.6	0.8
	4	2.5	3.2	5.8	0.8	0.2	0.0
Other Non-Intensive Manufacturing							
Wood Products	1	0.3	0.3	0.7	1.1	0.2	1.7
	2	0.8	0.8	2.1	3.3	0.3	1.1
	3	2.9	2.9	3.7	5.8	0.6	3.5
	4	1.3	1.3	2.2	3.5	0.4	2.4
Plastic Products	1	2.1	2.6	3.1	0.0	0.2	0.8
	2	5.5	6.7	10.0	0.0	0.5	0.9
	3	6.0	7.3	12.4	0.0	0.7	1.0
	4	1.2	1.5	1.8	0.0	0.1	0.0
Balance of Manufacturing	1	6.9	9.7	7.0	0.0	0.8	0.8
	2	16.0	22.4	31.3	0.0	1.9	1.8
	3	26.2	36.8	62.4	0.0	3.2	3.1
	4	7.8	10.9	16.7	0.0	0.8	0.8

HVAC = Heating, Ventilation, Air Conditioning.

Source: Energy Information Administration, *Model Documentation Report: Industrial Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2008), (Washington, DC, 2008).

Table 21. 2002 Boiler Fuel Consumption and Logit Parameter
(trilliion Btu)

Industry	Region	Alpha	Natural Gas	Coal	Oil	Renewables
Food Products	1	-2.0	28	2	5	2
	2	-2.0	125	154	4	15
	3	-2.0	86	10	3	33
	4	-2.0	53	13	4	6
Paper & Allied Products	1	-2.0	56	28	25	87
	2	-2.0	64	75	13	103
	3	-2.0	157	97	61	864
	4	-2.0	48	14	4	164
Bulk Chemicals	1	-2.0	43	3	56	0
	2	-2.0	98	34	46	0
	3	-2.0	685	194	271	0
	4	-2.0	50	1	3	0
Glass & Glass Products	1	-2.0	0	0	6	2
	2	-2.0	1	0	0	1
	3	-2.0	1	0	9	1
	4	-2.0	0	0	0	0
Cement	1	-2.0	0	1	0	0
	2	-2.0	0	2	0	0
	3	-2.0	0	3	0	0
	4	-2.0	0	2	0	0
Iron & Steel	1	-2.0	10	7	4	0
	2	-2.0	24	1	67	0
	3	-2.0	9	0	22	0
	4	-2.0	1	0	10	0
Aluminum	1	-2.0	2	0	0	1
	2	-2.0	5	0	0	0
	3	-2.0	10	0	0	8
	4	-2.0	2	0	0	0
Fabricated Metal Products	1	-2.0	2	0	0	2
	2	-2.0	7	0	1	2
	3	-2.0	5	0	0	0
	4	-2.0	1	0	0	0
Machinery	1	-2.0	2	0	0	1
	2	-2.0	9	1	0	1
	3	-2.0	3	0	0	0
	4	-2.0	1	0	0	0

Table 21. 2002 Boiler Fuel Consumption and Logit Parameter (cont.)
(trilliion Btu)

Industry	Region	Alpha	Natural Gas	Coal	Oil	Renewables
Computers and Electronic Products	1	-2.0	10	0	2	0
	2	-2.0	5	0	0	0
	3	-2.0	4	0	0	0
	4	-2.0	11	0	0	0
Electrical Equipment	1	-2.0	1	0	0	0
	2	-2.0	2	0	0	0
	3	-2.0	2	0	0	0
	4	-2.0	1	0	0	0
Transportation Equipment	1	-2.0	5	8	3	8
	2	-2.0	31	0	1	11
	3	-2.0	12	2	2	2
	4	-2.0	5	0	0	1
Wood Products	1	-2.0	1	0	0	11
	2	-2.0	4	0	0	20
	3	-2.0	7	1	1	142
	4	-2.0	4	0	0	56
Plastic Products	1	-2.0	6	2	2	1
	2	-2.0	21	20	1	1
	3	-2.0	24	0	4	2
	4	-2.0	4	0	0	0
Balance of Manufacturing	1	-2.0	15	9	43	8
	2	-2.0	68	50	16	3
	3	-2.0	137	54	54	7
	4	-2.0	35	7	1	2

Alpha: User-specified.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-064(2008), (Washington, DC, 2008).

The projection for additions to fossil-fueled cogeneration is based on assessing capacity that could be added to generate the industrial steam requirements that are not already met by existing CHP. The technical potential for onsite CHP is primarily based on supplying thermal requirements. Capacity additions are then determined by the interaction of payback periods and market penetration rates. Installed cost for the cogeneration systems is given in Table 22.

Technology

The amount of energy consumption reported by the industrial module is also a function of the vintage of the capital stock that produces the output. It is assumed that new vintage stock will consist of state-of-the-art technologies that are more energy efficient than the average efficiency of the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is less than that required by the existing capital stock. Capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital added in 2002 and earlier and is assumed to retire at a fixed rate each year (Table 23). Middle vintage capital is that which is added after 2002 but not including the year of the projection. New production capacity is built in the projection years when the capacity of the existing stock of capital in the industrial model cannot produce the output projected by the NEMS Regional Macroeconomic Model. Capital additions during the projection horizon are retired in subsequent years at the same rate as the pre-2003 capital stock.

Table 22. Cost Characteristics of Industrial CHP Systems

System	Size (kilowatts)	Installed Cost ($2005 per kilowatt)[1] 2005	2030
1 Engine	1000	1,373	989
2 Engine	3000	1,089	929
3 Gas Turbine	3000	1,530	1,265
4 Gas Turbine	5000	1,180	979
5 Gas Turbine	10000	1,104	959
6 Gas Turbine	25000	930	813
7 Gas Turbine	40000	808	743
8 Combined Cycle	100000	846	787

[1]Costs are given in 2005 dollars in original source document.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System,* DOE/EIA-MO64(2008) (Washington, DC, 2008).

Table 23. Retirement Rates

Industry	Retirement Rate (percent)	Industry	Retirement Rate (percent)
Food Products	1.7	Glass and Glass Products	1.3
Pulp and Paper	2.3	Cement	1.2
Bulk Chemicals	1.7	Aluminum	
Iron & Steel		Metal-Based Durables	1.3
Blast Furnace and Basic Stell Products	1.5	Other Non-Intensive Manufacturing	1.3
Electric Arc Furnace	1.5		
Coke Ovens	2.5		
Other Stell	2.9		

Note: Except for the Blast Furnace and Basic Steel Products Industry, the retirement rate is the same for each process step or end-use within an industry.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-MO64(2008), (Washington, DC, 2008).

Legislation and Regulations

The Energy Indpendence and Security Act of 2007

The EPAct of 1992 motor efficiency standards are superseded for purchase made after 2011. Section 313 increases or creates minimum efficiency standards for newly manufactured, general purpose electric motors that must be met within three years of enactment. The efficiency standards are raised for general purpose, integral-horsepower induction motors with the exception of fire pump motors. Minimum standards were created for seven types of poly-phase, integral-horsepower induction motors and NEMA design "B" 201-500 hp motors that were not previously covered by EPAct 1992 standards. After 2011, the industrial model requires that new motors meet the EISA2007 efficiency standards.

Energy Policy Act of 1992 (EPACT)

EPACT contains several implications for the industrial module. These implications concern efficiency standards for boilers, furnaces, and electric motors. The industrial module uses heat rates of 1.25 (80 percent efficiency) and 1.22 (82 percent efficiency) for gas and oil burners respectively. These efficiencies meet the EPACT standards. EPACT mandates minimum efficiencies for all motors up to 200 horsepower purchased after 1998. The choices offered in the motor model are all at least as efficient as the EPACT minimums.

Clean Air Act Amendments of 1990 (CAAA90)

The CAAA90 contains numerous provisions that affect industrial facilities. Three major categories of such provisions are as follows: process emissions, emissions related to hazardous or toxic substances, and SO2 emissions.

Process emissions requirements were specified for numerous industries and/or activities (40 CFR 60). Similarly, 40 CFR 63 requires limitations on almost 200 specific hazardous or toxic substances. These specific requirements are not explicitly represented in the NEMS industrial model because they are not directly related to energy consumption projections.

Section 406 of the CAAA90 requires the Environmental Protection Agency (EPA) to regulate industrial SO_2 emissions at such time that total industrial SO_2 emissions exceed 5.6 million tons per year (42 USC 7651). Since industrial coal use, the main source of SO_2 emissions, has been declining, EPA does not anticipate that specific industrial SO_2 regulations will be required (Environmental Protection Agency, *National Air Pollutant Emission Trends: 1990-1998*, EPA-454/R-00-002, March 2000, Chapter 4). Further, since industrial coal use is not projected to increase, the industrial cap is not expected be a factor in industrial energy consumption projections.[5]

Industrial Alternative Cases

Technology Cases

The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment. (Tables 24 and 25)[6] The *high technology case* also assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.1 percent per year to 0.7 percent per year. The availability of additional biomass leads to an increase in biomass-based cogeneration. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changes in the composition of industrial output. Since the composition of industrial output remains the same as in the reference case, delivered energy intensity declines by 1.1 (this number need to revised when a num is available) percent annually compared with the reference case, in which delivered energy intensity is projected to decline 0.9 (this number need to revised when a num is available) percent annually.

The *2008 technology case* holds the energy efficiency of plant and equipment constant at the 2008 level over the projection. Both cases were run with only the Industrial Demand Module rather than as a fully integrated NEMS run, (i.e., the other demand models and the supply models of NEMS were not executed). Consequently, no potential feedback effects from energy market interactions were captured.

AEO2008 also analyzed an integrated high technology case (*consumption high technology*), which combines the *high technology cases* of the four end-use demand sectors, the *electricity high fossil technology case,* the *advanced nuclear case,* and *the high renewables case*.

The *high renewables case* assumes that the rate at which biomass byproducts will be recovered from industrial processes increases from 0.1 percent per year to 0.7 percent per year. The availability of additional biomass leads to an increase in biomass-based CHP.

Table 24. Coefficients for Technology Possibility Curves, High Technology Case

Industry/Process Unit	Existing Facilities		New Faciliies	
	REI 2030[1]	TPC[2]	REI 2030[3]	TPC[2]
Food Products				
Process Heating	0.889	-0.004	0.702	-0.009
Process Cooling	0.889	-0.004	0.702	-0.009
Other	0.889	-0.004	0.702	-0.009
Paper & Allied Products				
Wood Preparation	0.747	-0.010	0.532	-0.018
Waste Pulping	0.898	-0.004	0.800	-0.006
Mechanical Pulping	0.771	-0.009	0.580	-0.017
Semi-chemical	0.948	-0.002	0.777	-0.008
Kraft, Sulfite, misc. Chemicals (a)	0.827	-0.007	0.549	-0.018
Bleaching	0.758	-0.010	0.627	-0.012
Paper Making	0.766	-0.009	0.451	-0.024
Bulk Chemicals				
Process Heating	0.893	-0.004	0.710	-0.009
Process Cooling	0.893	-0.004	0.710	-0.009
Electro-Chemical	0.893	-0.004	0.710	-0.009
Other	0.893	-0.004	0.710	-0.009
Glass & Glass Products[4]				
Batch Preparation	0.941	-0.002	0.819	-0.003
Melting/Refining	0.822	-0.007	0.449	-0.025
Forming	0.965	-0.001	0.826	-0.006
Post-Forming	0.971	-0.001	0.865	-0.004
Cement				
Dry Process	0.800	-0.008	0.531	-0.019
Wet Process[6]	0.894	-0.004	NA	NA
Finish Grinding	0.850	-0.006	0.600	-0.016
Iron & Steel				
Coke Oven[5]	0.845	-0.006	0.637	-0.012
BF/BOF	0.950	-0.002	0.785	-0.008
EAF	0.845	-0.006	0.655	-0.015
Ingot Casting/Primary Rolling[5]	1.000	-0.000	NA	NA
Continuous Casting[6]	1.000	-0.000	1.000	0.000
Hot Rolling[6]	0.761	-0.010	0.337	-0.030
Cold Rolling[6]	0.706	-0.012	0.400	-0.029
Aluminum				
Alumina Refining	0.915	-0.003	0.576	-0.016
Primary Smelting	0.800	-0.008	0.522	-0.021
Secondary	0.825	-0.007	0.376	-0.029
Semi-Fabrication, Sheet/plate/foil	0.750	-0.010	0.457	-0.024
Semi-Fabrication, Other	0.825	-0.007	0.467	-0.025
Metal-Based Durables				
Fabricated Metals				
Process Heating	0.704	-0.0124	0.380	-0.0203
Process Cooling	0.647	-0.0155	0.369	-0.0193
Other	0.741	-0.0106	0.386	-0.0203

Table 24. Coefficients for Technology Possibility Curves, High Technology Case (Continued)

Industry/Process Unit	Existing Facilities REI 2030[1]	Existing Facilities TPC[2]	New Facilities REI 2030[4]	New Facilities TPC[2]
Machinery				
Process Heating	0.704	-0.0124	0.284	-0.0305
Process Cooling	0.647	-0.0155	0.280	-0.0290
Other	0.738	-0.0108	0.281	-0.0314
Computers and Electronics				
Process Heating	0.792	-0.0083	0.541	-0.0102
Process Cooling	0.748	-0.0103	0.503	-0.0107
Other	0.817	-0.0072	0.545	-0.0105
Electrical Equipment				
Process Heating	0.890	-0.0083	0.780	-0.0102
Process Cooling	0.865	-0.0103	0.742	-0.0107
Other	0.905	-0.0072	0.793	-0.0105
Transportation Equipment				
Process Heating	0.849	-0.0058	0.609	-0.0081
Process Cooling	0.817	-0.0072	0.581	-0.0077
Other	0.870	-0.0050	0.619	-0.0051
Other Non-Intensive Manufacturing				
Wood Products				
Process Heating	0.705	-0.0124	0.356	-0.0202
Process Cooling	0.647	-0.0154	0.341	-0.0196
Other	0.742	-0.0106	0.354	-0.0209
Plastic Products				
Process Heating	0.793	-0.0083	0.508	-0.0253
Process Cooling	0.749	-0.0103	0.473	-0.0266
Other	0.817	-0.0072	0.512	-0.0260
Balance of Manufacturing				
Process Heating	0.665	-0.0145	0.330	-0.0253
Process Cooling	0.602	-0.0180	0.300	-0.0266
Other	0.702	-0.0126	0.328	-0.0260

,1REI 2030 Existing Facilities = Ratio of 2030 energy intensity to average 2002 energy intensity for existing facilities.

[2]TPC = annual rate of change between 2002 and 2030.

[3]REI 2030 New Facilities = Ratio of 2030 energy intensity for a new State-of-the-art facility to the average 2002 intensity for existing facilities.

[4] REIs and TPCs apply to virgin and recycled materials.

[5]No new plants are likely to be built with these technologies.

[6]Net shape casting is projected to reduce the energy requirements for hot and cold rolling rather than for the continuous casting step.

NA = Not applicable.

BF = Blast furnace.

BOF = Basic oxygen furnace.

EAF = Electric arc furnace.

Source: Energy Information Administration, *Model Documentation Report*, *Industrial Sector Demand Module of the National Energy Modeling System*, DOE/EIA-M064(2008) (Washington, DC, 2008).

Table 25. Cost Characteristics of Industrial CHP Systems, High Technology Case

System	Size (kilowatts)	Installed Cost ($2005 per kilowatt)[1] 2005	2030
1 Engine	1000	1,373	927
2 Engine	3000	1,089	918
3 Gas Turbine	3000	1,530	1036
4 Gas Turbine	5000	1,180	903
5 Gas Turbine	10000	1,104	895
6 Gas Turbine	25000	930	779
7 Gas Turbine	40000	808	728
8 Combined Cycle	100000	846	768

[1]Costs are given in 2005 dollars in original source document.

Source: Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System,* DOE/EIA-MO64(2008) (Washington, DC, 2008).

Notes and Sources

[1] Energy Information Administration, State Energy Data System, 2004, www.eia.doe.gov/emeu/_seds.html

[2] Energy Information Administration, Manufacturing Energy Consumption Survey, web site www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html.

[3] U.S., Department of Energy (2005). Motor Master+ 4.0 software database; available online: http://www1.eere.energy.gov/industry/bestpractices/software.html#mm.

[4] Energy Information Administration, Manufacturing Energy Consumption Survey, web site www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html.

[5] Emissions due to coal-to-liquids plants are included with the electric power sector because these are also large electricity generating plants.

[6] These assumptions are based in part on Energy Information Administration, Industrial Technology and Data Analysis Supporting the NEMS Industrial Model (Focis Associates, October 2005).

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Transportation Demand Module

The NEMS Transportation Demand Module estimates energy consumption across the nine Census Divisions (see Figure 5) and over ten fuel types. Each fuel type is modeled according to fuel-specific technology attributes applicable by transportation mode. Total transportation energy consumption is the sum of energy use in eight transport modes: light-duty vehicles (cars and light trucks), commercial light trucks (8,501-10,000 lbs gross vehicle weight), freight trucks (>10,000 lbs gross vehicle weight), freight and passenger aircraft, freight rail, freight shipping, and miscellaneous transport such as mass transit. Light-duty vehicle fuel consumption is further subdivided into personal usage and commercial fleet consumption.

Key Assumptions

Light-Duty Vehicle Assumptions

The light duty vehicle Manufacturers Technology Choice Model (MTCM) includes 63 fuel saving technologies with data specific to cars and light trucks (Tables 26 and 27) including incremental fuel efficiency improvement, incremental cost, first year of introduction, and fractional horsepower change. These assumed technology characterizations are scaled up or down to approximate the differences in each attribute for 6 Environmental Protection Administration (EPA) size classes of cars and light trucks.

The vehicle sales share module holds the share of vehicle sales by import and domestic manufacturers constant within a vehicle size class at 1999 levels based on National Highway Traffic and Safety Administration data.[1]

EPA size class sales shares are projected as a function of income per capita, fuel prices, and average predicted vehicle prices based on endogenous calculations within the MTCM.[2]

The MTCM utiizes 63 new technologies for each size class and origin of manufacturer (domestic or foreign) based on the cost-effectiveness of each technology and an initial availability year. The discounted stream of fuel savings is compared to the marginal cost of each technology. The fuel economy module assumes the following:

- All fuel saving technologies have a 3-year payback period.
- The real discount rate remains steady at 15 percent.
- For cars, the fuel economy standards are not attribute based, but apply to both the manufacturer's domestic and imported fleet. For cars, the fuel economy standard increases from 27.5 mpg in 2010 to 41.0 mpg in 2020 in AEO2008. For light trucks, the footprint based average fleet fuel economy standard increases from 24.0 mpg in 2011 to 31.0 mpg in 2020. In AEO2008, the light duty vehicle fuel economy standards are assumed to remain at the 2020 level.
- Expected future fuel prices are calculated based on an extrapolation of the growth rate between a five year moving average of fuel price 3 years and 4 years prior to the present year. This assumption is founded upon an assumed lead time of 3 to 4 years to significantly modify the vehicles offered by a manufacturer.

Table 26. Standard Technology Matrix For Cars[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.6	0	-10	1998	0
Material Substitution IV	9.9	0	0.9	0	-15	2006	0
Material Substitution V	13.2	0	1.2	0	-20	2014	0
Drag Reduction II	2.3	40	0	0	0	1988	0
Drag Reduction III	4.4	85	0	0	0.2	1992	0
Drag Reduction IV	6.3	145	0	0	0.5	2000	0
Drag Reduction V	8	225	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2004	0
Side Impact Technology	-1.5	100	0	0	2.2	2004	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	0.5	8	0	0	0	2002	0
Aggressive Shift Logic	2	60	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	6.5	435	0	20	0	1995	0
6-Speed Automatic	8	570	0	30	0	2003	0
6-Speed Manual	2	100	0	20	0	1995	0
CVT	10.5	615	0	-25	0	1998	0
Automated Manual Trans	8	100	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	80	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	100	0	0	0	1987	10
OHC/AdvOHV-8 Cylinder	3	120	0	0	0	1986	10
4-Valve/4-Cylinder	8	205	0	10	0	1988	17
4-Valve/6-Cylinder	8	280	0	15	0	1992	17
4 Valve/8-Cylinder	8	320	0	20	0	1994	17
5 Valve/6-Cylinder	8	300	0	18	0	1998	20
VVT-4 Cylinder	2.5	45	0	10	0	1994	5
VVT-6 Cylinder	2.5	115	0	20	0	1993	5
VVT-8 Cylinder	2.5	115	0	20	0	1993	5
VVL-4 Cylinder	4	170	0	25	0	1997	10
VVL-6 Cylinder	4	260	0	40	0	2000	10
VVL-8 Cylinder	4	330	0	50	0	2000	10
Camless Valve Actuation-4cyl	7.5	450	0	35	0	2009	13
Camless Valve Actuation-6cyl	7.5	600	0	55	0	2008	13
Camless Valve Actuation-8cyl	7.5	750	0	75	0	2007	13
Cylinder Deactivation	4.5	250	0	10	0	2004	0
Turbocharging/ Supercharging	6	650	0	-100	0	1980	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2008	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2006	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2006	10
Lean Burn GDI	5	250	0	20	0	2006	0
5W-30 Engine Oil	1	22.5	0	0	0	1998	0
5W-20 Engine Oil	2	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	140	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2007	0
Tires II	2	30	0	-8	0	1995	0
Tires III	4	75	0	-12	0	2005	0
Tires IV	6	135	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	3	600	0	80	0	2005	-5
42V-Engine Off at Idle	4.5	800	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2003	0
Variable Compression Ratio	4	450	0	25	0	2015	0

[1] Fractional changes refer to the percentage change from the 1990 values.
Sources: Energy and Environment Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

Table 27. Standard Technology Matrix For Light Trucks[1]

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/UnitWt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./UnitWt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.6	0	-10	2002	0
Material Substitution IV	9.9	0	0.9	0	-15	2010	0
Material Substitution V	13.2	0	1.2	0	-20	2018	0
Drag Reduction II	2.3	40	0	0	0	1992	0
Drag Reduction III	4.4	85	0	0	0.2	1998	0
Drag Reduction IV	6.3	145	0	0	0.5	2006	0
Drag Reduction V	8	225	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	0.5	8	0	0	0	2003	0
Aggressive Shift Logic	2	60	0	0	0	2003	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	6.5	435	0	20	0	1999	0
6-Speed Automatic	8	570	0	30	0	2003	0
6-Speed Manual	2	100	0	20	0	2000	0
CVT	10.5	615	0	-25	0	2004	0
Automated Manual Trans	8	100	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3	80	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	100	0	0	0	1990	10
OHC/AdvOHV-8 Cylinder	3	120	0	0	0	1990	10
4-Valve/4-Cylinder	7	205	0	10	0	1998	17
4-Valve/6-Cylinder	7	280	0	15	0	2000	17
4 Valve/8-Cylinder	7	320	0	20	0	2000	17
5 Valve/6-Cylinder	7	300	0	18	0	2010	20
VVT-4 Cylinder	2.5	45	0	10	0	1998	5
VVT-6 Cylinder	2.5	115	0	20	0	1997	5
VVT-8 Cylinder	2.5	115	0	20	0	1997	5
VVL-4 Cylinder	4	170	0	25	0	2002	10
VVL-6 Cylinder	4	260	0	40	0	2001	10
VVL-8 Cylinder	4	330	0	50	0	2006	10
Camless Valve Actuation-4cyl	7.5	450	0	35	0	2014	13
Camless Valve Actuation-6cyl	7.5	600	0	55	0	2012	13
Camless Valve Actuation-8cyl	7.5	750	0	75	0	2011	13
Cylinder Deactivation	4.5	250	0	10	0	2004	0
Turbocharging/Supercharging	6	650	0	-100	0	1987	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2010	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2008	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2010	10
Lean Burn GDI	5	250	0	20	0	2010	0
5W-30 Engine Oil	1	22.5	0	0	0	1998	0
5W-20 Engine Oil	2	37.5	0	0	0	2003	0
OW-20 Engine Oil	3.1	150	0	0	0	2030	0
Electric Power Steering	2	140	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2008	0
Tires II	2	30	0	-8	0	1995	0
Tires III	4	75	0	-12	0	2005	0
Tires IV	6	135	0	-16	0	2015	0
Front Wheel Drive	2	250	0	0	-3	1984	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	3	600	0	80	0	2005	-5
42V-Engine Off at Idle	4.5	800	0	45	0	2005	0
Tier 2 Emissions Technology	-1	160	0	20	0	2006	0
Increased Size/Weight	-2.5	0	0	0	3.75	2003	0
Variable Compression Ratio	4	450	0	25	0	2015	0

[1]Fractional changes refer to the percentage change from the 1990 values.

Sources: Energy and Environment Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

Degradation factors (Table 28) used to convert Environmental Protection Agency-rated fuel economy to actual "on the road" fuel economy are based on table values. Baseline degradation factors are tapplication of a logistic curve to the projections of three factors: increases in city/highway driving, increashen adjusted to reflect the percentage of reformulated gasoline consumed.

Table 28. Car and Light Truck Degradation Factors

	2000	2005	2010	2015	2020	2030
Cars	79.1	81.3	81.8	82.3	82.8	83.8
Light Trucks	81.0	80.3	80.8	81.3	81.8	82.8

Source: Energy Information Administration, *Transportation Sector Model of the National Energy Modeling System, Model Documentation 2007*, DOE/EIA-M070(2007), (Washington, DC, 2007).

The vehicle miles traveled (VMT) module forecasts VMT as a function of the cost of driving per mile, and disposable personal income per capita. Coefficients were re-estimated for AEO2008. Based on output from the model, the fuel price elasticity rises to a maximum of -0.13 as fuel prices rise above reference case levels in each year.

Commercial Light Duty Fleet Assumptions

With the current focus of transportation legislation on commercial fleets and their composition, the Transportation Demand Module is designed to divide commercial light-duty fleets into three types: business, government, and utility. Based on this classification, commercial light-duty fleet vehicles vary in survival rates and duration in fleet use before being sold for use as personal vehicles (Table 29). The average length of time vehicles are kept before being sold for personal use is 4 years for business use, 5 years for government use, and 6 years for utility use. While the total number of vehicles sold to fleets can vary over time, the share of total fleet sales by fleet type is held constant at 2003 levels in the Transportation Demand Module. Of total automobile sales to fleets, 84.8 percent are used in business fleets, 6.5 percent in government fleets, and 8.7 percent in utility fleets. Of total light truck sales to fleets, 58.4 percent are used in business fleets, 7.1 percent in government fleets, and 34.5 percent in utility fleets.[3] Both the automobile and light truck shares by fleet type are held constant from 2004 through 2030. In 2003, 19.1 percent of all automobiles sold and 12.2 percent of all light trucks sold were for fleet use. The share of total automobile and light truck sales to fleet remains constant at these levels over the entire forecast period.

Table 29. 2005 Percent of fleet Alternative Fuel Vehicles by Fleet Type by Size class

	Mini	Subcompact	Compact	Midsize	Large	2-Seater
Car						
Business	0.00	10.52	10.73	42.68	36.07	0.00
Government	0.00	2.80	39.98	2.84	54.39	0.00
Utility	0.00	7.86	34.74	12.32	45.08	0.00
	5 Pk	Pk	5 Van	1 Van	5 Util	1 Util
Light Truck						
Business	7.94	35.14	7.89	26.76	5.46	16.81
Government	6.75	50.81	28.41	4.60	1.62	7.81
Utility	8.22	52.06	5.99	32.69	0.32	0.72

Source: CNEAF Alternatives to Traditional Transportation Fuels 2005 (Part II - User and Fuel Data). http://www.eia.doe.gov/cneaf/alternate/page/aftables/afvtransfuel_II.html #in use

Alternative-fuel shares of fleet sales by fleet type are held constant at year 2005 levels. Size class sales shares of vehicles are held constant at anticipated levels (Table 30).[4] Individual sales shares of alternative-fuel fleet vehicles by technology type are assumed to remain constant for utility, government, and for business fleets[5](Table 31).

Annual VMT per vehicle by fleet type stays constant over the forecast period based on the Oak Ridge National Laboratory fleet data.

Fleet fuel economy for both conventional and alternative-fuel vehicles is assumed to be the same as the personal new vehicle fuel economy and is subdivided into six EPA size classes for cars and light trucks.

Table 30. Commercial Fleet Size Class Shares by Fleet and Vehicle Type
(Percentage)

Fleet Type by Size Class	Automobiles	Light Trucks
Business Fleet		
Mini	3.12	2.46
Subcompact	23.42	8.41
Compact	26.62	23.26
Midsize	36.15	8.12
Large	9.90	14.15
2-seater	0.78	43.60
Government Fleet		
Minl	0.19	6.67
Subcompact	4.58	43.60
Compact	20.55	10.44
Midsize	28.64	17.10
Large	45.99	3.82
2-seater	0.05	18.37
Utility Fleet		
Mini	1.50	7.26
Subcompact	12.47	38.71
Compact	10.01	11.79
Midsize	59.23	18.91
Large	16.42	7.19
2-seater	0.38	16.15

Source: Oak Ridge National Laboratory, *Fleet Characteristics and Data Issues*, Stacy Davis and Lorena Truett, final report prepared for the Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting, (Oak Ridge, TN, January 2003).

Table 31. Purchases of Alternative-Fuel Vehicles by Fleet Type and Technology Type
(Percentage)

Technology	Business	Government	Utility
Ethanol	72.6	54.0	26.8
Methanol	0.0	0.0	0.0
Electric	1.1	3.0	1.1
CNG	4.6	8.5	17.3
LPG	21.7	34.5	54.7

Sources: CNEAF Alternatives to Traditional Transportation Fuels 2005 (part II - User and Fuel Data).
http://www.eia.doe.gov/cneaf/alternate/page/aftables/afvtransfuel_II.html #in use.

The Light Commercial Truck Model

The Light Commercial Truck Module of the NEMS Transportation Model is constructed to represent light trucks that weigh 8,501 to 10,000 pounds gross vehicle weight (Class 2B vehicles). These vehicles are assumed to be used primarily for commercial purposes.

The module implements a twenty-year stock model that estimates vehicle stocks, travel, fuel efficiency, and energy use by vintage. Historic vehicle sales and stock data, which constitute the baseline from which the forecast is made, are taken from a recent Oak Ridge National Laboratory study.[6] The distribution of vehicles by vintage, and vehicle scrappage rates is derived from R.L. Polk company registration data.[7],[8] Vehicle travel by vintage was constructed using vintage distribution curves and estimates of average annual travel by vehicle.[9],[10]

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates are weighted by fleet vehicle stocks to create a composite

The vehicle sales module compares the legislatively mandated sales to the results from the consumer driven sales shares. If the consumer driven sales shares are less than the legislatively mandated sales The

The growth in light commercial truck VMT is a function of industrial output for agriculture, mining, construction, trade, utilities, and personal travel. These industrial groupings were chosen for their correspondence with output measures being forecast by NEMS. The overall growth in VMT reflects a weighted average based upon the distribution to total light commercial truck VMT by sector. Forecasted fuel efficiencies are assumed to increase at the same annual growth rate as light-duty trucks (<8,500 pounds gross vehicle weight).

Consumer Vehicle Choice Assumptions

The Consumer Vehicle Choice Module (CVCM) utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vehicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e., gasoline versus diesel hybrids). The third level choice determines market share among the different technology sets.[11] The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel and flex-fuel),
- Hybrid (gasoline and diesel),
- Dedicated alternative fuel (CNG, LPG, methanol, and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen), and
- Electric battery powered (lead acid, nickel-metal hydride,lithium polymer)[12]

The vehicle attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space. With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously.[13] The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase decisions for cars and light trucks separately.

Where applicable, CVCM fuel efficient technology attributes are calculated relative to conventional gasoline miles per gallon. It is assumed that many fuel efficiency improvements in conventional vehicles will be transferred to alternative-fuel vehicles. Specific individual alternative-fuel technological improvements are also dependent upon the CVCM technology type, cost, research and development, and availability over time. Make and model availability estimates are assumed according to a logistic curve based on the initial technology introduction date and current offerings. Coefficients summarizing consumer valuation of vehicle attributes were derived from assumed economic valuation compared to vehicle price elasticities. Initial CVCM vehicle stocks are set according to EIA surveys.[14] A fuel switching algorithm based on the relative fuel prices for alternative fuels compared to gasoline is used to determine the percentage of total VMT represented by alternative fuels in bi-fuel and flex-fuel alcohol vehicles.

Freight Truck Assumptions

The freight truck module estimates vehicle stocks, travel, fuel efficiency, and energy use of three size classes: light medium (Class 3), heavy medium (Classes 4 -6), and heavy (Classes 7-8). Within the size classes, the stock model structure is designed to cover twenty vehicle vintages and estimate energy use by four fuel types: diesel, gasoline, LPG, and CNG. Fuel consumption estimates are reported regionally (by Census Division) according to the distillate fuel shares from the State Energy Data Report.[15] The technology input data specific to the different types of trucks including the year of introduction, incremental fuel efficiency improvement, and capital cost of introducing the new technologies, is shown in Table 32.

Table 32. Standard Technology Matrix for Freight Trucks

	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
Technology Type	Introd-uction Year	Capital Cost	Incr. Fuel Econ. Improve-ment	Introd-uction Year	Capital Cost	Incr. Fuel Econ. Improve-ment	Introd-uction Year	Capital Cost	Incr. Fuel Econ. Improve-ment
Areo dynamic I: Cab top deflector, sloping hood and cab side flares	2002	600.00	0.023	0	750.00	0.023	0	750.00	0.018
Closing/covering of gap between tractor and trailer, aero dynamic bumper, underside air baffles, wheel well covers	N/A	N/A	0.000	2004	800.00	0.036	2005	1500.00	0.023
Trailer leading and trailing edge curvatures	N/A	N/A	0.000	2005	400.00	0.009	2005	500.00	0.012
Aero Dynamics IV: pneumatic blowing	N/A	N/A	0.000	N/A	N/A	0.000	2010	2500.00	0.045
Tires I: radials	0	40.00	0.018	0	180.00	0.018	0	300.00	0.014
Tires II: low rolling resistance	2004	180.00	0.023	2005	280.00	0.023	2005	550.00	0.027
Tires III: super singles	N/A	N/A	0.000	N/A	N/A	0.000	2008	700.00	0.018
Tires IV: reduced rolling resistance from pneumatic blowing	N/A	N/A	0.000	N/A	N/A	0.000	2015	500.00	0.011
Transmission: lock-up, electronic controls, reduced friction	2005	750.00	0.018	2005	900.00	0.018	2005	1000.00	0.020
Diesel Engine I: turbocharged, direct injection with better thermal management	2003	700.00	0.045	2004	1000.00	0.072	N/A	N/A	0.000
Diesel Engine II: integrated starter/alternator with idle off and limited regenerative breaking	2005	1500.00	0.045	2005	1200.00	0.045	N/A	N/A	0.000
Diesel Engine III: improved engine iwth lower friction, better injectors, and efficient combustion	2012	2000.00	0.090	2008	2000.00	0.072	N/A	300.00	0.000
Diesel Engine IV: hybrid electric powertrain	2010	6000.00	0.360	2010	8000.00	0.360	N/A	N/A	0.000
Diesel Engine V: internal friction reduction - iimproved lubricants and bearings	N/A	N/A	0.000	N/A	N/A	0.000	2005	500.00	0.020
Diesel Engine VI: increased peak cylinder pressure	N/A	NA	0.000	N/A	N/A	0.000	2006	1000.00	0.040
Diesel Engine VII: improved injectors and more efficient combustion	N/A	N/A	0.000	N/A	N/A	0.000	2007	N/A	0.060
Diesel Engine VIII: reduce waste heat improved thermal management	N/A	N/A	0.000	N/A	N/A	0.000	2010	N/A	0.000

Table 32. Standard Technology Matrix for Freight Trucks (cont.)

Technology Type	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
	Introduction Year	Capital Cost	Incr. Fuel Econ. Improvement	Introduction Year	Capital Cost	Incr. Fuel Econ. Improvement	Introduction Year	Capital Cost	Incr. Fuel Econ. Improvement
Gasoline Engine I: electronic fuel injection, DOHC, multiple values	2003	700.00	0.045	2003	1000.00	0.045	N/A	N/A	0.000
Gasoline Engine II: integrated starter/alternator with idle off and limited regenerative breaking	2005	1000.00	0.045	2005	1200.00	0.072	N/A	N/A	0.000
Gasoline Engine III: direct injection (GDI)	2008	700.00	0.108	2008	1000.00	0.108	N/A	N/A	0.000
Gasoline Engine IV; hybrid electric powertrain	2010	6000.00	0.405	2010	8000.00	0.405	N/A	N/A	0.000
Weight Reduction I: high strength lightweight materials	2010	1300.00	0.045	2007	2000.00	0.045	2005	2000.00	0.100
Diesel Emission-NO_x I: exhaust recirculation, timing retard, selective catalytic reduction	2002	250.00	-0.040	2003	400.00	-0.040	2003	500.00	-0.040
Diesel Emissions-NO_x II: nitrogen enriched combustion air	2003	500.00	-0.005	2003	700.00	-0.005	2003	750.00	-0.005
Diesel Emissions-NO_x III: non-thermal plasma catalyst	2007	1000.00	-0.015	2006	1200.00	-0.015	2007	1250.00	-0.015
Diesel Emissions-NO_x IV: NO_x absorber system	2007	1500.00	-0.030	2006	2000.00	-0.030	2007	2500.00	-0.030
Diesel Emission-PM I: oxidation catalyst	2002	150.00	-0.005	2002	200.00	-0.005	2002	250.00	-0.005
Diesel Emission-PM II: catalytic particulate filter	2006	1000.00	-0.015	2006	1250.00	-0.025	2006	1500.00	-0.015
Diesel Emission-HC/CO I: oxidation catalyst	2002	150.00	-0.005	2002	200.00	-0.005	2002	250.00	-0.005
Diesl Emission-HC/CO II: closed crankcase system	2005	50.00	0.000	2005	65.00	0.000	2005	75.00	0.000
Gasoline Emission-PM I: Improved oxidation catalyst	2005	250.00	-0.003	2005	350.00	-0.003	N/A	N/A	0.000
Gasoline Emission-NO_x I: EGR/spark retard	2002	25.00	-0.015	2002	25.00	-0.015	N/A	N/A	0.000
Gasoline Emission-NO_x II: oxygen sensors	2003	75.00	0.000	2003	75.00	0.000	N/A	N/A	0.000
Gasoline Emission-NO_x III: secondary air/closed loop system	2008	50.00	0.000	2008	50.00	0.000	N/A	N/A	0.000

Table 32. Standard Technology Matrix for Freight Trucks (cont.)

	Medium Light Trucks			Medium Heavy Trucks			Heavy Trucks		
Technology Type	Introd-uction Year	Capital Cost	Incr. Fuel Econ. Improve-ment	Introd-uction Year	Capital Cost	Incr. Fuel Econ. Improve-ment	Introd-uction Year	Capital Cost	Incr. Fuel Econ. Improve-ment
Gasoline Emission-HC/CO I: oxygen sensors	2003	75.00	0.000	2003	75.00	0.000	N/A	N/A	0.000
Gasoline Emission-HC/CO II: evap. canister w/improved vaccum, materials, and connectors	2003	50.00	0.000	2003	50.00	0.000	N/A	N/A	0.000
Gasoline Emission-HC/CO III: oxidation catalyst	2005	250.00	-0.003	2005	350.00	-0.003	N/A	N/A	0.000

1. Payback period is same for the three modes.

The freight module uses projections of dollars of industrial output to estimate growth in freight truck travel. The industrial output is converted to an equivalent measure of volume output using freight adjustment coefficients. [16],[17] These freight adjustment coefficients vary by North American Industrial Classification System (NAICS) code with the deviation diminishing gradually over time toward parity. Freight truck load-factors (ton-miles per truck) by NAICS code are constants formulated from historical data. [18]

Fuel economy of new freight trucks is dependent on the market penetration of various emission control technologies and advanced technology components.[19] For the advanced technology components, market penetration is determined as a function of technology type, cost effectiveness, and introduction year. Cost effectiveness is calculated as a function of fuel price, vehicle travel, fuel economy improvement, and incremental capital cost. Emissions control equipment is assumed to enter the market to meet regulated emission standards.

Heavy truck freight travel is estimated by class size and fuel type based on matching projected freight travel demand (measured by industrial output) to the travel supplied by the current fleet. Travel by vintage and size class is then adjusted so that total travel meets total demand. Initial heavy vehicle travel, by vintage and size class, is derived using Vehicle Inventory and Use Survey (VIUS) data.[20]

Initial freight truck stocks by vintage are obtained from R. L. Polk Co. and are distributed by fuel type using VIUS data.[21] Vehicle scrappage rates are also estimated using R. L. Polk Co. data.[22]

Freight and Transit Rail Assumptions

The freight rail module uses the industrial output by NAICS code measured in real 1987 dollars and converts these dollars into an adjusted volume equivalent. Coal production from the NEMS Coal Market Module is used to adjust coal rail travel. Freight rail adjustment coefficients (used to convert dollars to volume equivalents) are based on historical data and remain constant.[23],[24] Initial freight rail efficiencies are based on the freight model from Argonne National Laboratory.[25] The distribution of rail fuel consumption by fuel type is also based on historical data and remains constant.[26] Regional freight rail consumption estimates are distributed according to the State Energy Data Report.[27]

Domestic and International Shipping Assumptions

As done in the previous sub-module, the domestic freight shipping module uses the industrial output by NAICS code measured in real 1987 dollars and converts these dollars into an adjusted volume equivalent.

The freight adjustment coefficients (used to convert dollars to volume equivalents) are based on historical data. Domestic shipping efficiencies are based on the model developed by Argonne National Laboratory. The energy consumption in the international shipping module is a function of the total level of imports and exports. The distribution of domestic and international shipping fuel consumption by fuel type is based on historical data and remains constant throughout the forecast. [28] Regional domestic shipping consumption estimates are distributed according to the residual oil regional shares in the *State Energy Data Report*. [29]

Air Travel Demand Assumptions

The air travel demand module calculates the domestic and international ticket prices for travel as a function of fuel cost. The ticket price is constrained to be no lower than the current lowest cost per mile provider, adjusted by load factor. Domestic and international revenue passenger miles are based on historic data,[30] per capita income, and ticket price. The revenue ton miles of air freight are based on merchandise exports, gross domestic product, and fuel cost.[31]

Airport capacity constraints based on the *FAA's Airport Capacity Benchmark Report 2004* are incorporated into the air travel demand module using airport capacity measures.[32] Airport capacity is defined by the maximum number of flights per hour airports can routinely handle, the amount of time airports operate at optimal capacity, and passenger load factors. Capacity is expected to increase over time due to planned infrastructure improvements. If the projected demand in air travel exceeds the capacity constraint, demand is reduced to match the constraint.

Aircraft Stock/Efficiency Assumptions

The aircraft stock and efficiency module consists of a world, US and Non-US, stock model of wide body, narrow body, and regional jets by vintage. Total aircraft supply for a given year is based on the initial supply of aircraft for model year 2003, new passenger sales, and the survival rate by vintage (Table 33).[33] New passenger sales are a function of revenue passenger miles and gross domestic product.

Table 33. 2006 USA Passenger and Cargo Aircraft Supply and Survival Rate

	Age of Aircraft (years)					
Aircraft Type	New	1-10	11-20	21-30	>30	Total
Passenger						
Narrow Body	135	1,578	1,405	537	308	3,963
Wide Body	9	303	255	124	36	727
Regional Jets	94	1,863	70	7	12	2,046
Cargo						
Narrow Body	1	21	67	156	329	574
Wide Body	8	127	177	26	196	769
Regional Jets	0	0	4	23	13	40
Survival Curve (fraction)	New	5	10	20	30	
Narrow Body	1.0000	0.9998	0.9992	0.9911	0.9256	
Wide Body	1.0000	0.9980	0.9954	0.9754	0.8892	
Regional Jets	1.0000	0.9967	0.9942	0.9816	0.9447	

Source: Jet Information Services, 2006 World Jet Inventory, data tables (2006).

Older planes, wide and narrow body planes over 25 years of age are placed as cargo jets according to a cargo percentage varying from 50 percent of 25 year old planes to 100 percent of those aircraft 30 years and older. The available seat-miles per plane, which measure the carrying capacity of the airplanes by aircraft type, vary over time, with wide bodies remaining constant and narrow bodies increasing.[34] The difference between the seat-miles demanded and the available seat-miles represents potential newly purchased aircraft. If demand is less than supply, then passenger aircraft is either parked or exported, starting with twenty nine year old aircraft, at a pre-defined rate. Aircraft continues to be parked until equilibrium is reached. If supply is less than demand planes are either imported or unparked and brought back into service.

Technological availability, economic viability, and efficiency characteristics of new aircraft are assumed to grow at a fixed rate. Fuel efficiency of new aircraft acquisitions represents, at a minimum, a 5-percent improvement over the stock efficiency of surviving airplanes. Maximum growth rates of fuel efficiency for new aircraft are based on a fixed growth rate. Regional shares of all types of aircraft fuel use are assumed to be constant and are consistent with the State Energy Data Report estimate of regional jet fuel shares.

Legislation and Regulations

Energy Independence and Security Act of 2007 (EISA2007)

The EISA2007 legislation requires the development of fuel economy standards for work trucks (8,500 lbs. to less than 10,000 lbs GVWR) and commercial medium- and heavy-duty on-highway vehicles (10,000 lbs or more GVWR). The new fuel economy standards require consideration of vehicle attributes and duty requirements and can prescribe standards for different classes of vehicles, such as buses used in urban operation or semi-trucks used primarily in highway operation. The Act provides a minimum of 4 full model years lead time before the new fuel economy standard is adopted and 3 full model years after the new fuel economy standard has been established before the fuel economy standards for work trucks can be modified. Because these fuel economy standards are pending and NEMS does not currently model fuel economy regulation for work trucks or commercial medium- and heavy- duty vehicles, this aspect of the Act is not included in *AEO2008*.

A fuel economy credit trading program is established based on EISA2007. Currently, CAFE credits earned by manufacturers can be banked for up to 3 years and can only be applied to the fleet (car or light truck) from which the credit was earned. Starting in model year 2011 the credit trading program will allow manufacturers whose automobiles exceed the minimum fuel economy standards to earn credits that can be sold to other manufacturers whose automobiles fail to achieve the prescribed standards. The credit trading program is designed to ensure that the total oil savings associated with manufacturers that exceed the prescribed standards are preserved when credits are sold to manufacturers that fail to achieve the prescribed standards. While the credit trading program begins in 2011, EISA2007 allows manufacturers to apply credits earned to any of the 3 model years prior to the model year the credits are earned, and to any of the 5 model years after the credits are earned. The transfer of credits within a manufacturer's fleet is limited to specific maximums. For model years 2011 through 2013, the maximum transfer is 1.0 mpg; for model years 2014 through 2017, the maximum transfer is 1.5 mpg; and for model years 2018 and later, the maximum credit transfer is 2.0 mpg. NEMS currently has a switch that allows for sensitivity analysis of CAFE credit banking by manufacturer fleet, but does not model the trading of credits across manufacturers. The *AEO2008* does not consider trading of credits since this would require significant modifications to NEMS and detailed technology cost and efficiency data by manufacturer, which is not readily available.

The CAFE credits specified under the Alternative Motor Fuels Act (AMFA) through 2019 is extended. Prior to passage of this Act, the CAFE credits under AMFA were scheduled to expire after model year 2010. Currently, 1.2 mpg is the maximum CAFE credit that can be earned from selling alternative fueled vehicles. EISA2007 extends the 1.2 mpg credit maximum through 2014 and reduces the maximum by 0.2 mpg for each following year until it is phased out by model year 2020. NEMS does not model CAFE credits earned from alternative fuel vehicles sales because manufacturer specific data would be required and although some manufacturer detail is represented for light trucks, there is no manufacturer detail currently represented for cars. In addition, an algorithm that counts credits earned from the sale of alternative fueled vehicles would need to be added to NEMS, which would require significant modification to the model structure. *AEO2008* does not consider this section of the Act.

The Energy Policy Act of 2005

The Energy Policy Act of 2005 provides tax credits for the purchase of vehicles that have a lean burn engine or employ a hybrid or fuel cell propulsion system. The amount of the credit received for a vehicle is based the vehicle's inertia weight, improvement in city tested fuel economy relative to an equivalent 2002 base year value, emissions classification, and type of propulsion system. The tax credit is also sales limited by manufacturer for vehicles with lean burn engines or hybrid propulsion systems. After December 31, 2005, the first calendar quarter a manufacturer's sales of lean burn or hybrid vehicles reaches 60,000 units, the phase out period begins. Reduction of credits begins in the second calendar quarter following the initial quarter the sales maximum was reached. For that quarter and the following quarter, the applicable tax credit will be reduced by 50 percent. For the subsequent third and fourth calendar quarters, the applicable tax credit is reduced to 25 percent of the original value. These tax credits are included in the AEO2008.

Energy Policy Act of 1992 (EPACT)

Fleet alternative-fuel vehicle sales necessary to meet the EPACT regulations are derived based on the mandates as they currently stand and the Commercial Fleet Vehicle Module calculations. Total projected AFV sales are divided into fleets by government, business, and fuel providers (Table 34).

Table 34. EPACT Legislative Mandates for AFV Purchases by Fleet Type and Year
(Percent)

Year	Federal	State	Fuel Providers	Electric Utilities
2005	75	75	70	90

Source: EIA, Energy Efficiency and Renewable Energy (Washington, DC, 2005), http://www1.eere.energy.gov/femp/about/fleet-requirements.html, http://www1.eere.energy.gov/vehicles and fuels/epact/state/state-gov.html.

Because the commercial fleet model operates on three fleet type representations (business, government, and utility), the federal and state mandates are weighted by fleet vehicle stocks to create a composite mandate for both. The same combining methodology is used to create a composite mandate for electric utilities and fuel providers based on fleet vehicle stocks.[35]

Low Emission Vehicle Program (LEVP)

The LEVP was originally passed into legislation in 1990 in the State of California. It began as the implementation of a voluntary opt-in pilot program under the purview of Clean Air Act Amendments of 1990 (CAAA90), which included a provision that other States could opt in to the California program to achieve lower emissions levels than would otherwise be achieved through CAAA90. Twelve states have elected to adopt the California LEVP.

The LEVP is an emissions-based policy, setting sales mandates for 6 categories of low-emission vehicles: low-emission vehicles (LEVs), ultra-low-emission vehicles (ULEVs), super-ultra low emission vehicles (SULEVs), partial zero-emission vehicles (PZEVs), advanced technology partial zero emission vehicles (AT-PZEVs), and zero-emission vehicles (ZEVs). The LEVP requires that in 2005 10 percent of a manufacturer's sales are ZEVs or equivalent ZEV earned credits, increasing to 11 percent in 2009, 12 percent in 2012, 14 percent in 2015, and 16 percent in 2018 where it remains constant thereafter. In August 2004, CARB enacted further amendments to the LEVP that place a greater emphasis on emissions reductions from PZEVs and AT-PZEVs and requires that manufacturers produce a minimum number of fuel cell and electric vehicles. In addition, manufacturers are allowed to adopt alternative compliance requirements for ZEV sales that are based on cumulative fuel cell vehicle sales targets for vehicles sold in all States participating in California's LEVP. Under the alternative compliance requirements, ZEV credits can also be earned by selling battery electric vehicles. Currently, all manufacturers have opted to adhere to the alternative compliance requirements. The mandate still includes phase-in multipliers for pure ZEVs and allows 20 percent of the sales requirement to be met with AT-PZEVs and 60 percent of the requirement to be met with PZEVs. AT-PZEVs and PZEVs are allowed 0.2 credits per vehicle. EIA assumes that credit allowances for PZEVs will be met with conventional vehicle technology, hybrid vehicles will be sold to meet the AT-PZEV allowances, and that hydrogen fuel cell vehicles will be sold to meet the pure ZEV requirements under the alternative compliance path.

vehicle sales module compares the legislatively mandated sales to the results from the consumer driven sales shares. If the consumer driven sales shares are less than the legislatively mandated sales requirements, then the legislative requirements serve as a minimum constraint for the hybrid, electric, and fuel cell vehicle sales.

Transportation Alternative Cases

High Technology Case

In the *high technology case*, the conventional fuel saving technology characteristics came from a study by the American Council for an Energy Efficient Economy.[36] Tables 35 and 36 summarize the High Technology matrix for cars and light trucks. High technology case assumptions for heavy trucks reflect the optimistic values, with respect to efficiency improvement, for advanced engine and emission control technologies as reported by ANL.[37]

Table 35. High Technology Matrix For Cars

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremental Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1990	0
Material Substitution III	6.6	0	0.5	0	-10	1998	0
Material Substitution IV	9.9	0	0.5	0	-15	2006	0
Material Substitution V	13.2	0	1.1	0	-20	2014	0
Drag Reduction II	1.6	0	0	0	0	1988	0
Drag Reduction III	3.2	0	0	0	0.2	1992	0
Drag Reduction IV	6.3	145	0	0	0.5	2000	0
Drag Reduction V	8	225	0	0	1	2010	0
Roll-Over Technology	-1.5	100	0	0	2.2	2004	0
Side Impact Technology	-1.5	100	0	0	2.2	2004	0
Adv Low Loss Torque Converter	2	25	0	0	0	1999	0
Early Torque Converter Lockup	1	8	0	0	0	2002	0
Aggressive Shift Logic	3.5	65	0	0	0	1999	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	8	410	0	20	0	1995	0
6-Speed Automatic	9.5	495	0	30	0	2003	0
6-Speed Manual	2	80	0	20	0	1995	0
CVT	11.5	365	0	-25	0	1998	0
Automated Manual Trans	8	100	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1980	0
OHC/AdvOHV-4 Cylinder	3	60	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	80	0	0	0	1987	10
OHC/AdvOHV-8 Cylinder	3	100	0	0	0	1986	10
4-Valve/4-Cylinder	8.8	185	0	10	0	1988	17
4-Valve/6-Cylinder	8.8	260	0	15	0	1992	17
4 Valve/8-Cylinder	8.8	320	0	20	0	1994	17
5 Valve/6-Cylinder	9	300	0	18	0	1998	20
VVT-4 Cylinder	2.5	30	0	10	0	1994	5
VVT-6 Cylinder	2.5	90	0	20	0	1993	5
VVT-8 Cylinder	2.5	90	0	20	0	1993	5
VVL-4 Cylinder	7.5	150	0	25	0	1997	10
VVL-6 Cylinder	7.5	205	0	40	0	2000	10
VVL-8 Cylinder	7.5	290	0	50	0	2000	10
Camless Valve Actuation-4cyl	12	450	0	35	0	2009	13
Camless Valve Actuation-6cyl	12	600	0	55	0	2008	13
Camless Valve Actuation-8cyl	12	750	0	75	0	2007	13
Cylinder Deactivation	9	250	0	10	0	2004	0
Turbocharging/ Supercharging	5	475	0	-100	0	1980	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2008	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2006	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2006	10
Lean Burn GDI	6	250	0	20	0	2006	0
5W-30 Engine Oil	1	10.5	0	0	0	1998	0
5W-20 Engine Oil	2	20	0	0	0	2003	0
OW-20 Engine Oil	3.1	80	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2004	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2007	0
Tires II	1.5	15	0	-8	0	1995	0
Tires III	3	35	0	-12	0	2005	0
Tires IV	6	90	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-6	1980	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	5	400	0	80	0	2005	-5
42V-Engine Off at Idle	6	500	0	45	0	2005	0
Tier 2 Emissions Technology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	2.55	2003	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Environmental Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

Table 36. High Technology Matrix For Light Trucks

	Fractional Fuel Efficiency Change	Incremental Cost (1990$)	Incremental Cost ($/Unit Wt.)	Incremenal Weight (Lbs.)	Incremental Weight (Lbs./Unit Wt.)	Introduction Year	Fractional Horse-power Change
Unit Body Construction	4	100	0	0	-6	1980	0
Material Substitution II	3.3	0	0.4	0	-5	1994	0
Material Substitution III	6.6	0	0.5	0	-10	2002	0
Material Substitution IV	9.9	0	0.5	0	-15	2010	0
Material Substitution V	13.2	0	1.1	0	-20	2018	0
Drag Reduction II	1.6	0	0	0	0	1992	0
Drag Reduction III	3.2	0	0	0	0.2	1998	0
Drag Reduction IV	6.3	145	0	0	0.5	2006	0
Drag Reduction V	8	225	0	0	1	2014	0
Roll-Over Technology	-1.5	100	0	0	2.2	2006	0
Side Impact Technology	-1.5	100	0	0	2.2	2006	0
Adv Low Loss Torque Converter	2	25	0	0	0	2005	0
Early Torque Converter Lockup	1	8	0	0	0	2003	0
Aggressive Shift Logic	3.5	65	0	0	0	2003	0
4-Speed Automatic	4.5	285	0	10	0	1980	0
5-Speed Automatic	8	410	0	20	0	1999	0
6-Speed Automatic	9.5	495	0	30	0	2003	0
6-Speed Manual	2	80	0	20	0	2000	0
CVT	11.5	365	0	-25	0	2004	0
Automated Manual Trans	8	100	0	0	0	2004	0
Roller Cam	2	16	0	0	0	1985	0
OHC/AdvOHV-4 Cylinder	3	60	0	0	0	1980	10
OHC/AdvOHV-6 Cylinder	3	80	0	0	0	1990	10
OHC/AdvOHV-8 Cylinder	3	100	0	0	0	1990	10
4-Valve/4-Cylinder	8.8	185	0	10	0	1998	17
4-Valve/6-Cylinder	8.8	260	0	15	0	2000	17
4 Valve/8-Cylinder	8.8	320	0	20	0	2000	17
5 Valve/6-Cylinder	9	300	0	18	0	2010	20
VVT-4 Cylinder	2.5	30	0	10	0	1998	5
VVT-6 Cylinder	2.5	90	0	20	0	1997	5
VVT-8 Cylinder	2.5	90	0	20	0	1997	5
VVL-4 Cylinder	7.5	150	0	25	0	2002	10
VVL-6 Cylinder	7.5	205	0	40	0	2001	10
VVL-8 Cylinder	7.5	290	0	50	0	2006	10
Camless Valve Actuation-4cyl	12	450	0	35	0	2014	13
Camless Valve Actuation-6cyl	12	600	0	55	0	2012	13
Camless Valve Actuation-8cyl	12	750	0	75	0	2011	13
Cylinder Deactivation	9	250	0	10	0	2004	0
Turbocharging/Supercharging	5	475	0	-100	0	1987	15
Engine Friction Reduction I	2	25	0	0	0	1992	3
Engine Friction Reduction II	3.5	63	0	0	0	2000	5
Engine Friction Reduction III	5	114	0	0	0	2010	7
Engine Friction Reduction IV	6.5	177	0	0	0	2016	9
Stoichiometric GDI/4-Cylinder	7	300	0	20	0	2008	10
Stoichiometric GDI/6-Cylinder	7	450	0	30	0	2010	10
Lean Burn GDI	6	250	0	20	0	2010	0
5W-30 Engine Oil	1	10.5	0	0	0	1998	0
5W-20 Engine Oil	2	20	0	0	0	2003	0
OW-20 Engine Oil	3.1	80	0	0	0	2030	0
Electric Power Steering	2	50	0	0	0	2005	0
Improved Alternator	0.3	15	0	0	0	2005	0
Improved Oil/Water Pump	0.5	10	0	0	0	2000	0
Electric Oil/Water Pump	1	50	0	0	0	2008	0
Tires II	1.5	15	0	-8	0	1995	0
Tires III	3	35	0	-12	0	2005	0
Tires IV	6	90	0	-16	0	2015	0
Front Wheel Drive	6	250	0	0	-3	1984	0
Four Wheel Drive Improvements	2	100	0	0	-1	2000	0
42V-Launch Assist and Regen	5	400	0	80	0	2005	-5
42V-Engine Off at Idle	6	500	0	45	0	2005	0
Tier 2 EmissionsTechnology	-1	120	0	20	0	2006	0
Increased Size/Weight	-1.7	0	0	0	3.75	2003	0
Variable Compression Ratio	4	350	0	25	0	2015	0

Source: Energy and Enviromental Analysis, *Documentation of Technology included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (September, 2002). National Research Council, *Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards* (Copyright 2002).

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Electricity Market Module

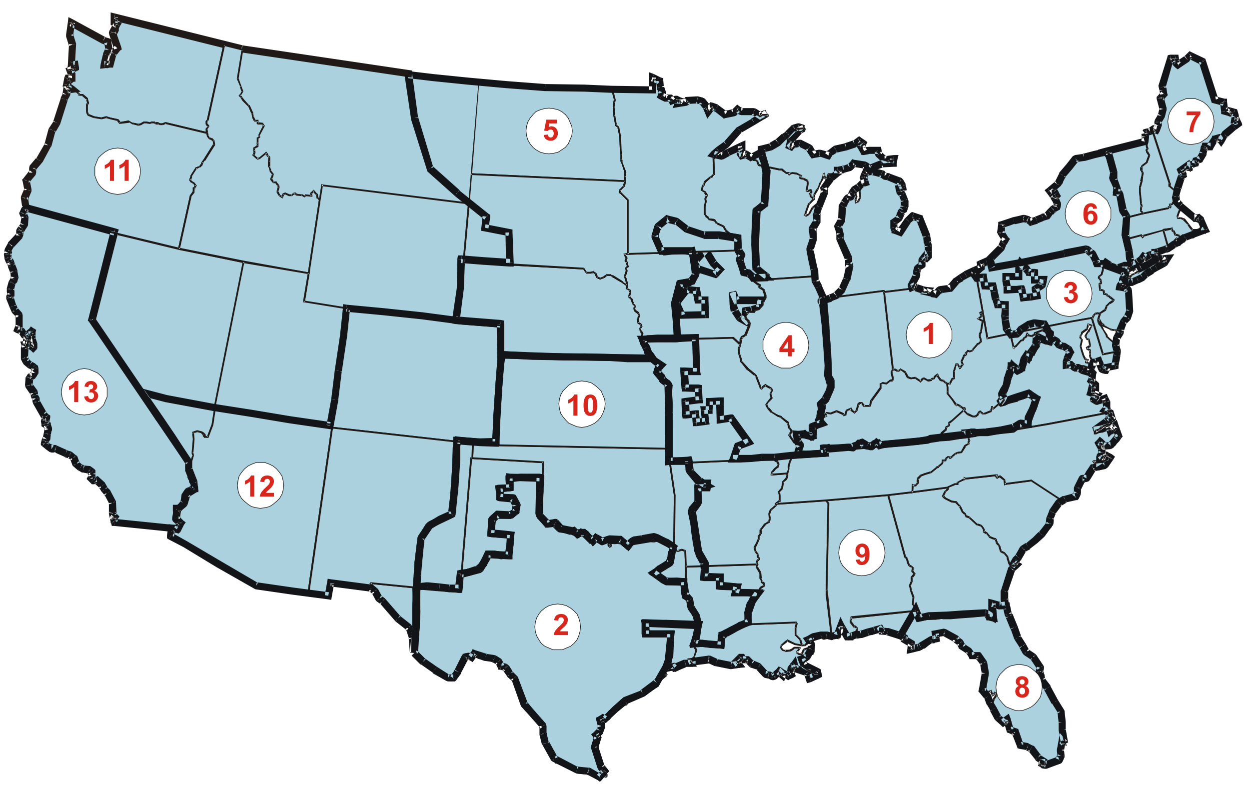
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, load and demand electricity, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, *Electricity Market Module of the National Energy Modeling System 2008*, DOE/EIA-M068(2008).

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

EMM Regions

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

Figure 6. Electricity Market Model Supply Regions



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

Model Parameters and Assumptions

Generating Capacity Types

The capacity types represented in the EMM are shown in Table 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
Wind Offshore

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

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

New Generating Plant Characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 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 2025.

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)	Leadtime (Years)	Base Overnight Cost in 2007 ($2006/kW)	Contingency Factors		Total Overnight Cost in 2007[4] (2006 $/kW)	Variable O&M[5] ($2006 mills/kWh)	Fixed O&M[5] ($2006/kW)	Heatrate[6] in 2007 (Btu/kWhr)	Heatrate nth-of-a-kind (Btu/kWr)
					Project Contingency Factor[2]	Technological Optimism Factor[3]					
Scrubbed Coal New[7]	2011	600	4	1,434	1.07	1.00	1,534	4.46	26.79	9,200	8,740
Integrated Coal-Gasification Combined Cycle (IGCC)[7]	2011	550	4	1,657	1.07	1.00	1,773	2.84	37.62	8,765	7,450
IGCC with Carbon Sequestration	2011	380	4	2,302	1.07	1.03	2,537	4.32	44.27	10,781	8,307
Conv Gas/Oil Comb Cycle	2010	250	3	683	1.05	1.00	717	2.01	12.14	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	2010	400	3	654	1.08	1.00	706	1.95	11.38	6,752	6,333
ADV CC with Carbon Sequestration	2010	400	3	1,254	1.08	1.04	1,409	2.86	19.36	8,613	7,493
Conv Combustion Turbine[8]	2009	160	2	476	1.05	1.00	500	3.47	11.78	10,833	10,450
Adv Combustion Turbine	2009	230	2	450	1.05	1.00	473	3.08	10.24	9,289	8,550
Fuel Cells	2010	10	3	4,653	1.05	1.10	5,374	46.62	5.50	7,930	6,960
Advanced Nuclear	2016	1350	6	2,143	1.10	1.05	2,475	0.48	66.05	10,400	10,400
Distributed Generation -Base	2009	5	2	972	1.05	1.00	1,021	6.93	15.59	9,200	8,900
Distributed Generation -Peak	2010	2	3	1,168	1.05	1.00	1,227	6.93	15.59	10,257	9,880
Biomass	2011	80	4	2,490	1.07	1.05	2,809	6.53	62.70	8,911	8,911
MSW - Landfill Gas	2010	30	3	1,773	1.07	1.00	1,897	0.01	111.15	13,648	13,648
Geothermal [7,9]	2011	50	4	1,057	1.05	1.00	1,110	0.00	160.18	35,376	33,729
Conventional Hydropower[9]	2011	500	4	1,410	1.10	1.00	1,551	3.41	13.59	10,022	10,022
Wind	2010	50	3	1,340	1.07	1.00	1,434	0.00	29.48	10,022	10,022
Wind Offshore	2011	100	4	2,547	1.10	1.03	2,872	0.00	87.05	10,022	10,022
Solar Thermal[7]	2010	100	3	3,499	1.07	1.00	3,744	0.00	55.24	10,022	10,022
Photovoltaic[7]	2009	5	2	5,380	1.05	1.00	5,649	0.00	11.37	10,022	10,022

[1]Online year represents the first year that a new unit could be completed, given an order date of 2007.

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

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

[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2007.

[5]O&M = Operations and maintenance.

[6]For hydro, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2006. 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 2009 if necessary to meet a given region's reserve margin.

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

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

Technological Optimism and Learning

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

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

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 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%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

[1]HRSG = Heat Recovery Steam Generator

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

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

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

International Learning. In *AEO2008*, capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new

Table 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.

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.

AEO2008 includes 5,000 megawatts of advanced coal gasification combined-cycle capacity, 5,244 megawatts of advanced combined-cycle natural gas capacity, 11 megawatts of biomass capacity and 47 megawatts each of traditional wind and offshore wind capacity to be built outside the United States from 2000 through 2003. The learning function also includes 7,200 megawatts of advanced nuclear capacity, representing two completed units and four additional units under construction in Asia.

Distributed Generation

Distributed generation is modeled in the end-use sectors as well as in the EMM, which is described in the appropriate chapters. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 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. The load duration curve in the EMM is made up of 9 time slices. First, the load data is split into three seasons, (winter - December through March, summer - June through September, and fall/spring). Within each season the load data is sorted from high to low, and three load segments are created - a peak segment representing the top 1 percent of the load, and then two off-peak segments representing the next 33 percent and 66 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an interative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted each model cycle until the two costs converge. The resulting reserve margins from the *AEO2008* reference case range from 10 to 14 percent.

Fossil Fuel-Fired and Nuclear Steam Plant Retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the expected revenues from these plants are not sufficient to cover the annual going forward costs, the plant is assumed to retire if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant specific based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $16 per kW for coal plants and $20 per kW for nuclear plants (in 2006 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 $30 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 $115 to $265 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 projection 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 *AEO2008* 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 AEO2008 nuclear power projection 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 projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2008* assumes that all of those uprates approved, pending or expected by the NRC will be implemented, for a capacity increase of 2.7 gigawatts between 2007 and 2030. Table 42 provides a summary of projected uprate capacity additions by region. In cases where the NRC did not specifically identify the unit expected to uprate, EIA assumed the units with the lowest operating costs would be the next likely candidates for power increases.

Table 42. Nuclear Upratres by EMM Region
(gigawatts)

Region	
East Central Area Reliability Coordination Agreement	0.1
Electric Reliability Council of Texas	0.4
Mid-Atlantic Area Council	0.1
Mid-America Interconnected Network	0.1
Mid-Continent Area Power Pool	0.0
New York	0.1
New England	0.0
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	1.8
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.1
California	0.1
Total	2.7

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

Interregional Electricity Trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the National Electric Reliability Council and Western Electric Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's *Electricity Supply and Demand Database 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 from the MAPLE-C model developed for Natural Resources Canada.

Electricity Pricing

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

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

In recent years, the move towards competition in the electricity business has led utilities to make efforts to reduce costs to improve their market position. These cost reduction efforts are reflected in utility operating data reported to the Federal Energy Regulatory Commission (FERC) and these trends have been incorporated in the *AEO2008*. Both General and Administrative (G&A) expenses and Operations and Maintenance (O&M) expenses have shown declines in recent years. The O&M declines show variation based on the plant type. A regression analysis of recent data was done to determine the trend, and the resulting function was used to project declines throughout the projection. The analysis of G&A costs used data from 1992 through 2001, which had a 15 percent overall decline in G&A costs, and a 1.8 percent average annual decline rate. The *AEO2008* projection assumes a further decline of 18 percent by 2025 based on the results of the regression analysis. The O&M cost data was available from 1990 through 2001, and showed average annual declines of 2.1 percent for all steam units, 1.8 percent for combined cycle and 1.5 percent for nuclear. The *AEO2008* assumes further declines in O&M expenses for these plant types, for a total decline through 2025 of 17 percent for combined cycle, 15 percent for steam and 8 percent for nuclear.

There have been ongoing changes to pricing structures for ratepayers in competitive States since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various States, and surcharges in California relating to the 2000-2001 energy crisis there. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were now explicitly added to the distribution portion, and sometimes the transmission portion of the customer bill regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, State regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee. For *AEO2008*, typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include: transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion.

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

Fuel Price Expectations

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

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

Legislation and Regulations

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

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 projection 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 43). 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.

Table 43. 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.

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 44.

Table 44. Coal Plant Retrofit Costs
(2006 Dollars)

Coal Plant Size (MW)	FGD Capital Costs ($/KW)	SCR Capital Costs ($/KW)
300	301	124
500	230	108
700	190	98

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.

Clean Air Mercury Rule (CAMR)[1]

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 $5 (2006 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 $64 per kilowatt of capacity.[2] The amount of activated carbon required to meet a given percentage removal target is given by the following equations.[3]

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

Table 45. Mercury Emission Modification Factors

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

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

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

Planned SO_2 Scrubber and NO_x Control Equipment Additions

In recent years, in response to state emission reduction programs and compliance agreements with the Environmental Protection Agency, some companies have announced plans to add scrubbers to their plants to reduce sulfur dioxide and particulate emissions. Where firm commitments appear to have been made these plans have been represented in NEMS. Based on EIA analysis of announced plans, 46.9 gigawatts of capacity are assumed to add these controls (Table 46). The greatest number of retrofits is expected to occur in the Midwestern States, where there is a large base of coal capacity impacted by the SO_2 limit in CAIR, as well as in the Southeastern Electric Reliability Council because of the Clean Smokestacks bill passed by the North Carolina General Assembly.

Table 46. Planned SO_2 Scrubber Additions Represented by Region

Region	Capacity (Gigawatts)
East Central Area Reliability Coordination Agreement	20.1
Electric Reliability Council of Texas	0.0
Mid-Atlantic Area Council	4.1
Mid-America Interconnected Network	1.7
Mid-Continent Area Power Pool	1.1
New York	0.0
New England	0.0
Florida Reliability Coordinating Council	0.0
Southeastern Electric Reliability Council	19.2
Southwest Power Pool	0.0
Northwest Power Pool	0.0
Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada	0.7
California	0.0
Total	46.9

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 35.5 gigawatts of selective catalytic reduction (SCR) and another 1.6 gigawatts of selective non-catalytic reduction (SNCR) equipment.

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

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million (per gigawatt) annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. In the *AEO2008* Reference case it is projected that 8 gigawatts of new nuclear capacity will be built by 2020, each receiving a credit worth 1.35 cents per kilowatthour. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

FERC Orders 888 and 889

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

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

Electricity Alternative Cases

Low and High Cost Fossil Cases

The *high cost 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 2008 levels. Capital costs of conventional generating technologies are the same as those assumed in the reference case (Table 47).

In the *low cost 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 31 percent below initial levels, while capital costs are reduced by 19 percent to 25 percent between 2008 and 2030.

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

Nuclear Cost Cases

For nuclear power plants, two nuclear cost cases analyze the sensitivity of the projections to lower and higher costs for new plants. The cost assumptions for the *low nuclear cost case* reflect a ten 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 18 percent reduction in capital costs between 2008 and 2030. The *low nuclear cost case* therefore assumes a 26 percent reduction between 2008 and 2030. The *high* nuclear cost case assumes that capital costs for the advanced nuclear technology do not decline from 2008 levels (Table 48). Cost and performance characteristics for all other technologies are as assumed in the reference case.

Table 47. Cost and Performance Characteristics for Fossil-Fueled Generating Technologies: Three Cases

	Total Overnight Cost in 2007 Reference (2006 $/kW)	Total Overnight Cost[1]			Heatrate in 2007 (Reference) Btu/kWhr	Heat Rate		
		Reference (2006 $/kW)	High Cost Fossil (2006 $/kW)	Low Cost Fossil (2006 $/kW)		Reference BTU/kWhr	High Cost Fossil Btu/kWhr	Low cost Fossil Btu/kWhr
Pulverized Coal	1534				9200			
2015		1504	1504	1504		9069	9069	9069
2020		1477	1472	1483		8904	8904	8904
2025		1453	1450	1462		8740	8740	8740
2030		1432	1429	1440		8740	8740	8740
Advanced Coal	1773				8765			
2015		1719	1774	1658		8389	8765	8176
2020		1681	1774	1574		7920	8765	7441
2025		1635	1774	1493		7450	8765	6705
2030		1566	1774	1409		7450	8765	6705
Advanced Coal with Sequestration	2537				10781			
2015		2423	2537	2343		10074	10781	9837
2020		2342	2537	2205		9191	10781	8656
2025		2254	2537	2067		8307	10781	7476
2030		2142	2537	1927		8307	10781	7476
Conventional Combined Cycle	717				7196			
2015		703	703	703		7064	7064	7064
2020		693	693	693		6932	6932	6932
2025		683	683	683		6800	6800	6800
2030		673	673	673		6800	6800	6800
Advanced Gas	706				6752			
2015		688	707	662		6612	6752	6401
2020		675	707	633		6473	6752	6051
2025		657	707	602		6333	6752	5700
2030		634	707	571		6333	6752	5700
Advanced Gas with Sequestration	1409				8613			
2015		1343	1271	1336		8240	8613	7990
2020		1296	1271	1255		7866	8613	7367
2025		1241	1271	1175		7493	8613	6744
2030		1181	1450	1094		7493	8613	6744
Conventional CombustionTurbine	500				10833			
2015		490	490	490		10675	10675	10675
2020		483	483	483		10563	10563	10563
2025		476	476	476		10450	10450	10450
2030		469	469	469		10450	10450	10450
Advanced CombustionTurbine	473				9289			
2015		459	473	440		9012	9289	8691
2020		449	473	416		8781	9289	8193
2025		433	473	395		8550	9289	7695
2030		412	473	371		8550	9289	7695

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

Source: AEO2008 National Energy Modeling System runs: AEO2008.D030208F, HCFOSS08.D030308A, LCFOSS08.D030308A.

Table 48. Cost Characteristics for Advanced Nuclear Technology: Two Cases

		Total Overnight Cost[1]		
Advanced Nuclear Technology	Overnight Cost in 2006 (Reference) (2006$/kW)	Reference Case (2006$/kW)	High Nuclear Cost (2006$/KW)	Low Nuclear Cost (2006$/kW)
	2475			
2015		2378	2474	2270
2020		2262	2474	2123
2025		2098	2474	1976
2030		2033	2474	1829

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

Source: AEO2008 National Energy Modeling System runs: AEO2008.D030208F, HCNUC08.D030308A, LCNUC08.D030308A.

Low and High Energy Project Cost Cases

The *AEO2008* Issues in Focus article, “Impacts of Uncertainties in Energy Project Costs”, examines two scenarios that vary cost assumptions in the power sector as well as the oil and gas and petroleum submodules. This section will discuss the assumptions used in the EMM for these two cases. Additional assumptions for these integrated cases can be found in the relevant oil and natural gas chapters of this document.

The reference case assumes that investment costs are based on the latest cost data, including any commodity price increases over the past few years, and that they will remain at these levels throughout the forecast. The base costs for all technologies in the reference case were increased by 15 percent relative to *AEO2007* to reflect recent cost increases.

The *high energy project cost case* assumes that the factor costs continue to rise, leading to increasing investment costs in the energy industry. In the power sector, it is assumed that the base costs of new generating construction increase by 2.5 percent per year from 2007 through 2030, a rate based on the construction cost growth of the past five years. Although changes in learning rates can also impact the cost projections, in general, costs for most technologies in 2030 are about 75 percent higher in the *high energy project cost case* than in the reference case.

The *low energy project cost case* assumes that the underlying factor cost markets gradually see cost declines back to the levels of the early 2000’s, before the spikes. In the power sector, it is assumed that the base costs of new generating construction decline by 15 percent over the next ten years.

Limited Electricity Generation Supply and Limited Natural Gas Supply Cases

The *AEO2008* Issues in Focus article, “Limited Electricity Generation Supply and Limited Natural Gas Supply Cases”, examines cases where severe pressure is put on the natural gas industry. Three cases were developed to analyze the uncertainties surrounding the availability of non-natural gas-fired power plants and the potential for new natural gas supplies. This section describes the assumptions used in the case restricting electricity technologies. The assumptions for the second case can be found in the natural gas chapter of this document. A combined case was also run for the article, and uses the assumptions from both the electricity and natural gas models.

The *limited electricity generation supply case* focuses on the potential challenges in the power sector facing non-natural gas-fired technologies. This case assumes that no new coal plants will be built unless they include carbon sequestration, due to uncertainty surrounding future environmental requirements. This case also assumes that new builds of nuclear, wind and biomass will be restricted to reference case levels. New non-natural gas-fired capacity, including sequestration and other renewables, is assumed to cost 25 percent more than in the reference case. Output from existing nuclear capacity is also assumed to decline after plants reach 40 years of age due to uncertainties surrounding the ability of older plants to maintain high capacity factors.

Notes and Sources

[1] On February 8, 2008, the U.S Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proven that mercury was a pollutant eligible for regulation under a less stringent portion of the Clean Air Act; however, EIA did not have time to revise *AEO2008* before publication to remove the impact of CAMR.

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

[3] 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 reviewed 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.

Aiken, Richard, Booz Allen Hamilton, Review of Fossil Energy Cost and Performance Assumptions in the Electricity Market Module of the National Energy Modeling System, May 2004.

DeLallo, Michael, Independent Expert (PEER) Review Program for the Energy Information Administration, May 17, 2004.

McGraw-Hill Companies, Top Plants, Power Magazine, Vol. 146, No. 5, August 2002.

A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010 (RDNN), available at the following link: http://www.nuclear.gov/Nuclear2010/NucPwr2010_PI.html.

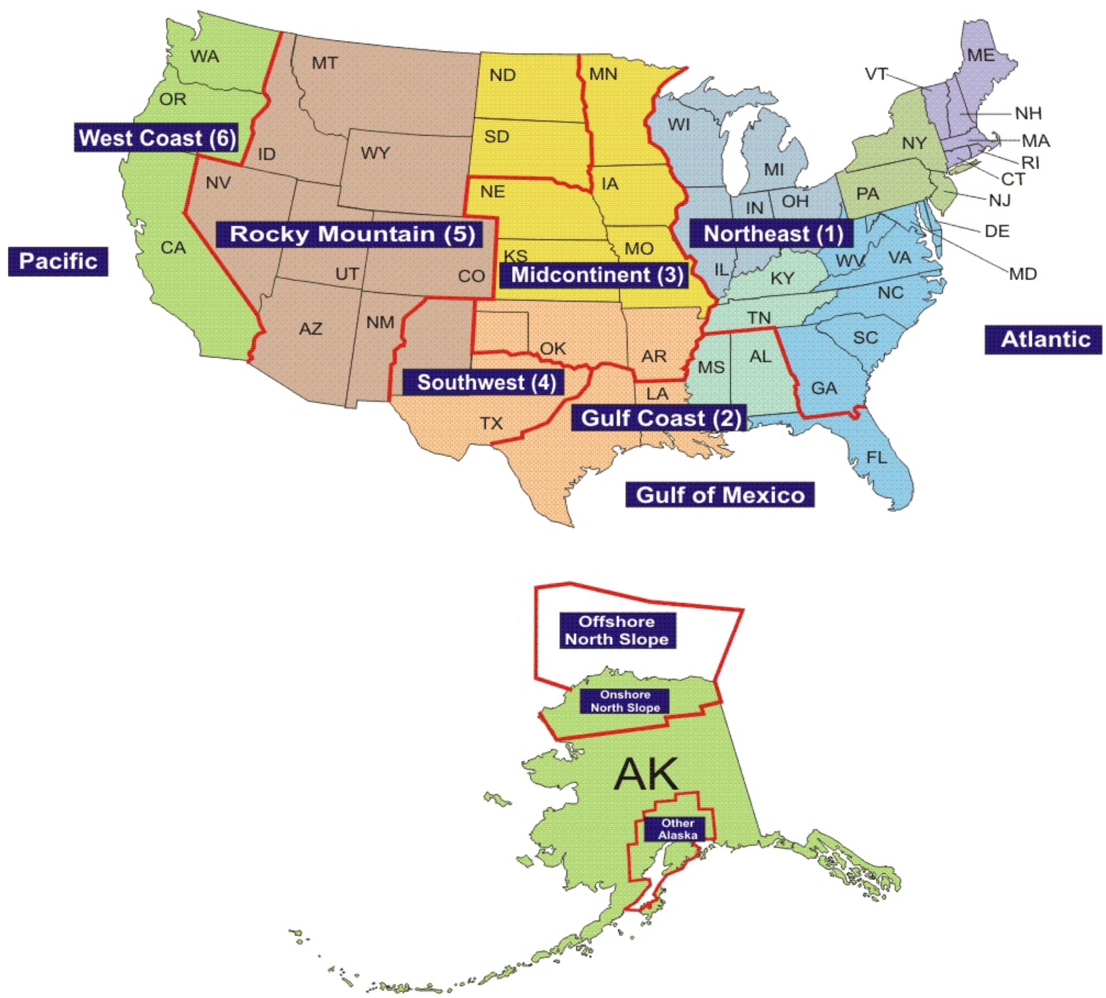
"New Fuel for the CANDU - And a new CANDU, too!"; NUKEM Market Report, June 2002.

Report #:DOE/EIA-0554(2008)
Release date: June 2008
Next release date: March 2009

Oil and Gas Supply Module

The NEMS Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework with which to analyze oil and gas supply on a regional basis (Figure 7). A detailed description of the OGSM is provided in the EIA publication, *Model Documentation Report: The Oil and Gas Supply Module (OGSM)*, DOE/EIA-M063(2007), (Washington, DC, 2007). The OGSM provides crude oil and natural gas short-term supply parameters to both the Natural Gas Transmission and Distribution Module and the Petroleum Market Module. The OGSM simulates the activity of numerous firms that produce oil and natural gas from domestic fields throughout the United States.

Figure 7. Oil and Gas Supply Model Regions



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

OGSM encompasses domestic crude oil and natural gas supply by both conventional and nonconventional recovery techniques. Nonconventional recovery includes unconventional gas recovery from low permeability formations of sandstone and shale, and coalbeds.

Primary inputs for the module are varied. One set of key assumptions concerns estimates of domestic technically recoverable oil and gas resources. Other factors affecting the projection include the assumed rates of technological progress, supplemental gas supplies over time, and natural gas import and export capacities.

Key Assumptions

Domestic Oil and Gas Technically Recoverable Resources

Domestic oil and gas technically recoverable resources[1] consist of proved reserves,[2] inferred reserves,[3] and undiscovered technically recoverable resources.[4] OGSM resource assumptions are based on estimates of technically recoverable resources from the United States Geological Survey (USGS) and the Minerals Management Service (MMS) of the Department of the Interior.[5] Supplemental adjustments to the USGS nonconventional gas resources are made by Advanced Resources International (ARI), an independent consulting firm. Based on estimates from the Reserves and Production Division of the EIA Office of Oil and Gas, 16.1 billion barrels[6] are added to US. inferred reserves to reflect a revised assessment of the potential of enhanced oil recovery to increase the recoverability of remaining in-place resources. While undiscovered resources for Alaska are based on USGS estimates, estimates of recoverable resources are obtained on a field-by-field basis from a variety of sources including trade press. Published estimates in Tables 49 and 50 reflect the removal of intervening reserve additions between the date of the latest available assessment and January 1, 2006.

Lower 48 Offshore

Most of the Lower 48 offshore oil and gas production comes from the deepwater of the Gulf of Mexico (GOM). Production from current producing fields and industry announced discoveries largely determine the short-term oil and natural gas production projection.

For currently producing fields, a 20-percent exponential decline is assumed for production except for natural gas production from fields in shallow water, which uses a 30-percent exponential decline. Fields that began production after 2001 are assumed to remain at their peak production level for 2 years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2007 are shown in Table 51. A field that is announced as an oil field is assumed to be 100 percent oil and a field that is announced as a gas field is assumed to be 100 percent gas. If a field is expected to produce both oil and gas, 70 percent is assumed to be oil and 30 percent is assumed to be gas. Production is assumed to

- ramp up to a peak level in 2 to 4 years depending on the size of the field,
- remain at the peak level until the ratio of cumulative production to initial resource reaches 20 percent for oil and 30 percent for natural gas,
- and then decline at an exponential rate of 20-30 percent.

The discovery of new fields (based on MMS's field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described in the previous paragraph).

Table 49. Crude Oil Technically Recoverable Resources
(Billion barrels)

Crude Oil Resource Category	As of January 1, 2006
Undiscovered	49.86
Onshore	20.55
Northeast	1.17
Gulf Coast	5.23
Midcontinent	1.12
Southwest	2.95
Rocky Moutain	7.77
West Coast	2.32
Offshore	29.31
Deep (>200 meters Water Depth)	27.24
Shallow (0-200 meters Water Depth)	2.07
Inferred Reserves	62.15
Onshore	50.69
Northeast	1.00
Gulf Coast	5.28
Midcontinent	6.88
Southwest	17.24
Rocky Mountain	11.75
West Coast	8.54
Offshore	11.46
Deep (>200 meters Water Depth)	6.61
Shallow (0-200 meters Water Depth)	4.85
Total Lower 48 States Unproved	112.01
Alaska	30.64
Total U.S. Unproved	142.65
Proved Reserves	23.02
Total Crude Oil	165.67

Note: Resources in areas where drilling is officially prohibited are not included in this table. The Alaska value is not explicitly utilized in the OGSM, but is included here to complete the table. The Alaska value does not include resources from the Arctic Offshore Outer Continental shelf.

Source: Conventional Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves - EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2006.

Table 50. Natural Gas Technically Recoverable Resources
(trillion cubic feet)

Natural Gas Resource Category	As of January 1, 2006
Lower 48 Nonassociated Conventional Gas	499.96
Undiscovered	273.30
Onshore	115.51
Northeast	4.53
Gulf Coast	64.86
Midcontinent	14.32
Southwest	11.15
Rocky Mountain	14.31
West Coast	6.33
Offshore	157.79
Deep (>200 meters water depth)	100.95
Shallow (0-200 meters water depth)	56.84
Inferred Reserves	226.66
Onshore	170.89
Northeast	0.55
Gulf Coast	79.45
Midcontinent	56.68
Southwest	16.84
Rocky Mountain	16.73
West Coast	0.64
Offshore	55.77
Deep (>200 meters water depth)	9.07
Shallow (0-200 (meters water depth)	46.71
Unconventional Gas Recovery	499.92
• Tight Gas	304.21
Northeast	55.98
Gulf Coast	46.20
Midcontinent	17.52
Southwest	13.82
Rocky Mountain	164.22
West Coast	6.48
• Shale	124.98
Northeast	27.73
Gulf Coast	0.00
Midcontinent	44.98
Southwest	38.01
Rocky Mountain	14.26
West Coast	0.00
• Coalbed	70.73
Northeast	5.13
Gulf Coast	3.66
Midcontinent	6..01
Southwest	0.00
Rocky Mountain	55.92
West Coast	0.00
Associated-Dissolved Gas	129.61
Total Lower 48 Unproved	1129.49
Alaska	30.74
Total U.S. Unproved	1160.23
Proved Reserves	204.39
Total Natural Gas	1364.61

Sources and Notes for this table are listed in the 'Notes and Sources' section at the end of chapter.

Table 51. Assumed Size and Initial Production Year of Major Announced Deepwater Discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBOE)	Start Year of Production
Neptune	AT575	6220	1995	13	182	2008
Tahiti	GC640	4292	2002	15	691	2008
Mirage	MC941	4457	1998	12	89	2008
Telemark	AT063	3927	2000	12	89	2009
GC238/GC282	GC238	4457	2001	13	182	2009
Shenzi	GC653	2386	2002	14	372	2009
Puma	GC823	4238	2002	14	372	2009
Blind Faith	MC696	4129	2003	14	372	2009
Thunder Hawk	MC734	6989	2001	13	182	2009
Thunder Horse	MC778	5724	2004	17	2954	2009
Great White	AC857	5993	1999	14	372	2010
Trident	AC903	9743	2001	13	182	2010
Sturgis	AT182	3710	2003	12	89	2010
Entrada	GC379	4690	2000	14	372	2010
Hornet	MC751	3878	2001	13	182	2010
Goose	MC766	1624	2002	12	89	2010
Thunder Horse North	MC726	5660	2000	15	691	2010
Cascade	WR206	8143	2002	14	372	2010
Chinook	WR469	8831	2003	14	372	2010
Knotty Head	GC512	3557	2005	14	372	2011
Ringo	MC546	2460	2006	14	372	2011
Tubular Bells	MC726	4334	2003	12	89	2011
Pony	GC468	3497	2006	13	182	2012
La Femme	MC427	5800	2004	12	89	2012
Stones	WR508	9556	2005	12	89	2012
Tiger	AC818	9004	2004	12	89	2013
Norman	GB434	5000	2006	15	691	2013
Jack	WR759	6963	2004	14	372	2013
Grand Cayman	GB517	5000	2006	13	182	2014
St. Malo	WR678	7036	2003	14	372	2014
Kaskida	KC292	5860	2006	15	691	2015
Egmont	MC413	2500	2006	13	182	2015
Big Foot	WR029	5235	2006	12	89	2015

Oil Shale Liquids Production

Projections for oil shale liquids production are based on underground mining and surface retorting technology and costs. The facility parameter values and cost estimates assumed in the projection are based on information reported for the Paraho Oil Shale Project, with the costs converted into 2004 dollars.[7] Oil shale rock mining costs, however, are based on current Rocky Mountain underground coal mining costs, which are representative oil shale rock mining costs. Oil shale facility investment and operating costs are assumed to decline by 1 percent per year. The construction of commercial oil shale production facilities is not permitted prior to 2017, based on the current status of petroleum company research, development and demonstration (RD&D) programs.

Although the petroleum company oil shale RD&D programs are focused on the in-situ production of oil shale liquids, the underground mining and surface retorting process shares many similarities with the in-situ process. Moreover, because the in-situ process is still at the experimental stage, there are no publicly available estimates as to the in-situ process capital and operating costs required to produce a barrel of oil shale liquids at a commercial scale. Consequently, the underground mining and surface retorting costs, in conjunction with the 1 percent per year cost decline, are intended to be a surrogate for the in-situ process costs.

Oil shale production facilities are assumed to be built when the net present value of the discounted cash flow exceeds zero. The discounted cash flow calculation uses a calculated discount rate that takes into consideration the financial risk associated with building oil shale facilities. Oil shale facilities take 5 years to construct, with an additional 5 years required to bring an in-situ facility into full production. An assumed technology penetration rate specifies that 5 years must pass from the time the first facility begins construction before the second facility can begin construction. Subsequent facilities are permitted to begin construction 3 years, 2 years, and then every year after a prior facility begins construction. Oil shale liquids production is not resource constrained, because approximately 400 billion barrels of petroleum liquids exist in oil shale rock with at least 30 gallons per ton of rock.

Because the in-situ process is still at the experimental stage, and because the underground mining and surface retorting process is unlikely to be environmentally acceptable, the oil shale liquids production projections should be considered highly uncertain.

Alaska Crude Oil Production

Projected Alaska oil production includes both existing producing fields and undiscovered fields that are expected to exist, based upon the region’s geology. The existing fields category includes the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. The initial production from these fields occurs in the first few years of the projection, with the projected oil production and the date of commencement based on the most current petroleum company announcements. Alaska crude oil production from the undiscovered fields is determined by the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on the expected capital and operating costs, and on the projected oil prices. Based on the latest U.S. Geological Survey resource assessments, the remaining North Slope fields are expected to be primarily small and mid-size oil fields that are smaller than the Alpine Field.

Oil and gas exploration and production currently are not permitted in the Alaska National Wildlife Refuge. The projections for Alaska oil and gas production assume that this prohibition remains in effect throughout the projection period.

The greatest uncertainty associated with the Alaska oil projections is whether the heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, will be producible in the foreseeable future at recovery rates exceeding a few percent.

Supplemental Natural Gas

The projection for supplemental gas supply is identified for three separate categories: synthetic natural gas (SNG) from liquids, SNG from coal, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). SNG from the currently operating Great Plains Coal Gasification Plant is assumed to continue through the projection period, at an average historical level of 50.9 billion cubic feet per year.[8] Other supplemental supplies are held at a constant level of 10.7 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not believed to change significantly in the context of a reference case. Synthetic natural gas from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.7 billion cubic feet per year.

Legislation and Regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the 5 years following its November 28, 1995, enactment. The volume of production on which no royalties were due for the 5 years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the MMS the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease by lease basis. In the model it is assumed that relief will be granted roughly the same levels as provided during the first 5 years of the act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for oil and gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or gas lease sale occurring within 5 years after enactment. The minimum volume of production with suspended royalty payments are:

(1) 5,000,000 barrels of oil equivalent (BOE) for each lease in water depths of 400 to 800 meters;

(2) 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters;

(3) 12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters; and

(4) 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

The water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. The suspension volumes are 5,000,000 BOE for leases in water depths 400 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depth of 1,600 to 2,400 meters; and 16,000,000 for leases in water depths greater than 2,400 meters. Examination of the resources available at 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not materially affect the model result.

The Minerals Management Service published its final rule on the “Oil and Gas and Sulphur Operations in the Outer Continental Shelf–Relief or Reduction in Royalty Rates–Deep Gas Provisions” on January 26, 2004, effective March 1, 2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Production of gas from the completed deep well must begin before 5 years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001.

Section 354 of the energy Policy Act of 2005 established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through CO_2 injection, while at the same time sequestering CO_2 produced from the combustion of fossil fuels in power plants and large industrial processes.

Oil and Gas Supply Alternative Cases

Rapid and Slow Technology Cases

Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases a number of parameters representing technological penetration in the reference case were adjusted to reflect a more rapid and a slower penetration rate. In the reference case, the underlying assumption is that technology will continue to penetrate at historically observed rates. Since technologies are represented somewhat differently in different submodules of the Oil and Gas Supply Module, the approach for representing rapid and slow technology penetration varied as well. For instance, the effects of technological progress on conventional oil and natural gas parameters in the reference case, such as finding rates, drilling, lease equipment and operating costs, and success rates, were adjusted upward and downward by 50 percent (Table 52), for the rapid and slow technology cases, respectively. The approach taken in unconventional natural gas is discussed below.

In the Canadian supply submodule, successful natural gas wells and production levels in the Western Canadian Sedimentary Basin (WCSB) are assumed to be progressively greater in the rapid technology case and lesser in the slow technology case across the projection horizon. By 2030, the number of successful natural gas wells associated with conventional and tight formations are approximately 16 percent higher and lower in the rapid and slow technology cases than in the reference case due to differences in assumed technological improvements. The resource base levels for the WCSB were assumed not to vary across technology cases. The technology growth parameter on production from coal bed natural gas wells is adjusted upward and downward by 75 percent under the rapid and slow technology cases, resulting in production levels approximately 26 percent higher or lower due to assumed technological differences. Finally, the minimum supply prices deemed necessary to trigger the Alaska and MacKenzie Delta natural gas pipelines are progressively decreased or increased over the projection in the rapid and slow technology cases, respectively, downward or upward from 0.0 to 12.5 percent by 2030. All other parameters in the model were kept at their reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Production costs in the MacKenzie Delta vary across the projection period based on the estimated change in drilling costs in the lower 48 states, indirectly capturing the impact of different assumptions about technological improvement.

The Unconventional Gas Recovery Supply Submodule (UGRSS) relies on Technology Impacts and Timing functions to capture the effects of technological progress on costs and productivity in the development of gas from deposits of coalbed methane, gas shales, and tight sands. The numerous research and technology initiatives are combined into 11 specific “technology groups,” that encompass the full spectrum of key disciplines — geology, engineering, operations, and the environment. The technology groups utilized for the *Annual Energy Outlook 2008* are characterized for three distinct technology cases — Slow Technological Progress, Reference Case, and Rapid Technological Progress — that capture three different futures for technology progress. The 11 technology groups are listed in Table 53. Table 54 provides a description of their treatment under the different technology cases.

Arctic National Wildlife Refuge (ANWR) Case

The Arctic National Wildlife Refuge (ANWR) case assumes that Congressional legislation opening the Federal 1002 Area to Federal oil and gas leasing would be enacted in 2008.

The ANWR case is solely focused on the potential for ANWR to produce crude oil. The ANWR case assumes that any gas found within ANWR would be re-injected into ANWR oil reservoirs to maintain reservoir pressure and that any Alaskan gas pipeline built during the projection period would rely on the natural gas reserves and resources found within the State lands located in the Central North Slope.

The ANWR case assumes that the opening of the Federal 1002 Area would also open the Native lands and State offshore region to oil exploration. The Federal, State, and Native lands are referred to collectively as

Table 52. Assumed Annual Rates of Technological Progress for Conventional Crude Oil and Natural Gas Sources
(percent/year)

Category	Slow	Reference	Rapid
Lower 48 Onshore			
Costs			
Drilling	0.25	0.50	0.75
Lease Equipment	0.28	0.55	0.83
Operating	0.19	0.39	0.58
Finding Rates			
New Field Discoveries	0.00	0.00	0.00
Known Fields	0.50	1.00	2.00
Success Rates			
Exploratory	0.25	0.50	0.75
Developmental	0.25	0.50	0.75
Lower 48 Offshore			
Exploration success rates	0.50	1.00	1.50
Delay to commence first exploration and between exploration (years)	0.25	0.50	1.00
Exploration and Development drilling costs	0.50	1.00	1.50
Operating costs	0.50	1.00	1.50
Time to construct production facility (years)	0.25	0.50	1.00
Production facility construction costs	0.50	1.00	1.50
Initial constant production rate	0.25	0.50	1.00
Production Decline rate	0.00	0.00	0.00
Alaska			
Costs			
Drilling	0.50	1.00	1.50
Lease Equipment	0.50	1.00	1.50
Operating	0.50	1.00	1.50
Finding Rates	1.50	3.00	4.50

Source: The values shown in this table are developed by the Energy Information Administration, Office of Integrated Analysis and Forecasting from econometric analysis for onshore costs and discussions with various industry and government sources for offshore and Alaska costs. Onshore drilling cost data are based on the American Petroleum Institute's *Joint Association Survey on Drilling Costs*. Onshore lease equipment and operating costs are based on the Energy Information Administration's *Costs and Indices for Domestic Oil & Gas Field Equipment and Production Operations*.

Table 53. Technology Types and Impacts

Technology Group	Technology Type	Impact
1	Basin assessments	Increase the available resource base by a) accelerating the time that hypothetical plays in currently unassessed areas become available for development and b) increasing the play probability for hypothetical plays – that portion of a given area that is likely to be productive.
2	Play specific, extended reservoir characterizations	Increase the pace of new development by accelerating the pace of development of emerging plays, where projects are assumed to require extra years for full development compared to plays currently under development.
3	Advanced well performance diagnostics and remediation	Expand the resource base by increasing reserve growth for already existing reserves.
4	Advanced exploration and natural fracture detection R&D	Increases the success of development by a) improving exploration/development drilling success rates for all plays and b) improving the ability to find the best prospects and areas.
5	Geology technology modeling and matching	Matches the “best available technology” to a given play with the result that the expected ultimate recovery (EUR) per well is increased.
6	More effective, lower damage well completion and stimulation technology	Improves fracture length and conductivity, resulting in increased EUR’s per well.
7	Targeted drilling and hydraulic fracturing R&D	Results in more efficient drilling and stimulation which lowers well drilling and stimulation costs.
8	New practices and technology for gas and water treatment	Result in more efficient gas separation and water disposal which lowers water and gas treatment operation and maintenance costs.
9	Advanced well completion technologies, such as cavitation, horizontal drilling, and multi-lateral wells:	Defines applicable plays, thereby accelerating the date such technologies are available and introduces and improved version of the particular technology, which increases EUR per well.
10	Other unconventional gas technologies, such as enhanced coalbed methane and enhanced gas shales recovery	Introduce dramatically new recovery methods that a) increase EUR per well and b) become available at dates accelerated by increase R&D, with c) increased operation and maintenance costs (in the case of coalbed methane) for the incremental gas produced.
11	Mitigation of environmental constraints	Removes development constraints in environmentally sensitive basins, resulting in an increase in basin areas available for development.

Source: Advanced Resources International.

Table 54. Assumed Rates of Technological Progress for Unconventional Gas Recovery

			Technology Case		
Technology Group	Item	Type of Deposit	Slow	Reference	Rapid
1	Year Hypothetical Plays Become Available	All Types-Non DOE	NA	NA	NA
		All Types-DOE	NA	2016	2009
2	Decrease in Extended Portion of Development Schedule for Emerging Plays (per year)	Coalbed Methane and Tight Sands - Non DOE	0.83%	1.67%	2.50%
		Gas Shales-Non DOE	1.25%	2.50%	3.75%
		All Types - DOE	1.25%	2.50%	3.75%
3	Expansion of Existing Reserves (per year -declining 0.1% per year; eg., 3.0, 2.0...)	Tight Sands	1.0%	2.0%	3.0%
		Coalbed Methane & Gas Shales	2.0%	4.0%	6.0%
4	Increase in Percentage of Wells Drilled Successfully (per year)	All Types	0.1%	0.2%	0.3%
	Year that Best 30 Percent of Basin is Fully Identified	All Types	2100	2044	2031
5	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
6	Increase in EUR per Well (per year)	All Types	0.13%	0.25%	0.38%
7	Decrease in Drilling and Stimulation Costs per Well (per year)	All Types	NA	NA	NA
8	Decrease in Water and Gas Treatment O&M Costs per Well (per year)	All Types	NA	NA	NA
9	Year Advanced Well Completion Technologies Become Available	Coalbed Methane	NA	NA	NA
		Tight Sands &Gas Shales	NA	2016	2009
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	NA
		Tight Sands	NA	10%	15%
		Gas Shales	NA	20%	30%
10	Year Advanced Recovery Technologies Become Available	Coalbed Methane & Tight Sands	NA	NA	2023
		Gas Shales	NA	NA	NA
	Increase in EUR per well (total increase)	Coalbed Methane	NA	NA	45%
		Tight Sands	NA	NA	15%
		Gas Shales	NA	NA	NA
	Increase in Costs ($1996/Mcf) for Incremental CBM production	Coalbed Methane	NA	NA	1.75
		Tight Sands	NA	NA	0.75
		GasShales	NA	NA	NA
11	Proportion of Areas Current Restricted that become Available for Development (per year)	All Types - Non DOE	0.5%	1.0%	1.5%
		All Types - DOE	0.25%	0.5%	0.75%

EUR = Estimated Ultimate Recovery.
O&M = Operation & Maintenance.
CBM = Coalbed Methane.
NA = Not applicable.
DOE = Those plays in the Rocky Mountain basins assessed as part of Department of Energy sponsored basin studies.
Source: Reference Technology Case, Advanced Resources, International; Slow and Rapid Technology Cases, Energy Information Administration, Office of Integrated Analysis and Forecasting.

the ANWR Coastal Plain. The ANWR case assumes that the size of the oil fields discovered within the coastal plain is based on the mean U.S. Geological Survey (USGS) estimate of 10.4 billion barrels of technically recoverable crude oil[9] that the USGS[10] estimated for the Federal, State, and Native lands in or adjacent to ANWR.

The ANWR case assumes first production from the ANWR area would occur 10 years after the 2008 enactment of legislation opening ANWR to oil and gas leasing. So first ANWR oil production would occur in 2018, based on the following timeline:

- 2 to 3 years to obtain U.S. Bureau of Land Management (BLM) leases.
- 2 to 3 years to drill a single exploratory well, due to the limited winter drilling season.
- 1 to 2 years to develop a production development plan and obtain BLM approval for that plan.
- 3 to 4 years to construct the necessary infrastructure and to drill and complete development wells.

The 10-year timeline for developing ANWR petroleum resources assumes that there are no protracted legal battles regarding the leasing and development of ANWR oil resources.

The ANWR case assumes that much of the oil resources in ANWR, like the other oil resources on Alaska's North Slope, could be profitably developed given the current levels of technology and at current and projected oil prices. This analysis also assumes that new fields in ANWR will begin development 2 years after a prior ANWR field begins oil production.

The ANWR case uses the USGS mean oil resource estimate of potential field sizes in the coastal plain area. Because the larger fields are generally easier to find and cheaper to develop, the ANWR case assumes that the largest oil fields are developed first. Based on the 2-year time lag assumption between the development of successive oil fields and the USGS field size distribution, the ANWR case assumes the following oil field development schedule:

Year In Which Field Begins Production	ANWR Case Field Size (million barrels)
2018	1,370
2020	700
2022	700
2024	360
2026	360
2028	360
2030	360
Total	4,210

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

Potential production from ANWR fields is based on the size of the field discovered and the production profiles of other fields of the same size in Alaska with similar geological characteristics. In general, fields are assumed to take 3 to 4 years to reach peak production, maintain peak production for 3 to 4 years, and then decline until they are no longer profitable and are closed.

Natural Gas Supply Assumptions for the Limited Natural Gas Supply Case and for the Combined Limited Alternatives Case

The combined limited alternatives case includes all the same assumptions regarding natural gas supply, but with additional assumptions regarding the electric power sector.

Two large natural gas pipelines are under consideration for development in the Arctic region of North America, which collectively would significantly add to lower 48 gas supply - a Mackenzie Delta gas pipeline in Canada and an Alaska gas pipeline.[11] In the reference case, the building of these pipelines is based on the prevailing economics of each pipeline; that is, the lower-48 natural gas price relative to the cost of building and operating each pipeline. In the limited natural gas supply case, neither Arctic pipeline is allowed to be built through 2030.

In the limited natural gas supply case, gross domestic LNG imports are held constant at 1.0 trillion cubic feet starting in 2009 and extending through 2030. This LNG supply assumption is identical to that used in the low LNG case.

The reference case oil and gas production projections are based on the U.S. Geological Survey (USGS) and U.S. Minerals Management Service (MMS) mean estimates of the technically recoverable domestic oil and gas resource base. The limited natural gas supply case assumes that the U.S. undiscovered oil and gas resource base is 15 percent less than the mean USGS and MMS estimates that are used in the reference case. The Canadian undiscovered natural gas resource base is also assumed to be 15 percent less in this case. This low oil and gas resource base assumption is identical to that assumed in the high price case.

Technological progress generally reduces the cost of finding, developing, and producing natural gas resources. In the limited natural gas supply case, the future rate of technological progress proceeds at half the rate embodied in the reference case, for both oil and gas in the United States and for natural gas in Canada. This assumption is the same as that used in the low oil and gas technology case.

In the limited natural gas supply case, coal-to-gas technology is assumed to be unavailable as a means for providing domestic natural gas supply.

Oil and Natural Gas Cost Assumptions for the Low and High Project Cost Cases

High Project Cost Case Assumptions for Oil and Natural Gas

In the high commodity cost case, it is assumed that the oil and gas wells and construction materials costs continue to rise beyond current levels.

In the oil and gas supply module, the oil and gas well drilling costs escalate from 2007 through 2010 to twice the reference case level in 2010. After 2010, oil and gas well drilling costs are held constant at twice the reference case level though 2030. This cost escalation is partly offset by an annual technology improvement factor. Pipeline construction costs are increased over the reference case by one percent per year for both Lower 48 pipeline construction and for the Alaska and Mackenzie Delta pipelines.

LNG liquefaction costs match the reference case increase through 2008. In 2009, LNG liquefaction costs are set to be 20 percent higher than those in 2008. LNG liquefaction costs remain constant at the 2009 through 2030. LNG regasification facilities construction costs are increased by 15 percent above the reference case in 2008 and held constant through 2030. LNG shipping costs are increased by seven percent through 2008 above the reference case level and then held constant through 2030.

In the refining sector, construction costs are increased above the reference case level by a factor equal to the percentage difference between the 2004 and 2006 Nelson-Farrar index and held constant from 2008 through 2030. Construction costs for corn and cellulosic ethanol plants are treated similarly using the Chemical Engineering Plant Cost Index (CEPCI).

Low Project Cost Case Assumptions for Oil and Natural Gas

In the low project cost case it is generally assumed that commodity prices will gradually decline back to price levels seen 5 years ago.

In the oil and gas supply module, the oil and gas well drilling costs decline from 2007 through 2010 to half the reference case level in 2010. After 2010, oil and gas well drilling costs are held constant at half the reference case level though 2030. Pipeline construction costs are decreased below the reference case by one percent per year. The increase applied to LNG liquefaction facility construction costs in the reference case is phased back down to the 2006 cost level by 2015 and is held constant thereafter. The 15 percent and 7 percent increases applied to the LNG regasification construction and shipping costs in the reference case are phased out starting in 2009 and ending in 2018.

The recent run-up in refinery construction costs is assumed to be a temporary aberration with construction costs returning to historic levels through the addition of new commodity supplies and/or a reduction in demand for those commodities. The Nelson-Farrar index and CEPCI are used to scale refinery and ethanol plant construction costs, respectively, down to their 2004 levels. These costs are then held constant through 2030.

Notes and Sources

[1]   Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[2] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[3]   Inferred reserves are that part of expected ultimate recovery from known fields in excess of cumulative production plus current reserves.

[4] Undiscovered resources are located outside oil and gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[5] Donald L. Gautier and others, U.S. Department of Interior, U.S. Geological Survey, 1995 National Assessment of the United States Oil and Gas Resources, (Washington, D.C., 1995); U.S. Department of Interior, Minerals Management Service, Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources, (February 2006); and 2003 estimates of conventionally recoverable hydrocarbon resources of the Gulf of Mexico and Atlantic Outer Continental Shelf as of January 1, 2003.

[6] The amounts added (in billion barrels) among the various OGSM regions are as follows: Northeast 0.4, Gulf Coast 5.0, Midcontinent 3.8, Southwest 4.1, Rocky Mountain 1.5, and West Coast 1.3.

[7]   Source: Noyes Data Corporation, *Oil Shale Technical Data Handbook*, edited by Perry Nowacki, Park Ridge, New Jersey, 1981, pages 89-97. The Paraho Oil Shale Project design had a maximum production rate of 100,000 syncrude barrels per day, which is used in the OSSS as the standard oil shale facility size.

[8] The potential for the introduction of new coal-to-gas capacity was not considered for AEO2008, but will be incorporated in AEO2009 projections.

[9] Technically recoverable resources are resources that can be produced using current technology.

[10] U.S. Department of Interior, U.S. Geological Survey, *The Oil and Gas Resource Potential of the Arctic National Wildlife Refuge 1002 Area, Alaska*, Open File Report 98-34, 1999; U.S. Geological Survey, USGS Fact Sheet FS-028-01, April 2001; and, *Oil and Gas Resources of the Arctic Alaska Petroleum Province,* by David W. Houseknecht and Kenneth J. Bird, U.S. Geological Survey Professional Paper 1732–A, 2005.

[11] The National Energy Modeling System assumes that Canadian and Alaska gas pipelines would be interconnected to U.S. lower 48 natural gas markets. The no Arctic pipelines assumption also precludes the building of a natural gas pipeline from the Alaska North Slope to South-Central Alaska, where the gas would be converted to liquefied natural gas (LNG) and then shipped to foreign and domestic LNG customers. However, this assumption does not preclude the conversion of Alaska North Slope gas into petroleum liquids, which would then be shipped through the existing Alyeska Oil Pipeline (also known as the TransAlaska Pipeline System).

Notes and Sources

Notes and Sources for Table 50

Note: Resources in areas where drilling is officially prohibited are not included in this table. Also, the Associated-Dissolved Gas and the Alaska values are not explicitly utilized in the OGSM, but are included here to complete the table. The Alaska value does not include stranded Arctic gas.

Source: Onshore, State Offshore, and Alaska - U.S. Geological Survey (USGS) with adjustments to Unconventional Gas Recovery resources by Advanced Resources, International; Federal (Outer Continental Shelf) Offshore - Minerals Management Service (MMS); Proved Reserves -- EIA, Office of Oil and Gas. Table values reflect removal of intervening reserve additions between the date of the latest available assessment and January 1, 2006.

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Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through the regional interstate network, for both a peak (December through March) and off peak period during each projection year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. Natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of the supply options available to bring gas to market centers within each of the NGTDM regions (Figure 8). The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) structural components of the model, (2) capacity expansion and pricing of transmission and distribution services, (3) Arctic pipelines, and (4) imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in *Model Documentation: Natural Gas Transmission and Distribution Model of the National Energy Modeling System, Model Documentation 2007,* DOE/EIA-M062(2007) (Washington, DC, 2007).

Figure 8. Natural Gas Transmission and Distribution Model Regions

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

Key Assumptions

Structural Components

The primary and secondary region-to-region flows represented in the model are shown in Figure 8. Primary flows are determined, along with nonassociated gas production levels, as the model equilibrates supply and demand. Associated-dissolved gas production is determined in the Oil and Gas Supply Module (OGSM). Secondary flows are established before the equilibration process and are generally set exogenously. Liquefied natural gas (LNG) imports are also not directly part of the equilibration process, but our set at the beginning of each NEMS iteration in response to the price from the previous iteration. Flows and production levels are determined for each season, linked by seasonal storage. When required, annual quantities (e.g., consumption levels) are split into peak and offpeak values based on historical averages. When multiple regions are contained in a Census Division, regional end-use consumption levels are approximated using historical average shares. Pipeline and storage capacity are added as warranted by the relative volumes and prices. Regional pipeline fuel and lease and plant fuel consumption are established by applying an historically based factor to the flow of gas through a region and the production in a region, respectively. Prices within the network, including at the borders and the wellhead, are largely determined during the equilibration process. Delivered prices for each sector are set by adding an endogenously estimated markup (generally a distributor tariff) to the regional representative citygate price. Supply curves and electric generator gas consumption are provided by other NEMS modules for subregions of the NGTDM regions, reflective of how their internal regions overlap with the NGTDM regions.

Capacity Expansion and Pricing of Transmission and Distribution Services

For the first 2 projection years, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and seasonal storage in the model. Subsequently, pipeline and storage capacity is added when increases in consumption, coupled with an anticipated price increase, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given an assumed increased tariff). Once it is determined that an expansion will occur, the associated capital costs are applied in the revenue requirement calculations in future years. Capital costs are assumed based on average costs of recent comparable expansions for compressors, looping, and new pipeline.

It is assumed that pipeline and local distribution companies build and subscribe to a portfolio of interstate pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 30 percent above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99 percent. In the off-peak period, the maximum is assumed to vary between 75 and 99 percent of the design capacity. The overall level and profile of consumption, as well as the availability and price of supplies, generally cause realized pipeline utilization levels to be lower than the maximum.

Pricing of Services

While transportation tariffs for interstate pipeline services are initially based on a regulated cost-of-service calculation, an adjustment to the tariffs is applied which is dependent on the realized utilization rate, to reflect a market-based differential. Transportation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base.

Delivered prices by sector and season are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional delivered and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor.

The distribution tariffs are projected using econometrically estimated equations, primarily in response to changes in consumption levels. An assumed differential is used to divide the industrial price into one for noncore customers (refineries and industrial boiler users) and one for core customers who have less alternative fuel options.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. In general, the distributor tariffs for natural gas to vehicles are set to *EIA's Natural Gas Annual* historical end-use prices minus citygate prices plus Federal and State VNG taxes (held constant in nominal dollars) plus an assumed dispensing cost. Dispensing costs are assumed to be $3.82 and $2.23 (2006 dollars per mcf) for non-fleet and fleet vehicles, respectively. The price to non-fleet vehicles is set to 75 percent of the equivalent motor gasoline price, if it would have been lower otherwise.

Pipelines from Arctic Areas into Alberta

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. Recent high natural gas prices seemingly raised the potential economic viability of such a project, although expected costs have increased as well. Setbacks in negotiations between the primary producers and the Alaska government have further delayed the project. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 55. A calculation is performed to estimate a regulated, levelized, tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect the potential impact on the market price once the pipeline comes on line.

For the Alaska pipeline the uncertainty associated with the initial capitalization is captured by applying a value that is 20 percent higher than the expected value. For comparison purposes, a price differential of $0.68 (2006 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaska gas, relative to the lower 48 wellhead price, is approximately $4.37 (2006 dollars per Mcf), with some variation across the projection due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is projected to commence if the assumed total costs for Alaska gas in the lower 48 States exceeds the average lower 48 gas price in each of the previous 2 years, on average over the previous 5 years (with greater weight applied to more recent years), and as expected to average over the next 3 years. An adjustment is made if prices were declining over the previous 5 years. Once the assumed 4-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $1.94 (2006 dollars per Mcf). When the Alaska to Alberta pipeline is built in the model, additional pipeline capacity is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaska gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Natural gas production from the MacKenzie Delta is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south. The basic methodology used to represent the decision to build a MacKenzie pipeline is similar to the process used for an Alaska-to-lower 48 pipeline, using the primary assumed parameters listed in Table 56. One exception is that wellhead costs are assumed to change across the projection period with estimated changes to drilling costs for the lower 48 States.

Natural Gas Imports and Exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS starting at 365 billion cubic feet per year in 2007 and increasing to 519 tcf by 2030. Canadian production and U.S. import flows from Canada are determined endogenously within the model.

Growth rates for consumption in Mexico are set exogenously based on projections from the *International Energy Outlook 2007* and are provided on Table 57, along with initially assumed growth rates for production in Mexico from the same source. Adjustments are made endogenously within the model to reflect a response to price fluctuations within the market. Domestic production is assumed to be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico that serve only the

Table 55. Primary Assumptions for Natural Gas Pipelines from Alaska and MacKenzie Delta into Alberta, Canada

	Alaska to Alberta	MacKenzie Delta to Alberta
Initial flow into Alberta	3.9 Bcf per day	1.1 Bcf per day
Expansion potential	22 percent	58 percent
Initial capitalization	20.9 billion (2006 dollars)	$10.0 billion (2006 dollars)
Cost of Debt (premium over AA bond rate)	0.0 percent	1.0 percent
Cost of equity (premium over AA bond rate)	5.0 percent	8.0 percent
Debt fraction	80 percent	70 percent
Depreciation period	15 years	15 years
Minimum wellhead price (including treatment and fuel costs)	$1.61 (2006 dollars per Mcf)	$2.94 (2006 dollars per Mcf)
Risk Premium	$0.34 (2006 dollars per Mcf)	$0.06 (2006 dollars per Mcf)
Additional cost for expansion	$1.94 (2006 dollars per Mcf)	$0.34 (2006 dollars per Mcf)
Construction period	4 years	3 years
Planning period	5 years	2 years
Earliest start year	2020	2014

Note: The potential for capital cost overruns is represented by using an initial capitalization that is 20 percent greater than the expected estimate. The minimum wellhead price for Alaska accounts for Alaska's 2007 Oil and Gas Production Tax.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/Conoco Phillips and reflect an assumed impact on Alaska pipeline finances as a result of the American Jobs Creation Act of 2004 and the Military Construction Appropriations Act, 2004.

National Energy Board of Canada, "Mackenzie Gas Project – Hearing Order GH-1-2004, Supplemental Information – Project Update 2007," dated May 15, 2007;

National Energy Board of Canada, "Mackenzie Gas Project – Project Cost Estimate and Schedule Update," dated March 12, 2007;

Canada Revenue Agency, "T2 Corporation Income Tax Guide 2006," T4012(E) Rev. 07.

Indian and Northern Affairs Canada, "Oil and Gas in Canada's North," website address http://www.ainc-inac.gc.ca/ps/ecd/env/nor_e.html.

National Energy Board of Canada, "Application for Approval of the Development Plan for Taglu Field - Project Description," submitted by Imperial Oil Resources Ltd., TDPA-P1, August 2004;

National Energy Board of Canada, "Application for Approval of the Development Plan for Niglintgak Field - Project Description," submitted by Shell Canada Ltd., NDPA-P1, August 2004; and

National Energy Board of Canada, "Application for Approval of the Development Plan for Parsons Lake Field - Project Description," submitted by ConocoPhillips Canada (North) Ltd., PLDPA-P1, August 2004.

Table 56. Assumed Annual Growth Rates for Mexico (percent)

	Consumption	Production
2007 - 2010	7.0	3.0
2011- 2015	3.5	2.1
2016 - 2020	2.2	3.7
2021 - 2025	1.9	1.6
2026 - 2030	2.2	2.9

Source: EIA, International Energy Outlook 2007, DOE/EIA-0484(2007) and Energy Information Administration, Office of Integrated Analysis and Forecasting.

Mexico market. Receiving terminal(s) in Baja California, Mexico, that serve both Mexico and the United States can be constructed if the market price at the tailgate exceeds a trigger price, based on the cost of bringing LNG to the region and the market price of LNG. The difference between production and consumption in any year is assumed to be either imported from, or exported to, the United States.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 58. Production in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an expected production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells (based on an econometric estimation) and a finding rate (set as a function of the remaining economically recoverable resource base). The initial coalbed methane and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 2004 are 70 trillion cubic feet and 92 trillion cubic feet, respectively.[1] Potential production from tight formations was approximated by increasing the conventional resource level by 1.5 percent annually. Production from coalbed sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous projection year. To temporarily approximate the impact of the 2007 average increase in the Alberta royalty rate, starting in 2009, the price drivers on western Canada supply in the model were assumed to be 5 percent less than they would have been otherwise.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to phase down from 2006 levels of 61 billion cubic feet per year through March of 2009, when the export license expires, and 0.0 through the remainder of the projection. LNG imports are determined endogenously within the model. The model provides for the construction of new facilities should gas prices be high enough to make construction economic — the prices (including regasification) that are needed to initially trigger new LNG construction in the United States and the Bahamas vary by region and, at the beginning of the forecast, range from $3.39 to $5.02/Mcf (2005 dollars).

Table 57. Exogenously Specified Canadian Production and Consumption
(billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2005	3,300	151
2010	4,000	240
2015	4,200	530
2020	4,600	670
2025	4,900	820
2030	5,200	710

Source: Consumption - EIA, International Energy Outlook 2007, DOE/EIA-0484(2007); Production - Energy Informatiion Administration, Office of Integrated Analysis and Forecasting.

Currently there are five LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; Elba Island, Georgia; and off the coast of Louisiana (Gulfport Energy Bridge). These five facilities including expansions currently in progress have a combined design capacity of 2,125 million cubic feet per day (2.1 trillion cubic feet per year). Further expansion is triggered when the regional LNG tailgate[2] price meets or exceeds a trigger price as determined in the model.

The model also has a provision for the construction of new facilities in all United States coastal regions, in eastern and western Canada and in Mexico. Mexico currently has one terminal at Altameria, in operation as of 2006. Supplies from a Baja California, Mexico, facility are assumed to enter the United States as pipeline imports from Mexico destined for Southwestern markets. A 1 Bcf per day facility, currently under construction, is assumed to come online in 2008 with one-half of its supplies available to the United States. As with expansion of existing facilities, construction of additional facilities is triggered when the regional LNG tailgate price meets or exceeds a trigger price. The trigger price for additional Baja California, Mexico, LNG facilities starts at $5.43/Mcf (2006 dollars). LNG is represented similarly in eastern Canada. A 1 Bcf/day facility, currently under construction, is assumed to come online in 2008. No assumption regarding the amount destined for the United States is made. The supply is simply added to the supply in eastern Canada. The trigger price for additional capacity in eastern Canada starts at $4.07/Mcf (2006 dollars). The trigger price for initial construction in western Canada is $5.48/Mcf (2006 dollars). These trigger prices are increased by a market price adjustment factor representing the difference between the world market price for LNG and the cost to bring it to the U.S. market. This factor is specified based on the assumed growth in world natural gas consumption from the *International Energy Outlook 2007* and the annual change in the world oil price.

Since LNG does not compete directly with wellhead prices, trigger prices are compared with regional prices in the vicinity of the LNG facility (i.e., the tailgate price) rather than with wellhead prices. With the exception of the Canada and Baja facilities, the individual trigger prices represent the least cost feasible combination of production, liquefaction, and transportation costs to the facility plus the regasification cost at the facility, plus the market price adjustment factor. Regasification costs at new facilities include capital costs for construction of the facility. A range of cost components used in determining trigger prices at new facilities is shown in Table 58. Regional risk premiums are determined based on regional specific factors that include proposal and site identification activity, population density, housing values, income values, and availability of deepwater ports.

Table 58. LNG Cost Components
(2006 dollars per mcf)

	Low		High	
2005 Production	$0.39	Nigeria	$1.75	Norway
2005 Liquefaction	$2.39	All facilities	$2.39	All facilities
Shipping	$0.40	Venezuala to the Bahamas	$2.21	Qatar to Gulf Mexico
Regasification	$0.40	Gulf of Mexico	$1.11	New England
Risk Premium	$0.63	West South Central	$2.00	East South Central

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Gas supply costs are based on a March 31, 2003 report produced under contract to EIA by the Gas Technology Institute (GTI), using a conversion factor of 1,100 Btus/cf. Regasification costs are based on Project Technical Liaison, Inc. estimates. Shipping costs are based on various sources, including www.dataloy.com for transportation distances, the GTI Report, and EIA judgement. Liquefaction costs are based on data from Wood MacKenzie. Liquefaction, shipping, and regasification costs are determined endogenously in the NGTDM.

The production costs reflect assumed market prices entering the liquefaction facility for various stranded gas[3] locations and average about $1.00 Mcf (2006 dollars). Different supply factors are estimated based on the existing and potential upstream projects for each supply source, and are applied to the average supply cost to arrive at the production cost by source.[4]

Liquefaction costs are revised to account for recent escalations of liquefaction plant costs around the world. The revised costs are estimated to have increased at least 50 percent over the average liquefaction cost estimated by EIA in 2006 and are assumed based on a generally declining liquefaction capital cost function for one train (3.9 million metric tons of LNG or 186 Bcf per year) starting at $500 per ton of plant capacity in 2006. The capital cost is to be amortized over a 20-year period with a 18 percent average cost of equity, 60 percent debt fraction, and 30 percent corporate tax rate. The cost of debt is assumed to equal the AA utility bond rate. These liquefaction costs are adjusted to account for individual plant factors such as the plant's age and location. The liquefaction plant utilization rate is assumed to be 93 percent.

LNG shipment costs from a supply source to a receiving terminal are a function of the distance between these two locations, an average per unit-mile shipment cost, and a port cost. The per unit-mile shipment cost is computed as a function of the return on invested capital for the tanker, number of round trips per year, distance between a supply source and an LNG terminal, average tanker capacity, estimated fuel cost, and administrative and general expenses for the tanker serving that route. Taxes are embedded in the administrative and general expenses.

Shipment costs are based on distances, an assumed average per unit capital cost for all the newly built tankers ($1,247 per cubic-meter capacity in 2006 dollars), an average rate of return on the invested capital, tanker fuel costs, administrative and general expenses, an assumed average tanker capacity per trip (159,000 cubic meters), and the assumed number of round trips per year for a tanker serving a particular route. The estimated shipment costs, in 2006 dollars/Mcf, were divided by the route distances to arrive at initial transportation costs. On average these calculations provide a result of $0.00022/Mcf-mile in 2006 dollars (i.e., roughly $0.22/Mcf per 1,000 nautical miles, based on a one-way trip). Finally, an assumed $0.05/Mcf port cost is added to each of these transportation costs to arrive at the final shipment costs.

Regasification costs include a fixed and variable component. Variable costs include administrative and general expenses, operating and maintenance expenses, taxes and insurance, electric power costs, and fuel usage and loss. The fixed costs reflect the expected annual return on capital and are based on the assumed capital cost, a 60 percent debt fraction, the cost of debt and equity, a 38 percent corporate tax rate, and a 20-year economic life. The capital costs are based on the cost of storage tanks, vaporizer units, marine facilities, site improvements and roads, buildings and services, installation, engineering and project management, land, contingency, and the capacity of the plant. The cost of debt is tied to the AA utility bond rate and the cost of equity is tied to the 10-year treasury note yield plus a 10-percent risk premium. A per-unit regasification charge for a given size facility is obtained by dividing total costs by an assumed annual throughput. Regional specific factors are applied to account for differences in costs associated with land purchase, labor, site specific permitting, special land and waterway preparation and/or acquisition, and other general construction and operating cost differences.

It is assumed that LNG facilities are developed with an initial design capacity along with a capability for future expansion. For existing terminals, original capital expenditures are considered sunk costs. Costs were additionally determined for expansion beyond currently announced expansion plans at all existing facilities, with the exception of Everett (where room for expansion is limited), under the assumption that if prices reached sustained levels at which new facilities would be constructed, additional expansion at existing facilities would likely be considered. The costs of expansion at existing facilities within a region are in general lower that those for the construction of new facilities. If market prices warrant, additional capacity can be added in a region either through expansion or construction of new facilities.

Legislation and Regulations

The methodology for setting reservation fees for transportation services is initially based on a regulated rate calculation, but is ultimately consistent with FERC's alternative ratemaking and capacity release position in that it allows some flexibility in the rates pipelines ultimately charge. The methodology is market-based in that rates for transportation services will respond positively to increased demand for services while rates will decline (reflecting discounts to retain customers) should the demand for services decline.

A number of legislative actions have been taken to provide a more favorable environment for the introduction of new liquefied natural gas (LNG) regasification facilities in the United States. In December 2002 under the Hackberry Decision, FERC terminated open access requirements for new onshore LNG terminals, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The Maritime Security Act, signed into law in November 2002, also amended the Deepwater Port Act of 1974 to include offshore natural gas facilities, transferring jurisdiction for these facilities from the FERC to the Maritime Administration and the U.S. Coast Guard. The result should be to streamline the permitting process and relax regulator requirements. More recently an EPACT2005 provision clarified the role of the FERC as the final decision making body on issues concerning onshore LNG facilities. While none of these legislative/regulatory actions is explicitly represented in the modeling framework, these provisions are indirectly reflected in selected model parameters.

Section 116 of the Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2004 (H.R.4837) gives the Secretary of Energy the authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska, through the Canadian border south of 68 degrees north latitude, into Canada, and to the lower-48 States. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. In aggregate the loan guarantee would not exceed: (1) 80 percent of total capital costs (including interest during construction); (2) $18 billion dollars (indexed for inflation at the time of enactment); or (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The loan guarantee is represented in the model by assuming the cost of debt at a percentage point lower than what would have been assumed otherwise and by assuming a debt fraction of 80 percent, instead of 70 percent.

Section 706 of the American Jobs Creation Act of 2004 (H.R.4520) provided a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the previously allowed 15-year recovery period, for tax purposes. The provision is effective for property placed in service after 2013 (or treated as such) and is represented in the model by using a cost of equity that is 3 percentage points lower than would have been assumed otherwise.

Section 707 of the American Jobs Creation Act extended the 15-percent tax credit previously applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plan on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision is effective for costs incurred after 2004 and is represented in the model by assuming a charge for natural gas treatment that is $0.05 per Mcf less than what would have been assumed otherwise.

Section 1113 of the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) raised the federal motor fuels tax for compressed natural gas vehicles (CNG) from 48.54 cents per Mcf to 18.3 cents per gasoline gallon equivalent (or about $1.46 per Mcf), all in nominal dollars. The same section also allows for a motor fuels excise tax credit of $0.50 per gasoline gallon equivalent to the seller through September 30, 2009. For *AEO2007*, the tax rate was changed accordingly and assumed constant in nominal terms throughout the projection. Similarly the tax credit was subtracted from the CNG cost estimates through the time period indicated, also in nominal terms.

Section 312 of the Energy Policy Act of 2005 authorizes the Federal Energy Regulatory Commission (FERC) to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. In the AEO2007 storage rates were allowed to vary from regulation-based rates, depending on market conditions.

Natural Gas Transmission and Distribution Alternative Cases

High and Low Liquefied Natural Gas Import Cases

Two cases were created to assess the impact of a range of liquefied natural gas (LNG) imports on the domestic natural gas market. The future level of LNG imports into the United States is highly uncertain. The levels will depend on such things as the ability and motivation of companies to site regasification facilities domestically, the ability and motivation of companies to site liquefaction facilities throughout the world, the world market for natural gas shipped via pipeline and in liquid form, the relative need for consuming the available natural gas in other parts of the world, the potential other uses for the gas (e.g., its conversion into liquid fuel), and finally the price of LNG on the world market, which in turn is impacted by the cost of producing, liquefying, shipping, and regasifying the gas. These cases are intended to highlight the impact if LNG imports were actually much different than under the reference case, for whatever reason. For the high liquefied natural gas import case, starting in 2011, LNG imports are increased above the reference case levels by 10 percent per year. Specifically, LNG imports are 10 percent above 2011 reference case levels in 2011, 20 percent above 2012 reference case levels in 2012, and 200 percent above 2030 reference case levels in 2030. For the low liquefied natural gas case, LNG import levels are held constant at 2009 reference case levels from 2010 forward.

Notes and Sources

[1] For unconventional (i.e., coalbed) -- Average undiscovered resources under the National Energy Board's Supply Push and Techno-vert scenarios in "Canada's Energy Future, Scenarios for Supply and Demand to 2025," 2003. For conventional -- "Canada's Conventional Natural Gas Resources -- A Status Report," April 2004.

[2] Tailgate LNG prices represents the price when natural gas exists the regasification facility.

[3] Gas reserves that have been located but are isolated from potential markets, commonly referred to as “stranded” gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

[4] Largely based on information from Gas Technology Institute, “Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS,” Report submitted to Energy Information Administration, March 31, 2003.

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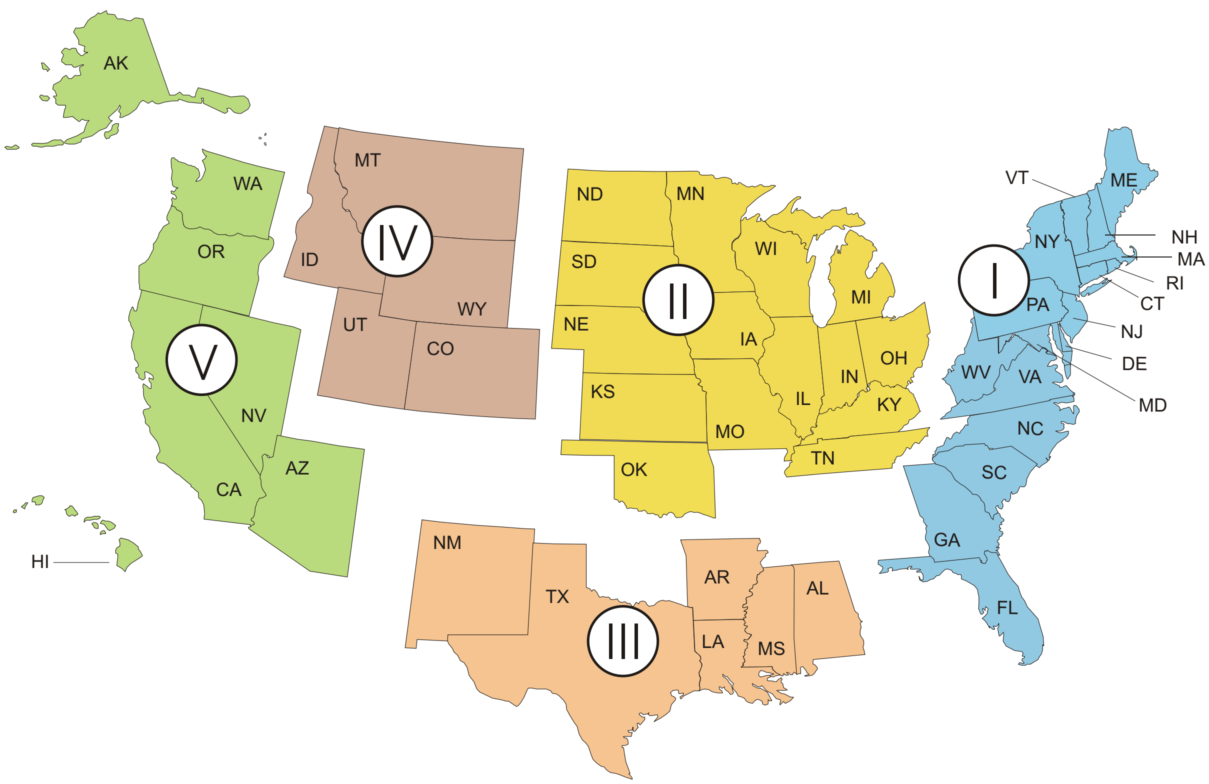
Petroleum Market Module

The NEMS Petroleum Market Module (PMM) projects petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, unfinished oil imports, other refinery inputs (including alcohols, ethers, bioesters, corn, biomass, and coal), natural gas plant liquids production, and refinery processing gain. In addition, the PMM projects capacity expansion and fuel consumption at domestic refineries.

The PMM contains a linear programming (LP) representation of U.S. refining activities in the five Petroleum Area Defense Districts (PADDs) (Figure 9). The LP model is created by aggregating individual refineries within a PADD into two types of representative refineries, and linking all five PADD's via crude and product transit links. This representation provides the marginal costs of production for a number of conventional and new petroleum products. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from PADD regions to other regional structures and vice versa. The linear programming results are used to determine end-use product prices for each Census Division (shown in Figure 5) using the assumptions and methods described below.

Figure 9. Petroleum Administration for Defense Districts



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

Key Assumptions

Product Types and Specifications

The PMM models refinery production of the products shown in Table 59.

The costs of producing different formulations of gasoline and diesel fuel that are required by State and Federal regulations are determined within the linear programming representation by incorporating specifications and demands for these fuels. The PMM assumes that the specifications for these fuels will remain the same as currently specified, with a few exceptions: the sulfur content, which will be phased down to reflect EPA regulations for all gasoline and diesel fuels; and, benzene will be reduced in gasoline beginning in 2011.

Table 59. Petroleum Product Categories

Product Category	Specific Products
Motor Gasoline	Conventional Unleaded, Oxygenated, Reformulated
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Low-Sulfur-Diesel, Ultra-Low-Sulfur-Diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Propane, Liquefied Petroleum Gases Mixed
Petrochemical Feedstocks	Petrochemical Naptha, Petrochemical Gas Oil, Propylene, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas Petroleum Coke, Special Naphthas, Aviation Gasoline

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

Motor Gasoline Specifications and Market Shares

The PMM models the production and distribution of three different types of gasoline: conventional, oxygenated, and reformulated (Phase 2). The following specifications are included in the PMM to differentiate between conventional and reformulated gasoline blends (Table 60): Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The sulfur content specification for gasoline is reduced annually through 2007 to reflect recent regulations requiring the average annual sulfur content of all gasoline used in the United States to be phased-down to 30 parts per million (ppm) between 2004 and 2007.[1] PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and meets the 30 ppm requirement in 2004. Regional assumptions for phasing-down the sulfur in conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries. The sulfur specifications assumed for each region and type of gasoline are provided in Table 61.

Conventional gasoline must comply with antidumping requirements aimed at preventing the quality of conventional gasoline from eroding as the reformulated gasoline program is implemented. Conventional gasoline must meet the Complex Model II compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[2]

Oxygenated gasoline is assumed to have specifications identical to conventional gasoline, with the exception of a higher oxygen requirement, specifically 2.7 percent oxygen by weight. Some areas that require oxygenated gasoline will also require reformulated gasoline. For the sake of simplicity, the areas of overlap are assumed to require gasoline meeting the reformulated specifications.

Cellulosic biomass feedstock supplies and costs are taken from the NEMS Renewable Fuels Model. Initial capital costs for biomass cellulosic ethanol were obtained from a research project reviewing cost estimates from multiple sources.[3] Operating costs and credits for excess electricity generated at biomass ethanol plants were obtained from a National Renewable Energy Laboratory report[4] and the USDA Agricultural Baseline Projections to 2015.[5]

Table 60. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max PSI)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	2007 Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Conventional							
PADD I	9.6	26.0	1.1	41.7	11.6	47.1	82.0
PADD II	10.2	26.1	1.1	32.2	11.6	47.1	81.9
PADD III	9.9	26.1	1.1	32.4	11.6	47.1	81.9
PADD IV	10.8	26.1	1.1	44.2	11.6	47.1	81.9
PADD V	9.2	26.7	1.1	33.7	11.7	45.7	81.4
Reformulated							
PADD I	8.5	20.7	0.6	30.0	11.9	50.2	84.6
PADD II	9.5	18.5	0.8	30.0	7.1	50.8	85.2
PADD III	8.6	19.8	0.6	30.0	11.2	51.6	83.9
PADD IV	8.6	19.8	0.6	30.0	11.2	51.6	83.9
PADD V							
Nonattainment	7.9	22.0	0.70	20.0	6.0	49.0	90.0
CARB (attainment)	7.9	22.0	0.70	20.0	6.0	49.0	90.0

Max = Maximum.

PADD = Petroleum Administration for Defense District.

PPM = Parts per Million by Weight.

PSI = Pounds per Square Inch.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using U.S. EPA's Complex Model, and updated with U.S. EPA's 2005 gasoline projection survey (http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm).

Table 61. Gasoline Sulfur Content Assumptions, by Region and Gasoline Type, Parts per Million (PPM)

	2004	2005	2006	2007	2008-2030
Conventional					
PADD I	143.4	90.0	43.4	41.7	30
PADD II	111.6	60.0	32.2	32.2	30
PADD III	114.5	60.0	32.4	32.4	30
PADD IV	140.0	90.0	44.2	44.2	30
PADD V	122.8	70.0	33.7	33.7	30
Reformulated					
PADD I-IV	30	30	30	30	30
PADD V	20	20	20	20	20

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-810 "Monthly Refinery Report" and U.S. Environmental Protection Agency, "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control requirements, February 2000, (Washington, DC).

Corn supply prices are estimated from the USDA baseline projections to 2017.[6] The capital cost of a 50-million-gallon-per-year corn ethanol plant was assumed to be $69 million (2006 $). Operating costs of corn ethanol plants are obtained from USDA survey of ethanol plant costs[7]. Energy requirements are obtained from a study of carbon dioxide emissions associated with ethanol production.[8]

Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, the EPA began certifying reformulated gasoline using the "Complex Model," which allows refiners to specify reformulated gasoline based on emissions reductions from their companies' respective 1990 baselines or the EPA's 1990 baseline. The PMM reflects "Phase 2" reformulated gasoline requirements which began in 2000. The PMM uses a set of specifications that meet the "complex Model" requirements, but it does not attempt to determine the optimal specifications that meet the "Complex Model." (Table 62).

Table 62. Market Share for Gasoline Types by Census Division

Gasoline Type/Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Conventional Gasoline	20	43	79	66	82	95	73	70	32
Oxygenated Gasoline (2.7% oxygen)	0	0	0	26	0	0	1	14	2
Reformulated Gasoline	80	57	21	8	17	5	27	15	76*

*Note: 61 percent is assumed to comply with the Federal RFG requirement, 15 percent is the result of State requirements.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption," January-December 2006.

AEO2008 assumes MTBE will be phased out by the end of 2006 as a result of decisions made by the petroleum industry to discontinue MTBE blending with gasoline. Ethanol is assumed to be used in areas where reformulated or oxygenated gasoline is required. Federal reformulated gasoline (RFG) is blended with 10% ethanol; oxygenated gasoline is blended with 10% ethanol; and California Air Resources Board (CARB) RFG is blended with 5.77% ethanol. Ethanol is also allowed to blend into conventional gasoline at up to 10 percent by volume, depending on its blending value and relative cost competitiveness with other gasoline blending components. EISA2007 defines a requirements schedule for having renewable fuels blended into transportation fuels by 2022.

Reid Vapor Pressure (RVP) limitations are effective during summer months, which are defined differently by consuming regions. In addition, different RVP specifications apply within each refining region, or PADD. The PMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summertime RVP limits, wintertime estimates, and seasonal weights.

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, and reformulated gasoline by applying assumptions about the annual market shares for each type. The shares are allowed to change over time based on assumptions regarding the market penetration of new fuels. In *AEO2008,* however, the annual market shares for each region reflect actual 2006 market shares and are held constant throughout the projection. (See Table 63 for *AEO2008* market share assumptions.)

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulphurization regulations related to Clean Air Act Amendment of 1990 (CAAA90), low-sulfur diesel is differentiated from other distillates. In NEMS, Census Division 9 is required to meet CARB standards. Both Federal and CARB standards currently limit sulfur to 15 ppm.

AEO2008 incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The ULSD regulation includes a phase-in period under the "80/20" rule, that requires the production of a minimum 80 percent ULSD for highway use between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. As NEMS produces annual average results, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

Table 63. Petroleum Product End-Use Markups by Sector and Census Division
(2005 dollars per gallon)

Sector/Product	Census Division: New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential Sector									
Distillate Fuel Oil	0.40	0.46	0.31	0.24	0.45	0.41	0.27	0.22	0.31
Kerosene	0.1	0.30	0.10	0.15	0.07	0.07	0.05	0.21	0.14
Liquefied Petroleum Gases	0.91	0.92	0.55	0.35	0.87	0.76	0.81	0.65	0.85
Commercial Sector									
Distillate Fuel Oil	0.14	0.14	0.06	0.03	0.07	0.04	0.07	0.00	0.10
Gasoline	0.10	0.15	0.14	0.1	0.08	0.12	0.12	0.14	0.15
Kerosene	0.1	0.27	0.09	0.15	0.09	0.07	0.00	0.20	0.13
Liquefied Petroleum Gases	0.47	0.57	0.41	0.41	0.50	0.48	0.52	0.51	0.46
Low-Sulfur Residual Fuel Oil	0.32	0.00	0.59	0.4	0.03	0.72	0.10	0.00	0.79
Utility Sector									
Distillate Fuel Oil	-0.23	0.06	-0.10	-0.09	0.00	-0.02	-0.15	0.01	-0.06
High-Sulfur Residual Fuel Oil[1]	-0.07	-0.10	0.00	-0.10	0.00	-0.06	0.00	0.00	0.01
Low-Sulfur Residual Fuel Oil[1]	-0.07	-0.10	0.00	-0.10	0.00	-0.06	0.00	0.00	0.01
Transportation Sector									
Distillate Fuel Oil	0.26	0.20	0.16	0.12	0.15	0.16	0.15	0.13	0.22
E85[2]	0.13	0.17	0.14	0.14	0.11	0.12	0.09	0.14	0.15
Gasoline	0.13	0.17	0.14	0.14	0.1	0.12	0.09	0.14	0.15
High-Sulfur Residual Fuel Oil[1]	-0.01	-0.03	0.15	0.1	0.00	0.23	0.19	0.00	0.29
Jet Fuel	0.03	0.00	-0.01	-0.01	0.07	0.00	-0.03	0.00	0.02
Liquefied Petroleum Gases	0.46	0.48	0.66	0.66	0.53	0.65	0.65	0.60	0.59
Industrial Sector									
Asphalt and Road Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel Oil	0.14	0.11	0.20	0.15	0.12	0.13	0.14	0.03	0.14
Gasoline	0.13	0.16	0.14	0.13	0.11	0.13	0.10	0.14	0.16
Kerosene	-0.01	0.01	0.01	-0.01	0.00	0.05	0.20	0.07	0.00
Liquefied Petroleum Gases	0.46	0.34	0.34	0.34	0.41	0.30	0.10	0.48	0.51
Low-Sulfur Residual Fuel Oil	0.11	0.00	0.20	0.09	0.06	0.21	0.21	-0.19	0.10

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a byproduct when crude oil is refined to make higher value products like gasoline and heating oil.

[2]74 percent ethanol and 26 percent gasoline.

Sources: Markups based on data from Energy Information Administration (EIA), Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*; EIA, Form EIA-782B, *Resellers'/Retailers' Monthly Petroleum Report Product Sales Report*; EIA, Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*; EIA, Form EIA-759 *Monthly Power Plant Report; EIA, State Energy Data Report 2006, Consumption (October 2007); EIA, State Energy Data 2006: Prices and Expenditures* (October 2007).

NEMS models ULSD as containing 7.5 ppm sulfur at the refinery gate in 2006, phasing down to 7ppm sulfur by 2011. This lower sulfur limit at the refinery reflects the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

It is assumed that revamping (retrofitting) existing refinery units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production and that the remaining refineries will build new units. The capital cost of revamping is assumed to be 50 percent of the cost of adding a new unit.

The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 7.8 percent at the start of the program, declining to 2.2 percent at full implementation. The decline reflects the expectation that the distribution system will become more efficient at handling ULSD with experience.

A revenue loss is assumed to occur when a portion of ULSD that is put into the distribution system is contaminated and must be sold as a lower value product. The amount of the revenue loss is estimated offline based on earlier NEMS results and is included in the *AEO2008* ULSD price projections as a distribution cost. The revenue loss associated with the 7.8 percent downgrade assumption for 2008 is 0.7 cents per gallon. The revenue loss estimate declines to 0.2 cents per gallon after 2010 to reflect the assumed decline to 2.2 percent.

The capital and operating costs associated with ULSD distribution are based on assumptions used by the EPA in the Regulatory Impact Analysis (RIA) of the rule.[9] Capital costs of 0.7 cents per gallon are assumed for additional storage tanks needed to handle ULSD during the transition period. These capital expenditures are assumed to be fully amortized by 2011. Additional operating costs for distribution of highway diesel of 0.2 cents per gallon are assumed over the entire projection period. Another 0.2 cent cost per gallon is assumed for lubricity additives. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulphurization process.

Demand for highway-grade diesel, both 500 ppm and ULSD combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway-grade diesel supplies have nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.

The energy content of ULSD is assumed to decline from that of 500 ppm diesel by 0.5 percent because undercutting and severe desulphurization will result in a lighter stream composition than that for 500 ppm diesel.

AEO2008 incorporates the “nonroad, locomotive, and marine” (NRLM) diesel regulation finalized in May 2004. The PMM model has been revised to reflect the nonroad rule and re-calibrated for market shares of highway, NRLM diesel, and other distillate (mostly heating oil, but excluding jet fuel and kerosene). The NRLM diesel rule follows the highway diesel rule closely and represents an incremental tightening of the entire diesel pool. The demand for high sulfur distillate is expected to diminish over time, while the demand for ULSD (both highway and NRLM) is expected to increase over time.

The final NRLM rule is implemented in multiple steps and requires sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 ppm starting mid-2007. It also establishes a new ultra-low-sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the rule establishes an ULSD limit of 15 ppm in mid-2012.

End-Use Product Prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs plus distribution costs and taxes. The marginal costs of production are determined within the LP and represent variable costs of production, including additional costs for meeting reformulated fuels provisions of the CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs are derived from a set of base distribution markups (Table 64).

Table 64. State and Local Taxes on Petroleum Transportation Fuels by Census Division
(2005 dollars per gallon)

Year/Product	Census Division								
	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Gasoline[1]	0.23	0.24	0.22	0.20	0.18	0.19	0.20	0.21	0.21
Diesel	0.24	0.28	0.23	0.21	0.20	0.18	0.19	0.23	0.21
Liquefied Petroleum Gases	0.12	0.12	0.17	0.19	0.18	0.17	0.13	0.14	0.06
E85[2]	0.23	0.24	0.23	0.20	0.18	0.19	0.20	0.21	0.21
Jet Fuel	0.05	0.05	0.00	0.04	0.05	0.05	0.02	0.04	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.

[2] 74 percent ethanol and 26 percent gasoline.

Source: "Compilation of United States Fuel Taxes, Inspection, Fees and Environmental Taxes and Fees," Defense energy support Center, Editions 2006-12, August 17, 2006. Gasoline, diesel and E85 aggregated from Petroleum Marketing Monthly DE/EIA-0380(2005/09), Table EN1, (Washington, DC, September 2005). LPG aggregated from Federal Highway Administration, Tax Rates on Motor Fuel, Jet fuel from EIA, Office of Oil and Gas.

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 65 and 66). Recent tax trend analysis indicates that State taxes increase at the rate of inflation, therefore, State taxes are held constant in real terms throughout the projection. This assumption is extended to local taxes which are assumed to average 2 cents per gallon.[10] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2008* assumption of current laws and regulations. Federal taxes are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Table 65. Federal Taxes
(Nominal dollars per gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases[3]	0.43
M85[1]	0.09
E85[2]	0.19

[1]85 percent methanol and 15 percent gasoline.

[2]74 percent ethanol and 26 percent gasoline.

[3]2010 data-based on EPACT05: excise tax is 4.3 cents/gal after 9-30-2011 and 18.3 cents/gal prior to that. A credit of 50 cents/gal is also applied between 10-1-06 and 9-30-09.

Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34), *Clean Fuels Report* (Washington, DC, April 1998) and Energy Policy Act of 2005 (PL 109-58).

Crude Oil Quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into five categories as defined by the ranges of gravity and sulfur shown in Table 66.

Table 66. Crude Oil Specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	25 - 60
Medium Sulfur Heavy	0.35 - 1.1	26 - 40
High Sulfur Light	> 1.1	>32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.9	< 23

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from EI-810, "Monthly Refinery Report" data.

A "composite" crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. While the domestic and foreign categories are the same, the composite crudes for each category may differ because different crude streams make up the composites. For domestic crude oil, estimates of total regional production are made first, then shared out to each of the five categories based on historical data. For imported crude oil, a separate supply curve is provided for each of the five categories.

Capacity Expansion

PMM allows for capacity expansion of all processing units including distillation, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation manufacturing. Capacity expansion occurs by processing unit, starting from base year capacities established by PADD using historical data.

Expansion occurs in NEMS when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment of about 9 percent. Capacity expansion plans are determined every 3 years. For example, the PMM looks ahead in 2008 and determines the optimal capacities given the estimated demands and prices expected in the 2011 projection year. The PMM then allows any of that capacity to be built in each of the projection years 2009, 2010, and 2011. At the end of 2011 the cycle begins anew, looking ahead to 2014. ACU capacity under construction that is expected to begin operating during by 2010. is added to existing capacities in their respective start year. Capacity expansion is also modeled for corn and cellulosic ethanol, coal-to-liquids, and biomass-to-liquids production.

Biofuels Supply

The PMM provides supply functions on an annual basis through 2030 for ethanol produced from both corn and cellulosic biomass to produce transportation fuel. It also assumes that small amounts of vegetable oil and animal fats are processed into biodiesel, a blend of methyl esters suitable for fueling diesel engines.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.

- Cellulosic (biomass) feedstock supply and costs are provided by the Renewable Fuels Module in NEMS. Cellulosic ethanol production and biomass-to-liquids (BTL) production compete for this feedstock.

- The Federal motor fuels excise tax credit for ethanol is 51 cents per gallon of ethanol (5.1 cents per gallon credit to gasohol at a 10-percent volumetric blending portion) is applied within the model. The tax credit is held constant in nominal terms, decreasing with inflation throughout the projection. It is assumed that the credit expires after 2010.

To model the new Renewable Fuels Standard in EISA07, several assumptions were required. In addition to using the text of the Bill it was also assumed that rules promulgated under the RFS in EPACT05 would govern the administration of the EISA07 RFS.

- The penetration of cellulosic ethanol into the market is limited before 2012 to the projects cosponsored by DOE grants currently scheduled to produce approximately 150 million gallons per year.

- Biomass-to-Liquid (Fischer-Tropsch) diesel fuel production contributes 1.5 credits towards the cellulosic mandate.

- Imported cane ethanol counts toward the advanced renewables mandate. In addition, a limited supply of cellulosic ethanol would be available for import and would count toward the cellulosic mandate.

- The cellulosic biofuel waiver, when activated, reduces the cellulosic, advanced, and total requirement by that amount in all future years. In years beyond 2022, the last year specified in the EISA, the RFS mandate levels are held constant.

- It is assumed that biodiesel and BTL diesel may be consumed in diesel without significant infrastructure modification (either vehicles or delivery infrastructure).

- Ethanol is assumed to be consumed as either E10 or E85, with no intermediate blends. The cost of placing E85 pumps at the most economic stations is spread over all transportation fuels. Using this assumption, the E10 blending market is assumed to be saturated and the E85 market consumes additional ethanol after 2014.

- To accommodate the ethanol requirements in particular, transportation modes are expanded or upgraded for both E10 and E85, and it is assumed that most ethanol originates from the Midwest, with transportation costs ranging from a low of 1.7 cents per gallon for expanded distribution in the Midwest, to as high as 2.6 cents per gallon for the Southeast and West Coast.

- For E85 dispensing stations, it is assumed the average cost of a retrofit and new station is about $45,000 per station, which translates into an incremental cost per gallon ranging from 26 cents in 2013 to 4.4 cents by 2020, depending on the average sales per dispenser.

- The total projected incremental infrastructure cost (transportation, distribution, dispensing) for E85 varies from 27 cents per gallon in 2013 to 6 cents per gallon in 2020.

Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in PMM. A subsidy is offered by the Department of Agriculture's Commodity Credit Corporation for the production of biodiesel. In addition, the American Jobs Creation Act of 2004 provides an additional tax credit of $1 per gallon of soybean oil for biodiesel and 50 cents per gallon for yellow grease biodiesel until 2006, and EPACT05 extends the credit again to 2008.

Gas-To-Liquids, Coal-To-Liquids, Biomass-To-Liquids, and Gasification Technologies

Gas-to-liquids (GTL) facilities convert natural gas into distillates, and are assumed to be built if the prices for lower sulfur distillates reach a high enough level to make it economic. In the PMM, gas-to-liquids facilities are assumed to be built only on the North Slope of Alaska, where the distillate product is transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. Given estimates showing that GTL technology is a less profitable means for monetizing the natural gas on the North Slope relative to an Alaska pipeline to the lower-48 states, the earliest start date for a GTL facility is set at 2015. Also, the source of feedstock gas to any GTL facility in Alaska is assumed to be from undiscovered, non-associated resources which will be more costly than the current, largely associated proved reserves on the North Slope (assumed dedicated to the pipeline). The GTL facilities are built incrementally, with output volumes of 50,000 barrels per day, at a cost of $49,100 per barrel of daily capacity (2006 dollars). Operating costs are assumed to be $4.55 per barrel (2006 dollars). The transportation cost to ship the GTL product from the North Slope to Valdez along the TAPS is assumed to be the price set to move oil (i.e. the TAPS revenue recovery rate). This rate is a function of allowable costs, profit, and flow, and can change over the projection.

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high enough to make them economic. One CTL facility is capable of processing 21,800 tons of bituminous coal per day, with a production capacity of 50,000 barrels of synthetic fuels per day and 200 megawatts of capacity for electricity cogeneration sold to the grid.[11] A CTL facility of this size is assumed to cost over $3.6 billion in initial capital investment (2006 dollars). CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). It is assumed that CTL facilities can only be built after 2010.

Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum resid, etc.) is represented in *AEO2008*. The PMM assumes petcoke to be the primary feedstock for gasification, which in turn could be converted to either combined heat and power (CHP) or hydrogen production based on refinery economics. A typical gasification facility is assumed to have a capacity of 2,000 ton-per-day (TPD) which includes the main gasifier and other integrated units in the refinery such as air separation unit (ASU), syngas clean-up, sulfur recovery unit (SRU), and two downstream process options - CHP or hydrogen production. Currently, there is more than 5,000 TPD gasification capacity in the Nation, producing CHP and hydrogen. Additional gasification capacity is projected to be built in the *AEO2008* projection, primarily for CHP production.

Combined Heat and Power (CHP)

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery CHP, and merchant CHP. Power generators and CHP plants are modeled in the PMM linear program as separate units which are allowed to compete along with purchased electricity. Both the refinery and merchant CHP units provide estimates of capacity, fuel consumption, and electricity sales to the grid based on historical parameters.

Refinery sales to the grid are estimated using the following percentages which are based on 2005 data:

Region	Percent Sold To Grid
PADD I	67.0
PADD II	0.9
PADD III	2.2
PADD IV	0.9
PADDV	45.4

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived using EIA-860B, “Annual Electric Generators Report-Nonutility”.

The PMM sells electricity back to the grid in these percentages at a price equal to the average wholesale price of electricity in each PMM region.

Merchant CHP plants are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. These sales occur at a price equal to the average wholesale price of electricity in each PMM region. Electricity prices are obtained from the Electricity Market Model.

Short-term Methodology

Petroleum balance and price information for 2007 are projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM adopts the *STEO* results for 2007, using regional estimates derived from the national *STEO* projections.

Legislation and Regulations

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the Federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and reduced-sulfur (500 ppm) on-highway diesel fuel. These are explicitly modeled in the PMM. Reformulated gasoline represented in the PMM meets the requirements of phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2008 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased-down to 30 ppm between the years 2004 and 2007. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2008 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements finalized by the EPA in December 2000. Between June 2006 and June 2010, this regulation requires that 80 percent of highway diesel supplies contain no more than 15 ppm sulfur while the remaining 20 percent of highway diesel supplies contain no more than 500 ppm sulfur. After June 2010, all highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2008 reflects nonroad locomotive and marine (NRLM) diesel requirements finalized by the EPA in May 2004. Between June 2007 and June 2010, this regulation requires that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

AEO2008 incorporates the American Jobs Creation Act of 2004 to extend the Federal tax credit of 51 cents per gallon of ethanol blended into gasoline through 2010.

AEO2008 represents major provisions in the Energy Policy Act of 2005 concerning the petroleum industry, including: 1) removal of oxygenate requirement in RFG; and 2) extension of tax credit of $1 per gallon for soybean oil biodiesel and $0.50 per gallon for yellow grease biodiesel through 2008.

AEO2008 includes provisions outlined in the Energy Independence and Security Act of 2007 concerning the petroleum industry, including a renewable Fuels Standard increasing total U.S. consumption of renewable fuels. Although the statute calls for higher levels, due to uncertainty about wheter the new RFS schedule can be achieved and the stated mechanisms for reducing the cellulosic biofuel schedule the final schedules in PMM were assumed to be: 1) 32.5 billion gallons in 2022 for all fuels; 2) 17.5 billion gallons in 2022 for advanced biofuels; 3) 12.5 billion gallons in 2022 for cellulosic biofuel; 4) 1 billion gallons of biodiesel by 2022.

Notes and Sources

[1] U.S. Environmental Protection Agency, “Tier 2” Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, February 2000, (Washington, DC).

[2] Federal Register, Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800, (Washington, DC, February 1994).

[3] Marano, John, "Alternative Fuels Technology Profile: Cellulosic Ethanol", March 2008.

[4] McAloon, Andrew; Taylor, Frank; Yee, Winnie; Ibsen, Kelly; and Wooley, Robert. "Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks," October 2000.

[5] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2017," February 2008, http://www.ers.usda.gov/publications/oce081.

[6] Ibid

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Coal Market Module

The NEMS Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, *Coal Market Module of the National Energy Modeling System 2008,* DOE/EIA-M060(2008) (Washington, DC, 2008*).*

Key Assumptions

Coal Production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the projection. Forty separate supply curves are developed for each of 14 supply regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, and the cost of factor inputs (labor and fuel).

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.

- Between 1980 and 1999, U.S. coal mining productivity increased at an average rate of 6.7 percent per year from 1.93 to 6.61 tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining.[1] Since 1999, however, growth in overall U.S. coal mining productivity has slowed substantially, decreasing at a rate of 0.8 percent per year to 6.26 tons per miner hour in 2006. By region, productivity in most of the coal producing basins represented in the CMM has remained essentially constant during the past 5 years. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by a significant 28 percent between 1999 and 2006, corresponding to an average decline of 4.6 percent per year.

  Over the projection period, labor productivity is expected to remain near current levels in most coal supply regions, reflecting the trend of the previous five years. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

  In the CMM, different rates of productivity improvement are assumed for each of the 40 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies.[2] Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report" and the Energy Information Administration's Form EIA-7A, *Coal Production Report*. In the reference case, overall U.S. coal mining labor productivity increases at rate of 0.6 percent a year between 2006 and 2030. Reference case projections of coal mining productivity by region are provided in Table 67.

- In the *AEO2008* scenarios, both the wage rate for U.S. coal miners and mine equipment costs are assumed to remain constant in 2006 dollars (i.e., increase at the general rate of inflation) over the projection period. This assumption primarily reflects the recent trends in these cost variables.

Coal Distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 10) and 14 demand regions (Figure 11) for 49 demand subsectors.

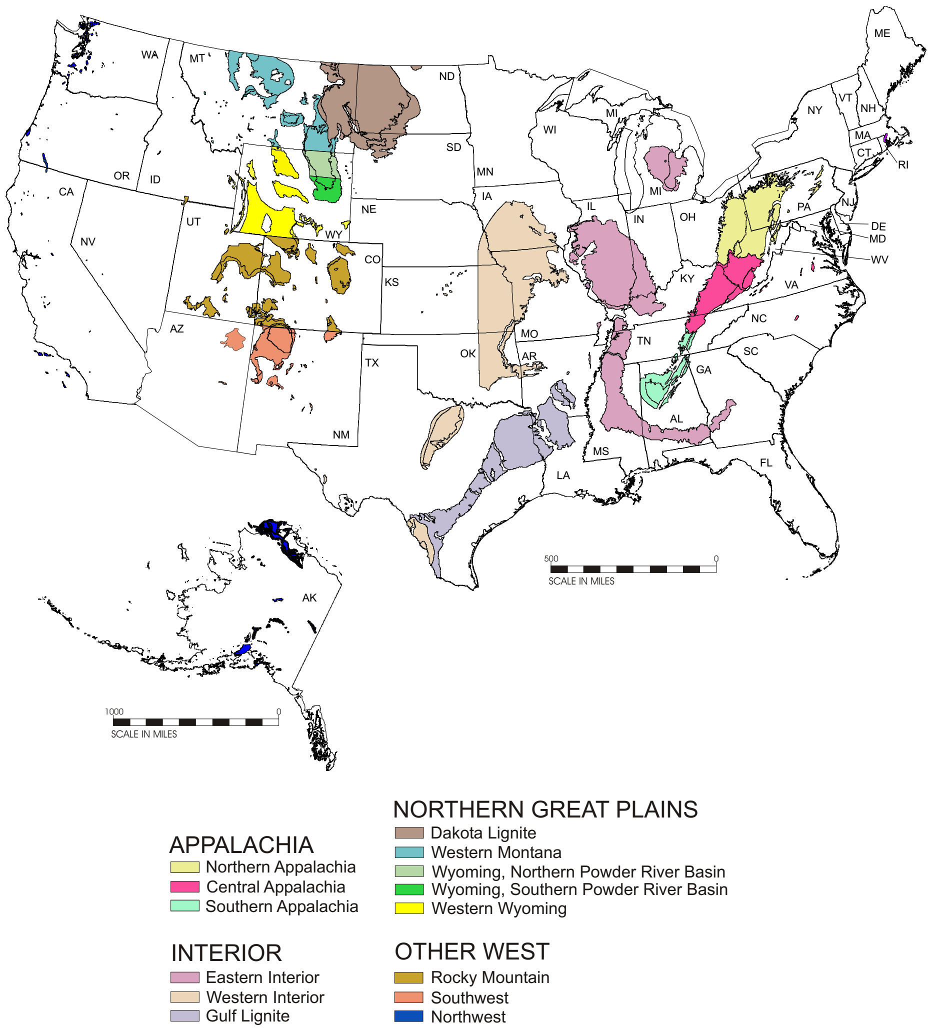
The projected levels of coal-to-liquids, industrial steam, coking, and residential/commercial coal demand are provided by the petroleum market, industrial, commercial, and residential demand modules, respectively; electricity coal demands are projected by the EMM; coal imports and coal exports are projected by the CMM based on non-U.S. coal supply availability, endogenously determined U.S. import demand, and exogenously determined world coal demand (non-U.S.).

Table 67. Coal Mining Productivity by Region
(Short Tons per Miner Hour)

Supply Region	2006	2010	2015	2020	2025	2030	Average Annual Growth 06-30
Northern Appalachia	4.02	3.86	4.00	4.07	4.10	4.12	0.1%
Central Appalachia	2.89	2.65	2.61	2.48	2.40	2.31	-0.9%
Southern Appalachia	2.02	1.91	1.80	1.70	1.64	1.59	-1.0%
Eastern Interior	4.17	4.22	4.32	4.35	4.38	4.37	0.2%
Western Interior	3.35	3.35	3.35	3.35	3.35	3.35	0.0%
Gulf Lignite	9.67	9.51	9.27	9.04	8.82	8.60	-0.5%
Dakota Lignite	17.00	17.26	17.69	18.14	18.60	19.07	0.5%
Western Montana	22.05	22.11	22.67	23.25	19.42	18.69	-0.7%
Wyoming, Northern Power River Basin	38.38	36.26	36.85	37.25	37.59	37.78	-0.1%
Wyoming, Southern Power River Basin	40.99	38.53	38.23	37.77	37.17	36.43	-0.5%
Western Wyoming	8.76	7.95	8.03	8.31	8.44	8.62	-0.1%
Rocky Mountain	7.06	6.70	6.84	6.96	7.07	7.15	0.1%
Arizona/New Mexico	8.38	8.46	8.57	8.65	8.71	8.76	0.2%
Alaska/ Washington	2.69	2.69	2.69	2.69	2.69	2.69	0.0%
U.S. Average	6.26	6.08	6.71	6.99	7.18	7.25	0.6%

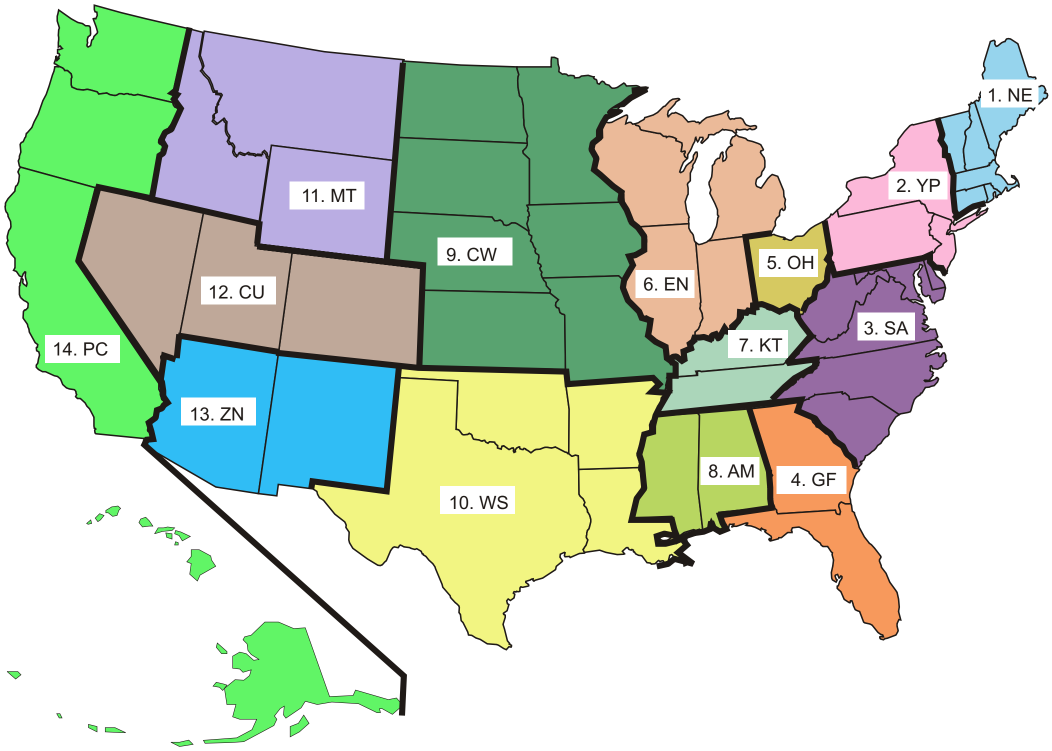
Source: Energy Information Administration, AEO2008 National Energy Modeling System run AEO2008.D030208f.

Figure 10. Coal Supply Regions



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

Figure 11. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

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

The key assumptions underlying the coal distribution modeling are:

- Base-year (2006) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, *Quarterly Coal Consumption Report-Manufacturing Plants*, Form EIA-5, *Quarterly Coke Consumption* and *Quality Report, Coke Plants*, Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*, Federal Energy Regulatory Commission (FERC) Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and the U.S. Bureau of the Census' Monthly Report EM-545. Minemouth price data are from Form EIA-7A, *Coal Production Report*.

- For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars).[3]

- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices are measures of the change in average transportation rates, on a tonnage basis, that occurs between successive years for rail and multi-mode coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The indices are calculated econometrically as a function of railroad productivity, the user cost of capital of railroad equipment, average contract duration, and average distance (west only). Although the indices are derived from railroad information, they are universally applied to all domestic coal transportation movements within the CMM. In the *AEO2008* reference case, eastern coal transportation rates are projected to be 1 percent higher in 2030 and western rates are projected to be 2 percent higher in 2030 compared to 2006.

  Railroad productivity, measured in freight ton-miles per employee per year, is expected to increase at an average rate of 2.9 percent per year for the east and 1.8 percent per year for the west from 2006. The user cost of capital for railroad equipment is calculated from the PPI for railroad equipment, projected exogenously to remain flat in real terms, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. Contract duration is held constant at 2001 levels over the projection reflecting the assumption that new contracts will continue to be, on average, less than 5 years in length. For the west, distance is held constant over the projection reflecting that distance is already implicitly accounted for in the model by using the origin-destination pair transportation rate structure. The transportation rate indices for seven *AEO2008* cases are shown in Table 68.

Table 68. Transportation Rate Multipliers
(Constant Dollar Index, 2006=1.000)

Scenario	Region:	2006	2010	2015	2020	2025	2030
Reference Case	East	1.000	1.0450	1.0308	1.0183	1.0094	1.0055
	West	1.000	1.0396	1.0311	1.0242	1.0194	1.0180
High Resource Price	East	1.000	1.0477	1.0308	1.0194	1.0146	1.0116
	West	1.000	1.0415	1.0311	1.0250	1.0233	1.0226
Low Resource Price	East	1.000	1.0437	1.0306	1.0178	1.0067	1.0023
	West	1.000	1.0386	1.0309	1.0238	1.0174	1.0156
High Economic Growth	East	1.000	1.0448	1.0337	1.0265	1.0219	1.0223
	West	1.000	1.0394	1.0332	1.0303	1.0287	1.0306
Low Economic Growth	East	1.000	1.0451	1.0279	1.0111	0.9985	0.9910
	West	1.000	1.0396	1.0289	1.0188	1.0112	1.0071
High Coal Cost	East	1.000	1.0439	1.0484	1.0548	1.0642	1.0796
	West	1.000	1.0393	1.0454	1.0534	1.0630	1.0767
Low Coal Cost	East	1.000	1.0452	1.0127	0.9830	0.9573	0.9360
	West	1.000	1.0391	1.0163	0.9958	0.9776	0.9622

Source: Projections: Energy Information Administration, National Energy Modeling System runs AEO2008.D030208f, HP2008.D031809a, LP2008.D031608a, HM2008.D031608a, LM2008.D031608a, HCCST08.D030508a, and LCCST08.D030508a. Based on methodology described in *Coal Market Module of the National Energy Modeling System, Model Documentation 2008*, DOE/EIA-060(2008), (Washington, DC, 2008).

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, has recommended that the railroads agree to develop some consistencies among their disparate programs and has likewise recommended closely linking the charges to actual fuel use. The STB has cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.

  For *AEO2008*, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on BNSF Railway Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100 percent of all coal shipments are subject to the surcharge program.

- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2006) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by electric utilities on FERC Form 423, *Monthly Report of Cost and Quality of Fuels for Electric Plants*, and by nonutility generators on Form EIA-423, *Monthly Cost and Quality of Fuels for Electric Plants Report*. Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data reported by electric utilities on FERC Form 580, "Interrogatory on Fuel and Energy Purchase Practices," historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.

- Electric generation demand received by the CMM is subdivided into "coal groups" representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting emissions requirements. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

- Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 652 MW and the capability of producing 50,000 barrels of liquid fuel per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 46 percent of the energy input is retained in the product with the remaining energy used for conversion (38 percent) and for the production of power sold to the grid (17 percent).

Coal Imports and Exports

Coal imports and exports are modeled as part of the CMM's linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

- The coal market is competitive. In other words, no large suppliers or groups of producers are able to influence the price through adjusting their output. Producers' decisions on how much and who they supply are driven by their costs, rather than prices being set by perceptions of what the market can bear. In this situation, the buyer gains the full consumer surplus.

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.

- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal trade modeling:

- U.S. coal exports are determined, in part, by the projected level of world coal import demand. World steam and metallurgical coal import demands for the *AEO2008* cases are shown in Tables 69 and 70.

- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.

- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account maximum vessel sizes that can be handled at export and import piers and through canals and reflect route distances in thousands of nautical miles.

Coal Quality

Each year the values of base year coal production, heat, sulfur and mercury (Hg) content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the FERC Form 423, a survey of the origin, cost and quality of fossil fuels delivered to electric utilities, the Form EIA 423, a survey of the origin, cost and quality of fossil fuels delivered to non-utility generating facilities, the Form EIA-5 which records the origin, cost, and quality of coal receipts at domestic coke plants, and the Form EIA 3, which records the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Hg content data for coal by supply region and coal type, in units of pounds of Hg per trillion Btu, shown in Table 71, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. The database included approximately 40,500 Hg samples reported for 1,143 generating units located at 464 coal-fired facilities. Carbon dioxide emission factors for each coal type are shown in Table 71 in pounds of carbon dioxide emitted per million Btu.[4]

The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

Table 69. World Steam Coal Import Demand by Import Region
(Million metric tons of coal equivalent)

Import Regions[1]	2006[2]	2010	2015	2020	2025	2030
The Americas	56.1	60.5	62.2	95.8	107.4	126.1
United States[3]	27.4	29.9	33.8	65.2	75.7	93.0
Canada	14.0	13.6	9.7	9.1	9.9	10.3
Mexico	5.7	7.1	8.5	9.4	9.4	9.4
South America	9.0	9.9	10.2	12.1	12.4	13.4
Europe	169.2	168.8	166.5	164.1	159.1	154.7
Scandinavia	10.8	10.1	7.8	6.4	5.7	4.9
U.K/Ireland	41.7	34.2	33.0	32.2	31.7	30.8
Germany/Austria	26.5	26.5	27.8	27.5	26.6	25.6
Other NW Europe	23.7	19.6	17.7	16.7	14.7	13.8
Iberia	23.2	22.5	21.2	20.1	18.8	17.3
Italy	14.2	23.0	24.8	26.6	26.6	26.6
Med/E Europe	29.1	32.9	34.2	34.6	35.0	35.7
Asia	283.9	320.7	350.0	386.3	409.7	429.9
Japan	87.8	86.0	86.0	86.0	86.0	86.0
East Asia	104.2	103.2	110.4	121.8	128.5	139.5
China/Hong Kong	40.8	64.9	74.6	87.4	92.9	94.7
ASEAN	24.1	31.7	39.8	48.5	57.2	63.2
Indian Sub	27.0	34.9	39.2	42.6	45.1	46.5
Total	509.2	550.0	578.7	646.2	676.2	710.7

[1]Import Regions: **South America:** Argentina, Brazil, Chile, Puerto Rico; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2]The base year of the world trade projection for coal is 2006.

[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.

Notes: One “metric ton of coal equivalent” contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Table 70. World Metallurgical Coal Import Demand by Import Region
(Million metric tons of coal equivalent)

Import Regions[1]	2006[2]	2010	2015	2020	2025	2030
The Americas	20.8	25.5	27.4	28.9	31.7	36.1
United States	1.3	1.3	1.3	1.3	1.3	1.3
Canada	4.6	3.6	3.5	3.3	3.2	3.0
Mexico	1.0	1.1	2.3	2.3	3.4	3.4
South America	13.9	19.5	20.3	21.9	23.8	28.4
Europe	57.7	52.1	49.5	53.0	54.2	55.8
Scandinavia	2.9	2.5	2.0	1.9	1.6	1.3
U.K/Ireland	8.8	7.2	7.2	7.2	7.2	7.2
Germany/Austria	9.0	7.5	6.5	6.5	6.5	6.5
Other NW Europe	14.5	14.2	13.1	12.0	11.5	11.6
Iberia	4.4	3.9	3.8	3.8	3.8	3.8
Italy	8.3	6.2	5.6	5.6	5.6	5.6
Med/E Europe	9.8	10.6	11.3	16.0	18.0	19.8
Asia	124.3	143.6	160.3	170.2	180.5	190.8
Japan	74.5	84.5	84.0	81.1	78.9	78.1
East Asia	27.3	27.7	27.8	29.1	32.2	33.2
China/Hong Kong	3.5	6.1	19.2	27.6	34.5	42.2
ASEAN	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	19.0	25.3	29.3	32.4	34.9	37.3
Total	202.8	221.2	237.2	252.1	266.4	282.7

[1]Import Regions: **South America:** Argentina, Brazil, Chile, Puerto Rico; **Scandinavia:** Denmark, Finland, Norway, Sweden; **Other NW Europe:** Belgium, France, Luxembourg, Netherlands; **Iberia:** Portugal, Spain; **Med/E Europe:** Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; **East Asia:** North Korea, South Korea, Taiwan; **ASEAN:** Malaysia, Philippines, Thailand; **Indian Sub:** Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2] The base year of the world trade projection for coal is 2006.

Notes: One “metric ton of coal equivalent” contains 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

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

Table 71. Production, Heat Content, and Sulfur, Mercury and Carbon Dioxide Emission Factors by Coal Type and Region

Coal Supply Region	Coal Rank and Sulfur Level	Mine Type	2006 Production (Million Short tons)	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds Per Trillion Btu)	CO_2 (Pounds Per Million Btu)
Northern Appalachia	Metallurgical	Underground	3.4	26.27	0.68	N/A	207.5
	Mid-Sulfur Bituminous	All	66.8	25.24	1.28	11.17	207.5
	High-Sulfur Bituminous	All	66.2	24.84	2.49	11.67	205.7
	Waste Coal (Gob and Culm)	Surface	13.6	12.70	2.82	63.9	205.7
Central Appalachia	Metallurgical	Underground	38.3	26.27	0.62	N/A	205.9
	Low-Sulfur Bituminous	All	44.9	24.84	0.55	5.61	205.9
	Mid-Sulfur Bituminous	All	153.4	24.74	0.86	7.58	205.9
Southern Appalachia	Metallurgical	Underground	7.4	26.27	0.51	N/A	205.4
	Low-Sulfur Bituminous	All	0.2	24.84	0.50	3.87	205.4
	Mid-Sulfur Bituminous	All	11.4	24.85	1.21	10.15	205.4
East Interior	Mid-Sulfur Bituminous	All	26.4	22.26	1.06	5.6	204.9
	High-Sulfur Bituminous	All	68.7	22.85	2.67	6.35	204.7
	Mid-Sulfur Lignite	Surface	3.8	10.23	0.94	14.11	213.5
West Interior	High-Sulfur Bituminous	Surface	2.8	22.66	2.42	21.55	204.4
Gulf Lignite	Mid-Sulfur Lignite	Surface	33.4	13.38	1.29	14.11	213.5
	High-Sulfur Lignite	Surface	16.3	12.57	2.40	15.28	213.5
Dakota Lignite	Mid-Sulfur Lignite	Surface	30.8	13.26	1.07	8.38	218.8
Western Montana	Low-Sulfur Subbituminous	Underground	0.3	20.03	0.58	5.06	209.6
	Low-Sulfur Subbituminous	Surface	22.5	18.72	0.37	5.06	213.5
	Mid-Sulfur Subbituminous	Surface	18.7	17.19	0.79	5.47	213.5
Northern Wyoming	Low-Sulfur Subbituminous	Surface	172.0	16.88	0.39	7.08	212.7
	Mid-Sulfur Subbituminous	Surface	4.0	16.27	0.83	7.55	212.7
Southern Wyoming	Low-Sulfur Subbituminous	Surface	255.1	17.66	0.31	5.22	212.7
Western Wyoming	Low-Sulfur Subbituminous	Underground	0.5	18.53	0.63	2.19	206.5
	Low-Sulfur Subbituminous	Surface	3.2	18.88	0.50	4.06	212.7
	Mid-Sulfur Subbituminous	Surface	11.9	19.00	0.77	4.35	212.7
Rocky Mountain	Low-Sulfur Bituminous	Underground	52.7	22.95	0.51	3.82	205.1
	Low-Sulfur Subbituminous	Surface	9.7	20.70	0.41	2.04	212.7
Southwest	Low-Sulfur Bituminous	Surface	13.0	20.89	0.47	4.66	207.5
	Mid-Sulfur Subbituminous	Surface	14.1	18.09	0.95	7.18	208.8
	Mid-Sulfur Bituminous	Underground	7.0	19.52	0.70	7.18	208.8
Northwest	Mid-Sulfur Subbituminous	Surface	4.0	15.61	0.95	6.99	210.0

N/A = not available.

Source: Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption Report—Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report—Annual"; Form EIA-7A, "Coal Production Report", and Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report." Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, *Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort* (Research Triangle Park, NC, 1999). B.D. Hong and E.R. Slatick, "Carbon Dioxide Emission Factors for Coal," in Energy Information Administration, *Quarterly Coal Report*, January-March 1994, DOE/EIA-0121 (94/Q1) (Washington, DC, August 1995).

Legislation and Regulations

The *AEO2008* reference case incorporates provisions of the Clean Air Act Amendments of 1990 as they apply to sulfur dioxide and nitrogen oxide emissions. EPA finalized the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR) in March 2005, and both are represented in the reference case. For affected states, CAIR further restricts emissions of sulfur dioxide beginning in 2010 to 3.6 million tons and nitrogen oxides beginning in 2009 to 1.5 million tons. Beginning in 2015, for affected states, tighter emission limits for sulfur dioxide (2.5 million tons) and nitrogen oxides (1.3 million tons) are required in Phase 2 of CAIR. A nationwide cap for mercury of 38 tons per year beginning in 2010 and then 15 tons per year beginning in 2018 are specified in CAMR. The reference case excludes any potential environmental actions not currently mandated such as carbon dioxide reductions or other rules or regulations not finalized.

Coal Alternative Cases

Coal Cost Cases

In the reference case, coal mine labor productivity is assumed to increase on average by 0.6 percent per year through 2030 while miner wage rates and mine equipment costs remain constant in 2006 dollars. Eastern and western railroad productivity is assumed to grow at an average rate of 2.9 and 1.8 percent respectively from 2006. Railroad equipment costs are assumed to remain flat in real terms from 2006 levels. In two alternative coal cost cases, productivity, average miner wages, and equipment cost assumptions were modified for 2009 through 2030 in order to examine the impacts on U.S. coal supply, demand, distribution and prices.

In the low mining cost case, coal mine labor productivity is assumed to increase at an average rate of 3.7 percent per year through 2030. Miner wages are assumed to decline in constant dollars by 1.0 percent per year. Mine equipment costs and railroad equipment costs are projected to fall by 1.0 percent. In the low mining cost case, eastern and western railroad productivity is assumed to grow at an average rate of 5.3 and 4.2 percent, respectively from 2006.

In the high mining cost case, coal mine labor productivity is assumed to decline at an average rate of 3.0 percent per year through 2030. Miner wages are assumed to increase in constant dollars by 1.0 percent per year. Mine equipment costs and railroad equipment costs are projected to increase by 1.0 percent. In the high mining cost case, eastern railroad productivity is assumed to increase by 0.5 percent per year and western railroad productivity is assumed to decrease by 0.6 percent per year from 2006.

For the coal cost cases, adjustments to the reference case coal mining and railroad productivity assumptions were based on variations in growth rates observed in the data for these industries since 1980. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

Notes and Sources

[1] Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559, (Washington, DC, November 1992).

[2] Stanley C. Suboleski, et.al., Central Appalachia: Coal Mine Productivity and Expansion, Electric Power Research Institute, EPRI IE-7117, (September 1991).

[3] The estimated cost of switching to subbituminous coal, $0.10 per million Btu (2000 dollars), was derived by Energy Ventures Analysis, Inc. and was recommended for use in the CMM as part of an Independent Expert Review of the Annual Energy Outlook 2002's Powder River Basin production and transportation rates. Barbaro, Ralph and Seth Schwartz. *Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal*, prepared for the Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002)

[4] Hong, B.D. and Slatick, E.R. “Carbon Dioxide Emission Factors for Coal,” Energy Information Administration, Quarterly Coal Report, January-March 1994, DOE/EIA-121 (94/Q1) (Washington, DC, August 1995).

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Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for projections of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has seven submodules representing various renewable energy sources, biomass, geothermal, conventional hydroelectricity, landfill gas, solar thermal, solar photovoltaics, and wind[1].

Some renewables, such as landfill gas (LFG) from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as water, wind, and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Renewable technologies cover the gamut of commercial market penetration, from hydroelectric power, which was one of the first electric generation technologies, to newer power systems using biomass, geothermal, LFG, solar, and wind energy. In some cases, they require technological innovation to become cost effective or have inherent characteristics, such as intermittency, which make their penetration into the electricity grid dependent upon new methods for integration within utility system plans or upon the availability of low-cost energy storage systems.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent upon the EMM.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Combined Heat and Power descriptions in the “Commercial Demand Module” section of the report.

Key Assumptions

Nonelectric Renewable Energy Uses

In addition to projections for renewable energy used in central station electricity generation, the *AEO2008* contains projections of nonelectric renewable energy uses for industrial and residential wood consumption, solar residential and commercial hot water heating, biofuels blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for their projections are found in the residential, commercial, industrial, and petroleum marketing sections of this report. Additional minor renewable energy applications occurring outside energy markets, such as direct solar thermal industrial applications or direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (e.g., district heating and greenhouses) are not included in the projections.

Electric Power Generation

The RFM considers only grid-connected central station electricity generation systems. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, conventional hydroelectricity, landfill gas, solar (thermal and photovoltaic), and wind submodules, which provide specific data or estimates that characterize that resource. A set of technology cost and performance values is provided directly to the EMM and are central to the build and dispatch decisions of the EMM. The technology cost and performance values are summarized in Table 38 in the chapter discussing the EMM. Overnight capital costs are presented in Table 72 and the assumed capacity factors for new plants in Table 73.

Table 72. Overnight Capital Cost Characteristics for Renewable Energy Generating Technologies in Three Cases (2006$/kW)

Technology	Year	Reference	High Cost Renewable[1]	Low Cost Renewable
Geothermal[2]	2010	1,126	1,149	1,093
	2020	3,231	3,511	3,031
	2030	3,122	3,647	2,808
Hydroelectric[2,]	2010	1,769	1,784	1,716
	2020	1,644	1,782	1,631
	2030	1,575	1,782	1,475
Landfill Gas	2010	1,881	1,897	1,881
	2020	1,828	1,897	1,828
	2030	1,776	1,897	1,776
Photovoltaic[3]	2010	4,915	5,084	4,825
	2020	4,331	5,084	4,077
	2030	3,681	5,084	3,397
Solar Thermal[3]	2010	3.004	3,370	2,941
	2020	2,524	3,370	2,337
	2030	2,149	3,370	1,888
Biomass[4]	2010	2,758	2,783	2,698
	2020	2,482	2,647	2,301
	2030	2,224	2,487	1,929
Offshore Wind	2010	2,812	2,872	2,808
	2020	2,641	2,872	2,621
	2030	2,473	2,872	2,452
Onshore Wind	2010	1,707	1,721	1,702
	2020	1,693	1,721	1,669
	2030	1,683	1,721	1,656

[1]Overnight capital cost (that is, excluding interest charges), plus contingency, learning, and technological optimism factors, excluding regional multipliers. 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. This is particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur.

[2]Geothermal and Hydroelectric costs are specific for each site. The table entries represent the least cost unit available in the specified year in the Northwest Power Pool region. In the 2006 Renewables cases, costs vary as different sites continue to be developed.

[3]Costs decline slightly in the Low Renewable case for photovoltaic and solar thermal technologies as technological optimism is factored into initial costs (see pg. 72 in the chapter discussing the EMM). However, there is no learning-by-doing assumed once the optimism factor has been removed.

[4]Biomass plants share significant components with similar coal-fired plants, these components continue to decline in cost in the Low Renewables case, although biomass-specific components (especially fuel handling components) do not see cost declines beyond 2005.

Source: AEO2008 National Energy Modeling System runs AEO2008.D030208F, HIRENCST.D030408A, and LORENCST.D030408A.

Table 73. Capacity Factors[1] for Renewable Energy Generating Technologies in Three Cases

Technology	Year	Reference	High Renewable Cost	Low Renewable Cost
Geothermal[2]	2010	0.90	0.90	0.90
	2020	0.90	0.90	0.90
	2030	0.90	0.90	0.90
Hydrolectric[2]	2010	0.64	0.64	0.64
	2020	0.50	0.51	0.57
	2030	0.49	0.51	0.54
Landfill Gas	2010	0.90	0.90	0.90
	2020	0.90	0.90	0.90
	2030	0.90	0.90	0.90
Photovoltaic	2010	0.21	0.21	0.21
	2020	0.21	0.21	0.21
	2030	0.21	0.21	0.21
Solar Thermal	2010	0.31	0.31	0.31
	2020	0.31	0.31	0.31
	2030	0.31	0.31	0.31
Biomass	2010	0.83	0.83	0.83
	2020	0.83	0.83	0.83
	2030	0.83	0.83	0.83
Offshore Wind[3]	2010	0.40	0.40	0.46
	2020	0.40	0.40	0.46
	2030	0.40	0.40	0.46
Onshore Wind[3]	2010	0.43	0.42	0.44
	2020	0.45	0.42	0.48
	2030	0.45	0.42	0.50

[1]Capacity factor for units available to be built in specified year. Capacity factor represents maximum expected annual power output as a fraction of theoretical output if plant were operated at rated capacity for a full year.

[2]Hydroelectric capacity factors are specific for each site. The table entries represent the least-cost unit available in the specified year in the Northwest Power Pool region.

[3]Wind capacity factors are based on regional resource availability and generation characteristics. The table entries represent the least-cost resource available in the specified year in the Northwest Power Pool region.

Source: AEO2008 National Energy Modeling System runs: AEO2008.D030208F, HIRENCST.D030408A, and LORENCST.D030408A.

Capital Costs

Capital costs for renewable technologies are affected by several factors. Capital costs for technology to exploit some resources, especially geothermal, hydroelectric, and wind power resources, are assumed to be dependent on the quality, accessibility, and/or other site-specific factors in the areas with exploitable resources. These factors can include additional costs associated with reduced resource quality; need to build or upgrade transmission capacity from remote resource areas to load centers; or local impediments to permitting, equipment transport, and construction in good resource areas due to siting issues, inadequate infrastructure, or rough terrain.

Short-term cost adjustment factors increase technology capital costs as a result of a rapid U.S. buildup in a single year, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise) to accommodate unexpected demand growth. These factors, which are applied to all new electric generation capacity, are a function of past production rates and are further described in *The Electricity Market Module of the National Energy Modeling System: Model Documentation Report*, available at http://www.eia.doe.gov/bookshelf/docs.html.

Independent of the other two factors, capital costs for all electric generation technologies, including renewable technologies, are assumed to decline as a function of growth in installed capacity for each technology.

For a description of NEMS algorithms lowering generating technologies' capital costs as more units enter service (learning), see "Technological Optimism and Learning" in the EMM chapter of this report. A detailed description of the RFM is provided in the EIA publication, *Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2005*, DOE/EIA-M069(2005) (Washington, DC, 2005).

Solar Electric Submodule

Background

The Solar Electric Submodule currently includes both concentrating solar power (thermal) and photovoltaics, including two solar technologies: 50 megawatt central receiver (power tower) solar thermal (ST) and 5 megawatt single axis tracking-flat plate photovoltaic (PV) technologies. PV is assumed available in all thirteen EMM regions, while ST is available only in the six Western regions where direct normal solar insolation is sufficient. Capital costs for both technologies are determined by EIA using multiple sources, including public reports of recent solar thermal capcity additions. Most other cost and performance characteristics for ST are obtained or derived from the August 6, 1993, California Energy Commission memorandum, *Technology Characterization for ER 94*; and, for PV, from the Electric Power Research Institute, *Technical Assessment Guide (TAG) 1993*. In addition, capacity factors are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- Capacity factors for solar technologies are assumed to vary by time of day and season of the year, such that nine separate capacity factors are provided for each modeled region, three for time of day and for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages. The current reference case solar thermal annual capacity factor for California, for example, is assumed to average 40 percent; California's current reference case PV capacity factor is assumed to average 24.6 percent.

- Because solar technologies are more expensive than other utility grid-connected technologies, early penetration will be driven by broader economic decisions such as the desire to become familiar with a new technology, environmental considerations, and the availability of limited Federal subsidies. Minimal early years' penetration is included by EIA as "floor" additions to new generating capacity (see "Supplemental and Floor Capacity Additions" below).

- Solar resources are well in excess of conceivable demand for new capacity; energy supplies are considered unlimited within regions (at specified daily, seasonal, and regional capacity factors). Therefore, solar resources are not estimated in NEMS. In the seven regions where ST technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is insufficient to make that technology commercially viable through 2030.

- NEMS represents the Energy Policy Act of 1992 (EPACT92) permanent 10-percent investment tax credit (ITC) for solar electric power generation by tax-paying entities. The current 30-percent ITC is scheduled to expire at the end of 2008.

Wind-Electric Power Submodule

Background

Because of limits to windy land areas, wind is considered a finite resource, so the submodule calculates maximum available capacity by Electricity Market Module Supply Regions. The minimum economically viable average wind speed is about 14 mph, and wind speeds are categorized by annual average wind speed based on a classification system from the Pacific Northwest Laboratory. The RFM tracks wind capacity (megawatts) by resource quality, distance to transmission, and other resource costs within a region and moves to the next best wind resource when one category is exhausted. For *AEO2008*, wind resource data on the amount and quality of wind per EMM region come from the National Renewable Energy Laboratory[2] The technological performance, cost, and other wind data used in NEMS are derived by EIA from available data and from available literature.[3] Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the

EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed wind generation are included in the commercial and residential modules.

- In the wind submodule, wind supply costs are affected by three modeling measures: addressing (1) average wind speed, (2) distance from existing transmission lines, and (3) resource degradation, transmission network upgrade costs, and market factors.

- Available wind resource is reduced by excluding all windy lands not suited for the installation of wind turbines because of: excessive terrain slope (greater than 20 percent); reservation of land for non-intrusive uses (such as National Parks, wildlife refuges, and so forth); inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports and water bodies, including offshore locations); insufficient contiguous windy land to support a viable wind plant (less than 5 square kilometers of windy land in a 100 square kilometer area). Half of the wind resource located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas are excluded from the available resource base to account for the uncertain ability to site projects at such locations. These assumptions are detailed in the Draft Final Report to EIA on *Incorporation of Existing Validated Wind Data into NEMS*, November 2003.

- Capital costs for wind technologies are assumed to increase in response to (1) declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors, (2) increasing cost of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of intermittent wind power, and (3) market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased 20, 50, 100 percent, and finally 200 percent, to represent the aggregation of these factors.

- Proportions of total wind resources in each category vary by EMM region. For all thirteen EMM regions combined, 1.3 percent of windy land is available with no cost increase, 5.4 percent is available with a 20 percent cost increase, 11.2 percent is available with a 50 percent cost increase, 27.3 percent is available with a 100 percent cost increase, and almost 54.8 percent of windy land is assumed to be available with a 200 percent cost increase.

- Depending on the EMM region, the cost of competing fuels, and other factors, wind plants can be built to meet system capacity requirements or as a “fuel saver” to displace generation from existing capacity. For wind to penetrate as a fuel saver, its total capital and fixed operations and maintenance costs minus applicable subsidies must be less than the variable operating costs, including fuel, of the existing (non-wind) capacity. When competing in the new capacity market, wind is assigned a capacity credit that declines based on its estimated contribution to regional reliability requirements.

- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from wind resources, about 6.5 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.

- Capacity factors are assumed to increase to a national average of 44 percent in the best wind class resulting from taller towers, more reliable equipment, and advanced technologies. Capacity factors for each wind class are calculated as a function of overall wind market growth. The capacity factors are assumed to be limited to about 48 percent for an average Class 6 site. As better wind resources are depleted, capacity factors are assumed to go down.

- *AEO2008* does not allow plants constructed after 2008 to claim the Federal Production Tax Credit (PTC), a 2 cent per kilowatt-hour tax incentive that is set to expire on December 31, 2008. Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery Schedule with a 5-year tax life.

Offshore wind resources are represented as a separate technology from onshore wind resources. Offshore resources are modeled with a similar model structure as onshore wind. However, because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions with regard to capital cost, learning-by-doing cost reductions, and variation of resource exploitation costs and performance differ significantly from onshore wind.

- Like onshore resources, offshore resources are assumed to have an upwardly sloping supply curve, in part influenced by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, variable terrain/seabed) but also explicitly by water depth.

- Because of the more difficult maintenance challenge offshore, performance for given annual average wind power density level is assumed to be somewhat reduced by reduced turbine availability. Offsetting this, however, is the availability of resource areas with higher overall power density than is assumed available onshore. Capacity factors for offshore are limited to be about 50 percent for a Class 7 site.

- Cost reductions in the offshore technology result in part from learning reductions in onshore wind technology as well as from cost reductions unique to offshore installations, such as foundation design and construction techniques. Because offshore technology is significantly less mature than onshore wind technology, offshore-specific technology learning occurs at a somewhat faster rate than on-shore technology.

Geothermal-Electric Power Submodule

Background

The Geothermal-Electric Submodule (GES) estimates the generating capacity and output potential of 89 hydrothermal sites in the Western United States. This estimation is based on two studies: *New Geothermal Site Identification and Qualification*, prepared by GeothermEx, Inc for the California Public Utility Commission, and *Western Governors' Association Geothermal Task Force Report*, which was co-authored by several geothermal experts from the public and private sectors. These studies focus on geothermal resources with confirmed temperatures greater than 100 Celsius, which is generally considered the threshold for economically feasible conventional development. While EIA had previously distinguished between binary and dual flash technologies, this is no longer an essential component of cost estimates. Instead, these studies incorporate expected power plant cost and performance based on each confirmed resource temperature. This enables greater projection precision relative to a static choice between two technologies. All plants are assumed to operate at 90 percent capacity factor. Enhanced Geothermal Systems (EGS), such as hot dry rock, are not included as potential resources since this technology is still in development and is not expected to be in significant commercial use within the projection horizon.

The two studies off of which EIA estimates are based maintain separate capital cost components for each site's development. The GeothermEx study divided individual site costs into four components: exploration, confirmation, development, and transmission. Site exploration is a small component of aggregate costs, oftentimes being zero. Confirmation and transmission costs may be significant, however the vast majority of capital costs are classified under site development which includes power plant construction. The WGA report, which was used to estimate geothermal potential outside of the GeothermEx database region, did not provide site specific, separate capital cost components. However, it did provide some sites with two levels of capital costs, meaning a portion of the resource could be developed at a lower cost than the remaining potential. Therefore, EIA maintained two categories of site specific capital development costs, with a cost premium placed on some sites beyond their most economic resource. Site specific operation and maintenance costs are also included in the submodule. As a result of revised supply estimations, the annual site build limit has been relaxed but still remains. Geothermal development is limited to 25 MW of generating capacity until 2010, when the 50 MW limit goes into effect for the remainder of the projection period.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Forms EIA-860A (utilities) and EIA-860B (nonutilities) and from supplemental additions (See Below).

- The permanent investment tax credit of 10 percent available in all projection years based on the EPACT applies to all geothermal capital costs, except through 2008 when the 1.9 cent production tax credit is available to this technology and is assumed chosen instead.

- Plants are not assumed to retire unless their retirement is reported to EIA. Geysers units are not assumed to retire but instead are assigned the 35 percent capacity factors reported to EIA reflecting their reduced performance in recent years.

- Capital and operating costs vary by site and year; values shown in Table 39 in the EMM chapter are indicative of those used by EMM for geothermal build and dispatch decisions.

Biomass Electric Power Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries, the so-called captive capacity, is included in the industrial sector module as cogeneration. Generation by the electricity sector is represented in the EMM, with capital and operating costs and capacity factors as shown in Table 38 in the EMM chapter, as well as fuel costs, being passed to the EMM where it competes with other sources. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol are produced by the Petroleum Market Module (PMM), with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, the EMM regional supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Form EIA-860.

- The conversion technology represented, upon which the costs in Table 39 in the EMM chapter are based, is an advanced gasification-combined cycle plant that is similar to a coal-fired gasifier. Costs in the reference case were developed by EIA to be consistent with coal gasifier costs. Short-term cost adjustment factors are used.

- Biomass cofiring can occur up to a maximum of 15 percent of fuel used in coal-fired generating plants.

Fuel supply schedules are a composite of four fuel types: forestry materials, wood residues, agricultural residues and energy crops. Energy crop data are presented in yearly schedules from 2010 to 2030 in combination with the other material types for each region. The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees.[4] The wood residue component consists of primary mill residues, silvicultural trimmings, and urban wood such as pallets, construction waste, and demolition debris that are not otherwise used.[5] Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops.[6] Energy crop data are for hybrid poplar, willow, and switchgrass grown on crop land, pasture land, or on Conservation Reserve Program lands.[7] The maximum amount of resources in each supply category is shown in Table 74.

Table 74. 2020 Maximum U.S. Biomass Resources, by Coal Demand Region and Type
(Trillion Btu)

Coal Demand Region	States	Agricultural Residue	Energy Crops	Forestry Residue	Urban Wood Waste/Mill Residue	Total[1]
1. NE	CT, MA, ME, NH, RI, VT	0	17	70	15	102
2..YP	NY, PA, NJ	22	95	45	59	221
3. SA	WV, MD, DC, DE, VA, NC, SC	72	272	429	56	829
4. GF	GA, FL	4	115	158	47	325
5. OH	OH	97	86	167	17	366
6. EN	IN, IL, MI, WI	726	286	426	47	1,485
7. KT	KY, TN	27	385	265	30	706
8. AM	AL, MS	0	281	37	19	338
9. CW	MN, IA, ND, SD, NE, MO, KS	1085	1,231	190	28	2,534
10. WS	TX, LA, OK, AR	14	632	152	57	855
11. MT	MT, WY, ID	26	20	326	25	397
12. CU	CO, UT, NV	53	1	155	7	215
13. ZN	AZ, NM	17	0	378	7	403
14. PC	AK, HI, WA, OR, CA	76	0	100	83	259
Total U.S.		2,218	3,422	2,898	497	9,034

[1]May include rounding error.

Sources: Urban Wood Wastes: Antares Group Inc., *Biomass Residue Supply Curves for the U.S (updated),* prepared for the National Renewable Energy Laboratory, June 1999; Agricultural residues, energy crops, and forestry residues from the University of Tennessee Department of Agricultural Economics POLYSIS model, 2007.

Landfill-Gas-to-Electricity Submodule

Background

Landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of “high”, “low”, and “very low” methane producing landfills located in each EMM region. An average cost-of-electricity for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by EPA’s “Energy Project Landfill Gas Utilization Software” (E-PLUS).[8]

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.

- Recycling is assumed to account for 35 percent of the total waste stream by 2005 and 50 percent by 2010 (consistent with EPA’s recycling goals).

- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.

- Emission parameters are the same as those used in calculating historical methane emissions in the EIA’s *Emissions of Greenhouse Gases in the United States 2003.*[9]

- The ratio of "high", "low", and "very low" methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Government Advisory Associates METH2000 database.[10]

- Cost-of-electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for "high", "low", and "very low" methane emitting wastes.

Conventional Hydroelectricity

The conventional hydroelectricity submodule represents U.S. potential for new conventional hydroelectric capacity 1 megawatt or greater from new dams, existing dams without hydroelectricity, and from adding capacity at existing hydroelectric dams. Summary hydroelectric potential is derived from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information, plus estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL).[11] Annual performance estimates (capacity factors) were taken from the generally lower but site specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs 10 cents per kilowatthour or lower are included in the supply. Pumped storage hydro, considered a nonrenewable storage medium for fossil and nuclear power, is not included in the supply; moreover, the supply does not consider offshore or in-stream hydro, efficiency or operational improvements without capital additions, or additional potential from refurbishing existing hydroelectric capacity.

In the hydroelectricity submodule, sites are first arrayed by NEMS region from least to highest cost per kilowatthour. For any year's capacity decisions, only those hydroelectric sites whose estimated levelized costs per kilowatthour are equal to or less than an EMM determined avoided cost (the least cost of other technology choices determined in the previous decision cycle) are submitted. Next, the array of below-avoided cost sites is parceled into three increasing cost groups, with each group characterized by the average capacity-weighted cost and performance of its component sites. Finally, the EMM receives from the conventional hydroelectricity submodule the three increasing-cost quantities of potential capacity for each region, providing the number of megawatts potential along with their capacity-weighted average overnight capital cost, operations and maintenance cost, and average capacity factor. After choosing from the supply, the EMM informs the hydroelectricity submodule, which decrements available regional potential in preparation for the next capacity decision cycle.

Legislation and Regulations

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

The RFM includes the investment and energy production tax credits codified in the Energy Policy Act of 1992 (EPACT 92) as amended. The investment tax credit established by EPACT 92 provides a credit to Federal income tax liability worth 10 percent of initial investment cost for a solar, geothermal, or qualifying biomass facility. This credit was temporarily raised to 30 percent for some solar projects and extended to residential projects. This change is reflected in the commercial and residential modules, but is not reflected for utility-scale installations, where impacts are expected to be minimal and not in a timeframe to impact the multi-year capacity planning process being modeled. The production tax credit, as established by EPACT 92, applied to wind and certain biomass facilities. As amended, it provides a 2 cent tax credit for every kilowatt-hour of electricity produced for the first 10 years of operation for a facility constructed by December 31, 2007. The value of the credit, originally 1.5 cents, is adjusted annually for inflation. With the various amendments, the production tax credit is available for electricity produced from qualifying geothermal, animal waste, certain small-scale hydroelectric, landfill gas, municipal solid waste, and additional biomass resources. Poultry litter and geothermal resources receive a 2 cent tax credit for the first 10 years of facility operations. All other renewable resources receive a 1 cent tax credit for the first 10 years of facility operations. The investment and production tax credits are exclusive of one another, and may not both be claimed for the same facility.

Alternative Renewable Cases

Renewable Technology Cases

Two cases examine the effect on energy supply using alternative assumptions for cost and performance of non-hyrdo, non-landfill gas renewable energy technologies. The High Renewable Cost case examines the effect if technology costs were to remain at current levels. The Low Renewable Cost case examines the effect if technology energy costs were reduced by 2030 to 10 percent below Reference case values.

The High Renewable Cost case does not allow “learning-by-doing” effects to reduce the capital cost of biomass, geothermal, solar, or wind technologies or to improve wind capacity factor beyond 2008 levels. The construction of the first four units of biomass integrated gasification combined cycle units are still assumed to reduce the technological optimism factor associated with this technology. All other parameters remain the same as in the Reference case.

The Low Renewable Cost case assumes that the non-hydro, non-landfill gas renewable technologies are able to reduce their overall cost-of-energy produced in 2030 by 10 percent from the Reference case. Because the cost of supply of renewable resources is assumed to increase with increasing utilization (that is, the renewable resource supply curves are upwardly sloping), the cost reduction is achieved by targeting the reduction on the “marginal” unit of supply for each technology in 2030 for the Reference case (that is, the next resource available to be utilized in the Reference case in 2030). This has the effect of reducing costs for the entire supply (that is, shifting the supply curve downward by 10 percent). As a result of the overall reduction in costs, more supply may be utilized, and a unit from higher on the supply curve may result in being the marginal unit of supply. Thus the actual market-clearing cost-of-energy for a given renewable technology may not differ by much from the Reference case, although that resource contributes more energy supply than in the Reference case. These cost reductions are achieved gradually through “learning-by-doing”, and are only fully realized by 2030.

For biomass, geothermal, and solar technologies, this cost reduction is achieved by a reduction in overnight capital costs sufficient to achieve the 10 percent targeted reduction in cost-of-energy. As a result, the supply of biomass fuel is increased by 10 percent at every price level. For geothermal, the capital cost of the lowest-cost site available in the year 2005 is reduced such that if it were available for construction in 2030, it would have a 10 percent lower cost-of-energy in the High Renewable case than the cost-of-energy it would have in 2030 were it available for construction in the Reference case. For solar technologies (both photovoltaic and solar thermal power), the resource is assumed to be unlimited and the reductions in cost-of-energy are achieved strictly through capital cost reduction.

Observation of wind energy markets indicates that improvements in performance (as measured by capacity factor) have, in recent years, dominated reductions in capital cost as a means of reducing cost-of-energy. Therefore, in the Low Renewable Cost case, the reduction in wind levelized cost comes from both modestly reduced capital cost and improved capacity factor. Other assumptions within NEMS are unchanged from the Reference case.

For the Low Renewable Cost case, demand-side improvements are also assumed in the renewable energy technology portions of residential and commercial buildings, industrial processes, and refinery fuels modules. Details on these assumptions can be found in the corresponding sections of this report.

State RPS Programs

Starting with AEO 2008, EIA represents various state-level policies generally referred to as Renewable Portfolio Standards (RPS). These policies vary significantly among states, but typically require the addition of renewable generation to meet a specified share of state-wide generation. Any non-discretionary limitations on meeting the generation or capacity target are modeled to the extent possible. However, because of the complexity of the various requirements, the regional target aggregation (described below), and nature of some of the limitations (also described below), measurement of compliance is assumed to be approximate.

For the AEO2008, regional renewable generation targets were estimated using the renewable generation targets in each state within the region. In many cases, regional boundaries intersect state boundaries; in these cases states were assigned to be within a single region, based on EIA expert judgment of factors such as predominant load locations and location of renewable resources eligible for that state's RPS program. Using state-level RPS compliance schedules and preliminary estimates of projected sales growth, EIA estimated the amount of renewable generation required in each state within a region. Required generation in each state was then summed to the regional level for each year, and a regional renewable generation share of total sales was determined, as shown in Table 75.

Table 75. Aggregate Regional RPS Requirements

Region[1]	2015	2025	2030
ECAR	0%	0%	0%
ERCOT	5%	5%	5%
MAAC	9%	13%	13%
MAIN	6%	12%	12%
MAPP	9%	11%	11%
NY[2]	*	*	*
NE	8%	12%	12%
FL	0%	0%	0%
STV	1%	2%	2%
SPP	0%	0%	0%
NWP	7%	12%	12%
RA	4%	7%	7%
CNV[3]	*	*	*

[1] See chapter on the electricity Market Module for a map of the electricity regions

[2]New York is not projected to meet RPS targets because of funding limitations. EIA projects that currently authorized funds will support 2.5 billion kilowatthours of new renewable generation by 2015.

[3]California is not projected to meet RPS targets because of funding limitations. EIA projects that currently authorized funds will support the addition of 700 MW of additional renewable capacity through 2011.

Only targets with established enforcement provisions or established state funding mechanisms were included in the calculation; goals, provisional RPS requirements, or requirements lacking established funding were not included. The California and New York programs require state funding, and these programs are assumed to be complied with only to the extent that state funding allows. Compliance enforcement provisions vary significantly among states and most states have established procedures for waiving compliance through the use of "alternative compliance" payments, penalty payments, discretionary regulatory waivers, or retail price impact limits. Because of the variety of mechanisms, even within a given electricity market region, these limits are not modeled.

Supplemental and Floor Capacity Additions

For *AEO2008,* EIA has continued its tradition of supplemental and floor renewable capacity additions. All specific project listings in Table 76 have been independently verified by EIA, with the exception of landfill gas listings that were obtained through EPA. In total, 6.4 gigawatts of capacity are represented in these listings. For 2008 and beyond, the capacity additions are a preview of the limited data EIA currently has on new projects. Listings additional for these years should not be viewed as comprehensive. This list of projects does not represent renewable capacity that will be induced by State RPS programs beyond 2007.

Table 76. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1]

Technology	Plant Identification	State	Net Summer Capability (Megawatts)	On-Line Years
Biomass	Okeelanta Cogeneration	FL	40	2007
	Fibrominn Biomass Power Plant	MN	55	2007
	Sierra Pacific Burlington Facility	WA	25	2007
	Plant Carl Project	GA	20	2007
	MN Poultry Litter	MN	55	2007
	Rough and Ready Lumber Biomas Project	OR	1.7	2007
	Lincoln Paper & Tissue	ME	10	2007
	Snowflake White Mountain Power Plant	AZ	24	2008
Geothermal	Galena Unit 2	NV	4.5	2007
	Raft River Geothermal Power Plant	ID	9.8	2007
	Salt Wells Geothermal	NV	11	2007
	Stillwater Addition	NV	15	2007
	Steamboat Hills	NV	4	2007
	Blundell Expansion (Roosevelt Hot Springs)	UT	11	2007
	Galena Unit 3	NV	12.8	2008
Landfill Gas (including mass-burn waste)	C& E Electric	MI	2.3	2007
	Ocean County Landfill	NJ	9.6	2007
	Seven Mile Creek LFG	WI	0.8	2007
	Horry Land Fill Gas Site	SC	1.1	2007
	Tullytown Land Fill	PA	2.2	2007
	Coventry LFG	VT	1.6	2007
	GROWS Land Fill	PA	2.5	2007
	Seccra Land Fill	PA	0.8	2007
	Rumpke/Pendleton County Land Fill	KY	3.2	2007
	Sauk County Land Fill	WI	0.4	2007
	Cape May County Land Fill	NNJ	0.3	2007
	Newland Park Land Fill	MD	3.1	2007
	Dry Creek Landfill	OR	3.2	2007
	Lee County Solid Waste Energy	FL	16	2007
	Lee County Landfill	SC	1.9	2008
Central Station Photovoltaics (PV)	SunE Alamosa	CO	8	2007
	Springerville Expansion 2008 C	AZ	1	2008
	Springerville Expansion 2009 C	AZ	1	2009
	Springerville Expansion 2010 C	AZ	1	2010
Solar Thermal	Eldorado Solar Thermal	NV	66.5	2007
	Solargenix Solar Thermal Project	NV	64	2007
Conventional Hydro	Gross Hydro Plant	CO	7.8	2007
	Manitou Springs	CO	0.5	2007
	Lower St. Anthony Falls	MN	9	2008
	Castle Creek Hyrdoplant	CO	1	2009

Table 76. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (cont)

Technology	Plant Identification	State	Net Summer Capability (Megawatts)	On-Line Years
Wind	Alta Mesca Phase IV	CA	40	2007
	Sweetwater Wind Phase IV	TX	241	2007
	Twin Groves Wind Farm Phase I	IL	198	2007
	Cedar Creek Wind	CO	300	2007
	Sweetwater Wind5	TX	81	2007
	Pakini Nui Wind Farm	HI	21	2007
	Top of Iowa Windfarm III	IA	29.4	2007
	Lone Star Wind Farm (frmly Cross Timbers)	TX	200	2007
	Wildorado Wind Ranch	TX	161	2007
	Mars Hill Wind Farm Project	ME	42	2007
	Allegheny Ridge Wind Farm	PA	80	2007
	MinnDakota Wind	SD	150	2007
	Twin Buttes Wind Farm	CO	75	2007
	Klondike Windpower Phase III	OR	221	2007
	Locust Ridge	PA	26	2007
	Sand Bluff	TX	90	2007
	Post Oak Wind LLC	TX	200	2007
	Biglow Canyon Wind Farm	OR	125.4	2007
	Smoky Hills Windfarm	KS	100.8	**2007**
	Mount Storm Wind Project	WV	164	2007
	Pomeroy Wind	IA	123	2007
	Scurry County Wind	TX	130.5	2007
	Cow Branch Wind Power	MO	50.4	2007
	CR Cleaning House Wind	MO	50.4	2007
	Loess Hills Wind Farm	MO	5	2007
	Bluegrass Ridge Wind Phase I	MO	33.4	2007
	Peetz Wind Farm	CO	400	2007
	Steel Winds Wind Farm	NY	20	2007
	Snyder Wind Farm	TX	63	2007
	Langdon Wind Farm	ND	159	2007
	Old Trail Wind Farm	IL	198	2007
	Fenton Wind Energy	MN	205	2007
	Consent Decree Wind Phase I	OH	3.7	2007
	Diamond Willow Wind	MT	20	2007
	Elkoorn Valley Wind	OR	101	2007
	Endeavor Wind Project	IA	100	2007

Table 76. Planned U.S. Central Station Generating Capacity Using Renewable Resources for 2004 and Beyond[1] (Cont.)

Technology	Plant Identification	State	Net Summer Capability (Megawatts)	On-Line Years
	Good Know Windfarm	WA	94	2007
	Prairie Star Wind Farm	MN	100	2007
	Cedar Ridge Wind	WI	68	2008
	Top of Iowa Windfarm II	IA	80	2008
	Blue Sky Green Field Wind Projcet	WI	145	2008
	Marengo Wind Plant	WA	140.4	2008
	White Creek Wind Farm	WA	204	2008
	Oliver Wind Phase II	ND	48	2008
	Champion Wind Farm	TX	126.5	2008
	Roscoe Wind Farm	TX	209	2008
	Clinton Wind Farm	NY	100.5	2008
	Ellenurg Wind Farm	NY	81	2008
	Bliss Windpark Phase II	NY	100.5	2008
	Harvest Wind Farm	MI	53	2008
	Taconite Ridge Energy Center	MN	25	2008
	Tehachapi Wind I	CA	0.6	2009
	Tehachapi Wind Resource II	CA	15.3	2009
	North Dakota Wind Expansion	ND	100	2009
	Consent Decree Wind Phase Ii	OH	19.3	2009

1Includes reported information and EIA estimates for goals, mandates, renewable portfolio standards (RPS), and California Assembly Bill 1890 required renewables.

[2]Regional estimates developed by EIA.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on publicly available information about specific projects, state renewable portfolio standards, mandates, goals, and commercial and other plans.

Notes and Sources

[1] For a comprehensive description of each submodule, see Energy Information Administration, Office of Integrated Analysis and Forecasting, Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2005), (Washington, DC, March 2005).

[2] *Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power*, Report to EIA from Princeton Energy Resources International, LLC. May 2007.

[3] Wiser, Ryan and Mark Bollinger. Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006. U.S. Department of Energy, Office of Energy Efficiency and Reneweable Energy. May 2007.

[4] United States Department of Agriculture, U.S. Forest Service, "Forest Resources of the United States, 1992", General Technical Report RM-234, (Fort Collins CO, June 1994).

[5] Antares Group Inc., "Biomass Residue Supply Curves for the U.S (updated)", prepared for the National Renewable Energy Laboratory, June 1999.

[6] Walsh, M.E., et.al., Oak Ridge National Laboratory, "The Economic Impacts of Bioenergy Crop Production on U.S. Agriculture", (Oak Ridge, TN, May 2000), http://bioenergy.ornl.gov/papers/wagin/index.html.

[7] Graham, R.L., et.al., Oak Ridge National Laboratory, “The Oak Ridge Energy Crop County Level Database”, (Oak Ridge TN, December, 1996).

[8] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[9] Energy Information Administration, "Emissions of Greenhouse Gases in the United States 2003", DOE/EIA-0573(2003) (Washington, DC, December 2004).

[10] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

[11] Douglas G. Hall, Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll, Idaho National Engineering and Environmental Laboratory, "Estimation of Economic Parameters of U.S. Hydropower Resources" INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003).

Appendix A: Handling of Federal and Selected State Legislation and Regulation in the Annual Energy Outlook

Legislation	Brief Description	AEO Handling	Basis
Residential Sector			
A. National Appliance Energy Conservation Act of 1987	Requires Secretary of Energy to set minimum efficiency standards for 10 appliance categories.	Included for categories represented in the AEO residential sector forecast.	
a. Room Air Conditioners		Current standard of 9.8 EER	Federal Register Notice of Final Rulemaking.
b. Other Air Conditioners (<5.4 tons)		Current standard 10 SEET for central air conditioners and heat pumps, increasing to 13 SEER in 2006.	Federal Register Notice of Final Rulemaking.
c. Water Heaters		Electric: Current standard .90 EF. Gas: Current standard .59 EF.	Federal Register Notice of Final Rulemaking.
d. Refrigerators/Freezers kWh/yr		Current standard of .51	Federal Register Notice of Final Rulemaking.
e. Dishwashers		Current standard of .46 EF.	Federal Register Notice of Final Rulemaking.
f. Fluorescent Lamp Ballasts		Current standard of .90 power factor	Federal Register Notice of Final Rulemaking.
g. Clothes Washers		Current standard of 1.18 EF, increasing to 1.04 MEF in 2004, further increasing to 1.26 MEF in 2007.	Federal Register Notice of Final Rulemaking.
h. Furnaces		Standard set at 78 AFUE for gas and oil furnaces.	Federal Register Notice of Final Rulemaking.
i. Clothes Dryers		Gas: Current standard 2.67 EF. Electric: Current standard 3.01 EF. The increase in MEF for clothes washers further increases the de facto standard for clothes dryers due to better extraction of water from clothes in washing process.	Federal Register Notice of Final Rulemaking.
B. Energy Policy Act of 1992 (EPACT92)			
a. Building Codes	For the IECC 2006, specifies whole house efficiency minimums.	Assumes that all States adopt the IECC 2006 code by 2017.	Trend of States adoption to codes, allowing for lead times for enforcement and builder compliance.
b. Energy-Efficient Mortgages	Allow homeowners to qualify for higher loan amounts if the home is energy-efficient, as scored by HERS.	Efficiency of equipment represented in technology choice parameters. Efficiency of shell represented in HVAC choice.	No way to separate out these purchases from others. Assumes historical effect in the forecast, with cost-reducing learning in the shell portion of HVAC choice.
C. Energy Policy Act of 2005 (EPACT05)			
a. Torchiere Lamp Standard		Sets 190 watt bulb limit in 2006.	EPACT05.
b. Ceiling Fan Light Kit Standard	Ceiling fans must be shipped with compact fluorescent bulbs or use no more than 190 watts per fixture in 2007.	Reduce lighting electricity consumption by appropriate amount.	Number of ceiling fan shipments and estimated kWh savings per unit determine overall savings.

Legislation	Brief Description	AEO Handling	Basis
c. Dehumidifier Standard	Sets standard for dehumidifiers in 2007 and 2012.	Reduce miscellaneous electricity consumption by appropriate amount.	Number of dehumidifier shipments and estimated kWh savings per unit determine overall savings.
d. Energy-Efficient Equipment Tax Credit	Purchasers of certain energy-efficient equipment can claim tax credits in 2006 and 2007.	Reduce cost of applicable equipment by specified amount.	EPACT05.
e. New Home Tax Credit	Builders receive $1000 or $2000 tax credit if they build homes 30 or 50 percent better than code in 2006 and 2007.	Reduce shell package cost for these homes by specified amount.	Cost reductions to consumers are assumed to be 100 percent of the builder's tax credit.
f. Energy-Efficient Appliance Tax Credit	Producers of energy-efficient refrigerators, dishwashers, and clothes washers receive tax credits for each unit they produce that meets certain efficiency specifications.	Assume the cost savings are passed on to the consumer, reducing the price of the appliance by the specified amount.	Cost reductions to consumers are assumed to be 100 percent of the producer's tax credit.
D. Energy Independence and Security Act of 2007			
a. General Service Incandescent Lamp Standard	Require less wattage for bulbs in 2012-2014 and 2020.	reduce wattage for new bulbs by 28 percent in 2013 and 67 percent in 2020.	EISA 2007
b. Dehumidifier Standard	Updates EPACT 2005 standard.	Reduce miscellaneous electricity consumption by appropriate amount.	Increase savings estimated for EPACT 2005 by appropriate amount.
c. Boiler Standard	Sets standards for boilers in 2013.	Require new purchases of boilers to meet the standard.	EISA 2007
d. Dishwasher Standard	Sets standards for dishwashers in 2010.	Require new purchases of dishwashers to meet the standard by 2010.	EISA 2007
e. External Power Supply Standard	Sets standards for external power supplies in 2008	Reduce miscellaneous electricity consumption by appropriate amount.	Number of shipments and estimated kWh savings per unit determine overall savings.
f. Manufactured Housing Code	Require manufactured homes to meet latest IECC in 2011.	Require that all manufactured homes shipped after 2011 meet the IECC 2006	EISA 2007
Commercial Sector			
A. National Appliance Energy Conservation Act of 1987	Requires Secretary of Energy to set minimum efficiency standards for 10 appliance categories.	Included for categories represented in the AEO commercial sector forecast.	
a. Room Air Conditioners		Current standard of 9.8 EER	Federal Register Notice of Final Rulemaking.
b. Other Residential-size Air Conditioners (<5.4 tons)		Current standard 10 SEER for central air conditioning and heat pumps, increasing to 13 SEER in 2006.	Federal Register Notice of Final Rulemaking.
c. Fluorescent Lamp Ballasts		Current standard if .90 power factor and minimum efficacy factor for F40 and F96 lamps based on lamp size and wattage, increasing to higher efficacy factor in 2005 that limits purchases to electronic ballasts.	Federal Register Notice of Final Rulemaking.

Legislation	Brief Description	AEO Handling	Basis
B. Energy Policy Act of 1992 (EPACT92)			
a. Buildings Codes		Incorporated in commercial building shell assumptions. Efficiency of new relative to existing shell represented in shell efficiency indices. Assume shell efficiency improves 5 and 7 percent by 2030 for existing buildings and new construction, respectively.	Based on Arthur D. Little commercial shell indices developed for EIA in 1998, updated to 1999 CBECS building stock.
b. Window labeling	Designed to help consumers determine which windows are more energy efficient.	Incorporated in commercial building shell assumptions. Efficiency of new relative to existing shell represented I shell efficiency indices. Assume shell efficiency improves 5 and 7 percent by 2030 for existing buildings and new construction, respectively.	Based on Arthur D. Little commercial shell indices developed for EIA in 1998, updated to 1999 CBECS building stock.
c. Commercial Furnaces and Boilers		Gas-fired furnaces and boilers: Current standard is 0.80 thermal efficiency. Oil furnaces and boilers: Current standard is 0.81 thermal efficiency for furnaces, 0.83 thermal efficiency for boilers.	Public Law 102-486: EPACT92. Federal Register Notice of Final Rulemaking.
d. Commercial Air Conditioners and Heat Pumps		Air-cooled air conditioners and heat pumps less than 135,000 Btu: Current standard of 8.9 EER. Air-cooled air conditioners and heat pumps greater than 135,000 Btu: Current standard of 8.5 EER.	Public Law 102-486: EPACT92.
e. Commercial Water Heaters		Natural gas and oil: EPACT standard .78 thermal efficiency increasing to .80 thermal efficiency for gas units in 2003.	Public Law 102-486: EPACT92. Federal Register Notice of Final Rulemaking.
f. Lamps		Incandescent: Current standard 16.9 lumens per watt. Fluorescent: Current standard 75 and 80 lumens per watt for 4 and 8 foot lamps, respectively.	
g. Electric Motors	Specifies minimum efficiency levels for a variety of motor types and sizes.	End-use services modeled at the equipment level. Motors contained in new equipment must meet the standards.	Public Law 102-486: EPACT92.
h. Federal Energy Management	Requires Federal agencies to reduce energy consumption 20 percent by 2000 relative to 1985.	Superseded by Executive Order 13123 and EPACT05.	Superseded by Executive Order 13123.
I. Business Investment Energy Credit	Provides a permanent 10 percent investment tax credit for solar property.	Tax credit incorporated in cash flow for solar generation systems. Investment cost reduced 10 percent for solar water heaters.	Public Law 102-486: EPACT92.
C. Executive Order 13123, "Greening the Government Through Efficient Energy Management	Requires Federal agencies to reduce energy consumption 30 percent by 2005 and 35 percent by 2010 relative to 1985 through life-cycle cost-effective energy measures.	Superseded by EPACT05 and EISA07.	Superseded by EPACT05 and EISA07.

Legislation	Brief Description	AEO Handling	Basis
D. Energy Policy Act of 2005 (EPACT05)			
a. Commercial Package Air Conditioners and Heat Pumps	Sets minimum efficiency levels in 2010.	Air-cooled air conditioners/heat pumps less than 135,000 Btu: standard of 11.2/11.0 EER and heating COP of 3.3. Air-cooled air conditioners/heat pumps greater than 135,000 Btu: standard of 11.0/10/6 EER and heating COP of 3.2.	Public Law 109-58: EPACT05.
b. Commercial Refrigerators, Freezers, and Automatic Icemakers	Sets minimum efficiency levels in 2010 based on volume.	Set standard by level of improvement above stock average efficiency in 2003.	Public Law 109-58: EPACT05.
c. Lamp Ballasts	Bans manufacture or import of mercury vapor lamp ballasts in 2008. Sets minimum efficacy levels fir T12 energy saver ballasts in 2009 and 2010 based on application.	Remove mercury vapor lighting system from technology choice menu in 2008. Set minimum efficacy of T12 ballasts at specified standard levels.	Public Law 109-58: EPACT05.
d. Compact Fluorescent Lamps	Sets standard for medium base lamps at Energy Star requirements in 2006.	Set efficacy level of compact fluorescent lamps at required level.	Public Law 109-58: EPACT05.
e. Illuminated Exit Signs and Traffic Signals	Set standards at Energy Star requirements in 2006.	Reduce miscellaneous electricity consumption by appropriate amount.	Number of shipments, share of shipments that currently meet standard, and estimated kWh savings per unit determine overall savings.
f. Distribution Transformers	Sets standard as National Electrical Manufacturers Association Class I Efficiency levels in 2007.	Effects of the standard are included in estimating the share of miscellaneous electricity consumption attributable to transformer losses.	Public Law 109-58: EPACT05.
g. Prerinse Spray Valves	Sets maximum flow rate to 1.6 gallons per minute in 2006.	Reduce energy use for water heating by appropriate amount.	Number of shipments, share of shipments that currently meet standard, and estimated kWh savings per unit determine overall savings.
h. Federal Energy Management	Requires Federal agencies to reduce energy consumption 20 percent by 2015 relative to 2003 through life-cycle cost-effective energy measures.	The Federal "share" of the commercial sector uses the 10 year treasury bond rate as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10 year treasury bond rate to develop discount rates for other commercial decisions.	Public Law 109-58: EPACT05. Superseded by EISA07.
I. Business Investment Tax Credit for Fuel Cells and Microturbines	Provides a 30 percent investment tax credit for fuel cells and a 10 percent investment tax credit for microturbines installed in 2006 through 2008.	Tax credit incorporated in cash flow for fuel cells and microturbines.	Public Law 109-58: EPACT05. Extended through 2008 by Public Law 109-432
j. Business Solar Investment Tax Credit	Provides a 30 percent investment tax credit for solar property installed in 2006 through 2008.	Tax credit incorporated in cash flow for solar generation systems, investment cost reduced 30 percent for solar water heaters.	Public Law 109-58: EPACT05. Extended through 2008 by Public Law 109-432.

Legislation	Brief Description	AEO Handling	Basis
E. Energy Independence and Security Act of 2007 (EISA07)			
a. Commercial Walk-in Coolers and Walk-in Freezers	Requires use of specific energy efficiency measures in equipment manufactured in or after 2009.	Set standard by equivalent level of improvement above stock average efficiency in 2003.	Public Law 110-140: EISA97.
b. Incandescent and Halogen lamps	Sets maximum allowable wattage based on lumen output starting in 2012.	Remove incandescent and halogen general service lighting systems that do not meet standard from technology choice menu in 2012.	Public Law 110-140: EISA97.
c. Metal Halide Lamp Ballasts	Sets minimum efficiency levels for metal halide lamp ballasts starting in 2009.	Remove metal halide lighting systems that do not meet standard from technology choice menu in 2009. Set minimum system efficiency to include specified standard levels for ballasts - ranging from 88 to 94 percent based on ballast type.	Public Law 110-140: EISA97.
d. Federal Use of Energy Efficient Lighting	Requires use of energy efficient lighting fixtures and bulbs in Federal buildings to the maximum extent possible starting in 2009.	Increase proportion of sector using 10 year treasury bond rate for lighting purchase decisions to represent all existing and new Federal floorspace in 2009.	Public Law 110-140: EISA97.
e. Federal Energy Management	Requires Federal agencies to reduce energy consumption per square foot 30 percent by 2015 relative to 2003 through life-cycle cost-effective energy measures.	The Federal “share” of the commercial sector uses the 10 year treasury bond rate as a discount rate in equipment purchase decisions as opposed to adding risk premiums to the 10 year treasury bond rate to develop discount rates for other commercial decisions.	Public Law 110-140: EISA97.
Industrial Sector			
A. Energy Policy Act of 1992 (EPACT92)			
a. Motor Efficiency Standards	Specifies minimum efficiency levels for a variety of motor types and sizes.	New motors must meet the standards.	Standard specified in EPACT92. 10 CFR 431.
b. Boiler Efficiency Standards	Specifies minimum combustion efficiency for package boilers larger than 300,000 Btu/hr. Natural Gas boilers: 80 percent, oil boilers: 83 percent.	All package boilers are assumed to meet the efficiency standards. While the standards do not apply to field-erected boilers, which are typically used in steam-intensive industries, we assume they meet the standard in the AEO.	Standard specified in EPACT92. 10 CFR 431.
B. Clean Air Act Amendments (CCCA90)			
a. Process Emissions	Numerous process emissions requirements for specified industries and/or activities.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60.
b. Emissions related to hazardous/toxic substances	Numerous emissions requirements relative to hazardous and/or toxic substances.	Not modeled because they are not directly related to energy projections.	CAAA90, 40 CFR 60.
c. Industrial SO2 emissions	Sets annual limit for industrial SO2 emissions at 5.6 million tons. If limit is reached, specific regulations could be implemented.	Industrial SO2 emissions are not projected to reach the limit (Source: EPA, National Air Pollutant Emissions Trends: 1990-1998, EPA-454/R-00-002, March 2000, p. 4-3.)	CAAA90, Section 406 (42 USC 7651)

Legislation	Brief Description	AEO Handling	Basis
d. Industrial boiler hazardous air pollutants	Requires industrial boilers and process heaters to meet emissions limits on HAPs to comply with the Maximum Achievable Control Technology (MACT) floor.	Not explicitly modeled because new boilers are expected to meet the standards in the absence of the rule and retrofit costs should be relatively small.	Environmental Protection Agency, National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heatrates, 40 CFR Part 63.
e. Emissions from stationary diesel engines	Requires engine manufacturers to meet the same emission standards as nonroad diesel engines. Fully effective in 2011.	New stationary engines meet the standards.	40 CFR Parts 60, 85, 89, 94, 1039, 1065, and 1068.
C. Energy Policy Act of 2005 (EPACT 05)			
a. Physical Energy Intensity	Voluntary commitments to reduce physical energy intensity by 2.5 percent annually for 2007-2016.	Not modeled because participation is voluntary; actual reductions will depend on future, unknown commitments.	EPACT2005, Section 106 (42 USC 15811)
b. Mineral components of cement of concrete	Increase in mineral component of Federally procured cement or concrete.	Not modeled because specific proportion will be specified in the future.	EPACT2005, Section 108 (42 USC 6966).
c. Tax credits for coke oven	Provides a tax credit of $3.00 per barrel oil equivalent, limited to 4000 barrels per day average. Applies to most producers of coal coke or coke gas.	Not modeled because no impact on U.S. coke plant activity is anticipated.	EPACT2005, Section 1321 (29 USC 29).
d. Emissions from stationary diesel engines	Requires engine manufactures to meet the same emission standards as nonroad diesel engines. Fully effective in 2011.	New stationary engines meet the standards	40 CFR Parts 60, 85, 89, 94, 1039, 1065, and 1068
D. The Energy Independence and Security Act of 2007			
Motor Efficiency Standards	Supersedes EPAct1992 Efficiency Standards no later than 2011	Motor purchases must meet the EPAct1992 standards through 2010; afterwards purchases must meet the EISA2007 standards	EISA2007
Transportation Sector			
A. Energy Policy Act of 1992 (EPACT92)	Increases the number of alternative fuel vehicles and alternative fuel use in Federal, State, and fuel provided fleets.	Assumes Federal, State and fuel provider fleets meet the mandated sales requirements.	Energy Policy Act of 1992, Public Law 102-486-Oct. 24, 1992.
B. Low Emission Vehicle Program (LEVP)	The Clean Air Act provides California the authority to set vehicle criteria emission standards that exceed Federal standards. Apart of that program mandates the sale of zero emission vehicles by manufacturers, other nonattainment. States are given the option of opting into the Federal or California emission standards.	Incorporates the LEVP program as amended on August 4, 2005. Assumes California, Connecticut, Maine, Massachusetts, New Jersey, New York, Rhode island, Vermont, Oregon, and Washington adopt the LEVP program as amended August 4, 2005 and that the proposed sales requirements for hybrid, electric, and fuel cell vehicles are met.	Section 177 of the Clean Air Act, 42 U.S.C. sec. 7507 (1976) and CARB, California Exhaust Emissions Standards and Test Procedures for Passenger Cars, Light-Duty Trucks, and Medium-Duty Vehicles, August 4, 2005.
C. Light Vehicle GHG Emission Standards	California has enacted light vehicle GHG emission standards as part of the Low Emission Vehicle Program (A.B. 1493), which requires that GHG emissions from new light vehicles be significantly reduced from 2009 to 2016.	AEO2008 does not incorporate. EPA has denied the California claim.	The alliance of Automobile Manufacturers and Several California auto dealerships filed suit against A.B. 1493 on December 7, 2004.

Legislation	Brief Description	AEO Handling	Basis
D. Corporate Average Fuel Economy (CAFÉ) Standard	Requires manufacturers to produce vehicles whose average fuel economy meets a minimum Federal standard. Cars and light trucks are regulated separately.	The current CAFÉ standard for cars is 27.5 mpg. The car standard is unchange through 2011. The current CAFÉ standard for light trucks is 22.5 mpg, increasing to 23.1 mpg in 2009, 23.5 mpg in 2010 and 24.0 mpg in 2011. The assumed standard increases to 41.0 mpg for cars and 30.5 mpg for light trucks in 2020.	Energy Policy Conservation Act of 1975; Title 49 United States Code, Chapter 329; Federal Register, Vol. 68, No. 66, Monday, April 7, 2003; and Federal Register, Vol. 71, No. 66, April 6, 2006. For 2011 and beyond, EISA 2007, Title I, Section 102.
E. Electric, Hybrid, and Alternative Fuel Vehicle Tax Incentives	Federal tax incentives are provided to encourage the purchase of electric, hybrid and or alternative fuel vehicles. For example, tax incentives for hybrid vehicles in the form of a $2,000 income tax deduction.	Incorporates the Federal tax incentives for hybrid and electric vehicles.	IRS Technical Publication 535; Business Expenses
F. The Working Families Tax Relief Act of 2004	The Act repeals the phase out of the credits which were allowed for qualified electric and clean fuel vehicles for property acquired in 2004 and 2005. The credit is reduced by 75 percent for vehicles acquired in 2006. This will provide an incentive to purchase electric and clean fuel vehicles.	The federal tax incentives are embodied in the code. This will provide an incentive to purchase electric and clean fuel vehicles but little impact is realized on projections of total highway energy use.	Sections 318 and 319 of the Working families Tax Relief Act of 2004.
G. State Electric, Hybrid, and Alternative Fuel Vehicle Tax and other incentives	Approximately 20 States provide tax and other incentives to encourage the purchase of electric, hybrid and or alternative fuel vehicles. The tax incentives are in the form of income reductions, tax credits, and exemptions. Other incentives include use of HOV lanes and exemptions from emissions inspections from emissions inspections and licensing fees. The incentives offered and the mix varies by state. For example, Georgia offers a tax credit of $5,000 for electric vehicles and Oklahoma offers a tax credit of $1,500 for hybrid and alternative fuel vehicles.	Does not incorporate State tax and other incentives for hybrid, electric, and other alternative fuel vehicle.	State laws in Arizona, Arkansas, California, Colorado, Delaware, Florida, Georgia, Iowa, Kansas, Louisiana, Maine, Maryland, Michigan, New Hampshire, New York, Oklahoma, Pennsylvania, Utah, Virginia, and Washington.
H. Energy Policy Act of 2005	Provides tax credits for the purchase of vehicles that have a lean burn engine or employ a hybrid or fuel cell propulsion system. The amount of the credit received for a vehicle is based on the vehicle's inertia weight, improvement in city tested fuel economy relative to an equivalent 2002 base year value, emissions classification, type of propulsion system, and number of vehicles sold.	Incorporates the Federal tax incentives for hybrid and fuel cell vehicles.	Title XIII, Section 1341 of the Energy Policy Act of 2005.

Legislation	Brief Description	AEO Handling	Basis
Electric Power Generation			
A. Clean Air Act Amendment of 1990	Established a national limit on electricity generator emissions of sulfur dioxide to be achieved through a cap and trade program.	Sulfur dioxide cap and trade program is explicitly modeled, choosing the optimal mix of options for meeting the national emissions cap.	Clean Air Act Amendments of 1990, Title IV, Sections 401 through 406, Sulfur Dioxide Reduction Program, 42 U.S.C. 7651a through 7651e.
	Set boiler type specific nitrogen oxide emissions limits for electricity generators.	Assumes each boiler installs the options necessary to comply with their nitrogen oxide emissions limit.	Clean Air Act Amendments of 1990, Title IV, Sections 407, Nitrogen Oxide Emission Reduction Program, 42 U.S.C. 7651f.
	Under section 126, Northeast states petitioned the EPA arguing that generators in other states contributed to the nitrogen oxide emissions problems in their states. EPA established a summer season nitrogen oxide emission cap and trade program covering 22 states (three were removed by the courts) to start in May 2003 (delayed until May 2004).	The 19-state summer season nitrogen oxide cap and trade program is explicitly modeled, allowing electricity generators to choose the optimal mix of control options to meet the emission cap.	Section 126 Rule: Revised Deadlines, Federal Register: April 30, 2002 (volume 67, Number 83). Rules and Regulations, Pages 21521-21530.
	Requires the EPA to establish national ambient air quality standards. In 1997, EPA set new standards for ground level ozone and fine particulates. EPA is currently determining which areas of the country are not in compliance with the new standards. Area designations will be made in December 2004. States will then have until December 2007 to submit their compliance plans, and until 2009-2014 to bring all areas into compliance.	Because stat implementation plans have not been established, these revised standards are not currently represented.	Clean Air Act Amendment of 1990, Title I, Sections 108 and 109, National Ambient Air Quality Standards for Ozone, 40 CFR Part 50, Federal Register, Vol 68, No 3, January 8, 2003. National Ambient Air Quality Standards for Particulate Matter, 40 CFR Part 50, Federal Register, Vol. 62, No. 138, July 18, 1997.
B. Clean Air Interstate Rule (CAIR)	CAIR imposes a two-phased limit on emissions of sulfur dioxide and/or nitrogen oxide from electric generators in 28 states and the District of Columbia	Cap and trade programs for SO_2 and NO_x are modeled explicitly, allowing the model to choose the best method for meeting the emission caps.	*Federal Register*, Vol. 70, No. 91 (May 12, 2005), 40 CFR Parts 51, 72, 73, 74, 77, 78 and 96.
C. Clean Air Mercury Rule (CAMR)	Establishes a national cap on mercury emissions from coal-fired power plants through a cap and trade program, implemented in two phases with a banking provision.	The cap and trade program is modeled explicitly.	Modifies Section 112 of Clean Air Act Amendment of 1990, *Federal Register*, Vol. 70, No. 95 (May 18, 2005), 40 CFR Parts.
D. Energy Policy Act of 1992 (EPACT92)	Created a class of generators referred to as exempt wholesale generators (EWGs), exempt from PUCHA as long as they sell wholesale power.	Represents the development of Exempt Wholesale Generators (EWGs) or what are now referred to as independent power producers (IPPs) in all regions.	Energy Policy Act of 1992, Title VII, Electricity, Subtitle A, Exempt Wholesale Generators.
	Created a permanent investment tax credit (ITC) for solar and geothermal facilities.	The ITCs for renewables are explicitly modeled as stated in the law.	Energy Policy Act of 1992, Title XII, Renewable Energy, Section 1212, Renewable.

Legislation	Brief Description	AEO Handling	Basis
E. The Public Utility Holding Company Act of 1935 (PUCHA)	PUCHA is a US federal statue which was enacted to legislate against abusive practices in the utility industry. The act grants power to the US Securities and Exchange Commission (SEC) to oversee and outlaw large holding companies which might otherwise control the provision of electrical service to large regions of the country. It gives the SEC power to approve or deny mergers and acquisitions and, if necessary, force utility companies to dispose of assets or change business practices if the company's structure of activities are not deemed to be in the public interest.	It is assumed that holding companies act competitively and do not use their regulated power businesses to cross-subsidize their unregulated businesses.	Public Utility Holding Company Act of 1936.
F. FERC Orders 888 and 889	FERC has issues 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 a 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 the forecast 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.	Promoting Wholesale Competition Through Open Access, Non-discriminatory Transmission Services by Public Utilities; Public Utilities and Transmitting Utilities, ORDER NO. 888 (Issued April 24, 1996), 18 CFR Parts 35 and 385, Docket Nos. RM95-8-000 and RM94-7-001. Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, ORDER NO. 889, (Issued April 24, 1996), 18 CFR Part 37, Docket No. RM95-9-000.
G. New Source Review (NSR)	On August 28m 2003, the EPA issued a final rule defining certain power plant and industrial facility activities as routine maintenance, repair and replacement, which are not subject to new source review (NSR). As stated by EPA, these changes provide a category of equipment replacement activities that are not subject to Major NSR requirements under the routine	It is assumed that coal plants will be able to increase their output as electricity demand increases. Their maximum capacity factor is set at 84 percent. No increases in the capacity of existing plants is assumed. If further analysis shows that capacity uprates may result from the NSR rule, they will be incorporated in future AEOs. However, at this time, the NSR rile is being contested in the courts.	EPA, 40 CFR Parts 51 and 52, Prevention of Significant Deterioration (PSD) and Non-Attainment New Source Review (NSR): Equipment Replacement Provision of the Routine Maintenance, Repair and Replacement Exclusion; Final Rule, Federal Register, Vol. 68, No. 207, page 61248, October 27, 2003.

Legislation	Brief Description	AEO Handling	Basis
	maintenance, repair and replacement (RMRR) exclusion.[1] Essentially this means that power plants and industrial facilities engaging in RMRR activities will not have to get preconstruction approval from the State or EPA and will not have to install best available emissions control technologies that might be required if NSR were triggered.		
H. State RPS laws, mandates, and goals	Several States have enacted laws requiring that a certain percentage of their generation come from qualifying renewable sources.	The AEO reference case does not represent the widely varying state requirements for renewable energy capacity because of uncertainty regarding policy design and enforcement. A scenario is presented in the AEO 2007 that examines these laws assuming full compliance.	The 23 states with RPS or other mandates providing quantified projections are detailed in the Legislation and Regulations section of this report.
I. State Environmental Laws	Several Sates have enacted laws requiring emissions reductions from their generating plants.	Where compliance plans have been announced, they have been incorporated. In total 22 gigawatts of planned SO2 scrubbers, 27 gigawatts of planned selective catalytic reduction (SCR) and 3 gigawatts of planned selective non-catalytic reduction (SNCR) are represented.	North Carolina's Clean Smoke Stacks Act, Session Law 2002-4, Senate Bill 1078, An Act to Improve Air Quality in the State by Imposing Limits on the Emission of Certain Pollutants from Certain Facilities that Burn Coal to Generate Electricity and to Provide for Recovery by Electric Utilities of the Costs of Achieving Compliance with those Limits.
J. Energy Policy Act of 2005	Extends Production Tax Credit (PTC) for certain renewable generation through December 31, 2007. The PTC was created by EPACT 1992, and originally applied to wind and some biomass fuels. It was subsequently amended to extend the eligibility period and add additional qualifying fuels. EPAC2005 further extends the eligibility period, and adds certain hydroelectric facilities as qualifying fuels.	EPACT2005 also adds a PTC for up to 6,000 megawatts of new nuclear capacity and a $1.3 billion investment tax credit for new or repowered coal-fired power projects. The tax credits for renewables, nuclear and coal projects are explicitly modeled as specified in the law.	Energy Policy Act of 2005, Sections 1301, 1306, and 1307.
Oil and Gas Supply			
A. The Outer Continental Shelf Deep Water Royalty Relief Act (DWRRA)	Mandates that all tracts offered by November 22, 2000, in deep water in certain areas of the Gulf of Mexico must be offered under the new bidding system permitted by the DWRRA. The Secretary of Interior must offer such tracts with a specific minimum royalty suspension volume based on water depth.	Incorporates royalty rates based on water depth.	43 U.S.C. SS 1331-1356 (2002).
B. Energy Policy and Conservation Act Amendments of 2000	Required the USGS to inventory oil and gas resources beneath Federal lands.	To date, the Rocky Mountain oil and gas resource inventory has been completed by the USGS. The results of this	Scientific Inventory of Onshore Federal Lands: Oil and Gas Resources and Reserves and the Extent and Nature of

Legislation	Brief Description	AEO Handling	Basis
		inventory have been incorporated in the technically recoverable oil and gas resource volumes used for the Rocky Mountain region.	Restrictions or Impediments to their Development: The Paradox/San Juan, Uinta/Piceance, Greater Green River, and Powder River Basins and the Montana Thrust Belt. Prepared by the Departments of Interior, Agriculture and Energy, January 2003.
C. Hackberry Decision	Terminated open access requirements for new onshore LNG terminals and authorized them to charge market-based rather than cost-of-service rates.	This is reflected in lower risk premiums for new terminal construction.	Docket No. PL02-9, Natural Gas Markets Conference (2002).
D. Maritime Security Act of 2002 Amendments to the Deepwater Port Act of 1974	Transfers jurisdiction over offshore LNG facilities from FERC to the Maritime Administration (MARAD) and the Coast Guard, both under the Department of Transportation (DOT), provides these facilities with a new, streamlined application process, and relaxes regulatory requirements (offshore LNG facilities are no longer required to operate as common carriers or to provide open access as they did while under FERC jurisdiction).	This is reflected in lower risk premiums for new terminal construction.	P.L. 107-295.
E. Section 29 Tax Credit for Nonconventional Fuels	The Alternative Fuel Production Credit (Section 29 of the IRC) applies to qualified nonconventional fuels from wells drilled or facilities placed in service between January 1, 1980, and December 31, 1992. Gas production from qualifying wells could receive a 3 dollar (1979 constant dollars) per barrel of oil equivalent credit on volumes produced through December 31, 2002. The qualified fuels are: oil produced from shale and tar sands; gas from geopressurized brine, Devonian shale, coal seams, tight formations, and biomass; liquid, gaseous, or solid synthetic fuels produced from coal; fuel from qualified processed formations or biomass; and steam from agricultural products.	The Section 29 Tax Credit expired on December 31, 2002, and it not considered in new production decisions. However, the effect of these credits is implicitly included in the parameters that are derived from historical data reflecting such credits.	Alternative Fuel Production Credit (Section 29 of the Internal Revenue Code), initially established in the Windfall Profit Tax of 1980.
F. Energy Policy Act of 2005	Established a program to provide grants to enhance oil and gas recovery through CO_2 injection.	Additional oil resources were added to account for increased use of CO_2-enhanced oil recovery.	Title III, Section 354 of the Energy Policy Act of 2005.
Natural Gas Transmission and Distribution			
A. Alaska Natural Gas Pipeline Act, Sections 101-116 of the Military	Disallows approval for a pipeline to enter Canada via Alaska north of 68 degrees	Assumes the pipeline construction cost estimate for the “southern”Alaska pipeline route in projecting when an	P.L. 108-324.

Legislation	Brief Description	AEO Handling	Basis
Construction Hurricane Supplemental Appropriations Act, 2005.	latitude. Also, provides Federal guarantees for loans and other debt obligations assigned to infrastructure in the United States or Canada related to any natural gas pipeline system that carries Alaska natural gas to the border between Alaska and Canada south of 68 degrees north latitude. This authority	Alaska gas pipeline would be profitable to build. Also, when calculating the tariff associated with the Alaska pipeline, the return on debt was lowered by 1 percentage point and the percentage of capital financed by debt was increased by 10, to account for the impact of the loan guarantee.	
	would expire 2 years after the final certificate of public convenience and necessity is issued. The guarantee will not exceed 1) 80 percent of the total capital costs (including interest during construction), 2) $18 billion dollars (indexed for inflation at the time of enactment), or 3) a term of 30 years.		
B. American Jobs Creation Act of 2004, Sections 706 and 707.	Provides a 70year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the currently allowed 15-year recovery period, for tax purposes. The provision would be effective for property placed in service after 2013, or treated as such. Effectively extends the 15-percent tax credit currently applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant on the on the North Slope that would feed gas into an Alaska pipeline to Canada.	When calculating the tariff associated with the Alaska pipeline, the return on equity was lowered by 3 percentage points. Also, the charge associated with removing liquids from natural gas at the gas processing plant for the Alaska natural gas pipeline was decreased by $0.05 per Mcf.	P.L. 108-357.
C. Pipeline Safety Improvement Act of 2002	Imposes a stricter regime on pipeline operators designed to prevent leaks and ruptures.	Costs associated with implementing the new safety features are assumed to be a small percentage of total pipeline costs and are partially offset by benefits gained through reducing pipeline leakage. It is assumed that the Act accelerates the schedule of repair work that would have been done otherwise.	P.L. 107-355, 116 Stat. 2985.
D. FERC Order 436 (Issued in 1985)	Order 436 changed gas transmission from a merchant business, wherein the pipeline buys the gas commodity at the inlet and sold the gas commodity at the delivery point, to being a transportation business wherein the pipeline does not take title to the gas. Order 436 permitted pipelines to apply for blanket transportation certificates, in	Natural gas is priced at the wellhead at a competitive rate determined by the market. The flow of gas in the system is a function of the relative costs and is set to balance supply, demand, and prices in the market. Transportation costs are based on a regulated rate calculation	50 F. R. 42408, FERC Statutes and Regulations Paragraph 30,665 (1985).

Legislation	Brief Description	AEO Handling	Basis
	return for becoming non-discriminatory, open-access transporters. Order 436 also allocated gas pipeline capacity on a first-com, first-serve basis, allowed pipelines to discount below the maximum rate, allowed local gas distributors to convert to transportation only contracts, and created optional expedited certificates for the construction of new facilities.		
E. FERC Order 636 (Issued in 1992)	FERC Order 636 completed the separation of pipeline merchant services from pipeline transportation services, requiring pipelines to offer separate tariffs for firm transportation, interruptible transportation, and storage services. Order 636 also permitted pipelines to resell unused firm capacity as interruptible transportation, gave shippers the right to first refusal at the expiration of their firm transportation contracts, adopted Straight-Fixed-Variable rate methodology, and created a mechanism for pipelines to recover the costs incurred by prior take-or-pay contracts.	A straight-fixed-variable rate design is used to establish regulated rates. To reflect some of the flexibility built into the system, the actual tariffs charged are allowed to vary from the regulated rates as a function of the utilization of the pipeline. End-use prices are set separately for firm and interruptible customers for the industrial and electric generation sectors.	57 F.R. 13267, FERC Statutes and Regulations Paragraph 30,939 (1992)
F. Energy Policy Act of 2005	Allowed natural gas storage facilities to charge market-based rates if it was believed they would not exert market power.	Storage rates are allowed to vary from regulation-based rates depending on market conditions.	Title III, Section 312 of the Energy Policy Act of 2005.
Petroleum Refining			
A. Ultra-Low-Sulfur Diesel (ULSD) regulations under the Clean Air Act Amendment of 1990	80 percent of highway diesel pool must contain 15 ppm sulfur or less starting in fall 2006. By mid-2010, all highway diesel must be 15 ppm or less. All nonroad, locomotive, and marine diesel fuel produced must contain less than 500 ppm starting mid-2007. By mid-2010 nonroad diesel must contain less than 15 ppm. Locomotive and marine diesel must contain less than 15 ppm by mid-2012.	Reflected in diesel specifications	40 CFR Parts 69, 80, 86, 89, 94, 1039, 1048, 1065, and 1068
B. Mobile Source Air Toxics (MSAT) controls under the Clean Air Act Amendment of 1990	Establishes a list of 21 substances emitted from motor vehicles and known to cause serious human health effects, particularly benzene, formaldehyde, 1.3 butadiene, acetaldehyde, diesel exhaust organic gases, and diesel particulate matter. Establishes anti-backsliding and anti-dumping rules for gasoline.	Modeled by updating gasoline specifications to most current EPA gasoline survey data (2005) representing anti-backsliding requirements.	40 CFR Parts 60 and 86.

Legislation	Brief Description	AEO Handling	Basis
C. Low-Sulfur Gasoline Regulations under the Clean Air Act Amendment of 1990	Gasoline must contain an average of 30 ppm sulfur or less by 2006. Small refiners may be permitted to delay compliance until 2008.	Reflected in gasoline specifications.	40 CFR Parts 80, 85 and 86
D. MTBE Bans in 25 States	23 States ban the use of MTBE in gasoline by 2007	Ethanol assumed to be the oxygenate of choice in RFG where MTBE is banned.	State laws in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin.
E. Regional clean fuel formulations under the Clean Air Act Amendments of 1990	States with air quality problems can specify alternative gasoline or diesel formulations with EPA's permission. California has long had authority to set its own fuel standards.	Reflected in PADD-level gasoline and diesel specifications.	State implementation plans required by the Clean Air Act Amendments of 1990, as approved by EPA.
F. Federal Motor Fuels Excise Taxes	Taxes are levied on each gallon of transportation fuels to fund infrastructure and general revenue. These taxes are set to expire at various times in the future but are expected to be renewed, as they have been in the past.	Gasoline, diesel, and ethanol blend tax rates are included in end-use prices and are assumed to be extended indefinitely at current nominal rates.	26 USC 4041 Extended by American Jobs Creation Act of 2004
G. State Motor Fuel Taxes	Taxes are levied on each gallon of transportation fuels. The assumption that State taxes will increase at the rate of inflation supports an implied need for additional highway revenues as driving increases.	Gasoline and diesel rates are included in end-use prices and are assumed to be extended indefinitely in real terms (to keep pace with inflation).	Determined by review of existing State laws performed semi-annually by EIA's Office of Oil and Gas.
H. Diesel Excise Taxes	Phases out the 4.3 cents excise tax on railroads between 2005 and 2007.	Modeled by phasing out.	American Jobs Creation Act of 2004, Section 241.
I. Energy Policy Act of 2005 (EPACT05)			
a. Ethanol/biodiesel Tax Credit	Petroleum product blenders may claim tax credits for blending ethanol into gasoline and for blending biodiesel into diesel fuel or heating oil. The credits may be claimed against the Federal motor fuels excise tax or the income tax. The tax credits are 51 per gallon of nonvirgin biodiesel, and $1.00 per gallon of virgin biodiesel. The ethanol tax credit expires in 2010. The biodiesel tax credits expire after 2008.	The tax credits are applied against the production costs of the products into which they are blended. Ethanol is used in gasoline and E85. Virgin biodiesel is assumed to be blended into highway diesel, and nonvirgin biodiesel is assumed to be blended into nonroad diesel or heating oil.	26 USC 40, 4041 and American Jobs Creation Act of 2004. Biodiesel tax credits extended to 2008 under Energy Policy Act of 2005.
b. Renewable Fuels Standard (RFS)	This section has largely been redefined by EISA07 (see below) however EPA rulemaking completed for this law was assumed to contain guiding principles for the rules and administration of EISA07.		Energy Policy Act of 2005, Section 1501.

Legislation	Brief Description	AEO Handling	Basis
c. Elimination of Oxygen Content Requirement in Reformulated Gasoline	Within 270 days of enactment of the Act, except for California where it is effective immediately.	Oxygenate waiver already in option of the model. MTBE is assumed to phase out in 2006 resulting from the petroleum industry''s decision to discontinue use. AEO projection may still show use of ethanol in gasoline based on the economics between ethanol and other gasoline blending components.	Energy Policy Act of 2005, Section 1504.
d. Coal Gasification Provisions	Investment tax credit program for qualifying advanced clean coal projects including Coal to Liquids Projects.	Two CTL units are available to build with lower capital costs reflecting the provision's funding.	Energy Policy Act of 2005, Section 1307.
J. Energy Independence and Security Act of 2007 (EISA07)			
a. Renewable Fuels Standard (RFS)	Requires the use of 36 billion gallons of ethanol per year by 2022, with corn ethanol limited to 15 billion gallons. Any other biofuel may be used to fulfill the balance of the mandate, but the balance must include 16 billion gallons per year of cellulosic biofuel by 2022 and 1 billion gallons per year of biodiesel by 2012.	The RFS is included in AEO2008, however it is assumed that the schedule for cellulosic biofuel is adjusted downward consistent with waiver provisions contained in the law.	

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

Abbreviations:

AEO: Annual Energy Outlook
AFUE: Average Fuel Use Efficiency
Btu: British Thermal Unit
CAF…: Corporate Average Fuel Economy
CBECS: Commercial Building Energy Consumption Survey
CFR: Code of Federal Regulations
DOE: Department of Energy
DOT: Department of Transportation
DWRRA: Deep Water Royalty Relief Act
EER: Energy Efficient Ratio
EF: Energy Efficiency
EIA: Energy Information Administration
EPA: Environmental Protection Agency
EPACT92: Energy Policy Act of 1992
EPACT05: Energy Policy Act of 2005
EWGs: Exempt Wholesale Generators
FERC: Federal Energy Regulatory Commission
HERS: Home Energy Efficiency Rating
HVAC: Heating, Ventilation, and Air Conditioning IECC: International Energy Conservation Code ITC: Investment Tax Credit
kWh: Kilowatthour
LBNL: Lawrence Berkeley National Laboratory
LEVP: Low Emission Vehicle Program
LNG: Liquified Natural Gas
MARAD: Maritime Administration
MEF: Modified Energy Factor
MSAT: Mobile Source Air Toxics MTBE: Methyl-Tertiary-Butyl-Ether
OASIS: Open Access Same-Time Information System
PADD: Petroleum Administration for Defense Districts
P.L.: Public Law
PPM: Parts Per Million
PTC: Production Tax Credit
PUCHA: Public Utility Holding Company Act of 1935
RECS: Residential Energy Consumption Survey
RPS: Renewable Portfolio Standard
SCR: Selective Catalytic Reduction
SEER: Seasonal Energy Efficiency Rating
SO2: Sulfur Dioxide
SNCR: Selective Non-Catalytic Reduction
ULSD: Ultra-Low Sulfur Dioxide
U.S.C.: United States Code
USGS: United States Geological Survey
ZEV: Zero Emission Vehicle