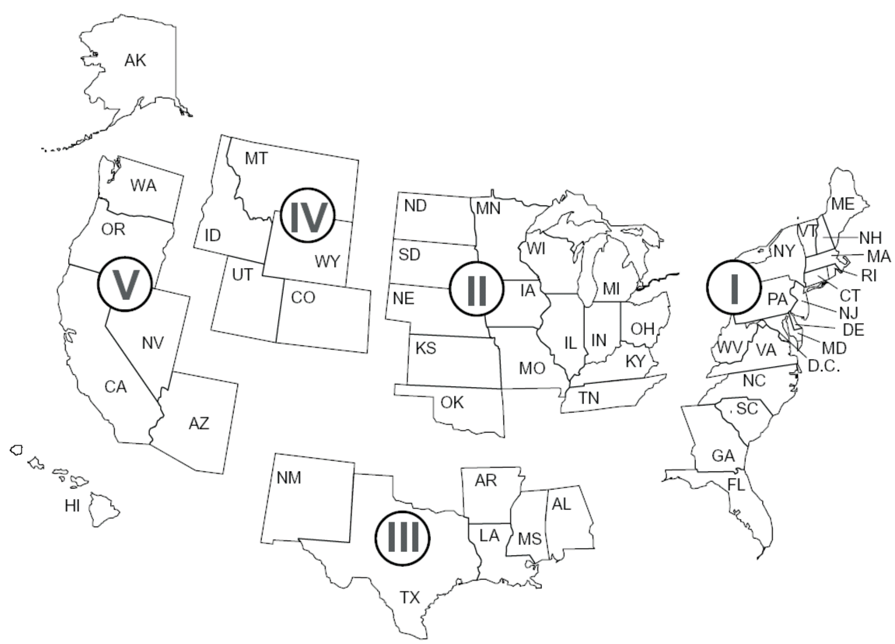
Petroleum Market Module

The NEMS Petroleum Market Module (PMM) forecasts 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, other refinery inputs including alcohols, ethers, and bioesters natural gas plant liquids production, and refinery processing gain. In addition, the PMM estimates capacity expansion and fuel consumption of domestic refineries.

The PMM contains a linear programming representation of U.S. refining activities in the five Petroleum Area Defense Districts (PADDs) (Figure 9). The PADDs are created by aggregating individual refineries into one linear programmming representation for each region. This representation provides the marginal costs of production for a number of traditional 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 60.

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, except that the sulfur content of all gasoline and on-highway diesel fuel will be phased down to reflect EPA regulations.

Table 60. 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

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 PMM to differentiate between conventional and reformulated gasoline blends (Table 61): oxygen content, Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, olefin content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The sulfur specification for gasoline is reduced 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 the years 2004 and 2007.[98] PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The reduction in sulfur content between now and 2004 is assumed to reflect incentives for “early reduction”. The 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

Table 61. Year Round Gasoline Specifications by Petroleum Administration for Defense Districts (PADD)

PADD	Reid Vapor Pressure (Max PSI)	Oxygen Weight Percent (Min)	Oxygen Weight Percent (Max)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Initial Sulfur PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200°	Percent Evaluated at 300°
Conventional									
PADD I	9.6	—	—	26.0	1.1	338.4	11.6	47.1	82.0
PADD II	10.2	—	—	26.1	1.1	338.4	11.6	47.1	81.9
PADD III	9.9	—	—	26.1	1.1	338.4	11.6	47.1	81.9
PADD IV	10.8	—	—	26.1	1.1	338.4	11.6	47.1	81.9
PADD V	9.2	—	—	26.7	1.1	338.4	11.6	45.7	81.4
Reformulated									
PADD I	8.5	2.0	2.1	20.7	0.6	135.0	11.9	50.2	84.6
PADD II	9.5	2.0	2.1	18.5	0.8	135.0	7.1	50.8	85.6
PADD III	8.6	2.0	2.1	19.8	0.6	135.0	11.2	51.6	83.9
PADD V									
Nonattainment	7.9	2.0	2.1	22.0	0.70	25.0	6.0	49.0	85.0
CARB (attainment)	7.9	—	1.2	22.0	0.70	25.0	6.0	49.0	85.0

Max = Maximum.

Min = Minimum.

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 2002 gasoline projection survey (http://www.epa.gov/otag/regs/fuels/rfg/properf/rfgper.htm).

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 are provided in Table 62.

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 compliance standards which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions.[99]

Table 62. Gasoline Sulfur Content Assumptions, by Region and Gasoline Type, Parts per Million (PPM)

	2004	2005	2006	2007	2008-2025
Conventional					
PADD I	143.4	90.0	43.4	41.7	30
PADD II	167.7	111.0	60.0	33.2	30
PADD III	170.5	114.5	60.0	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).

Oxygenated gasoline, which has been required during winter in many U.S. cities since October of 1992, requires an oxygenated content of 2.7 percent by weight. Oxygenated gasoline is assumed to have specifications identical to conventional gasoline with the exception of a higher oxygen requirement. 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. Capital and operating costs for biomass ethanol are derived from an Oak Ridge National Laboratory report.[100]

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 company; 1990 baseline 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 61).

The Clean Air Act Amendments of 1990 (CAAA90) provided for special treatment of California that would allow different specifications for oxygenated and reformulated gasoline in that State. In 1992, California requested a waiver from the winter oxygen requirements of 2.7 percent to reduce the requirement to a range of 1.8 to 2.2 percent. The PMM assumes that PADD V refiners must meet the California Air Resources Board (CARB) Phase 3 specifications after 2003. The CARB Phase 3 specifications reflect the removal of the oxygen requirement designed to complement the State's plans to ban the oxygenate, methyl tertiary butyl ether (MTBE) by the end of 2003. Without a waiver from the U.S. EPA, a minimum oxygen content will still be required in the areas of California covered by the Federal reformulated gasoline program (Los Angeles, San Diego, Sacramento, and San Joaquin Valley). *AEO2004* assumes that the oxygen requirement remains intact in these areas because no waiver had been granted at the time of the development of the forecast.

AEO2004 reflects legislation which bans or limits the use of MTBE in 16 additional States: Colorado, Connecticut, Illinois, Iowa, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, Wisconsin, Washington, Indiana, Kentucky, Ohio, and Missouri. Since the oxygen requirement on RFG is assumed to continue in these States, the MTBE ban is modeled as a requirement to produce ethanol blended RFG. Ethanol blends were assumed to account for the following market percentages:

— 29.0 percent of RFG in New England
— 36.5 percent of RFG in Mid-Atlantic
— 99.0 percent of RFG in Mountain
— 100.0 percent of RFG(with 2.0 percent oxygen requirement) in Pacific
— 100.0 percent of oxygenated gasoline in West North Central
— 100.0 percent of oxygenated gasoline in Mountain
— 100.0 percent of oxygenated gasoline in Pacific

Rvp limitations are effective during summer months, which are defined differently in different 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 able to change over time based on assumptions about the market penetration of new fuels. In *AEO2004,* the annual market shares for each region reflect actual 2001 market shares and are held constant throughout the forecast. (See Table 63 for *AEO2004* market share assumptions.)

Table 63. 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 Slouth Central	Mountain	Pacific
Conventional Gasoline	20	42	80	69	82	94	71	70	20
Oxygenated Gasoline (2.7% oxygen)	0	0	0	24	0	0	0	15	6
Reformulated Gasoline (2.0% oxygen)	80	58	20	7	18	6	29	15	74*

*Note: 59 percent is assumed to continue the 2.0 percent Federal oxygen 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 2002.

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulfurization regulations related to 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 500 ppm.

AEO2004 also 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 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. As NEMS is an annual average model, 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.

NEMS models ULSD as containing 7.5 ppm sulfur at the refinery gate in 2006, phasing down to 7ppm sulfur by 2010. 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.

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

The capital costs for new distillate hydrotreaters reflected in *AEO2004* are $1,243 to $2,437 (2002 dollars) per barrel per day (Inside Battery Limit). The lower estimate is for a 30,000 barrel per day unit utilizing Conoco Philips Z-sorb desulfurization tehnology. The higher estimate is for a 30,000 barrel per day unit processing higher sulfur feed streams with greater aromatics improvement.

The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the start of the program, declining to 4.4 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 lower value product. The amount of the revenue loss is estimated offline based on earlier NEMS results and is included in *AEO2004* ULSD price projections as a distribution cost. The revenue loss associated with the 10 percent downgrade assumption for 2007 is 0.7 cents per gallon. The revenue loss estimate declines to 0.2 cents per gallon after 2010 when the downgrade assumption declines to 4.4 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.[101] Capital costs of 0.7 cents per gallon are assumed for additional storage tanks 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 for the entire forecast. Another 0.2 cents per gallon is assumed for the cost of 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 desulfurization process.

Demand for highway-grade diesel, both 500 ppm and ULSD combined, is assumed to be equivalent to 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 by 0.5 percent because undercutting and severe desulfurization will result in a lighter stream composition than that for 500 ppm diesel.

No change in the sulfur level of non-road diesel is assumed because the EPA has not yet promulgated these standards.

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 by the model 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 fixed distribution costs to the marginal and refinery fixed costs of products. The distribution costs are applied at the Census Division level (Table 64) and are assumed to be constant throughout the forecast and across scenarios.

Table 64. Petroleum Product End-Use Markups by Sector and Census Division
(2002 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	0.47	0.34	0.27	0.45	0.31	0.21	0.29	0.42
Kerosene	0.17	0.31	0.43	0.26	0.32	0.40	0.23	0.19	0.08
Liquefied Petroleum Gases	0.91	0.97	0.54	0.36	0.82	0.69	0.61	0.57	0.84
Commercial Sector									
Distillate Fuel Oil	0.15	0.12	0.06	0.03	0.07	0.04	0.04	0.04	0.07
Gasoline	0.16	0.13	0.14	0.15	0.13	0.17	0.17	0.16	0.16
Kerosene	0.16	0.26	0.46	0.26	0.30	0.41	0.19	0.20	0.10
Liquefied Petroleum Gases	0.57	0.57	0.48	0.36	0.57	0.45	0.38	0.49	0.61
Low-Sulfur Residual Fuel Oil	0.00	0.03	0.01	0.01	0.00	0.03	-0.01	0.03	0.09
Utility Sector									
Distillate Fuel Oil	0.02	0.03	0.02	0.01	0.02	0.06	0.03	0.07	0.02
High-Sulfur Residual Fuel Oil[2]	0.00	0.03	0.09	-0.04	0.01	-0.06	0.07	0.01	0.08
Low-Sulfur Residual Fuel Oil[3]	-0.01	0.00	0.08	-0.07	0.01	-0.11	0.11	0.23	0.19
Transportation Sector									
Distillate Fuel Oil	0.24	0.18	0.14	0.12	0.14	0.16	0.13	0.14	0.20
E85[1]	0.17	0.14	0.16	0.17	0.15	0.19	0.20	0.19	0.15
Gasoline	0.15	0.13	0.14	0.15	0.13	0.17	0.17	0.17	0.13
High-Sulfur Residual Fuel Oil[2]	-0.02	0.04	0.12	-0.04	0.00	-0.08	0.06	0.28	0.05
Jet Fuel	0.02	-0.01	-0.02	-0.04	-0.03	0.00	0.00	-0.02	0.00
Liquefied Petroleum Gases	0.51	0.53	0.59	0.33	0.52	0.40	0.32	0.42	0.55
Industrial Sector									
Asphalt and Road Oil	0.23	0.18	0.29	0.17	0.16	0.09	0.19	0.36	0.18
Distillate Fuel Oil	0.16	0.14	0.14	0.11	0.11	0.09	0.10	0.08	0.13
Gasoline	0.15	0.13	0.14	0.16	0.13	0.18	0.17	0.16	0.14
Kerosene	0.10	0.11	0.15	0.18	0.15	0.17	0.08	0.13	0.11
Liquefied Petroleum Gases	0.44	0.49	0.55	0.29	0.49	0.40	0.24	0.29	0.54
Low-Sulfur Residual Fuel Oil	0.00	0.00	0.03	0.02	0.01	-0.01	0.01	0.09	0.09

[1]85 percent ethanol and 15 percent gasoline.

[2]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.

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 1999*, DOE/EIA-0214(99), (Washington, DC, May 2001); EIA, *State Energy Price and Expenditures Report 1999*, DOE/EIA-0376(99), (Washington, DC, November 2001).

Distribution costs for each product, sector, and Census Division represent average historical differences between end-use and wholesale prices. The distribution costs for kerosene are the average difference between end-use prices of kerosene and wholesale distillate prices. Distribution costs for E85 are assumed to be equal to distribution costs for gasoline.

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 65 and 66). Recent tax trend analysis indicated that State taxes increase at the rate of inflation, therefore, State taxes are held constant in real terms throughout the forecast. This assumption is extended to local taxes which are assumed to average 2 cents per gallon.[102] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2004* assumption of current laws and regulation. 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. State and Local Taxes on Petroleum Transportation Fuels by Census Division
(2002 dollars per gallon)

	Census Division								
Year/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Gasoline[1]	0.25	0.23	0.26	0.22	0.19	0.21	0.22	0.23	0.27
Diesel	0.21	0.24	0.22	0.20	0.19	0.16	0.20	0.22	0.24
Liquefied Petroleum Gases	0.21	0.12	0.16	0.19	0.17	0.16	0.15	0.09	0.05
E85[2]	0.27	0.19	0.16	0.17	0.14	0.17	0.20	0.14	0.13
Jet Fuel	0.03	0.03	0.01	0.03	0.05	0.03	0.00	0.03	0.03

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

[2] 85 percent ethanol and 15 percent gasoline.

Source: Gasoline, diesel and E85 aggregated from Petroleum Marketing Monthly DE/EIA-0380(2003/04), Table EN1, (Washington, DC, September 2003). LPG aggregated from Federal Highway Administration, Tax Rates on Motor Fuel, Jet fuel from EIA, Office of Oil and Gas.

Table 66. Federal Taxes
(Nominal dollars per gallon)

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases	0.14
M85[1]	0.09
E85[2]	0.13

[1]85 percent methanol and 15 percent gasoline.

[2] 85 percent ethanol and 15 percent gasoline.

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

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 67.

Table 67. Crude Oil Specifications

Crude Oil Categories	Sulfur (percent)	Gravity (degrees API)
Low Sulfur Light	0 - 0.5	> 32
Medium Sulfur Heavy	0.35 - 1.1	> 24
High Sulfur Light	> 1.1	> 32
High Sulfur Heavy	> 1.1	24 - 33
High Sulfur Very Heavy	> 0.7	0 - 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 that fall into each 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 capacity, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, alkylation, and methyl tertiary butyl ether manufacture. 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 a10-percent hurdle rate in the decision to invest and a 10-percent rate of return over a 15-year financial plant life. Expansion through 2004 is determined by adding to the existing capacities of units planned and under construction that are expected to begin operating during this time. Capacity expansion plans are done every 3 years. The PMM looks ahead in 2002 and determines the optimal capacities given the estimated demands and prices expected in the 2005 forecast year. The PMM then allows one-third of that capacity to be built in each of the forecast years 2003, 2004, and 2005. At the end of 2005 the cycle begins anew, looking ahead to 2008.

Capacity expansion of ethanol plants are not modeled explicitly, but as a variable in computing ethanol supply curves. A more detailed description of this process can be found in Appendix I of the PMM documentation, NEMS Petroleum Market Model Documentation, DOE/EIA-M059(Washington, DC, 2004).

Strategic Petroleum Reserve Fill Rate

AEO2004 assumes no additions for the Strategic Petroleum Reserve (SPR) during the forecast period. Any SPR draw is assumed to be in the form of a swap with a zero net annual change.

Biofuels Supply

The PMM provides supply functions on an annual basis through 2025 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.

- Current U.S ethanol production capacity is aggregated by Census Division in the PMM. Cellulose ethanol demonstration plants are modeled in Census Divisions 2 and 7. However, the majority of cellulose ethanol growth is projected in Census Divisions 3 and 4 using corn stover as feedstock, and in Census Division 9 with rice straw and forest residue as the primary feedstock.

- The tax subsidy to ethanol is 53 cents per gallon of ethanol (5.3 cents per gallon subsidy to gasohol at a 10-percent volumetric blending portion) is applied within the model. This subsidy is scheduled to be reduced to 51 cents by 2007. The tax subsidy is held constant in nominal terms, decreasing with inflation throughout the forecast. The subsidy is assumed not to expire during the forecast period.

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. Based on data through the third quarter of 2002, biodiesel output is projected to grow by 8.2 million gallons per year until the subsidy expires at the end of 2006. Thereafter, biodiesel output is projected to grow by 1.8 percent per year.

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

If prices for lower sulfur distillates reach a high enough level to make gas-to-liquids (GTL) facilities economic, it is assumed that they will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,750 per barrel of daily capacity (2002 dollars). Operating costs are assumed to be $4.04 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.88 to $4.50 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feed is assumed to cost $0.83 per thousand cubic feet (2002 dollars).

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 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic fuels per day and 696 megawatts of capacity for electricity cogeneration sold to the grid.[103] A CTL facility of this size is assumed to cost over $2 billion in initial capital investment. CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($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). CTL capacity is projected to be built only in the *AEO2004* high world oil price case.

Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum resid, etc.) is represented in *AEO2004*. 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 *AEO2004* forecast, 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 2002 data:

Region	Percent Sold To Grid
PADD I	67.0
PADD II	0.9
PADD III	2.2
PADD IV	0.9
PADD V	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 price of electricity.

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 of the generation price and the industrial price of electricity for each PMM region. Electricity prices are obtained from the Electricity Market Model.

Short-term Methodology

Petroleum balance and price information for the years 2003 and 2004 are projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM adopts the *STEO* results for 2003 and 2004, 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, which 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. The reformulated gasoline in areas of the Pacific region covered by the Federal RFG program continue to require 2.0 percent oxygen.

AEO2004 reflects legislation which bans or limits the use of the gasoline blending component MTBE in the following states: California, Colorado, Connecticut, Illinois, Iowa, Kansas, Michigan, Minnesota, Nebraska, New York, South Dakota, Washington, Wisconsin, Indiana, Kentucky, Ohio, and Missouri.

AEO2004 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.

AEO2004 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.

Lifting the ban on exporting Alaskan crude oil was passed and signed into law (PL 104-58) in November 1995. Alaskan exports of crude oil have represented about 60 percent of U.S. crude oil exports since November 1995 and are assumed to equal 60 percent of total U.S. crude oil exports in the forecast.

Notes and Sources

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

[99] 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).

[100] M. Walsh, R. Perlock, D. Becker, A Turhollow, and R. Graham, "Evolution of the Fuel Ethanol Industry: Feedstock Availability and Price", Oak Ridge National Laboratory (June 5, 1997).

[101] U.S. Environmental Protection Agency, Regulatory Impact Analysis: Heavy=Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements, EPA420-R-00-026 (Washington, DC, December 2000).

[102] American Petroleum Institute, *How Much We Pay for Gasoline*: 1996 Annual Review, May 1997.

[103] Based on the methodology described in D. Gray and G. Tomlinson, Coproduction: A Green Coal Technology, Technical Report MP 2001-28 (Mitretek, March 2001).