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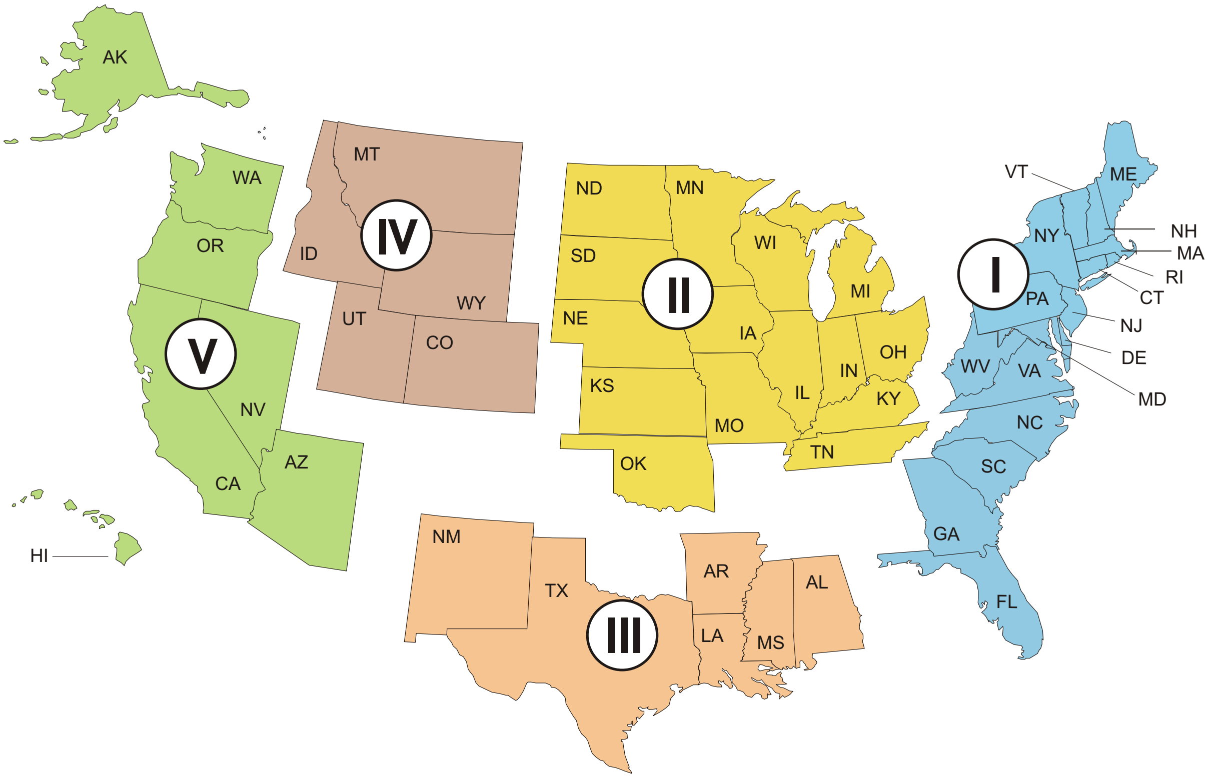
# Petroleum Market Module

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, 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 model is created by aggregating individual refineries into one linear programmming representation for each PADD. 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 9) 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 61.

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 diesel fuel will be phased down to reflect EPA regulations.

**Table 61. 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<br>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 PMM to differentiate between conventional and reformulated gasoline blends (Table 62): 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 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.[95] PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and meets the 30 ppm requirement in 2004. 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 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 63.

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.[96]

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[97] and the USDA Agricultural Baseline Projections to 2013.[98]

## Table 62. 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) | 2006 Sulfur PPM (Max) | Olefin Volume Percent (Max) | Percent Evaporated at 200° | Percent Evaluated at 300° |
|---|---|---|---|---|---|---|---|
| **Conventional** | | | | | | | |
| PADD I | 9.6 | 26.0 | 1.1 | 43.4 | 11.6 | 47.1 | 82.0 |
| PADD II | 10.2 | 26.1 | 1.1 | 60.0 | 11.6 | 47.1 | 81.9 |
| PADD III | 9.9 | 26.1 | 1.1 | 60.0 | 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 | 11.6 | 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 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 2004 gasoline projection survey (http://www.epa.gov/otag/regs/fuels/rfg/properf/rfgperf.htm).

## Table 63. 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 | 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).

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).

*AEO2006* reflects legislation which bans or limits the use of MTBE in 25 States: Arizona, California, Colorado, Connecticut, Illinois, Iowa, Kansas, Maine, Michigan, Minnesota, Montana, Nebraska, New Hampshire, New Jerxey, New York, North Carolina, Rhode Island, South Dakota, Vermont, Wisconsin, Washington, Indiana, Kentucky, Ohio, and Missouri. Furthermore, MTBE is assumed to phase out by the end of 2008 as a result of Energy Policy Act of 2005 (EPACT05) which allows refiners to discontinue use of oxygenates in reformulated gasoline, and on the concern over MTBE's impact to surface water and groundwater resources. Ethanol is assumed to be the oxygenate of choice in areas required to use oxygenated gasoline. Ethanol is also allowed to blend into conventional or reformulated gasoline up to 10 percent by volume, depending on its blending value and relative cost competitiveness with other gasoline blending components. EPACT05 requires 7.5 billion gallons of renewable fuels (mostly ethanol) to be blended into transportation fuels by 2012. With the world oil price and ethanol cost assumptions for *AEO2006*, ethanol is projected to be blended at 10 percent in gasoline in the Midwest and mostly all RFG after 2008.

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 *AEO2006,* the annual market shares for each region reflect actual 2004 market shares and are held constant throughout the forecast. (See Table 64 for *AEO2006* market share assumptions.)

**Table 64. 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** | 19 | 42 | 80 | 67 | 82 | 95 | 72 | 71 | 22 |
| **Oxygenated Gasoline** (2.7% oxygen) | 0 | 0 | 0 | 25 | 0 | 0 | 1 | 14 | 3 |
| **Reformulated Gasoline** | 81 | 58 | 20 | 8 | 18 | 5 | 27 | 15 | 75* |

*Note: 59 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 2004.

## *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.

*AEO2006* 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 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 *AEO2006* are $1,804 to $2,507 (2004 dollars) per barrel per day (Inside Battery Limit). The lower estimate is for a 30,000 barrel per day unit processing relatively low aromatic streams. 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 *AEO2006* 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.[99]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.

*AEO2006* 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 will diminish over time while the demand for ULSD (both highway and NRLM) will increase over time.

The final 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 and establishes a new ultra-low-sulfur diesel (ULSD) limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the action establishes a ULSD limit of 15 ppm in mid-2012.

## *Energy Policy Act of 2005*

Numerous provisions of EPACT05 will affect the supply, composition, and refining of petroleum and related products. Major provisions of EPACT05 represented in the model for *AEO2006* are discussed below.

EPACT05 requires the production and use of 4.0 billion gallons of renewable fuels in 2006, increasing to 7.5 billion gallons by 2012. For calendar year 2013 and each year thereafter, the minimum required volume of renewable fuels will be determined as equal to the percentage amount that 7.5 billion gallons represents of the total gasoline sold in the Nation in 2012. Additionally, starting in 2013 the renewable fuels shall include a minimum of 250 million gallons that are derived from cellulosic biomass. Both ethanol and biodiesel are considered to be renewable fuels receiving one credit towards the renewable fuels standard for every gallon produced. Ethanol produced from cellulosic biomass will receive 2.5 credits.

The renewable fuels standard (RFS) is modeled in *AEO2006*, by setting the minimum required volumes for the RFS as well as for the ethanol derived from cellulosic biomass. Actual renewable fuel supplies may or may not exceed those minimum requirements depending on the relative costs between renewable fuels and competing petroleum products. For example, in the *AEO2006* reference case, more ethanol is projected than the RFS due to cheaper costs. *AEO2006* implicitly reflects the ethanol production and consumption behavior that resembles the effect of a national RFS credit trading system, resulting in ethanol blending in gasoline varying by region.

EPACT05 also eliminates the oxygen content requirement for reformulated gasoline. This provision takes effect 270 days after enactment of EPACT05. Without the oxygen content requirement, refiners are likely to phase out methyl tertiary butyl ether (MTBE) in gasoline as soon as practical to minimize exposure to environmental liabilities in the future. The elimination of the oxygen requirements for reformulated gasoline (RFG) are modeled in *AEO2006.* MTBE is assumed to be completely phased out by the end of 2008 — first in the East Coast by 2006, then Mid-Atlantic by 2007, and finally Texas and Louisiana by 2008. Ethanol is likely to be favored in RFG blending in most regions still based on economics and its other attractive blending characteristics, such as its high octane value.

## *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 product-specific distribution costs to the marginal refinery costs of products (product wholesale price). The distribution costs are derived from a set of base distribution markups (Table 65), with 1/3 of the cost's value adjusted in response to the change in product retail price. For example, given the base markup of 0.25 for transportation sector gasoline in the NE, the distribution cost would be 2/3 * 0.25 plus 1/3 * (base ratio of markup to product wholesale price) * product wholesale price. The base ratio of markup to product wholesale price is set at the beginning of the forecast using the 2003 product wholesale prices and base distribution markups. The distribution costs are applied at the Census Division level, and will vary throughout the forecast and across scenarios

**Table 65. Petroleum Product End-Use Markups by Sector and Census Division**
(2004 dollars per gallon)

| | Census Division | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Sector/Product | 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 | 0.42 | 0.49 | 0.35 | 0.28 | 0.47 | 0.32 | 0.22 | 0.30 | 0.43 |
| Kerosene | 0.17 | 0.32 | 0.45 | 0.27 | 0.33 | 0.41 | 0.24 | 0.20 | 0.09 |
| Liquefied Petroleum Gases | 0.95 | 1.01 | 0.56 | 0.38 | 0.85 | 0.72 | 0.64 | 0.59 | 0.87 |
| **Commercial Sector** | | | | | | | | | |
| Distillate Fuel Oil | 0.16 | 0.13 | 0.06 | 0.03 | 0.07 | 0.04 | 0.05 | 0.04 | 0.08 |
| Gasoline | 0.16 | 0.14 | 0.15 | 0.15 | 0.14 | 0.18 | 0.18 | 0.17 | 0.17 |
| Kerosene | 0.17 | 0.27 | 0.48 | 0.27 | 0.31 | 0.43 | 0.20 | 0.21 | 0.10 |
| Liquefied Petroleum Gases | 0.59 | 0.60 | 0.50 | 0.36 | 0.59 | 0.47 | 0.39 | 0.51 | 0.64 |
| Low-Sulfur Residual Fuel Oil | 0.00 | 0.04 | 0.02 | 0.01 | 0.00 | 0.04 | -0.01 | 0.04 | 0.10 |
| **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[1] | 0.00 | 0.03 | 0.09 | -0.04 | 0.01 | -0.06 | 0.07 | 0.01 | 0.08 |
| Low-Sulfur Residual Fuel Oil[1] | -0.01 | 0.00 | 0.09 | -0.07 | 0.01 | -0.11 | 0.11 | 0.24 | 0.20 |
| **Transportation Sector** | | | | | | | | | |
| Distillate Fuel Oil | 0.25 | 0.19 | 0.15 | 0.12 | 0.15 | 0.16 | 0.13 | 0.15 | 0.21 |
| E85[2] | 0.16 | 0.13 | 0.15 | 0.16 | 0.14 | 0.18 | 0.18 | 0.17 | 0.14 |
| Gasoline | 0.26 | 0.24 | 0.23 | 0.25 | 0.21 | 0.26 | 0.27 | 0.26 | 0.22 |
| High-Sulfur Residual Fuel Oil[1] | -0.02 | 0.04 | 0.13 | -0.04 | 0.00 | -0.09 | 0.06 | 0.29 | 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 | 0.54 | 0.55 | 0.62 | 0.34 | 0.54 | 0.41 | 0.33 | 0.44 | 0.57 |
| **Industrial Sector** | | | | | | | | | |
| Asphalt and Road Oil | 0.24 | 0.18 | 0.30 | 0.18 | 0.17 | 0.10 | 0.20 | 0.38 | 0.19 |
| Distillate Fuel Oil | 0.17 | 0.15 | 0.14 | 0.11 | 0.11 | 0.09 | 0.11 | 0.08 | 0.13 |
| Gasoline | 0.16 | 0.14 | 0.15 | 0.16 | 0.14 | 0.18 | 0.18 | 0.17 | 0.14 |
| Kerosene | 0.10 | 0.11 | 0.16 | 0.19 | 0.15 | 0.18 | 0.08 | 0.13 | 0.12 |
| Liquefied Petroleum Gases | 0.46 | 0.51 | 0.57 | 0.30 | 0.50 | 0.40 | 0.25 | 0.30 | 0.56 |
| Low-Sulfur Residual Fuel Oil | 0.00 | 0.00 | 0.03 | 0.02 | 0.01 | -0.01 | 0.01 | 0.10 | 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 2000, Consumption (March 2003); EIA, State Energy Data 2000: Prices and Expenditures* (March 2003).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 66 and 67). 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.[100] Federal taxes are assumed to remain at current levels in accordance with the overall *AEO2006* 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 66. State and Local Taxes on Petroleum Transportation Fuels by Census Division**
(2004 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 | 0.25 | 0.24 | 0.22 | 0.19 | 0.20 | 0.22 | 0.23 | 0.22 |
| Diesel | 0.28 | 0.24 | 0.24 | 0.22 | 0.22 | 0.19 | 0.21 | 0.25 | 0.23 |
| Liquefied Petroleum Gases | 0.11 | 0.11 | 0.16 | 0.17 | 0.16 | 0.16 | 0.12 | 0.13 | 0.05 |
| E85[2] | 0.24 | 0.23 | 0.24 | 0.18 | 0.19 | 0.20 | 0.22 | 0.23 | 0.15 |
| Jet Fuel | 0.04 | 0.04 | 0.00 | 0.03 | 0.05 | 0.02 | 0.01 | 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 2005-14, July 14, 2005. 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.

**Table 67. 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] 74 percent ethanol and 26 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 68.

**Table 68. 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 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, and alkylation 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 a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment at about 9 percent. Capacity expansion plans are done every 3 years. The PMM looks ahead in 2004 and determines the optimal capacities given the estimated demands and prices expected in the 2007 forecast year. The PMM then allows one-third of that capacity to be built in each of the forecast years 2005, 2006, and 2007. At the end of 2007 the cycle begins anew, looking ahead to 2010. Expansion through 2006 is determined by adding to the existing capacities of units planned and under construction that are expected to begin operating during this time, which overwrites the projected capacity expansion by the model for 2005 and 2006.

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, 2006).

## Strategic Petroleum Reserve Fill Rate

*AEO2006* 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 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.

- Current U.S ethanol production capacity is aggregated by Census Division in the PMM. Cellulose ethanol plants are modeled in all Census Divisions. However, the growth of cellulose ethanol is dependent on its relative cost competiveness to corn ethanol and other gasoline blending components.

- The Federal motor fuels excise tax credit to 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 forecast. The credit 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. In addition, the American Jobs Creation Act of 2004 provides additional tax credit of $1 per gallon 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, 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 2020. 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 $22,775 per barrel of daily capacity (2004 dollars). Operating costs are assumed to be $4.25 per barrel (2004 dollars). 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 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic fuels per day and 466 megawatts of capacity for electricity cogeneration sold to the grid.[101] 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). 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 *AEO2005*. 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 *AEO2006* 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 2004 data:

| Region | Percent Sold To Grid |
|---|---|
| PADD I | 61.3 |
| PADD II | 0.8 |
| PADD III | 2.2 |
| PADD IV | 0.8 |
| PADD V | 45.8 |

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 2005 and 2006 are projected at the U.S. level in the *Short-term Energy Outlook, (STEO*). The PMM adopts the *STEO* results for 2005 and 2006, 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.

*AEO2006* reflects legislation which bans or limits the use of the gasoline blending component MTBE in the following states: Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Maine, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin.

*AEO2006* 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.

*AEO2006* 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.

*AEO2006* 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.

*AEO2006* 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.

*AEO2006* represents major provisions in the Energy Policy Act of 2005 concerning the petroleum industry, including: 1) 7.5 billion gallons of renewable fuels (mostly ethanol) by 2012; 2) removal of oxygenate requirement in RFG; and 3) extension of tax credit of $1 per gallon for soybean oil biodiesel and $0.50 per gallon for yellow grease biodiesel through 2008.

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

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

[96] 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).

[97] 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).

[98] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2013," February 2004, http://www.usda.gov/agency/oce/waob/commodity-projections/2013projections.pdf.

[99] 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).

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

[101] Based on the methodology described in D. Gray and G. Tomlinson, Coproduction: A Green Coal Technology, Technical Report MP 2001-28 (Mitretek, March 2001). Note: The source reports 696 MW of electricity fr cogeneration sold to the grid, assuming a 60-percent CHP efficiency. The PMM assumes a 46-percent efficiency, resulting in 466 MW capacity for cogeneration to the grid.