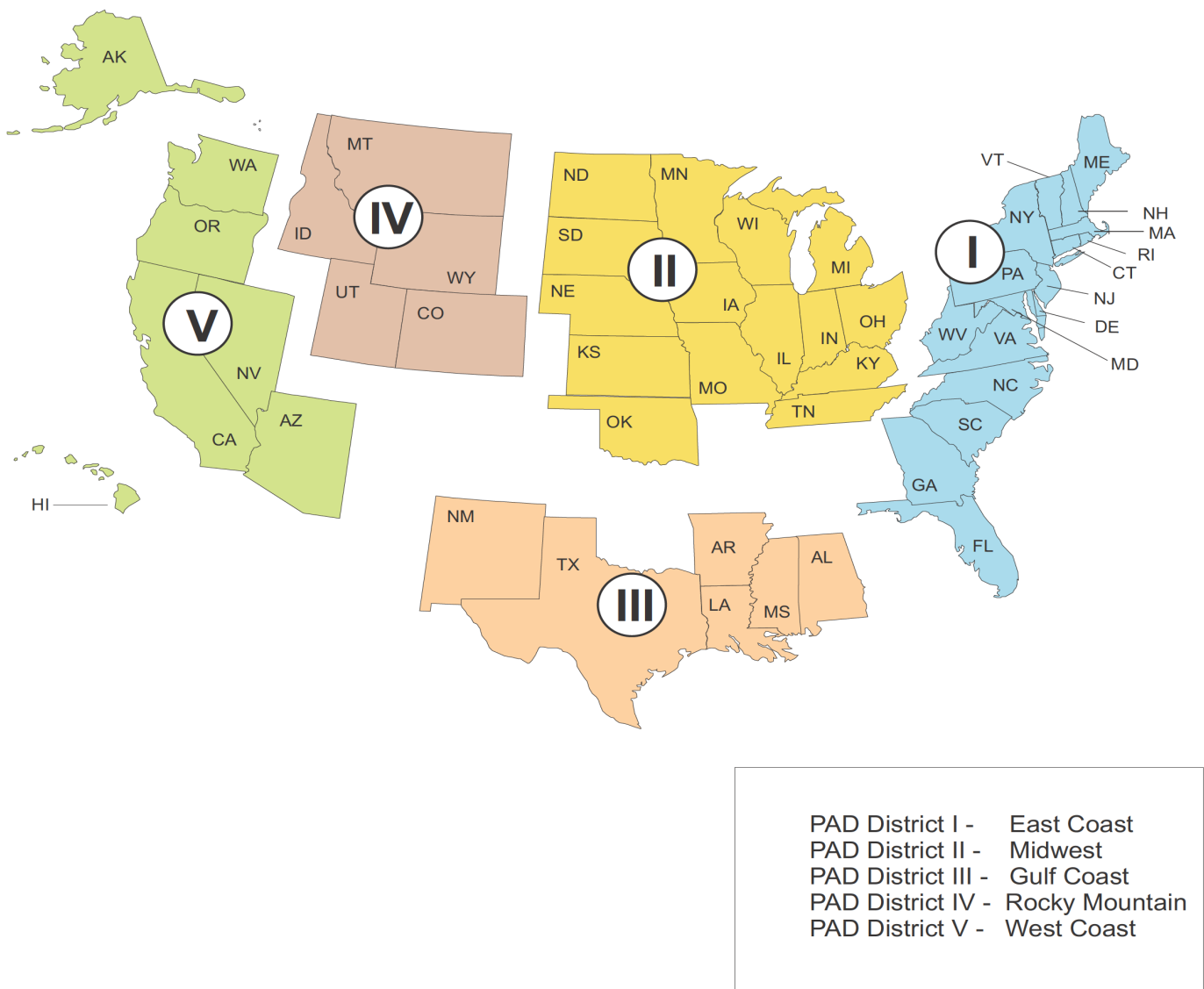# Petroleum Market Module

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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, esters, 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 Administration for Defense Districts (PADDs) (Figure 10), linked to a simplified world refining industry representation used to model U.S. crude and product imports. The U.S. segment of the LP model is created by aggregating individual U.S. refineries within a PADD into two types of representative refineries and linking all five PADDs and world refining regions 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 10. Petroleum Administration for Defense Districts

PAD District I -   East Coast
PAD District II -   Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V -   West Coast

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Key assumptions

Product types and specifications

The PMM models refinery production of the products shown in Table 11.1.

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 (LP) representation of refineries by incorporating the 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: sulfur content, which is phased down to reflect EPA regulations for all gasoline and diesel fuels; and benzene content, which was reduced in gasoline in 2011.

Table 11.1. Petroleum product categories

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

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Motor gasoline specifications and market shares

The PMM models the production and distribution of two different types of gasoline: conventional and reformulated (Phase 2). The following specifications are included in the PMM to differentiate between conventional and reformulated gasoline blends (Table 11.2): 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). As of 2007, the sulfur content specification for gasoline has been reduced to 30 parts per million (ppm) [1].

Conventional gasoline must comply with anti-dumping 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].

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 survey of literature [4] and the USDA Agricultural Baseline Projections to 2019 [5].

Corn supply prices are estimated from the USDA baseline projections to 2019 [6]. The capital cost of a 50-million-gallon-per-year corn ethanol plant was assumed to be $84 million (2008 $). 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 11.3).

Table 11.2. Year-round gasoline specifications by Petroleum Administration for Defense Districts (PADD), as of 2011

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 Evaporated at 300°
Conventional							
PADD I	9.6	26.0	1.1	30.0	11.6	47.1	82.0
PADD II	10.2	26.1	1.1	30.0	11.6	47.1	81.9
PADD III	9.9	26.1	1.1	30.0	11.6	47.1	81.9
PADD IV	10.8	26.1	1.1	30.0	11.6	47.1	81.9
PADD V	9.2	26.7	1.1	30.0	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.
Benzene volume percent changed to 0.6 for all regions and type in 2011 to meet the MSAT2 ruling.
Source: U.S. Energy Information Administration, Office of Energy Analysis. Derived using U.S. EPA's Complex Model, and updated with U.S. EPA's gasoline projection survey "Fuel Trends Report: Gasoline 1995-2005", January 2008, EPA420-R-08-002. (www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm).

Table 11.3. 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	19	39	82	90	81	95	72	87	25
Reformulated Gasoline	12	61	18	10	19	5	28	13	75

Source: U.S. Energy Information Administration, Office of Energy Analysis. Derived from EIA-782C, "Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption," January-December 2010.
As of January 2007, Oxygenated Gasoline is included within Conventional Gasoline.

AEO2012 assumes MTBE was phased out by the end of 2007 as a result of decisions made by the petroleum industry. Ethanol is assumed to be used in areas where reformulated gasoline is required. Federal reformulated gasoline (RFG) is blended with up to 15 percent ethanol in light-duty vehicles of model year 2001 and newer. Ethanol is also allowed to blend into conventional gasoline at up to 15 percent by volume, depending on its blending value and relative cost competitiveness with other gasoline blending components. However, current state regulation along with marketplace constraints limit the full penetration of E15 in the early part of the projection. 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 and reformulated gasoline by applying assumptions about the annual market shares for each type. In *AEO2012* the annual market shares for each region reflect actual 2010 market shares and are held constant throughout the projection. (See Table 11.3 for *AEO2012* market share assumptions.)

Diesel fuel specifications and market shares

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

AEO2012 incorporates the 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 starting in 2011.

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

Refiners revamped (retrofitted) existing refinery units to produce ULSD, representing two-thirds of highway diesel production, and that the remaining refineries built 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 *AEO2012* ULSD price projections as a distribution cost. The revenue loss associated with the 7.8 percent downgrade assumption for 2009 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 cent per gallon are assumed for additional storage tanks needed to handle ULSD during the transition period. These capital expenditures have been fully amortized by 2011. Additional operating costs for distribution of highway diesel of 0.2 cent 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.

AEO2012 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 was implemented in multiple steps and required sulfur content for all NRLM diesel fuel produced by refiners to be reduced to 500 ppm starting mid-2007. It also established a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the rule established 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 11.4).

State and Federal taxes are also added to transportation fuels to determine final end-use prices (Tables 11.5 and 11.6). 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 *AEO2012* assumption of current laws and regulations.   Federal taxes are not held constant but deflated as follows:

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

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 11.7.

Table 11.4. Petroleum product end-use markups by sector and Census Division
2010 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	0.45	0.50	0.25	0.21	0.38	0.24	0.37	0.29	0.36
Kerosene	1.37	0.75	0.30	0.32	0.22	0.34	0.34	0.77	0.87
Liquefied Petroleum Gases	1.32	1.36	0.83	0.58	1.31	1.15	1.02	0.97	1.15
Commercial Sector									
Distillate Fuel Oil	0.37	0.30	0.18	0.09	0.21	0.13	0.13	0.12	-0.17
Gasoline	0.15	0.15	0.14	0.13	0.13	0.15	0.14	0.18	0.19
Kerosene	1.38	0.57	0.28	0.34	0.22	0.30	0.30	1.01	1.08
Liquefied Petroleum Gases	0.56	0.82	0.63	0.63	0.81	0.72	0.76	0.79	0.65
Low-Sulfur Residual Fuel Oil	1.15	-0.04	0.78	0.73	0.12	0.15	0.06	0.00	0.14
Utility Sector									
Distillate Fuel Oil	0.31	0.25	0.10	-0.04	-0.01	-0.54	-0.39	0.21	-0.24
Residual Fuel Oil[1]	0.64	0.76	0.41	0.33	0.64	0.39	0.24	0.32	0.47
Transportation Sector									
Distillate Fuel Oil	0.35	0.24	0.17	0.14	0.18	0.14	0.14	0.16	0.24
E85[2]	0.14	0.14	0.11	0.10	0.11	0.12	0.09	0.15	0.15
Gasoline	0.18	0.18	0.15	0.14	0.14	0.15	0.12	0.20	0.19
High-Sulfur Residual Fuel Oil[1]	1.02	0.45	-0.19	0.15	-0.57	0.10	-0.50	-0.55	0.00
Jet Fuel	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.02
Liquefied Petroleum Gases	0.48	0.72	0.96	0.97	0.83	0.98	1.01	0.92	0.94
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	0.38	0.39	0.32	0.25	0.26	0.22	0.16	0.16	-0.21
Gasoline	0.18	0.17	0.14	0.13	0.14	0.16	0.14	0.19	0.19
Kerosene	-0.82	-0.04	0.04	0.00	-0.02	0.18	0.01	0.40	0.54
Liquefied Petroleum Gases	0.97	0.90	0.61	0.61	0.74	0.53	0.24	0.56	0.83
Low-Sulfur Residual Fuel Oil	0.91	-0.10	0.79	0.73	0.10	0.24	0.08	0.04	0.19

[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]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used.
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 2010*, Consumption (June 2011); EIA, *State Energy Data 2010: Prices and Expenditures* (June 2011).

Table 11.5. State and local taxes on petroleum transportation fuels by Census Division, as of May 2011
2010 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]	0.31	0.27	0.25	0.25	0.21	0.22	0.22	0.24	0.24
Diesel	0.27	0.32	0.22	0.22	0.22	0.19	0.19	0.22	0.31
Liquefied Petroleum Gases	0.13	0.13	0.18	0.20	0.19	0.18	0.14	0.15	0.06
E85[2]	0.22	0.19	0.18	0.17	0.14	0.15	0.15	0.16	0.17
Jet Fuel	0.07	0.05	0.00	0.04	0.08	0.08	0.03	0.04	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.
[2]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used.
Source: "Compilation of United States Fuel Taxes, Inspection, Fees and Environmental Taxes and Fees," Defense Energy Support Center, Editions 2011-09, May 18, 2011).

Table 11.6 Federal taxes, as of October 2011
nominal dollars per gallon

Product	Tax
Gasoline	0.18
Diesel	0.24
Jet Fuel	0.04
Liquefied Petroleum Gases[3]	0.043
M85[1]	0.09
E85[2]	0.20

[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 was 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). IRS Internal Revenue Bulletin 2006-43 available on the web at www.irs.gov/pub/irs-irbs/irb06-43.pdf

Table 11.7. 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: U.S. Energy Information Administration, Office of Energy Analysis. 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. Each import supply curve is linked to a world oil supply market balance for that crude type, such that the quantity of crude oil imported depends on the economic competition with use by the rest of the world.

Capacity expansion

The PMM allows for capacity expansion of all processing unit types including atmospheric distillation, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation. Capacity expansion occurs by processing unit, starting from regional capacities established 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 2011 and determines the optimal capacities given the estimated demands and prices expected in the 2014 projection year. The PMM then allows any of that capacity to be built in each of the projection years 2012, 2013, and 2014. At the end of 2014 the cycle begins anew, looking ahead to 2017. Atmospheric Crude Unit (ACU) capacity under construction that is expected to begin operating in the future is added to existing capacities in their respective start year. Capacity expansion is also modeled for corn and cellulosic ethanol, coal-to-liquids, gas-to-liquids, and biomass-to-liquids production.

Alternative fuel technology characteristics

The PMM explicitly models a number of liquid fuels technologies that do not require petroleum feedstock. These technologies produce both fuel-grade products for blending with traditional petroleum products, and alternative feedstock for the traditional petroleum refinery (Table 11.8).

Estimates of capital costs, operating cost, and process yield for these technologies are shown in Table 11.9. Costs are defined for 2010 and are escalated in the PMM using the GDP deflator. Owner's Capital Cost is defined as the anticipated cost for a fully continuous, commercial scale plant. However, some of the technologies have not yet been proven at a commercial scale. As a result, a technology optimism factor is applied to the owner's capital cost for the first plant of those technologies. For the next four plants, the capital cost decreases linearly such that the fifth plant is built at the owner's capital cost defined in the table. Following this phase, capital cost is decreased at a rate corresponding to the maturity of the components that make up the technology, reflecting the principle of learning by doing. This principle is implemented in the PMM in the same way as it is in the Electricity Market Module. Model parameters are shown in Table 11.10.

Table 11.8 Alternative fuel technology product type

Technology	Product Type
Biochemical	
Corn Ethanol	Fuel Grade
Barley Ethanol	Fuel Grade
Cellulosic Ethanol	Fuel Grade
Thermocatalytic	
Biomass Fisher-Tropsch	Fuel Grade/Refinery Feed
Pyrolysis Oil	Refinery Feed
Methyl Ester Biodiesel	Fuel Grade
Renewable Diesel	Fuel Grade
Biomass-to-Liquids (CBTL)	Fuel Grade/Refinery Feed
Natural-Gas-to-Liquids (GTL)	Fuel Grade/Refinery Feed
Coal-to-Liquids (CTL)	Fuel Grade/Refinery Feed

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 11.9. Alternative fuel technology characteristics

United States Gulf Coast AEO2011 2020 Basis (2011$)	Online Year	Nameplate Capacity[1]	Base Overnight Capital	Contingency Factors[2,3]		Total Overnight Capital[4]	Total Variable Cost[5]	Fixed O&M[6]	Thermal Efficiency[7]
		barrels/day	$/daily barrel	Project	Optimism	$/daily barrel	$/barrel	$/barrel	Energy Percent
Biochemical									
Corn Ethanol	-	6,523	$24,147	5%	0%	$27,591	$68.83	-	54%
Advanced Ethanol	2011	4,240	$26,562	5%	0%	$30,350	$78.41	-	49%
Cellulosic Ethanol (1st plant)	2012	3,700	$99,948	5%	25%	$142,755	$49.39	$12.41	28%
Cellulosic Ethanol (50th plant)	-	3,700	$99,948	5%	25%	$82,428	$49.39	$12.41	28%
Thermocatalytic									
Coal/Biomass FT Liquids	2015	30,000	$136,731	10%	2.5%	$151,014	$12.46	$21.74	45%
Biomass FT Liquids (1st plant)	2012	3,143	$242,560	10%	25%	$326,703	$15.65	$39.11	47%
Biomass FT Liquids (50th plant)	-	3,143	$242,560	10%	25%	$246,608	$15.65	$39.11	47%
Pyrolysis Oil (1st plant)	2014	687	$56,450	10%	25%	$78,726	$31.12	$24.56	52%
Pyrolysis Oil (50th plant)	2014	687	$56,450	10%	25%	$54,770	$31.12	$24.56	52%
Coal FT Liquids	2015	50,000	$136,856	10%	0%	$147,465	$12.68	$20.18	43%
Natural Gas FT Liquids[8]	2017	34,000	$68,448	10%	0%	$73,923	$48.36	$10.37	59%
Methyl Ester Biodiesel	-	1,305	$26,747	5%	0%	$28,085	$132.24	-	36%
Nonester Renewable Diesel	2010	2,000	$10,761	5%	2.5%	$11,471	$129.81	$1.80	38%

[1]For all processes except corn ethanol and FAME biodiesel, annual capacity refers to the capacity of one plant as defined in the Petrolem Market Module of NEMS. For corn ethanol and FAME biodiesel, annual capacity is the most common plant size as of 2008.

[2]Contingency is defined by the Amercian Association of Cost Engineers as a "specific provision for unforeseeable elements in 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 technology optimism factor is applied to the first four units of an unproven design, reflecting a demonstrated tendency to underestimate costs for a first-of-a-kind unit.

[4]Total Overnight cost including contingency factors, excluding regional multipliers, learning effects, and interest charges.

[5]Variable Operating and Maintenance costs (O&M) include sales of electricity to the grid and coproduct value where applicable.

[6]For Corn Ethanol, Advanced Ethanol, and Biodiesel, fixed costs are included in Variable Operating Cost.

[7]A soybean oil mass yield of 20% is assumed in the crush facility in order to compute yield. Efficiency is defined as the heat content of the liquid products divided by the heat content of the feedstock.

[8]While these costs are for a Gulf Coast facility, the costs in other regions, particularly Alaska, are expected to be much higher.

Sources: The values shown in this table are developed by the Energy Information Administration, Office of Electricity, Coal, Nuclear, and Renewables Analysis, from analysis of reports and discussions with various sources from industry, government, and the Department of Energy Fuel Offices and National Laboratories. They are meant to represent the cost and performance of typical plants under normal oprating conditions for each technology. Key sources reviewed are listed in "Notes and Sources" at the end of the chapter.

Variable operating cost includes the cost of feedstock, utility requirements, coproduct credit, and other costs that depend on capacity utilization, and they represent the expected costs to operate a fully continuous, commercial-scale plant for each technology. The breakdown is shown in Table 11.11.

Alternative fuels market dynamics

In the PMM, overnight capital costs are amortized and then added to variable and fixed costs in order to provide a cost of production [11]. As a result of this inclusion of capital cost in the cost of production, a given technology's production cost has the potential to become more or less attractive relative to other technologies as plants are built.

While cost of production defines a basis for comparison, market competition is often defined by the required feedstock. For example, technologies requiring greases and oils (biodiesel and renewable diesel) compete with each other for that feedstock, limiting the overall market share of each technology. As a consequence of this and the Renewable Fuels Standard, cellulosic ethanol and Biomass to Liquids (BTL) technologies, which include Fischer-Tropsch and Pyrolysis, compete directly with each other. By contrast, technologies like Gas-to-Liquids and Coal-to-Liquids compete more directly with petroleum fuels, since their feedstock are more similar to petroleum and their fuels are not required by the RFS.

Table 11.10. Alternative fuel technology learning parameters

	Plants Built	1st of a Kind	5th of a Kind		32nd of a Kind	
	Mature	0%	33%	67%	0%	100%
Cellulosic Ethanol	Decline Factor	0.079	0.415	0.014	0.152	0.072
	Cumulative Capacity	1.25	0.708	0.754	0.288	0.75
	Plant %	0%	0%	100%	0%	100%
Biomass Fischer-Tropsch	Decline Factor	0.079	0.415%	0.014	0.152	0.072
	Cumulative Capacity	1.250	1.128	1.126	0.000	1.126
	Plant %	0%	18%	82%	0%	100%
Pyrolysis Oil	Decline Factor	0.079	0.418	0.014	0.152	0.072
	Cumulative Capacity	1.28	0.386	0.923	0.155	0.923

Source: U.S. Energy Information Administration.

Table 11.11. Alternative fuel technology variable costs[1]

AEO2011 2020 Basis

(Real 2011 $/barrel)Technology	Total	Feedstock Cost	Net Utility Cost[2]	Coproduct Credit	Other Variable[3]
Biochemical	-	-	-	-	-
Corn Ethanol	$68.83	$70.69	$10.91	$19.78	$7.01
Barley Ethanol	$78.41	$89.73	-$3.99	$14.34	$7.01
Cellulosic Ethanol	$49.39	$23.64	-$16.83	-	$42.58
Thermocatalytic	-	-	-	-	-
Coal/Biomass FT Liquids	$12.46	$18.16	$9.57	-	$3.76
Biomass FT Liquids	$15.65	$22.42	-$11.16	-	$4.39
Pyrolysis Oil	$31.12	$20.54	$0.00	$3.64	$14.21
Coal FT Liquids	$12.68	$18.39	-$9.57	-	$3.86
Natural Gas FT Liquids	$48.36	$47.11	$0.00	-	$1.25
Methyl Ester Biodiesel	$132.24	$124.87	$1.61	$0.74	$6.50
Nonester Renewable Diesel	$129.81	$127.27	$0.11	-	$2.43

[1]This table is based on the *AEO2011* Reference case projections for year 2020.
[2]Sales of electricity to the Grid from cogeneration are included in net utility costs.
[3]These costs are specific to each technology. Often cooling water, catalyst, and chemicals are applied here. For cellulosic ethanol, this includes enzyme costs and therefore is expected to decrease from $50.53/barrel in 2010 to $30.48/barrel in 2035.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear, and Renewables Analysis.

Biofuels supply

The PMM provides supply functions on an annual basis through 2035 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.
- The Federal motor fuels excise tax credit of 45 cents per gallon of ethanol (4.5 cents per gallon credit to gasohol at a 10-percent volumetric blending portion) is no longer applied within the model projections as the credit expired after 2011.

To model the Renewable Fuels Standard in EISA2007, several assumptions were required. In addition to using the text of the legislation, it was also assumed that rules promulgated under the RFS in EPACT05 would govern the administration of the EISA2007 RFS through June 2010. After that point, the administration is governed by the most recent RFS rulemaking.

- The penetration of cellulosic ethanol into the market is limited before 2012 to the likely projects currently expected to produce approximately 4 million gallons per year.
- Methyl ester biodiesel production contributes 1.5 credits towards the advanced mandate.
- Renewable diesel fuel, including that from Pyrolysis oil, and Fischer-Tropsch diesel contribute 1.7 credits toward the cellulosic mandate.
- Renewable gasoline, including that from Pyrolysis oil, and Fischer-Tropsch naphtha contribute 1.54 credits toward the cellulosic mandate.
- Imported Brazilian sugarcane ethanol counts towards the advanced renewable mandate. Supply curves for sugarcane ethanol imports allow for substantial penetration by 2022 (1.5 billion gallons) into the U.S. advanced fuel supply pool, after which sugarcane ethanol remains competitive due to its relatively low production cost, availability, and the expiration of the 54 cents/gallon import tariff on Jan. 1, 2012. Ample sugarcane ethanol supply for export from Brazil is supported by outside forecasts [12]. In addition, cellulosic ethanol would be available for export to the U.S. (largely from bagasse feedstock) but this supply is limited in part due to competition with the growing use of sugarcane residue for electricity generation in Brazil.
- Separate biofuel waivers can be activated by the EPA for each of the four RFS fuel categories. In years beyond 2022, the RFS mandate levels continue to increase toward 36 billion gallons. When this value is reached, the volumes continue to rise with U.S. demand for transportation fuel.
- It is assumed that biodiesel and BTL diesel may be consumed in diesel engines without significant infrastructure modification (either vehicles or delivery infrastructure).
- Ethanol is assumed to be consumed as E10, E15 or E85, with no intermediate blends. The cost of placing E85 pumps at the most economic stations is spread over diesel and gasoline.
- To accommodate the ethanol requirements in particular, transportation modes are expanded or upgraded for E10, E15 and E85, and it is assumed that most ethanol originates from the Midwest, with nominal 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 3 cents by 2020, depending on the average sales per dispenser.
- The total projected incremental nominal infrastructure cost (transportation, distribution, dispensing) for E85 varies from 27 cents per gallon of E85 in 2013 to 5 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 provided an additional tax credit of $1 per gallon of soybean oil for biodiesel and 50 cents per gallon for yellow grease biodiesel through 2006, and EPACT05 extended the credit to 2008. The Emergency Stabilization Act of 2008 extended it again to 2009 and increased the yellow grease credit to $1 per gallon

Non-biofuel alternative supply

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. The earliest start date for a GTL facility is set at 2017. Since the Alaska Natural Gas Transportation System (ANGTS) is not economic in the *AEO2012*, the Alaska GTL plant has access to associated gas resources currently used to increase oil recovery. 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. Additionally, a process which allows co-firing of coal with biomass (CBTL) is explicitly modeled for producers who wish to receive RFS credit for a portion of their product. A 50,000-barrel-per-day CTL facility is assumed to cost about $7 billion in initial capital investment (2009 dollars) while a 30,000-barrel-per-day CBTL facility is expected to cost about $4.4 billion. These 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. It is further assumed that CTL facilities can only be built after 2014.

Gasification of petroleum coke (petcoke) and heavy oil (asphalt, vacuum resid, etc.) is represented in *AEO2012*. 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 tons-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 of gasification capacity in the United States that produces CHP and hydrogen.

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
PADD V	45.4

Source: U.S. Energy Information Administration. Derived using EIA-860B, "Annual Electric Generators Report-Nonutility".

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, which are obtained from the Electricity Market Model.

Short-term methodology

Petroleum balance and price information for 2011 are projected at the U.S. level in the Short-Term Energy Outlook, (STEO). The PMM adopts the STEO results for 2011, using regional estimates derived from the national STEO projections.

Legislation and regulation

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.

AEO2012 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 was not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2012 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.

AEO2012 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.

AEO2012 represents major provisions in the Energy Policy Act of 2005 (EPACT05) 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.

The Emergency Stabilization Act of 2008 extended the soybean oil for biodiesel tax credit again to 2009 and increased the yellow grease credit to $1 per gallon.

AEO2012 includes provisions outlined in the Energy Independence and Security Act of 2007 (EISA2007) concerning the petroleum industry, including a Renewable Fuels Standard (RFS) increasing total U.S. consumption of renewable fuels. Although the statute calls for higher levels, due to uncertainty about whether 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) 30.9 billion gallons in 2023 for all fuels; 2) 15.9 billion gallons in 2023 for advanced biofuels; 3) 10.9 billion gallons in 2023 for cellulosic biofuel; 4) 1 billion gallons of biodiesel by 2023 [13].

AEO2012 includes the EPA Mobil Source Air Toxics (MSAT 2) rule which includes the requirement that all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year will need to contain no more than 0.61 percent benzene by volume. This does not include gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline Program.

AEO2012 does not include California's Low Carbon Fuel Standard which aims to reduce the Carbon Intensity (CI) of gasoline and diesel fuels in that State by 10% respectively from 2012 through 2020. As of December 2011, the U.S. District Court for the Eastern Division of California ruled in favor of numerous trade groups that claimed the LDFS violated the Interstate Commerce Clause of the U.S. Constitution, thus locking its enforcement by the California Air Resources Board.

AEO2012 includes mandates passed in 2010 by Connecticut, Maine, New York, and New Jersey that aim to lower the sulfur content of all heating oil to ultra-low-sulfur diesel over different time schedules, as well as transition to a 2% biodiesel content by mid-2011 in the case of Maine and Connecticut.

Due to the uncertainty surrounding compliance options, *AEO2012* did not include any explicit modeling treatment of the International Maritime Organization's "MARPOL Annex 6" rule covering cleaner marine fuels and ocean ship engine emissions.

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, U.S. 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] Ibid.

[5] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2019," February 2009, www.ers.usda.gov/publications/oce091.

[6] Ibid

[7] Shapouri Hosein; Gallagher, Paul; and Graboski, Mike. USDA's 1998 Ethanol Cost-of-Production Survey. January 2002.

[8] Marland, G. and A.F. Turhollow. 1991. "CO2 Emissions from the Production and Combustion of Fuel Ethanol from Corn." Energy, 16(11/12):1307-1316.

[9] 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).

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

[11] Economic lifetime is 15 years for cellulosic ethanol, biomass Fischer-Tropsch, and Pyrolysis Oil. It is 20 years for all others. Required rate of return is calculated using a 60:40 debt to equity ratio and the capital asset pricing model for the cost of equity.

[12] www.agrievolution.com/atti/brasile_02.ppt.

[13] The 2023 RFS levels used in the PMM reinstates the temporary reductions (1.1 billion gallons) that were needed in 2022 for the all fuels, advanced biofuels, and cellulosic biofuel categories.