Liquid Fuels Market Module

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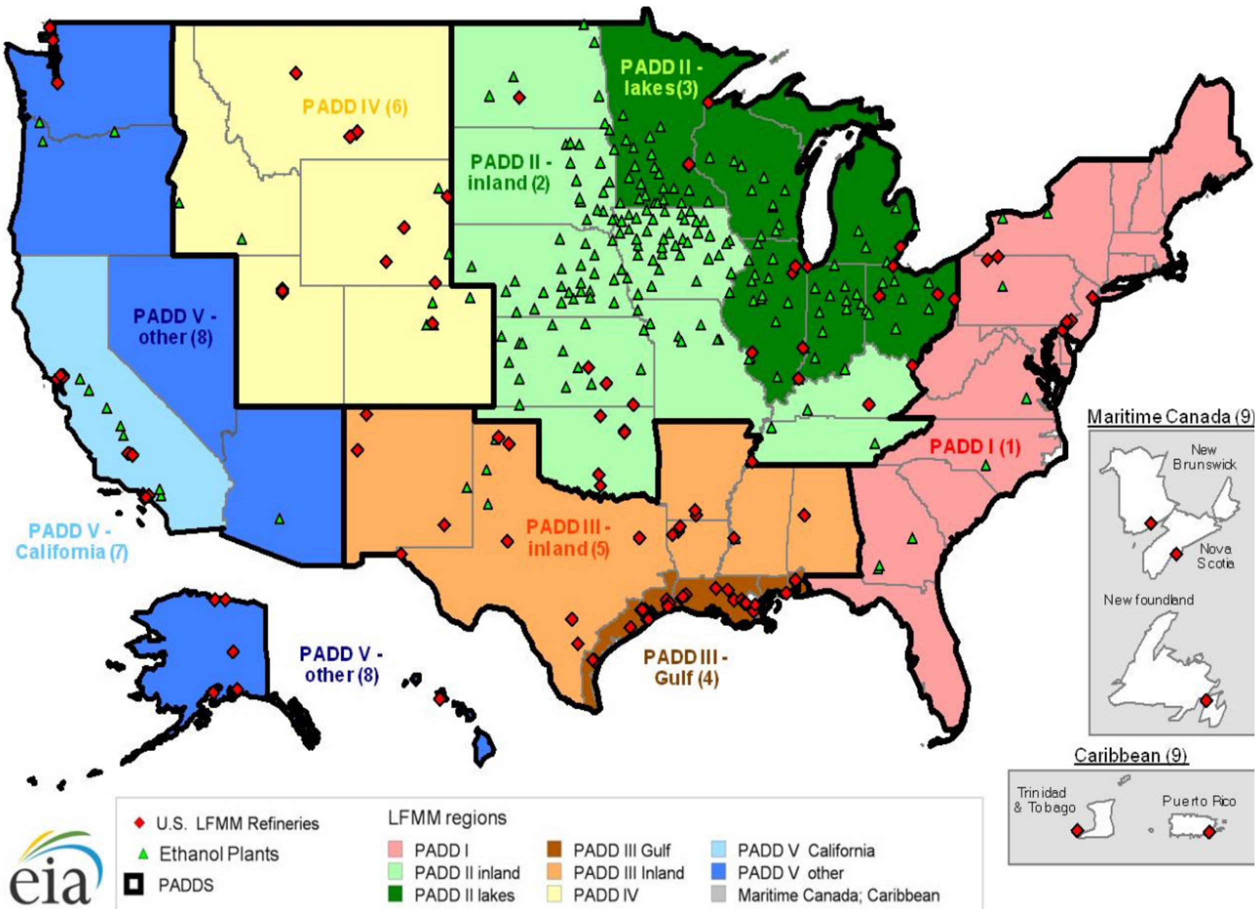
The NEMS Liquid Fuels Market Module (LFMM) projects petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, unfinished oil imports, other refinery inputs (including alcohols,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

The LFMM contains a linear programming (LP) representation of U.S. petroleum refining activities, biofuels production activities, and other non-petroleum liquid fuels production activity in eight domestic U.S. regions and refining activity in a new Maritime Canada/Caribbean refining region (created to represent short-haul international refineries that predominantly serve U.S. markets). In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions were defined by subdividing three of the five Petroleum Administration for Defense Districts (PADDs) (Figure 10). The LP model also represents crude import supply curves, gasoline import supply curves from Europe, advanced ethanol import supply curves from Brazil, and exogenously defined imports and exports for selected products. The nine LFMM regions and import/export curves are connected in the LP via crude and product transit links. In order to interact with other NEMS modules with different regional representations, certain LFMM inputs and outputs are converted from sub-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. Liquid Fuels Market Module Regions



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

Key assumptions

Product types and specifications

The LFMM 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 LFMM assumes that the specifications for these fuels will remain the same as currently specified.

Table 11.1. Petroleum product categories

Product Category	Specific Products
Motor Gasoline	Conventional, Reformulated (including CARB gasoline)
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	Ethane, Propane, Propylene, normal- and iso-Butane
Petrochemical Feedstock	Petrochemical Naphtha, Petrochemical Gas Oil, 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 LFMM models the production and distribution of two different types of gasoline: conventional and reformulated (Phase 2). The following specifications are included in the LFMM 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).

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 LFMM reflects "Phase 2" reformulated gasoline requirements which began in 2000. The LFMM 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. (http://www.epa.gov/otaq/regs/fuels/fueltrends.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	18	41	81	88	81	95	72	86	25
Reformulated Gasoline	82	59	19	12	19	5	28	14	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.

AEO2013 assumes a minimum 10 percent blend of ethanol in domestically consumed motor gasoline. Federal reformulated gasoline (RFG) and conventional gasoline can be blended with up to 15 percent ethanol in light-duty vehicles of model year 2001 and newer, but actual levels will depend on ethanol's blending value and relative cost competitiveness with other gasoline blending components. In addition, 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 LFMM 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 LFMM, total gasoline demand is disaggregated into demand for conventional and reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2013 the annual market shares for each region reflect actual 2010 market shares and are held constant throughout the projection. (See Table 11.3 for *AEO2013* 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 California portion of the Pacific Region (Census Division 9) is required to meet CARB standards. Both Federal and CARB standards currently limit sulfur to 15 ppm.

AEO2013 incorporates the ULSD regulation finalized in December 2000. ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump.

Demand for highway-grade diesel 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 non-transportation uses such as construction and agriculture.

AEO2013 incorporates the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004.

The final NRLM rule 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 *AEO2013* assumption of current laws and regulations. Federal taxes are not held constant but deflated as follows:

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

Crude oil quality

In the LFMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into nine categories as defined by the ranges of gravity and sulfur shown in Table 11.7.

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. In the LFMM, the domestic and foreign categories are the same, and the composite crudes for each category are derived from both domestic and foreign crude characteristics. For domestic crude oil, estimates of total regional production are made first, then shared out to each of the nine categories based on their API gravity and sulfur content. For imported crude oil, a separate supply curve is provided for each category.

Table 11.4. Petroleum product end-use markups by sector and Census Division

2010 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	0.66	0.77	0.42	0.33	0.65	0.40	0.37	0.33	0.48
Kerosene	0.18	0.42	0.17	0.31	0.29	0.23	0.34	0.65	1.39
Liquefied Petroleum Gases	0.08	1.57	1.00	0.68	1.41	1.26	1.02	1.09	1.23
Commercial Sector									
Distillate Fuel Oil	0.40	0.26	0.15	0.05	0.15	0.14	0.13	0.12	0.12
Gasoline	0.16	0.16	0.15	0.13	0.14	0.16	0.14	0.18	0.19
Kerosene	0.18	0.40	0.13	0.31	0.28	0.29	0.30	0.60	1.39
Liquefied Petroleum Gases	0.69	0.86	0.70	0.70	0.78	0.82	0.76	0.83	0.70
Low-Sulfur Residual Fuel Oil	0.15	0.06	0.06	0.57	0.17	-0.10	0.06	1.12	1.40
Utility Sector									
Distillate Fuel Oil	0.10	-0.01	0.07	0.01	0.17	0.13	-0.39	0.22	-0.14
Residual Fuel Oil[1]	-0.41	-0.21	-0.13	0.90	0.36	1.51	0.24	1.67	1.51
Transportation Sector									
Distillate Fuel Oil	0.36	0.25	0.17	0.15	0.18	0.15	0.14	0.16	0.25
E85[2]	0.15	0.14	0.12	0.11	0.12	0.12	0.09	0.16	0.15
Gasoline	0.18	0.18	0.15	0.14	0.14	0.16	0.12	0.20	0.19
High-Sulfur Residual Fuel Oil[1]	0.04	-0.18	1.09	-0.13	0.15	0.19	-0.50	0.00	0.47
Jet Fuel	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.00	0.02
Liquefied Petroleum Gases	0.60	0.84	1.10	1.11	0.84	1.12	1.01	1.00	1.00
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	0.24	0.25	0.22	0.17	0.28	0.22	0.16	0.17	0.17
Gasoline	0.18	0.17	0.15	0.14	0.14	0.16	0.14	0.19	0.19
Kerosene	0.00	0.06	0.02	-0.02	0.01	0.09	0.01	0.56	1.26
Liquefied Petroleum Gases	0.92	0.94	0.60	0.60	0.72	0.49	0.24	0.52	0.86
Low-Sulfur Residual Fuel Oil	0.07	-0.08	0.90	0.75	0.35	-0.01	0.08	-0.09	0.21

[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
2011 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]	0.31	0.27	0.25	0.25	0.21	0.22	0.22	0.24	0.24
Diesel	0.28	0.32	0.23	0.22	0.22	0.19	0.19	0.23	0.32
Liquefied Petroleum Gases	0.13	0.13	0.19	0.21	0.20	0.19	0.15	0.15	0.06
E85[2]	0.22	0.23	0.18	0.17	0.14	0.15	0.15	0.16	0.27
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]E85refers 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)
Light Sweet	<0.3	>35
Light Sour	0.3-1.1	>35
Medium Medium Sour	0.3-1.1	27-35
Medium Sour	1.1-2.6	27-35
Heavy Sweet	0.3-1.1	<27
Heavy Sour	>2.6	<27
California	1.1-2.6	<27
Syncrude	<0.3	27-35
DilBit/SynBit	>2.6	<27

Source: Memorandum "Composite Crude Oils for the LFMM", March 22, 2011, to Less Goudarzi, OnLocation, Inc, from Dave Hirshfeld, MathPro Inc. submitted to U.S. Energy Information Administration, Office of Energy Analysis, under contract number DT0001767, Oil and Gas Supply Module Development. Converted to ranges by OnLocation, Inc and EIA, 2011.

Capacity expansion

The LFMM allows for capacity expansion of all processing unit types including atmospheric distillation, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation; however, atmospheric distillation expansion is not allowed in *AEO2013*. Capacity expansion occurs by processing unit, starting from regional capacities established using historical data.

Expansion occurs in LFMM 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 nine percent. The LFMM models capacity expansion using a new three-period planning approach similar to that used in the NEM Electricity Market Module (EMM). The first two periods contain a single planning year (current year and next year, respectively), and the third period represents a net present value of the next 19 years in the projection. The second and third planning periods work together to establish an economic plan for capacity expansion for the next NEM model year. In period 2, product demands and legislative requirements must be met exactly. Period 3 acts like a leverage in the capacity expansion decision for period 2, and is controlled by the discount rate assumptions. Larger discount rates increase the relative impacts from early periods and decrease the impacts of the later periods. The LFMM has the option to use multiple discount rates for the NPV calculation to represent various categories of risk. For *AEO2013*, the LFMM uses an 18 percent discount rate. Atmospheric Crude Unit (ACU) capacity, as well as downstream process unit 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 production of corn and cellulosic ethanol, biomass pyrolysis oil, biodiesel, renewable diesel, coal-to-liquids, gas-to-liquids, and biomass-to-liquids. The retirement and replacement of existing refining capacity due to economics or life is not currently represented in the LFMM.

Non-petroleum fuel technology characteristics

The LFMM 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 LFMM 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 LFMM 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
Advanced Grain Ethanol	Fuel Grade
Cellulosic Ethanol	Fuel Grade
Thermocatalytic	
Biomass-to-Liquids	Fuel Grade/Refinery Feed
Pyrolysis	Fuel Grade
Methyl Ester Biodiesel	Fuel Grade
Nonester Renewable Diesel	Fuel Grade
Coal/Biomass-to-Liquids (CBTL)	Fuel Grade/Refinery Feed
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. Non-petroleum fuel technology characteristics[1]

United States Gulf Coast AEO2011 2020 Basis (2011$)	Online Year	Nameplate Capacity[2]	Base Overnight Capital	Contingency Factors[3,4]		Total Overnight Capital[5]	Total Variable Cost[6]	Fixed O&M[7]	Thermal Efficiency[8]
		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 Grain 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-to-Liquids (CBTL)	2015	30,000	$136,731	10%	2.5%	$151,014	$12.46	$21.74	45%
Biomass-to-Liquids (1st plant)	2012	3,143	$242,560	10%	25%	$326,703	$15.65	$39.11	47%
Biomass-to-Liquids (50th plant)	-	3,143	$242,560	10%	25%	$246,608	$15.65	$39.11	47%
Pyrolysis (1st plant)	2014	687	$56,450	10%	25%	$78,726	$31.12	$24.56	52%
Pyrolysis (50th plant)	2014	687	$56,450	10%	25%	$54,770	$31.12	$24.56	52%
Coal-to-Liquids (CTL)	2015	50,000	$136,856	10%	0%	$147,465	$12.68	$20.18	43%
Gas-to-Liquids (GTL)[9]	2017	34,000	$68,448	10%	0%	$73,923	$48.36	$10.37	59%
Methyl Ester Biodiesel (FAME)	-	1,305	$26,747	5%	0%	$28,085	$132.24	-	36%
Nonester Renewable Diesel (NERD)	2010	2,000	$10,761	5%	2.5%	$11,471	$129.81	$1.80	38%

[1]This table is based on the *AEO2011* Reference case projections for year 2020.
[2]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.
[3]Contingency is defined by the American 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."
[4]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.
[5]Total Overnight cost including contingency factors, excluding regional multipliers, learning effects, and interest charges.
[6]Variable Operating and Maintenance costs (O&M) include sales of electricity to the grid and coproduct value where applicable.
[7]For Corn Ethanol, Advanced Ethanol, and Biodiesel, fixed costs are included in Variable Operating Cost.
[8]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.
[9]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 operating 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.

Non-petroleum fuels market dynamics

In the LFMM, 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. Non-petroleum fuel technology learning parameters

	Plants Built	1st of a Kind	5th of a Kind		32nd of a Kind	
Cellulosic Ethanol	Mature	0%	33%	67%	0%	100%
	Decline Factor	0.079	0.415	0.014	0.152	0.072
	Cumulative Capacity	1.25	0.708	0.754	0.288	0.75
Biomass-to-Liquids (BTL)	Plant %	0%	0%	100%	0%	100%
	Decline Factor	0.079	0.415%	0.014	0.152	0.072
	Cumulative Capacity	1.250	1.128	1.126	0.000	1.126
Pyrolysis	Plant %	0%	18%	82%	0%	100%
	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. Non-petroleum 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
Advanced Grain Ethanol	$78.41	$89.73	-$3.99	$14.34	$7.01
Cellulosic Ethanol	$49.39	$23.64	-$16.83	-	$42.58
Thermocatalytic	-	-	-	-	-
Coal/Biomass-to-Liquids (CBTL)	$12.46	$18.16	$9.57	-	$3.76
Biomass-to-Liquids (BTL)	$15.65	$22.42	-$11.16	-	$4.39
Pyrolysis	$31.12	$20.54	$0.00	$3.64	$14.21
Coal-to-Liquids (CTL)	$12.68	$18.39	-$9.57	-	$3.86
Gas-to-Liquids (GTL)	$48.36	$47.11	$0.00	-	$1.25
Methyl Ester Biodiesel (FAME)	$132.24	$124.87	$1.61	$0.74	$6.50
Nonester Renewable Diesel (NERD)	$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 over time.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear, and Renewables Analysis.

Biofuels supply

The LFMM provides supply functions on an annual basis through 2040 for ethanol produced from corn, non-corn grain, and cellulosic biomass to produce transportation fuel. The LFMM provides supply functions on an annual basis though 2040 for soy oil, other seed-based oils, and grease used as feedstock for biodiesel and renewable diiesel.

- 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.

To model the Renewable Fuels Standard in EISA2007, several assumptions were required.

- The penetration of cellulosic ethanol into the market is limited before 2016 to several planned projects with aggregate nameplace capacity of approximately 250 million gallons per year. Planned capacity through 2016 for Pyrolysis and Biomass-to-Liquids processes is not allowed to exceed 95 million gallons.
- 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.
- Cellulosic drop-in gasoline contributes 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 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.
- 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
- 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 of a few cents per gallon.
- For E85 dispensing stations, it is assumed the average cost of a retrofit and new station is about $45,000 per station.

Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in LFMM.

Non-petroleum fossil fuel 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 them economic. The earliest start date for a GTL facility is set at 2018.

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 modeled in the LFMM, but not made available for AEO2013. 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 2017.

Combined heat and power (CHP)

Electricity consumption at the refinery and other liquid fuels production facilities is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, and CHP from other liquid fuels producers (including cellulosic/advanced ethanol, coal and biomass to liquids). Power generators and CHP plants are modeled in the LFMM linear program as separate units, and are allowed to compete along with purchased electricity. Operating characteristics for these electricity producers are based on historical parameters and available data. Sales to the grid or own use decisions are made on an economic basis within the LP solution. The price for electricity sales to the grid is set to the marginal energy price for baseload generation (provided by the EMM).

Short-term methodology

Petroleum balance and price information for 2012 and 2013 are projected at the U.S. level in the Short-Term Energy Outlook, (STEO). The LFMM adopts the STEO results for 2012 and 2013, 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 on-highway diesel fuel. These are explicitly modeled in the LFMM. Reformulated gasoline represented in the LFMM meets the requirements of phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2013 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements requires that the average annual sulfur content of all gasoline used in the United States be 30 ppm annual average.

AEO2013 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. All highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2013 reflects nonroad locomotive and marine (NRLM) diesel requirements 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.

AEO2013 represents major provisions in the Energy Policy Act of 2005 (EPACT05) concerning the petroleum industry, including removal of the oxygenate requirement in RFG.

AEO2013 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. In order to account for the possibility that RFS targets might be unattainable at reasonable cost, LFMM includes a provision for purchase of waivers. In essence, the LFMM RFS waivers function as maximum allowed RIN prices

AEO2013 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 0.62 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.

AEO2013 includes California's Low Carbon Fuel Standard which aims to reduce the Carbon Intensity (CI) of gasoline and diesel fuels in that State by about 10% respectively from 2012 through 2020.

AEO2013 incorporates the cap-and-trade program within the California Assembly Bill (AB 32), the Global Warming Solutions Act of 2006. The program started January 1, 2012, with enforceable compliance obligations beginning in 2013. Petroleum refineries are given allowances (calculated in the LFMM) in the cap-and-trade system based on the volumetric output of aviation gasoline, motor gasoline, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels and asphalt. Suppliers of RBOB and Distillate Fuel Oil #1 and #2 are required to comply starting in 2015 if the emissions from full combustion of these products are greater than or equal to 25,000 MTCO2e in any year 2011-2014.

AEO2013 does not include 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. Nor does it include transition to a 2% biodiesel content in the case of Maine and Connecticut. These will be added next AEO cycle.

Due to the uncertainty surrounding compliance options, *AEO2013* 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.

Liquids fuels alternative cases

Low/no net imports case

In the reference case, maximum market penetration for gas-to-liquids (GTL) and coal-to-liquids (CTL) was defined at a nominal 5 percent per year. Given the expectation for high net exports in this case, this maximum penetration rate was increased to 10 percent per year. Capacity expansion of biomass pyrolysis production was also allowed to increase beyond the base build level, but at a higher investment cost. In addition, assumptions associated with E85 availability and E15 market penetration were more optimistic, such that E85 availability was nearly three times the reference case level in 2040, and E15 penetration was about 15% higher than the reference case in 2040. Additional changes were made in two NEMS models (OGSM and TDM) resulting in higher domestic crude and natural gas production (described in section "Oil and gas supply alternative cases", High resource case), and lower liquid fuels demand. As described in the "Transportation demand alternative cases" section in the TDM chapter, the methodology used to achieve lower demands includes the use of more optimistic assumptions about improvements in LDV fuel economy and reductions in LDV technology costs, lower vehicle miles traveled (VMT) due to changes in consumer behavior, an extension of the LDV CAFE standards beyond 2025 at an average annual rate of 1.4 percent through 2040, expanded market availability of LNG/CNG in heavy-duty trucks, rail and marine, and use of assumptions from the optimistic battery case (*AEO2012*) for electric vehicle battery and drivetrain costs.

High net imports case

No changes were made to the LFMM for this scenario. Changes were made in two NEMS models (OGSM and TDM) such that domestic crude production was lowered (described in section "Oil and gas supply alternative cases", Low resource case), and the domestic liquid fuels demand was increased, as compared to the *AEO2013* reference case. As described in the "Transportation demand alternative cases" section in the TDM chapter, an increase in domestic liquids fuels demand was achieve by assuming lower improvement in vehicle efficiency (driven by limits on technology improvement and non-enforcement of CAFE standards), and higher VMT.

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.

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