Liquid Fuels Market Module

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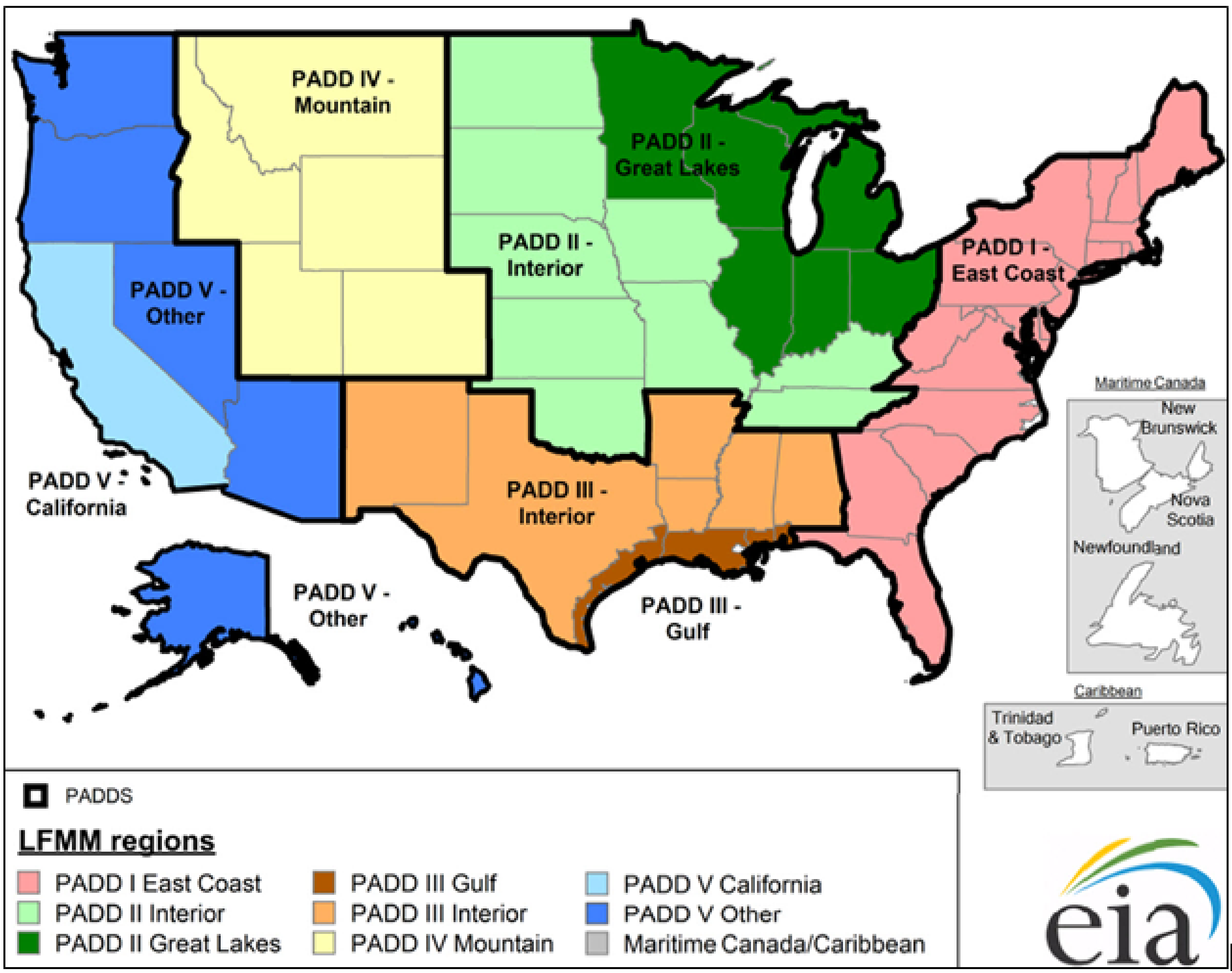
The NEMS Liquid Fuels Market Module (LFMM) projects petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include crude oil (both domestic and imported), petroleum product imports, unfinished oil imports, other refinery inputs (including alcohols, 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, as well as refining activity in the non-U.S. 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, petroleum product import and export curves, biodiesel import supply curves, and advanced ethanol import supply curves from Brazil. 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 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).

Table 11.2. Year-round gasoline specifications by Petroleum Administration for Defense District (PADD)

PADD/Type	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° (Min)	Percent Evaporated at 300° (Min)
Conventional							
PADD I	10.11	24.23	0.62	22.4	10.8	45.9	81.7
PADD II	10.11	24.23	0.62	22.4	10.8	45.9	81.7
PADD III	10.11	24.23	0.62	22.4	10.8	45.9	81.7
PADD IV	10.11	24.23	0.62	22.4	10.8	45.9	81.7
PADD V	10.11	24.23	0.62	22.4	10.8	45.9	81.7
Reformulated							
PADD I	8.8	21.0	0.62	23.8	10.36	54.0	81.7
PADD II	8.8	21.0	0.62	23.8	10.36	54.0	81.7
PADD III	8.8	21.0	0.62	23.8	10.36	54.0	81.7
PADD IV	8.8	21.0	0.62	23.8	10.36	54.0	81.7
PADD V							
Nonattainment	8.8	21.0	0.62	23.8	10.36	54.0	81.7
CARB (attainment)	7.7	23.12	0.58	10.0	6.29	42.9	86.3

Max = maximum, Min.= minimum, PADD = Petroleum Administration for Defense District. PPM = parts per million by weight, PSI = pounds per square inch.
Benzene volume percent changed to 0.62 for all regions and types 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).

Reformulated gasoline must meet the Complex Model II compliance standards, which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions [1]. Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, 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 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."

Cellulosic biomass feedstock supplies and costs are provided by the NEMS Renewable Fuels Model. Initial capital costs for biomass cellulosic ethanol were obtained from a research project reviewing cost estimates from multiple sources [2]. Operating costs and credits for excess electricity generated at biomass ethanol plants were obtained from a survey of literature [3].

Corn supply prices are estimated from the USDA baseline projections to 2019 [4]. Operating costs of corn ethanol plants are obtained from USDA survey of ethanol plant costs [5]. Energy requirements are obtained from a study of carbon dioxide emissions associated with ethanol production [6].

AEO2014 assumes a minimum 10% blend of ethanol in domestically consumed motor gasoline. Federal reformulated gasoline (RFG) and conventional gasoline can be blended with up to 15% ethanol (E15) in light-duty vehicles of model year 2001 and newer. Reformulated and conventional gasoline can also be blended with 16% biobutanol. Actual levels will depend on the ethanol and biobutanol 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 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 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 AEO2014 the annual market shares for each region reflect actual 2010 market shares and are held constant throughout the projection. (See Table 11.3 for AEO2014 market share assumptions.)

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.

Diesel fuel specifications and market shares

In order to account for ultra-low-sulfur diesel (ULSD) regulations related to the Clean Air Act Amendments of 1990 (CAAA90), ULSD 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 parts per million (ppm). AEO2014 incorporates the ULSD regulation finalized in December 2000. ULSD is highway diesel.

Demand for highway-grade diesel is assumed to be equivalent to the total transportation distillate demand. Over the past few years, 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.

AEO2014 incorporates the "nonroad, locomotive, and marine" (NRLM) diesel regulation finalized in May 2004 for large refiners and importers. 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 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).

Table 11.4. Petroleum product end-use markups by sector and Census Division
2012 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	0.59	0.69	0.43	0.21	0.58	0.24	0.16	0.38	0.43
Kerosene	0.19	0.77	0.63	0.64	0.68	0.59	0.66	0.79	0.00
Liquefied Petroleum Gases	1.16	1.22	0.63	0.42	1.15	0.99	0.98	0.82	1.07
Commercial Sector									
Distillate Fuel Oil	0.27	0.22	0.13	0.08	0.14	0.09	0.11	0.06	-0.03
Gasoline	0.16	0.16	0.15	0.14	0.14	0.16	0.15	0.19	0.20
Kerosene	0.18	0.78	0.63	0.64	0.75	0.69	0.55	1.05	0.00
Liquefied Petroleum Gases	0.42	0.66	0.42	0.42	0.55	0.52	0.56	0.47	0.36
Low-Sulfur Residual Fuel Oil[1]	0.14	-0.07	-0.13	-0.36	-0.02	-0.03	-0.03	0.00	0.00
Utility Sector									
Distillate Fuel Oil	0.02	0.05	0.11	0.08	0.02	0.09	0.10	0.19	0.13
Residual Fuel Oil[1]	-0.38	-0.11	0.78	0.65	-0.07	-0.35	-0.60	0.00	0.00
Transportation Sector									
Distillate Fuel Oil	0.56	0.55	0.51	0.50	0.45	0.51	0.52	0.47	0.62
E85[2]	0.15	0.14	0.12	0.11	0.12	0.13	0.10	0.16	0.15
Gasoline	0.19	0.18	0.15	0.14	0.15	0.16	0.12	0.20	0.19
High-Sulfur Residual Fuel Oil[1]	0.18	-0.03	-0.19	-0.63	-0.23	-0.42	-0.47	0.00	0.52
Jet Fuel	0.03	-0.03	0.01	0.01	0.00	0.05	0.03	0.01	-0.03
Liquefied Petroleum Gases	0.37	0.71	0.91	0.91	0.68	0.95	0.99	0.82	0.79
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	0.18	0.20	0.22	0.23	0.14	0.17	0.16	0.10	0.03
Gasoline	0.19	0.17	0.15	0.14	0.15	0.17	0.15	0.19	0.20
Kerosene	0.00	0.09	0.00	0.03	0.03	0.02	0.01	0.41	0.00
Liquefied Petroleum Gases	0.76	0.97	0.63	0.63	0.63	0.54	0.21	0.52	0.70
Low-Sulfur Residual Fuel Oil[1]	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% ethanol (renewable) and 15 % motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% 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*; Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants* prior to 2008; Form EIA-923, *Power Plant Operations Report starting in 2008;* EIA Form EIA-759 Monthly Power Plant Report; EIA, *State Energy Data Report 2010*, Consumption (June 2012); EIA, *State Energy Data 2010: Prices and Expenditures* (June 2012).

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 1% of motor gasoline prices [7]. Federal taxes are assumed to remain at current levels in accordance with the overall AEO2014 assumption of current laws and regulations. Federal taxes are not held constant but deflated as follows:

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

Table 11.5. State and local taxes on petroleum transportation fuels by Census Division, as of May 2011
2012 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]	0.46	0.42	0.40	0.40	0.36	0.37	0.37	0.39	0.39
Diesel	0.98	0.33	0.23	0.23	0.22	0.19	0.19	0.23	0.32
Liquefied Petroleum Gases	0.14	0.14	0.19	0.21	0.20	0.19	0.15	0.16	0.06
E85[2]	0.22	0.23	0.18	0.17	0.15	0.16	0.15	0.17	0.27
Jet Fuel	0.07	0.06	0.00	0.04	0.08	0.08	0.03	0.05	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.
[2]E85 refers to a blend of 85% ethanol (renewable) and 15% motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% 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	0.184
Diesel	0.244
Jet Fuel	0.04
E85[1]	0.20

[1]74% ethanol and 26% gasoline.
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.

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 (by the IEM) for each category.

Table 11.7. Crude oil specifications

Crude Oil Categories	Sulfur (%)	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 11, 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. 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% equity and 40% debt, with a hurdle rate and an after-tax return on investment of about 9%. The LFMM models capacity expansion using a three-period planning approach similar to that used in the NEMS 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 NEMS 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 AEO2014, the LFMM uses an 18% discount rate. Capacity expansion is also modeled for production of corn and cellulosic ethanol, biobutanol, biomass pyrolysis oil, biodiesel, renewable diesel, coal-to-liquids, gas-to-liquids, and biomass-to-liquids. All process unit capacity that is expected to begin operating in the future is added to existing capacities in their respective start year. The retirement and replacement of existing refining capacity due to economics or life is not explicitly 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).

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
Biobutanol	Fuel Grade
Thermochemical Catalytic	
Methyl Ester Biodiesel	Fuel Grade
Non-Ester Renewable Diesel	Fuel Grade
Pyrolysis	Fuel Grade
Thermochemical Fischer-Tropsch	
Gas-to-Liquids (GTL)	Fuel Grade/Refinery Feed
Coal-to-Liquids (CTL)	Fuel Grade/Refinery Feed
Biomass-to-Liquids (BTL)	Fuel Grade/Refinery Feed

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

Estimates of capital and operating costs corresponding to specified nameplate capacities for these technologies are shown in Table 11.9. The cost data are defined assuming a 2020 base year, and are deflated to 2012 dollars using the GDP deflator in NEMS.

Overnight Capital Cost is defined as the anticipated cost for a standard size commercial-scale plant. Since some components of technologies have not yet been proven at a commercial scale, a technology optimism factor is applied to the assumed first-of-a-kind capital cost, a multiplier that increases the first-of-a-kind plant cost (e.g., 1.25). The multiplier is an estimate of the underestimated construction errors (redos) and underestimated costs in building the first full-scale commercial plant. As experience is gained (after building the first 4 units), the technological optimism factor is gradually reduced to 1.0.

The learning function has the nonlinear form:

$OC(C) = a^*C^{-b}$,

where C is the cumulative capacity (or number of standard-sized units) for each technology component and OC represents the overnight capital cost expected with cumulative capacity C of the technology.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of construction experience with the component. In the case of the LFMM, the second and third phases of a technology will have only evolutionary/revolutionary (fast) and mature (slower) learning components, depending on the mix (percent) of new and mature processes that compose a particular technology.

The progress ratio (pr) is related by the speed of learning or learning rate (LR) (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (LR) is an exogenous input parameter for each component. The progress ratio and LR are related by:

$pr = 2^{-b} = (1 - LR)$.

The parameter "b" is calculated from the second half of the equality above:

$b =-(\ln(1-LR)/\ln(2))$.

The parameter "a" is computed from initial overnight cost and capacity conditions of the nonlinear learning curve.

$a = OC(C0)/Co^{-b}$

Note that Co is the cumulative capacity or number of units built as of the beginning of the current time period/year.

As a new technology matures, the capital cost is expected to decline, reflecting the principle of "learn by doing" and manufacturing experience. This principle is implemented in the LFMM similar to the methodology used in the EMM. The learning occurs in three phases. The first phase is represented by the linear phase out of optimism (and some revolutionary learning) over the first four plants (such that the optimism factor for the fifth and later plant is 1.0). The non-linear learning function shown above is used for the second (up to 32 plants built) and third (beyond 32 plants) phases..

Each technology was assessed to determine the mix of technological maturity of each component (revolutionary/evolutionary or mature). This was used to define what percent (m) of the cost would decline slowly (slow for mature) versus quickly (fast for evolutionary/revolutionary) due to learning. Next, for each learning category (fast and slow), a rate of learning (f) is assumed (i.e., a percent reduction in overnight capital cost for every doubling of cumulative capacity).

The overall learning factor is the weighted combination of the fast and slow learning factors (OC), weighted by the percentage that each component represents of the technology. Model parameters are shown in Table 11.10.

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 [8]. 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 feedstocks are more similar to petroleum, and their fuels do not count toward RFS requirements.

Table 11.9. Non-petroleum fuel technology characteristics[1]

US Gulf Coast AEO2014 2020 Basis (2012$)	Online Year	Nameplate Capacity[2]	Base Overnight Capital	Contingency Factors[3,4]		Total Overnight Capital[5]	Feedstock Cost[6]	Non-- Feedstock O&M[7]	Thermal Efficiency[8]
		barrels/day	$/daily barrel	Project	Optimism	$/daily barrel	$/daily barrel	$/daily barrel	Energy %
Biochemical									
Corn Ethanol	-	6,800	$18,200	3%	0%	$18,700	$69	$16	49%
Advanced Grain Ethanol	2014	3,400	$43,400	3%	0%	$44,700	$73	$16	49%
Cellulosic Ethanol	2013	4,400	$114,000	10%	20%	$150,500	$11	$16	28%
Biobutanol (retrofit of corn ethanol plant)	2015	6,500	$9,500	10%	20%	$12,540	$87	$0	62%
Thermochemical Catalytic									
Methyl Ester Biodiesel (FAME)	-	1,200	$19,700	3%	0%	$20,300	$192	$29	21%
Non-Ester Renewable Diesel (NERD)	-	2,100	$28,000	10%	0%	$30,800	$187	$20	21%
Pyrolysis	2013	5,200	$232,000	10%	20%	$306,230	$14	$20	60%
Thermochemical Fisher-Tropsch									
Gas-to-Liquids (GTL)[9]	2018	48,000	$126,000	10%	10%	$152,500	$60	$18	55%
Coal-to-Liquids (CTL)	2018	48,000	$150,000	10%	15%	$189,800	$45	$15	49%
Biomass-to-Liquids (BTL)	2020	6,000	$262,000	10%	20%	$345,800	$34	$16	45%

[1]This table is based on the *AEO2014* 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 Liquid Fuels Market Module of NEMS. For corn ethanol and FAME biodiesel, annual capacity is the most common plant size as of 2013.
[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]Feedstock costs include cost of materials being converted to liquid fuels.
[7]Non-feedstock operating and maintenance (O&M) costs include labor cost and other variable costs.
[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 Analysis, PNGBA, 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.

Table 11.10. Non-petroleum fuel technology learning parameters

Technology Type	Cumulative Plants (k)	Phase 1 1st of a Kind Optimism	Phase 2 5th of a Kind Fast[1]	Phase 2 5th of a Kind slow[1]	Phase 3 32nd of a Kind Fast[1]	Phase 3 32nd of a Kind Slow[1]
Cellulosic Ethanol	Optimism Factor and Revolutionary Learning	1.25	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	33%	67%	33%	67%
	Learning Rate (f)	--	0.25	0.10	0.10	0.05
Pyrolysis	Optimism Factor and Revolutionary Learning	1.25	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	33%	67%	33%	67%
	Learning Rate (f)	--	0.25	1.0.10	0.10	0.05
Biomass-to-Liquids (BTL)	Optimism Factor and Revolutionary Learning	1.25	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	15%	85%	15%	85%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01
Coal-to-Liquids (CTL)	Optimism Factor and Revolutionary Learning	1.25	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	15%	85%	15%	85%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01
Gas-to-Liquids (GTL)	Optimism Factor and Revolutionary Learning	1.25	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	10%	90%	10%	90%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01

[1]Fast = evolutionary/revolutionary learning; slow = mature learning.
Source: U.S. Energy Information Administration.

Biofuels supply

Supply functions for corn, non-corn grain, and cellulosic biomass feedstocks are provided on an annual basis through 2040 for the production of ethanol (blended into transportation fuel). Supply functions for soy oil, other seed-based oils, and grease are provided on an annual basis through 2040 for the production of biodiesel and renewable diesel.

- Potential RFS target reductions by EPA are provided exogenously to NEMS.
- 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.
- Biodiesel and renewable diesel feedstock supplies and costs are provided exogenously to NEMS.
- 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 2020 to several planned projects with aggregate nameplate capacity of approximately 185 million gallons per year. Planned capacity through 2019 for Pyrolysis and Biomass-to-Liquids processes is approximately 110 million gallons per year.
- Methyl ester biodiesel production contributes 1.5 credits towards the advanced mandate.
- Renewable diesel fuel and cellulosic 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.

- Separate biofuel waivers can be activated for each of the four RFS fuel categories.
- Biodiesel and BTL diesel are assumed to be compatible with 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 $152,700 per station (2012 dollars). Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in the 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. A 48,000-barrel-per-day CTL facility is assumed to cost over $7 billion in initial capital investment (2012 dollars). 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 2018.

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 2013 and 2014 are projected at the U.S. level in the Short-Term Energy Outlook, (STEO). The LFMM adopts the STEO results for 2013 and 2014, 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.

AEO2014 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements which requires that the average annual sulfur content of all gasoline used in the United States be 30 ppm.

AEO2014 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.

AEO2014 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.

AEO2014 represents major provisions in the Energy Policy Act of 2005 (EPACT05) concerning the petroleum industry, including removal of the oxygenate requirement in RFG.

AEO2014 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. The price of a cellulosic waiver is specified in EISA2007. The non-cellulosic LFMM RFS waivers function as maximum allowed RIN prices. LFMM also assumes that EPA will reduce RFS targets as allowed by the EISA2007 statute.

AEO2014 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.

AEO2014 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.

AEO2014 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 metric tons CO_2 equivalent ($MTCO_2e$) in any year 2011-2014.

AEO2014 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. It also includes transition to a 2% biodiesel content in the case of Maine and Connecticut.

Due to the uncertainty surrounding compliance options, AEO2014 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.

The AEO2014 Reference Case does not include proposed but not yet enacted extensions of the $1.00-per-gallon biodiesel excise tax credit or the $1.01-per-gallon cellulosic biofuels production tax credit.

Notes and sources

[1] 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).

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

[3] Ibid.

[4] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2019," February 2009, www.ers.usda.gov/publications/oce-usda-agricultural-projections/oce-2010-1.aspx.

[5] Shapouri, Hosein and Gallagher, Paul. USDA's 2002 Ethanol Cost-of-Production Survey, July 2005.

[6] U.S. Department of Agriculture. 2008 Energy Balance for the Corn-Ethanol Industry, June 2010.

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

[8] Economic lifetime is 20 years for cellulosic ethanol, biomass Fischer-Tropsch, and Pyrolysis Oil. 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.