Assumptions to the Annual Energy Outlook 2026: Natural Gas Market Module

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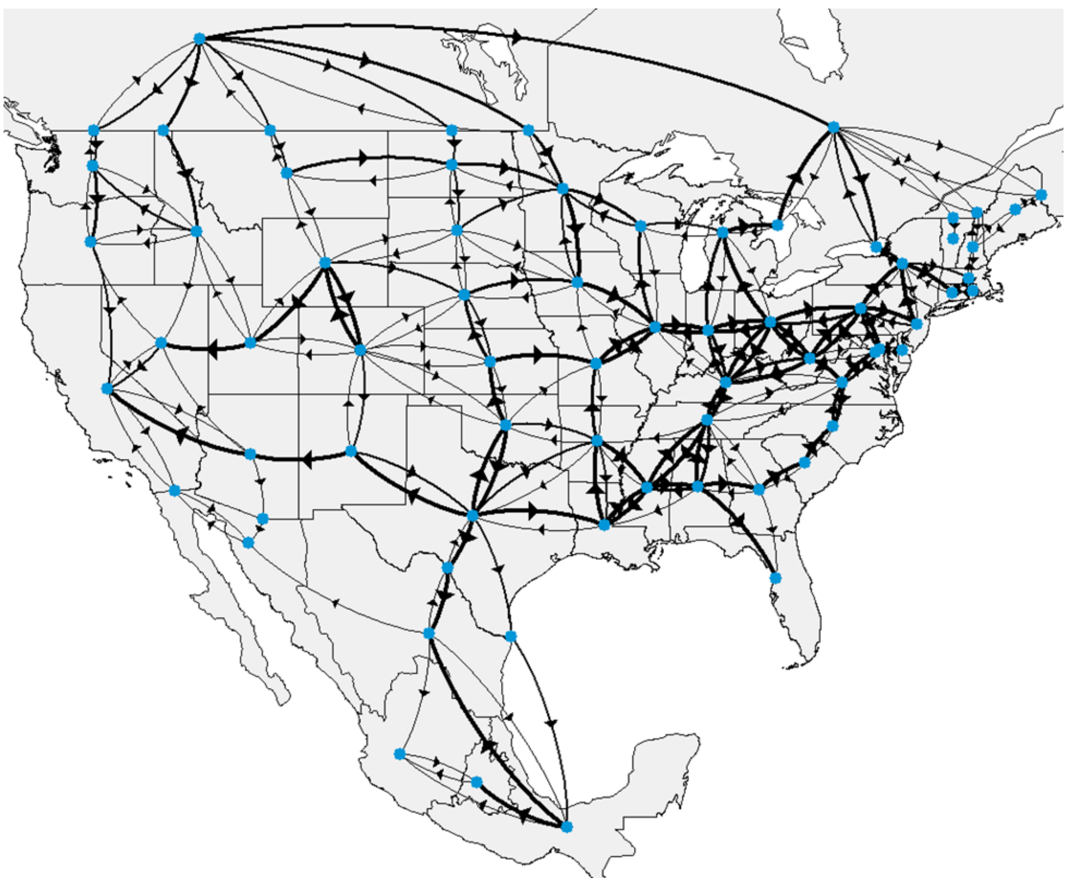
Overview

The Natural Gas Market Module (NGMM) of the National Energy Modeling System (NEMS) projects wellhead, border, spot, citygate, and delivered prices that balance monthly natural gas supply and demand through a simplified North American pipeline network (Figure 1). We generate these projections using a quadratic program (QP) that maximizes consumer plus producer surplus minus variable transportation costs (with a nonlinear representation). Some linear constraints affect the program: mass balance requirements, pipeline capacity limits, and assumed storage withdrawals and injections. The NGMM model code solves for:

- Nonassociated dry natural gas production
- State-to-state flows
- Imports and exports
- Pipeline fuel
- Lease and plant fuel

Figure 1. Map of Natural Gas Market Module (NGMM) network representation, April 2026



Source: U.S. Energy Information Administration, Natural Gas Market Module (NGMM)
Note: Blue circles represent transshipment nodes. Arcs represent pipeline capacity existing between nodes. Bidirectional flows indicate monthly (that is, seasonal) variability in the direction of natural gas flow. We model Alaska's natural gas market in the NGMM independent of the integrated network.

We project interstate pipeline capacity additions in the NGMM using a similar but modified QP to solve for months representing peak consumption: January and August. The NGMM represents natural gas markets in Canada (two regions) and Mexico (five regions), as well as domestic consumption and production at state and substate levels. You can find a complete list of NGMM assumptions and an in-depth description of the methodology in the latest Natural Gas Market Module – NEMS Documentation.

Because other modules in NEMS provide natural gas consumption data to the NGMM at a more aggregate level (generally for each year by census division), the NGMM disaggregates these volumes for the Lower 48 states at a monthly level based on historical average shares for the past five years, after subtracting econometrically estimated consumption for Alaska. The Hydrocarbon Supply Module (HSM) provides state and substate dry associated-dissolved natural gas production and expected dry nonassociated production as a basis for establishing annual, short-term natural gas supply curves at state and substate levels for the United States and for Eastern and Western Canada. The NGMM uses these curves in the QP to project realized production levels and their associated wellhead prices.

The module projects liquefied natural gas (LNG) export capacities separately, and we use these export capacity projections to develop LNG export demand curves for the QP. The module also has fixed additional assumptions about supplemental natural gas supplies, LNG imports, consumption in Canada and Mexico, and supply in Mexico. In the *Annual Energy Outlook 2026* (AEO2026), NGMM benchmarked to the November 2025 *Short-Term Energy Outlook* (STEO). We use the following NGMM outputs as benchmarks to align with the STEO for 2025 and 2026:

National

- Production
- Supplemental supplies
- Lease and plant fuel
- Pipeline fuel[1]
- Storage withdrawals
- Pipeline imports and exports
- LNG imports and exports
- Henry Hub price
- Delivered natural gas price to electric generators

Regional

- Delivered prices to residential and commercial customers

Over the next five years in the projection period, we phase out the STEO benchmark factors calculated for this alignment in 2026 except in cases where no phaseout applies: pipeline imports, pipeline exports, and the Henry Hub price. For LNG exports, we make average LNG capacity utilization assumptions in the years following the November 2025 STEO (beginning in January 2027) instead of explicitly phasing out the STEO benchmark factors.

Key assumptions

Supply curves for natural gas production in North America

We assume that projections of associated-dissolved natural gas production do not change in response to current-year natural gas prices in the supply and demand balancing process in the NGMM's QP. The NGMM represents nonassociated natural gas in each state and substate (or region, for Canada and Mexico) using a short-term supply curve. We base each curve on a price and quantity pair, where the quantity is the expected production and the price is equal to the price from the previous projection year. For each state and substate, we define a piecewise linear supply curve with five segments by this price and quantity pair using assumed slopes or elasticities. This curve has four options that vary the quantities that define the endpoints of these lines and the slopes of each segment (the percentage change in production divided by the percentage change in price) (Table 1).

Table 1. Piecewise linear supply curve options and associated elasticity parameters

Segment	Option 1[a]	Option 2[b]	Option 3	Option 4
Segment quantities	± 0%, ± 0%	± 3%, ± 9%	± 6%, ± 18%	± 1%, ± 3%
Slope-Segment 1[c]	—	0.8	1.25	0.7
Slope-Segment 2	—	0.7	1.0	0.5
Slope-Segment 3	—	0.5	1.0	0.1
Slope-Segment 4	—	0.3	0.8	0.05
Slope-Segment 5	—	0.2	0.5	0.05

Data source: U.S. Energy Information Administration
[a] Option 1 corresponds to fixed supply that cannot vary with price.
[b] Option 2 defines most supply regions.
[c] The slope of each segment is the percentage change in production divided by the percentage change in price.

International representation

The NGMM exogenously sets LNG imports and exports to and from Canada and Mexico based on projections from the *International Energy Outlook 2023* (IEO2023) (Table 2). We assume Mexico's and Canada's natural gas consumption in the residential, commercial, industrial, transportation, and electric power sectors equals the IEO2023 consumption volumes. We additionally calibrated Canada's natural gas consumption to the most recent historical data.

The NGMM represents production in Eastern and Western Canada just as it does for U.S. states by using the expected production values the HSM computes. The NGMM sets production in Mexico using expected production estimated in NGMM. We set associated-dissolved production by using a historically estimated equation as a function of oil production,[2] world oil price, and the previous year's production volumes. In contrast, we assume expected nonassociated production relates to the previous year's nonassociated natural gas production and the Henry Hub price. We also assume nonassociated natural gas production from Mexico's shale gas resources to be undeveloped.

Table 2. Exogenous assumptions for North American production and trade

Year	Mexico oil production, thousand barrels per year	Mexico LNG imports, billion cubic feet per year	Canada LNG exports, billion cubic feet per year	Mexico LNG export capacity, billion cubic feet per year
2020	858	90	—	—
2023	880	26	—	—
2025	—	—	1,440	71
2030	—	—	2,000	428
2035	—	—	3,440	428
2040	—	—	5,147	428
2045	—	—	5,147	428
2050	—	—	5,147	428

Data source: U.S. Energy Information Administration, *International Energy Outlook 2023*
Note: LNG=liquefied natural gas

U.S. LNG export capacity representation

NGMM endogenously sets the capacity to export LNG from the United States beyond existing infrastructure and new projects already under construction through 2030 outside of the QP. We determine the actual exports out of each region in the QP by using:

- A demand curve based on the projected available capacity
- The estimated competing price in Asia or Europe in the given year
- A liquefaction and pipeline transport fee equal to the variable cost component (in other words, excluding assumed capacity reservation or sunk charges for liquefaction)

Exports fall lower than the operating capacity if the regional spot price plus liquefaction, shipping, and regasification costs exceed the price in Asia or Europe. We assume that projects that were under construction during the AEO2026 production cycle will come online or will have come online within the timeframes in Table 3.[3]

For all projects, we assume trains will ramp up to their utilization rates (Table 4). After the ramp-up period ends, we assume the trains will operate at a long-term utilization rate of 90%. These ramp-up rates assume added capacity is in the form of traditional, large-scale trains.

For the year following the STEO benchmarking period (2027), we assume an LNG capacity utilization that phases out the higher STEO utilization assumptions, which can often be significantly more than 100% baseload utilization, into the long-term NGMM assumption for LNG capacity utilization (Table 5).

Table 3. In-service dates of known recently completed or under-construction LNG export facilities

Project	Trains	In-service date
Calcasieu Pass, Louisiana	1–9	March 2022
	10–18	September 2022
Corpus Christi Stage III	1–7	February 2025
	8–9	December 2028
Plaquemines LNG	1–18	December 2024
	19–36	September 2025
Golden Pass LNG, Louisiana	1	June 2026
	2	December 2026
	3	June 2027
Port Arthur LNG Phase 1	1–2	December 2027
	3–4	December 2031
Rio Grande LNG Phase 1	1	June 2027
	2	December 2027
	3	December 2028
	4	December 2030
Woodside Louisiana LNG	1–3	December 2029
CP2	1–26	December 2029

Data source: U.S. Energy Information Administration, U.S. Liquefaction Capacity spreadsheet, third-quarter 2025
Note: LNG=liquefied natural gas

Table 4. Capacity utilization by LNG train number and months after initial in-service date

Months after initial in-service date	Train 1	Train 2	Train 3	Train 4
In-service month	10%	10%	50%	50%
1	25%	25%	85%	85%
2	50%	50%	90%	90%
3	50%	85%	90%	90%
4	85%	90%	90%	90%
5	90%	90%	90%	90%

Data source: U.S. Energy Information Administration
Note: LNG=liquefied natural gas

Table 5. Average annual LNG capacity utilization following STEO period

Year	Utilization
2027	98%
2028 and later	90%

Data source: U.S. Energy Information Administration
Note: LNG=liquefied natural gas; STEO=*Short-Term Energy Outlook*

For each projection year, the module assesses the relative economics of constructing and operating from one to four generic trains, each of which produces 200 billion cubic feet per year for 20 years in four representative Lower 48 states (Maryland, Georgia, Louisiana, and Texas) or in a four-train Alaska LNG terminal. This assessment compares model-generated estimates of the expected market price in Europe and Asia during the period with the expected domestic natural gas price (assuming exports increase) in each state in addition to the assumed charges for liquefaction, shipping, and regasification (Table 6). We set the present value of the differential with a 10% discount rate. The first train will come online with a positive present value, but the next two trains require a progressively higher present value to reflect additional risk. Once the module determines that a train is economically viable, the LNG export capacity increases for three years in the state showing the greatest positive economic potential. We assume the decision to build a liquefaction facility is made four years before the facility first comes online.

Table 6. Selected charges related to LNG exports

2025 dollars per million British thermal units

	Maryland	Georgia	Louisiana	Texas	Alaska
Liquefaction and pipe fee	$3.86	$3.86	$3.51	$3.51	$8.85
Reservation charge	$3.51	$3.51	$3.51	$3.51	
Shipping to Europe	$0.92	$0.98	$1.21	$1.23	$2.57
Shipping to Asia	$2.71	$2.64	$2.63	$2.64	$1.03
Regasification	$0.12	$0.12	$0.12	$0.12	$0.12
Fuel charges	15%	15%	15%	15%	15%

Data source: U.S. Energy Information Administration
Note: LNG=liquefied natural gas
[a] Percentage increase in market price of natural gas charged by liquefaction facility to cover fuel-related expenses, mostly fuel used in the liquefaction process.

We consider other constraining assumptions, such as the earliest start year and maximum number of trains that can be added each year. We consider capacity in each state, and we project market prices of LNG in Europe (Title Transfer Facility [TTF] in the United Kingdom) and Asia (Japan-Korea Marker [JKM]) based on the assumed volumes in Table 7, projected Brent crude oil prices, and North American LNG exports. Regional natural gas consumption is consistent with growth rates in IEO2023 and most recent historical data. The international (non-U.S.) LNG export capacity for historical years is from the most recent annual report from the International Group of Liquefied Natural Gas Importers (GIIGNL),[4] with projected capacity through 2030 assumed based on the International Energy Agency.[5] Beyond 2030, we assumed growth using the average annual capacity increases from 2000–2025. A 90% utilization rate was assumed for all global LNG export facilities and applied to the global capacities above.

We base LNG import volumes on historical levels, and we assume they total 32 billion cubic feet per year in the projection period after benchmarking to STEO values.

Table 7. International LNG volume drivers for world LNG Europe and Asia market price projections

Year	World LNG export capacity[a] billion cubic feet	Natural gas consumption, OECD Europe[b] billion cubic feet	Natural gas consumption, Asia[c] billion cubic feet
2025	17,503	19,806	33,931
2026	18,625	20,561	35,126
2030	22,784	21,765	37,732
2035	25,248	21,650	40,249
2040	27,712	21,746	43,312
2045	30,175	21,880	47,330
2050	32,639	22,233	51,295
2055	35,103	22,697	55,696
2060	37,567	23,172	60,556
2065	40,030	23,656	65,921
2070	42,783	24,150	71,841

Data source: U.S. Energy Information Administration, *International Energy Outlook 2023* (IEO2023)
Note: IEO2023 defines these regions. LNG=liquefied natural gas, OECD=Organization for Economic Cooperation and Development
[a] GIIGNL Annual Report 2024, IEA Global LNG Capacity Tracker (as of Nov 2025)
[b] OECD Europe includes all OECD countries in Europe except Turkey.
[c] The following IEO2023 regions are included: China, India, Japan, South Korea, and other non-OECD Asian countries. Australia and New Zealand are not included.

Other miscellaneous volumes

Although the NGMM receives primary production and consumption volumes from other NEMS modules, other miscellaneous volumes are set within the NGMM, including storage withdrawals and injections, supplemental supplies, and lease and plant fuel:

- Monthly and state-level storage withdrawals and injections are held constant during the projection period at the average historical level for the previous five years, after being scaled to ensure that the net withdrawals during the year sum to zero for each state.
- The relatively small supplemental natural gas supply projections, which include synthetically produced natural gas and other gaseous substances mixed with the natural gas stream (such as propane), remain constant at the average historical level for the previous five years and continue to remain constant throughout the projection period. Renewable natural gas (RNG) volumes are projected separately from supplemental natural gas supply projections.
- Natural gas plant liquids (NGPL) production (as set in the HSM by state and substate levels on an annual basis) moves to an assumed state for processing based on historical data, where each state's volumes were moved in recent years. We establish the amount of natural gas used in processing facilities in each state by using the ratio of NGPL processed to the natural gas fuel needed to process it in the most recent historical year. We assume volumes are constant throughout the projection period.
- Similarly, we calculate lease fuel consumption by state and substate using historically based ratios (averaged for the previous five years) of natural gas produced to lease fuel consumed.

- Pipeline fuel use includes fuel used for distribution and storage services, as well as inter- and intrastate pipelines. The NGMM sets fuels used for storage and distribution using external, historically based ratios of the fuel used. We assume storage fuel use to be 0.4% of gross storage injections and withdrawals and distribution fuel use to be a state-specific percentage of delivered natural gas volumes (0.3%–6.2%). We assume the remaining volumes reflect fuel used on interstate pipelines, and the NGMM represents these as a percentage of state-to-state flows that are lost.[6] We allocate the fuel volumes for historical years to state-to-state arcs in proportion to the historical flows in and out of the region to calculate a historically based loss factor for the projection period.

We assume natural gas used at facilities that liquefy natural gas for export to equal 10.1% of the exported volumes.

Pipeline capacity expansion

The NGMM assumes that currently known pipeline capacity additions, such as projects under construction or projects approved by the Federal Energy Regulatory Commission (FERC), are completed and come online in November of the expected in-service year.[7] After 2027 and before the regular QP is solved in each NEMS iteration, we determine unplanned pipeline capacity additions by running a structurally identical QP but with two changes in the primary model inputs: the weather assumption driving consumption levels and the limits on pipeline flows. NEMS provides consumption levels for the regular QP that reflect normal weather, and projected capacity levels limit flows between states and nodes.

For the capacity expansion QP, we multiply consumption levels by a sector- or state-specific factor to reflect the most extreme weather potential. We base the weather factors applied to the residential and commercial sectors in winter months to reflect historical differences between the most extreme January consumption level and average January consumption in recent years. We base the other months on similar differences in August. We assume the factors for the industrial and electric power sectors to be 10% higher than normal in all months. These sectors are not always the driving force behind pipeline additions because they can frequently employ other options in extreme weather. In addition, in the capacity expansion, the NGMM limits QP pipeline capacity additions to 40% of the existing capacity. Accordingly, each variable tariff curve is extended from its price point at full utilization to a price point at a utilization rate 40% higher than existing capacity; this price is generally twice as high as the price at 100% utilization. We use this method to reflect the reality that pipeline capacity will only be added if enough users are willing to pay an additional reservation fee.

Pricing

Spot prices are effectively set within the QP based on the marginal price (shadow price on each balancing constraint in the QP) at each node in the transportation network. Each state has a node where the monthly flows into and out of the state are balanced, including the internal state supply and consumption. We use the marginal prices at these nodes as a proxy for representative state-level spot prices. The NGMM sets the price at each supply node (wellhead price) equal to the spot price minus the assumed transport or gathering charge ($0.36 [2025 dollars] per thousand cubic feet). We assign most of the other arcs in the QP, usually representing state-to-state flows, a variable tariff in the QP via a curve. This method allows the tariff to vary as a function of the pipeline utilization. These curves vary by arc and are informed by historical spot price differentials, historical state-to-state total pipeline capacities (January 2025), and monthly historical state-to-state flows. All curves have the same shape: a generally constant or flat tariff at low utilization rates and a sharply increasing tariff as utilization approaches 100%. The difference in the price from one node to the next (or basis differential) will also reflect the pipeline fuel loss on the arc, and it can be even higher if pipeline flow constraints on the arc are binding in the QP.

The NGMM sets state-level, monthly citygate prices by using econometrically estimated equations that are a function of the spot price and the volume of natural gas consumed by residential and commercial customers in a state during a specific month. Additional markups are applied to the citygate price to calculate a delivered end-use price for each of the sectors.

Residential and commercial sector markups

We set annual, census division-level delivered prices to residential and commercial customers by adding a sector-specific, econometrically estimated distributor tariff to the average annual citygate price in the census division. The distributor tariffs are a function of:

- Residential consumption per household in the residential sector
- Commercial consumption per unit of commercial floorspace in the commercial sector

State-level data are aggregated to census division-level data using combined residential and commercial consumption in each state and month as a quantity weight.

Industrial sector markups

For industrial customers, the NGMM sets markups to annual and census division delivered prices at the historical average from the previous five years of the industrial price minus the average annual spot price in the region. To aggregate state level data to the nine census divisions, we use industrial consumption in each state and month as a quantity weight. We estimate historical industrial prices based on prices published in our *Manufacturing Energy Consumption Survey*.

For the electric power sector, the NEMS transfers consumption volumes and prices between the NGMM and the Electricity Market Module (EMM) for 16 regions in the Lower 48 states for each of the three seasons defined in the EMM: peak, off-peak, and shoulder.[8] The NGMM sets the delivered prices to electric power generators by adding a markup to the average spot price in the region or season, which the NGMM develops using electric power consumption as a quantity weight.

The NGMM initially sets these markups at the historical average for the previous five years, and they increase or decrease during the projection period as the ratio of electric power sector consumption to other consumption in a given region or season increases or decreases. This method reflects the need for natural gas-fired generators to purchase more firm pipeline service as their market shares increase.

Transportation sector markups

Several characteristics distinguish the natural gas used in the transportation sector, excluding pipeline fuel use:

- Fuel type

    - Compressed natural gas (CNG)
    - LNG
- Vehicle category
    - Personal road vehicle (purchased fuel at public station)
    - Fleet road vehicle (purchased fuel at private station)
    - Train
    - Ship

We assume six differences when calculating delivered natural gas prices for different transportation modes and fuel types:

- Prices can be marked up from either the citygate price or the industrial price of delivered natural gas.
- Road vehicles pay the state and federal motor fuels taxes for either CNG or LNG.
- Ships do not pay a state motor fuels tax on CNG or LNG.
- Trains pay neither a state nor a federal motor fuels tax on CNG or LNG.
- Retail markups are higher for personal vehicles because of the smaller volumes of fuel being sold.
- Retail markups are lower for rail and ship use because of lower infrastructure costs.

The NEMS Transportation Demand Module further disaggregates the rail and ship prices, but the prices assigned in the NGMM are not distinguished further.

For delivered prices to the transportation sector for vehicles using LNG, we estimate the price for delivered dry natural gas to a liquefaction plant by using the price for delivered natural gas to industrial customers. The retail LNG price for a vehicle, train, or ship is equal to:

- The sum of the price to industrial customers
- The assumed price to liquefy and transport the LNG to a station
- The retail price markup at the station and the excise taxes
- The national average state excise tax in the model varies by region (Table 8)

For delivered prices to vehicles using CNG in the transportation sector, we base the markup from the regional citygate price on posted rates in the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy's *Clean Cities Alternative Fuel Price Report*. We adjust these markups to account for any historical changes in the state and federal excise taxes against what we assume in the projection period. Prices at public and private stations are reported separately. The NGMM assumes that public stations are for personal vehicles and that private stations are for fleet vehicles. The module assumes these reported prices include the retail markup. Therefore, we use only CNG fleet assumptions to calculate a retail markup for rail and shipping transport using CNG's industrial price. The values used throughout the projection period for these components and the primary assumptions behind them are in Table 8.

Table 8. Assumptions for setting CNG and LNG fuel prices

Assumption	CNG private	LNG private	LNG public
Retail markup after dry gas pipeline delivery, with no excise tax (2025$/dge)	$1.15	$0.92	$1.19
Capacity (dge/day)	1,600	4,000	4,000
Usage (percentage of capacity)	80%	80%	60%
Capital cost (million 2025$)	1.15	1.44	1.44
Capital recovery (years)	5	5	10
Weighted average cost of capital (rate)	0.1	0.1	0.15
Operating cost (2025$/dge)	$0.49	$0.58	$0.84
Federal excise tax (nominal$/dge)[1]	$0.21	$0.24	$0.24
State excise tax (nominal$/dge)[2]	$0.21	$0.22	$0.22
Fuel loss for liquefying and delivering LNG (percentage of input volumes)	--	10%	10%
Fuel loss at station (percentage of input volumes)	0.50%	1.00%	2.00%

Data source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis; U.S. Tax Code[9] and state tax codes[10]
Note: dge=diesel gallon equivalent, CNG=compressed natural gas, LNG=liquefied natural gas

Alaska markups

The NGMM sets the price in Alaska by adding a historically based markup to an econometrically estimated citygate price.

Renewable natural gas

The NGMM represents renewable natural gas (RNG) production within the model. Historical RNG production at the state level is derived from capacities listed in the 2024 Argonne National Laboratory (ANL) RNG Database. Potential production from landfill RNG projects is derived from the EPA's Landfill Methane Outreach Program (LMOP) Landfill and Project Database (November 2022). Potential production from dairy farm-based RNG is derived using data from the 2017 Agricultural Census.

Legislation and Regulations

We apply current federal and state motor fuels taxes to both CNG and LNG used in vehicles.

We assume that RNG production projected by the NGMM will satisfy the latest Renewable Fuel Standard (RFS) volume targets for cellulosic biofuel when combined with ethanol production from corn kernel fiber (CKF), which is handled by the Liquid Fuels Market Module.

Table 9. Cellulosic biofuel RFS volume targets (million RINs)

Year	RNG	Ethanol from CKF	Total cellulosic biofuel
2023	831	7	838
2024	1,039	51	1,090
2025	1,299	77	1,376

Data source: U.S. Environmental Protection Agency, Final Rule RFS Program: Standards for 2023–2025 and Other Changes

Note: CKF=corn kernal fiber; RNG=renewable natural gas; RIN=renewable identification number, one RIN equals one ethanol-equivalent gallon of renewable fuel

Notes and Sources

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[1] The STEO forecast for pipeline fuel includes fuel used for liquefaction at LNG export facilities. We calculate this total separately in the NGMM; therefore, the NGMM benchmarks to pipeline fuel after subtracting this volume from STEO. We assume fuel used for liquefaction is 10.5% of the LNG export volume.
[2] We base oil production in Mexico on initial assumptions used in IEO2023 on the upstream component of the World Hydrocarbon Activity Module and the world oil price path in the IEO2023 Reference case. Assumed values are used through 2026, after which oil production is a function of world oil price.
[3] The dates and base capacities for LNG export facilities were consistent with our U.S. liquefaction capacity reports as of October 2025.
[4] https://www.giignl.org/annual-report
[5] https://www.iea.org/data-and-statistics/data-tools/global-lng-capacity-tracker
[6] Although we assume all remaining pipeline fuel in AEO2025 will be used by compressor stations on interstate pipelines, the NGMM does structurally allow for pipeline fuel use or losses on arcs coming from supply nodes (in other words, intrastate pipeline transport primarily serves to bring natural gas from processing plants to the interstate pipeline system).
[7] Historically, many projects are planned for the in-service date to coincide with the start of the peak demand (winter) season. See our natural gas Pipeline Projects (July 2025) spreadsheet for the in-service dates for recently completed and historical natural gas pipeline projects.
[8] For a discussion of the seasonality representation in the EMM, refer to *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2025*.
[9] H.R. 3236 (Public Law 114-41) and 26 U.S. Code 4041 and 4081 (Internal Revenue Service). Propane and compressed natural gas (CNG) are subject to a federal excise tax of $0.183 per gasoline gallon equivalent (GGE).
[10] U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy's Alternative Fuels Data Center. When state motor vehicle fuel tax information was unavailable for alternative fuels, we used the following state government sources:

- Connecticut, State Department of Revenue Services, PS 92 (10.1)
- Illinois, Department of Revenue, Tax Rate Database, Motor Fuel Tax Rates and Fees
- Massachusetts, Department of Revenue, DOR Motor Fuel Excise
- Comptroller of Maryland, Motor Fuel Tax Rates
- Montana Legislature, Montana Code Annotated, Montana Department of Transportation
- New Hampshire Department of Safety, Road Toll Bureau
- Ohio, Department of Taxation, Motor Fuel Tax
- Rhode Island, Division of Taxation, Taxability of Special Fuels
- Wisconsin, Department of Revenue, Alternate Fuel Tax
- Wyoming Department of Transportation, Tax Rates