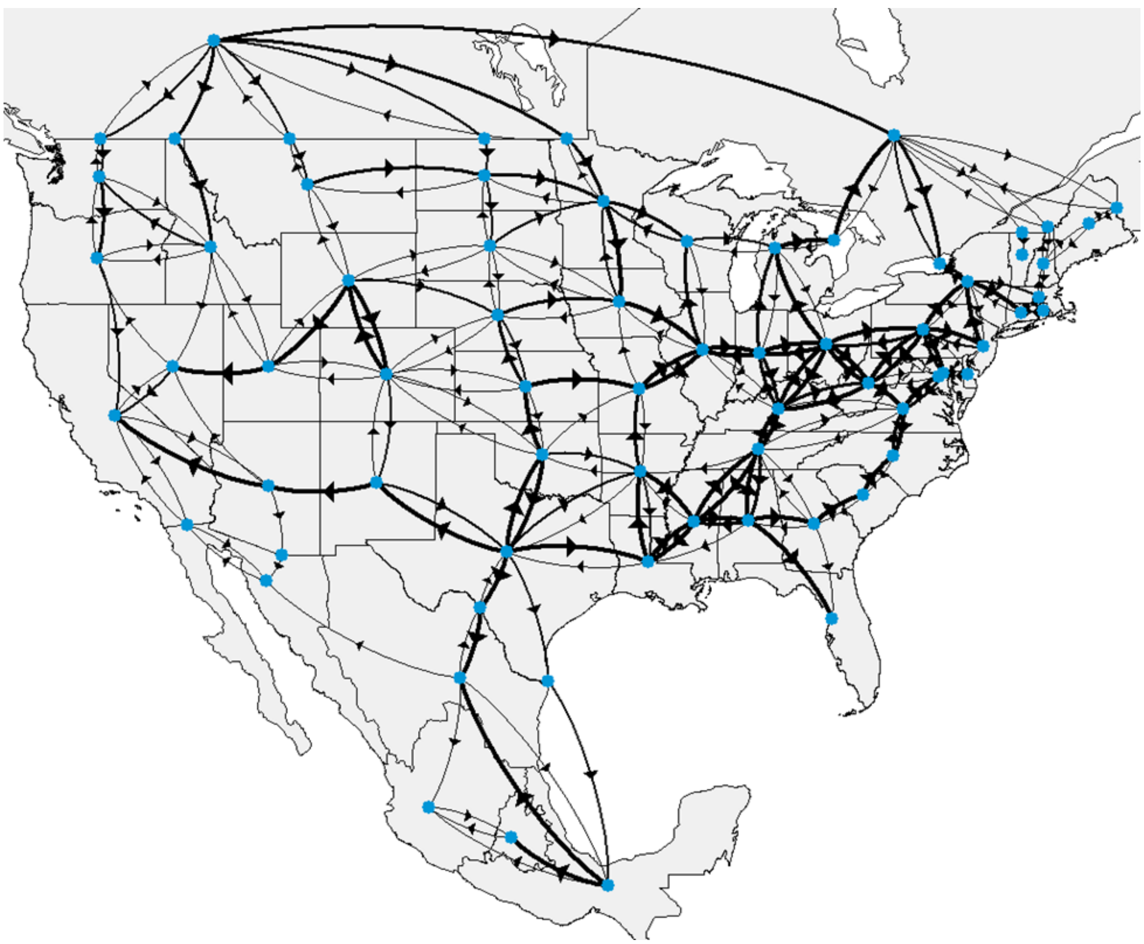
Natural Gas Market Module

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). The program is subject to several linear constraints: 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. Natural Gas Market Module network representation



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 *Natural Gas Market Module of the National Energy Modeling System: Model Documentation 2020*.

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 levels for Alaska. The Oil and Gas Supply Module (OGSM) 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 a state and substate level 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. Typically, NGMM benchmarks to the October *Short-Term Energy Outlook* (STEO); however, for AEO2022, we used the November 2021 STEO to consider impacts from the Infrastructure Investment and Jobs Act. We use the following NGMM outputs as benchmarks to align with the STEO for 2021 and 2022:

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

We phase out the STEO benchmark factors calculated for this alignment in 2021 during the next five years except in cases where no phaseout is applied—pipeline imports, pipeline exports, and the Henry Hub price. For LNG exports, average LNG capacity utilization assumptions are made in the years following STEO 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. Each curve is based on a price and quantity pair, where the quantity is the expected production level and the price is assumed to be equal to the price from the previous projection year. For each state and substate, a piecewise linear supply curve with five segments is defined 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). Option 2 defines most supply regions; Option 1 corresponds to fixed supply that cannot vary with price.

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

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

LNG imports and exports to and from Canada and Mexico are set externally in the NGMM, based on projections from the *International Energy Outlook 2021* (IEO2021)(Table 2). The NGMM assumes Mexico's natural gas consumption in the residential, commercial, transportation, and electric power sectors equals the IEO2021 consumption volumes.[2] We calculate Mexico's natural gas consumption in the industrial sector endogenously, and we assume to have an *other industrial* component and a component related to oil production. The *other industrial* component is a function of the Henry Hub price, and the oil-related component is related to oil production. The coefficients defining this relationship are estimated using historical data. We assume consumption of natural gas in Canada to equal the projections published by the Canada Energy Regulator in *Canada's Energy Future 2020*.

The NGMM represents production in Eastern and Western Canada just as it does for U.S. states by using expected production values computed by the OGSM. The NGMM sets production in Mexico using expected production levels set within the NGMM. Associated-dissolved production is set using a historically estimated equation as a function of oil production,[3] world oil price, and the previous year's production volumes. In contrast, we assume expected nonassociated production is related 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 are undeveloped.

Table 2. Exogenously specified oil production and LNG trade for Canada and Mexico

Year	Mexico oil production, thousand barrels per year	Mexico LNG imports, billion cubic feet per year	Canada LNG exports, billion cubic feet per year
2020	607	450	—
2021	579	450	—
2025	607	100	526
2030	—	—	730
2035	—	—	1,221
2040	—	—	1,879
2045	—	—	1,879
2050	—	—	1,879

Source: U.S. Energy Information Administration, *International Energy Outlook 2021*
Note: LNG=liquefied natural gas

U.S. LNG export capacity representation

The capacity to export LNG from the United States beyond existing infrastructure and new projects already under construction through 2025 is set endogenously in the NGMM outside of the QP. The actual level of exports out of each region is determined 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 AEO2022 production cycle will come online or will have come online within the timeframes in Table 3.[4]

Table 3. In-service dates of known LNG export facilities

Project	In-service date
Cameron LNG, Louisiana	
Train 2	March 2020
Train 3	June 2020
Corpus Christi LNG, Texas	
Train 3	August 2020
Freeport LNG, Texas	
Train 2	January 2020

Train 3	June 2020
Elba Liquefaction Project, Georgia	December 2019–May 2020
Sabine Pass LNG Terminal, Louisiana	
Train 6	December 2021
Calcasieu Pass, Louisiana	
Trains 1–5	December 2021
Trains 6–10	May 2022
Golden Pass LNG, Louisiana	
Train 1	January 2024
Train 2	July 2025
Train 3	January 2025

Source: U.S. Energy Information Administration, U.S. Liquefaction Capacity spreadsheet, July 2021
LNG=liquefied natural gas

For all projects, we assume trains will ramp up to their utilization rates as shown in Table 4.

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

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

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

In the two years following the STEO benchmarking period (2023–2025), we assume monthly LNG capacity utilizations that phase out into the long-term NGMM assumption for LNG capacity utilization. (Table 5)

Table 5. Percentage of average annual LNG capacity utilization following STEO period

Year	Utilization
2023	100%
2024	95%
2025 and later	90%

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

In each projection year, the module assesses the relative economics of constructing and operating one to three generic trains, each of which produces 200 billion cubic feet per year for 20 years, in four representative Lower 48 states 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 price of domestic natural gas (assuming the increased exports) in each state, in addition to the assumed charges for liquefaction, shipping, and regasification (Table 6). A present value of the differential is set 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

2021 dollars per million British thermal units

	Maryland	Georgia	Louisiana	Texas	Alaska
Liquefaction and pipe fee	$3.30	$3.30	$3.00	$3.00	$7.00
Reservation charge	$3.00	$3.00	$3.00	$3.00	—
Shipping to Europe	$0.70	$0.70	$0.86	$0.86	$2.00
Shipping to Asia	$1.92	$1.92	$1.87	$1.87	$0.65
Regasification	$0.10	$0.10	$0.10	$0.10	$0.10
Fuel charge[a]	15%	15%	15%	15%	15%

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, largely fuel used in the liquefaction process.

EIA considers other constraining assumptions, such as the earliest start year and maximum export We consider capacity in each state, and we project market prices of LNG in Europe (National Balancing Point in the United Kingdom) and Asia (Japan-Korea Marker, or JKM) based on the assumed volumes in Table 7, projected Brent oil prices, and North American LNG exports. The flexible LNG volumes and regional natural gas consumption are consistent with growth rates in the *International Energy Outlook 2021* (IEO2021).

LNG import volumes are based on historical levels and are assumed to total 78 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

	Flexible LNG[a] billion cubic feet	Natural gas consumption, OECD Europe[b] billion cubic feet	Natural gas consumption, Asia[c] billion cubic feet
2021	4,083	19,540	29,800
2025	5,032	19,954	33,429
2030	7,293	20,260	37,211
2035	9,429	20,230	39,160
2040	11,305	20,210	41,603
2045	16,098	20,670	44,143
2050	16,889	21,320	47,240
2055	17,679	21,739	51,650

2060	18,470	22,166	56,562
2065	19,260	22,602	62,031
2070	20,051	23,046	68,114

Source: U.S. Energy Information Administration, *International Energy Outlook 2021* (IEO2021)
Note: The IEO2021 defines these regions.
LNG=liquefied natural gas, OECD= Organization for Economic Cooperation and Development
[a] Flexible LNG is a baseline projection of the volumes of LNG sold in the spot market or effectively available for sale at flexible destinations.
[b] OECD Europe includes all OECD countries in Europe except Turkey.
[c] The following IEO2021 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), are held constant at the average historical level for the previous five years and are assumed constant throughout the projection period.
- Natural gas plant liquids production (as set in the OGSM by state and substate levels on an annual basis) is moved to an assumed state for processing based on historical data for where each state’s volumes were moved in recent years. The amount of natural gas used in processing facilities in each state is established using the ratio of natural gas plant liquids 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. Fuel used for storage and distribution are set using exogenous, 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%). The remaining volumes are assumed to reflect fuel used on interstate pipelines and are represented as a percentage of state-to-state flows that are lost.[5] In the historical years, these fuel volumes are allocated 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 use in the projection period.
- Natural gas used at facilities that liquefy natural gas for export is assumed to equal 10% 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.[6] After 2023 and before the regular QP is solved in each NEMS iteration, unplanned pipeline capacity additions are determined by running a structurally identical QP but with two changes in 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 flows between states and nodes are limited by projected capacity levels.

For the capacity expansion QP, we multiply consumption levels by a sector- or state-specific factor to reflect the most extreme weather potential. For AEO2022, the weather factors applied to the residential and commercial sectors in winter months are based on historical differences between the most extreme January consumption level and average January consumption in recent years. The other months are based 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, QP pipeline capacity additions are limited 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 price at each supply node (wellhead price) is set equal to the spot price minus the assumed transport or gathering charge ($0.31 [2021 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, 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.

State-level, monthly citygate prices are set using econometrically estimated equations as 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. Annual, census division-level delivered prices to residential and commercial customers are set by adding a sector-specific, econometrically estimated distributor tariff to the average annual citygate price in the census division, which is calculated by using residential plus commercial consumption in each state and month as a quantity weight. Distributor tariffs are a function of residential consumption per household and commercial consumption per unit of commercial floorspace for the residential and commercial sectors, respectively. Markups to annual and census division delivered prices to industrial customers are set at the historical average from the previous five years of the industrial price minus the average annual spot price in the region, calculated using 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.[7] NEMS sets the delivered prices to electric power generators by adding a markup to the average spot price in the region or season, which was generated using electric consumption as a quantity-weight. NEMS 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 consumption to other consumption in a given region or season increases or decreases. This method reflects the need for electric generators to purchase more firm pipeline service as their market shares increase. NEMS sets the price in Alaska by adding a historically based markup to an econometrically estimated citygate price.

The following 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 the following 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 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

Table 8 shows the national average state excise tax, and in the model, these taxes vary by region.

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 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

Year	CNG private	LNG private	LNG public
Retail markup after dry gas pipeline delivery, with no excise tax (2021$/dge)	$0.98	$0.79	$1.02
Capacity (dge/day)	1,600	4,000	4,000
Usage (percentage of capacity)	80%	80%	60%
Capital cost (million (M) 2021$)	$0.98 M	$1.23 M	$1.23 M
Capital recovery (years)	5	5	10
Weighted average cost of capital (rate)	0.10	0.10	0.15
Operating cost (2021$/dge)	$0.42	$0.50	$0.72
Federal excise tax (nominal$/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)	0.5%	1.0%	2.0%

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis; U.S. Tax Code[8] and state tax codes[9]
Note: dge=diesel gallon equivalent, CNG=compressed natural gas, LNG=liquefied natural gas

Legislation and regulations

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

Notes and sources

[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 8.1% of the LNG export volume.
[2] Although the published natural gas consumption volumes in IEO2021 combine Mexico and Chile, Chile contributes only to the industrial and electric power sectors. The NGMM does not include industrial consumption, and electric power sector consumption in 2020 is for Mexico alone when including private electric power producers. We assume growth in natural gas consumption in Chile's electric power sector is negligible.
[3] We base oil production in Mexico on initial assumptions used in IEO2021 on the upstream component of the Global Hydrocarbon Supply Module and the world oil price path in the Reference case. Assumed values are used through 2025, after which oil production is a function of world oil price.
[4] The dates and base capacities for LNG export facilities were consistent with our U.S. liquefaction capacity reports as of July 2021.
[5] Although we assume all remaining pipeline fuel in AEO2022 to 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).
[6] 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 spreadsheet for the in-service dates for recently completed and historical natural gas pipeline projects.
[7] For a discussion of the seasonality representation in the EMM, refer to *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2020*.
[8] Source: 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).
[9] Source: U.S. Department of Energy 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 2019, Chapter 70. Gasoline and Vehicle Fuels Taxes
- 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