Natural Gas Transmission and Distribution Module

The NEMS Natural Gas Transmission and Distribution Module (NGTDM) derives domestic natural gas production, wellhead and border prices, end-use prices, and flows of natural gas through a regional interstate representative pipeline network, for both a peak (December through March) and off-peak period during each projection year. These are derived by solving for the market equilibrium across the three main components of the natural gas market: the supply component, the demand component, and the transmission and distribution network that links them. Natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of the supply options available to bring gas to market centers within each of the NGTDM regions (Figure 9). The major assumptions used within the NGTDM are grouped into four general categories. They relate to (1) structural components of the model, (2) capacity expansion and pricing of transmission and distribution services, (3) Arctic pipelines, and (4) imports and exports. A complete listing of NGTDM assumptions and in-depth methodology descriptions are presented in Model Documentation: Natural Gas Transmission and Distribution Module of the National Energy Modeling System, Model Documentation 2013, DOE/EIA-M062(2013) (Washington, DC, 2013).

Figure 8. Oil and Gas Supply Model regions

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

Key assumptions

Structural components

The primary and secondary region-to-region flows represented in the model are shown in Figure 9. Primary flows are determined, along with nonassociated gas production levels, as the model equilibrates supply and demand. Associated-dissolved gas production is determined in the Oil and Gas Supply Module (OGSM). Secondary flows are established before the equilibration process and are generally set exogenously. In the Northeast, where secondary flows are expected to grow significantly, secondary flows are endogenously set based on price differentials between sending and receiving regions. Liquefied natural gas (LNG) imports and domestically-produced natural gas exports are also not directly part of the equilibration process, but are set at the beginning of each NEMS iteration in response to the price from the previous iteration and projected future prices, respectively. LNG re-exports are set exogenously to the model. Flows and production levels are determined for each season, linked by seasonal storage. When required, annual quantities (e.g., consumption levels) are split into peak and off-peak values based on historical averages. When multiple regions are contained in a Census Division, regional end-use consumption levels are approximated using historical average shares. Pipeline and storage capacity are added as warranted by the relative volumes and prices. Regional pipeline fuel and lease and plant fuel consumption are established by applying an historically based factor to the flow of gas through a region and the production in a region, respectively. Prices within the network, including at the borders and the wellhead, are largely determined during the equilibration process. Delivered prices for each sector are set by adding an endogenously estimated markup (generally a distributor tariff) to the regional representative city gate price. Supply curves and electric generator gas consumption are provided by other NEMS modules for subregions of the NGTDM regions, reflective of how their internal regions overlap with the NGTDM regions.

Capacity expansion and pricing of transmission and distribution

For the first two projection years, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and seasonal storage in the model. Subsequently, pipeline and storage capacity is added when increases in consumption, coupled with an anticipated price increase, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given an assumed increased tariff). Once it is determined that an expansion will occur, the associated capital costs are applied in the revenue requirement calculations in future years. Capital costs are assumed based on average costs of recent comparable expansions for compressors, looping, and new pipeline.

It is assumed that pipeline and local distribution companies build and subscribe to a portfolio of interstate pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 30% above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99%. In the off-peak period, the maximum is assumed to vary between 75 and 99% of the design capacity. The overall level and profile of consumption, as well as the availability and price of supplies, generally cause realized pipeline utilization levels to be lower than the maximum.

Pricing of services

Transport rates between regions are set for the purposes of determining natural gas flows through the representative pipeline network based on historical observed differentials between regional spot prices. Ultimately regional city gate prices reflect the addition of reservation charges along each of the connecting routes and within a region. Per unit pipeline reservation charges are initially based on a regulated cost-of-service calculation and an assumed flow rate, and are dynamically adjusted based on the realized utilization rate. Reservation rates for interstate pipeline services (both between NGTDM regions and within a region) are calculated assuming that the costs of new pipeline capacity will be rolled into the existing rate base.

For the industrial and electric generator sectors delivered natural gas prices are based on regional prices which do not directly include any pipeline reservation fees, (i.e., spot prices), with an added markup based on averaged or econometrically estimated historical values. For the residential and commercial customers delivered natural gas prices are based on regional city gate prices with an added econometrically estimated distributor markup. The distributor tariffs are projected using econometrically estimated equations, primarily in response to changes in consumption levels. Historically based differentials are used to establish separate prices for energy-intensive and non-energy-intensive industrial customers. Prices are originally set on a seasonal basis and are averaged with quantity-weights to derived annual prices.

The natural gas vehicle sector is segregated into compressed natural gas (CNG) and liquefied natural gas (LNG) at private refueling stations (fleets) and at public retail stations. The distributor markup for natural gas delivered via pipeline to a CNG station is based off historical data for the sector. A retail markup and motor fuel (excise) taxes are added to set the final retail price. The excise taxes applied and the value and assumptions behind the retail markups assumed are shown in Table 10.1. The price for delivered dry natural gas to a liquefaction plant is approximated by using the price to electric generators. The price for LNG is therefore set to the price to electric generators, plus the assumed price to liquefy and transport the LNG, the retail price markup at the station, and the excise taxes. The values for these components and the primary assumptions behind them are shown in Table 10.1. The table shows the national average State excise tax, while in the model these taxes vary by region.

Table 10.1. Assumptions related to CNG and LNG fuel prices

Year	CNG fleet	CNG retail	LNG fleet	LNG retail
Retail markup after dry gas pipeline delivery, with no excise tax (2010$/dge)	0.80	0.93	1.39	1.58
Capacity (dge/day)	1600	1100	4000	4000
Usage (percent of capacity)	80	60	80	60
Capital cost (million 2010$)	80	0.5	1.0	1.0
Capital recovery (years)	5	10	5	10
Weighted average cost of capital (rate)	0.10	0.15	0.10	0.15
Operating cost (2010$/dge)	0.34	0.51	0.41	0.59
Charge for liquefying and delivering LNG (2010$/dge)	--	--	0.75	0.75
Federal excise tax (nominal$/dge)	0.21	0.21	0.42	0.42
State excise tax (nominal$/dge)	0.15	0.15	0.24	0.24
Fuel loss for liquefying and delivering LNG (percent of input volumes)	--	--	10	10
Fuel loss at station (percent of input volumes)	0.5	0.5	1.0	2.0

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, U.S. Tax Code and State Tax Codes.

Prices for natural gas to fuel ships are set at the same rate as for vehicles less state motor fuel taxes. For trains both federal and state motor fuels taxes are not included in the price. In addition, the retail markup above the cost of dry gas for LNG for rail was assumed at $0.90 (2010$ per diesel gallon equivalent (dge)) (compared to $1.39/dge for fleet vehicles as shown in Table 10.1), with the assumption that liquefaction would occur at the refueling point and cost $0.53/dge (compared to $0.75/dge for vehicles), operating costs would be $0.21/dge (compared to $0.41/dge for fleet vehicles), and capital cost recovery for additional equipment beyond the liquefiers would be $0.16/dge (compared to $0.23/dge for fleet vehicles, not shown in table).

Pipelines from arctic areas into Alberta

The outlook for natural gas production from the North Slope of Alaska is affected strongly by its extreme distance from the necessary infrastructure to transport it to major commercial markets. At present there are three basic options for commercializing the natural gas that has been produced in association with the Prudhoe Bay oil fields and reinjected in the oil wells to maintain pressure, and is therefore relatively low-cost to recover: build a pipeline to the Lower 48 states via Alberta, produce and transport the natural gas as liquid fuel in a gas-to-liquid (GTL) plant, or pipe the natural gas to a seaport, liquefy and ship it overseas. The GTL option was not considered for AEO2014. Which, if any, of the other two options that is determined within the model to be economically viable first is assumed to have primary access to the proved, low-cost, reserves on the North Slope and preclude the economic viability of the other option. The assumptions associated with the LNG option are provided in a later section. The primary assumptions associated with estimating the cost of North Slope Alaskan gas to Alberta, as well as for Mackenzie Delta gas from Canada's Northwest Territories to Alberta, are shown in Table 10.2. A calculation is performed to estimate a regulated, levelized tariff for each pipeline. Additional items are added to account for the wellhead price, treatment costs, pipeline fuel costs, and a risk premium to reflect the potential impact on the market price if the pipeline comes on line.

To assess the market value of Alaskan and Mackenzie Valley gas against the Lower 48 market, a price differential of $0.76 (2012 dollars per Mcf) is assumed between the price in Alberta and the average Lower 48 wellhead price. The resulting cost of Alaska gas, relative to the Lower 48 wellhead price, is approximately $8.20 (2012 dollars per Mcf), with some variation across the projection due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is projected to commence if the assumed total costs for Alaska gas in the Lower 48 states exceed the average Lower 48 gas price in each of the previous two years, on average over the previous five years (with greater weight applied to more recent years), and as expected to average over the next three years. An adjustment is made if prices were declining over the previous five years. Once the assumed four-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $6.99 (2012 dollars per Mcf). Supplies to fill an expanded pipeline are assumed to require new gas wells. When the Alaska-to-Alberta pipeline is built in the model, additional pipeline capacity is added to bring the gas across the border into the United States. For accounting purposes, the model assumes that all of the Alaska gas will be consumed in the United States and that sufficient economical supplies are available at the North Slope to fill the pipeline over the depreciation period.

Natural gas production from the Mackenzie Delta is assumed to be sufficient to fill a pipeline over the projection period should one be built connecting the area to markets in the south in the United States and Canada. The basic methodology used to represent the decision to build a Mackenzie pipeline is similar to the process used for an Alaska-to-Lower 48 pipeline, using the primary assumed parameters listed in Table 10.2.

Table 10.2. Primary assumptions for natural gas pipelines from Alaska and Mackenzie delta into Alberta, Canada

	Alaska to Alberta	Mackenzie Delta to Alberta
Initial flow into Alberta	3.8 billion cubic feet per day	1.1 billion cubic feet per day
Expansion potential	22%	58%
Initial capitalization	$37.5 billion (2012 dollars)	$11.2 billion (2012 dollars)
Cost of Debt (premium over 10-year treasury note yield)	0.75%	0.0%
Cost of equity (premium over 10-year treasury note yield)	6.5%	7.5%
Debt fraction	70%	60%
Depreciation period	20 years	20 years
Minimum wellhead price (including treatment and fuel costs)	$3.70 (2012 dollars per Mcf)	$4.39 (2012 dollars per Mcf)
Expected price reduction	$1.05 (2012 dollars per Mcf)	$0.06 (2012 dollars per Mcf)
Construction period	4 years	4 years
Planning period	5 years	2 years
Earliest start year	2021	2018

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis. Alaska pipeline cost data are based on Federal Energy Regulatory Commission, Docket PF09-11-001, “Open Season Plan Documents Submitted in Connection with Request for Commission Approval of Detailed Plan for Conducting an Open Season,” submitted by TransCanada Alaska Company LLC on January 29, 2010, Volume III of III, Appendix C, Exhibit J – Recourse Rate Output, various pages. Note that the capital cost figure is the arithmetic average of the two $30.7 and$40.4 2009 billion dollars capital cost estimates that include the mainline gas pipeline and the gas treatment plant, but which exclude the gas field line from Point Thomson to the gas treatment plant. National Energy Board of Canada, “Mackenzie Gas Project – Hearing Order GH-1-2004, Supplemental Information – Project Update 2007,” dated May 15, 2007; National Energy Board of Canada, “Mackenzie Gas Project – Project Cost Estimate and Schedule Update,” dated March 12, 2007; Canada Revenue Agency, “T2 Corporation Income Tax Guide 2006,” T4012(E) Rev. 07. National Energy Board of Canada, “Application for Approval of the Development Plan for Taglu Field - Project Description,” submitted by Imperial Oil Resources Ltd., TDPA-P1, August 2004; National Energy Board of Canada, “Application for Approval of the Development Plan for Niglintgak Field - Project Description,” submitted by Shell Canada Ltd., NDPA-P1, August 2004; and National Energy Board of Canada, “Application for Approval of the Development Plan for Parsons Lake Field - Project Description.”

Supplemental natural gas

The projection for supplemental gas supply is identified for three separate categories: pipeline quality synthetic natural gas (SNG) from coal or coal-to-gas (CTG), SNG from liquids, and other supplemental supplies (propane-air, coke oven gas, refinery gas, biomass air, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas). The third category, other supplemental supplies, are held at a constant level of 7.0 billion cubic feet per year throughout the projection because this level is consistent with historical data and it is not believed to change significantly in the context of a Reference case. SNG from liquid hydrocarbons in Hawaii is assumed to continue over the projection at the average historical level of 2.6 billion cubic feet per year. SNG production from coal at the currently operating Great Plains Coal Gasification Plant is also assumed to continue through the projection period at an average historical level of 52.1 billion cubic feet per year. It is assumed that additional CTG facilities will be built if and when natural gas prices are high enough to make them economic. One CTG facility is assumed capable of processing 6,040 tons of bituminous coal per day, with a production capacity of 0.1 billion cubic feet per day of synthetic fuel and approximately 100 megawatts of capacity for electricity cogeneration sold to the grid. A CTG facility of this size is assumed to cost nearly $1 billion in initial capital investment (2012 dollars). CTG facilities are assumed to be built near existing coal mines. All NGTDM regions are considered potential locations for CTG facilities except for New England. Synthetic gas products from CTG facilities are assumed to be competitive when natural gas prices rise above the cost of CTG production (adjusted for credits from the sale of cogenerated electricity). It is assumed that CTG facilities will not be built before 2015.

Natural gas imports and exports

U.S. natural gas trade with Mexico is determined endogenously based on various assumptions about the natural gas market in Mexico. Natural gas consumption levels in Mexico are set exogenously based on projections from the International Energy Outlook 2013 and are provided in Table 10.3, along with initially assumed Mexico natural gas production and LNG import levels targeted for markets in Mexico. Adjustments to production are made endogenously within the model to reflect a response to price fluctuations within the market and reflect laws concerning foreign investment at the time of the projection. Domestic production is assumed to be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico. Maximum LNG import volumes targeted for markets in Mexico are set exogenously and will be realized if endogenously determined LNG imports into North America are sufficient. The difference between production plus LNG imports and consumption in Mexico in any year is assumed to be either imported from, or exported to, the United States.

Similarly to Mexico, Canada is modeled through a combination of exogenously and endogenously specified components. Canadian production, U.S. import flows from Canada, and U.S. export flows to Canada are determined endogenously within the model. Canadian natural gas production in Eastern Canada, consumption, and LNG exports are set exogenously in the model and are shown in Table 10.4. Production from conventional and tight formations in the Western Canadian Sedimentary Basin (WCSB) is calculated endogenously to the model using annual supply curves based on beginning-of-year proved reserves and an estimated production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells and a finding rate (both based on an econometric estimation). The initial coalbed methane, shale gas, and conventional WCSB economically recoverable unproved resource base estimates assumed in the model are 45 trillion cubic feet, 90 trillion cubic feet, and 127 trillion cubic feet, respectively, all as of 2011. [1] Potential production from tight formations was approximated by increasing the conventional resource level by 2.35% annually. Production from coalbed and shale sources is established based on an assumed production path which varies in response to the level of remaining resources and the solution price in the previous projection year. LNG imports to Canada are set in conjunction with the LNG import volumes for the Lower 48 states.

Table 10.3. Exogenously specified Mexico natural gas consumption, production, and LNG imports
billion cubic feet per year

	Consumption	Initial Dry Production	Initial LNG Imports
2015	2,615	1,587	145
2020	3,134	1,575	475
2025	3,868	1,562	835
2030	4,599	1,725	915
2035	5,389	2,098	815
2040	6,224	2,678	585

Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis, based on U.S. Energy Information Administration, International Energy Outlook 2013 DOE/EIA-0484(2013).
Note: Excludes any LNG imported to Mexico for export to the United States.

Table 10.4. Exogenously specified Canada natural gas consumption, production, and LNG exports and supply
billion cubic feet per year

Year	Consumption	Production Eastern Canada	LNG Exports
2015	3.075	156	0
2020	3,570	150	255
2025	3,999	165	771
2030	4,305	114	1,022
2035	4,581	74	1,228
2040	4,870	54	1,603

Source: Consumption - U.S. Energy Information Administration. International Energy Outlook 2013, DOE/EIA-0484(2013); Production - Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis. LNG exports - U.S. Energy Information Administration. International Energy Outlook 2013, DOE/EIA-0484(2013).

LNG imports to the United States and Canada are determined endogenously within the model using Atlantic/Pacific and peak/off-peak supply curves derived from model results generated by EIA's International Natural Gas Model (INGM). Prices from the previous model iteration are used to establish the total level of U.S./Canada LNG imports in the peak and off-peak period and in the Atlantic and Pacific regions. First, assumed LNG imports which are consumed in Mexico are subtracted (presuming the volumes are sufficient). Then, the remaining levels are allocated to the model regions based on last year's import levels, the available regasification capacity, and the relative prices. Regasification capacity is limited to facilities currently in existence and those already under construction, which is fully sufficient to accommodate import levels projected by the model.

LNG exports of domestically produced natural gas from the Lower 48 states and Alaska are set endogenously in the model. The model assesses the relative economics of a generic project in operation over the next 20 years in each viable coastal region by comparing a model-generated estimate of the expected market price in Europe and Asia over the next 20 years against the expected price of natural gas in each coastal region plus assumed charges for liquefaction, shipping, and regasification (shown in Table 10.5). A present value of the differential is set using a discount rate of 10%. The model limits the annual liquefaction capacity builds to three trains a year, at 200 billion cubic feet per train. When the evaluation is made, the region showing the greatest positive economic potential, if any, is selected as the location for adding capacity. A new project is assumed to consist of two trains and is phased in over a two-year period, partially to reflect a mid year project start-up. Once a facility is built, it is assumed to operate at its design capacity throughout the projection period unless the competing price in Asia or Europe falls below the delivered price of U.S. LNG in the region, excluding assumed reservation charges (i.e., "sunk" costs) for liquefaction. Other constraining assumptions are considered, such as earliest start year and maximum export volumes. Any existing facilities or ones under construction are set exogenously to the model, which for AEO2014 include the two trains under construction at Sabine Pass (at 1.1 Bcf per day starting in mid-2016). The projected market price of LNG in Europe (National Balancing Point) and Asia (Japan) is based on the assumed values shown in Table 10.6, projected Brent oil prices, and the level of North American LNG exports. Annual U.S. exports of liquefied natural gas (LNG) to Japan via Alaska's existing Kenai facility are assumed to cease in 2012. LNG re-exports are assumed to stay at 8 billion cubic feet per year throughout the projection period.

Table 10.5. Charges related to LNG exports

2010 dollars per million Btu

	South Atlantic	West South Central	Washington/Oregon	Alaska
Liquefaction & Pipe Fee	3.30	3.00	4.10	7.00
Shipping to Europe	0.98	1.28	3.86	3.65
Shipping to Asia	2.63	2.55	1.15	0.90
Regasification	0.10	0.10	0.10	0.10
Fuel charge (percent)*	15	15	15	15

*Percent increase in market price of natural gas charged by liquefaction facility to cover fuel-related expenses, largely fuel used in the liquefaction process.
Source: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis.

Table 10.6. International natural gas volume drivers for world LNG Europe and Asia market price projections

billion cubic feet

	Flexible LNG*	Consumption OECD Europe	Consumption Japan	Consumption S. Korea	Consumption China	Production China
2015	4,362	19,714	4,318	1,532	5,615	3,806
2020	5,821	20,378	4,583	1,657	7,752	4,242
2025	7,273	20,774	4,937	1,858	10,270	5,165
2030	8,577	22,052	5,143	1,968	13,041	6,702
2035	10,097	23,183	5,233	2,291	15,634	8,500
2040	11,452	24,478	5,242	2,502	17,498	10,119

*Flexible LNG is a baseline projection of the volumes of LNG sold in the spot market or effectively available for sale at flexible destinations.
Source: U.S. Energy Information Administration, International Energy Outlook 2013, DOE/ EIA-0484(2013) and U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis.

Legislation and regulations

The methodology for setting reservation fees for transportation services is initially based on a regulated rate calculation, but is ultimately consistent with FERC's alternative ratemaking and capacity release position in that it allows some flexibility in the rates pipelines ultimately charge. The methodology is market-based in that rates for transportation services will respond positively to increased demand for services while rates will decline should the demand for services decline.

Section 116 of the Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005 (Public Law 108-324) gives the Secretary of Energy the authority to issue Federal loan guarantees for an Alaska natural gas transportation project, including the Canadian portion, that would carry natural gas from northern Alaska, through the Canadian border south of 68 degrees north latitude, into Canada, and to the Lower 48 states. This authority would expire 2 years after the final certificate of public convenience and necessity is issued. In aggregate, the loan guarantee would not exceed: (1) 80% of total capital costs (including interest during construction); (2) $18 billion (indexed for inflation at the time of enactment); or (3) a term of 30 years. The Act also promotes streamlined permitting and environmental review, an expedited court review process, and protection of rights-of-way for the pipeline. The assumed costs of borrowing money for the pipeline were reduced to reflect the decreased risk as a result of the loan guarantee.

Section 706 of the American Jobs Creation Act of 2004 (Public Law 108-357) provided a 7-year cost-of-investment recovery period for the Alaska natural gas pipeline, as opposed to the previously allowed 15-year recovery period, for tax purposes. The provision is effective for property placed in service after 2013 (or treated as such) and is assumed to have minimal impact on the decision to build the pipeline.

Section 707 of the American Jobs Creation Act extended the 15-percent tax credit previously applied to costs related to enhanced oil recovery to construction costs for a gas treatment plant that supplies natural gas to a 2 trillion Btu per day pipeline, lies in Northern Alaska, and produces carbon dioxide for injection into hydrocarbon-bearing geological formations. A gas treatment plant on the North Slope that feeds gas into an Alaska pipeline to Canada is expected to satisfy this requirement. The provision is effective for costs incurred after 2004. The impact of this tax credit is assumed to be factored into the cost estimates filed by the participating companies.

Section 312 of the Energy Policy Act of 2005 authorizes the Federal Energy Regulatory Commission (FERC) to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. Storage rates are allowed to vary in the model from regulation-based rates, depending on market conditions.

Notes and sources

[1] Coalbed, shale gas, and tight sands unproved resource based on the National Energy Board of Canada's "Canada's Energy Future: Energy supply and demand projections to 2035," November 2011.

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