Natural Gas Transmission and Distribution Module

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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 Model of the National Energy Modeling System, Model Documentation 2012, DOE/EIA-M062(2012) (Washington, DC, 2012).

Figure 9. Natural Gas Transmission and Distribution Module 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. Liquefied natural gas (LNG) imports 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. LNG exports, both re-exports and domestically sourced volumes, 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 citygate 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 percent above the daily average. Maximum pipeline capacity utilization in the peak period is set at 99 percent. In the off-peak period, the maximum is assumed to vary between 75 and 99 percent 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

While transportation tariffs for interstate pipeline services are initially based on a regulated cost-of-service calculation, an adjustment to the tariffs is applied which is dependent on the realized utilization rate, to reflect a market-based differential. Reservation and operation transportation 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.

Delivered prices by sector and season are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are reported on an annual basis and represent quantity-weighted averages of the two seasons.) These markups include the cost of service provided by intraregional interstate pipelines, intrastate pipelines, and local distributors. The intrastate tariffs are accounted for endogenously through historical model benchmarking. Distributor tariffs represent the difference between the regional delivered and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor.

The distribution tariffs are projected using econometrically estimated equations, primarily in response to changes in consumption levels. An assumed differential is used to divide the industrial price into one for non-core customers (refineries and industrial boiler users) and one for core customers who have fewer alternative fuel options.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. In general, the distributor tariffs for natural gas to vehicles are set to EIA's Natural Gas Annual historical end-use prices minus citygate prices plus Federal and State VNG taxes (held constant in nominal dollars) plus an assumed dispensing cost. Dispensing costs are assumed to be $2.40 (2010 dollars per Mcf) as long as natural gas vehicles do not increase notably in market share. The assumed cost for adding a compressed natural gas retail facility is $406,000 (2010 dollars), after accounting for the tax value of depreciation, and is not considered economically viable at the low vehicle penetration rates projected.

Pipelines from arctic areas into Alberta

The outlook for natural gas production from the North Slope of Alaska is affected strongly by the unique circumstances regarding its transport to market. Unlike virtually all other identified deposits of natural gas in the United States, North Slope gas lacks a means of economic transport to major commercial markets. The lack of viable marketing potential at present has led to the use of Prudhoe Bay gas to maximize crude oil recovery in that field. The option of exporting North Slope gas as LNG was not included in the model for *AEO2012*. The primary assumptions associated with estimating the cost of North Slope Alaskan gas in Alberta, as well as for MacKenzie Delta gas into Alberta, are shown in Table 10.1. 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 once 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 $0.73 (2010 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 $6.10 (2010 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 $6.72 (2010 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. 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 10.1. One exception is that wellhead costs are assumed to change across the projection period with estimated changes to drilling costs for the lower 48 States.

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 12.3 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 52.2 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 (2010 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 2012.

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 2010* and are provided in Table 10.2, along with initially assumed Mexico 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. 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. Natural gas exports from the United States to Canada are set exogenously in NEMS starting at 721 billion cubic feet per year in 2010 and increasing to 1524 billion cubic feet by 2035. Canadian production and U.S. import flows from Canada are determined endogenously within the model. Canadian natural gas production in Eastern Canada and consumption are set exogenously in the

Table 10.1. 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 percent	58 percent
Initial capitalization	$36.0 billion (2009 dollars)	$10.7 billion (2010 dollars)
Cost of Debt (premium over 10-year treasury note yield)	0.75 percent	0.0 percent
Cost of equity (premium over 10-year treasury note yield)	6.5 percent	7.5 percent
Debt fraction	70 percent	60 percent
Depreciation period	20 years	20 years
Minimum wellhead price (including treatment and fuel costs)	$1.72 (2010 dollars per Mcf)	$3.16 (2010 dollars per Mcf)
Expected price reduction	$1.01 (2010 dollars per Mcf)	$0.06 (2010 dollars per Mcf)
Additional cost for expansion	$6.73 (2010 dollars per Mcf)*	$0.37 (2010 dollars per Mcf)
Construction period	4 years	4 years
Planning period	5 years	2 years
Earliest start year	2021	2018

*Includes added cost to explore for and produce natural gas beyond what has already been proven.
Source: U.S. Energy Information Administration, Office of Energy 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 billion 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. Indian and Northern Affairs Canada, "Oil and Gas in Canada's North," website address www.ainc-inac.gc.ca/ps/ecd/env/nor_e.html. 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,"

Table 10.2. Exogenously specified Mexico natural gas consumption and supply
billion cubic feet per year

	Consumption	Initial Dry Production	Initial LNG Imports
2015	2471	1775	3
2020	2987	1592	501
2025	3705	1533	977
2030	4353	1679	1231
2035	5020	1988	1367

Source: Consumption - U.S. Energy Information Administration. *International Energy Outlook 2011* DOE/EIA-0484(2011); Production - U.S. Energy Information Administration, Office of Petroleum, Gas, and Biofuels Analysis. LNG imports - U.S. Energy Information Administration, International Energy Outlook 2011, DOE/EIA-0484(2011).
Note: Excludes LNG imported to Mexico for export to the United States.

model and are shown in Table 10.3. 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 78.4 trillion cubic feet (starting in 2008), 108.0 trillion cubic feet (starting in 2011), and 95.8 trillion cubic feet (starting in 2004), respectively. [1] Potential production from tight formations was approximately by increasing the conventional resource level by 2.3 percent 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 prce in the previous projection year.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to cease in 2011. For *AEO2012* potential future LNG exports from Alaska were not modeled. LNG exports of domestially produced natural gas from the lower 48 States are assumed to start during 2016 at 1.1 billion cubic feet per day and double during 2019. LNG re-exports are assumed to stay at 100 billion cubic feet per year throughout the forecast period, close to current historical levels. LNG imports to the United States are determined endogenously within the model. For the most part, LNG imports are set endogenously in the model based on 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 North American imports in the peak or off-peak period and in the Atlantic or Pacific. 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.

Table 10.3. Exogenously specified Canada natural gas consumption and supply
billion cubic feet per year

Year	Consumption	Production Eastern Canada
2010	2,913	119
2015	3,507	98
2020	3,742	78
2025	4,175	61
2030	4,558	48
2035	5,041	38

Source: Consumption - U.S. Energy Information Administration. *International Energy Outlook 2011*, DOE/EIA-0484(2011); Production - Energy Information Administration, Office of Petroleum, 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, 2004 (H.R.4837) 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 percent 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 (H.R.4520) 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 plan 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.

The Heavy-duty vehicles reference and the heavy-duty natural gas vehicle potential cases

The HD NGV Potential case permits expansion of the HDV market to allow a gradual increase in the share of HDV owners who would consider purchasing a NGV if justified by the fuel economics over a payback period with a weighted average of 3 years. Details of this case are described in the Transportation Demand Module chapter. In the process of defining this case, EIA reexamined and modified the assumptions that were used for the *AEO2012* Reference case related to setting the prices for compressed natural gas (CNG) and liquefied natural gas (LNG) at private refueling stations (fleets) and at public retail stations above the price for the dry natural gas itself. The HDV Reference case was developed using these updated assumptions in order to provide a consistent basis for comparison with the HD HGV Potential case. The same assumptions, as described below, are used for setting these prices in both the HD NGV Potential case and the HDV Reference case.

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 10.4. 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 10.4. The table shows the national average State excise tax, while in the model these taxes vary by region.

Table 10.4. Assumptions related to CNG and LNG fuel prices

Year	CNG	CNG	LNG	LNG
	fleet	retail	fleet	retail
Retail markup after dry gas pipeline delivery, with no excise tax (2010$/dge)	0.80	0.93	1.39	1.58
Capacity (dge/day)	1600	1100	4000	4000
Usage (percent of capacity)	80	0	80	0
Capital cost (million 2010$)	0.8	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$/dge)	0.34	0.51	0.41	0.59
Charge for liquefying an ddelivering LNG (2010$/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.	0.5	1.0	2.0

Source: U.S. Energy Information Administration, U.S. Tax Code and State Tax Codes.
Note: dge is diesel-gallon equivalent.

Notes and sources

[1] Coalbed, shale gas, and tight sands unproved resource based on assumptions used in EIA's International Natural Gas Model for the *International Energy Outlook 2011*.