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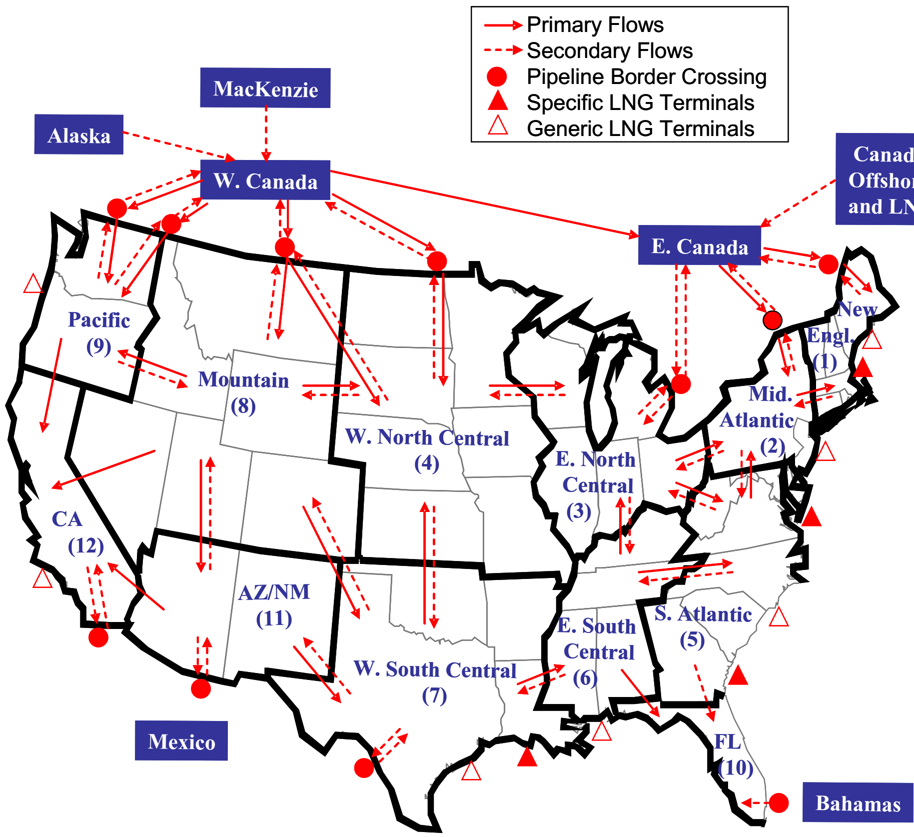
Natural Gas Transmission and Distribution Module

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 the regional interstate network, for both a peak (December through March) and off peak period during each forecast 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 8). The major assumptions used within the NGTDM are grouped into five 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 2006,* DOE/EIA-M062(2005) (Washington, DC, 2006).

Figure 8. Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting

Key Assumptions

Structural Components

The primary and secondary region-to-region flows represented in the model are shown in Figure 8. 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 imports are also not directly part of the equilibration process, but our set at the beginning of each NEMS iteration in response to the price from the previous iteration. 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 offpeak 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. Production 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 Services

For the first 2 forecast 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 demand, 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 more market-based approach. 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 noncore customers (refineries and industrial boiler users) and one for core customers who have less 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 $3.70 and $2.16 (2005 dollars per mcf) for non-fleet and fleet vehicles, respectively. The price to non-fleet vehicles is set to 75 percent of the equivalent motor gasoline price, if it would have been lower otherwise.

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. Recent high natural gas prices seemingly raised the potential economic viability of such a project, although expected costs have increased as well. Recent setbacks in negotiations between the primary producers and the Alaska government have further delayed the project. 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 56. 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 market price uncertainty.

For the Alaska pipeline the uncertainty associated with the initial capitalization is captured by applying a value that is 20 percent higher than the expected value. For comparison purposes, a price differential of $0.66 (2005 dollars per Mcf) is assumed between the price in Alberta and the average lower 48 price. The resulting cost of Alaska gas, relative to the lower 48 wellhead price, is approximately $4.00 (2005 dollars per Mcf), with some variation across the forecast due to changes in gross domestic product. Construction of an Alaska-to-Alberta pipeline is forecast to commence if the assumed total costs for Alaska gas in the lower 48 States exceeds the average lower 48 gas price in each of the previous 2 years, on average over the previous 5 years (with greater weight applied to more recent years), and as expected to average over the next 3 years. An adjustment is made if prices were declining over the previous 5 years. Once the assumed 4-year construction period is complete, expansion can occur if the price exceeds the initial trigger price by $0.72 (2005 dollars per Mcf). 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 56. One exception is that the uncertainty associated with the initial capitialization is captured in the risk premium.

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. U.S. natural gas exports from the United States to Canada are set exogenously in NEMS at 364 billion cubic feet per year, post 2006. Canadian production and U.S. import flows from Canada are determined endogenously within the model.

It is initially assumed that Mexican natural gas production grows at an average annual rate of 2.6 percent through 2030 and that consumption grows at an average annual rate of 3.4 percent. It is further assumed that domestic production will be supplemented by LNG from receiving terminals constructed on both the east and west coasts of Mexico that serve only the Mexican market. Receiving terminal(s) in Baja California, Mexico, that serve both Mexico and the United States can be constructed if the regional LNG price exceeds a trigger price. The difference between production and consumption in any year is assumed to be either

Table 56. 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	3.9 Bcf per day	1.2 Bcf per day
Expansion potential	22 percent	58 percent
Initial capitalization	18.4 billion (2005 dollars)	8.6 billion (2005 dollars)
Cost of Debt (premium over AA bond rate)	0.0 percent	1.0 percent
Cost of equity (premium over AA bond rate)	5.0 percent	8.0 percent
Debt fraction	80 percent	70 percent
Depreciation period	15 years	15 years
Minimum wellhead price	$0.88 (2005 dollars per Mcf)	$1.10 (2005 dollars per Mcf)
Treatment and fuel costs	$0.45 (2005 dollars per Mcf)	$0.44 (2005 dollars per Mcf)
Risk Premium	$0.37 (2005 dollars per Mcf)	$0.29 (2005 dollars per Mcf)
Additional cost for expansion	$0.72 (2005 dollars per Mcf)	$0.11 (2005 dollars per Mcf)
Construction period	4 years	3 years
Planning period	5 years	2 years
Earliest start year	2018	2012

Note: The potential for capital cost overruns is represented by using an initial capitalization that is 20 percent greater than the expected estimate.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Alaska pipeline data are partially based on information from British Petroleum/ExxonMobil/Conoco Phillips and reflect an assumed impact on Alaska pipeline finances as a result of the American Jobs Creation Act of 2004 and the Military Construction Appropriations Act, 2004.

imported from, or exported to, the United States. Adjustments to these figures are made endogenously within the model to reflect a response to price fluctuations within the market.

Canadian consumption and production in Eastern Canada are set exogenously in the model and are shown in Table 57. Production 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 expected production-to-reserve ratio. Reserve additions are set equal to the product of successful natural gas wells (based on an econometric estimation) and a finding rate (set as a function of the number of successful wells drilled and the assumed economically recoverable resource base). The coalbed methane and conventional WCSB economically recoverable resource base estimates assumed in the model for the beginning of 2004 are 70 trillion cubic feet and 96 trillion cubic feet, respectively.[91] Potential production from tight formations was approximated by increasing the conventional resource level by 20 percent. For conventional gas, the initial resource level is assumed to grow by 0.5 percent per year throughout the projection period to reflect improvements in and penetration of technology. Production from coalbed sources is established based on

Table 57. Exogenously Specified Canadian Production and Consumption
(billion cubic feet per year)

Year	Consumption	Production Eastern Canada
2005	3,300	153
2010	4,200	340
2015	4,200	530
2020	4,700	570
2025	5,000	820
2030	5,300	710

Source: Consumption - EIA, International Energy Outlook 2006, DOE/EIA-0484(2006); Production - Energy Informatiion Administration, Office of Integrated Analysis and Forecasting.

an assumed production path which varies in response to the level of remaining resources and the solution price in the previous forecast year.

Annual U.S. exports of liquefied natural gas (LNG) to Japan are assumed to be constant at 64.3 billion cubic feet per year through March of 2009, when the export license expires, and 0.0 through the remainder of the forecast. LNG imports are determined endogenously within the model. The model provides for the construction of new facilities should gas prices be high enough to make construction economic — the prices (including regasification) that are needed to initially trigger new LNG construction in the United States and the Bahamas vary by region and, at the beginning of the forecast, range from $3.39 to $5.02/Mcf (2005 dollars).

Currently there are five LNG facilities in operation, located at Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; Elba Island, Georgia; and off the coast of Louisiana (Gulfport Energy Bridge). These five facilities including expansions currently in progress have a combined design capacity of 2,125 million cubic feet per day (2.1 trillion cubic feet per year). Further expansion is triggered when the regional LNG tailgate[92] price meets or exceeds a trigger price as determined in the model.

The model also has a provision for the construction of new facilities in all United States coastal regions, in eastern and western Canada and in Mexico. Mexico currently has one terminal at Altameria, in operation as of 2006. Supplies from a Baja California, Mexico, facility are assumed to enter the United States as pipeline imports from Mexico destined for Southwestern markets. A 1 Bcf per day facility, currently under construction, is assumed to come online in 2008 with one-half of its supplies available to the United States. As with expansion of existing facilities, construction of additional facilities is triggered when the regional LNG tailgate price meets or exceeds a trigger price. The trigger price for additional Baja California, Mexico, LNG facilities starts at $4.07/Mcf (2005 dollars). LNG is represented similarly in eastern Canada. A 1 Bcf/day facility, currently under construction, is assumed to come online in 2008. No assumption regarding the amount destined for the United States is made. The supply is simply added to the supply in eastern Canada. The trigger price for additional capacity in Canada starts at $5.06/Mcf (2005 dollars). The trigger price for initial construction in western Canada is $4.07/Mcf (2005 dollars). These trigger prices are increased by a factor representing the difference between the world market price for LNG and the cost to bring it to the U.S. market. This factor is specified based on the assumed growth in world natural gas consumption from the *International Energy Outlook 2006* and the annual change in the world oil price.

Since LNG does not compete directly with wellhead prices, trigger prices are compared with regional prices in the vicinity of the LNG facility (i.e., the tailgate price) rather than with wellhead prices. With the exception of the Canada and Baja facilities, the individual trigger prices represent the least cost feasible combination of production, liquefaction, and transportation costs to the facility plus the regasification cost at the facility. Regasification costs at new facilities include capital costs for construction of the facility. A range of cost components used in determining trigger prices at new facilities is shown in Table 58. Regional risk

Table 58. LNG Cost Components

(2005 dollars per mcf)

	Low		High	
2005 Production	$0.36	Nigeria	$1.65	Norway
2005 Liquefaction	$1.53	All facilities	$1.53	All facilities
Shipping	$0.33	Venezuala to the Bahamas	$1.75	Qatar to Gulf Mexico
Regasification	$0.35	Gulf of Mexico	$1.08	Florida
Risk Premium	$0.10	New England	$0.85	Florida

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Gas supply costs are based on a March 31, 2003 report produced under contract to EIA by the Gas Technology Institute (GTI), using a conversion factor of 1,100 Btus/cf. Regasification costs are based on Project Technical Liaison, Inc. estimates. Shipping costs are based on various sources, including www.dataloy.com for transportation distances, the GTI Report, and EIA judgement. Liquefaction costs are based on data from Wood MacKenzie. Liquefaction, shipping, and regasification costs are determined endogenously in the NGTDM.

premiums are determined based on regional specific factors that include proposal and site identification activity, population density, housing values, income values, and availability of deepwater ports.

The production costs reflect assumed market prices entering the liquefaction facility for various stranded gas[93] locations and average about $0.61 Mcf (2005 dollars). Different supply factors are estimated based on the existing and potential upstream projects for each supply source, and are applied to the average supply cost to arrive at the production cost by source.[94]

Liquefaction costs are estimated based on a declining liquefaction capital cost function for one train (3.9 million metric tons of LNG or 186 Bcf per year) starting at $333 per ton of plant capacity in 2005 and gradually declining to $307 per ton in 2030. The capital cost is to be amortized over a 20-year period with a 18 percent average cost of equity, 60 percent debt fraction, and 30 percent corporate tax rate. The cost of debt is assumed to equal the AA utility bond rate. These liquefaction costs are adjusted to account for individual plant factors such as the plant's age and location. The liquefaction plant utilization rate is assumed to be 93 percent.

LNG shipment costs from a supply source to a receiving terminal are a function of the distance between these two locations, an average per unit-mile shipment cost, and a port cost. The per unit-mile shipment cost is computed as a function of the return on invested capital for the tanker, number of round trips per year, distance between a supply source and an LNG terminal, average tanker capacity, estimated fuel cost, and administrative and general expenses for the tanker serving that route. Taxes are embedded in the administrative and general expenses.

Shipment costs are based on distances, an assumed average per unit capital cost for all the newly built tankers ($1,170 per cubic-meter capacity in 2005 dollars), an average rate of return on the invested capital, tanker fuel costs, administrative and general expenses, an assumed average tanker capacity per trip (157,000 cubic meters), and the assumed number of round trips per year for a tanker serving a particular route. The estimated shipment costs, in 2005 dollars/Mcf, were divided by the route distances to arrive at initial transportation costs. On average these calculations provide a result of $0.000175/Mcf-mile in 2005 dollars (i.e., roughly $0.18/Mcf per 1,000 nautical miles). Finally, an assumed $0.05/Mcf port cost is added to each of these transportation costs to arrive at the final shipment costs.

Regasification costs include a fixed and variable component. Variable costs include administrative and general expenses, operating and maintenance expenses, taxes and insurance, electric power costs, and fuel usage and loss. The fixed costs reflect the expected annual return on capital and are based on the assumed capital cost, a 60 percent debt fraction, the cost of debt and equity, a 38 percent corporate tax rate, and a 20-year economic life. The capital costs are based on the cost of storage tanks, vaporizer units, marine facilities, site improvements and roads, buildings and services, installation, engineering and project management, land, contingency, and the capacity of the plant. The cost of debt is tied to the AA utility bond rate and the cost of equity is tied to the 10-year treasury note yield plus a 10-percent risk premium. A per-unit regasification charge for a given size facility is obtained by dividing total costs by an assumed annual throughput. Regional specific factors are applied to account for differences in costs associated with land purchase, labor, site specific permitting, special land and waterway preparation and/or acquisition, and other general construction and operating cost differences.

It is assumed that LNG facilities are developed with an initial design capacity along with a capability for future expansion. For existing terminals, original capital expenditures are considered sunk costs. Costs were additionally determined for expansion beyond currently announced expansion plans at all existing facilities, with the exception of Everett (where room for expansion is limited), under the assumption that if prices reached sustained levels at which new facilities would be constructed, additional expansion at existing facilities would likely be considered. The costs of expansion at existing facilities within a region are in general lower that those for the construction of new facilities. If market prices warrant, additional capacity can be added in a region either through expansion or construction of new facilities.

Legislation and Regulation

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 (reflecting discounts to retain customers) should the demand for services decline.

A number of legislative actions have been taken to provide a more favorable environment for the introduction of new liquefied natural gas (LNG) regasification facilities in the United States. In December 2002 under the Hackberry Decision, FERC terminated open access requirements for new onshore LNG terminals, placing them on an equal footing with offshore terminals regulated under provisions of the Maritime Security Act of 2002. The Maritime Security Act, signed into law in November 2002, also amended the Deepwater Port Act of 1974 to include offshore natural gas facilities, transferring jurisdiction for these facilities from the FERC to the Maritime Administration and the U.S. Coast Guard. The result should be to streamline the permitting process and relax regulator requirements. More recently an EPACT2005 provision clarified the role of the FERC as the final decision making body on issues concerning onshore LNG facilities. While none of these legislative/regulatory actions is explicitly represented in the modeling framework, these provisions are indirectly reflected in selected model parameters.

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 dollars (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 loan guarantee is represented in the model by assuming the cost of debt at a percentage point lower than what would have been assumed otherwise and by assuming a debt fraction of 80 percent, instead of 70 percent.

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 represented in the model by using a cost of equity that is 3 percentage points lower than would have been assumed otherwise.

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 and is represented in the model by assuming a charge for natural gas treatment that is $0.05 per Mcf less than what would have been assumed otherwise.

Section 1113 of the Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) raised the federal motor fuels tax for compressed natural gas vehicles (CNG) from 48.54 cents per Mcf to 18.3 cents per gasoline gallon equivalent (or about $1.46 per Mcf), all in nominal dollars. The same section also allows for a motor fuels excise tax credit of $0.50 per gasoline gallon equivalent to the seller through September 30, 2009. For AEO2007, the tax rate was changed accordingly and assumed constant in nominal terms throughout the projection. Similarly the tax credit was subtracted from the CNG cost estimates through the time period indicated, also in nominal terms.

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. In the AEO2007 storage rates were allowed to vary from regulation-based rates, depending on market conditions.

High and Low Liquefied Natural Gas Import Cases

Two cases were created to assess the impact of a range of liquefied natural gas (LNG) imports on the domestic natural gas market. The future level of LNG imports into the United States is highly uncertain. The levels will depend on such things as the ability and motivation of companies to site regasification facilities domestically, the ability and motivation of companies to site liquefaction facilities throughout the world, the world market for natural gas shipped via pipeline and in liquid form, the relative need for consuming the available natural gas in other parts of the world, the potential other uses for the gas (e.g., its conversion into liquid fuel), and finally the price of LNG on the world market, which in turn is impacted by the cost of producing, liquefying, shipping, and regasifying the gas. These cases are intended to highlight the impact if LNG imports were actually much different than under the reference case, for whatever reason. The high and low liquefied natural gas import cases were formulated by setting the LNG import levels to 30 percent more and 30 percent less than the LNG import levels determined within the low price and the high price cases, respectively.

Notes and Sources

[91] For unconventional (i.e., coalbed) -- Average undiscovered resources under the National Energy Board's Supply Push and Techno-vert scenarios in "Canada's Energy Future, Scenarios for Supply and Demand to 2025," 2003. For conventional -- "Canada's Conventional Natural Gas Resources -- A Status Report," April 2004.

[92] Tailgate LNG prices represents the price when natural gas exists the regasification facility.

[93] Gas reserves that have been located but are isolated from potential markets, commonly referred to as "stranded" gas, are likely to provide most of the natural gas for LNG in the future. Reserves that can be linked to sources of demand via pipeline are unlikely candidates to be developed for LNG.

[94] Largely based on information from Gas Technology Institute, "Liquefied Natural Gas (LNG) Methodology Enhancements in NEMS," Report submitted to Energy Information Administration, March 31, 2003.