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. In addition, natural gas flow patterns are a function of the pattern in the previous year, coupled with the relative prices of gas supply options as translated to the represented market "hubs." The major assumptions used within the NGTDM are grouped into five general categories. They relate to (1) the classification of demand into core and noncore transportation service classes, (2) the pricing of transmission and distribution services, (3) pipeline and storage capacity expansion and utilization, and (4) the implementation of recent regulatory reform. 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 2003,* DOE/EIA-M062(2003) (Washington, DC, January 2003).

Key Assumptions

Demand Classification

Customers demanding natural gas are classified as either core or noncore customers, with core customers assumed to transport their gas under firm (or near firm) transportation agreements and noncore customers assumed to transport their gas under interruptible or short-term capacity release transportation agreements. A distinction is made between core and noncore customers because the price differentials can be significant and it allows for a different algorithm to be used in setting the prices. All residential, commercial, and transportation (vehicles using compressed natural gas) end-use customers are assumed to be core customers. Industrial customers fall into both categories, with industrial boilers and refineries assumed to be noncore and all other industrial users assumed to be core. Likewise, customers in the electric generator sector are assumed to be both core and noncore. Gas steam and gas combined-cycle units are considered to be core; and the remaining units are classified as noncore.

End-use sector specific load patterns are based on recent historical patterns and do not change over the forecast, with the exception of the electric generation sector[104] (i.e., there is no representation of changes in load patterns from new technologies like natural gas cooling.) However, pipeline load factors do change over the forecast as the composition of end-use consumption changes across sectors and as more pipeline and storage capacity becomes available.

Pricing of Services

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. While cost-of-service still forms the basis for pricing these services, an adjustment to the tariffs is made based on changes in utilization to reflect a more market-based approach. Capital expenditures for refurbishment are generally relatively small, are offset by retirements, and are therefore not considered, nor are potential future expenditures for pipeline safety (refurbishment costs include any expenditures for repair and/or replacement of existing pipe). Existing gross plant in service is only based on new capacity additions.

End-use prices for residential, commercial, and core industrial customers are derived by adding a markup to the average regional market price of natural gas in both peak and off-peak periods. (Prices are only 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 end-use and citygate price, independent of whether or not a customer class typically purchases gas through a local distributor. The distribution tariffs are initially based on average historical values (Table 57). For residential, commercial, and core industrial customers, distributor tariffs are adjusted throughout the forecast in response to changes in consumption levels and cost of labor and capital. Although the markups in Table 58 represent annual averages, the model actually uses separate markups for the peak and offpeak periods.

Table 58. Base Level Annual Distributor Markup for Local Transportation Service
(2001 Dollars per thousand cubic feet)

Region	Residential	Commercial	Core Industrial
New England	5.42	2.93	-0.14
Mid Atlantic	5.09	2.46	0.69
East North Central	2.54	1.95	0.05
West North Central	2.80	1.67	0.00
South Atlantic	4.39	2.84	0.06
East South Central	3.57	2.54	-0.18
West South Central	3.48	1.94	0.28
Mountain	2.74	1.88	0.68
Pacific	3.66	2.37	1.91
Florida	8.32	3.02	-1.56
Arizona/New Mexico	4.34	2.35	0.54
California	4.32	3.81	1.06

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting. Derived from Form EI-857, “Monthly Report of Natural Gas Purchases and Deliveries to Consumers” for residential, commercial, and citygate, and from various Manufacturing Energy Consumption Surveys for core industrial.

End-use prices for noncore industrial and electric generator customers are simularly established by adding a markup to the regional natural gas market price. These markups are endogenously derived as the difference between estimated historical end-use prices,[105] and the NGTDM regional market price. For noncore industrial customers, these markups are held constant throughout the forecast. For electric generator customers, these markups are adjusted each forecast year by a fraction (0.15 for core, 0.05 for noncore) of the annual percentage change in the associated electric generator consumption. This adjustment is intended to reflect anticipated additional infrastructure devoted to serving core electric generation consumption growth.

The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are set to *EIA’s Natural Gas Annual* historical end-use minus citygate prices plus Federal and State VNG taxes (Table 59). The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed $4.23 (2001 dollars per thousand cubic feet) dispensing charge plus Federal and State taxes, set constant in nominal dollars. It is assumed that the retailer will lower the dispensing charge by up to 20 percent if needed to be competitive with gasoline prices.

Table 59. Vehicle Natural Gas (VNG) Pricing
(Nominal dollars per thousand cubic feet)

Modified Census Divisions	Total Federal and State VNG Tax[1]
New England	0.51
Middle Atlantic	2.23
East North Central	2.18
West North Central	1.65
South Atlantic (excludes Florida)	1.29
East South Central	1.68
West South Central	1.84
Mountain (excludes Arizona and New Mexico)	1.16
Pacific (excludes California)	1.11
Florida	0.88
Arizona and New Mexico	0.69
California	1.04

[1]Assuming a $0.4844 (nominal dollars per thousand cubic feet) Federal tax.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on the Federal tax published in the Information Resources, Inc., publication *Octane Week*, August 9, 1993, and State taxes posted at Hart Energy Networks Motor Fuels Information Center at www.hartenergynetwork.com/motorfuels/state/doc/glance/glnctax.htm.

Capacity Expansion and Utilization

For the first 2 forecast years of the model, announced pipeline and storage capacity expansions (that are deemed highly likely to occur) are used to establish limits on flows and storage in the model. Subsequently, pipeline and storage capacity is added when increases in demand, coupled with anticipated price impacts, warrant such additions (i.e., flow is allowed to exceed current capacity if the demand still exists given the adjusted tariff, thus indicating an expansion). When the decision to add capacity is made, a simple representation is incorporated to capture the average capital costs for pipeline and storage expansion and the resulting tariff. Once it is determined that an expansion will occur, the associated capital costs are estimated based on costs of recent expansions in that area and are used in the revenue requirement calculations in future years.

It is assumed that pipelines and local distribution companies build and subscribe to a portfolio of pipeline and storage capacity to serve a region-specific colder-than-normal winter demand level, currently set at 5 percent for all pipeline area. 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. For each sector, consumption is disaggregated into peak and off-peak periods based on average historical patterns.

Additions to underground storage capacity are constrained to capture limitations of geology in each of the market regions. The constraints limit total storage additions to be less than an expansion factor times the 1990 storage capacity. The model methodology represents net injections of natural gas into storage in the off-peak period and net withdrawals during the peak period. Total annual net storage withdrawals equal zero in all years of the forecast.

Legislation and Regulation

The methodology for setting reservation fees for transportation services is consistent with FERC's alternative ratemaking and capacity release position in that it allows flexibility in the rates pipelines charge. The methodology is market-based in that prices for transportation services will respond positively to increased demand for services while prices will decline (reflecting discounts to retain customers) should the demand for services decline. The model also reflects current legislation and regulation.

Notes and Sources

[104] Natural gas consumption by electric generators is established in the Electricity Market Module of NEMS on a seasonal basis. These values are used as a basis for adjusting the related load patterns throughout the forecast.

[105] Historical core and noncore industrial prices were based on data from various Energy Information Administration Manufacturing Energy Consumption Surveys.