Independent Statistics & Analysis
U.S. Energy Information Administration

Model Documentation Report: Natural Gas Transmission and Distribution Module of the National Energy Modeling

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Contact Information

The Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System is developed and maintained by the U.S. Energy Information Administration (EIA), Office of Petroleum, Natural Gas, and Biofuels Analysis. General questions about the use of the model can be addressed to Michael Schaal (202) 586-5590, Director of the Office of Petroleum, Natural Gas, and Biofuels Analysis. Specific questions concerning the NGTDM may be addressed to:

Joe Benneche, EI-33
Forrestal Building, Room 2H026
1000 Independence Ave., S.W.
Washington, DC 20585
(202/586-6132)
Joseph.Benneche@eia.doe.gov

This report documents the archived version of the NGTDM that was used to produce the natural gas forecasts presented in the *Annual Energy Outlook 2013*, (DOE/EIA-0383(2013). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic approach, and provides detail on the methodology employed.

The model documentation is updated annually to reflect significant model methodology and software changes that take place as the model develops. The next version of the documentation is planned to be released in the first quarter of 2014.

Update Information

This edition of the model documentation of the Natural Gas Transmission and Distribution Module (NGTDM) reflects changes made to the module over the past year for the *Annual Energy Outlook 2013*. Aside from general data and parameter updates, the notable changes include the following:

- Added endogenous projections for liquefied natural gas exports of domestically produced natural gas.
- Added pricing for liquefied natural gas for vehicles and revised pricing algorithm for compressed natural gas for vehicles.
- Set initial prices to producers based on historical spot prices rather than historical wellhead prices, allowing for the setting of projected regional spot prices based on regional wellhead prices in the model.
- Defined core and noncore industrial prices as associated with non-energy-intensive industries and energy-intensive industries, respectively, setting the associated historical prices based on industry specific price data in EIA's Manufacturing Consumption Survey. In the process, reestimated associated industrial distributor tariffs.

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Abbreviations and Acronyms

AEO	Annual Energy Outlook
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
Btu	British thermal unit
DTS	Distributor Tariff Submodule
EMM	Electricity Market Module
GAMS	Gas Analysis Modeling System
gas	natural gas
IFFS	Integrated Future Forecasting System
ITS	Interstate Transmission Submodule
LFMM	Liquid Fuels Market Module
MEFS	Mid-term Energy Forecasting System
MMBtu	Million British thermal units
Mcf	Thousand cubic feet
MMcf	Million cubic feet
MMcfd	Million cubic feet per day
MMbbl	Million barrels
NEMS	National Energy Modeling System
NGA	Natural Gas Annual
NGM	Natural Gas Monthly
NGTDM	Natural Gas Transmission and Distribution Module
OGSM	Oil and Gas Supply Module
PIES	Project Independence Evaluation System
PTS	Pipeline Tariff Submodule
STEO	Short-Term Energy Outlook
Tcf	Trillion cubic feet
WCSB	Western Canadian Sedimentary Basin

1. Background/Overview

Background

The Natural Gas Transmission and Distribution Module (NGTDM) is the component of the National Energy Modeling System (NEMS) that is used to represent the U.S. domestic natural gas transmission and distribution system. NEMS was developed by the former Office of Integrated Analysis and Forecasting of the U.S. Energy Information Administration (EIA) and is the third in a series of computer-based, midterm energy modeling systems used since 1974 by EIA and its predecessor, the Federal Energy Administration, to analyze and project U.S. domestic energy-economy markets. From 1982 through 1993, the Intermediate Future Forecasting System (IFFS) was used by EIA for its integrated analyses. Prior to 1982, the Midterm Energy Forecasting System (MEFS), an extension of the simpler Project Independence Evaluation System (PIES), was employed. NEMS was developed to enhance and update EIA's modeling capability. Greater structural detail in NEMS permits the analysis of a broader range of energy issues. While NEMS was initially developed in 1992, the model is updated each year, from simple historical data updates to complete replacements of submodules.

The time horizon of NEMS is the midterm period that extends approximately 25 years, currently to year 2040. In order to represent the regional differences in energy markets, the component modules of NEMS function at regional levels appropriate for the markets represented, with subsequent aggregation/disaggregation to the Census Division level for reporting purposes. The projections in NEMS are developed assuming that energy markets are in equilibrium[1] using a recursive price adjustment mechanism.[2] For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for the economic competition between the various fuels and sources. NEMS is organized and implemented as a modular system.[3] The NEMS modules represent each of the fuel supply markets, conversion sectors (e.g., refineries and power generation), and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The system includes a routine that simulates a carbon emissions cap and trade system with annual fees to limit carbon emissions from energy-related fuel combustion. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, Census Division, and end-use sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability.

The integrating routine of NEMS controls the execution of each of the component modules. The modular design provides the capability to execute modules individually, thus allowing independent analysis with, as well as development of, individual modules. This modularity allows the use of the methodology and level of detail most appropriate for each energy sector. Each forecasting year, NEMS

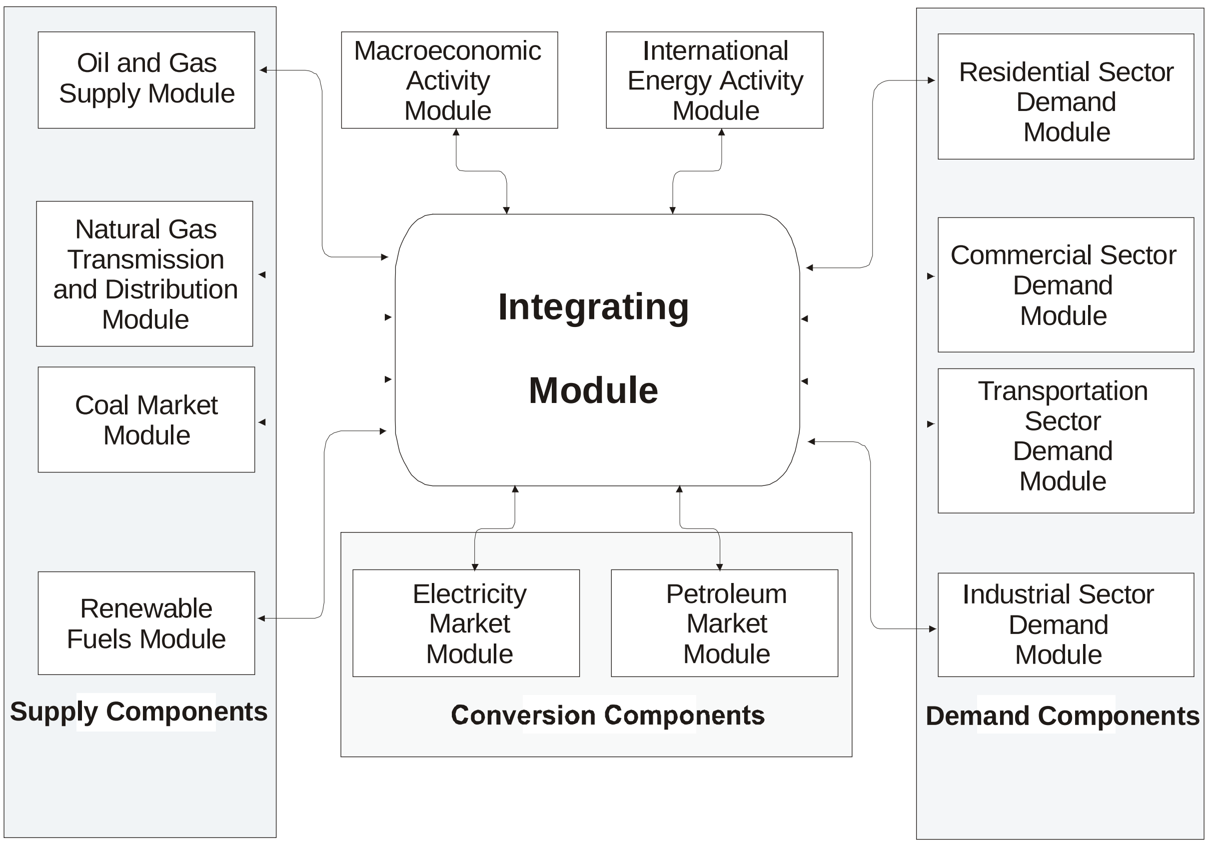
[1] Markets are said to be in equilibrium when the quantities demanded equal the quantities supplied at the same price; that is, at a price that sellers are willing to provide the commodity and consumers are willing to purchase the commodity.

[2] The central theme of the approach used is that supply and demand imbalances will eventually be rectified through an adjustment in prices that eliminates excess supply or demand.

[3] NEMS is composed of 13 modules including a system integration routine.

solves by iteratively calling each module in sequence (once in each NEMS iteration) until the delivered prices and quantities of each fuel in each region have converged within tolerance between the various modules, thus achieving an economic equilibrium of supply and demand in the consuming sectors. For some applications the model is also run in multiple cycles, generally to converge on a solution that involves the need to look ahead at other projected values for future years when solving the current forecasting year. Module solutions are reported annually through the midterm horizon. A schematic of NEMS is provided in **Figure 1-1**, while a list of the associated model documentation reports is in Appendix C, including a report providing an overview of the whole system.

Figure 1-1. Schematic of the National Energy Modeling System



NGTDM overview

The NGTDM module within NEMS represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGTDM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGTDM links natural gas suppliers (including importers) and consumers in the lower 48 States, including liquefied natural gas (LNG) export terminals, and across the Mexican and Canadian borders via a natural gas transmission and distribution network, while determining the flow of natural gas and the regional market clearing prices between suppliers and end-users. For two seasons of each forecast year, the NGTDM determines the production, flows, and prices of natural gas within an aggregate representation of the U.S./Canadian pipeline network, connecting domestic and foreign supply regions with 12 U.S. and 2 Canadian demand regions. Since

NEMS operates on an annual (not a seasonal) basis, NGTDM results are generally passed to other NEMS modules as annual totals or quantity-weighted annual averages. Since the Electricity Market Module has a seasonal component, peak and off-peak[4] prices are also provided for natural gas to electric generators.

Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The methodology employed allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline and storage capacity expansion requirements. Key components of interstate pipeline tariffs are projected, along with distributor tariffs.

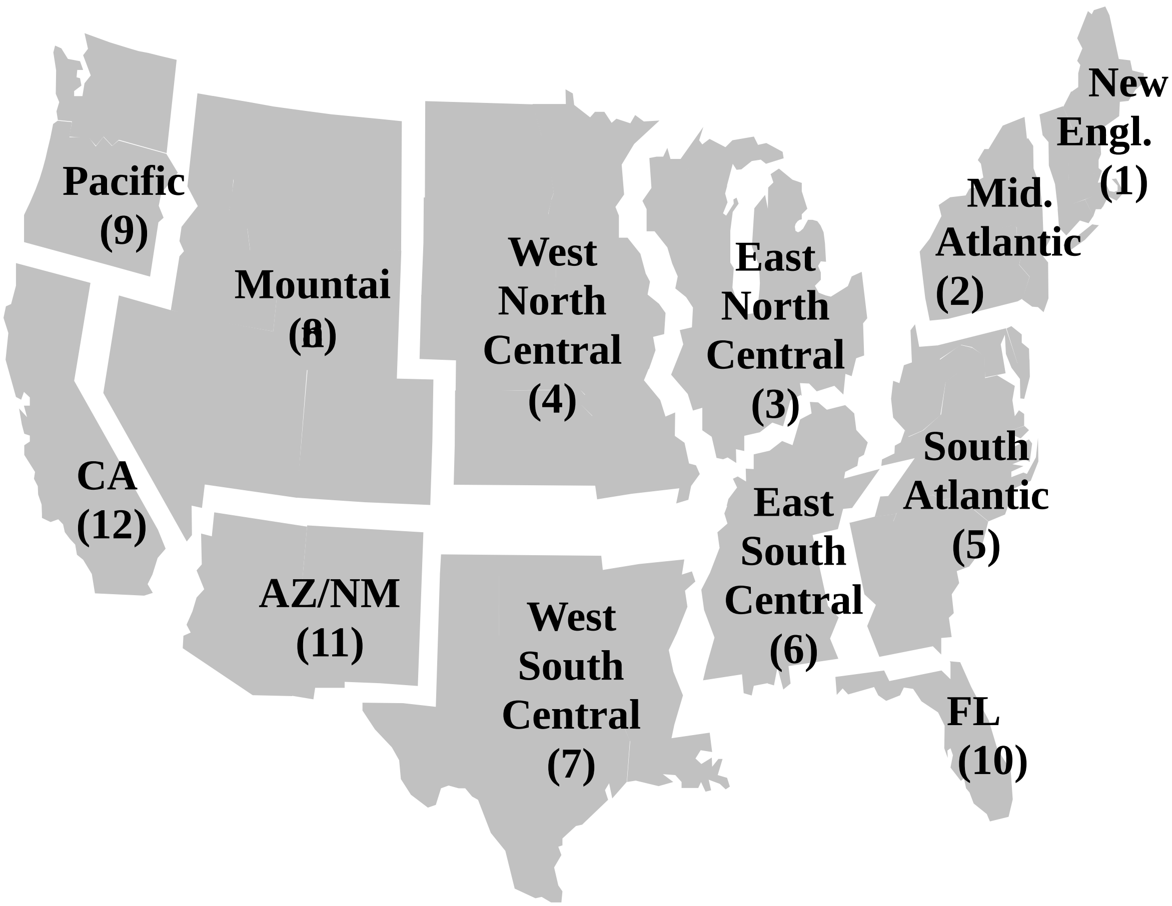
The lower-48 demand regions represented are the 12 NGTDM regions (**Figure 1-2**). These regions are an extension of the nine Census Divisions, with Census Division 5 split into South Atlantic and Florida, Census Division 8 split into Mountain and Arizona/New Mexico, Census Division 9 split into California and Pacific, and Alaska and Hawaii handled independently. Within the U.S. regions, consumption is represented for five end-use sectors: residential, commercial, industrial, electric generation, and transportation (or natural gas vehicles), with the industrial and electric generator sectors further distinguished by core and noncore segments. One or more domestic supply region is represented in each of the 12 NGTDM regions. Canadian supply and demand are represented by two interconnected regions -- East Canada and West Canada -- which connect to the lower-48 regions via seven border crossing nodes. The demarcation of East and West Canada is at the Manitoba/Ontario border. In addition, the model accounts for the potential construction of a pipeline from Alaska to Alberta and one from the Mackenzie Delta to Alberta, if market prices are high enough to make the projects economic. The representation of the natural gas market in Canada is much less detailed than for the United States since the primary focus of the model is on the domestic U.S. market. Potential LNG imports into and LNG exports out of North America are modeled for each of the coastal regions represented in the model, including seven regions in the United States, a potential import point in the Bahamas, potential import/export points in eastern and western Canada, and imports into western Mexico (if destined for the United States).[5] Any LNG facilities in existence or under construction are represented in the model. While the model does not project the construction of any additional import facilities, the construction of LNG export facilities are projected. Finally, imports and exports with Mexico are projected at three border crossings.

The module consists of three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS), as well as several satellite components to establish various market elements not represented elsewhere in NEMS such as: a coal-to-gas conversion component, an Alaska demand component, a Canadian supply/demand component, a Mexico supply/demand component, and an LNG supply/demand component. The ITS is the integrating submodule of the NGTDM. It simulates the natural gas price determination process by bringing together all major economic factors that influence regional natural gas trade in the United States, including

[4] The peak period covers the period from December through March; the off-peak period covers the remaining months.
[5] Maximum LNG imports into Mexico to serve the Mexico market are set exogenously.

pipeline and storage capacity expansion decisions. The Pipeline Tariff Submodule (PTS) generates a representation of tariffs for interstate transportation and storage services, both existing and expansions. The Distributor Tariff Submodule (DTS) generates markups for distribution services provided by local distribution companies and for transmission services provided by intrastate pipeline companies. The modeling techniques employed are a heuristic/iterative process for the ITS, an accounting algorithm for the PTS, and a series of historically based and econometrically based equations for the DTS.

Figure 1-2. Natural Gas Transmission and Distribution Module (NGTDM) Regions



NGTDM Objectives

The primary purpose of the NGTDM is to derive natural gas delivered and supply prices, as well as flow patterns for movements of natural gas through the regional interstate network. Although NEMS operates on an annual basis, the NGTDM was designed to be a two-season model, to better represent important features of the natural gas market. The prices and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The representations of the key features of the transmission and distribution network are the focus of the various components of the NGTDM. These key modeling objectives/capabilities include:

- Represent interregional flows of gas and pipeline capacity constraints
- Represent regional and import supplies, as well as demands for exports

- Determine the amount and the location of required additional pipeline and storage capacity on a regional basis
- Provide a peak/off-peak or seasonal analysis capability
- Represent transmission and distribution service pricing

Overview of the documentation report

The archived version of the NGTDM that was used to produce the natural gas forecasts used in support of the *Annual Energy Outlook 2013*, DOE/EIA-0383(2013) is documented in this report. The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic design, provides detail on the methodology employed, and describes the model inputs, outputs, and key assumptions. It is intended to fulfill the legal obligation of EIA to provide adequate documentation in support of its models (Public Law 94-385, Section 57.b.2). Subsequent chapters of this report provide:

- A description of the interface between NEMS and the NGTDM and the representation of demand and supply used and established in the module (Chapter 2)
- An overview of the solution methodology of the NGTDM (Chapter 3)
- The solution methodology for the Interstate Transmission Submodule (Chapter 4)
- The solution methodology for the Distributor Tariff Submodule (Chapter 5)
- The solution methodology for the Pipeline Tariff Submodule (Chapter 6)
- A description of module assumptions, inputs, and outputs (Chapter 7)

The archived version of the model is available through the National Energy Information Center (202-586-8800, infoctr@eia.gov) and is identified as NEMS2013 (part of the National Energy Modeling System archive package as archived for the Annual Energy Outlook 2013, DOE/EIA-0383(2013)).

The document includes a number of appendices to support the material presented in the main body of the report. Appendix A presents the module abstract. Appendix B lists the major references used in developing the NGTDM. Appendix C lists the various NEMS Model Documentation Reports for the various modules that are mentioned throughout the NGTDM documentation. A mapping of equations presented in the documentation to the relevant subroutine in the code is provided in Appendix D. Appendix E provides a mapping between the variables that are assigned values through READ statements in the module and the data input files that are read. The input files contain detailed descriptions of the input data, including variable names, definitions, sources, units and derivations.[6] Appendix F documents the derivation of all empirical estimations used in the NGTDM. Variable cross-reference tables are provided in Appendix G. Finally, Appendix H contains a description of the algorithm used to project new coal-to-gas plants and the pipeline-quality gas produced.

[6] The NGTDM data files are available upon request by contacting Joe Benneche at Joseph.Benneche@eia.gov or (202) 586-6132. Alternatively, an archived version of the NEMS model (source code and data files) can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

2. Demand and Supply Representation

This chapter describes how supply and demand are represented within the NGTDM and the basic function that the Natural Gas Transmission and Distribution Module (NGTDM) fulfills in NEMS. First, a general description of NEMS is provided, along with an overview of the NGTDM. Second, the data passed to and from the NGTDM and other NEMS modules is described along with the methodology used within the NGTDM to transform the input values prior to their use in the model. The natural gas demand representation used in the module is described, followed by a section on the natural gas supply interface and representation, and concluding with a section on the representation of demand and supply in Alaska.

A brief overview of NEMS and the NGTDM

NEMS represents all of the major fuel markets (crude oil and petroleum products, natural gas, coal, electricity, and imported energy) and iteratively solves for an annual supply/demand balance for each of the nine Census Divisions, accounting for the price responsiveness in both energy production and end-use demand, and for the interfuel substitution possibilities. NEMS solves for an equilibrium in each forecast year by iteratively operating a series of fuel supply and demand modules to compute the end-use prices and consumption of the fuels represented, effectively finding the intersection of the theoretical supply and demand curves reflected in these modules.[7] The end-use demand modules (for the residential, commercial, industrial, and transportation sectors) are detailed representations of the important factors driving energy consumption in each of these sectors. Using the delivered prices of each fuel, computed by the supply modules, the demand modules evaluate the consumption of each fuel, taking into consideration the interfuel substitution possibilities, the existing stock of fuel and fuel conversion burning equipment, and the level of economic activity. Conversely, the fuel conversion and supply modules determine the end-use prices needed in order to supply the amount of fuel demanded by the customers, as determined by the demand modules. Each supply module considers the factors relevant to that particular fuel, for example: the resource base for oil and gas, the transportation costs for coal, or the refinery configurations for petroleum products. Electric generators and refineries are both suppliers and consumers of energy.

Within the NEMS system, the NGTDM provides the interface for natural gas between the Oil and Gas Supply Module (OGSM) and the demand modules in NEMS, including the Electricity Market Module (EMM). Since the other modules provide little, if any, information on markets outside of the United States, the NGTDM uses supply curves for liquefied natural gas (LNG) imports based on output results from EIA's separate International Natural Gas Model (INGM) and includes a simple representation of natural gas markets in Canada and Mexico in order to project LNG and pipeline import levels into the United States. It similarly represents/projects exports via pipeline and as LNG. The NGTDM estimates the price and flow of dry natural gas supplied internationally from the contiguous U.S. border[8] or domestically from the wellhead (and indirectly from natural gas processing plants) to the domestic end-

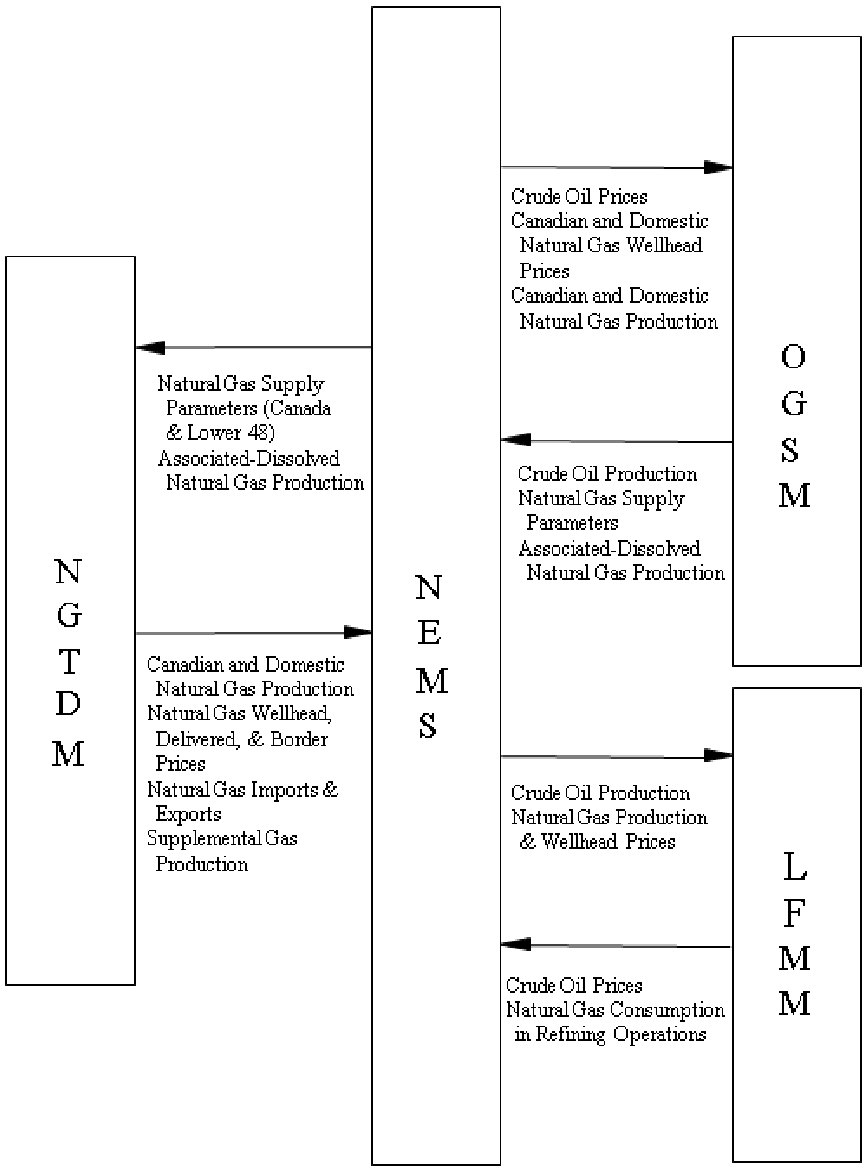
[7] A more detailed description of the NEMS system, including the convergence algorithm used, can be found in "Integrating Module of the National Energy Modeling System: Model Documentation 2012." DOE/EIA-M057(2012), August 2012 or "The National Energy Modeling System: An Overview 2009," DOE/EIA-0581(2009), October 2009.

[8] Natural gas exports are also accounted for within the model.

user. In so doing, the NGTDM models the markets for the transmission (pipeline companies) and distribution (local distribution companies) of natural gas in the contiguous United States.[9] The primary data flows between the NGTDM and the other oil and gas modules in NEMS, the Liquid Fuels Market Module (LFMM) and the OGSM are depicted in **Figure 2-1**.

[9] Because of the distinct separation in the natural gas market between Alaska, Hawaii, and the contiguous United States, natural gas consumption in, and the associated supplies from, Alaska are modeled separately from the contiguous United States within the NGTDM. Since volumes associated with Hawaii are relatively small, they are just considered part of the NGTDM region for California.

Figure 2-1. Primary Data Flows between Oil and Gas Modules of NEMS



In each NEMS iteration, the demand modules in NEMS provide the level of natural gas that would be consumed at the burner-tip in each region by the represented sector at the delivered price set by the NGTDM in the previous NEMS iteration. At the beginning of each forecast year during a model run, the OGSM provides an expected annual level of natural gas produced at the wellhead in each region represented, given the oil and gas wellhead prices from the previous forecast year. (Some supply sources (e.g., Canada) are modeled directly in the NGTDM.) The NGTDM uses this information to build "short-term" (annual or seasonal) supply and demand curves to approximate the supply or demand response to price. Given these short-term demand and supply curves, the NGTDM solves for the delivered, spot, [10] wellhead, and border prices that represent a natural gas market equilibrium, while accounting for the costs and market for transmission and distribution services (including its physical and regulatory constraints).[11] These solution prices, and associated production levels, are in turn passed to the OGSM and the demand modules, including the EMM, as primary input variables for the next NEMS iteration and/or forecast year. Most of the calculations within OGSM are performed only once each NEMS iteration, after NEMS has converged to an equilibrium solution. Information from OGSM is passed as needed to the NGTDM to solve for the following forecast year.

The NGTDM is composed of three primary components or submodules: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS). The ITS is the central module of the NGTDM, since it is used to derive network flows and prices of natural gas in conjunction with a peak[12] and off-peak natural gas market equilibrium. Conceptually the ITS is a simplified representation of the natural gas transmission and distribution system, structured as a network composed of nodes and arcs. The other two primary components serve as satellite submodules to the ITS, providing parameters which define the tariffs to be charged along each of the interregional, intraregional, intrastate, and distribution segments. Data are also passed back to these satellite submodules from the ITS. Other parameters for defining the natural gas market (such as supply and demand curves) are derived based on information passed primarily from other NEMS modules. However in some cases, supply (e.g., synthetic gas production) and demand (e.g., pipeline fuel) components are modeled exclusively in the NGTDM.

The NGTDM is called once each NEMS iteration, but all submodules are not run for every call. The PTS is executed only once for each forecast year, on the first iteration for each year. The ITS and the DTS are executed once every NEMS iteration. The calling sequence of and the interaction among the NGTDM modules is as follows for each forecast year executed in NEMS:

First Iteration:

- The PTS determines the revenue requirements associated with interregional/interstate pipeline company transportation and storage services, using a cost-based approach, and uses this

[10] For *AEO2013* spot prices were introduced and effectively are equivalent to the wellhead price plus an assumed gathering charge of $0.15 87$/Mcf).

[11] Parameters are provided by OGSM for the construction of supply curves for domestic non-associated natural gas production. The NGTDM establishes a supply curve for tight/other Western Canada. The use of demand curves in the NGTDM is an option; the model can also respond to fixed consumption levels.

[12] The peak period covers the period from December through March; the off-peak period covers the remaining months.

information and cost of expansion estimates as a basis in establishing fixed rates and volume-dependent tariff curves (variable rates) for pipeline and storage usage.

- The ITS establishes supply levels (e.g., for supplemental supplies) and supply curves for production and LNG imports based on information from other modules.

Each Iteration:

- The DTS sets markups for intrastate transmission and for distribution services using econometric relationships based on historical data, largely driven by changes in consumption levels.
- The ITS establishes projected values for supporting components, generally set as a function of prices from the previous iteration, for such things as LNG imports and exports, consumption in Alaska, coal-to-gas production, and imports and exports from Mexico.
- The ITS processes consumption levels from NEMS demand modules as required, (e.g., annual consumption levels are disaggregated into peak and off-peak levels) before determining a market equilibrium solution across the two-period NGTDM network.
- The ITS employs an iterative process to determine a market equilibrium solution which balances the supply and demand for natural gas across a U.S./Canada network, thereby setting prices throughout the system and production and import levels. This operation is performed simultaneously for both the peak and off-peak periods.

Last Iteration:

- In the process of establishing a network/market equilibrium, the ITS also determines the associated pipeline and storage capacity expansion requirements. These expansion levels are passed to the PTS and are used in the revenue requirements calculation for the next forecast year. One of the inputs to the NGTDM is “planned” pipeline and storage expansions. These are based on reported pending and commenced construction projects and analysts’ judgment as to the likelihood of the project’s completion. For the first two forecast years, the model does not allow builds beyond these planned expansion levels.
- Other outputs from NGTDM are passed to report-writing routines.

For the historical years (1990 through 2011), a modified version of the above process is followed to calibrate the model to history. Most, but not all, of the model components are known for the historical years. In a few cases, historical levels are available annually, but not for the peak and off-peak periods (e.g., the interstate flow of natural gas and regional supply prices). The primary unknowns are pipeline and storage tariffs and regional market prices. When prices are translated from the supply nodes, through the network to the end-user (or city gate) in the historical years, the resulting prices are compared against published values for city gate prices. These differentials (benchmark factors) are carried through and applied during the forecast years as a calibration mechanism. In the most recent historical year (2011) even fewer historical values are known, and the process is adjusted accordingly.

The primary outputs from the NGTDM, which are used as input in other NEMS modules, result from establishing a natural gas market equilibrium solution: delivered prices, spot, wellhead and border crossing prices, and non-associated natural gas production. In addition, the NGTDM provides a forecast of natural gas imports and exports, lease and plant fuel consumption, and pipeline fuel use, as well as pipeline and distributor tariffs, pipeline and storage capacity expansion, and interregional natural gas flows.

Natural gas demand representation

Natural gas produced within the United States is consumed in lease and plant operations, delivered to consumers, exported internationally, or consumed as pipeline fuel. Within the NGTDM, natural gas demand in the United States is represented for the five primary consuming sectors (residential, commercial, industrial, electric generators, and transportation) based on projected values set in the NEMS demand modules. In addition, the NGTDM internally represents natural gas consumed for lease, plant, and pipeline fuel, as well as pipeline and liquefied natural gas exported out of the United States and the rest of North America (discussed in a later section, along with assumptions used for natural gas consumption in Canada and Mexico). In order to deal with the distinct natural gas markets between Alaska and the lower-48 region, natural gas consumption in Alaska is estimated separately in the NGTDM (also discussed later) although it is already included in projected volumes for the Pacific Census Division.

Classification of natural gas consumers

Natural gas that is delivered to consumers is represented within NEMS at the Census Division level and by five primary end-use sectors: residential, commercial, industrial, transportation, and electric generation.[13] These demands are further distinguished by customer class (core or non-core), reflecting the type of natural gas transmission and distribution service that is assumed to be predominantly purchased. A “core” customer is expected to generally require guaranteed or firm service, particularly during peak days/periods during the year. A “non-core” customer is expected to require a lower quality of transmission services (non-firm service) and therefore, consume gas under a less-certain and/or less-continuous basis. While customers are distinguished by customer class for the purpose of assigning different delivered prices, the NGTDM does not explicitly distinguish firm versus non-firm transmission service. Currently in NEMS, all customers in the transportation, residential, and commercial sectors are classified as core.[14] Within the industrial sector the non-core segment is made up of the energy-intensive industries, while the core is made up of the non-energy-intensive industries. The electric generating units defining each of the two customer classes modeled are as follows: (1) core − gas steam

[13] Natural gas burned in the transportation sector is defined as compressed natural gas or liquefied natural gas that is burned in natural gas vehicles; and the electric generation sector includes all electric power generators whose primary business is to sell electricity, or electricity and heat, to the public, including combined heat and power plants, small power producers, and exempt wholesale generators.

[14] NEMS is structurally able to classify a segment of these sectors as non-core, but currently sets the non-core consumption at zero for the residential, commercial, and transportation sectors.

units or gas combined-cycle units, (2) non-core − dual-fired turbine units, gas turbine units, or dual-fired steam plants (consuming both natural gas and residual fuel oil). [15]

For any given NEMS iteration and forecast year, the demand modules in NEMS determine the level of natural gas consumption for each region and customer class given the delivered price for the same region, class, and sector, as calculated by the NGTDM in the previous NEMS iteration. Within the NGTDM, each of these consumption levels (and its associated price) is used in conjunction with an assumed price elasticity as a basis for building an annual demand curve. (The price elasticities are set to zero if fixed consumption levels are to be used.) These curves are used within the NGTDM to minimize the required number of NEMS iterations by approximating the demand response to a different price. In so doing, the price where the implied market equilibrium would be realized can be approximated. Each of these market equilibrium prices is passed to the appropriate demand module during the next NEMS iteration to determine the consumption level that the module would actually forecast at this price. Once NEMS converges, the difference between the actual consumption, as determined by the NEMS demand modules, and the approximated consumption levels in the NGTDM are insignificant.

For all but the electric sector, the NGTDM disaggregates the annual Census division regional consumption levels into the regional and seasonal representation that the NGTDM requires. The regional representation for the electric generation sector differs from the other NEMS sectors as described below.

Regional/seasonal representations of demand

Natural gas consumption levels by all non-electric[16] sectors are provided by the NEMS demand modules for the nine Census divisions, the primary integrating regions represented in NEMS. Alaska and Hawaii are included within the Pacific Census Division. The EMM represents the electricity generation process for 22 electricity supply regions (**Figure 2-2**). Within the EMM, the electric generators' consumption of natural gas is disaggregated into subregions that can be aggregated into Census Divisions or into the regions used in the NGTDM.

With the following few exceptions, the regional detail provided at a Census division level is adequate to build a simple network representative of the contiguous U.S. natural gas pipeline system. First, Alaska is not connected to the rest of the Nation by pipeline and is therefore treated separately from the contiguous Pacific Division in the NGTDM. Second, Florida receives its gas via a distinctly different route than the rest of the South Atlantic Division and is therefore isolated. A similar statement applies to Arizona and New Mexico relative to the Mountain Division. Finally, California is split off from the contiguous Pacific Division because of its relative size coupled with its unique energy-related regulations. The resulting 12 primary regions represented in the NGTDM are referred to as the "NGTDM Regions" (**Figure 1-2**).

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[15] Currently natural gas prices for the core and non-core segments of the electric generation sector are set to the same average value.

[16] The term "non-electric sectors" refers to sectors (other than commercial and industrial combined heat and power generators) that do not produce electricity using natural gas (i.e., the residential, commercial, industrial, and transportation demand sectors).

The regions represented in the EMM do not always align with State borders and generally do not share common borders with the Census divisions or NGTDM regions. Therefore, demand in the electric generation sector is represented in the NGTDM at a 17-subregional (NGTDM/EMM) level which allows for a reasonable regional mapping between the EMM and the NGTDM regions (**Figure 2-3**). The seventeenth region is Alaska. Within the EMM, the disaggregation into subregions is based on the relative geographic location (and natural gas-fired generation capacity) of the current and proposed electricity generation plants within each region.

Annual consumption levels for each of the non-electric sectors are disaggregated from the nine Census divisions to the two seasonal periods and the twelve NGTDM regions by applying average historical shares (2001 to 2011) that are held constant throughout the forecast (census − NG_CENSHR, seasons − PKSHR_DMD). For the Pacific Division, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii was considered to be negligible and is not handled separately. Within the NGTDM, a relatively simple series of equations (described later in the chapter) was included for approximating the consumption of natural gas by each non-electric sector in Alaska. These estimates, combined with the levels provided by the EMM for consumption by electric generators in Alaska, are used in the calculation of the production of natural gas in Alaska.

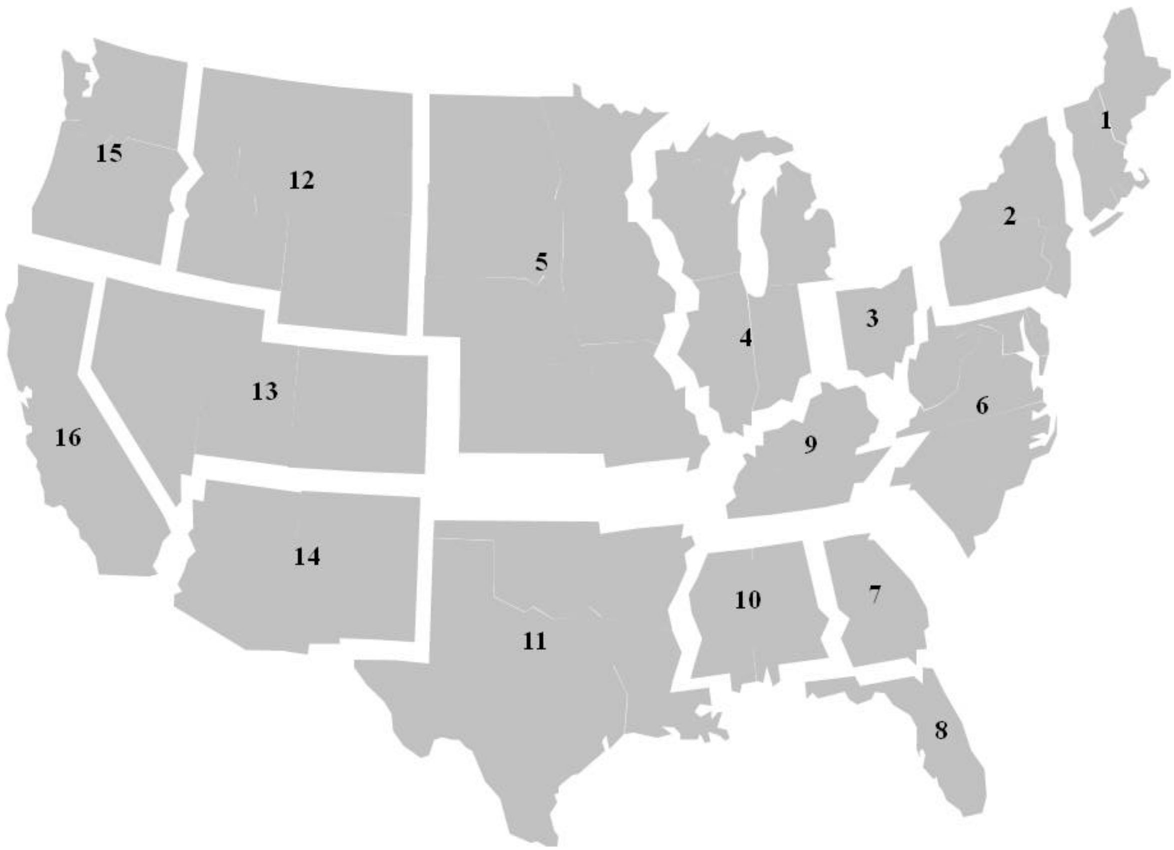
Figure 2-2. Electricity Market Module (EMM) Regions

1.	ERCT	ERCOT All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Unlike the non-electric sectors, the factors (core – PKSHR_UDMD_F, non-core – PKSHR_UDMD_I) for disaggregating the annual electric generator sector consumption levels (for each NGTDM/EMM region and customer type – core and non-core) into seasons are adjusted over the forecast period. Initially average historical shares (1994 to 2011, except New England – 1997 to 2011) are established as base-level shares. The peak-period shares are increased each year of the forecast by 0.5 percent (with a corresponding decrease in the off-peak shares) not to exceed 32 percent of the year.[17]

[17] The peak period covers 33 percent of the year.

Figure 2-3. NGTDM/EMM Regions



Natural gas demand curves

While the primary analysis of energy demand takes place in the NEMS demand modules, the NGTDM itself directly incorporates price-responsive demand curves to speed the overall convergence of NEMS and to improve the quality of the results obtained when the NGTDM is run as a stand-alone model. The NGTDM may also be executed to determine delivered prices for fixed consumption levels (represented by setting the price elasticity of demand in the demand curve equation to zero). The intent is to capture relatively minor movements in consumption levels from the provided base levels in response to price changes, not to accurately mimic the expected response of the NEMS demand modules. The form of the demand curves for the firm transmission service type for each non-electric sector and region is:

$$NGDMD\_CRVF_{s,r} = BASQTY\_F_{s,r} * (PR / BASPR\_F_{s,r})^{NONU\_ELAS\_F_s} \quad (1)$$

where,

$BASPR\_F_{s,r}$	=	delivered price to core sector s in NGTDM region r in the previous NEMS iteration (1987 dollars per Mcf)
$BASQTY\_F_{s,r}$	=	natural gas quantity which the NEMS demand modules indicate would be consumed at price BASPR_F by core sector s in NGTDM region r (Bcf)

$NONU\_ELAS\_F_s$	=	short-term price elasticity of demand for core sector s (set to zero for *AEO2013* or to represent fixed consumption levels)
PR	=	delivered price at which demand is to be evaluated (1987 dollars per Mcf)
$NGDMD\_CRVF_{s,r}$	=	estimate of the natural gas which would be consumed by core sector s in region r at the price PR (Bcf)
s	=	core sector (1-residential, 2-commercial, 3-industrial, 4- transportation)

The form of the demand curves for the non-electric interruptible transmission service type is identical, with the following variables substituted: NGDMD_CRVI, BASPR_I, BASQTY_I, and NONU_ELAS_I (all set to zero for *AEO2013*). For the electric generation sector the form is identical as well, except there is no sector index and the regions represent the 16 NGTDM/EMM lower 48 regions, not the 12 NGTDM regions. The corresponding set of variables for the core and non-core electric generator demand curves are [NGUDMD_CRVF, BASUPR_F, BASUQTY_F, UTIL_ELAS_F] and [NGUDMD_CRVI, BASUPR_I, BASUQTY_I, UTIL_ELAS_I], respectively. For *AEO2013* all of the electric generator demand curve elasticities were set to zero.

Lease, plant, and pipeline fuel

The consumption of gas as lease, plant, and pipeline fuel is determined within the NGTDM. Gas used in well, field, and lease operations and in natural gas processing plants is set equal to an historically observed percentage of dry gas production.[18] In addition, natural gas consumed in the process of liquefying natural gas for export out of the lower 48 region and for liquefied natural gas vehicles was added to the lease and plant fuel category and set as a percent of liquefied natural gas exported (PERLIQFUEL, Appendix E) or a percent of the natural gas entering the liquefaction plant associated with vehicle use (LNGV_LOSS, Appendix E), respectively. Pipeline fuel use depends on the amount of gas flowing through each region, as described in Chapter 4.

Domestic natural gas supply interface and representation

The primary categories of natural gas supply represented in the NGTDM are non-associated and associated-dissolved gas from onshore and offshore U.S. regions; pipeline imports from Mexico; eastern, western (shale/coalbed and tight/other), and Arctic Canada production; LNG imports; natural gas production in Alaska (including that which is transported through Canada via pipeline[19]); synthetic

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[18] The regional factors used in calculating lease and plant fuel consumption (PCTLP) are initially based on historical averages (2008 through 2010) and held constant throughout the forecast period. However, a model option allows for these factors to be scaled in the first one or two forecast years so that the resulting national lease and plant fuel consumption will match the annual published values presented in the latest available *Short-Term Energy Outlook* (STEO), DOE/EIA-0202, (Appendix E, STQLPIN). The adjustment attributable to benchmarking to STEO (if selected as an option) is phased out by the year STPHAS_YR (Appendix E). For *AEO2013* these factors were phased out by 2015. A similar adjustment is performed on the factors used in calculating pipeline fuel consumption using STEO values from STQGPTR (Appendix E).

[19] Several different options have been proposed for bringing stranded natural gas in Alaska to market (e.g., by pipeline, as LNG, and as liquids). In previous AEOs the Petroleum Market Module forecast the potential conversion of Alaska natural gas into liquids, but this option was not included in *AEO2013*. While the NGTDM still allows for the building of a generic pipeline from Alaska into Alberta (although not at the same time as a Mackenzie Valley pipeline), for *AEO2013* the option of building a new LNG export facility in Alaska (supplied by North Slope gas) was added and tends to trigger on first. Therefore, the export facility is assumed to have first access to the currently proved reserves in Alaska which are assumed to be producible at a relatively low cost given their association with oil production.

natural gas produced from coal and from liquid hydrocarbons; and other supplemental supplies. Outside of Alaska (which is discussed in a later section) the only supply categories from this list that are allowed to vary within the NGTDM in response to a change in the current year's natural gas price are the non-associated gas from onshore and offshore U.S. regions, tight/other gas from the western Canada region, and LNG imports.[20] The supply levels for the remaining categories are fixed at the beginning of each forecast year (i.e., before market clearing prices are determined), with the exception of associated-dissolved gas (determined in OGSM).[21] With the exception of LNG imports, which have a peak and off-peak representation, the NGTDM applies average historical relationships to convert annual "fixed" supply levels to peak and off-peak values. These factors are held constant throughout the forecast period.

Within the OGSM, natural gas supply activities are modeled for 12 U.S. supply regions (6 onshore, 3 offshore, and 3 Alaskan geographic areas). The six onshore OGSM regions within the contiguous United States, shown in **Figure 2-4**, do not generally share common borders with the NGTDM regions. The NGTDM represents onshore supply for the 17 regions resulting from overlapping the OGSM and NGTDM regions (**Figure 2-5**). A separate component of the NGTDM models the foreign sources of gas that are transported via pipeline from Canada and Mexico. Seven Canadian and three Mexican border crossings demarcate the foreign pipeline interface in the NGTDM. Potential LNG imports are represented at each of the coastal NGTDM regions; however, import volumes will only be projected based on where existing or exogenously set additional regasification capacity exists (e.g., if a facility is under construction or deemed highly likely to be constructed).[22]

"Variable" dry natural gas production supply curve

The two "variable" (or price-responsive) natural gas supply categories represented in the model are domestic non-associated production and total production from the Western Canadian Sedimentary Basin (WCSB). Non-associated natural gas is largely defined as gas that is produced from gas wells, and is assumed to vary in response to a change in the natural gas price. Associated-dissolved gas is defined as gas that is produced from oil wells and can be classified as a byproduct in the oil production process. Each domestic supply curve is defined through its associated parameters as being net of lease and plant fuel consumption (i.e., the amount of dry gas available for market after any necessary processing and before being transported via pipeline). For both of these categories, the supply curve represents annual

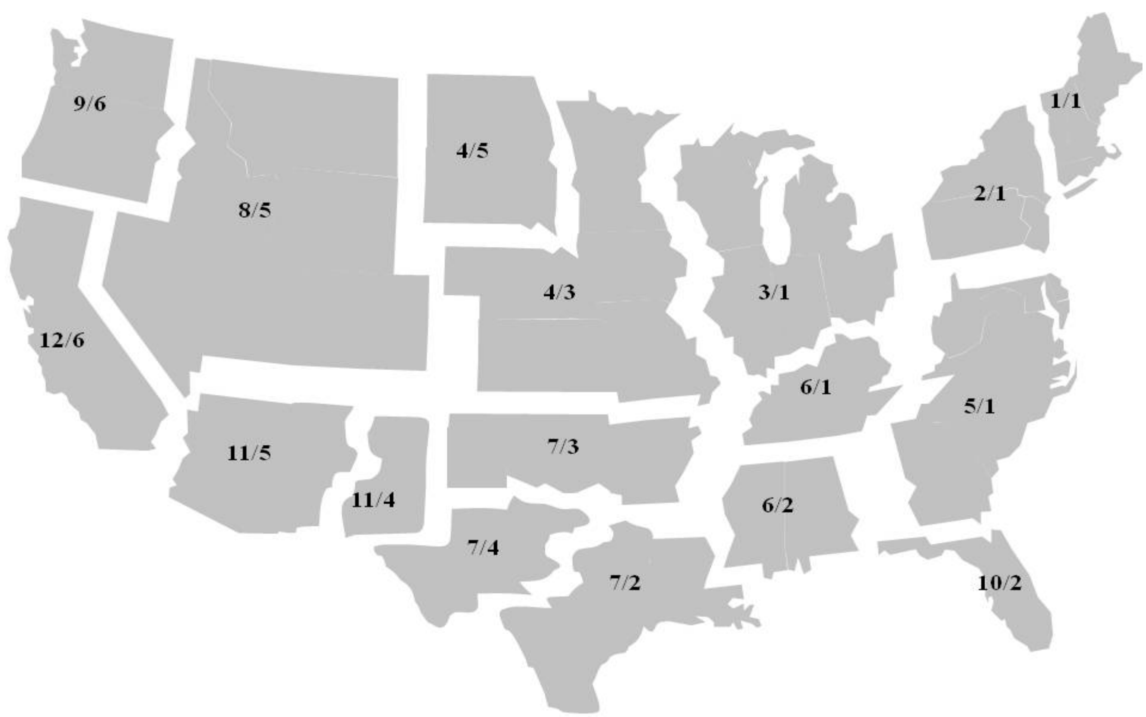
[20] Liquefied natural gas imports are set based on the price in the previous NEMS iteration and are effectively "fixed" when the NGTDM determines a natural gas market equilibrium solution; whereas the other two categories are determined as a part of the market equilibrium process in the NGTDM.

[21] For programming convenience natural gas produced with oil shales (OGSHALENG) is also added to this category.

[22] Structurally an LNG regasification terminal in the Bahamas would be represented as entering into Florida and be reported as pipeline imports, although modeled as LNG imports. No regasification terminals were considered for Alaska or Hawaii in *AEO2013* even though there has been some recent discussion about potential imports in both states.

Figure 2-4. Oil and Gas Supply Module (OGSM) Regions

Figure 2-5. NGTDM/OGSM Regions



production levels. The methodology for translating this annual form into a seasonal representation is presented in Chapter 4.

The supply curve for regional non-associated lower 48 natural gas production and for WCSB production is built from a price/quantity (P/Q) pair, where quantity is the “expected” production (XQBASE) or the base production level as defined by the product of reserves times the “expected” production-to-reserves ratio (as set in the OGSM) and price is the projected associated regional spot price (XPBASE, presented below) for the expected production.[23] The basic assumption behind the curve is that the realized market price will increase from the base price if the current year’s production levels exceed the expected production; and the opposite will occur if current production is less. In addition, it is assumed that the relative price response will likely be greater for a marginal increase in production above the expected production, compared to below. To represent these assumptions, five segments of the curve are defined from the base point. The middle segment is centered around the base point, extends plus or minus a percent (PARM_SUPCRV3, Appendix E) from the base quantity, and if activated, is generally set nearly horizontal (i.e., there is little price response to a quantity change). The next two segments, on either side of the middle, extend more vertically (with a positive slope), and reach plus or minus a percent (PARM_SUPCRV5, Appendix E) beyond the end of the middle segment. The remaining two segments extend the curve above and below even further for the case with relatively large annual production changes, and can be assigned the same or different slopes from their adjacent segments. The slope of the upper segment(s) is generally set greater than or equal to that of the lower segment(s). An illustrative presentation of the supply curve is provided in **Figure 2-6**. The general structure for all five segments of the supply curve, in terms of defining price (NGSUP_PR) as a function of the quantity or production level (QVAR), is:

$$\text{NGSUP\_PR} = \text{PBASE} * \left\{ \left[\left(\frac{1}{\text{ELAS}}\right) * \left(\frac{\text{QVAR - QBASE}}{\text{QBASE}}\right) \right] + 1 \right\} \quad (2)$$

Each of the five segments is assigned different values for the variables ELAS, PBASE, and QBASE, as follows:

Lowest segment:

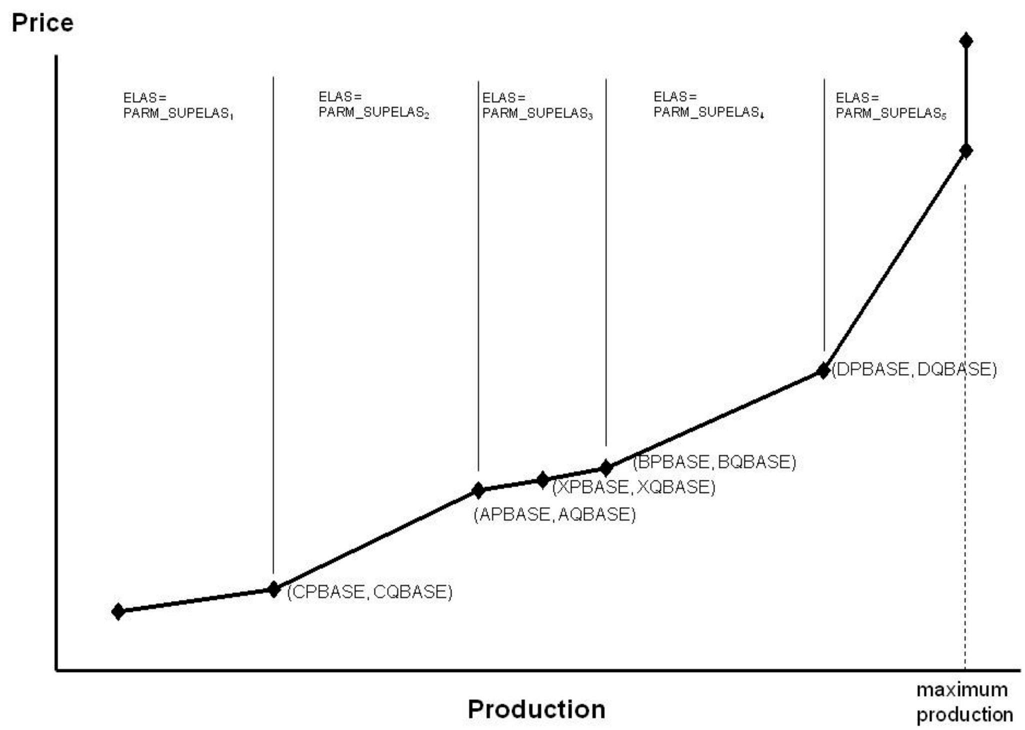
$$\begin{aligned} \text{PBASE} = \text{CPBASE} = \text{APBASE} * \\ (1 - (\text{PARM\_SUPCRV5/PARM\_SUPELAS2}) \end{aligned} \quad (3)$$

$$\text{QBASE} = \text{CQBASE} = \text{AQBASE} * (1 - \text{PARM\_SUPCRV5}) \quad (4)$$

$$\text{ELAS} = \text{PARM\_SUPELAS1} = 0.40 \quad (5)$$

[23] For *AEO2013*, the values for HPBASE in the historical years and in the first forecast year are based on historical data for key regional spot prices, with the supply curves effectively representing the supply price at representative regional market hubs. The wellhead prices sent to OGSM are the regional spot price minus an assumed gathering charge of $0.15 1987$/Mcf.

Figure 2-6. Generic supply curve



Lower segment:

$$PBASE = CPBASE = APBASE * (1 - (PARM\_SUPCRV3/PARM\_SUPELAS3) \quad (6)$$

$$QBASE = AQBASE = XQBASE * (1 - PARM\_SUPCRV3) \quad (7)$$

$$ELAS = PARM\_SUPELAS2 = 0.35 \quad (8)$$

Middle segment:

(in historical years)

$$PBASE = XPBASE = \text{historical} \quad \text{wellhead} \quad \text{price} \quad (9)$$

$$QBASE = AQBASE = XQBASE * (1 - PARM\_SUPCRV3) \quad (10)$$

(in forecast years)

$$PBASE = XPBASE = ZWPRLAG_s \quad (11)$$

$$QBASE = XQBASE = ZOGRESNG_s * ZOGPRRNG_s \quad (12)$$

$$ELAS = PARM\_SUPELAS3 = 0.30 \tag{13}$$

Upper segment:

$$PBASE = BPBASE = XPBASE * (1 + (PARM\_SUPCRV3/PARM\_SUPELAS3)) \tag{14}$$

$$QBASE = BQBASE = XQBASE * (1 + PARM\_SUPCRV3) \tag{15}$$

$$ELAS = PARM\_SUPELAS4 = 0.25 \tag{16}$$

Uppermost segment:

$$PBASE = DPBASE = BPBASE * (1 + (PARM\_SUPCRV5/PARM\_SUPELAS4)) \tag{17}$$

$$QBASE = DQBASE = BQBASE * (1 + PARM\_SUPCRV5) \tag{18}$$

$$ELAS = PARM\_SUPELAS5 = 0.20 \tag{19}$$

where,

NGSUP_PR	=	spot price (1987$/Mcf)
QVAR	=	production, including lease & plant (Bcf)
XPBASE	=	base spot price on the supply curve (1987$/Mcf)
XQBASE	=	base wellhead production on the supply curve (Bcf)
PBASE	=	base spot price on a supply curve segment (1987$/Mcf)
QBASE	=	base wellhead production on a supply curve segment (Bcf)
AQBASE, BQBASE, CQBASE, DQBASE	=	production levels defining the supply curve in **Figure 2-6** (Bcf)
APBASE, BPBASE, CPBASE, DPBASE	=	price levels defining the supply curve in **Figure 2-6** (Bcf)
ELAS	=	elasticity (percent change in quantity over percent change in price) (analyst judgment)
PARM_SUPCRV3	=	(defined in preceding paragraph)
PARM_SUPCRV5	=	(defined in preceding paragraph)
PARM_SUPELAS#	=	elasticity (percentage change in quantity over percentage change in price) on different segments (#) of supply curve
$ZWPRLAG_s$	=	lagged (last year's) spot price for supply source s (1987$/Mcf)
$ZOGRESNG_s$	=	natural gas proved reserves for supply source s at the beginning of the year (Bcf)
$ZOGPRRNG_s$	=	natural gas production to reserves ratio for supply sources (fraction)
$PERCNT_n$	=	percent lease and plant
s	=	supply source
n	=	region/node
t	=	year

The parameters above will be set depending on the location of QVAR relative to the base quantity (XQBASE) (i.e., on which segment of the curve QVAR falls). In the above equation, the QVAR variable includes lease and plant fuel consumption. Since the ITM domestic production quantity (VALUE) represents supply levels net of lease and plant, this value must be adjusted once it is sent to the supply curve function, and before it can be evaluated, to generate a corresponding supply price. The adjustment equation is:

$$QVAR = (VALUE - FIXSUP) / (1.0 - PERCNT_n)$$
$$[\text{where,} \quad FIXSUP = \quad ZOGCCAPPRD_s * (1.0 - PERCNT_n)\ ]$$

where,

QVAR	=	production, including lease and plant consumption
VALUE	=	production, net of lease and plant consumption
$PERCNT_n$	=	percent lease and plant consumption in region/node n (set to PCTLP, set to zero for Canada)
$ZOGCCAPPRD_s$	=	coalbed gas production related to the Climate Change Action Plan[24]
FIXSUP	=	ZOGCCAPPRD net of lease and plant consumption
s	=	NGTDM/OGSM supply region
n	=	region/node

Associated-dissolved natural gas production

Associated-dissolved natural gas refers to the natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved). The production of associated-dissolved natural gas is tied directly with the production (and price) of crude oil. The OGSM projects the level of associated-dissolved natural gas production and the results are passed to the NGTDM for each iteration and forecast year of NEMS. Within the NGTDM, associated-dissolved natural gas production is considered “fixed” for a given forecast year and is split into peak and off-peak values based on average (1994-2011) historical shares of total (including non-associated) peak production in the year (PKSHR_PROD).

Supplemental gas sources

Existing sources for synthetically produced pipeline-quality natural gas and other supplemental supplies are assumed to continue to produce at historical levels. While the NGTDM has an algorithm (see Appendix H) to project potential new coal-to-gas plants and their gas production, the annual production of synthetic natural gas from coal at the existing plant is exogenously specified (Appendix E, SNGCOAL), independent of the price of natural gas in the current forecast year. The *AEO2013* forecast assumes that the sole existing plant (the Great Plains Coal Gasification Plant in North Dakota) will continue to operate at recent historical levels indefinitely. Regional forecast values for other supplemental supplies (SNGOTH) are set at historical averages (2003 to 2010) and held constant over the forecast period. Synthetic natural gas is no longer produced from liquid hydrocarbons in the continental United States, although small amounts were produced in Illinois in some historical years. This production level (SNGLIQ) is set to zero for the forecast. The small amount produced in Hawaii is accounted for in the

[24] This special production category is not included in the reserves and production-to-reserve ratios calculated in the OGSM, so it was necessary to account for it separately when relevant. It is no longer relevant and is set to zero in OGSM.

output reports (set to the historical average from 1997 to 2010). If the option is set for the first two forecast years of the model to be calibrated to the *Short-Term Energy Outlook* (*STEO*) forecast, then these three categories of supplemental gas are similarly scaled so that their sum will equal the national annual forecast for total supplemental supplies published in the STEO (Appendix E, STOGPRSUP). To guarantee a smooth transition, the scaling factor in the last STEO year can be progressively phased out over the first STPHAS_YR (Appendix E) forecast years of the NGTDM. Regional peak and off-peak supply levels for the three supplemental gas supplies are generated by applying the same average (1990-2011) historical share (PKSHR_SUPLM) of national supplemental supplies in the peak period.

Natural gas imports and exports interface and representation

The NGTDM sets the parameters for projecting gas imported and exported through LNG facilities in the U.S. and Canada, the other parameters and forecast values associated with the Canada gas market, and the projected values for imports from and exports to Mexico.

Canada

A node for east and west Canada is included in the NGTDM equilibration network, as well as seven border crossings with the United States. The model includes a representation/accounting of the U.S. border-crossing pipeline capacity, east and west seasonal storage transfers, east and west consumption, east and west LNG imports and (described in a later section), eastern production, tight sands/other production in the west, and coalbed/shale production. The ultimate determination of the import volumes into the United States occurs in the equilibration process of the NGTDM.

Base-level consumption of natural gas in eastern and western Canada (Appendix E, CN_DMD), including gas used in lease, plant, and pipeline operations, is set exogenously,[25] adjusted based on oil sands production and world oil prices, and ultimately split into seasonal periods using PKSHR_CDMD (Appendix E). The projected level of oil produced from oil sands is set exogenously to the NGTDM (based on the most recently available EIA projections) and varies depending on the world oil price case. Starting in a recent historical year (Appendix E, YDCL_GASREQ), the natural gas required to support the oil sands production is set at an assumed ratio (Appendix E, INIT_GASREQ) of the oil sands production. Over the projection period this ratio is assumed to decline with technological improvements and as other fuel options become viable. The ratio in year t is set by multiplying the initially assumed rate by $(t\text{-}YDCL\_GASREQ+1)^{DECL\_GASREQ}$, where DECL_GASREQ is assumed based on anecdotal information (Appendix E). The oil-sands-related gas consumption under reference case world oil prices is subtracted from the base-level total consumption and the remaining volumes are adjusted slightly based on differences in the world oil price in the model run versus the world oil price used in setting the base-level consumption, using an assumed elasticity (Appendix E, CONNOL_ELAS). Finally, total consumption is set to this adjusted value plus the calculated gas consumed for oil sands production under the world oil price case selected. Oil sands production is assumed to occur only in western Canada.

Currently, the NGTDM exogenously sets a forecast of the physical capacity of natural gas pipelines crossing at seven border points from Canada into the United States (excluding any expansion related to the building of an Alaska pipeline). This option can also be used within the model, if border-crossing

[25] These consumption values were based on projections taken from the *International Energy Outlook 2011*.

capacity is set endogenously, to establish a minimum pipeline build level (Appendix E, ACTPCAP and PLANPCAP). The model allows for an endogenous setting of annual Canadian pipeline expansion at each Canada/U.S. border crossing point based on the annual growth rate of consumption in the U.S. market it predominantly serves. The resulting physical capacity limit is then multiplied by a set of exogenously specified maximum utilization rates for each seasonal period to establish maximum effective capacity limits for these pipelines (Appendix E, PKUTZ and OPUTZ). "Effective capacity" is defined as the maximum seasonal, physically sustainable, capacity of a pipeline times the assumed maximum utilization rate. It should be noted that some of the natural gas on these lines passes through the United States only temporarily before reentering Canada, and therefore is not classified as imports.[26] If a decision is made to construct a pipeline from Alaska (or the Mackenzie Delta) to Alberta, the import pipeline capacity added from the time the decision is made until the pipeline is in service is tracked. This amount is subtracted from the size of the pipeline to Alberta to arrive at an approximation for the amount of additional import capacity that will be needed to bring the Alaska or Mackenzie[27] gas to the United States. This total volume is apportioned to the pipeline capacity at the western import border crossings according to their relative size at the time.

Tight and other western Canada production

The vast majority of natural gas produced in Canada currently is from the WCSB. Therefore, a different approach was used in modeling supplies from this region. The model consists of a series of estimated and reserves accounting equations for forecasting tight and other[28] wells drilled, reserves added, reserve levels, and expected production-to-reserve ratios in the WCSB. Drilling activity, measured as the number of successful natural gas wells drilled, is estimated directly as a function of various market drivers rather than as a function of expected profitability. No distinction is made between wells for exploration and development. Next, an econometrically specified finding rate is applied to the successful wells to determine reserve additions; a reserves accounting procedure yields reserve estimates (beginning of year reserves). Finally, an estimated extraction rate determines production potential [production-to-reserves ratio (PRR)].

Wells determination

The total number of successful tight and other natural gas wells drilled in western Canada each year is forecast econometrically as a function of the Canadian natural gas wellhead price, remaining undiscovered resources, last year's production-to-reserve ratio, and a proxy term for the drilling cost per well, as follows:

[26] A significant amount of natural gas flows into Minnesota from Canada on an annual basis only to be routed back to Canada through Michigan. The levels of gas in this category are specified exogenously (Appendix E, FLOW_THRU_IN) and split into peak and off-peak levels based on average (1990-2011 historically based shares for general Canadian imports (PKSHR_ICAN).

[27] All of the gas from the Mackenzie Delta is not necessarily targeted for the U.S. market directly, although it is anticipated that the additional supply in the Canadian system will reduce prices and increase the demand for Canadian gas in the United States. The methodology for representing natural gas production in the Mackenzie Delta and the associated pipeline is described in the section titled "Alaskan Natural Gas Routine."

[28] Since current data tend to combine statistics for drilling and production from other (i.e., traditionally "conventional") sources and that from tight gas formations, the model does not distinguish between the two at present. The baseline "other" resource estimate was increased by an assumed percent per year (RESTECH, Appendix E) as a rough estimate of the future contribution from resource appreciation and from tight formations until more reliable estimates can be generated.

$$\begin{aligned}SUCWELL_t = {} & \exp((1-0.327292)*-21.64607)*OGCNPPRD_t^{0.688283}*URRCAN_t^{2.933252} \\ & *CURPRRCAN_t^{2.328811}*SUCWELLAG^{0.327292}*OGCNPPRD_{t-1}^{0.688283*-0.327292} \\ & *URRLAG^{2.933252*-0.327292}*PRRATLAG^{2.328811*-0.327292}\end{aligned} \quad (20)$$

where,

$SUCWELL_t$	=	total tight and other successful gas wells completed in western Canada in the current forecast year t
SUCWELLAG	=	total tight and other successful gas wells completed in western Canada in the previous forecast year (i.e., the lagged value of SUCWELL)
$OGCNPPRD_t$	=	average western Canada wellhead price per Mcf (1987 U.S. dollars)
$URRCAN_t$	=	remaining tight and other marketable gas resources in the beginning of the current forecast year in western Canada in (Bcf), specified below
URRLAG	=	remaining tight and other marketable gas resources in the beginning of the previous forecast year in western Canada in (Bcf) (i.e., the lagged value of URRCAN)
$CURPRRCAN_t$	=	expected production-to-reserve ratio from the previous forecast year, specified below
PRRATLAG	=	expected production-to-reserve ratio from the forecast year two years prior (i.e., the lagged value of CURPRRCAN)
t	=	forecast year

Parameter values and details about the estimation of this equation can be found in Table F10 of Appendix F. The number of wells is restricted to increase by no more than 30 percent annually.

Reserve additions

The reserve additions algorithm calculates units of gas added to Western Canadian Sedimentary Basin proved reserves. The methodology for conversion of gas resources into proved reserves is a critically important aspect of supply modeling. The actual process through which gas becomes proved reserves is a highly complex one. This section presents a methodology that is representative of the major phases that occur, although by necessity, it is a simplification from a highly complex reality.

Gas reserve additions are calculated using a finding rate equation. Typical finding rate equations relate reserves added to 1) wells or feet drilled, in such a way that reserve additions per well decline as more wells are drilled; and/or 2) remaining resources, in such a way that reserve additions per well decline as remaining resources deplete. The reason for this is that, all else being equal, the larger prospects typically are drilled first. Consequently, the finding rate can be expected to decline as a region matures, although the rate of decline and the functional forms are a subject of considerable debate. In previous versions of the model the finding rate (reserves added per well) was assumption-based, while the current version is econometrically estimated using the following:

$$\begin{aligned}FRCAN_t = {} & \exp\{(1-0.530872)*-18.84688\}*URRCAN_t^{1.546983}* \\ & FRLAG^{0.530872}*URRLAG^{-0.530872*1.546983}\end{aligned} \quad (21)$$

where,

$FRCAN_t$ = finding rate in current forecast year (Bcf per well)
FRLAG = finding rate in previous forecast year or lagged value of FRCAN (Bcf per well)
$URRCAN_t$ = remaining tight and other gas marketable resources in current forecast year in western Canada (Bcf)
URRLAG = remaining tight and other gas marketable resources in previous forecast year in western Canada or lagged value of URRCAN (Bcf)
t = forecast year

Parameter values and details about the estimation of this equation can be found in Table F11 of Appendix F. Remaining tight and other gas marketable resources are initialized in 2011 and set each year thereafter as follows:

$$URRCAN_t = RESBASE * (1 + RESTECH)^T - CUMRCAN_t \tag{22}$$

where,

$URRCAN_t$ = remaining tight and other gas marketable resources in current forecast year in western Canada (Bcf)
RESBASE = initial other marketable resources in 2011 (set at 127,000 Bcf)[29]
RESTECH = assumed rate of increase, primarily due to the contribution from tight gas formations, but also attributable to technological improvement (3 percent or 0.03)[30]
$CUMRCAN_t$ = cumulative reserves added since initial year of 2011 in Bcf
T = the forecast year (t) minus the base year of 2011.
t = forecast year

Total reserve additions in period t are given by:

$$RESADCAN_t = FRCAN_t * SUCWELL_t \tag{23}$$

where,

$RESADCAN_t$ = reserve additions in year t, in Bcf
$FRCAN_{t-1}$ = finding rate in the previous year, in Bcf per well
$SUCWELL_t$ = successful gas wells drilled in year t
t = forecast year

Total end-of-year proved reserves for each period equal proved reserves from the previous period plus new reserve additions less production.

$$RESBOYCAN_{t+1} = CURRESCAN_t + RESADCAN_t - OGPRDCAN_t \tag{24}$$

[29] Source: National Energy Board's "Canada's Energy Future: Energy supply and demand projections to 2035", Table A4.1, November 2011.
[30] Set to fully add tight gas resources from National Energy Board's "Canada's Energy Future: Energy supply and demand projections to 2035", Table A4.1, November 2011 by 2040.

where,

$RESBOYCAN_{t+1}$ = beginning of year reserves for year t+1, in Bcf
$CURRESCAN_t$ = beginning of year reserves for year t, in Bcf
$RESADCAN_t$ = reserve additions in year t, in Bcf
$OGPRDCAN_t$ = production in year t, in Bcf
t = forecast year

Gas production

Production is commonly modeled using a production-to-reserves ratio. A major advantage to this approach is its transparency. Additionally, the performance of this function in the aggregate is consistent with its application on the micro level. The production-to-reserves ratio, as the relative measure of reserves drawdown, represents the rate of extraction, given any stock of reserves.

Tight/other gas production in the WCSB in year t is determined in the NGTDM through a market equilibrium mechanism using a supply curve based on an expected production level provided by the OGSM. The realized extraction is likely to be different. The expected or normal operating level of production is set as the product of the beginning-of-year reserves (RESBOYCAN) and an expected extraction rate under normal operating conditions. This expected production-to-reserve ratio is estimated as follows:

$$PRRATCAN_t = \frac{e^{-72.31364+0.123062*\ln SUCWELL_t+0.032055*\ln FRCAN_t+0.03433*RLYR}}{1+e^{-72.31364+0.123062*\ln SUCWEL_t+0.032055*\ln FRCAN_t+0.03433*RLYR}} * \left(\frac{PRRATCAN_{t-1}}{1-PRRATCAN_{t-1}}\right)^{0.940628} * e^{-0.940628*(-72.31364+0.123062*\ln SUCWELLAG+0.032055*\ln FRLAG+0.03433*(RLYR-1))} \quad (25)$$

where,

$PRRATCAN_t$ = expected production-to-reserve natural gas ratio in western Canada for tight and other gas in forecast year t
$FRCAN_t$ = finding rate in year t (Bcf per well)
FRLAG = finding rate in previous forecast year (Bcf per well), lagged value of PRCAN
$SUCWELL_t$ = successful gas wells drilled in forecast year t
SUCWELLAG = successful gas wells drilled in previous forecast year, lagged value of SUCWELL
RLYR = calendar year (e.g, 2020)
t = forecast year

Parameter values and details about the estimation of this equation can be found in Table F12 of Appendix F. The resulting production-to-reserve ratio is limited, so as not to increase or decrease more than 5 percent from one year to the next and to stay within the range of 0.07 to 0.12.

The potential or expected production level is used within the NGTDM to build a supply curve for tight and other natural gas production in western Canada. The form of this supply curve is effectively the same as the one used to represent non-associated natural gas production in lower 48 regions. This curve is described later in this chapter, with the exceptions related to Canada noted. A primary difference is that the supply curve for the lower 48 states represents non-associated natural gas production net of lease and plant fuel consumption; whereas the western Canada supply curve represents total tight and other natural gas production inclusive of lease and plant fuel consumption.

Canada shale and coalbed

Natural gas produced from coal beds and shale in western Canada (PRD2) is based on an assumed production profile, with the area under the curve equal to the assumed remaining economically recoverable resource (CUR_ULTRES). The production level is initially specified in terms of the forecast year and is set using one functional form before reaching its peak production level and a second functional form after reaching its peak production level. Before reaching peak production, the production levels are assumed to follow a quadratic form, where the level of production is zero in the first year (LSTYR0) and reaches its peak level (PKPRD) in the peak year (PKIYR). The area under the assumed production function equals the assumed economically recoverable resource level (CUR_ULTRES) times the assumed percentage (PERRES) produced before hitting the peak level. After peak production the production path is assumed to decline linearly to the last year (LSTYR) when production is again zero. The two curves meet in the peak year (PKIYR) when both have a value equal to the peak production level (PKPRD). The actual production volumes are adjusted to reflect assumed technological improvement and by a factor that depends on the difference between an assumed price trajectory and the actual price projected in the model. The specifics follow:

Before Peak Production

Assumptions:

production function

$$\text{PRD2} = \text{PARMA}*(\text{PRDIYR}-\text{PKIYR})^2 + \text{PARMB} \tag{26}$$

area under the production function

$$\text{CUR\_ULTRES}*\text{PERRES} = \int_{\text{LSTYR0}}^{\text{PKIYR}} [\text{PARMA}*(\text{PRDIYR}-\text{PKIYR})^2 + \text{PARMB}]\, d\text{PRDIYR} \tag{27}$$

production in year LSTYR0:

$$0 = \text{PARMA}*(\text{LSTYR0}-\text{PKIYR})^2 + \text{PARMB} \tag{28}$$

production in peak year when PRDIYR = PKIYR

$$\text{PKPRD} = \text{PARMA}*(\text{PKIYR}-\text{PKIYR})^2 + \text{PARMB} = \text{PARMB} \tag{29}$$

Derived from above:

$$\text{PARMA} = \frac{-3}{2} * \frac{\text{CUR\_ULTRES}*\text{PERRES}}{(\text{PKIYR}-\text{LSTYRO})^3} \tag{30}$$

$$\text{PARMB} = -\text{PARMA}*(\text{LSTYRO}-\text{PKIYR})^2 \tag{31}$$

After Peak Production

Assumptions:

production function

$$PRD2 = (PARMC*PRDIYR) + PARMD \tag{32}$$

area under the production function

$$CUR\_ULTRES*(1-PERRES) = \int_{PKIYR}^{LSTYR} [(PARMC*PRDIYR)+PARMD]\,dPRDIYR \tag{33}$$

production in peak year when PRDIYR = PKIYR

$$PKPRD = PARMB = (PARMC*PKIYR) + PARMD \tag{34}$$

production in last year LSTYR

$$0 = (PARMC*LSTYR) + PARMD \tag{35}$$

Derived from above:

$$PARMC = \frac{-PARMB^2}{2*CUR\_ULTRES*(1-PERRES)} \tag{36}$$

$$LSTYR = \frac{2*CUR\_ULTRES*(1-PERRES)}{PARMB} + PKIYR \tag{37}$$

$$PARMD = -PARMC*LSTYR \tag{38}$$

given,

$$CUR\_ULTRES = ULTRES*(1+RESTECH)^{(MODYR-RESBASE)}*(1+RESADJ) \tag{39}$$

and,

PRD2	=	unadjusted Canada shale/coalbed gas production (Bcf)
PKPRD	=	peak production level in year PKIYR
CUR_ULTRES	=	estimate of ultimate recovery of natural gas from shale/coalbed Canada sources in the current forecast year (Bcf)
ULTRES	=	estimate of ultimate recovery of natural gas from shale/coalbed Canada sources in the year RESBASE (45,000 Bcf for coalbed in 2011 and 90,000 Bcf for shale in 2011, based on assumed resource levels from the National Energy Board, 2011)
RESBASE	=	year associated with CUR_ULTRES
RESTECH	=	technology factor to increase resource estimate over time (1.0)
MODYR	=	current forecast year
RESADJ	=	scenario-specific resource adjustment factor (default value of 0.0)

PERRES	=	percent of ultimate resource produced before the peak year of production (0.25, fraction)
PKIYR	=	assumed peak year of production (2040)
LSTYR0	=	last year of zero production (1999)
PRDIYR	=	implied year of production along cumulative production path after price adjustment

The actual production is set by taking the unadjusted shale/coalbed gas production (PRD2) and multiplying it by a price adjustment factor, as well as a technology factor. The price adjustment factor (PRCADJ) is based on the degree to which the actual price in the previous forecast year compares against a prespecified expected price path (exprc), represented by the functional form: exprc = (2.1 + [0.08*(MODYR-2010)]). The price adjustment factor is set to the price in the previous forecast year divided by the expected price, all raised to the 0.7 power. Technology is assumed to progressively increase production by 1 percent per year (TECHGRW) more than it would have been otherwise (e.g., in the fifth forecast year production is increased by 5 percent above what it would have been otherwise).[31] Once the production is established for a given forecast year, the value of PRDIYR is adjusted to reflect the actual production in the previous year and incremented by 1 for the next forecast year.

The remaining forecast elements used in representing the Canada gas market are set exogenously in the NGTDM. When required, such annual forecasts are split into peak and off-peak values using historically based or assumed peak shares that are held constant throughout the forecast. For example, the level of natural gas exports to the United States (Appendix E, CANEXP) is currently set exogenously to NEMS, is distinguished by seven Canada/U.S. border crossings, and is split between peak and off-peak periods by applying average (1992 to 2011, Appendix E, PKSHR_ECAN) historical shares to the assumed annual levels. While most Canadian import levels into the U.S. are set endogenously, the flow from eastern Canada into the East North Central region is secondary to the flow going in the opposite direction and is therefore set exogenously (Appendix E, Q23TO3). “Fixed” supply values for the entire eastern Canada region are set exogenously (Appendix E, CN_FIXSUP)[32] and split into peak and off-peak periods using PKSHR_PROD (Appendix E).

Mexico

The Mexico model is largely based on exogenously specified assumptions about consumption and production growth rates and LNG import levels. For the most part, natural gas imports from Mexico are set exogenously for each of the three border crossing points with the United States, with the exception of any gas that is imported into Baja, Mexico, in liquid form only to be exported to the United States. Exports to Mexico from the United States are established before the NGTDM equilibrates and represent the required level to balance the assumed consumption in (and exports from) Mexico against domestic production and LNG imports. The supply levels are also largely assumption-based, but are set to vary to a degree with changes in the expected average spot price in the United States. Peak and off-peak values for imports from and exports to Mexico are based on average historical shares (1994 or 1991 to 2011, PKSHR_IMEX and PKSHR_EMEX, respectively).

[31] If a rapid or slow technology case is being run, this value is increased or decreased accordingly.

[32] Eastern Canada is expected to continue to provide only a small share of the total production in Canada and is almost exclusively offshore.

Mexican gas production and trade is a complex issue, as a range of non-economic factors will influence, if not determine, future flows of gas between the United States and Mexico. Despite the uncertainty and the significant influence of non-economic factors that influence Mexican gas production, and therefore trade with the United States, a methodology to anticipate the path of future Mexican imports from, and exports to, the United States has been incorporated into the NGTDM. This outlook is generated using assumptions regarding regional supply from indigenous production and/or liquefied natural gas (LNG) and regional/sectoral demand growth for natural gas in Mexico.

Assumptions for the growth rate of consumption (Appendix E, PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC) were based on the projections from the *International Energy Outlook 2011*. Assumptions about base-level domestic production (PRD_GFAC) are based in part on the same source and analyst judgment. The production growth rate is adjusted using an additive factor based on the degree to which the average lower 48 spot price varies from a set base price, as follows:

$$PRC\_FAC = MIN\left\{ \left(\frac{OGWPRNG}{3.00}\right)^{0.03125} - 1,\quad 0.05\right\} \tag{40}$$

where,

PRC_FAC	=	factor to add to assumed base-level production growth rate (PRD_GFAC)
OGWPRNG	=	lower 48 average natural gas spot price in the current forecast year (1987$/Mcf)
0.03125	=	an assumed parameter
0.05	=	assumed minimum price factor
3. 00	=	fixed base price, approximately equal to the average lower 48 natural gas wellhead price over the projection period in *AEO2011* reference case (1987$/Mcf), [set in the code and converted at $5.14 (2010$/Mcf)]

The volumes of LNG imported into Mexico for use in the country are initially set exogenously (Appendix E, MEXLNG). However, these values are scaled back if the projected total volumes available to North America (see below) are not sufficient to accommodate these levels. LNG imports into Baja destined for the United States are set endogenously with the LNG import volumes for the rest of North America, as discussed below. Finally, any excess supply in Mexico is assumed to be available for export to the United States, and any shortfall is assumed to be met by imports from the United States.[33]

Liquefied natural gas

LNG imports and exports are largely set endogenously in NGTDM. An assessment is made at the beginning of each forecast year as to the economic viability of adding a generic LNG export facility in the United States or Canada, with a limit placed on how much capacity can be added each year. Once added, a facility is assumed to be utilized throughout the rest of the forecast at a set level. LNG imports

[33] A minimum import level from Mexico is set exogenously (DEXP_FRMEX, Appendix E), as well as a maximum decline from historical levels for exports to Mexico (DFAC_TOMEX, Appendix E).

not associated with re-exports are set at the beginning of each NEMS iteration within the model by evaluating seasonal supply curves, based on outputs from EIA's International Natural Gas Model (INGM), at associated regasification tailgate prices set in the previous NEMS iteration. LNG re-export levels are set exogenously (REEXP, Appendix E) based on historical levels and added to the projected import levels, as well as to the exports of domestically sourced LNG. LNG exports to Japan from the existing facility in Kenai, Alaska are set exogenously (OGQNGEXP, Appendix E) and end in 2012.

Imports

LNG import levels are established/set for each region in North America (excluding Alaska), and period (peak and off-peak). The basic process is as follows for each NEMS iteration (except for the first step): 1) at the beginning of each forecast year set up LNG supply curves for eastern and western North America for each period (peak and off-peak), 2) using the supply curves and the quantity-weighted average regasification tailgate price from the previous NEMS iteration, determine the amount of LNG available for import into North America, 3) subtract the volumes that are exogenously set and dedicated to the Mexico market (unless they exceed the total), and 4) allocate the remaining amount to the associated LNG terminals using a share based on the regasification capacity, the volumes imported last year, and the relative prices.

The LNG import supply curves are developed off of a base price/quantity pair (Appendix E, LNGPPT, LNGQPT) from a reference case run of the INGM, using the same, or very similar, world oil price assumptions. The quantities equal the sum of the LNG imports into east or west North America in the associated period, and the prices equal the quantity-weighted average tailgate price at the regasification terminals. The mathematical specification of the curve is exactly like the one used for domestic production described earlier in this chapter, except that the assumed elasticities are represented with different variables and have different values.[34] This representation represents a first cut at integrating the information from INGM in the domestic projections.[35]

Once the North American LNG import volumes are established, the exogenously specified LNG imports into Mexico are subtracted,[36] along with the sum of any assumed minimum level (Appendix E, LNGMIN) for each of the representative terminals in the U.S., Canada, and Baja, Mexico (as shown in **Table 2-1**). The remainder (TOTQ) is shared out to the terminals and then added to the terminal's assumed minimum import level to arrive at the final LNG import level by terminal and season. The shares are initially set as follows and then normalized to total to 1.0:

[34] For LNG the variables are called PARM_LNGxx, instead of PARM_SUPxx, and are also traceable using Appendix E.

[35] As first implemented, the resulting LNG import volumes were somewhat erratic, so a five-year moving average (2 years back, current year, 2 years in the future) was applied to the quantity inputs to smooth out the trajectory and more closely approximate a trend line.

[36] If the total available LNG import levels exceed the assumed LNG imports into Mexico, the volumes into Mexico are adjusted accordingly, not to be set below assumed minimums (Appendix E, MEXLNGMIN).

$$LSHR_{n,r} = \left\{\frac{QLNGLAG_{n,r} - (LNGMIN_r * SH_{r,n})}{TOTQ_{n,c}} * PERQ + \frac{LNGCAP_r - LNGMIN_r}{TOTCAP_c} * (1 - PERQ)\right\} * \left\{\frac{PLNG_{n,r}}{AVGPR_{n,c}}\right\}^{BETA} \quad (41)$$

where,

$LSHR_{n,r}$	=	initial share (before normalization) of LNG imports going to terminal r in period n from the east or west coast, fraction
$TOTQ_{n,c}$	=	the level of LNG imports in the east or west coast to be shared out for a period n to the associated U.S. regasification regions
$QLNGLAG_{n,r}$	=	LNG import level last year (Bcf)
$LNGMIN_r$	=	minimum annual LNG import level (Bcf) (Appendix E)
$SH_{r,n}$	=	fraction of LNG imported in period n last year
$LNGCAP_r$	=	beginning of year LNG sendout capacity[37] (Bcf) (Appendix E)
$TOTCAP_c$	=	total LNG sendout capacity on the east or west coast (Bcf)
PERQ	=	assumed parameter (0.5)
$PLNG_{n,r}$	=	regasification tailgate price (1987$/Mcf)
$AVGPR_{n,r}$	=	average regasification tailgate price by coast (1987$/Mcf)
BETA	=	assumed parameter (1.2)
r	=	regasification terminal number (See Table 2-1)
n	=	network or period (peak or off-peak)
c	=	east or west coast

Table 2-1. LNG regasification regions

Number	Regasification Terminal/Region	Number	Regasification Regions
1	Everett, MA	9	Alabama/Mississippi
2	Cove Point, MD	10	Louisiana/Texas
3	Elba Island, GA	11	California
4	Lake Charles, LA	12	Washington/Oregon
5	New England	13	Eastern Canada
6	Middle Atlantic	14	Western Canada
7	South Atlantic	15	Baja into the U.S.
8	Florida/Bahamas	--	--

Source: Office of Petroleum, Natural Gas, & Biofuels Analysis, U.S. Energy Information Administration.

Exports

For *AEO2013* and for the first time, LNG exports from domestically sourced natural gas are projected endogenously in the NGTDM. The basic approach is to evaluate the long-term economic viability of adding a generic LNG liquefaction facility consisting of two trains of prespecified sustained capacity

[37] Send-out capacity is the maximum annual volume of gas that can be delivered by a regasification facility into the pipeline.

(EVOL_INCR, Appendix E) independently in each of the coastal regions of the United States and Canada, selecting the most economically profitable for construction (if any and accounting for any assumed restrictions, like earliest start year), and building it over the next two years, one train a year at a time. Once built, the liquefaction facility is assumed to operate at full sustained capacity (accounting for some operational down-time) throughout the rest of the forecast period.

In order to assess economic viability, the model projects a representative price of natural gas in Europe and Asia where the LNG is assumed to be sold. These prices are largely based on projections taken from EIA's *International Energy Outlook 2011* (*IEO2011*), with updates to account for recent market events, and some additional nonpublished information and analysis based on EIA's International Natural Gas Model (INGM) results. The world natural gas prices are assumed to start at their recent historical ratio to the world oil price and become less (or potentially more) tied to the world oil price as the ratio of flexibly priced LNG to a representative regional natural gas demand figure increases relative to its base year level over time. The concept is that the ratio reflects the tightness or looseness of the world LNG market pushing or pulling, respectively, world natural gas prices toward or away from the world oil price. The specific form of the price equation follows:

$$ALTPRC_{y,c} = \left(\frac{XBRENT\_PRICE_{t+y}}{5.8}\right)^{ALP_c} * RAT_c^{BET_c} \tag{42}$$

where for Europe,

$$RAT_1 = \frac{[FLEXLNG_{t+y} + ((FLEXADD_{t+y} + EVOL\_INCR) * PERTOFLEX_1)] / OECD\_EUR_{t+y}}{[FLEXLNG_{lhisyr} + ((FLEXADD_{lhisyr} + EVOL\_INCR) * PERTOFLEX_1)] / OECD\_EUR_{lhisyr}} \tag{43}$$

where for Asia,

$$RAT_2 = \frac{[FLEXLNG_{t+y} + ((FLEXADD_{t+y} + EVOL\_INCR) * PERTOFLEX_1)] / NETASIA_{t+y}}{[FLEXLNG_{lhisyr} + ((FLEXADD_{lhisyr} + EVOL\_INCR) * PERTOFLEX_1)] / NETASIA_{lhisyr}} \tag{44}$$

[Note: when evaluating RAT in years beyond the last forecast year a conservative extrapolation is used such that the value of RAT for post forecast years does not vary much from the value of RAT in the last forecast year.]

where,

$ALTPRC_{y,c}$ = the expected competing natural gas price in continent Europe or Asia for LNG in y years from the current forecast year (1987$/MMBtu) [38]

$XBRENT\_PRICE_{t+y}$ = the Brent crude oil price in y years from the current forecast year t (1987$/bbl) [Note: the 5.8 converts the price into 1987$/MMBtu.]

[38] In theory, ALTPRC is not allowed to fall below a floor of 15 percent above the price being compared to in the United States. However, this is generally not expected to influence the projected LNG export volumes as relatively low world gas prices will make U.S. export volumes uncompetitive in the world arena.

ALP_c = an assumed coefficient representing the value necessary to align the oil price to the natural gas price in each continent in history when "RAT" has value of 1 [Appendix E]

BET_c = an assumed coefficient which drives the movement of the natural gas price away from (or to) the oil price as the market loosens (or tightens), as indicated by RAT [Appendix E]

$FLEXLNG_{t+y}$ = exogenously set projected level of flexibly priced LNG on the world market, excluding any potential volumes from the United States (Bcf)

$FLEXADD_{t+y}$ = LNG exports from the United States in the current forecast year from liquefaction facilities constructed as of the current forecast year (Bcf)

EVOL_INCR = LNG exports from the United States from liquefaction facility under consideration for construction (represents two generic trains) [Appendix E] (Bcf)

$PERTOFLEX_c$ = the fraction of the LNG exports from the United States that are assumed to be flexibly priced

$OECD\_EUR_{t+y}$ = exogenously set projected natural gas consumption for Organization for Economic Cooperation and Development (OECD) Europe [Appendix E] (Bcf)

$NETASIA_{t+y}$ = exogenously set projected representative net natural gas consumption for Asia equal to consumption in Japan, South Korea, and China, minus production in China [QJAP + QSKOR + QCHINA – PCHINA, Appendix E] (Bcf)

c = continent (1-Europe, 2-Asia)

t = forecast year

lhisyr = last year of historical year data

y = number of years after the current forecast year

Once prices are established for Europe and Asia for the next 20 years (the assumed planning life of a liquefaction plant), a comparison is made between expected future prices for natural gas in the United States plus assumed costs for liquefaction (including pipeline costs) [39] [CST_LIQ, Appendix E], shipping [CST_SHP, Appendix E], and regasification [CST_RGAS]. [40] The differences in these two prices represents the added value to the consumer (or to whomever is able to capture the economic return) of purchasing LNG from the United States over potential other supply options. These price differences are accumulated over the 20-year time horizon and set in present forecast year terms using an assumed discount rate [DCF_RATE, Appendix E]. The region with the resulting highest present economic value is assumed to be the location of the next liquefaction build with completion date three years from the current forecast year, presuming other assumed limiting factors are not binding (i.e., earliest potential start year [FYREXP, Appendix E], maximum allowed export volume [MAXEXP, Appendix E]). Another potentially significant limiting factor is that the model limits the number of trains built in a year to one, reflecting practical limits on the necessary resources/manpower for such specialized construction.

[39] The pipeline costs from wellhead to liquefaction terminal are of particular significance for a liquefaction facility in Alaska, bringing North Slope gas to market. If two trains have already been built in a region, a potential third and fourth train are assumed to be able to charge a lower rate [BONUS, Appendix E] to reflect lower marginal costs.

[40] A risk factor to account for any externalities (positive or negative) beyond price is included in the model but set to 0 for *AEO2013*.

Alaska natural gas routine

The NEMS demand modules provide a forecast of natural gas consumption for the total Pacific Census Division, which includes Alaska. Currently natural gas that is produced in Alaska cannot be transported to the lower 48 states via pipeline. Therefore, the production and consumption of natural gas in Alaska is handled separately within the NGTDM from the contiguous states. Annual estimates of contiguous Pacific Division consumption levels are derived within the NGTDM by first estimating Alaska natural gas consumption for all sectors, and then subtracting these from the core market consumption levels in the Pacific Division provided by the NEMS demand modules. The use of natural gas in compressed natural gas vehicles in Alaska is assumed to be negligible or nonexistent. The Electricity Market Module provides a value for natural gas consumption in Alaska by electric generators. The series of equations for specifying the consumption of gas by Alaska residential and commercial customers follows:

$$\begin{aligned} AK\_RN_t &= -4.69 + (1.46 * AK\_RN_{t-1}) + (-0.499 * AK\_RN_{t-2}) \\ &\quad + (0.0172 * AK\_POP_t) + (-0.31 * oMC\_RUC_t) \end{aligned} \tag{45}$$

$$\begin{aligned} AK\_CN_y &= 4.05 - 0.625 + (0.17 * AK\_POP_t) + (-0.158 * oMC\_RUC_t) \\ &\quad + (-0.182 * oMC\_RUC_{t-1}) \end{aligned} \tag{46}$$

$$(res):\ AKQTY\_F_{s=1,t} = \{4129.965 + (133.66 * AK\_RN_t\} / 1000. \tag{47}$$

$$\begin{aligned} (com):\ AKQTY\_F_{s=2,t} &= \{17251.45 + (124.55 * AK\_CM_t) \\ &\quad - (125.132 * oMC\_RUC_t)\} / 1000. \end{aligned} \tag{48}$$

where,

$AKQTY\_F_{s=1,t}$	=	consumption of natural gas by residential (s=1) customers in Alaska (MMcf, converted to Bcf, Table F1, Appendix F)
$AKQTY\_F_{s=2,t}$	=	consumption of natural gas by commercial (s=2) customers in Alaska (MMcf, converted to Bcf, Table F1, Appendix F)
AK_RN_t	=	number of residential customers (thousands, Table F2, Appendix F)
AK_CN_t	=	number of commercial customers (thousands, Table F2, Appendix F)
AK_POP_t	=	exogenously specified projection of the population in Alaska (thousands, Appendix E)
oMC_RUC_t	=	U.S. unemployment rate (percent) from NEMS Macroeconomic Activity Module
t	=	year

Gas consumption by Alaska industrial customers is set as follows:

$$(ind):\ AKQTY\_F_{s=3,t} = AK\_QIND\_S_t + (oNALNGEXP_{r,t} * PERLIQFUEL) \tag{49}$$

where,

$AKQTY\_F_{s=3,t}$	=	consumption of natural gas by industrial customers (s=3), (Bcf)
AK_QIND_S	=	exogenous component reflecting historical consumption of natural gas by industrial customers in southern Alaska (Bcf), equal to the sum of

		consumption at the Agrium fertilizer plant (assumed to close in 2007, Appendix E) and at the Kenai LNG liquefaction facility (assumed to close in 2013, Appendix E), as well as a nominal small volume thereafter of around 3 Bcf.
oNALNGEXP	=	North American LNG export volume out of region r (Bcf)
PERLIQFUEL	=	natural gas consumed in liquefying natural gas for export as a fraction of the exported volumes (Appendix E).
s	=	sector
r	=	LNG export region representing Alaska
t	=	year

While the above equations are meant to reflect total gas consumption in the state, if a pipeline is built to bring North Slope gas to the South, it is possible that the projected volumes could be higher, particularly for the industrial sector, since consumption growth is currently hindered by declining supplies in South Alaska. The current modeling approach does not sufficiently capture such potential.

The production of gas in Alaska is basically set equal to the sum of the volumes consumed in and transported out of Alaska. Therefore production depends on whether a pipeline is constructed from Alaska to Alberta or whether a new LNG export facility is built in Alaska,[41] as well as any exports from the existing facility in Alaska[42] and any gas consumed in the state. The production of gas related to an Alaska pipeline to Alberta or one to a new LNG export facility in the South equals the volumes delivered to Alberta or exported, respectively, plus what is consumed for related lease, plant, and pipeline operations (calculated as the delivered or exported volume divided by 1 minus the percent used for lease, plant, and pipeline operations). The production volumes related to both projects are summed together (N.AK2 below), although the model restricts construction to one or the other. Other production in North Alaska that is not related to either pipeline project is largely lease and plant fuel associated with the crude oil extraction processes, whereas gas is produced in the south largely to satisfy state consumption requirements. The quantity of lease and plant fuel not related to either pipeline in Alaska (N.AK1 below) is assigned separately, includes lease and plant fuel used in the north and south, and is added to the other production (N.AK2 below) to arrive at total North Alaska production. The details follow:

$$\begin{aligned}(\mathrm{S.AK}):\ \mathrm{AK\_PROD}_{r=1} = {} & \mathrm{AK\_CONS\_S} + \mathrm{EXPJAP} + \mathrm{QALK\_LAP\_S} + \\ & \mathrm{QALK\_PIP\_S} - \mathrm{AK\_DISCR}\end{aligned} \tag{50}$$

$$\begin{aligned}(\mathrm{N.AK_1}):\ \mathrm{AK\_PROD}_{r=2} = \mathrm{QALK\_LAP\_N} = {} & (0.0943884 * \mathrm{QALK\_LAP\_NLAG}) \\ & + (0.038873 * \sum_{s=1}^{3} \mathrm{oOGPRCOAK}_{s,t})\end{aligned} \tag{51}$$

[41] The process for deciding to build a pipeline to Alberta is discussed later, whereas the LNG export facility decision was discussed in the previous section.

[42] Although there has been some discussion about the potential need to import LNG into Alaska to satisfy consumption requirements, this potential is not being modeled in the current version of the NGTDM. The inherent assumption is that sufficient production will be found in or transported to South Alaska.

$$(N.AK_2):\ AK\_PROD_{r=3} = \frac{QAK\_ALB_t + oNALNGEXP_{e,t}}{1. - AK\_PCTLSE_{r=3} - AK\_PCTPLT_{r=3} - AK\_PCTPIP_{r=3}} \quad (52)$$

where,

$$AK\_CONS\_S = \sum_{s=1}^{4}(AKQTY\_F_s + AKQTY\_I_s) \quad (53)$$

$$QALK\_LAP\_S = 0.0 \qquad (\textit{total is assigned to the North}) \quad (54)$$

$$QALK\_PIP\_S = (AK\_CONS\_S + EXPJAP) * AK\_PCTPIP_2 \quad (55)$$

where,

AK_PROD_r	=	dry gas production in Alaska (Bcf)
AK_CONS_S	=	total gas delivered to customers in South Alaska (Bcf)
$AKQTY\_F_s$	=	total gas delivered to core customers in Alaska in sector s (Bcf)
$AKQTY\_I_s$	=	total gas delivered to non-core customers in Alaska in sector s (Bcf)
EXPJAP	=	quantity of gas liquefied and exported from existing Kenai facility (Bcf)
QALK_LAP_N	=	quantity of gas consumed in Alaska for lease and plant operations, excluding that related to either Alaska pipeline from the North Slope (Bcf)
QALK_LAP_NLAG	=	quantity of gas consumed for lease and plant operations in the previous year, excluding that related to either pipeline (Bcf)
$oOGPRCOAK_{s,y}$	=	crude oil production in Alaska by sector
$QALK\_PIP_r$	=	quantity of gas consumed as pipeline fuel (Bcf)
AK_DISCR	=	discrepancy, the average (2006-2010) historically based difference in reported supply levels and consumption levels in Alaska (Bcf)
QAK_ALB_t	=	gas produced on North Slope entering Alberta via pipeline (Bcf)
oNALNGEXP	=	quantity of LNG exported out of a new Alaskan LNG export facility (Bcf)
AK_PCTLSE_r	=	(for r=1) not used, (for r=2) lease and plant consumption as a percent of gas consumption, (for r=3) lease consumption as a percent of gas production (fraction, Appendix E)
AK_PCTPLT_r	=	(for r=1 and r=2) not used, (for r=3) plant fuel as a percent of gas production (fraction, Appendix E)
AK_PCTPIP_r	=	(for r=1) not used, (for r=2) pipeline fuel as a percent of gas consumption, (for r=3) pipeline fuel as a percent of gas production fraction, Appendix E)
s	=	sectors (1=residential, 2=commercial, 3=industrial, 4=transportation, 5=electric generators)
r	=	region (1 = south, 2 = north not associated with a pipeline to Alberta or a new export facility, 3 = north associated with a pipeline to Alberta or a new export facility

Lease, plant, and pipeline fuel consumption are calculated as follows. For south Alaska, the calculation of pipeline fuel (QALK_PIP_S) and lease and plant fuel (QALK_LAP_S) are shown above. For either Alaska pipeline, all three components are set to the associated production times the percentage of lease

(AK_PCTLSE_3), plant (AK_PCTPLT_3), or pipeline fuel (AK_PCTPIP_3). For the rest of north Alaska, pipeline fuel consumption is assumed to be negligible, while lease and plant fuel not associated with either pipeline (QALK_LAP_N) is set based on an estimated equation shown previously (Table F9, Appendix F).

Estimates for natural gas wellhead and delivered prices in Alaska are estimated in the NGTDM for proper accounting, but have a very limited impact on the NEMS system. The average Alaska wellhead price (AK_WPRC) over the North and South regions (not accounting for the impact if a pipeline ultimately is connected to Alberta) is set using the following estimated equation:

$$AK\_WPRC_1 = WPRLAG^{0.934077} * oIT\_WOP_{y,1}^{(0.280960*(1-0.934077))} \tag{56}$$

where,

AK_WPRC_1	=	natural gas wellhead price in Alaska, presuming no pipeline to Alberta (1987$/Mcf) (Table F1, Appendix F)
WPRLAG	=	AK_WPRC in the previous forecast year ($/Mcf)
$oIT\_WOP_{y,1}$	=	world oil price (1987$ per barrel)

The wellhead price for natural gas associated with a pipeline to Alberta or to a new LNG export facility is exogenously specified (FR_PMINWPR1, Appendix E) and does not vary by forecast year. The average wellhead price for the state is calculated as the quantity-weighted average of AK_WPRC and FR_PMINWPR1. Delivered prices in Alaska are set equal to the wellhead price (AK_WPRC) resulting from the equation above plus a fixed, exogenously specified markup (Appendix E -- AK_RM, AK_CM, AK_IN, AK_EM).

Within the model, the commencement of construction of the Alaska-to-Alberta pipeline is restricted to the years beyond an earliest start date (FR_PMINYR, Appendix E) and can only occur if a pipeline from the Mackenzie Delta to Alberta is not under construction and the decision to build a new LNG export terminal has not already been made. The same is true for the Mackenzie Delta pipeline relative to construction of the Alaska pipeline. Otherwise, the structural representation of the Mackenzie Delta pipeline is nearly identical to that of the Alaska pipeline, with different numerical values for model parameters. Therefore, the following description applies to both pipelines. Within the model the same variable names are used to specify the supporting data for the two pipelines, with an index of 1 for Alaska and an index of 2 for the Mackenzie Delta pipeline.

The decision to build a pipeline is triggered if the estimated cost to supply the gas to the lower 48 States is lower than an average of the lower 48 average wellhead price over the planning period of FR_PPLNYR (Appendix E) years.[43] Construction is assumed to take FR_PCNSYR (Appendix E) years. Initial pipeline capacity is assumed to accommodate a throughput delivered to Alberta of FR_PVOL (Appendix E). The first year of operation, the volume is assumed to be half of its ultimate throughput. If the trigger price exceeds the minimum price by FR_PADDTAR (Appendix E) after the initial pipeline is built, then the

[43] The prices are weighted, with a greater emphasis on the prices in the recent past. An additional check is made that the estimated cost is lower than the lower 48 price in the last two years of the planning period and lower than a weighted average of the expected prices in the three years after the planning period, during the construction period.

capacity will be expanded the following year by a fraction (FR_PEXPFAC, Appendix E) of the original capacity.

The expected cost to move the gas to the lower 48 is set as the sum of the wellhead price,[44] the charge for treating the gas, and the fuel costs (FR_PMINWPR, Appendix E), plus the pipeline tariff for moving the gas to Alberta and an assumed differential between the price in Alberta and the average lower 48 wellhead price (ALB_TO_L48, Appendix E). A risk premium is also included to largely reflect the expected initial price drop as a result of the introduction of the pipeline, as well as some of the uncertainties in the necessary capital outlays and in the ultimate selling price (FR_PRISK, Appendix E).[45] The cost-of-service based calculation for the pipeline tariff (NGFRPIPE_TAR) to move gas from each production source to Alberta is presented at the end of Chapter 6.

[44] The required wellhead price in the Mackenzie Delta is progressively adjusted in response to changes in the U.S. national average drilling cost per well projections and across the forecast horizon in a higher or lower oil and gas technology case, such that by the last year (2040) the price is higher or lower than the price in the reference case by a fraction equal to 0.25 times the technology factor adjustment rate.

[45] If there is an annual decline in the average lower 48 wellhead price over the planning period for the Alaska pipeline, an additional adjustment is made to the expected cost (although it is not a cost item), equivalent to half of the drop in price averaged over the planning period, to account for the additional concern created by declining prices.

3. Overview of Solution Methodology

The previous chapter described the function of the NGTDM within NEMS and the transformation and representation of supply and demand elements within the NGTDM. This chapter will present an overview of the NGTDM model structure and of the methodologies used to represent the natural gas transmission and distribution industries. First, a detailed description of the network used in the NGTDM to represent the U.S. natural gas pipeline system is presented. Next, a general description of the interrelationships between the submodules within the NGTDM is presented, along with an overview of the solution methodology used by each submodule.

NGTDM regions and the pipeline flow network

General description of the NGTDM network

In the NGTDM, a transmission and distribution network (**Figure 3-1**) simulates the interregional flow of gas in the contiguous United States and Canada in either the peak (December through March) or off-peak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional transfers to move gas from supply sources to end-users. Each NGTDM region contains one transshipment node, a junction point representing flows coming into and out of the region. Nodes have also been defined at the Canadian and Mexican borders, as well as in eastern and western Canada. Arcs connecting the transshipment nodes are defined to represent flows between these nodes, and thus to represent interregional flows. Each of these interregional arcs represents an aggregation of pipelines that are capable of moving gas from one region into another region. Bidirectional flows are allowed in cases where the aggregation includes some pipelines flowing in one direction and other pipelines flowing in the opposite direction.[46] Bidirectional flows can also be the result of directional flow shifts within a single pipeline system due to seasonal variations in flows. Arcs leading from or to international borders generally[47] represent imports or exports. The arcs which are designated as "secondary" in **Figure 3-1** generally represent relatively low flow volumes and are handled somewhat differently and separately from those designated as "primary."

Flows are further represented by establishing arcs from the transshipment node to each demand sector/subregion represented in the NGTDM region. Demand in a particular NGTDM region can only be satisfied by gas flowing from that same region's transshipment node. Similarly, arcs are also established from supply points into transshipment nodes. The supply from each NGTDM/OGSM region is directly available to only one transshipment node, through which it must first pass if it is to be made available to the interstate market (at an adjoining transshipment node). During a peak period, one of the supply sources feeding into each transshipment node represents net storage withdrawals in the region during

[46] Historically, one out of each pair of bidirectional arcs in Figure 3-1 represents a relatively small amount of gas flow during the year. These arcs are referred to as "the bidirectional arcs" and are identified as the secondary arcs in Figure 3-1, excluding 3 to 15, 5 to 10, 15 to E. Canada, 20 to 7, 21 to 11, 22 to 12, and Alaska to W. Canada. The flows along these arcs are initially set at the last historical level and are only increased (proportionately) when a known (or likely) planned capacity expansion occurs.
[47] Some natural gas flows across the Canadian border into the United States, only to flow back across the border without changing ownership or truly being imported. In addition, any natural gas that might flow from Alaska to the lower 48 states would cross the Canadian/U.S. border, but not be considered as an import.

the peak period. Conversely during the off-peak period, one of the demand nodes represents net storage injections in the region during the off-peak period.

Figure 3-1. Natural gas transmission and distribution module network

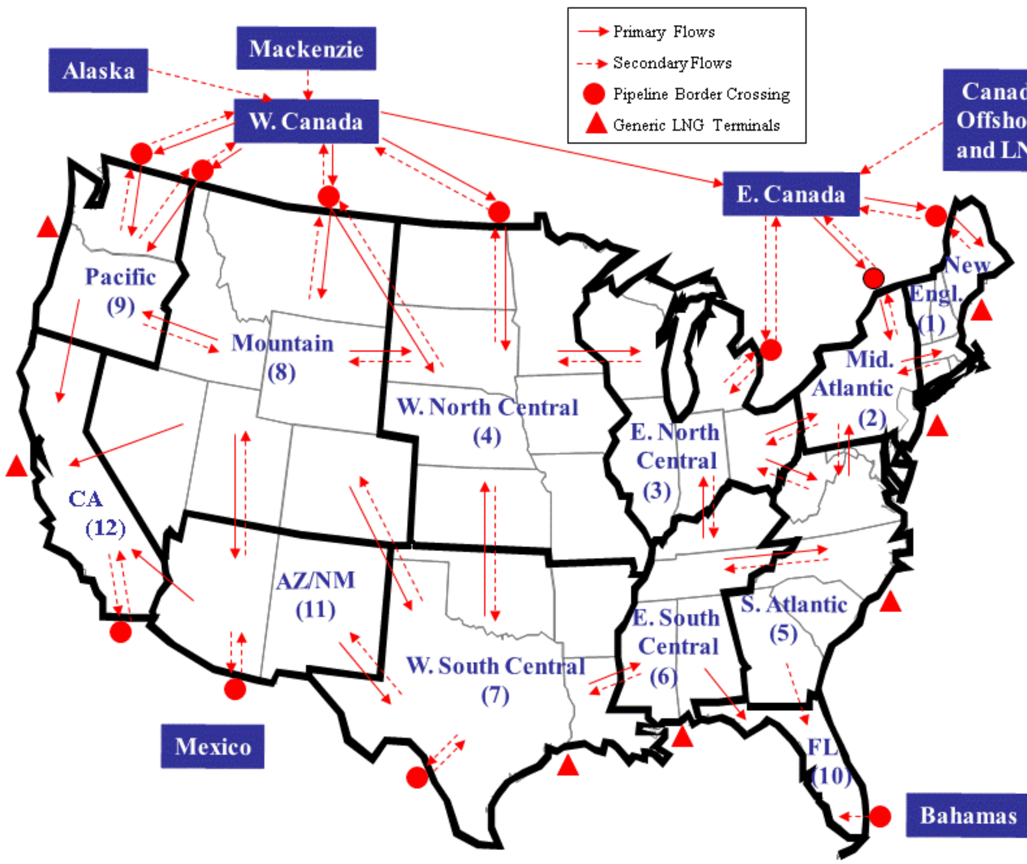
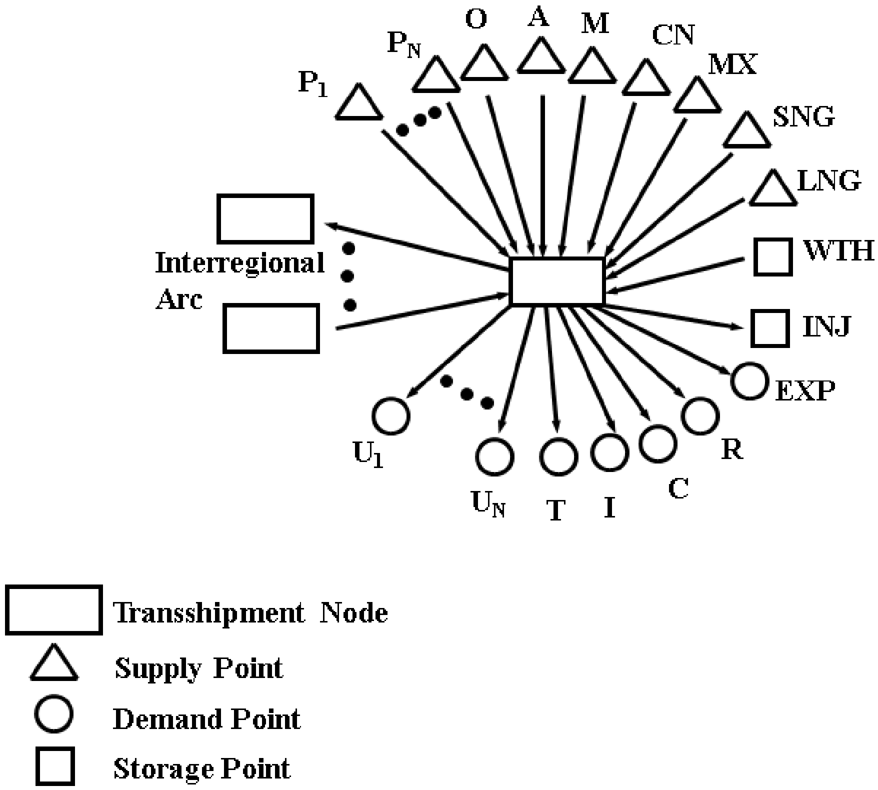


Figure 3-2 shows an illustration of all possible flows into and out of a transshipment node. Each transshipment node has one or more arcs to represent flows from or to other transshipment nodes. The transshipment node also has an arc representing flow to each end-use sector in the region (residential, commercial, industrial, electric generators, and transportation), including separate arcs to each electric generator subregion.[48] Exports and (in the off-peak period) net storage injections are also represented as flow out of a transshipment node. Each transshipment node can have one or more arcs flowing in from each supply source represented within the region. These supply points represent U.S. or Canadian onshore or U.S. offshore production, liquefied natural gas imports, gas produced in Alaska and transported via pipeline, Mexican imports, (in the peak period) net storage withdrawals in the region, or supplemental gas supplies.

[48] Conceptually within the model, the flow of gas to each end-use sector passes through a common city gate point before reaching the end-user.

Figure 3- 2. Transshipment node



P_i - Production in NGTDM/OGSM Region i
O - Offshore Supplies
A - Alaskan Supplies via pipeline to Alberta
M - Mackenzie Delta Gas via pipeline to Alberta
CN - Canadian Supplies
MX - Mexican Imports
SNG - Supplemental Supplies
LNG - Liquefied Natural Gas Imports
WTH - Storage Withdrawals (peak only)
INJ - Storage Injections (offpeak only)
EXP - Exports to either Canada or Mexico or as LNG
R - Residential Demand
C - Commercial Demand
I - Industrial Demand
T - Transportation Demand
U_i - Electric Generator Demand in NGTDM/EMM Region i

Two items accounted for but not presented in **Figure 3-2** are discrepancies or balancing items (i.e., average historically observed differences between independently reported natural gas supply and disposition levels (DISCR for the United States, CN_DISCR for Canada) and backstop supplies.[49]

Many of the types of supply listed above are relatively low in volume and are set independently of current prices and before the NGTDM determines a market equilibrium solution. As a result, these sources of supply are handled differently within the model. Structurally within the model only the price-responsive sources of supply (i.e., onshore and offshore lower 48 U.S. production, Western Canadian Sedimentary Basin (WCSB) production, and storage withdrawals) are explicitly represented with supply nodes and connecting arcs to the transshipment nodes when the NGTDM is determining a market equilibrium solution. However, other sources of supply or demand requirements can effectively be represented as price-responsive if their volumes are adjusted in response to price outside of the NGTDM equilibrium solution process.

Once the types of end-use destinations and supply sources into and out of each transshipment node are defined, a general network structure is created. Each transshipment node does not necessarily have all supply source types flowing in, or all demand source types flowing out. For instance, some transshipment nodes will have liquefied natural gas available while others will not. The specific end-use sectors and supply types specified for each transshipment node in the network are listed in **Table 3-1.** This table also provides the mapping of Electricity Market Module regions and Oil and Gas Supply Module regions to NGTDM regions (**Figure 2-3** and **Figure 2-5** in Chapter 2). The transshipment node numbers in the U.S. align with the NGTDM regions in **Figure 3-1**. Transshipment nodes 13 through 19 are pass-through nodes for the border crossings on the Canada/U.S. border, going from east to west.

As described earlier, the NGTDM determines the flow and price of natural gas in both a peak and off-peak period. The basic network structure separately represents the flow of gas during the two periods within the Interstate Transmission Submodule. Conceptually this can be thought of as two parallel networks, with three areas of overlap. First, pipeline expansion is determined only in the peak-period network (with the exception of pipelines going into Florida from the East South Central Division). These levels are then used as constraints for pipeline flow in the off-peak period. Second, net withdrawals from storage in the peak period establish the net amount of natural gas that will be injected in the off-peak period, within a given forecast year. Similarly, the price of gas withdrawn in the peak period is the sum of the price of the gas when it was injected in the off-peak, plus an established storage tariff. Third, the supply curves provided by the Oil and Gas Supply Module are specified on an annual basis. Although these curves are used to approximate peak and off-peak supply curves, the model is constrained to solve on the annual supply curve (i.e., when the annual curve is evaluated at the quantity-weighted average annual spot price, the resulting quantity should equal the sum of the production in the peak and off-peak periods). The details of how this is accomplished are provided in Chapter 4.

[49] Backstop supplies are allowed when the flow out of a transshipment node exceeds the maximum flow into a transshipment node. A high price is assigned to this supply source and it is generally expected not to be required (or desired). Chapter 4 provides a more detailed description of the setting and use of backstop supplies in the NGTDM.

Table 3-1. Demand and supply types at each transshipment node in the network

Transshipment Node	Demand Types	Supply Types
1	R, C, I, T, U(1), EXP	P(1/1), LNG, SNG
2	R, C, I, T, U(2), INJ, EXP	P(2/1), WTH, LNG, SNG
3	R, C, I, T, U(3), U(4), INJ	P(3/1), WTH, SNG
4	R, C, I, T, U(5), INJ	P(4/3), P(4/5), WTH, SNG
5	R, C, I, T, U(6), U(7), INJ, EXP	P(5/1), Atlantic Offshore, WTH, LNG, SNG
6	R, C, I, T, U(9), U(10), INJ, EXP	P(6/1), P(6/2), WTH, LNG, SNG
7	R, C, I, T, U(11), INJ, EXP	P(7/2), P(7/3), P(7/4), Gulf of Mexico, WTH, LNG, SNG
8	R, C, I, T, U(12), U(13), INJ	P(8/5), WTH, SNG
9	R, C, I, T, U(15), INJ, EXP	P(9/6), WTH, LNG, SNG
10	R, C, I, T, U(6), U(8), INJ	P(10/2), WTH, LNG, SNG
11	R, C, I, T, U(14), INJ	P(11/4), P(11/5), WTH, SNG
12	R, C, I, T, U(16), INJ, EXP	P(12/6), Pacific Offshore, WTH, LNG, SNG
13 – 19	--	--
20	Exports to Mexico (TX)	Mexican Imports (TX)
21	Exports to Mexico (AZ/NM)	Mexican Imports (AZ/NM)

22	Exports to Mexico (CA)	Mexican Imports (CA)
23	East Canada consumption, INJ, EXP	East Canada production, WTH, LNG
24	West Canada consumption, INJ, EXP	West Canada production, WTH, LNG, Alaska and Mackenzie Valley gas via a pipeline

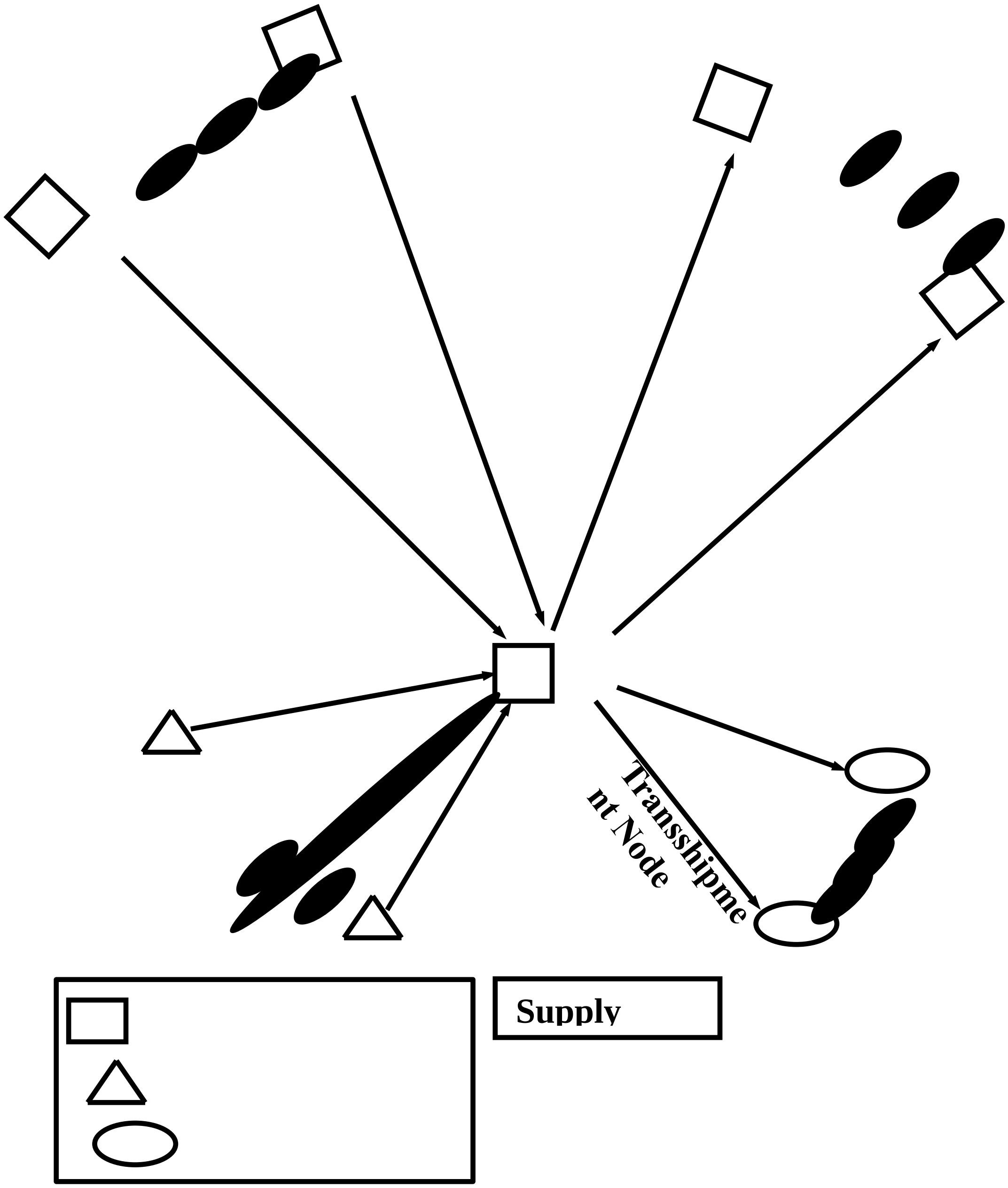
Abreviations as defined in Figure 3-2. P(x/y) – production in region defined in Figure 2-5 for NGTDM region x and OGSM region y. U(z) – electric generator consumption in region z, defined in Figure 2-3

Specifications of a network arc

Each arc of the network has associated variable inputs and outputs. The variables that define an interregional arc in the Interstate Transmission Submodule (ITS) are the pipeline direction, available capacity from the previous forecast year, the “fixed” tariffs and/or tariff curve, the flow on the arc from the previous year, the maximum capacity level, and the maximum utilization of the capacity (**Figure 3-3**). While a model solution is determined (i.e., the quantity of the natural gas flow along each interregional arc is determined), the “variable” or quantity-dependent tariff and the required capacity to support the flow are also determined in the process.

For the peak period, the maximum capacity build levels are set to a factor above the 1990 levels. The factor is set high enough so that this constraint is rarely, if ever, binding. However, the structure could be used to limit growth along a particular path. In the off-peak period the maximum capacity levels are set to the capacity level determined in the peak period. The maximum utilization rate along each arc is used to capture the impact that varying demand loads over a season have on the utilization along an arc.

Figure 3-3. Variables defined and determined for network arc



For the peak period, the maximum utilization rate is calculated based on an estimate of the ratio of January-to-peak-period consumption requirements. For the off-peak the maximum utilization rates are set exogenously (HOPUTZ, Appendix E). Capacity and flow levels from the previous forecast year are used as input to the solution algorithm for the current forecast year. In some cases, capacity that is newly available in the current forecast year will be exogenously set (PLANPCAP, Appendix E) as “planned” (i.e., highly probable that it will be built by the given forecast year based on project announcements). Any additional capacity beyond the planned level is determined during the solution process and is checked against maximum capacity levels and adjusted accordingly. Each of the interregional arcs has an associated “fixed” and “variable” tariff, to represent usage and reservation fees, respectively. The variable tariff is established by applying the flow level along the arc to the associated tariff supply curve, established by the Pipeline Tariff Submodule. During the solution process in the Interstate Transmission Submodule, the resulting tariff in the peak or off-peak period is added to the price at the source node to arrive at a price for the gas along the interregional arc right before it reaches its destination node. Through an iterative process, the relative values of these prices for all of the arcs entering a node are used as the basis for reevaluating the flow along each of these arcs.[50]

For the arcs from the transshipment nodes to the final delivery points, the variables defined are tariffs and flows (or consumption). The tariffs here represent the sum of several charges or adjustments, including interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups. Associated with each of these arcs is the flow along the arc, which is equal to the amount of natural gas consumed by the represented sector. For arcs from supply points to transshipment nodes, the input variables are the production levels from the previous forecast year, a tariff, and the maximum limit on supplies or production. In this case the tariffs theoretically represent gathering charges, but are currently set to zero.[51] Maximum supply levels are set at a percentage above a baseline or “expected” production level (described in Chapter 4). Although capacity limits can be set for the arcs to and from end-use sectors and supply points, respectively, the current version of the module does not impose such limits on the flows along these arcs.

Note that any of the above variables may have a value of zero, if appropriate. For instance, some pipeline arcs may be defined in the network that currently have zero capacity, yet where new capacity is expected in the future. On the other hand, some arcs such as those to end-use sectors are defined with infinite pipeline capacity because the model does not forecast limits on the flow of gas from transshipment nodes to end users.

Overview of the NGTDM submodules and their interrelationships

NEMS generates an annual forecast of the outlook for U.S. energy markets for the years 1990 through 2040. For the historical years, many of the modules in NEMS do not execute, but simply assign historically published values to the model’s output variables. The NGTDM similarly assigns historical values to most of the known module outputs for these years. However, some of the required outputs from the module are not known (e.g., the flow of natural gas between regions on a seasonal basis). Therefore, the model is run in a modified form to fill in such unknown, but required values. Through this process, historical values are generated for the unknown parameters that are consistent with the known historically based values (e.g., the unknown seasonal interregional flows sum to the known annual totals).

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[50] During the off-peak period in a previous version of the module, only the usage fee was used as a basis for determining the relative flow along the arcs entering a node. However, the total tariff was ultimately used when setting delivered prices.

[51] For *AEO2013*, the gathering charges were set in OGSM, represented by subtracting an assumed fix price ($0.15 87$/Mcf) from the hub prices passed from the NGTDM to OGSM to arrive at a price seen by producers, that is equivalent to a wellhead price.

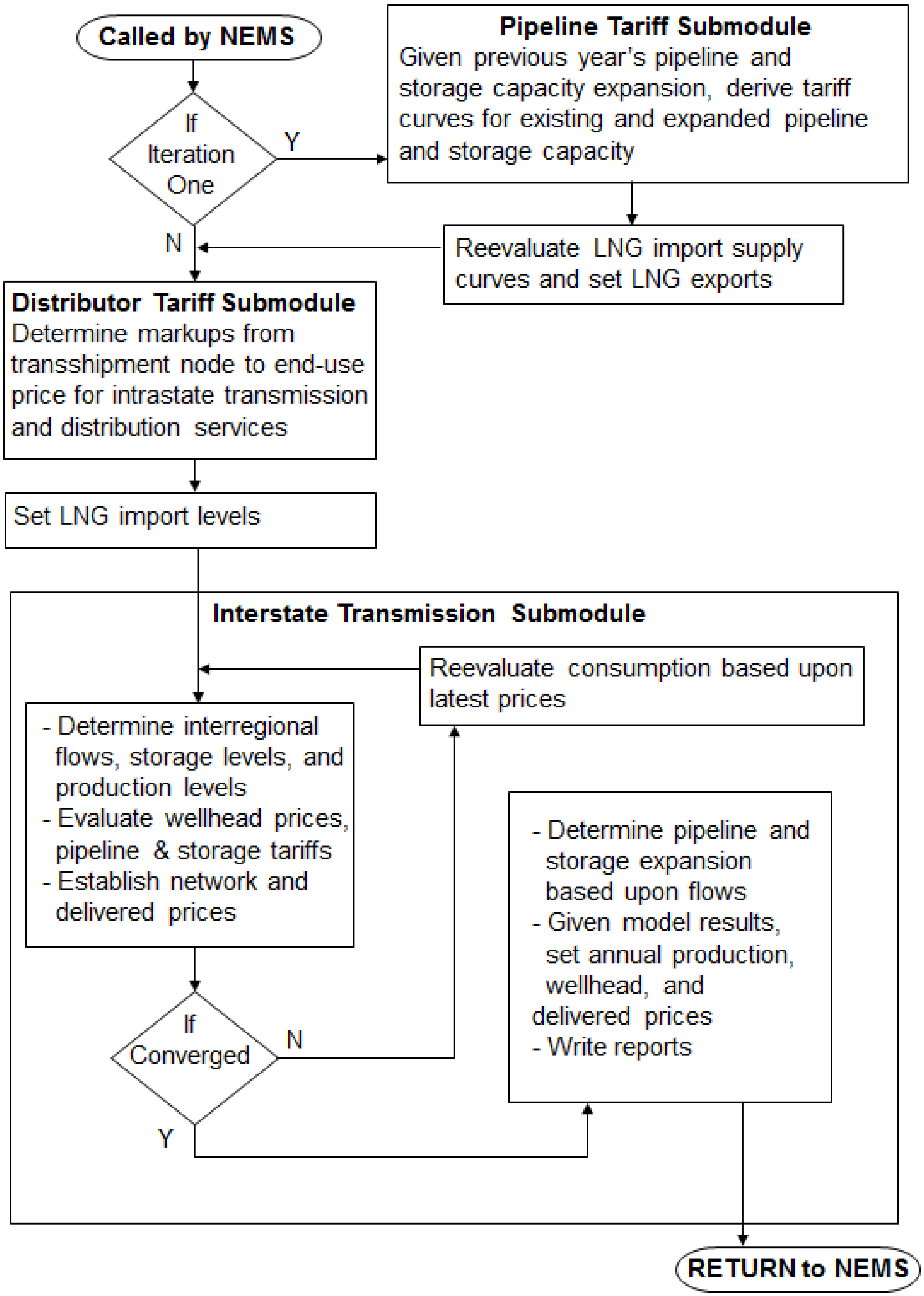
Although the NGTDM is executed for each iteration of each forecast year solved by NEMS, it is not necessary that all of the individual components of the module be executed for all iterations. Of the NGTDM's three components or submodules, the Pipeline Tariff Submodule is executed only once per forecast year since the submodule's input values do not change from one iteration of NEMS to the next. However, the Interstate Transmission Submodule and the Distributor Tariff Submodule are executed during every iteration for each forecast year because their input values can change by iteration. Within the Interstate Transmission Submodule an iterative process is used. The basic solution algorithm is repeated multiple times until the resulting spot prices and production levels from one iteration are within a user-specified tolerance of the resulting values from the previous iteration, and equilibrium is reached. A process diagram of the NGTDM is provided in **Figure 3-4**, with the general calling sequence.

The Interstate Transmission Submodule is the primary submodule of the NGTDM. One of its functions is to forecast interregional pipeline and underground storage expansions and produce annual pipeline load profiles based on seasonal loads. Using this information from the previous forecast year and other data, the Pipeline Tariff Submodule uses an accounting process to derive revenue requirements for the current forecast year. This submodule builds pipeline and storage tariff curves based on these revenue requirements for use in the Interstate Transmission Submodule. These curves extend beyond the level of the current year's capacity and provide a means for assessing whether the demand for additional capacity, based on a higher tariff, is sufficient to warrant expansion of the capacity. The Distributor Tariff Submodule provides distributor tariffs for use in the Interstate Transmission Submodule. The Distributor Tariff Submodule must be called in each iteration because some of the distributor tariffs are based on consumption levels that may change from iteration to iteration. Finally, using the information provided by these other NGTDM submodules and other NEMS modules, the Interstate Transmission Submodule solves for natural gas prices and quantities that reflect a market equilibrium for the current forecast year. A brief summary of each of the NGTDM submodules follows.

Interstate Transmission Submodule

The Interstate Transmission Submodule (ITS) is the main integrating module of the NGTDM. One of its major functions is to simulate the natural gas price determination process. The ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end-user, or to the border for exporting, where and when (peak versus off-peak) it is needed. In the process, the ITS models the decision-making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in the NGTDM. Storage serves as the primary link between the two seasonal periods represented.

Figure 3-4. NGTDM process diagram

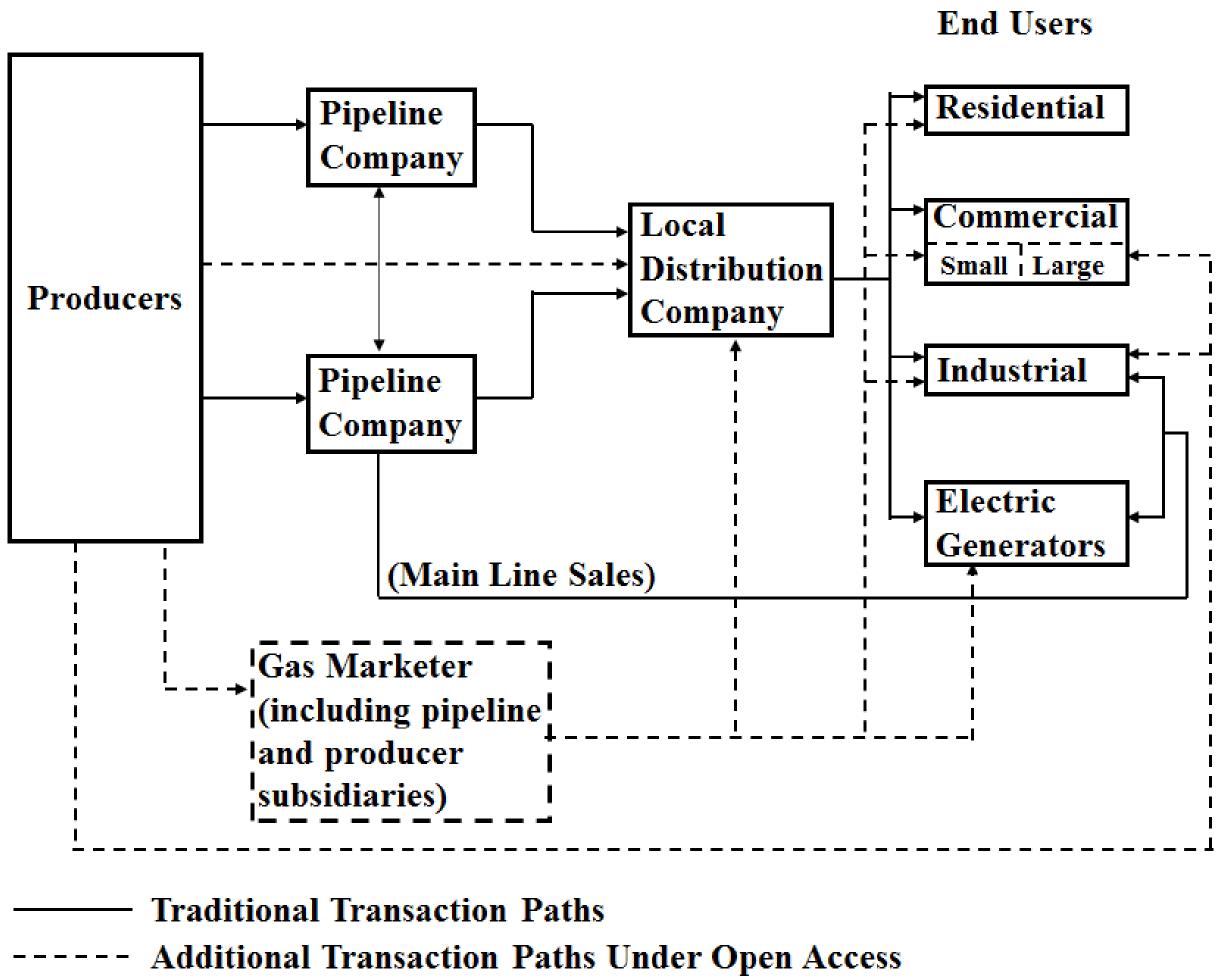


The ITS employs an iterative heuristic algorithm to establish a market equilibrium solution. Given the consumption levels from other NEMS modules and the established export volumes, the basic process followed by the ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas (from the previous ITS iteration). This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the off-peak period. Second, using the model's supply curves, spot prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariff curves from the Pipeline Tariff Submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end-users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the off-peak to arrive at the price of the gas when withdrawn in the peak period. Delivered prices are derived for residential, commercial, electric generation, and transportation customers, as well as for both the core and non-core industrial sectors, using the distributor tariffs provided by the Distributor Tariff Submodule. At this point consumption and/or export levels can be reevaluated given the resulting set of delivered and export prices. Either way, the process is repeated until the solution has converged.

In the end, the ITS derives average seasonal (and ultimately annual) natural gas prices (spot, wellhead, city gate, delivered, imported, and exported), and the associated production and flows, that reflect an interregional market equilibrium among the competing participants in the market. In the process of determining interregional flows and storage injections/withdrawals, the ITS also forecasts pipeline and storage capacity additions. In the calculations for the next forecast year, the Pipeline Tariff Submodule will adjust the requirements to account for the associated expansion costs. Other primary outputs of the module include lease, plant, and pipeline fuel use, Canadian import levels, and net storage withdrawals in the peak period.

The historical evolution of the price determination process simulated by the ITS is depicted schematically in **Figure 3-5**. At one point, the marketing chain was very straightforward, with end-users and local distribution companies contracting with pipeline companies, and the pipeline companies in turn contracting with producers. Prices typically reflected average costs of providing service plus some regulator-specified rate of return. Although this approach is still used as a basis for setting pipeline tariffs, more pricing flexibility has been introduced, particularly in the interstate pipeline industry and more recently by some local distributors. Pipeline companies are also offering a range of services under competitive and market-based pricing arrangements.

Figure 3 5. Principal buyer/seller transaction paths for natural gas marketing



The level of competition for pipeline services (generally a function of the number of pipelines having access to a customer and the amount of capacity available) drives the prices for interruptible transmission service and is having an effect on firm service prices. Currently, there are significant differences across regions in pipeline capacity utilization.[52] These regional differences are evolving as new pipeline capacity has been and is being constructed to relieve capacity constraints in the Northeast, to expand markets in the Midwest and the Southeast, and to move more gas out of the Middle Atlantic region and other shale-rich areas. As capacity changes take place, prices of services should adjust accordingly to reflect new market conditions. Mechanisms used to make the transmission sector more competitive include the widespread capacity release programs, market-based rates, and the market centers with deregulated upstream pipeline services. The ITS is not designed to model any specific type of program, but to simulate the pricing of market-based transmission services.

[52] Further information can be found on the U.S. Energy Information Administration web page under "Pipeline Capacity and Usage," www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/index.html .

Pipeline Tariff Submodule

The primary purpose of the Pipeline Tariff Submodule (PTS) is to provide volume-dependent curves for computing tariffs for interstate transportation and storage services within the Interstate Transmission Submodule. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a forecast of the associated regulated revenue requirement. An accounting system is used to track costs and compute revenue requirements associated with both reservation and usage fees under a current typical regulated rate design. Other than an assortment of macroeconomic indicators, the primary input to the PTS from other modules/submodules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is projected to occur, the submodule calculates the resulting impact on the revenue requirement. The PTS currently assumes rolled-in (or average), not incremental, rates for new capacity (i.e., the cost of any additional capacity is lumped in with the remaining costs of existing capacity when deriving a single tariff for all the customers along a pipeline segment).

Transportation revenue requirements (and associated tariff curves) are established for interregional arcs defined by the NGTDM network. These network tariff curves reflect an aggregation of the revenue requirements for individual pipeline companies represented by the network arc. Storage tariff curves are defined at regional NGTDM network nodes, and similarly reflect an aggregation of individual company storage revenue requirements. Note that these services are unbundled and do not include the price of gas, except for the cushion gas used to maintain minimum gas pressure. Furthermore, the submodule cannot address competition for pipeline or storage services along an aggregate arc or within an aggregate region, respectively. It should also be noted that the PTS deals only with the interstate market, and thus does not capture the impacts of state-specific regulations for intrastate pipelines. Intrastate transportation charges are accounted for within the Distributor Tariff Submodule.

Pipeline tariffs for transportation and storage services represent a more significant portion of the price of gas to industrial and electric generator end-users than to other sectors. Consumers of natural gas are grouped generally into two categories: (1) those that need firm or guaranteed service because gas is their only fuel option or because they are willing to pay for security of supply, and (2) those that do not need guaranteed service because they can either periodically terminate operations or use fuels other than natural gas. The first group of customers (core customers) is assumed to purchase firm transportation services, while the latter group (non-core customers) is assumed to purchase non-firm service (e.g., interruptible service, released capacity). Pipeline companies guarantee to their core customers that they will provide peak day service up to the maximum capacity specified under their contracts even though these customers may not actually request transport of gas on any given day. In return for this service guarantee, these customers pay monthly reservation fees (or demand charges). These reservation fees are paid in addition to charges for transportation service based on the quantity of gas actually transported (usage fees or commodity charges). The pipeline tariff curves generated by the PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and off-peak seasons. They are also used when setting the price of gas along the NGTDM network and ultimately to the end-users.

The actual rates or tariffs that pipelines are allowed to charge are largely regulated by the Federal Energy Regulatory Commission (FERC). FERC's ratemaking traditionally allows (but does not necessarily guarantee) a pipeline company to recover its costs, including what the regulators consider a fair rate of return on capital. Furthermore, FERC not only has jurisdiction over how cost components are allocated to reservation and usage categories, but also how reservation and usage costs are allocated across the various classes of transmission (or storage) services offered (e.g., firm versus non-firm service). Previous versions of the NGTDM (and therefore the PTS) included representations of natural gas moved (or stored) using firm and non-firm service. However, in an effort to simplify the module, this distinction has been removed in favor of moving from an annual to a seasonal model. The impact of the distinction of firm versus non-firm service on core and non-core delivered prices is indirectly captured in the markup established in the Distributor Tariff Submodule. More recent initiatives by FERC have allowed for more flexible processes for setting rates when a service provider can adequately demonstrate that it does not possess significant market power. The use of volume-dependent tariff curves partially serves to capture the impact of alternate rate-setting mechanisms. Additionally, various rate-making policy options discussed by FERC would allow peak-season rates to rise substantially above the 100-percent load factor rate (also known as the full cost-of-service rate). In capacity-constrained markets, the basis differential between markets connected via the constrained pipeline route will generally be above the full cost of service pipeline rates. The NGTDM's ultimate purpose is to project market prices; it uses cost-of-service rates as a means in the process of establishing market prices.

Distributor Tariff Submodule

The primary purpose of the Distributor Tariff Submodule (DTS) is to determine the price markup from the regional market hub to the end-user. For most customers, this consists of (1) distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end-user and (2) markups charged by intrastate pipeline companies for intrastate transportation services. Intrastate pipeline tariffs are specified exogenously to the model and are currently set to zero (INTRAST_TAR, Appendix E). However, these tariffs are accounted for in the module indirectly. For most industrial and electric generator customers, gas is not purchased through a local distribution company, so they are not specifically charged a distributor tariff. In this case, the "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the price paid by the average industrial or electric generator customer. Distributor tariffs are distinguished within the DTS by sector (residential, commercial, industrial, transportation, and electric generator), region (NGTDM/EMM regions for electric generators and NGTDM regions for the rest), seasons (peak or off-peak), and as appropriate by service type or class (core or non-core).

Distribution markups represent a significant portion of the price of gas to residential, commercial, and transportation customers, and less so to the industrial and electric generation sectors. Each sector has different distribution service requirements, and frequently different transportation needs. For example, the core customers in the model (residential, transportation, commercial and some industrial and electric generator customers) are assumed to require guaranteed on-demand (firm) service because natural gas is largely their only fuel option. In contrast, large portions of the industrial and electric generator sectors may not rely solely on guaranteed service because they can either periodically terminate operations or switch to other fuels. These customers are referred to as non-core. They can elect to receive some gas supplies through a lower-priority (and lower-cost) interruptible transportation service. While not specifically represented in the model, during periods of peak demand, services to these sectors can be interrupted in order to meet the natural gas requirements of core customers. In addition, these customers frequently select to bypass the local distribution company pipelines and hook up directly to interstate or intrastate pipelines.

The rates that local distribution companies and intrastate carriers are allowed to charge are regulated by State authorities. State ratemaking traditionally allows (but does not necessarily guarantee) local distribution companies and intrastate carriers to recover their costs, including what the regulators consider a fair return on capital. These rates are derived from the cost of providing service to the end-use customer. The State authority determines which expenses can be passed through to customers and establishes an allowed rate of return. These measures provide the basis for distinguishing rate differences among customer classes and type of service by allocating costs to these classes and services based on a rate design. The DTS does not project distributor tariffs through a rate base calculation as is done in the PTS, partially due to limits on data availability.[53] In most cases, projected distributor tariffs in the model depend initially on base year values, which are established by subtracting historical city gate prices from historical delivered prices, and generally fall within the range of recent historical values.

Distributor tariffs for all but the electric and transportation sector are set using econometrically estimated equations.[54] Transportation sector markups, representing sales for natural gas vehicles, are set separately for fleet and personal vehicles and account for distribution to delivery stations, retail markups, and federal and state motor fuels taxes. Electric sector markups are initially set at an historical average and adjusted over the forecast in response to changes in consumption by electric generators.

[53] In theory these cost components could be compiled from rate filings to state Public Utility Commissions; however, such an extensive data collection effort is beyond the available resources.

[54] An econometric approach was used largely as a result of data limitations. EIA data surveys do not collect the cost components required to derive revenue requirements and cost-of-service for local distribution companies and intrastate carriers. These cost components can be compiled from rate filings to Public Utility Commissions; however, an extensive data collection effort is beyond the scope of NEMS at this time.

4. Interstate Transmission Submodule Solution Methodology

As a key component of the NGTDM, the Interstate Transmission Submodule (ITS) determines the market equilibrium between supply and demand of natural gas within the North American pipeline system. This translates into finding the price such that the quantity of gas that consumers would desire to purchase equals the quantity that producers would be willing to sell, accounting for the transmission and distribution costs, pipeline fuel use, capacity expansion costs and limitations, and mass balances. To accomplish this, two seasonal periods were represented within the module: a peak and an off-peak period. The network structures within each period consist of an identical system of pipelines, and are connected through common supply sources and storage nodes. Thus, two interconnected networks (peak and off-peak) serve as the framework for processing key inputs and balancing the market to generate the desired outputs. A heuristic approach is used to systematically move through the two networks solving for production levels, network flows, pipeline and storage capacity requirements,[55] supply and citygate prices, and ultimately delivered prices, until mass balance and convergence are achieved. (The methodology used for calculating distributor tariffs is presented in Chapter 5.) Primary input requirements include seasonal consumption levels, capacity expansion cost curves, annual natural gas supply levels and/or curves, a representation of pipeline and storage tariffs, as well as values for pipeline and storage starting capacities, and network flows and prices from the previous year. Some of the inputs are provided by other NEMS modules, some are exogenously defined and provided in input files, and others are generated by the module in previous years or iterations and used as starting values. Spot, [56] import, and delivered prices, supply quantities, and resulting flow patterns are obtained as output from the ITS and sent to other NGTDM submodules or other NEMS modules after some processing. Network characteristics, input requirements, and the heuristic process are presented more fully below.

Network characteristics in the ITS

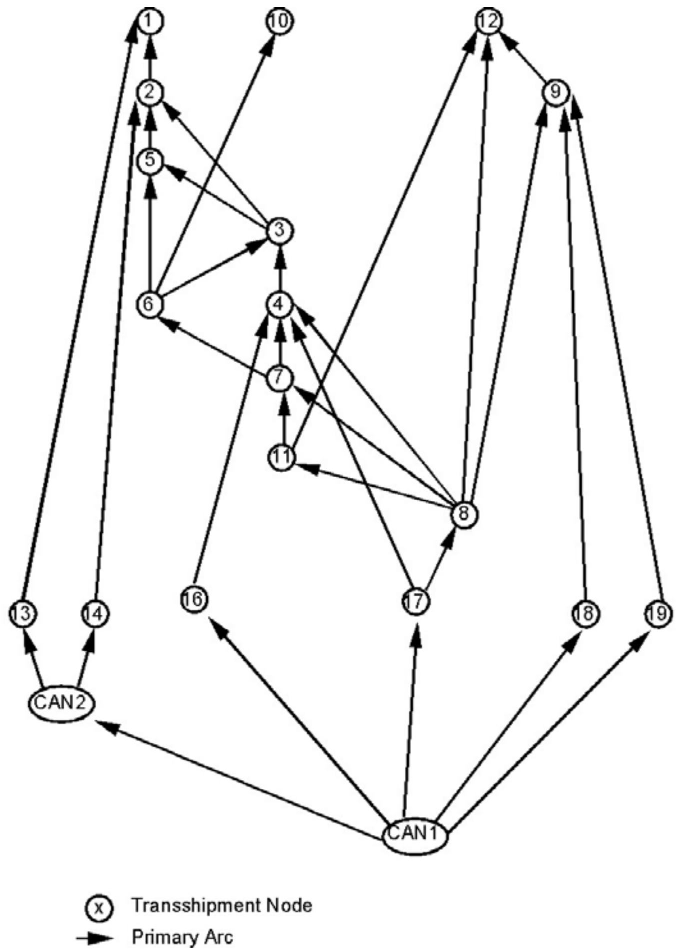
As described in an earlier chapter, the NGTDM network consists of 12 NGTDM regions (or transshipment nodes) in the lower 48 states, three Mexican border crossing nodes, seven Canadian border crossing nodes, and two Canadian supply/demand regions. LNG imports and exports are represented as a supply or demand, respectively, within each coastal region. Interregional arcs connecting the nodes represent an aggregation of pipelines that are capable of moving gas from one region (or transshipment node) into another. These arcs have been classified as either primary flow arcs or secondary flow arcs. The primary flow arcs (see **Figure 3-1**) represent major flow corridors for the transmission of natural gas. Secondary arcs represent either flow in the opposite direction from the primary flow (historically about 3 percent of the total flow) or relatively low flow volumes that are set exogenously or outside the ITS equilibration routine (e.g. Mexican and LNG imports and exports). In the ITS, this North American natural gas pipeline flow network has been restructured into a hierarchical, acyclic network representing just the primary flow of natural gas (**Figure 4-1**). The representation of flows along secondary arcs is described in the Solution Process section below. A hierarchical, acyclic network structure allows for the

[55] OGSM sets wellhead prices equal to the regional spot minus an assumed gather charge .

[56] Backstop supply can be thought of as a high-priced alternative supply when no other options are available. Within the model, it also plays an operational role in sending a price signal when equilibrating the network that additional supplies are unavailable along a particular path in the network.

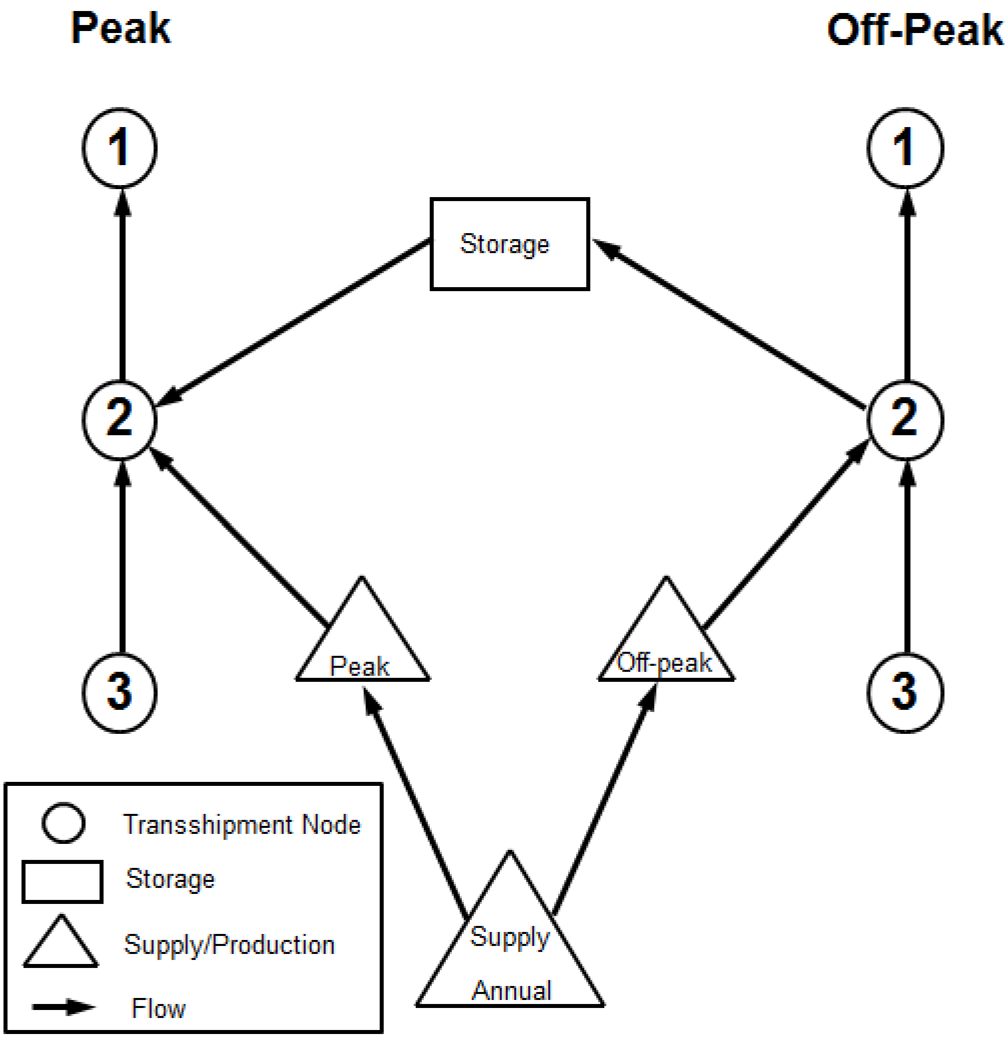
systematic representation of the flow of natural gas (and its associated prices) from the supply sources, represented towards the bottom of the network, up through the network to the end-use consumer at the upper end of the network.

Figure 4-1. Network “tree” of hierarchical, acyclic network of primary arcs



In the ITS, two interconnected acyclic networks are used to represent natural gas flow to end-use markets during the peak period (PK) and flow to end-use markets during the off-peak period (OP). These networks are connected regionally through common supply sources and storage nodes (**Figure 4-2**). Storage within the module only represents the transfer of natural gas produced in the off-peak period to meet the higher demands in the peak period. Therefore, net storage injections are included only in the off-peak period, while net storage withdrawals occur only in the peak period. Within a given forecast year, the withdrawal level from storage in the peak period establishes the level of gas injected in the off-peak period. Annual supply sources provide natural gas to both networks based on the combined network production requirements and corresponding annual supply availability in each region.

Figure 4-2. Simplified example of supply and storage links across networks



Input requirements of the ITS

The following is a list of the key inputs required during ITS processing:

- Seasonal end-use consumption or demand curves for each NGTDM region and Canada
- Seasonal imports (except Canada) and exports by border crossing
- Canadian import capacities by border crossing
- Total natural gas production in eastern Canada and shale/coalbed production in western Canada, by season
- Natural gas flow by pipeline from Alaska to Alberta
- Natural gas flow by pipeline from the Mackenzie Delta to Alberta

- Regional supply curve parameters for U.S. nonassociated and western Canadian tight/other natural gas supply[57]
- Seasonal supply quantities for U.S. associated-dissolved gas, synthetic gas, and other supplemental supplies by NGTDM region
- Seasonal network flow patterns from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Seasonal network prices from the previous year, by arc (including flows from storage, variable supply sources, and pipeline arcs)
- Pipeline capacities, by arc
- Seasonal maximum pipeline utilizations, by arc
- Seasonal pipeline (and storage) tariffs representing variable costs or usage fees, by arc (and region)
- Pipeline capacity expansion/tariff curves for the peak network, by arc
- Storage capacity expansion/tariff curves for the peak network, by region
- Seasonal distributor tariffs by sector and region

Many of the inputs are provided by other NEMS submodules, some are defined from data within the ITS, and others are ITS model results from operation in the previous year. For example, supply curve parameters for lower 48 nonassociated onshore and offshore natural gas production and lower 48 associated-dissolved gas production are provided by the Oil and Gas Supply Module (OGSM). In contrast, Canadian data are set within the NGTDM as direct input to the ITS. U.S. end-use consumption levels are provided by NEMS demand modules; pipeline and storage capacity expansion/tariff curve parameters are provided by the Pipeline Tariff Submodule (PTS, see chapter 6); and seasonal distributor tariffs are defined by the Distributor Tariff Submodule (DTS, see Chapter 5). Seasonal network flow patterns and prices are determined within the ITS. They are initially set based on historical data, and then from model results in the previous model year.

Because the ITS is a seasonal model, most of the input requirements are on a seasonal level. In most cases, however, the information provided is not represented in the form defined above and needs to be processed into the required form. For example, regional end-use consumption levels are initially defined by sector on an annual basis. The ITS disaggregates each of these sector-specific quantities into a seasonal peak and off-peak representation, and then aggregates across sectors within each season to set a total consumption level. Also, regional fixed supplies and some of the import/export levels represent annual values. A simple methodology has been developed to disaggregate the annual information into peak and off-peak quantities using item-specific peak-sharing factors (e.g., PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_SUPLM, PKSHR_ILNG, PKSHR_ELNG, and PKSHR_YR). For more detail on these inputs see Chapter 2. A similar method is used to approximate the consumption and supply in the peak month of each period. This information is used to

[57] These supply sources are referred to as the "variable" supplies because they are allowed to change in response to price changes during the ITS solution process. A few of the "fixed" supplies are adjusted each NEMS iteration, generally in response to price, but are held constant within the ITS solution process.

verify that sufficient sustained[58] capacity is available for the peak day in each period; if not, it is used as a basis for adding additional capacity. The assumption reflected in the model is that, if there is sufficient sustained capacity to handle the peak month, line packing[59] and propane injection can be used to accommodate a peak day in this month.

Heuristic process

The basic process used to determine supply and delivered prices in the ITS involves starting from the top of the hierarchical, acyclic network or "tree" (as shown in **Figure 4-1**) with end-use consumption levels, systematically moving down each network (in the opposite direction from the primary flow of gas) to define seasonal flows along network arcs that will satisfy the consumption, evaluating spot prices for the desired production levels, and then moving up each network (in the direction of the primary flow of gas) to define transmission, node, storage, and delivered prices.

While progressively moving down the peak or off-peak network, net regional demands are assigned for each node on each network. Net regional demands are defined as the sum of consumption in the region plus the gas that is exiting the region to satisfy consumption elsewhere, net of fixed[60] supplies in the region. The consumption categories represented in net regional demands include end-use consumption in the region, exports, pipeline fuel consumption, secondary and primary flows out of the region, and for the off-peak period, net injections into regional storage facilities. Regional fixed supplies include imports (except tight/other gas from western Canada), secondary flows into the region, and the region's associated-dissolved production, supplemental supplies, and other fixed supplies. The net regional demands at a node will be satisfied by the gas flowing along the primary arcs into the node, the local "variable" supply flowing into the node, and for the peak period, the gas withdrawn from the regional storage facilities on a net basis.

Starting with the node(s) at the top of the network tree (i.e., nodes 1, 10, and 12 in **Figure 4-1**), the model uses a sharing algorithm to determine the percentage of the represented region's net demand that is satisfied by each arc going into the node. The resulting shares are used to define flows along each arc (supply, storage, and interregional pipeline) into the region (or node). The interregional flows then become additional consumption requirements (i.e., primary flows out of a region) at the corresponding source node (region). If the arc going into the original node is from a supply or storage[61] source, then the flow represents the production or storage withdrawal level, respectively. The sharing algorithm is systematically applied (going down the network tree) to each regional node until flows have been defined for all arcs along a network, such that consumption in each region is satisfied.

Once flows are established for each network (and pipeline tariffs are set by applying the flow levels to the pipeline tariff curves), resulting production levels for the variable supplies are used to determine regional spot or wellhead prices and, ultimately, storage, node, and delivered prices. By systematically

[58] "Sustained" capacity refers to levels that can operationally be sustained throughout the year, as opposed to "peak" capacity which can be realized at high pressures and would not generally be maintained other than at peak demand periods.
[59] Line packing is a means of storing gas within a pipeline for a short period of time by compressing the gas.
[60] Fixed supplies are those supply sources that are not allowed to vary in response to changes in the natural gas price during the ITS solution process.
[61] For the peak period networks only.

moving up each network tree, regional spot or wellhead prices are used with pipeline tariffs, while adjusting for price impacts from pipeline fuel consumption, to calculate regional node prices for each season. Next, intraregional and intrastate markups are added to the regional/seasonal node prices, followed by the addition of corresponding seasonal, sectoral distributor tariffs, to generate delivered prices. Seasonal prices are then converted to annual delivered prices using quantity-weighted averaging. To speed overall NEMS convergence,[62] the delivered prices can be applied to representative demand curves to approximate the demand response to a change in the price and to generate a new set of consumption levels. This process of going up and down the network tree is repeated until convergence is reached.

The order in which the networks are solved differs depending on whether movement is down or up the network tree. When proceeding down the network trees, the peak network flows are established first, followed by the off-peak network flows. This order has been established for two reasons. First, capacity expansion is decided based on peak flow requirements.[63] This in turn is used to define the upper limits on flows along arcs in the off-peak network. Second, net storage injections (represented as consumption) in the off-peak season cannot be defined until net storage withdrawals (represented as supplies) in the peak season are established. When going up the network trees, prices are determined for the off-peak network first, followed by the peak network. This order has been established mainly because the price of fuel withdrawn from storage in the peak season is based on the cost of fuel injected into storage in the off-peak season plus a storage tariff.

If net demands exceed available supplies on a network in a region, then a backstop supply is made available at a higher price than other local supply. The higher price is passed up the network tree to discourage (or decrease) demands from being met via this supply route. Thus, network flows respond by shifting away from the backstop region until backstop supply is no longer needed.

Movement down and up each network tree (defined as a cycle) continues within a NEMS iteration until the ITS converges. Convergence is achieved when the regional seasonal supply prices determined during the current cycle down the network tree are within a designated minimum percentage tolerance from the supply prices established the previous cycle down the network tree. In addition, the absolute change in production between cycles within supply regions with relatively small production levels are checked in establishing convergence. In addition, the presence of backstop will prevent convergence from being declared. Once convergence is achieved, only one last movement up each network tree is required to define final regional/seasonal node and delivered prices. If convergence is not achieved, then a set of "relaxed" supply prices is determined by weighting regional production results from both the current and the previous cycle down the network tree, and obtaining corresponding new annual and seasonal supply prices from the supply curves in each region based on these "relaxed" production levels. The concept of "relaxation" is a means of speeding convergence by solving for quantities (or prices) in

[62] At various times, NEMS has not readily converged and various approaches have been taken to improve the process. If the NGTDM can anticipate the potential demand response to a price change from one iteration to the next, and accordingly moderate the price change, NEMS will theoretically converge to an equilibrium solution in less iterations.
[63] Pipeline capacity into region 10 (Florida) is allowed to expand in either the peak or off-peak period because the region experiences its peak usage of natural gas in what is generally the off-peak period for consumption in the rest of the country.

the current iteration based on a weighted average of the prices (or quantities) from the previous two iterations, rather than just using the previous iteration's values.[64]

The following subsections describe many of these procedures in greater detail, including: net node demands, pipeline fuel consumption, sharing algorithm, spot/wellhead prices, tariffs, arc, node, and storage prices, backstop, convergence, and delivered and import prices. A simple flow diagram of the overall process is presented in **Figure 4-3**.

Net node demands

Seasonal net demands at a node are defined as total seasonal demands in the region, net of seasonal fixed supplies entering the region. Regional demands consist of primary flows exiting the region (including net storage injections in the off-peak), pipeline fuel consumption, end-use consumption, discrepancies (or historical balancing item), Canadian consumption, exports, and other secondary flows exiting the region. Fixed supplies include associated-dissolved gas, Alaskan gas supplies to Alberta, synthetic natural gas, other supplemental supplies, LNG imports, fixed Canadian supplies (including Mackenzie Delta gas), and other secondary flows entering the region. Seasonal net node demands are represented by the following equations:

Peak:

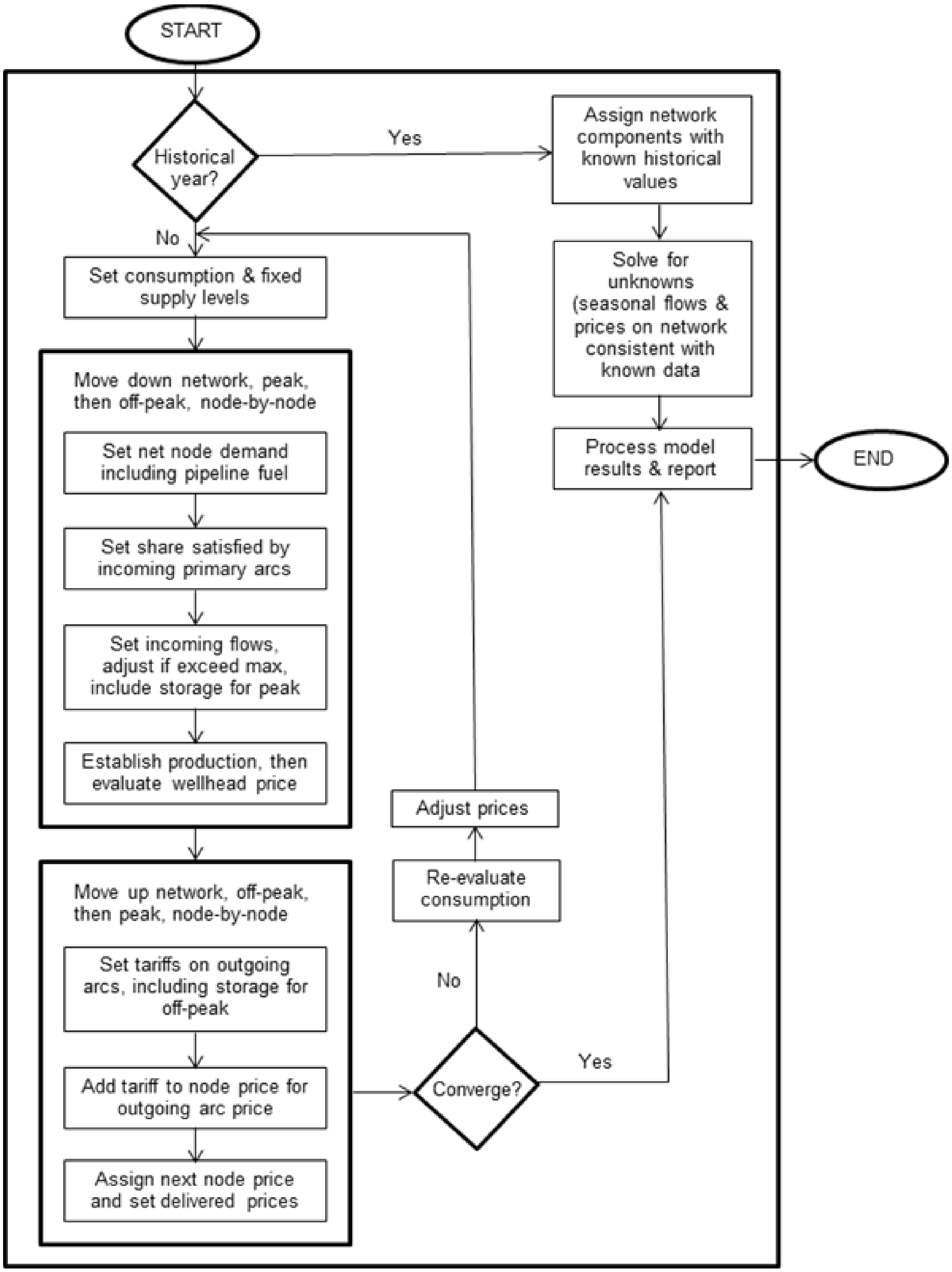
$$\begin{aligned} NODE\_DMD_{PK,r} = {} & PFUEL_{PK,r} + FLOW_{PK,a} + NODE\_CDMD_{PK,r} \\ & \sum_{nonu}(PKSHR\_DMD_{nonu,r} * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ & \sum_{jutil \subset r}(PKSHR\_UDMD_{jutil} * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) \end{aligned} \tag{57}$$

$$\begin{aligned} NODE\_CDMD_{PK,r} = {} & YEAR\_CDMD_{PK,r} - (PKSHR\_PROD_s * ZFIXSUP_s) - \\ & (PKSHR\_ILNG * OGQNGIMP_{L,t}) + (PKSHR\_YR * \\ & (OGQNGEXP_{L,t} - REEXP_{if\, r=7)}) * (1 + PERLIQFUEL)) \end{aligned} \tag{58}$$

$$\begin{aligned} YEAR\_CDMD_{PK,r} = {} & DISCR_{PK,r,t} + CN\_DISCR_{PK,cn} \\ & ((PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & (PK1 * SAFLOW_{a,t}) - (PK2 * SAFLOW_{a',t}) - \\ & (PKSHR\_YR * QAK\_ALB_t) - (PKSHR\_SUPLM * ZTOTSUP_r) - \\ & (PKSHR\_PROD_s * CN\_FIXSUP_{cn,t}) - \\ & (PKSHR\_ILNG * CNLNG\_FLOW) \end{aligned} \tag{59}$$

[64] The model typically solves within 3 to 6 cycles.

Figure 4-3. Interstate Transmission Submodule System



Off-Peak:

$$\begin{aligned} NODE\_DMD_{OP,r} = {} & PFUEL_{OP,r} + FLOW_{OP,a} + FLOW_{PK,st} + NODE\_CDMD_{OP,r} + \\ & \sum_{nonu} ((1 - PKSHR\_DMD_{nonu,r}) * (ZNGQTY\_F_{nonu,r} + ZNGQTY\_I_{nonu,r})) + \\ & \sum_{jutil \in r} ((1 - PKSHR\_UDMD_{jutil}) * (ZNGUQTY\_F_{jutil} + ZNGUQTY\_I_{jutil})) + \end{aligned} \tag{60}$$

$$\begin{aligned} NODE\_CDMD_{OP,r} = {} & YEAR\_CDMD_{OP,r} - ((1 - PKSHR\_PROD_s) * ZFIXSUP_s) - \\ & ((1 - PKSHR\_ILNG) * OGQNGIMP_{L,t}) - \\ & ((1 - PKSHR\_YR * (OGQNGEXP_{L,t} - REEXP_{if\, r=7})) * (1 + PERLIQFUEL)) \end{aligned} \tag{61}$$

$$\begin{aligned} YEAR\_CDMD_{OP,r} = {} & DISCR_{OP,r,t} + CN\_DISCR_{OP,cn} + \\ & ((1 - PKSHR\_CDMD) * CN\_DMD_{cn,r}) + \\ & ((1 - PK1) * SAFLOW_{a,t}) - ((1 - PK2) * SAFLOW_{a',t}) - \\ & ((1 - PKSHR\_YR) * QAK\_ALB_t) - \\ & ((1 - PKSHR\_SUPLM) * ZTOTSUP_r) - \\ & ((1 - PKSHR\_PROD_s) * CN\_FIXSUP_{cn,t}) + \\ & (1 - PKSYR\_ILNG * CNLNG\_FLOW) \end{aligned} \tag{62}$$

where,

$NODE\_DMD_{n,r}$	=	net node demands in region r, for network n (Bcf)
$NODE\_CDMD_{n,r}$	=	net node demands remaining constant each NEMS iteration in region r, for network n (Bcf)
$YEAR\_CDMD_{n,r}$	=	net node demands remaining constant within a forecast year in region r, for network n (Bcf)
$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$FLOW_{n,a}$	=	seasonal flow on network n, along arc a [out of region r] (Bcf)
$ZNGQTY\_F_{nonu,r}$	=	core demands in region r, by non-electric sectors nonu (Bcf)
$ZNGQTY\_I_{nonu,r}$	=	noncore demands in region r, by non-electric sectors nonu(Bcf)
$ZNGUQTY\_F_{jutil}$	=	core utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZNGUQTY\_I_{jutil}$	=	noncore utility demands in NGTDM/EMM subregion jutil [subset of region r] (Bcf)
$ZFIXSUP_s$	=	fixed supply values (i.e., values that do not change during market balance routine, in supply subregion s (Bcf)
$DISCR_{n,r,t}$	=	lower 48 discrepancy in region r, for network n, in forecast year t (Bcf)[65]
$CN\_DISCR_{n,cn}$	=	Canada discrepancy in Canadian region cn, for network n (Bcf)
$CN\_DMD_{cn,t}$	=	Canada demand in Canadian region cn, in forecast year t (Bcf, Appendix E)

[65] Projected lower 48 discrepancies are primarily based on the average historical level from 1999 to 2010. Discrepancies are adjusted in the STEO years to account for STEO discrepancy (Appendix E, STDISCR) and annual net storage withdrawals (Appendix E, NNETWITH) forecasts, and differences between NEMS and STEO total consumption levels Appendix E, STENDCON). These adjustments are phased out over a user-specified number of years (Appendix E, STPHAS_YR).

$SAFLOW_{a,t}$	=	secondary flows out of region r, along arc a [includes Canadian and Mexican exports, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
$SAFLOW_{a',t}$	=	secondary flows into region r, along arc a' [includes Mexican imports, Canadian imports into the East North Central Census Division, Canadian gas that flows through the U.S., and lower 48 bidirectional flows] (Bcf)
QAK_ALB_{t}	=	natural gas flow from Alaska into Alberta via pipeline (Bcf)
$ZTOTSUP_{r}$	=	Total supply from SNG liquids, SNG coal, and other supplemental in forecast year t (Bcf)
$OGQNGIMPL_{,t}$	=	LNG imports from LNG region L, in forecast year t (Bcf)
$CN\_FIXSUP_{cn,t}$	=	fixed supply from Canadian region cn, in forecast year t (Bcf, Appendix E)
$OGQNGEXPL_{,t}$	=	LNG export levels (Bcf)
PERLIQFUEL	=	fraction of fuel to liquefaction facilities used in facility (fraction)
REEXP	=	level of re-exports, all assumed out of the East South Central Census division (Bcf) (REEXP, Appendix E)
PK1, PK2	=	fraction of either in-flow or out-flow volumes corresponding to peak season (composed of PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, or PKSHR_YR)
$PKSHR\_DMD_{nonu,r}$	=	average (2001-2011) fraction of annual consumption in each non-electric sector in region r corresponding to the peak season
$PKSHR\_UDMD_{jutil}$	=	average (1994-2011, except New England 1997-2011) fraction of annual consumption in the electric generator sector in region r corresponding to the peak season
PKSHR_PRODs	=	average (1994-2011) fraction of annual production in supply region s corresponding to the peak season (fraction, Appendix E)
PKSHR_CDMD	=	fraction of annual Canadian demand corresponding to the peak season (fraction, Appendix E)
PKSHR_YR	=	fraction of the year represented by the peak season
PKSHR_SUPLM	=	average (1990-2011) fraction of supplemental supply corresponding to the peak season
PKSHR_ILNG	=	fraction of LNG imports corresponding to the peak season
PKSHR_ECAN	=	fraction of Canadian exports transferred in peak season
PKSHR_ICAN	=	fraction of Canadian imports transferred in peak season
PKSHR_EMEX	=	fraction of Mexican exports transferred in peak season
PKSHR_IMEX	=	fraction of Mexican imports transferred in peak season
r	=	region/node
n	=	network (peak or off-peak)
PK,OP	=	peak and off-peak network, respectively
nonu	=	non-electric sector ID: residential, commercial, industrial, transportation
jutil	=	utility sector subregion ID in region r
a,a’	=	arc ID for arc entering (a’) or exiting (a) in region 4
s	=	supply subregion ID into region r (1-21)
cn	=	Canadian supply subregion ID in region r (1-2)
L	=	LNG import/export region ID into region r (1-12)
st	=	arc ID corresponding to storage supply into region r
t	=	current forecast year

Pipeline fuel use and intraregional flows

Pipeline fuel consumption represents the natural gas consumed by compressors to transmit gas along pipelines within a region. In the ITS, pipeline fuel consumption is modeled as a regional demand component. It is estimated for each region on each network using a historically based factor, corresponding net demands, and a multiplicative scaling factor. The scaling factor is used to calibrate the results to equal the most recent national *Short-Term Energy Outlook (STEO)* forecast[66] for pipeline fuel consumption (Appendix E, STQGPTR), net of pipeline fuel consumption in Alaska (QALK_PIP), and is phased out by a user-specified year (Appendix E, STPHAS_YR). The following equation applies:

$$PFUEL_{n,r} = PFUEL\_FAC_{n,r} * NODE\_DMD_{n,r} * SCALE\_PF \qquad (63)$$

where,

$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$PFUEL\_FAC_{n,r}$	=	average (2006-2011) historical pipeline fuel factor in region r, for network n (calculated historically for each region as equal PFUEL/NODE_DMD)
$NODE\_DMD_{n,r}$	=	net demands (excluding pipeline fuel) in region r, for network n (Bcf)
SCALE_PF	=	STEO benchmark factor for pipeline fuel consumption
n	=	network (peak and off-peak)
r	=	region/node

After pipeline fuel consumption is calculated for each node on the network, the regional/seasonal value is added to net demand at the respective node. Flows into a node ($FLOW_{n,a}$) are then defined using net demands and a sharing algorithm (described below). The regional pipeline fuel quantity (net of intraregional pipeline fuel consumption)[67] is distributed over the pipeline arcs entering the region. This is accomplished by sharing the net pipeline fuel quantity over all of the interregional pipeline arcs entering the region, based on their relative levels of natural gas flow:

$$ARC\_PFUEL_{n,a} = (PFUEL_{n,r} - INTRA\_PFUEL_{n,r}) * \frac{FLOW_{n,a}}{TFLOW} \qquad (64)$$

where,

$ARC\_PFUEL_{n,a}$	=	pipeline fuel consumption along arc a (into region r), for network n (Bcf)
$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$INTRA\_PFUEL_{n,r}$	=	intraregional pipeline fuel consumption in region r, for network n (Bcf)

[66] EIA produces a separate quarterly forecast for primary national energy statistics over the next several years. For certain forecast items, NEMS is calibrated to produce an equivalent (within 2 to 5 percent) result for these years. For *AEO2013*, the years calibrated to *STEO* results were 2012 and 2013.

[67] Currently, intraregional pipeline fuel consumption (INTRA_PFUEL) is set equal to the regional pipeline fuel consumption level (PFUEL); therefore, pipeline fuel consumption along an arc (ARC_PFUEL) is set to zero. The original design was to allocate pipeline fuel according to flow levels on arcs and within a region. It was later determined that assigning all of the pipeline fuel to a region would simplify benchmarking the results to the STEO and would not change the later calculation of the price impacts of pipeline fuel use.

$FLOW_{n,a}$	=	interregional pipeline flow along arc a (into region r), for network n (Bcf)
TFLOW	=	total interregional pipeline flow [into region r] (Bcf)
n	=	network (peak and off-peak)
r	=	region/node
a	=	arc

Pipeline fuel consumption along an interregional arc and within a region on an intrastate pipeline will have an impact on pipeline tariffs and node prices. This will be discussed later in the Arc, Node, and Storage Prices subsection.

The flows of natural gas on the interstate pipeline system within each NGTDM region (as opposed to between two NGTDM regions) are established for the purpose of setting the associated revenue requirements and tariffs. The charge for moving gas within a region (INTRAREG_TAR), but on the interstate pipeline system, is taken into account when setting city gate prices, described below. The algorithm for setting intraregional flows is similar to the method used for setting pipeline fuel consumption. For each region in the historical years, a factor is calculated reflective of the relationship between the net node demand and the intraregional flow. This factor is applied to the net node demand in each forecast year to approximate the associated intraregional flow. Pipeline fuel consumption is excluded from the net node demand for this calculation, as follows:

Calculation of intraregional flow factor based on data for an historical year:

$$FLO\_FAC_{n,r} = INTRA\_FLO_{n,r} \; / \; (NODE\_DMD_{n,r} - PFUEL_{n,r}) \qquad (65)$$

Forecast of intraregional flow:

$$INTRA\_FLO_{n,r} = FLO\_FAC_{n,r} * (NODE\_DMD_{n,r} - PFUEL_{n,r}) \qquad (66)$$

where,

$INTRA\_FLO_{n,a}$	=	intraregional, interstate pipeline flow within region r, for network n (Bcf)
$PFUEL_{n,r}$	=	pipeline fuel consumption in region r, for network n (Bcf)
$NODE\_DMD_{n,r}$	=	net demands (with pipeline fuel) in region r, for network n (Bcf)
$FLO\_FAC_{n,r}$	=	average (1990 - 2011) historical relationship between net node demand and intraregional flow
n	=	network (peak and off-peak)
r	=	region/node

Historical annual intraregional flows are set for the peak and off-peak periods based on the peak and off-peak share of net node demand in each region.

Sharing algorithm, flows, and capacity expansion

Moving systematically downward from node to node through the acyclic network, the sharing algorithm allocates net demands ($NODE\_DMD_{n,r}$) across all arcs feeding into the node. These "inflow" arcs carry flows from local supply sources, storage (net withdrawals during peak period only), or other regions (interregional arcs). If any of the resulting flows exceed their corresponding maximum levels,[68] then the excess flows are reallocated to the unconstrained arcs, and new shares are calculated accordingly. At each node within a network, the sharing algorithm determines the percent of net demand ($SHR_{n,a,t}$) that is satisfied by each of the arcs entering the region.

The sharing algorithm (shown below) dictates that the share ($SHR_{n,a,t}$) of demand for one arc into a node is a function of the share defined in the previous model year[69] and the ratio of the price on the one arc relative to the average of the prices on all of the arcs into the node, as defined the previous cycle up the network tree. These prices ($ARC\_SHRPR_{n,a}$) represent the unit cost associated with an arc going into a node, and are defined as the sum of the unit cost at the source node ($NODE\_SHRPR_{n,r}$) and the tariff charge along the arc ($ARC\_SHRFEE_{n,a}$). (A description of how these components are developed is presented later.) The variable γ is an assumed parameter that is always positive. This parameter can be used to prevent (or control) broad shifts in flow patterns from one forecast year to the next. Larger values of γ increase the sensitivity of $SHR_{n,a,t}$ to relative prices; a very large value of γ would result in behavior equivalent to cost minimization. The algorithm is presented below:

$$SHR_{n,a,t} = \frac{ARC\_SHRPR_{n,a}^{-\gamma}}{\frac{\sum_b ARC\_SHRPR_{n,b}^{-\gamma}}{N}} * SHR_{n,a,t-1} \tag{67}$$

where,

$SHR_{n,a,t}$, $SHR_{n,a,t-1}$	=	the fraction of demand represented along inflow arc a on network n, in year t (or year t-1) [Note: The value for year t-1 has a lower limit set to 0.01]
$ARC\_SHRPR_{n,a \text{ or } b}$	=	the last price calculated for natural gas from inflow arc a (or b) on network n [i.e., from the previous cycle while moving up the network] (1987$/Mcf)
N	=	total number of arcs into a node
γ	=	coefficient defining degree of influence of relative prices (represented as GAMMAFAC, Appendix E)
t	=	forecast year
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node
b	=	set of arcs into a region

[Note: The resulting shares ($SHR_{n,a,t}$) along arcs going into a node are then normalized to ensure that they add to one.]

[68] Maximum flows include potential pipeline or storage capacity additions, and maximum production levels.

[69] When planned pipeline capacity is added at the beginning of a forecast year, the value of SHRt-1 is adjusted to reflect a percent usage (PCTADJSHR, Appendix E) of the new capacity. This adjustment is based on the assumption that last year's share would have been higher if not constrained by the existing capacity levels.

Seasonal flows are generated for each arc using the resulting shares and net node demands, as follows:

$$FLOW_{n,a} = SHR_{n,a,t} * NODE\_DMD_{n,r} \tag{68}$$

where,

$FLOW_{n,a}$	=	interregional flow (into region r) along arc a, for network n (Bcf)
$SHR_{n,a,t}$	=	the fraction of demand represented along inflow arc a on network n, in year t
$NODE\_DMD_{n,r}$	=	net node demands in region r, for network n (Bcf)
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node

These flows must not exceed the maximum flow limits ($MAXFLO_{n,a}$) defined for each arc on each network. The algorithm used to define maximum flows may differ depending on the type of arc (storage, pipeline, supply, Canadian imports) and the network being referenced. For example, maximum flows for all peak network arcs are a function of the maximum permissible annual capacity levels ($MAXPCAP_{PK,a}$) and peak utilization factors. However, maximum *pipeline* flows along the *off-peak* network arcs are a function of the annual capacity defined by peak flows and off-peak utilization factors. Thus, maximum flows along the off-peak network depend on whether or not capacity was added during the peak period. Also, maximum flows from *supply* sources in the off-peak network are limited by maximum annual capacity levels and off-peak utilization. (Note: *storage* arcs do not enter nodes on the off-peak network; therefore, maximum flows are not defined there.) The following equations define maximum flow limits and maximum annual capacity limits:

Maximum peak flows (note: for storage arcs, PKSHR_YR=1):

$$MAXFLO_{PK,a} = MAXPCAP_{PK,a} * (PKSHR\_YR * PKUTZ_a) \tag{69}$$

with $MAXPCAP_{PK}$,a defined by type as follows:

for *Supply*[70] :

$$\begin{aligned} MAXPCAP_{PK,a} = {} & ZOGRESNG_s * ZOGPRRNG_s * MAXPRRFAC * \\ & (1 - (PCTLP_r * SCALE\_LP_t)) \end{aligned} \tag{70}$$

for *Pipeline*:

$$MAXPCAP_{PK,a} = PTMAXPCAP_{i,j} \tag{71}$$

for *Storage*:

$$MAXPCAP_{PK,a} = PTMAXPSTR_{st} \tag{72}$$

[70] In historical years, historical production values are used in place of the product of ZOGRESNG and ZOGPRRNG.

for *Canadian imports*:

$$MAXPCAP_{PK,a} = CURPCAP_{a,t} \tag{73}$$

Maximum off-peak pipeline flows:

$$MAXFLO_{OP,a} = MAXPCAP_{OP,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{74}$$

with $MAXPCAP_{OP,a}$ is defined as follows for

either *current capacity*:

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} \tag{75}$$

or *current* capacity plus *capacity additions*,

$$MAXPCAP_{OP,a} = CURPCAP_{a,t} + ((1 + XBLD) * \left(\frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} - CURPCAP_{a,t}\right)) \tag{76}$$

or, *for pipeline arc entering region 10 (Florida), peak maximum capacity*,

$$MAXPCAP_{OP,a} = MAXPCAP_{PK,a} \tag{77}$$

Maximum off-peak flows from supply sources:

$$MAXFLO_{OP,a} = MAXPCAP_{PK,a} * ((1 - PKSHR\_YR) * OPUTZ_a) \tag{78}$$

where,

$MAXFLO_{n,a}$	=	maximum flow on arc a, in network n [PK-peak or OP-off-peak] (Bcf)
$MAXPCAP_{n,a}$	=	maximum annual physical capacity along arc a for network n (Bcf)
$CURPCAP_{a,t}$	=	current annual physical capacity along arc a in year t (Bcf)
$ZOGRESNG_s$	=	natural gas reserve levels for supply source s [defined by OGSM] (Bcf)
$ZOGPRRNG_s$	=	expected natural gas production-to-reserves ratio for supply source s [defined by OGSM] (fraction)
MAXPRRFAC	=	factor to set maximum production-to-reserves ratio [MAXPRRCAN for Canada] (Appendix E)
$PCTLP_t$	=	average (2008-2011) fraction of production consumed as lease and plant fuel in forecast year t
$SCALE\_LP_t$	=	scale factor for STEO year percent lease and plant consumption for forecast year t to force regional lease and plant consumption forecast to total to STEO forecast.
$PTMAXPCAP_{i,j}$	=	maximum pipeline capacity along arc defined by source node i and destination node j [defined by PTS] (Bcf)
$PTMAXPSTR_{st}$	=	maximum storage capacity for storage source st [defined by PTS] (Bcf)

$FLOWPK_{,a}$	=	flow along arc a for the peak network (Bcf)
PKSHR_YR	=	fraction of the year represented by peak season
$PKUTZ_a$	=	pipeline utilization along arc a for the peak season (fraction, Appendix E)
$OPUTZ_a$	=	pipeline utilization along arc a for the off-peak season (fraction, Appendix E)
XBLD	=	percent increase over capacity builds to account for weather (fraction, Appendix E)
a	=	arc
t	=	forecast year
n	=	network (peak or off-peak)
PK, OP	=	peak and off-peak network, respectively
s,st	=	supply or storage source
i,j	=	regional source (i) and destination (j) link on arc a

If the model has been restricted from building capacity through a specified forecast year (Appendix E, NOBLDYR), then the maximum pipeline and storage flow for either network will be based only on current capacity and utilization for that year.

If the flows defined by the sharing algorithm above exceed these maximum levels, then the excess flow is reallocated along adjacent arcs that have excess capacity. This is achieved by determining the flow distribution of the qualifying adjacent arcs, and distributing the excess flow according to this distribution. These adjacent arcs are checked again for excess flow; if excess flow is found, the reallocation process is performed again on all arcs with space remaining. This applies to supply and pipeline arcs on all networks, as well as storage withdrawal arcs on the peak network. To handle the event where insufficient space or supply is available on all inflowing arcs to meet demand, a backstop supply ($BKSTOP_{n,r}$) is available at an incremental price ($RBKSTOP\_PADJ_{n,r}$). The intent is to dissuade use of the particular route, or to potentially lower demands. Backstop pricing will be defined in another section below.

With the exception of import and export arcs,[71] the resulting interregional flows defined by the sharing algorithm for the peak network are used to determine if *pipeline* capacity expansion should occur. Similarly, the resulting storage withdrawal quantities in the peak season define the *storage* capacity expansion levels. Thus, initially capacity expansion is represented by the difference between new capacity levels ($ACTPCAP_a$) and current capacity ($CURPCAP_{a,t}$, previous model year capacity plus planned additions). In the module, these initial new capacity levels are defined as follows:

Storage:

$$ACTPCAP_a = \frac{FLOW_{PK,a}}{PKUTZ_a} \tag{79}$$

[71] For *AEO2013* capacity expansions on Canadian import arcs were set exogenously (PLANPCAP, Appendix E).

Pipeline:

$$ACTPCAP_a = MAXPCAP_{OP,a} \tag{80}$$

Pipeline arc entering region 10 (Florida):

$$ACTPCAP_a = \text{MAX between } \frac{FLOW_{PK,a}}{PKSHR\_YR * PKUTZ_a} \text{ and } \frac{FLOW_{OP,a}}{(1 - PKSHR\_YR) * OPUTZ_a} \tag{81}$$

where,

$ACTPCAP_a$	=	annual physical capacity along an arc a (Bcf)
$MAXPCAP_{OP,a}$	=	maximum annual physical capacity along pipeline arc a for network n [see equation above] (Bcf)
$FLOW_{n,a}$	=	flow along arc a on network n (Bcf)
$PKUTZ_a$	=	maximum peak utilization of capacity along arc a (fraction, Appendix E)
$OPUTZ_a$	=	maximum off-peak utilization of capacity along arc a (fraction, Appendix E)
PKSHR_YR	=	fraction of the year represented by the peak season
a	=	pipeline and storage arc
n	=	network (peak or off-peak)
PK	=	peak season
OP	=	off-peak season

A second check and potential adjustment are made to these capacity levels to insure that capacity is sufficient to handle estimated flow in the peak month of each period.[72] Since capacity is defined as sustained capacity, it is assumed that the peak month flows should be in accordance with the maximum capacity requirements of the system, short of line packing, propane injections, and planning for the potential of above-average temperature months.[73] Peak month consumption and supply levels are set at an assumed fraction of the corresponding period levels. Based on historical relationships, an initial guess is made at the fraction of each period's net storage withdrawals removed during the peak month. With this information, peak month flows are set at the same time flows are set for each period, while coming down the network tree, and following a similar process. At each node a net monthly demand is set equal to the sum of the monthly flows going out of the node, plus the monthly consumption at the node, minus the monthly supply and net storage withdrawals. The period shares are then used to set initial monthly flows, as follows:

[72] Currently this is only done in the model for the peak period of the year.

[73] To represent that the pipeline system is built to accommodate consumption levels outside the normal range due to colder than normal temperatures, the net monthly demand levels are increased by an assumed percentage (XBLD, Appendix E).

$$MTHFLW_{n,a} = MTH\_NETNOD_{n,r} * \frac{SHR_{n,a,t}}{\sum_{c} SHR_{n,c,t}} \tag{82}$$

where,

$MTHFLW_{n,a}$	=	monthly flow along pipeline arc a (Bcf)
$MTH\_NETNOD_{n,r}$	=	monthly net demand at node r (Bcf)
$SHR_{n,a,t}$	=	fraction of demand represented along inflow arc a
c	=	set of arcs into a region representing pipeline arcs
n	=	network (peak or off-peak)
a	=	arc into a region
r	=	region/node
t	=	forecast year

These monthly flows are then compared against a monthly capacity estimate for each pipeline arc and reallocated to the other available arcs if capacity is exceeded, using a method similar to what is done when flows for a period exceed maximum capacity. These adjusted monthly flows are used later in defining the net node demand for nodes lower in the network tree. Monthly capacity is estimated by starting with the previously set ACTPCAP for the pipeline arc divided by the number of months in the year, to arrive at an initial monthly capacity estimate (MTH_CAP). This number is increased if the total of the monthly capacity entering a node exceeds the monthly net node demand, as follows:

$$MTH\_CAPADD_{n,a} = MTH\_TCAPADD_{n} * \frac{INIT\_CAPADD_{n,a}}{\sum_{c} INIT\_CAPADD_{n,c}} \tag{83}$$

where,

$MTH\_CAPADD_{n,a}$	=	additional added monthly capacity to accommodate monthly flow estimates (Bcf)
$MTH\_TCAPADD_{n}$	=	total initial monthly capacity entering a node minus monthly net node demand (Bcf), if value is negative then it is set to zero
$INIT\_CAPADD_{n,a}$	=	MTHFLWa - MTH_CAPa, if value is negative then it is set to zero (Bcf)
n	=	network (peak or off-peak)
a	=	arc into a region
c	=	set of arcs into a region representing pipeline arcs

The additional added monthly capacity is multiplied by the number of months in the year and added to the originally estimated pipeline capacity levels for each arc (ACTPCAP). Finally, if the net node demand is not close to zero at the lowest node on the network tree (node number 24 in western Canada), then monthly storage levels are adjusted proportionally throughout the network to balance the system for the next time quantities are brought down the network tree.

Wellhead, Spot, and Henry Hub prices

Ultimately, all of the network-specific consumption levels are transferred down the network trees and into supply nodes, where corresponding supply prices are calculated. The Oil and Gas Supply Module

(OGSM) provides only annual price/quantity supply curve parameters for each supply subregion. Because this alone will not provide a price differential between seasons, a special methodology has been developed to approximate seasonal prices that are consistent with the annual supply curve. First, in effect the quantity axis of the annual supply curve is scaled to correspond to seasonal volumes (based on the period's share of the year); and the resulting curves are used to approximate seasonal prices. (Operationally within the model this is done by converting seasonal production values to annual equivalents and applying these volumes to the annual supply curve to arrive at seasonal prices.) Finally, the resulting seasonal prices are scaled to ensure that the quantity-weighted average annual supply price equals the price obtained from the annual supply curve when evaluated using total annual production. To obtain seasonal supply prices, the following methodology is used. Taking one supply region at a time, the model estimates equivalent annual production levels (ANNSUP) for each season.

Peak:

$$\text{ANNSUP} = \frac{\text{NODE\_QSUP}_{\text{PK,s}}}{\text{PKSHR\_YR}} \tag{84}$$

Off-peak:

$$\text{ANNSUP} = \frac{\text{NODE\_QSUP}_{\text{OP,s}}}{(1 - \text{PKSHR\_YR})} \tag{85}$$

where,

ANNSUP	=	equivalent annual production level (Bcf)
$\text{NODE\_QSUP}_{n,s}$	=	seasonal (n=PK or OP) production level for supply region s (Bcf)
PKSHR_YR	=	fraction of year represented by peak season
PK	=	peak season
OP	=	off-peak season
s	=	supply region

Next, estimated seasonal prices (SPSUP_n) are obtained using these equivalent annual production levels and the annual supply curve function. These initial seasonal prices are then averaged, using quantity weights, to generate an equivalent *average* annual supply price (SPAVG*s*). An *actual* annual price (PSUP*s*) is also generated, by evaluating the price on the annual supply function for a quantity equal to the sum of the seasonal production levels. The average annual supply price is then compared to the *actual* price. The corresponding ratio (FSF) is used to adjust the estimated seasonal prices to generate final seasonal supply prices ($\text{NODE\_PSUP}_{n,s}$) for a region.

For a *supply source* s,

$$\text{FSF} = \frac{\text{PSUP}_s}{\text{SPAVG}_s} \tag{86}$$

and,

$$NODE\_PSUP_{n,s} = SPSUP_n * FSF \tag{87}$$

where,

FSF	=	scaling factor for seasonal prices
$PSUP_s$	=	annual supply price from the annual supply curve for supply region s (1987$/Mcf)
$SPAVG_s$	=	quantity-weighted average annual supply price using peak and off-peak prices and production levels for supply region s (1987$/Mcf)
$NODE\_PSUP_{n,s}$	=	adjusted seasonal supply prices for supply region s (1987$/Mcf)
SPSUPn	=	estimated seasonal supply prices for supply region s (1987$/Mcf)
n	=	network (peak or off-peak)
s	=	supply source

Previous to *AEO2013*, the prices seen by producers in the NEMS model were based initially on historical wellhead prices. Going forward, since EIA will no longer be collecting wellhead price data it was necessary to establish another basis for setting the supply price. After reviewing historical values for wellhead and regional spot prices, it was observed that the two series track each other reasonably well on a regional basis, particularly in more recent years, with about a $0.15 (1987$/Mcf) average difference. Therefore regional representative historical spot prices were used in the model instead of wellhead prices to represent the price seen by producers, net of an assumed gathering charge of $0.15 (1987$/Mcf) that is subtracted out within OGSM to set a price seen by producers.

The projected Henry Hub price prior to *AEO2013* was set as a function of the projected lower 48 average wellhead price for report purposes only. Once the regional wellhead prices were established in the model, the Henry Hub was set using an econometrically derived equation as a function of the average lower 48 wellhead price. Over the years two different forms were used: HH = a + (b*L48_avg_wellhead) or lnHH = a + (b*lnL48_avg_wellhead). Historically, the difference in the two price series widens when prices are high, which is also typically when prices spike, hence the reason for using the “b” term. At the time this equation was first implemented EIA published a paper discussing the relationship.[74] While this approach may have provided a better fit to the historical data, in hindsight it equates rising lower 48 wellhead prices with a greater differential between the Henry Hub and the wellhead, which is likely attributable more to price spikes than high prices. As previously formulated, as wellhead prices rise slowly over the forecast period the differential increases and the Henry Hub price rises faster than the average wellhead price.

In order to project a price for the Henry Hub going forward, the representative spot price in the NGTDM/OGSM subregion containing the Henry Hub is used. Historically the representative spot price for the region reflects a quantity-weighted average of spot prices in the region. In the projection the Henry Hub price is set as a function of this regional spot price as follows:

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[74] Energy Information Administration, “U.S. Natural Gas Markets: Relationship between Henery Hub Spot Prices and U.S. Wellhead Prices (www.eia.gov/oiaf/analysispaper/henryhub/index.html).

$$oOGHHPRNG_t = -0.03693 + (1.022 * PSUP_9) / CFNGC_t \quad (88)$$

where,

$oOGHHPRNG_t$	=	natural gas price at the Henry Hub (1987$/MMBtu)
$PSUP_9$	=	spot price in region 9 in current forecast year (1987$/Mcf)
CFNGC	=	factor to convert units from Mcf to MMBtu
9	=	NGTDM/OGSM supply region containing Henry Hub
t	=	forecast year

Details about the generation of this estimated equation and associated parameters are provided in Table F8, Appendix F.

In previous AEOs the national average wellhead prices (lower 48 only) generated by the model for the STEO years were typically benchmarked to the national STEO wellhead price. Since the model is now equilibrating on spot prices, the model is benchmarked to STEO based on how its Henry Hub price matches the STEO's projection for the Henry Hub. During the STEO years (2012 and 2013 for AEO2013) a benchmark factor (SCALE_WPR) is generated that equals STEO's Henry Hub price divided by the NGTDM's projected Henry Hub price. This factor is used to adjust the regional (annual and seasonal) lower 48 spot/wellhead prices to equal STEO results. This benchmark factor is only applied for the STEO years. The benchmark factor is applied as follows:

Annual:

$$PSUP_s = PSUP_s * SCALE\_WPR_t \quad (89)$$

Seasonal:

$$NODE\_PSUP_{n,s} = NODE\_PSUP_{n,s} * SCALE\_WPR_t \quad (90)$$

where,

PSUPs	=	annual supply price from the annual supply curve for supply region s (1987$/Mcf)
$NODE\_PSUP_{n,s}$	=	adjusted seasonal supply prices for supply region s (1987$/Mcf)
$SCALE\_WPR_t$	=	STEO benchmark factor for spot price in year t
n	=	network (peak or off-peak)
s	=	supply source
t	=	forecast year

A similar adjustment is made for the Canadian supply price, with an additional multiplicative factor applied (STSCAL_CAN, Appendix E) which is set to align Canadian import levels with STEO results.

Arc fees (tariffs)

Fees (or tariffs) along arcs are used in conjunction with supply, storage, and node prices to determine competing arc prices that, in turn, are used to determine network flows, transshipment node prices, and delivered prices. Arc fees exist in the form of pipeline tariffs, storage fees, and gathering charges.

Pipeline tariffs are transportation rates along interregional arcs, and reflect the average rate charged over all of the pipelines represented along an arc. Storage fees represent the charges applied for storing, injecting, and withdrawing natural gas that is injected in the off-peak period for use in the peak period, and are applied along arcs connecting the storage sites to the peak network. Gathering charges are applied to the arcs going from the supply points to the transshipment nodes.

Pipeline and storage tariffs consist of both a fixed (volume-independent) term and a variable (volume-dependent) term. For pipelines, the fixed term ($ARC\_FIXTAR_{n,a,t}$) is set in the PTS at the beginning of each forecast year to represent pipeline usage fees and does not vary in response to changes in flow in the current year. For storage, the fixed term establishes a minimum and is set to $0.001 per Mcf. The variable term is obtained from tariff/capacity curves provided by two PTS functions and represents reservation fees for pipelines and all charges for storage. These two functions are NGPIPE_VARTAR and X1NGSTR_VARTAR. When determining network flows a different set of tariffs ($ARC_SHRFEE_{n,a}$) are used than are used when setting delivered prices ($ARC_ENDFEE_{n,a}$).

In the peak period ARC_SHRFEE equals ARC_ENDFEE and the total tariff (reservation plus usage fee). In the off-peak period, ARC_ENDFEE represents the total tariff as well, but ARC_SHRFEE represents the fee that drives the flow decision. In previous AEOs this was set to just the usage fee. The assumption behind this structure was that delivered prices will ultimately reflect reservation charges, but that during the off-peak period in particular, decisions regarding the purchase and transport of gas are made largely independently of where pipeline is reserved and the associated fees. For *AEO2013*, the ARC_SHRFEE was set similarly to ARC_ENDFEE because the usage fees seemed to be underestimating off-peak market prices. (This decision will be reexamined in the future.) During the peak period, the gas is more likely to flow along routes where pipeline is reserved; therefore the flow decision is more greatly influenced by the relative reservation fees.[75] The following arc tariff equations apply:

Pipeline:

$$\begin{aligned} ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \\ ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + NGPIPE\_VARTAR(n,a,i,j,FLOW_{n,a}) \end{aligned} \tag{91}$$

Storage:

$$\begin{aligned} ARC\_SHRFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \\ ARC\_ENDFEE_{n,a} &= ARC\_FIXTAR_{n,a,t} + X1NGSTR\_VARTAR(st,FLOW_{n,a}) \end{aligned} \tag{92}$$

where,

[75] Reservation fees are frequently considered "sunk" costs and are not expected to influence short-term purchasing decisions as much, but still must ultimately be paid by the end-user. Therefore within the ITS, the arc prices used in determining flows can have tariff components defined differently than their counterparts (arc and node prices) ultimately used to establish delivered prices.

$ARC\_SHRFEE_{n,a}$ = total arc fees along arc a for network n [used with sharing algorithm] (1987$/Mcf)
$ARC\_ENDFEE_{n,a}$ = total arc fees along arc a for network n [used with delivered pricing] (1987$/Mcf)
$ARC\_FIXTAR_{n,a,t}$ = fixed (or usage) fees along an arc a for a network n in time t (1987$/Mcf)
NGPIPE_VARTAR = PTS function to define pipeline tariffs representing reservation fees for specified arc at given flow level
X1NGSTR_VARTAR = PTS function to define storage fees at specified storage region for given storage level
$FLOW_{n,a}$ = flow of natural gas on the arc in the given period
n = network (peak or off-peak)
a = arc
i, j = from transshipment node i to transshipment node j

The supply arc indices in the variable $ARC\_FIXTAR_{n,a}$ have been reserved for gathering charges but are currently set to zero, as the supply price is being used as a proxy for a regional spot price. In OGSM for *AEO2013* gathering charges are subtracted from the regional spot prices to arrive an an estimated wellhead price.[76]

Arc, node, and storage prices

Prices at the transshipment nodes (or node prices) represent intermediate prices that are used to determine regional delivered prices. Node prices (along with tariffs) are also used to help make model decisions, primarily within the flow-sharing algorithm. In both cases it is not required (as described above) to set delivered or arc prices using the same price components or methods used to define prices needed to establish flows along the networks (e.g., in setting $ARC\_SHRPR_{n,a}$ in the share equation). Thus, *process-specific* node prices ($NODE\_ENDPR_{n,r}$ and $NODE\_SHRPR_{n,r}$) are generated using *process-specific* arc prices ($ARC\_ENDPR_{n,a}$ and $ARC\_SHRPR_{n,a}$) which, in turn, are generated using *process-specific* arc fees/tariffs ($ARC\_ENDFEE_{n,a}$ and $ARC\_SHRFEE_{n,a}$).

The following equations define the methodology used to calculate arc prices. Arc prices are first defined as the average node price at the source node plus the arc fee (pipeline tariff, storage fee, or gathering charge). Next, the arc prices along pipeline arcs are adjusted to account for the cost of pipeline fuel consumption. These equations are as follows:

$$ARC\_SHRPR_{n,a} = NODE\_SHRPR_{n,rs} + ARC\_SHRFEE_{n,a}$$

$$ARC\_ENDPR_{n,a} = NODE\_ENDPR_{n,rs} + ARC\_ENDFEE_{n,a} \tag{93}$$

with the adjustment accomplished through the assignment statements:

[76] This structure will be modified for *AEO2014* by setting regional hub prices in the NGTDM to reflect spot prices and by assigning a nonzero gathering charge ARC_FIXTAR for the supply arcs.

$$ARC\_SHRPR_{n,a} = \frac{(ARC\_SHRPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

(94)

$$ARC\_ENDPR_{n,a} = \frac{(ARC\_ENDPR_{n,a} * FLOW_{n,a})}{(FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

where,

$ARC\_SHRPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used with sharing algorithm] (1987$/Mcf)
$ARC\_ENDPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (1987$/Mcf)
$NODE\_SHRPR_{n,r}$	=	node price for region i on network n [used with sharing algorithm] (1987$/Mcf)
$NODE\_ENDPR_{n,r}$	=	node price for region i on network n [used with delivered pricing] 1987$/Mcf
$ARC\_SHRFEE_{n,a}$	=	tariff along inflow arc a for network n [used with sharing algorithm] (1987$/Mcf)
$ARC\_ENDFEE_{n,a}$	=	tariff along inflow arc a for network n [used with delivered pricing] (1987$/Mcf)
$ARC\_PFUEL_{n,a}$	=	pipeline fuel consumption along arc a, for network n (Bcf)
$FLOW_{n,a}$	=	network n flow along arc a (Bcf)
n	=	network (peak or off-peak)
a	=	arc
rs	=	region corresponding to source link on arc a

Although each type of node price may be calculated differently (e.g., average prices for delivered price calculation, marginal prices for flow sharing calculation, or some combination of these for each), the current model uses the quantity-weighted averaging approach to establish node prices for both the delivered pricing and flow sharing algorithm pricing. Prices from all arcs entering a node are included in the average. Node prices then are adjusted to account for intraregional pipeline fuel consumption. The following equations apply:

$$NODE\_SHRPR_{n,rd} = \frac{\Sigma_a (ARC\_SHRPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

(95)

$$NODE\_ENDPR_{n,rd} = \frac{\Sigma_a (ARC\_ENDPR_{n,a} * FLOW_{n,a})}{\Sigma_a (FLOW_{n,a} - ARC\_PFUEL_{n,a})}$$

and,

$$NODE\_SHRPR_{n,rd} = \frac{(NODE\_SHRPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})}$$

(96)

$$NODE\_ENDPR_{n,rd} = \frac{(NODE\_ENDPR_{n,rd} * NODE\_DMD_{n,rd})}{(NODE\_DMD_{n,rd} - INTRA\_PFUEL_{n,rd})}$$

where,

$NODE\_SHRPR_{n,r}$	=	node price for region r on network n [used with flow sharing algorithm] (1987$/Mcf)
$NODE\_ENDPR_{n,r}$	=	node price for region r on network n [used with delivered pricing] (1987$/Mcf)
$ARC\_SHRPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used with flow sharing algorithm] (1987$/Mcf)
$ARC\_ENDPR_{n,a}$	=	price calculated for natural gas along inflow arc a for network n [used with delivered pricing] (1987$/Mcf)
$FLOW_{n,a}$	=	network n flow along arc a (Bcf)
$ARC\_PFUEL_{n,a}$	=	pipeline fuel consumed along the pipeline arc a, network n (Bcf)
$INTRA\_PFUEL_{n,r}$	=	intraregional pipeline fuel consumption in region r, network n (Bcf)
$NODE\_DMD_{n,r}$	=	net node demands (w/ pipeline fuel) in region r, network n (Bcf)
n	=	network (peak or off-peak)
a	=	arc
rd	=	region r destination link along arc a

Once node prices are established for the off-peak network, the cost of the gas injected into storage can be modeled. Thus, for every region where storage is available, the storage node price is set equal to the off-peak regional node price. This applies for both the delivered pricing and the flow sharing algorithm pricing:

$$NODE\_SHRPR_{PK,i} = NODE\_SHRPR_{OP,r}$$

(97)

$$NODE\_ENDPR_{PK,i} = NODE\_ENDPR_{OP,r}$$

where,

$NODE\_SHRPR_{PK,i}$	=	price at node i [used with flow sharing algorithm] (1987$/Mcf)
$NODE\_SHRPR_{OP,r}$	=	price at node r in off-peak network [used with flow sharing algorithm] (1987$/Mcf)
$NODE\_ENDPR_{PK,ii}$	=	price at node i [used with delivered pricing] (1987$/Mcf)
$NODE\_ENDPR_{OP,r}$	=	price at node r in off-peak network [used with delivered pricing] (1987$/Mcf)
PK, OP	=	peak and off-peak network, respectively
i	=	node ID for storage
r	=	region ID where storage exists

Backstop price adjustment

Backstop supply[77] is activated when seasonal net demand within a region exceeds total available supply for that region. When backstop occurs, the corresponding *share* node price ($NODE\_SHRPR_{n,r}$) is adjusted upward in an effort to reduce the demand for gas from this source. If this initial price adjustment ($BKSTOP\_PADJ_{n,r}$) is not sufficient to eliminate backstop, on the next cycle down the network tree, an additional adjustment ($RBKSTOP\_PADJ_{n,r}$) is added to the original adjustment, creating a cumulative price adjustment. This process continues until the backstop quantity is reduced to zero, or until the maximum number of ITS cycles has been completed. If backstop is eliminated, then the cumulative price adjustment level is maintained, as long as backstop does not resurface, and until ITS convergence is achieved. Maintaining a backstop adjustment is necessary because complete removal of this high-price signal would cause demand for this source to increase again, and backstop would return. However, if the need for backstop supply recurs following a cycle which did not need backstop supply, then the price adjustment ($BKSTOP\_PADJ_{n,r}$) factor is reduced by one-half and added to the cumulative adjustment variable, with the process continuing as described above. The objective is to eliminate the need for backstop supply at the lowest associated price. The node prices are adjusted as follows:

$$NODE\_SHRPR_{n,r} = NODE\_SHRPR_{n,r} + RBKSTOP\_PADJ_{n,r} \qquad (98)$$

$$RBKSTOP\_PADJ_{n,r} = RBKSTOP\_PADJ_{n,r} + BKSTOP\_PADJ_{n,r} \qquad (99)$$

where,

$NODE\_SHRPR_{n,r}$	=	node price for region r on network n [used with flow sharing algorithm] (1987$/Mcf)
$RBKSTOP\_PADJ_{n,r}$	=	cumulative price adjustment due to backstop (1987$/Mcf)
$BKSTOP\_PADJ_{n,r}$	=	incremental backstop price adjustment (1987$/Mcf)
n	=	network (peak or off-peak)
r	=	region

Currently, this cumulative backstop adjustment ($RBKSTOP\_PADJ_{n,r}$) is maintained for each NEMS iteration and set to zero only on the first NEMS iteration of each model year. Also, it is not used to adjust the NODE_ENDPR because it is an adjustment for making flow allocation decisions, not for pricing gas for the end-user.

ITS convergence

The ITS is considered to have converged when the regional/seasonal spot/wellhead prices are within a defined percentage tolerance (PSUP_DELTA) of the prices set during the last ITS cycle and, for those supply regions with relatively small production levels (QSUP_SMALL), production is within a defined tolerance (QSUP_DELTA) of the production set during the last ITS cycle. If convergence does not occur, then a new spot/wellhead price is determined based on a user-specified weighting of the seasonal production levels determined during the current cycle and during the previous cycle down the network. The new production levels are defined as follows:

[77] Backstop supply can be thought of as a high-priced alternative supply when no other options are available. Within the model, it also plays an operational role in sending a price signal when equilibrating the network that additional supplies are unavailable along a particular path in the network.

$$NODE\_QSUP_{n,s} = (QSUP\_WT * NODE\_QSUP_{n,s}) + ((1 - QSUP\_WT) * NODE\_QSUPPREV_{n,s}) \quad (100)$$

where,

$NODE\_QSUP_{n,s}$ = production level at supply source s on network n for current ITS cycle (Bcf)
$NODE\_QSUPPREV_{n,s}$ = production level at supply source s on network n for previous ITS cycle (Bcf)
QSUP_WT = weighting applied to production level for current ITS cycle (Appendix E)
n = network (peak or off-peak)
s = supply source

Seasonal prices (NODE_PSUPn,s) for these quantities are then determined using the same methodology defined above for obtaining spot/wellhead prices.

End-use sector prices

The NGTDM provides regional end-use or delivered prices for the Electricity Market Module (electric generation sector) and the other NEMS demand modules (non-electric sectors). For the non-electric sectors (residential, commercial, industrial, and transportation), prices are established at the NGTDM region and then averaged (when necessary) using quantity weights to obtain prices at the Census Division level. For the electric generation sector, prices are provided on a seasonal basis and are set for core and noncore services at two different regional levels: the Census Division level and the NGTDM/EMM level (Chapter 2, **Figure 2-3**).

The first step toward generating these delivered prices is to translate regional, seasonal node prices into corresponding city gate prices ($CGPR_{n,r}$). To accomplish this, seasonal intraregional and intrastate tariffs are added to corresponding regional end-use node prices (NODE_ENDPR). This sum is then adjusted using a city gate benchmark factor ($CGBENCH_{n,r}$) which represents the average difference between historical city gate prices and model results for the historical years of the model. These equations are defined below:

$$CGPR_{n,r} = NODE\_ENDPR_{n,r} + INTRAREG\_TAR_{n,r} + INTRAST\_TAR_{r} + CGBENCH_{n,r} \quad (101)$$

such that:

$$CGBENCH_{n,r} = avg(HCG\_BENCH_{n,r,HISYR}) = avg(HCGPR_{n,r,HISYR} - CGPR_{n,r}) \quad (102)$$

where,

$CGPR_{n,r}$ = city gate price in region r on network n in each HISYR (1987$/Mcf)
$NODE\_ENDPR_{n,r}$ = node price for region r on network n (1987$/Mcf)
$INTRAREG\_TAR_{n,r}$ = intraregional tariff for region r on network n (1987$/Mcf)
$INTRAST\_TAR_{r}$ = intrastate tariff in region r (1987$/Mcf)
$CGBENCH_{n,r}$ = city gate benchmark factor for region r on network n (1987$/Mcf)

$HCG\_BENCH_{n,r,HISYR}$ = city gate benchmark factors for region r on network n in historical years HISYR (1987$/Mcf)
$HCGPR_{n,r,HISYR}$ = historical city gate price in region r on network n in historical year HISYR (1987$/Mcf)
n = network (peak and off-peak)
r = region (lower 48 only)
HISYR = historical year, over which average is taken (2004-2011, excluding the outlier year of 2009)
avg = straight average of indicated value over indicated historical years of the model.

The intraregional tariffs are the sum of a usage fee (INTRAREG_FIXTAR), provided by the Pipeline Tariff Submodule, and a reservation fee that is set using the same function NGPIPE_VARTAR that is used in setting interregional tariffs and was described previously. The benchmark factor represents an adjustment to calibrate city gate prices to historical values.

Seasonal distributor tariffs are then added to the city gate prices to get seasonal, sectoral delivered prices by the NGTDM regions for non-electric sectors and by the NGTDM/EMM subregions for the electric generation sector. The prices for residential, commercial, and electric generation sectors (core and noncore) are then adjusted using STEO benchmark factors ($SCALE\_FPR_{sec,t}$, $SCALE\_IPR_{sec,t}$)[78] to calibrate the results to equal the corresponding national STEO delivered prices. Each seasonal sector price is then averaged to get an annual, sectoral delivered price for each representative region. The following equations apply.

Non-electric Sectors (except core transportation):

$$NGPR\_SF_{n,sec,r} = CGPR_{n,r} + DTAR\_SF_{n,sec,r} + SCALE\_FPR_{sec,t}$$

$$NGPR\_SI_{n,sec,r} = CGPR_{n,r} + DTAR\_SI_{n,sec,r} + SCALE\_IPR_{sec,t} \qquad (103)$$

$$NGPR\_F_{sec,r} = NGPR\_SF_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SF_{OP,sec,r} * (1.-PKSHR\_DMD_{sec,r})$$

$$NGPR\_I_{sec,r} = NGPR\_SI_{PK,sec,r} * PKSHR\_DMD_{sec,r} + NGPR\_SI_{OP,sec,r} * (1.-PKSHR\_DMD_{sec,r}) \qquad (104)$$

where,

$NGPR\_SF_{n,sec,r}$ = seasonal (n) core non-electric sector (sec) price in region r (1987$/Mcf)
$NGPR\_SI_{n,sec,r}$ = seasonal (n) noncore non-electric sector (sec) price in region r (1987$/Mcf)
$NGPR\_F_{sec,r}$ = annual core non-electric sector (sec) price in region r (1987$/Mcf)
$NGPR\_I_{sec,r}$ = annual noncore non-electric sector (sec) price in region r (1987$/Mcf)

[78] The STEO scale factors are linearly phased out over a user-specified number of years (Appendix E, STPHAS_YR) after the last STEO year. STEO benchmarking is not done for the transportation sector since the STEO does not include a comparable value.

$CGPR_{n,r}$ = city gate price in region r on network n (1987$/Mcf)
$DTAR\_SF_{n.sec,r}$ = seasonal (n) distributor tariff to core non-electric sector (sec) in region r (1987$/Mcf)
$DTAR\_SI_{n.\ sec,r}$ = seasonal (n) distributor tariff to noncore non-electric sector (sec) in region r (1987$/Mcf)
$PKSHR\_DMD_{sec,r}$ = average (2001-2011) fraction of annual consumption for non-electric sector in peak season for region r
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (1987$/Mcf)
$SCALE\_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (1987$/Mcf)
n = network (peak or off-peak)
sec = non-electric sector
r = region (lower 48 only)

Electric Generation Sector:

$$NGUPR\_SF_{n,j} = CGPR_{n,r} + UDTAR\_SF_{n,j} + SCALE\_FPR_{sec,t}$$

$$NGUPR\_SI_{n,j} = CGPR_{n,r} + UDTAR\_SI_{n,j} + SCALE\_IPR_{sec,t} \tag{105}$$

$$NGUPR\_F_j = NGUPR\_SF_{PK,j} * PKSHR\_UDMD_j + NGUPR\_SF_{OP,j} * (1.- PKSHR\_UDMD_j)$$

$$NGUPR\_I_j = NGUPR\_SI_{PK,j} * PKSHR\_UDMD_j + NGUPR\_SI_{OP,j} * (1.- PKSHR\_UDMD_j) \tag{106}$$

where,

$NGUPR\_SF_{n,j}$ = seasonal (n) core utility sector price in region j (1987$/Mcf)
$NGUPR\_SI_{n,j}$ = seasonal (n) noncore utility sector price in region j (1987$/Mcf)
$NGUPR\_F_j$ = annual core utility sector price in region j (1987$/Mcf)
$NGUPR\_I_j$ = annual noncore utility sector price in region j (1987$/Mcf)
$CGPR_{n,r}$ = city gate price in region r on network n (1987$/Mcf)
$UDTAR\_SF_{n,j}$ = seasonal (n) distributor tariff to core utility sector in region j (1987$/Mcf)
$UDTAR\_SI_{n,j}$ = seasonal (n) distributor tariff to noncore utility sector in region j (1987$/Mcf)
$PKSHR\_UDMD_j$ = average (1994-2011, except for New England 1997-2011) fraction of annual consumption for the electric generator sector in peak season, for region j
$SCALE\_FPR_{sec,t}$ = STEO benchmark factor for core delivered prices for sector sec, in year t (1987$/Mcf)

$SCALE\_IPR_{sec,t}$ = STEO benchmark factor for noncore delivered prices for sector sec, in year t (1987$/Mcf)
n = network (peak PK or off-peak OP)
sec = utility sector (electric generation only)
r = region (lower 48 only)
j = NGTDM/EMM subregion

For *AEO2013*, the natural gas price that was finally sent to the Electricity Market Module for both core and noncore customers was the quantity-weighted average of the core and noncore prices derived from the above equations. This was done to alleviate some difficulties within the Electricity Market Module as selections were being made between different types of natural gas generation equipment.

Core transportation sector:

A somewhat different methodology is used to determine natural gas delivered prices for the core (F) transportation sector. The core transportation sector consists of a personal vehicles component and a fleet vehicles component. Like the other non-electric sectors, seasonal distributor tariffs are added to the regional city gate prices to determine seasonal delivered prices for both components. Annual core prices are then established for each component in a region by averaging the corresponding seasonal prices, as follows:

$$NGPR\_TRPV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRPV\_SF_{n,r} + SCALE\_FPR_{sec,t}$$
$$NGPR\_TRFV\_SF_{n,r} = CGPR_{n,r} + DTAR\_TRFV\_SF_{n,r} + SCALE\_FPR_{sec,t} \qquad (107)$$

$$NGPR\_TRPV\_F_{r} = NGPR\_TRPV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRPV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r})$$
$$NGPR\_TRFV\_F_{r} = NGPR\_TRFV\_SF_{PK,r} * PKSHR\_DMD_{sec,r} + NGPR\_TRFV\_SF_{OP,r} * (1. - PKSHR\_DMD_{sec,r}) \qquad (108)$$

where,

$NGPR\_TRPV\_SF_{n,r}$ = seasonal (n) price of natural gas used by personal vehicles (core) in region r (1987$/Mcf)
$NGPR\_TRFV\_SF_{n,r}$ = seasonal (n) price of natural gas used by fleet vehicles (core) in region r (1987$/Mcf)
$DTAR\_TRPV\_SF_{n,r}$ = seasonal (n) distributor tariff to core transportation (personal vehicles) sector in region r (1987$/Mcf)
$DTAR\_TRFV\_SF_{n,r}$ = seasonal (n) distributor tariff to core transportation (fleet vehicles) sector in region r (1987$/Mcf)
CGPRn,r = city gate price in region r on network n (1987$/Mcf)
$NGPR\_TRPV\_F_{r}$ = annual price of natural gas used by personal vehicles (core) in region r (1987$/Mcf)

$NGPR\_TRFV\_F_{r}$	=	annual price of natural gas used by fleet vehicles (core) in region r (1987$/Mcf)
$PKSHR\_DMD_{sec,r}$	=	fraction of annual consumption for the transportation sector (sec=4) in the peak season for region r (set to PKSHR_YR)
$SCALE\_FPR_{sec,t}$	=	STEO benchmark factor for core delivered prices for sector sec, in year t (set to 0 for transportation sector), (1987$/Mcf)
n	=	network (peak PK or off-peak OP)
sec	=	transportation sector =4
r	=	region (lower 48 only)

Once the personal vehicles price for natural gas is established, the two core component prices are averaged (using quantity weights) to produce an annual core price for each region ($NGPR\_F_{sec=4,r}$). Seasonal core prices are also determined by quantity-weighted averaging of the two seasonal components ($NGPR\_SF_{n,sec=4,r}$).

Regional delivered prices can be used within the ITS cycle to approximate a demand response. The submodule can then be resolved with adjusted consumption levels in an effort to speed NEMS convergence. Finally, once the ITS has converged, regional prices are averaged using quantity weights to compute Census Division prices, which are sent to the corresponding NEMS modules.

Import prices

The price associated with Canadian imports at each of the module's border crossing points is established during the ITS convergence process. Each of these border-crossing points is represented by a node in the network. The import price for a given season and border crossing is therefore equal to the price at the associated node. For reporting purposes, these node prices are averaged using quantity weights to derive an average annual Canadian import price. The prices for imports at the three Mexican border crossings are set to the average spot price in the nearest NGTDM region plus a markup (or markdown) that is based on the difference between similar import and spot prices historically. The structure for setting LNG import prices is similar to setting Mexican import prices, although regional city gate prices are used instead of spot prices. For the facilities for which historical prices are not available (i.e., generic new facilities), an assumption was made about the difference between the regional city gate price and the LNG import price (LNGDIFF, Appendix E).

5. Distributor Tariff Submodule Solution Methodology

This chapter discusses the solution methodology for the Distributor Tariff Submodule (DTS) of the Natural Gas Transmission and Distribution Module (NGTDM). Within each region, the DTS develops seasonal, market-specific distributor tariffs (or city-gate-to-end-use markups) that are applied to projected seasonal city gate prices to derive end-use or delivered prices. Since most industrial and electric generator customers do not purchase their gas through local distribution companies, their "distributor tariff" represents the difference between the average price paid by local distribution companies at the city gate and the average price paid by the industrial or electric generator customer.[79] Distributor tariffs are defined for both core and noncore markets within the industrial and electric generator sectors, while residential, commercial, and transportation sectors have distributor tariffs defined only for the core market, since noncore customer consumption in these sectors is assumed to be insignificant and set to zero. The core transportation sector is composed of two categories of compressed natural gas (CNG) consumers (fleet vehicles and personal vehicles); therefore, separate distributor tariffs are developed for each of these two categories.

For the residential, commercial, industrial, and electric generation sectors, distributor tariffs are based on econometrically estimated equations and are driven in part by sectoral consumption levels.[80] This general approach was taken since data are not reasonably obtainable to develop a detailed cost-based accounting methodology similar to the approach used for interstate pipeline tariffs in the Pipeline Tariff Submodule. Distribution charges for CNG in vehicles are set to the sum of historical tariffs for delivering natural gas to refueling stations, federal and state motor fuels taxes and credits, and estimates of dispensing charges. The specific methodologies used to calculate each sector's distributor tariffs are discussed in the remainder of this chapter.

Residential and commercial sectors

Residential and commercial distributor tariffs are projected using econometrically estimated equations. The primary explanatory variables are floorspace and commercial natural gas consumption per floorspace for the commercial tariff, and number of households and natural gas consumption per household for the residential sector tariff. For the commercial sector, the distributor tariffs are estimated separately for the peak and off-peak periods, whereas the combined equation was used for residential, as follows:

[79] It is not unusual for these "markups" to be negative.

[80] Historical distributor tariffs for a sector in a particular region/season can be estimated by taking the difference between the average sectoral delivered price and the average city gate price in the region/season (Appendix E, HCGPR).

Residential peak and off-peak

$$DTAR\_SF_{s=1,r,n} = e^{PRSREGPK20_{r,n}} * NUMRS_{r,t}^{0.237781} * \left(\frac{BASQTY\_SF_{s=1,r,n} + BASQTY\_SI_{s=1,r,n}}{NUMRS_{r,t}}\right)^{-0.722013} * DTAR\_SFPREV_{s=1,r,n}^{0.275330} * e^{(-0.275330*PRSREGPK20_{r,n})} * NUMRS_{r,t-1}^{-0.275330*0.237781} * \left(\frac{BASQTY\_SFPREV_{s=1,r,n} + BASQTY\_SIPREV_{s=1,r,n}}{NUMRS_{r,t-1}}\right)^{(-0.275330*-0.722013)} \quad (109)$$

Commercial peak

$$DTAR\_SF_{s=2,r,n=2} = e^{PCMREGPK15_{r,n=1}} * FLRSPC12_{r,t}^{0.150704} * \left(\frac{BASQTY\_SF_{s=2,r,n=1} + BASQTY\_SI_{s=2,r,n=1}}{FLRSPC12_{r,t}}\right)^{-0.218276} * DTAR\_SFPREV_{s=2,r,n=1}^{0.277930} * e^{(-0.277930*PCMREGPK15_{r,n=1})} * FLRSPC12_{r,t-1}^{-0.277930*0.150704} * \left(\frac{BASQTY\_SFPREV_{s=2,r,n=1} + BASQTY\_SIPREV_{s=2,r,n=1}}{FLRSPC12_{r,t-1}}\right)^{(-0.277930*-0.218276)} \quad (110)$$

Commercial off-peak

$$DTAR\_SF_{s=2,r,n=2} = e^{PCMREGPK15_{r,n=2}} * FLRSPC12_{r,t}^{0.503207} * \left(\frac{BASQTY\_SF_{s=2,r,n=2} + BASQTY\_SI_{s=2,r,n=2}}{FLRSPC12_{r,t}}\right)^{-0.608792} * DTAR\_SFPREV_{s=2,r,n=2}^{0.176525} * e^{(-0.176525*PCMREGPK15_{r,n=2})} * FLRSPC12_{r,t-1}^{-0.176525*0.503207} * \frac{BASQTY\_SFPREV_{s=2,r,n=2} + BASQTY\_SIPREV_{s=2,r,n=2}}{FLRSPC12_{r,t-1}}^{(-0.176525*-0.608792)} \quad (111)$$

where,

$$NUMRS_{r,t} = oRSGASCUST_{cd,t} * RECS\_ALIGN_r * NUM\_REGSHR_r \quad (112)$$

and,

$$FLRSPC12_{r,t} = (MC\_COMMFLSP_{1,cd,t} - MC\_COMMFLSP_{8,cd,t}) * SHARE_r \quad (113)$$

where,

$DTAR\_SF_{s,r,n}$	=	core distributor tariff in current forecast year for sector s, region r, and network n (1987$/Mcf)
$DTAR\_SFPREV_{s,r,n}$	=	core distributor tariff in previous forecast year (1987$/Mcf). [For first forecast year set at the 2011 historical value.]
$BASQTY\_SF_{s,r,n}$	=	sector (s) level firm gas consumption for region r, and network n (Bcf)
$BASQTY\_SI_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n (Bcf) (assumed at 0 for residential and commercial)
$BASQTY\_SFPREV_{s,r,n}$	=	sector (s) level gas consumption for region r, and network n in previous year (Bcf) (assumed at 0 for residential and commercial)
$BASQTY\_SIPREV_{s,r,n}$	=	sector (s) level nonfirm gas consumption for region r, and network n in previous year (Bcf)
NUMRS	=	number of residential customers in year t
$PRSREGPK20_{r,n}$	=	residential, regional, period specific, constant term (Table F6, Appendix F)
$PCMREGPK15_{r,n}$	=	commercial, regional, peak specific, constant term (Table F7, Appendix F)
$oRSGASCUST_{cd,t-1}$	=	number of residential gas customers by census division in the previous forecast year (from NEMS residential demand module)
$RECS\_ALIGN_{r}$	=	factor to align residential customer count data from EIA's 2005 Residential Consumption Survey (RECS), the data on which oRSGASCUST is based, with similar data from EIA's Natural Gas Annual, the data on which the DTAR_SF estimation is based.
NUM_REGSHR_{r}	=	share of residential customers in NGTDM region r relative to the number in the larger or equal-sized associated Census Division, set to values in last historical year, 2010 (fraction, Appendix E)
FLRSPC12	=	commercial floorspace by NGTDM region (total net of for manufacturing) (billion square feet)
$MC\_COMMFLSP_{1,cd,t}$	=	commercial floorspace by Census Division (total, including manufacturing)
$MC\_COMMFLSP_{8,cd,t}$	=	commercial floorspace by Census Division (manufacturing)
$SHARE_{r}$	=	assumed fraction of the associated census division's commercial floorspace within each of the 12 NGTDM regions based on population data (1.0, 1.0, 1.0, 1.0, 0.66, 1.0, 1.0, 0.59, 0.24, 0.34, 0.41, 0.75)
s	=	sector (=1 for residential, =2 for commercial)
cd	=	census division
r	=	region (12 NGTDM regions)
n	=	network (=1 for peak, =2 for off-peak)
t	=	forecast year (e.g., 2020)

Parameter values and details about the estimation of these equations can be found in Tables F6 and F7 of Appendix F.

Industrial sector

The industrial sector is distinguished by a price and distributor tariff for two market segments representing non-energy-intensive and energy-intensive industries and labeled respectively as core and noncore. An examination by industry of the natural gas price data from the quadrennial Manufacturing Energy Consumption Survey (MECS) revealed that the more energy-intensive industries have historically paid a lower band of prices compared to the less-energy-intensive energies. These historical prices by the four Census Divisions were used as a basis for generating estimates for historical industrial prices for the core and noncore categories for the 12 NGTDM regions in all historical years. For the regions and years available from MECS, econometrically derived equations were developed for core and noncore prices as a function of the average regional supply price and the average industrial price as purchased through local distribution companies. These equations are used to estimate industrial prices for all historical years for both the core and noncore categories, as follows:

$$PIN\_FNG_{r,t} = 0.657744 + (0.398046 * PW\_NRG_{r,t}) + (0.530439 * HPIN_{r,t}) \quad (114)$$

$$PIN\_ING_{r,t} = 0.220117 + (0.602180 * PW\_NRG_{r,t}) + (0.421469 * HPIN_{r,t}) \quad (115)$$

where,

$PIN\_FNG_{r,t}$	=	estimated natural gas historical price to core (non-energy-intensive) industrial consumers in NGTDM region r (1987$/Mcf)
$PIN\_ING_{r,t}$	=	estimated natural gas historical price to noncore (energy-intensive) industrial consumers in NGTDM region r (1987$/Mcf)
$PW\_NRG_{r,t}$	=	average historical supply price (production and import price weighted together) in NGTDM region r (1987$/Mcf)
$HPIN_{r,t}$	=	average NGTDM regional historical price to industrial customers that purchase gas from a local distribution company as published by EIA (1987$/Mcf) (from SPIN, Appendix E)
r	=	NGTDM region
t	=	year

Parameter values and details about the estimation of these two equations can be found in Table F5, Appendix F.

The industrial distributor tariffs are projected for the core and noncore categories using separately derived econometric equations based in part on data derived from the estimated historical prices described above. The equations are specified by NGTDM region and season. The noncore distributor tariffis are estimated as a function of the industrial noncore (i.e., energy-intensive industries) natural gas consumption levels, while the core tariffs are estimated as a function of the noncore distributor tariffs, as follows:

$$\begin{aligned} DTAR\_SI_{n,s,r} = {} & PINREG19I_r + PIN\_REGPK19I_{r,n} + \\ & (-0.000651 * BASQTY\_SI_{n,s,r}) + (0.434485 * DTAR\_SFPREV_{n,s,r}) \\ & - 0.4334485 * [PIN\_REG19I_r + PIN\_REGPK19I_{r,n} + \\ & (-0.000651 * BASQTY\_SIPREV_{n,s,r})] \end{aligned} \quad (116)$$

$$\begin{aligned}DTAR\_SF_{n,s,r} = &PINREG19F_r + PIN\_REGPK19F_{r,n} + \\ &(1.017384 * DTAR\_SI_{n,s,r}) + (0.533751 * DTAR\_SFPREV_{n,s,r}) \\ &- 0.533751 * [PIN\_REG19F_r + PIN\_REGPK19F_{r,n} + \\ &(1.017384 * DTAR\_SIPREV_{n,s,r})]\end{aligned} \tag{117}$$

where,

$DTAR\_SF_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (1987$/Mcf)
$DTAR\_SI_{n,s,r}$	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (1987$/Mcf)
PIN_REG19F_r, PIN_REG19I_r	=	estimated constant terms for core and noncore equations (Table F4, Appendix F)
$PIN\_REGPK19F_{r,n}$, $PIN\_REGPK19I_{r,n}$	=	estimated coefficients for core and noncore equations, set to zero for the off-peak period and for any region where the coefficient is not statistically significant (Table F4, Appendix F)
$DTAR\_SFPREV_{n,s,r}$	=	seasonal distributor tariff for the core industrial sector (s=3) in region r (1987$/Mcf) in the previous forecast year [In the first forecast year set to the value for the last historical year, 2011]
$DTAR\_SIPREV_{n,s,r}$	=	seasonal distributor tariff for the noncore industrial sector (s=3) in region r (1987$/Mcf) in the previous forecast year [In the first forecast year set to the value for the last historical year, 2011]
$BASQTY\_SI_{n,s=3,r}$	=	seasonal noncore natural gas consumption for industrial sector (s=3) in the current forecast year (Bcf)
$BASQTY\_SIPREV_{n,s=3,r}$	=	seasonal noncore natural gas consumption for industrial sector (s=3) in the previous forecast year (Bcf)
s	=	end-use sector index (s=3 for industrial sector)
n	=	network (peak or off-peak)
r	=	NGTDM region

Parameter values and details about the estimation of these two equations can be found in Table F4 and F5, Appendix F.

Electric generation sector

Distributor tariffs for the electric generation sector do not represent a charge imposed by a local distribution company; rather, they represent the difference between the average city gate price in each NGTDM region and the natural gas price paid on average by electric generators in each NGTDM/EMM region, and are often negative. A single markup or tariff (i.e., no distinction between core and noncore) is projected for each season and region using the equation below. The current version of the model (as used for *AEO2013*) assigns this same value to both the core and noncore segments.[81] The equation for the distributor tariffs for electric generators is set as a function of natural gas consumption by the

[81] This distinction was eliminated several years ago because of operational concerns in the Electricity Market Module. In addition, there are some remaining issues concerning the historical data necessary to generate separate price series for the two segments.

electric sector relative to consumption by the other sectors. The greater the electric consumption share, the greater the price difference between the electric sector and the average, as they are anticipated to need to reserve more space on the pipeline system. The specific equation follows:

$$UDTAR\_SF_{n,j} = (UDTAR\_SFPREV_{n,j} + CGPR_{n,r})* \left(\frac{1 + \frac{qelec_{n,j} - qeleclag_{n,j}}{qelec_{n,j}}}{1 + \frac{OTHR_r - OTHRLAG_r}{OTHR_r}} \right)^{0.1} - CGPR_{n,r} \tag{118}$$

where,

$$qelec_{n,j} = (BASUQTY\_SF_{n,j} + BASUQTY\_SI_{n,j}) * 1000 \tag{119}$$

$$qeleclag_{n,j} = (BASUQTY\_SFPREV_{n,j} + BASUQTY\_SIPREV_{n,j}) * 1000 \tag{120}$$

$$UDTAR\_SI_{n,j} = UDTAR\_SF_{n,j} \text{ for all n and j,} \tag{121}$$

where,

$UDTAR\_SF_{n,j}$	=	seasonal core electric generation sector distributor tariff, current forecast year ($/Mcf)
$UDTAR\_SI_{n,j}$	=	seasonal noncore electric generation sector distributor tariff, current forecast year ($/Mcf)
$UDTAR\_SFPREV_{n,j}$	=	seasonal core electric generation sector distributor tariff, previous forecast year ($/Mcf)
$BASUQTY\_SF_{n,j}$	=	core electric generator gas consumption, current forecast year (Bcf)
$BASUQTY\_SI_{n,j}$	=	noncore electric generator gas consumption, current forecast year (Bcf)
$BASUQTY\_SFPREV_{n,j}$	=	core electric generator gas consumption in previous forecast year (Bcf)
$BASUQTY\_SIPREV_{n,j}$	=	noncore electric generator gas consumption in previous forecast year (Bcf)
OTHRr	=	total consumption by other end-use sectors (residential, commercial, industrial, transportation) in associated NGTDM region for given network/season (Bcf)
$OTHRLAG_r$	=	last year's value for OTHRr
$CGPR_{n,r}$	=	city gate price in associated NGTDM region for given network/season ($/Mcf)
n	=	network (peak=1 or off-peak=2)
j	=	NGTDM/EMM region (see chapter 2)
r	=	NGTDM region (see chapter 2)

Transportation sector

Consumers of compressed natural gas (CNG) and liquefied natural gas (LNG) for vehicles have both been classified into two end-use categories within the core transportation sector: fleet vehicles and personal vehicles (i.e., sold at retail). A distributor tariff markup is set for each fuel and for both categories to capture the total markup from city gate to vehicle, that is: 1) the cost of the natural gas delivered to the dispensing station or liquefaction facility above the city gate price; 2) in the case of LNG, the cost of liquefying and transporting the LNG to the dispensing station; 3) the per-unit cost or charge for dispensing the gas; and 4) federal and state motor fuels taxes and credits.

The cost related to moving natural gas from the city gate to a CNG station is based on the historical difference between the price reported for the transportation sector in EIA's *Natural Gas Annual* (which should reflect this delivered price) and the city gate price. For LNG, natural gas delivered to a liquefaction facility (a large-volume customer) is assumed to see the same price as an electric generator in the region. An analysis was performed exogenously to establish separate retail markups (RETAIL_COST and RETAIL_COSTL) for the four categories of natural gas vehicle fuel which encompass the total markup from the point it exits the distribution pipeline until it enters the vehicle, short of taxes. Details about the derivation of the retail markups are provided in the AEO Assumptions document. Finally, appropriate federal and state motor fuels taxes, net of credits, are added into the distributor tariff and held constant in nominal dollars throughout the forecast period.[82] The equations for setting distribution markups for natural gas vehicles follow:

$$\begin{aligned} DTAR\_TRFV\_SF_{n,r} = &\{HDTAR\_SF_{n,s=4,r,EHISYR} \\ &* (1 - TRN\_DECL)^{YR\_DECL}\} + RETAIL\_COST_2 \\ &+ \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{122}$$

$$\begin{aligned} DTAR\_TRPV\_SF_{n,r} = &\{HDTAR\_SF_{n,s=4,r,EHISYR} \\ &* (1 - TRN\_DECL)^{YR\_DECL}\} + RETAIL\_COST_1 \\ &+ \frac{(STAX_r + FTAX)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{123}$$

$$\begin{aligned} DTAR\_TRFV\_SL_{n,r} = &UTARNG_{n,r} + RETAIL\_COSTL_2 \\ &+ \frac{(STAXL_r + FTAXL)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{124}$$

$$\begin{aligned} DTAR\_TRPV\_SL_{n,r} = &UTARNG_{n,r} + RETAIL\_COSTL_1 \\ &+ \frac{(STAXL_r + FTAXL)}{MC\_PCWGDP_t / MC\_PCWGDP_{87}} \end{aligned} \tag{125}$$

where,

$DTAR\_TRFV\_SF_{n,r}$ = CNG distributor tariff for the fleet vehicle transportation sector (1987\$/Mcf)

[82] Motor vehicle fuel taxes are assumed constant in current-year dollars throughout the forecast to reflect current laws. Within the model these taxes are specified in 1987 dollars.

$DTAR\_TRPV\_SF_{n,r}$	=	CNG distributor tariff markup for the personal vehicle transportation sector (1987$/Mcf)
$DTAR\_TRFV\_SL_{n,r}$	=	LNG distributor tariff markup for the fleet vehicle transportation sector (1987$/Mcf)
$DTAR\_TRPV\_SL_{n,r}$	=	LNG distributor tariff markup for the personal vehicle transportation sector (1987$/Mcf)
$HDTAR\_SF_{n,s,r,EHISYR}$	=	historical (2011) distributor tariff for the transportation sector to deliver the CNG to the station[83] (1987$/ Mcf)
$UTARNG_{n,r}$	=	quantity-weighted average distributor tariff markup for electric generators in the region and network
TRN_DECL	=	fleet vehicle distributor decline rate, set to zero for *AEO2013* (fraction, Appendix E)
YR_DECL	=	difference between the current year and the last historical year over which the decline rate is applied
RETAIL_COST	=	assumed additional charge related to providing CNG dispensing service to customers, at a refueling station for personal (index=1) or fleet (index=2) station (1987$/Mcf, Appendix E)
RETAIL_COSTL	=	assumed additional charge related to liquefying and transporting LNG and dispensing it to customers at a refueling station for personal (index=1) or fleet (index=2) vehicles (1987$/Mcf, Appendix E)
$STAX_r$	=	State motor vehicle fuel tax for CNG (current year $/Mcf, Appendix E)
$STAXL_r$	=	State motor vehicle fuel tax for LNG (current year $/Mcf, Appendix E)
FTAX	=	Federal motor vehicle fuel tax minus any federal excise motor fuel credit for CNG (current year $/Mcf, Appendix E)
FTAXL	=	Federal motor vehicle fuel tax minus any federal excise motor fuel credit for CNG (current year $/Mcf, Appendix E)
MC_PCWGDP_t	=	GDP conversion from current year dollars to 1987 dollars [from the NEMS macroeconomic module]
n	=	network (peak or off-peak)
s	=	end-use sector index (s=4 for transportation sector)
r	=	NGTDM region
EHISYR	=	index defining last year that historical data are available
t	=	forecast year

[83] EIA-published, annual, state-level data are used to set regional historical end-use prices for CNG vehicles. Since monthly data are not available for this sector, seasonal differentials for the industrial sector are applied to annual CNG data to approximate seasonal CNG prices.

6. Pipeline Tariff Submodule Solution Methodology

The Pipeline Tariff Submodule (PTS) sets rates charged for storage services and interstate pipeline transportation. The rates developed are based on actual costs for transportation and storage services. These cost-based rates are used as a basis for developing tariff curves for the Interstate Transmission Submodule (ITS). The PTS tariff calculation is divided into two phases: an historical year initialization phase and a forecast year update phase. Each of these two phases includes the following steps: (1) determine the various components, in nominal dollars, of the total cost-of-service; (2) classify these components as fixed and variable costs based on the rate design (for transportation); (3) allocate these fixed and variable costs to rate components (reservation and usage costs) based on the rate design (for transportation); and (4) for transportation, compute rates for services during peak and off-peak time periods; for storage, compute annual regional tariffs. For the historical year phase, the cost of service is developed from historical financial data on 28 major U.S. interstate pipeline companies; while for the forecast year update phase the costs are estimated using a set of econometric equations and an accounting algorithm. The pipeline tariff calculations are described first, followed by the storage tariff calculations, and finally a description of the calculation of the tariffs for moving gas by pipeline from Alaska and from the Mackenzie Delta to Alberta. A general overview of the methodology for deriving rates is presented in the following box. The PTS system diagram is presented in **Figure 6-1**.

The purpose of the historical year initialization phase is to provide an initial set of transportation revenue requirements and tariffs. The last historical year for the PTS is currently 2006, which need not align with the last historical year for the rest of the NGTDM. Ultimately the ITS requires pipeline and storage tariffs; whether they are based on historical or projected financial data is mechanically irrelevant. The historical year information is developed from existing pipeline company transportation data. The historical year initialization process draws heavily on three databases: (1) a pipeline financial database (1990-2006) of 28 major interstate natural gas pipelines developed by Foster Associates,[84] (2) "a competitive profile of natural gas services" database developed by Foster Associates,[85] and (3) a pipeline capacity database developed by the former Office of Oil and Gas, EIA.[86] The first database represents the existing physical U.S. interstate pipeline and storage system, which includes production processing, gathering, transmission, storage, and other. The physical system is at a more disaggregate level than the NGTDM network. This database provides detailed company-level financial, cost, and rate base parameters. It contains information on capital structure, rate base, and revenue requirements by major line item of the cost of service for the historical years of the model. The second Foster database contains detailed data on gross and net plant in service and depreciation, depletion, and amortization

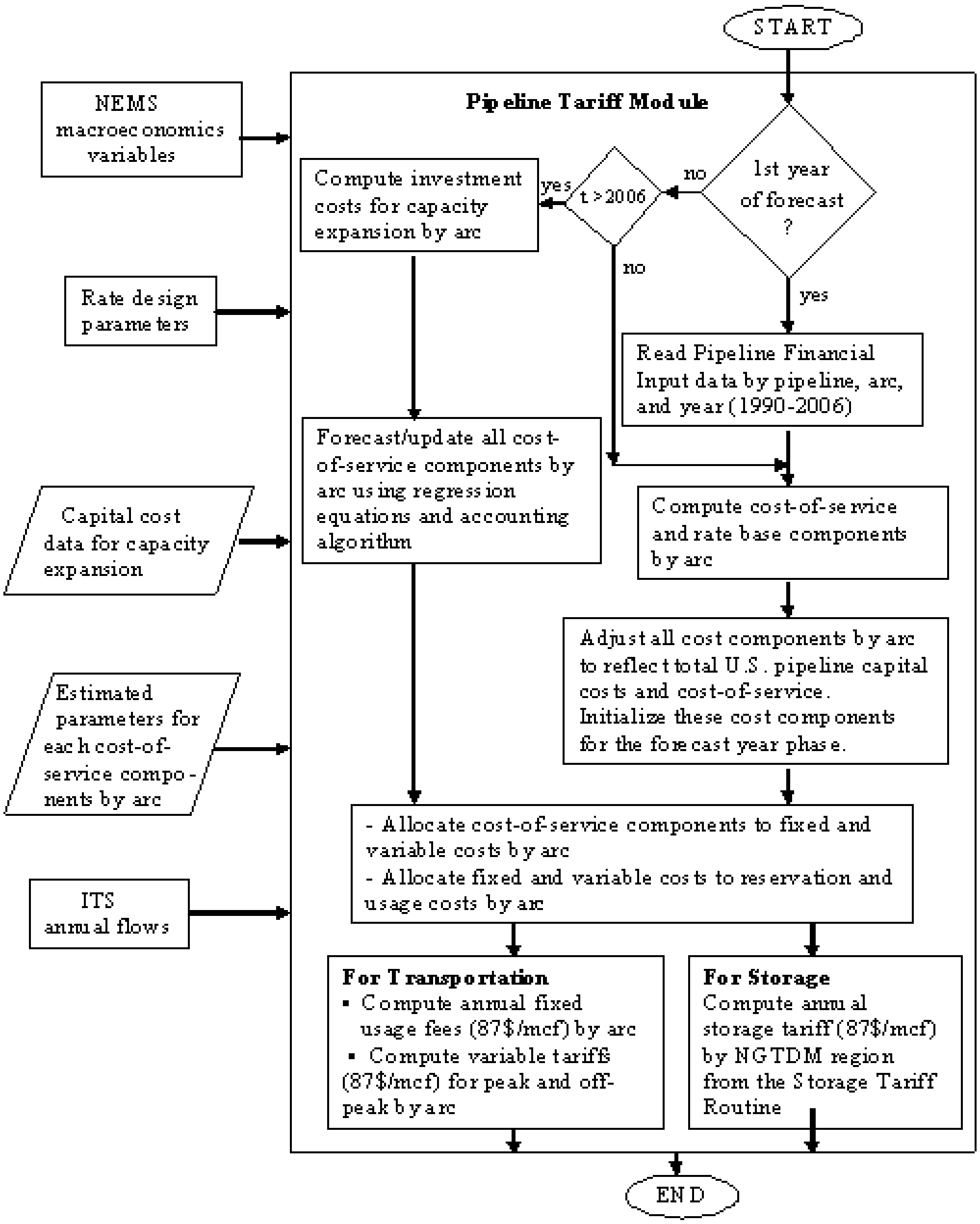
[84] Foster Financial Reports, 28 Major Interstate Natural Gas Pipelines, 2000, 2004 and 2007 Editions, Foster Associates, Inc., Bethesda, Maryland. The primary sources of data for these reports are FERC Form 2 and the monthly FERC Form 11 pipeline company filings. These reports can be purchased from Foster Associates.

[85] Competitive Profile of Natural Gas Services, Individual Pipelines, December 1997, Foster Associates, Inc., Bethesda, Maryland. Volumes III and IV of this report contain detailed information on the major interstate pipelines, including a pipeline system map, capacity, rates, gas plant accounts, rate base, capitalization, cost of service, etc. This report can be purchased from Foster Associates.

[86] A spreadsheet compiled by James Tobin of the Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

for individual plants (production processing and gathering plants, gas storage plants, gas transmission plants, and other plants) and is used to compute sharing factors by pipeline company and year to single out financial cost data for transmission plants from the "total plants" data in the first database.

Figure 6-1. Pipeline tariff submodule system diagram



The third database contains information on pipeline financial construction projects by pipeline company, state-to-state transfer, and year (1996-2011). This database is used to determine factors to allocate the pipeline company financial data to the NGTDM interstate pipeline arcs based on capacity level in each historical year. These three databases are pre-processed offline to generate the pipeline transmission financial data by pipeline company, NGTDM interstate arc, and historical year (1990-2006) used as input into the PTS.

PTS Process for Deriving Rates

For Each Pipeline Arc

- Read historical financial database for 28 major interstate natural gas pipelines by pipeline company, arc, and historical year (1990-2006).
- Derive the total pipeline cost of service (TCOS)
  - Historical years
  - Aggregate pipeline TCOS items to network arcs
    - Adjust TCOS components to reflect all U.S. pipelines based on annual "Pipeline Economics" special reports in the Oil & Gas Journal
  - Forecast years
    - Include capital costs for capacity expansion
    - Estimate TCOS components from forecasting equations and accounting algorithm
- Allocate total cost of service to fixed and variable costs based on rate design
- Allocate costs to rate components (reservation and usage costs) based on rate design
- Compute rates for services for peak and off-peak time periods

For Each Storage Region:

- Derive the total storage cost of service (STCOS)
  - Historical years: read regional financial data for 33 storage facilities by node (NGTDM region) and historical year (1990-1998)
  - Forecast years:
    - Estimate STCOS components from forecasting equations and accounting algorithm
    - Adjust STCOS to reflect total U.S. storage facilities based on annual storage capacity data reported by EIA
- Compute annual regional storage rates for services

Historical year initialization phase

The following section discusses two separate processes that occur during the historical year initialization phase: (1) the computation and initialization of the cost-of-service components, and (2) the computation of rates for services. The computation of historical year cost-of-service components and rates for services involves four distinct procedures as outlined in the above box and discussed below. Rates are calculated in nominal dollars and then converted to real dollars for use in the ITS.

Computation and initialization of pipeline cost-of-service components

In the historical year initialization phase of the PTS, rates are computed using the following process: (Step 1) derivation and initialization of the total cost-of-service components, (Step 2) classification of cost-of-service components as fixed and variable costs, (Step 3) allocation of fixed and variable costs to rate components (reservation and usage costs) based on rate design, and (Step 4) computation of rates at the arc level for transportation services.

Step 1: Derivation and initialization of the total cost-of-service components

The total cost-of-service for existing capacity on an arc consists of a just and reasonable return on the rate base plus total normal operating expenses. Derivations of return on rate base and total normal operating expenses are presented in the following subsections. The total cost of service is computed as follows:

$$TCOS_{a,t} = TRRB_{a,t} + TNOE_{a,t} \tag{126}$$

where,

$TCOS_{a,t}$	=	total cost-of-service (dollars)
$TRRB_{a,t}$	=	total return on rate base (dollars)
$TNOE_{a,t}$	=	total normal operating expenses (dollars)
a	=	arc
t	=	historical year

Just and Reasonable Return. In order to compute the return portion of the cost-of-service at the arc level, the determination of capital structure and adjusted rate base is necessary. Capital structure is important because it determines the cost of capital to the pipeline companies associated with a network arc. The weighted average cost of capital is applied to the rate base to determine the return component of the cost-of-service, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{127}$$

where,

$TRRB_{a,t}$	=	total return on rate base after taxes (dollars)
$WAROR_{a,t}$	=	weighted-average after-tax return on capital (fraction)
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
a	=	arc
t	=	historical year

In addition, the return on rate base $TRRB_{a,t}$ is broken out into the three components as shown below.

$$PFEN_{a,t} = \sum_{p} [(PFES_{a,p,t} / TOTCAP_{a,p,t}) * PFER_{a,p,t} * APRB_{a,p,t}] \tag{128}$$

$$CMEN_{a,t} = \sum_{p} [(CMES_{a,p,t} / TOTCAP_{a,p,t}) * CMER_{a,p,t} * APRB_{a,p,t}] \tag{129}$$

$$LTDN_{a,t} = \sum_{p} [(LTDS_{a,p,t} / TOTCAP_{a,p,t}) * LTDR_{a,p,t} * APRB_{a,p,t}] \tag{130}$$

such that,

$$TRRB_{a,t} = (PFEN_{a,t} + CMEN_{a,t} + LTDN_{a,t}) \tag{131}$$

where,

$PFEN_{a,t}$ = total return on preferred stock (dollars)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$PFER_{a,p,t}$ = coupon rate for preferred stock (fraction) [read as D_PFER]
$APRB_{a,p,t}$ = adjusted pipeline rate base (dollars) [read as D_APRB]
$CMEN_{a,t}$ = total return on common stock equity (dollars)
$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction) [read as D_CMER]
$LTDN_{a,t}$ = total return on long-term debt (dollars)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction) [read as D_LTDR]
p = pipeline company
a = arc
t = historical year

Note that the first terms (fractions) in parentheses on the right-hand side of equations 128 to 130 represent the capital structure ratios for each pipeline company associated with a network arc. These fractions are computed exogenously and read in along with the rates of return and the adjusted rate base. The total returns on preferred stock, common equity, and long-term debt at the arc level are computed immediately after all the input variables are read in. The capital structure ratios are exogenously determined as follows:

$$GPFESTR_{a,p,t} = PFES_{a,p,t} / TOTCAP_{a,p,t} \qquad (132)$$

$$GCMESTR_{a,p,t} = CMES_{a,p,t} / TOTCAP_{a,p,t} \qquad (133)$$

$$GLTDSTR_{a,p,t} = LTDS_{a,p,t} / TOTCAP_{a,p,t} \qquad (134)$$

where,

$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction) [read as D_GPFES]
$GCMESTR_{a,p,t}$ = capital structure ratio for common equity for existing pipeline (fraction) [read as D_GCMES]
$GLTDSTR_{a,p,t}$ = capital structure ratio for long-term debt for existing pipeline (fraction) [read as D_GLTDS] value of long-term debt (dollars)
$TOTCAP_{a,p,t}$ = total capitalization (dollars), equal to the sum of value of preferred stock, common stock equity, and long-term debt
p = pipeline company
a = arc
t = historical year

In the financial database, the estimated capital (capitalization) for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital $TOTCAP_{a,p,t}$ defined in the above equations is equal to the adjusted rate base $APRB_{a,p,t.}$

$$TOTCAP_{a,p,t} = APRB_{a,p,t} \quad (135)$$

where,

$TOTCAP_{a,p,t}$ = total capitalization (dollars)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
a = arc
p = pipeline company
t = historical year

Substituting the adjusted rate base $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 132 to 134, the values of preferred stock, common stock, and long-term debt by pipeline and arc can be computed by applying the capital structure ratios to the adjusted rate base, as follows:

$$\begin{aligned} PFES_{a,p,t} &= GPFESTR_{a,p,t} * APRB_{a,p,t} \\ CMES_{a,p,t} &= GCMESTR_{a,p,t} * APRB_{a,p,t} \\ LTDS_{a,p,t} &= GLTDSTR_{a,p,t} * APRB_{a,p,t} \\ GPFESTR_{a,p,t} &+ GCMESTR_{a,p,t} + GLTDSTR_{a,p,t} = 1.0 \end{aligned} \quad (136)$$

where,

$PFES_{a,p,t}$ = value of preferred stock in nominal dollars
$CMES_{a,p,t}$ = value of common equity in nominal dollars
$LTDS_{a,p,t}$ = long-term debt in nominal dollars
$GPFESTR_{a,p,t}$ = capital structure ratio for preferred stock for existing pipeline (fraction)
$GCMESTR_{a,p,t}$ = capital structure ratio of common stock for existing pipeline (fraction)
$GLTDSTR_{a,p,t}$ = capital structure ratio of long-term debt for existing pipeline (fraction)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = forecast year

The cost of capital at the arc level (WARORa,t) is computed as the weighted average cost of capital for preferred stock, common stock equity, and long-term debt for all pipeline companies associated with that arc, as follows:

$$\begin{aligned} WAROR_{a,t} = \sum_{p} [(&PFES_{a,p,t} * PFER_{a,p,t} + CMES_{a,p,t} * CMER_{a,p,t} + \\ &LTDS_{a,p,t} * LTDR_{a,p,t})] / APRB_{a,t} \end{aligned} \quad (137)$$

$$APRB_{a,t} = PFES_{a,t} + CMES_{a,t} + LTDS_{a,t} \quad (138)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax return on capital (fraction)
$PFES_{a,p,t}$ = value of preferred stock (dollars)
$PFER_{a,p,t}$ = preferred stock rate (fraction)

$CMES_{a,p,t}$ = value of common stock equity (dollars)
$CMER_{a,p,t}$ = common equity rate of return (fraction)
$LTDS_{a,p,t}$ = value of long-term debt (dollars)
$LTDR_{a,p,t}$ = long-term debt rate (fraction)
$APRB_{a,p,t}$ = adjusted rate base (dollars)
p = pipeline
a = arc
t = historical year

The adjusted rate base by pipeline and arc is computed as the sum of net plant in service and total cash working capital (which includes plant held for future use, materials and supplies, and other working capital) minus accumulated deferred income taxes. This rate base is computed offline and read in by the PTS. The computation is as follows:

$$APRB_{a,p,t} = NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t} \tag{139}$$

where,

$APRB_{a,p,t}$ = adjusted rate base (dollars)
$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars) [read as D_NPIS]
$CWC_{a,p,t}$ = total cash working capital (dollars) [read as D_CWC]
$ADIT_{a,p,t}$ = accumulated deferred income taxes (dollars) [read as D_ADIT]
p = pipeline company
a = arc
t = historical year

The net plant in service by pipeline and arc is the original capital cost of plant in service minus the accumulated depreciation. It is computed offline and then read in by the PTS. The computation is as follows:

$$NPIS_{a,p,t} = GPIS_{a,p,t} - ADDA_{a,p,t} \tag{140}$$

where,

$NPIS_{a,p,t}$ = net capital cost of plant in service (dollars)
$GPIS_{a,p,t}$ = original capital cost of plant in service (dollars) [read as D_GPIS]
$ADDA_{a,p,t}$ = accumulated depreciation, depletion, and amortization (dollars) [read as D_ADDA]
p = pipeline company
a = arc
t = historical year

The adjusted rate base at the arc level is computed as follows:

$$\begin{aligned} APRB_{a,,t} &= \sum_p APRB_{a,p,t} = \sum_p (NPIS_{a,p,t} + CWC_{a,p,t} - ADIT_{a,p,t}) \\ &= (NPIS_{a,t} + CWC_{a,t} - ADIT_{a,t}) \end{aligned} \tag{141}$$

with,

$$NPIS_{a,,t} = \sum_{p}(GPIS_{a,p,t} - ADDA_{a,p,t}) \\ = (GPIS_{a,t} - ADDA_{a,t}) \tag{142}$$

where,

$APRB_{a,p,t}$	=	adjusted rate base (dollars) at the arc level
$NPIS_{a,p,t}$	=	net capital cost of plant in service (dollars) at the arc level
$CWC_{a,t}$	=	total cash working capital (dollars) at the arc level
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars) at the arc level
$GPIS_{a,p,t}$	=	original capital cost of plant in service (dollars) at the arc level
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars) at the arc level
p	=	pipeline company
a	=	arc
t	=	historical year

Total Normal Operating Expenses. Total normal operating expense line items include depreciation, taxes, and total operating and maintenance expenses. Total operating and maintenance expenses include administrative and general expenses, customer expenses, and other operating and maintenance expenses. In the PTS, taxes are disaggregated further into federal, state, and other taxes and deferred income taxes. The equation for total normal operating expenses at the arc level is given as follows:

$$TNOE_{a,t} = \sum_{p}(DDA_{a,p,t} + TOTAX_{a,p,t} + TOM_{a,p,t}) \tag{143}$$

where,

$TNOE_{a,t}$	=	total normal operating expenses (dollars)
$DDA_{a,p,t}$	=	depreciation, depletion, and amortization costs (dollars) [read as D_DDA]
$TOTAX_{a,p,t}$	=	total federal and state income tax liability (dollars)
$TOM_{a,p,t}$	=	total operating and maintenance expense (dollars) [read as D_TOM]
p	=	pipeline
a	=	arc
t	=	historical year

Depreciation, depletion, and amortization costs, and total operating and maintenance expense are available directly from the financial database. The equations to compute these costs at the arc level are as follows:

$$DDA_{a,t} = \sum_{p} DDA_{a,p,t} \tag{144}$$

$$TOM_{a,t} = \sum_{p} TOM_{a,p,t} \tag{145}$$

Total taxes at the arc level are computed as the sum of federal and state income taxes, other taxes, and deferred income taxes, as follows:

$$TOTAX_{a,t} = \sum_{p} (FSIT_{a,p,t} + OTTAX_{a,p,t} + DIT_{a,p,t}) \tag{146}$$

$$FSIT_{a,t} = \sum_{p} FSIT_{a,p,t} = \sum_{p} (FIT_{a,p,t} + SIT_{a,p,t}) \tag{147}$$

where,

$TOTAX_{a,t}$	=	total federal and state income tax liability (dollars)
$FSIT_{a,p,t}$	=	federal and state income tax (dollars)
$OTTAX_{a,p,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes and deferred income tax (dollars) [read as D_OTTAX]
$DIT_{a,p,t}$	=	deferred income taxes (dollars) [read as D_DIT]
$FIT_{a,p,t}$	=	federal income tax (dollars)
$SIT_{a,p,t}$	=	state income tax (dollars)
p	=	pipeline company
a	=	arc
t	=	historical year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the federal tax rate. The after-tax profit at the arc level is determined as follows:

$$ATP_{a,t} = \sum_{p} (PFER_{a,p,t} * PFES_{a,p,t} + CMER_{a,p,t} * CMES_{a,p,t}) \tag{148}$$

where,

$ATP_{a,t}$	=	after-tax profit (dollars) at the arc level
$PFER_{a,p,t}$	=	preferred stock rate (fraction)
$PFES_{a,p,t}$	=	value of preferred stock (dollars)
$CMER_{a,p,t}$	=	common equity rate of return (fraction)
$CMES_{a,p,t}$	=	value of common stock equity (dollars)
a	=	arc
t	=	historical year

and the federal income taxes at the arc level are,

$$FIT_{a,t} = \frac{FRATE * ATP_{a,t}}{(1.-FRATE)} \tag{149}$$

where,

$FIT_{a,t}$	=	federal income tax (dollars) at the arc level
FRATE	=	federal income tax rate (fraction) (Appendix E)
$ATP_{a,t}$	=	after-tax profit (dollars)

State income taxes are computed by multiplying the sum of taxable profit and the associated federal income tax by a weighted-average state tax rate associated with each pipeline company. The weighted-average state tax rate is based on peak service volumes in each state delivered by the pipeline company. State income taxes at the arc level are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{150}$$

where,

$SIT_{a,t}$ = state income tax (dollars) at the arc level
$SRATE$ = average state income tax rate (fraction) (Appendix E)
$FIT_{a,t}$ = federal income tax (dollars) at the arc level
$ATP_{a,t}$ = after-tax profits (dollars) at the arc level

Thus, total taxes at the arc level can be expressed by the following equation:

$$TOTAX_{a,t} = (FSIT_{a,t} + OTTAX_{a,t} + DIT_{a,t}) \tag{151}$$

where,

$TOTAX_{a,t}$ = total federal and state income tax liability (dollars) at the arc level
$FSIT_{a,t}$ = federal and state income tax (dollars) at the arc level
$OTTAX_{a,t}$ = all other taxes assessed by federal, state, or local governments except income taxes and deferred income taxes (dollars), at the arc level
$DIT_{a,t}$ = deferred income taxes (dollars) at the arc level
a = arc
t = historical year

All other taxes and deferred income taxes at the arc level are expressed as follows:

$$OTTAX_{a,t} = \sum_{p} OTTAX_{a,p,t} \tag{152}$$

$$DIT_{a,t} = \sum_{p} DIT_{a,p,t} \tag{153}$$

Adjustment from 28 major pipelines to U.S. total. Note that all cost-of-service and rate base components computed so far are based on the financial database of 28 major interstate pipelines. According to the U.S. natural gas pipeline construction and financial reports filed with FERC and published in the Oil and Gas Journal,[87] there were more than 100 interstate natural gas pipelines operating in the United States in 2006. The total annual gross plant in service and operating revenues for all these pipelines are much higher than those for the 28 major interstate pipelines in the financial database. All the cost-of-service and rate base components at the arc level computed in the above sections are scaled up as follows:

[87] *Pipeline Economics*, Oil and Gas Journal, 1994, 1995, 1997, 1999, 2001, 2002, 2003, 2004, 2005, 2006.

For the capital costs and adjusted rate base components,

$$
\begin{aligned}
GPIS_{a,t} &= GPIS_{a,t} * HFAC\_GPIS_t \\
ADDA_{a,t} &= ADDA_{a,t} * HFAC\_GPIS_t \\
NPIS_{a,t} &= NPIS_{a,t} * HFAC\_GPIS_t \\
CWC_{a,t} &= CWC_{a,t} * HFAC\_GPIS_t \\
ADIT_{a,t} &= ADIT_{a,t} * HFAC\_GPIS_t \\
APRB_{a,t} &= APRB_{a,t} * HFAC\_GPIS_t
\end{aligned}
\tag{154}
$$

For the cost-of-service components,

$$
\begin{aligned}
PFEN_{a,t} &= PFEN_{a,t} * HFAC\_REV_t \\
CMEN_{a,t} &= CMEN_{a,t} * HFAC\_REV_t \\
LTDN_{a,t} &= LTDN_{a,t} * HFAC\_REV_t \\
DDA_{a,t} &= DDA_{a,t} * HFAC\_REV_t \\
FSIT_{a,t} &= FSIT_{a,t} * HFAC\_REV_t \\
OTTAX_{a,t} &= OTTAX_{a,t} * HFAC\_REV_t \\
DIT_{a,t} &= DIT_{a,t} * HFAC\_REV_t \\
TOM_{a,t} &= TOM_{a,t} * HFAC\_REV_t
\end{aligned}
\tag{155}
$$

where,

$GPIS_{a,t}$	=	original capital cost of plant in service (dollars)
$HFAC\_GPIS_t$	=	adjustment factor for capital costs to total U.S. (Appendix E)
$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization (dollars)
$NPIS_{a,t}$	=	net capital cost of plant in service (dollars)
$CWC_{a,t}$	=	total cash working capital (dollars)
$ADIT_{a,t}$	=	accumulated deferred income taxes (dollars)
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
$PFEN_{a,t}$	=	total return on preferred stock (dollars)
$HFAC\_REV_t$	=	adjustment factor for operation revenues to total U.S. (Appendix E)
$CMEN_{a,t}$	=	total return on common stock equity (dollars)
$LTDN_{a,t}$	=	total return on long-term debt (dollars)
$DDA_{a,t}$	=	depreciation, depletion, and amortization costs (dollars)
$FSIT_{a,t}$	=	federal and state income tax (dollars)
$OTTAX_{a,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes and deferred income taxes (dollars)
$DIT_{a,t}$	=	deferred income taxes (dollars)
$TOM_{a,t}$	=	total operations and maintenance expense (dollars)
a	=	arc
t	=	historical year

Except for the federal and state income taxes and returns on capital, all the cost-of-service and rate base components computed at the arc level above are also used as initial values in the forecast year update phase that starts in 2007.

Step 2: Classification of cost-of-service line items as fixed and variable costs

The PTS breaks each line item of the cost of service (computed in Step 1) into fixed and variable costs. Fixed costs are independent of storage/transportation usage, while variable costs are a function of usage. Fixed and variable costs are computed by multiplying each line item of the cost of service by the percentage of the cost that is fixed and the percentage of the cost that is variable. The classification of fixed and variable costs is defined by the user as part of the scenario specification. The classification of line item cost Ri to fixed and variable cost is determined as follows:

$$R_{i,f} = ALL_f * R_i / 100 \quad (156)$$

$$R_{i,v} = ALL_v * R_i / 100 \quad (157)$$

where,

$R_{i,f}$	=	fixed cost portion of line item Ri (dollars)
ALL_f	=	percentage of line item Ri representing fixed cost
R_i	=	total cost of line item i (dollars)
$R_{i,v}$	=	variable cost portion of line item Ri (dollars)
ALLv	=	percentage of line item Ri representing variable cost
i	=	line item index
f,v	=	fixed or variable
100	=	ALLf + ALLv

An example of this procedure is illustrated in **Table 6-1**.

Table 6-1. Illustration of fixed and variable cost classification

Cost of Service Line Item	Total (dollars)	Cost Allocation Factors (percent) Fixed	Variable	Cost Component (dollars) Fixed	Variable
Total Return					
Preferred Stock	1,000	100	0	1,000	0
Common Stock	30,000	100	0	30,000	0
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	100	0	25,000	0
State Tax	5,000	100	0	5,000	0
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operation & Maintenance	105,000	60	40	63,000	42,000
Total Cost-of-Service	227,000			185,000	42,000

The resulting fixed and variable costs at the arc level are obtained by summing all line items for each cost category from the above equations, as follows:

$$FC_a = \sum_i R_{i,f} \tag{158}$$

$$VC_a = \sum_i R_{i,v} \tag{159}$$

where,

FC_a	=	total fixed cost (dollars) at the arc level
VC_a	=	total variable cost (dollars) at the arc level
a	=	arc

Step 3: Allocation of fixed and variable costs to rate components

Allocation of fixed and variable costs to rate components is conducted only for transportation services because storage service is modeled in a more simplified manner using a one-part rate. The rate design to be used within the PTS is specified by input parameters, which can be modified by the user to reflect changes in rate design over time. The PTS allocates the fixed and variable costs computed in Step 2 to rate components as specified by the rate design. For transportation service, the components of the rate consist of a reservation and a usage fee. The reservation fee is a charge assessed based on the amount of capacity reserved. It typically is a monthly fee that does not vary with throughput. The usage fee is a charge assessed for each unit of gas that moves through the system.

The actual reservation and usage fees that pipelines are allowed to charge are regulated by the Federal Energy Regulatory Commission (FERC). How costs are allocated determines the extent of differences in the rates charged for different classes of customers for different types of services. In general, if more fixed costs are allocated to usage fees, more costs are recovered based on throughput.

Costs are assigned either to the reservation fee or to the usage fee according to the rate design specified for the pipeline company. The rate design can vary among pipeline companies. Three typical rate designs are described in **Table 6-2**. The PTS provides two options for specifying the rate design. In the first option, a rate design for each pipeline company can be specified for each forecast year. This option permits different rate designs to be used for different pipeline companies while also allowing individual company rate designs to change over time. Since pipeline company data subsequently are aggregated to network arcs, the composite rate design at the arc level is the quantity-weighted average of the pipeline company rate designs. The second option permits a global specification of the rate design, where all pipeline companies have the same rate design for a specific time period but can switch to another rate design in a different time period.

The allocation of fixed costs to reservation and usage fees entails multiplying each fixed cost line item of the total cost of service by the corresponding fixed cost rate design classification factor. A similar process is carried out for variable costs. This procedure is illustrated in **Tables 6-3a and 6-3b** and is generalized in the equations that follow. The classification of transportation line item costs $R_{i,f}$ and $R_{i,v}$ to reservation and usage cost is determined as follows:

Table 6-2. Approaches to rate design

Modified Fixed Variable (Three-Part Rate)	Modified Fixed Variable (Two-Part Rate)	Straight Fixed Variable (Two-Part Rate)
●Two-part reservation fee - Return on equity and related taxes are held at risk to achieving throughput targets by allocating these costs to the usage fee. Of the remaining fixed costs, 50 percent are recovered from a peak day reservation fee and 50 percent are recovered through an annual reservation fee.	●Reservation fee based on peak day requirements - all fixed costs except return on equity and related taxes recovered through this fee.	●One-part capacity reservation fee. All fixed costs are recovered through the reservation fee, which is assessed based on peak day capacity requirements.
●Variable costs allocated to the usage fee. In addition, return on equity and related taxes are also recovered through the usage fee.	●Variable costs plus return on equity and related taxes are recovered through the usage fee.	●Variable costs are recovered through the usage fee.

$$R_{i,f,r} = ALL_{f,r} * R_{i,f} / 100 \tag{160}$$

$$R_{i,f,u} = ALL_{f,u} * R_{i,f} / 100 \tag{161}$$

$$R_{i,v,r} = ALL_{v,r} * R_{i,v} / 100 \tag{162}$$

$$R_{i,v,u} = ALL_{v,u} * R_{i,v} / 100 \tag{163}$$

where,

R = line item cost (dollars)
ALL = percentage of reservation or usage line item R representing fixed or variable cost (Appendix E -- AFR, AVR, AFU=1-AFR, AVU=1-AVR)
100 = $ALL_{f,r} + ALL_{f,u}$
100 = $ALL_{v,r} + ALL_{v,u}$
i = line item number index
f = fixed cost index
v = variable cost index
r = reservation cost index
u = usage cost index

At this stage in the procedure, the line items comprising the fixed and variable cost components of the reservation and usage fees can be summed to obtain total reservation and usage components of the rates.

Table 6-3a. Illustration of allocation of fixed costs to rate components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	1,000	100	0	0	1,000
Common Stock	30,000	100	0	0	30,000
Long-Term Debt	29,000	100	0	29,000	0
Normal Operating Expenses					
Depreciation	30,000	100	0	30,000	0
Taxes					
Federal Tax	25,000	0	100	0	25,000
State Tax	5,000	0	100	0	5,000
Other Tax	1,000	100	0	1,000	0
Deferred Income Taxes	1,000	100	0	1,000	0
Total Operations & Maintenance	63,000	100	0	63,000	0
Total Cost-of-Service	185,000			124,000	61,000

Table 6-3b. Illustration of allocation of variable costs to rate components

Cost of Service Line Item	Total (dollars)	Allocation Factors (percent) Reservation	Usage	Cost Assigned to Rate Component (dollars) Reservation	Usage
Total Return					
Preferred Stock	0	0	100	0	0
Common Stock	0	0	100	0	0
Long-Term Debt	0	0	100	0	0
Normal Operating Expenses					
Depreciation	0	0	100	0	0
Taxes					
Federal Tax	0	0	100	0	0
State Tax	0	0	100	0	0
Other Tax	0	0	100	0	0
Deferred Income Taxes	0	0	100	0	0
Total Operation & Maintenance	42,000	0	100	0	42,000
Total Cost-of-Service	42,000			0	42,000

$$RCOST_a = \sum_i (R_{i,f,r} + R_{i,v,r}) \quad (164)$$

$$UCOST_a = \sum_i (R_{i,f,u} + R_{i,v,u}) \quad (165)$$

where,

$RCOST_a$ = total reservation cost (dollars) at the arc level
$UCOST_a$ = total usage cost (dollars) at the arc level
a = arc

After ratemaking Steps 1, 2 and 3 are completed for each arc by historical year, the rates are computed below.

Computation of rates for historical years

The reservation and usage costs-of-service (RCOST and UCOST) developed above are used separately to develop two types of rates at the arc level: *variable tariffs* and *annual fixed usage fees*.

Variable tariff curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other parameters.

In the PTS code, these variable tariff curves are defined by FUNCTION (NGPIPE_VARTAR) which is used by the ITS to compute the variable peak and off-peak tariffs by arc and by forecast year. The pipeline tariff curves are a function of peak or off-peak flow and are specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \quad (166)$$

such that,

For peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_t)} \quad (167)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \quad (168)$$

For off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_t)} \quad (169)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \quad (170)$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (1987$/Mcf)
$PNOD_{a,t}$	=	base point, price (1987$/Mcf)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf), dependent variable for the function
ALPHA_PIPE	=	price elasticity for pipeline tariff curve for current capacity
$RCOST_{a,t}$	=	reservation cost-of-service (dollars)
$PTNETFLOW_{a,t}$	=	natural gas network flow (throughput, Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

Annual fixed usage fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, utilization rates for peak and off-peak time periods, and annual arc capacity. These fees are computed as the average fees over each historical year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t] \quad (171)$$

where,

$FIXTAR_{a,t}$	=	annual fixed usage fees for existing and new capacity (1987$/Mcf)
$UCOST_{a,t}$	=	annual usage cost of service for existing and new capacity (dollars)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	historical year

Canadian tariffs

In the historical year phase, Canadian tariffs are set to the historical differences between the import prices and the Western Canada Sedimentary Basin (WCSB) wellhead price.

Computation of storage rates

The annual storage tariff for each NGTDM region and year is defined as a function of storage flow and is specified using a base point [price and quantity (PNOD, QNOD)] and an assumed price elasticity, as follows:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (172)$$

such that,

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR \tag{173}$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \tag{174}$$

where,

$X1NGSTR\_VARTAR_{r,t}$	=	function to define storage tariffs (1987$/Mcf)
$Q_{r,t}$	=	peak period net storage withdrawals (Bcf)
$PNOD_{r,t}$	=	base point, price (1987$/Mcf)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
ALPHA_STR	=	price elasticity for storage tariff curve (ratio, Appendix E)
$STCOS_{r,t}$	=	existing storage capacity cost of service, computed from historical cost-of-service components
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio), defined as annual storage working gas capacity divided by Foster storage working gas capacity
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	annual storage working gas capacity (Bcf)
r	=	NGTDM region
t	=	historical year

Forecast year update phase

The purpose of the forecast year update phase is to project, for each arc and subsequent year of the forecast period, the cost-of-service components that are used to develop rates for the peak and off-peak periods. For each year, the PTS forecasts the adjusted rate base, cost of capital, return on rate base, depreciation, taxes, and operation and maintenance expenses. The forecasting relationships are discussed in detail below.

After all of the components of the cost-of-service at the arc level are forecast, the PTS proceeds to: (1) classify the components of the cost of service as fixed and variable costs, (2) allocate fixed and variable costs to rate components (reservation and usage costs) based on the rate design, and (3) compute arc-specific rates (variable and fixed tariffs) for peak and off-peak periods.

Investment costs for generic pipelines

The PTS projects the capital costs to expand pipeline capacity at the arc level, as opposed to determining the costs of expansion for individual pipelines. The PTS represents arc-specific generic pipelines to generate the cost of capacity expansion by arc. Thus, the PTS tracks costs attributable to capacity added during the forecast period separately from the costs attributable to facilities in service in the historical years. The PTS estimates the capital costs associated with the level of capacity expansion forecast by the ITS in the previous forecast year based on exogenously specified estimates for the average pipeline capital costs at the arc level ($AVG\_CAPCOST_a$) associated with expanding capacity for compression, looping, and new pipeline. These average capital costs per unit of expansion (2005 dollars per Mcf) were computed based on a pipeline construction project cost database[88] compiled by the Office of Oil and Gas. These costs are adjusted for inflation from 2007 throughout the forecast period (i.e., they are held constant in real terms).

The average capital cost to expand capacity on a network arc is estimated given the level of capacity additions in year t provided by the ITS and the associated assumed average unit capital cost. This average unit capital cost represents the investment cost for a generic pipeline associated with a given arc, as follows:

$$CCOST_{a,t} = AVG\_CAPCOST_a * MC\_PCWGDP_t / MC\_PCWGDP_{2000} \tag{175}$$

where,

$CCOST_{a,t}$	=	average pipeline capital cost per unit of expanded capacity (nominal dollars per Mcf)
$AVG\_CAPCOST_a$	=	average pipeline capital cost per unit of expanded capacity in 2000 dollars per Mcf (Appendix E, AVGCOST)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived from the above average unit capital cost and the amount of incremental capacity additions determined by the ITS for each arc, as follows:

$$NCAE_{a,t} = CCOST_{a,t} * CAPADD_{a,t} * 1{,}000{,}000 * (1 + PCNT\_R) \tag{176}$$

where,

$NCAE_{a,t}$	=	capital cost to expand capacity on a network arc (dollars)
$CCOST_{a,t}$	=	average capital cost per unit of expansion (dollars per Mcf)
$CAPADDa_{,t}$	=	capacity additions for an arc as determined in the ITS (Bcf/yr)
PCNT_R	=	assumed average percentage (fraction) for pipeline replacement costs (Appendix E)
t	=	forecast year

To account for additional costs due to pipeline replacements, the PTS increases the capital costs to expand capacity by a small percentage (PCNT_R). Once the capital cost of new plant in service is

[88] A spreadsheet compiled by James Tobin of EIA's Office of Oil and Gas containing historical and proposed state-to-state pipeline construction project costs, mileage, and capacity levels and additions by year from 1996 to 2011, by pipeline company (data as of August 16, 2007).

computed by arc in year t, this amount is used in an accounting algorithm for the computation of gross plant in service for new capacity expansion, along with its depreciation, depletion, and amortization. These will in turn be used in the computation of updated cost-of-service components for the existing and new capacity for an arc.

Forecasting cost-of-service[89]

The primary purpose in forecasting cost-of-service is to capture major changes in the composition of the revenue requirements and major changes in cost trends through the forecast period. These changes may be caused by capacity expansion or maintenance and life extension of nearly depreciated plants, as well as by changes in the cost and availability of capital.

The projection of the cost-of-service is approached from the viewpoint of a long-run marginal cost analysis for gas pipeline systems. This differs from the determination of cost-of-service for the purpose of a rate case. Costs that are viewed as fixed for the purposes of a rate case actually vary in the long-run with one or more external measures of size or activity levels in the industry. For example, capital investments for replacement and refurbishment of existing facilities are a long-run marginal cost of the pipeline system. Once in place, however, the capital investments are viewed as fixed costs for the purposes of rate cases. The same is true of operations and maintenance expenses that, except for short-run variable costs such as fuel, are most commonly classified as fixed costs in rate cases. For example, customer expenses logically vary over time based on the number of customers served and the cost of serving each customer. The unit cost of serving each customer, itself, depends on changes in the rate base and individual cost-of-service components, the extent and/or complexity of service provided to each customer, and the efficiency of the technology level employed in providing the service.

The long-run marginal cost approach generally projects total costs as the product of unit cost for the activity multiplied by the incidence of the activity. Unit costs are projected from cost-of-service components combined with time trends describing changes in level of service, complexity, or technology. The level of activity is projected in terms of variables external to the PTS (e.g., annual throughput) that are both logically and empirically related to the incurrence of costs. Implementation of the long-run marginal cost approach involves forecasting relationships developed through empirical studies of historical change in pipeline costs, accounting algorithms, exogenous assumptions, and inputs from other NEMS modules. These forecasting algorithms may be classified into three distinct areas, as follows:

- The projection of adjusted rate base and cost of capital for the combined existing and new capacity.
- The projection of components of the revenue requirements.
- The computation of variable and fixed rates for peak and off-peak periods.

The empirically derived forecasting algorithms discussed below are determined for each network arc.

[89] All cost components in the forecast equations in this section are in nominal dollars, unless explicitly stated otherwise.

Projection of adjusted rate base and cost of capital

The approach for projecting adjusted rate base and cost of capital at the arc level is summarized in **Table 6-4**. Long-run marginal capital costs of pipeline companies reflect changes in the AA utility bond index rate. Once projected, the adjusted rate base is translated into capital-related components of the revenue requirements based on projections of the cost of capital, total operating and maintenance expenses, and algorithms for depreciation and tax effects.

The projected adjusted rate base for the combined existing and new pipelines at the arc level in year t is computed as the amount of gross plant in service in year t minus previous year's accumulated depreciation, depletion, and amortization plus total cash working capital minus accumulated deferred income taxes in year t.

Table 6-4. Approach to projection of rate base and capital costs

Projection Component	Approach
1. Adjusted Rate Base	
a. Gross plant in service in year t	
I. Capital cost of existing plant in service	Gross plant in service in the last historical year (2006)
II. Capacity expansion costs for new capacity	Accounting algorithm [equation 179]
b. Accumulated Depreciation, Depletion & Amortization	Accounting algorithm [equations 185, 186, 188] and empirically estimated for existing capacity [equation 187]
c. Cash and other working capital	User-defined option for the combined existing and new capacity [equation 189]
d. Accumulated deferred income taxes	Empirically estimated for the combined existing and new capacity [equation 140]
f. Depreciation, depletion, and amortization	Existing Capacity: empirically estimated [equation 187] New Capacity: accounting algorithm [equation 188]
2. Cost of Capital	
a. Long-term debt rate	Projected AA utility bond yields adjusted by historical average deviation constant for long-term debt rate
b. Preferred equity rate	Projected AA utility bond yields adjusted by historical average deviation constant for preferred equity rate
c. Common equity return	Projected AA utility bond yields adjusted by historical average deviation constant for common equity return
3. Capital Structure	Held constant at average historical values

$$APRB_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} + CWC_{a,t} - ADIT_{a,t} \qquad (177)$$

where,

$APRB_{a,t}$ = adjusted rate base in dollars
$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
ADDAa,t = accumulated depreciation, depletion, and amortization in dollars
CWCa,t = total cash working capital including other cash working capital in dollars
ADITa,t = accumulated deferred income taxes in dollars

a = arc
t = forecast year

All the variables in the above equation represent the aggregate variables for all interstate pipelines associated with an arc. The aggregate variables on the right-hand side of the adjusted rate base equation are forecast by the equations below. First, total (existing and new) gross plant in service in the forecast year is determined as the sum of existing gross plant in service and new capacity expansion expenditures added to existing gross plant in service. New capacity expansion can be compression, looping, and new pipelines. For simplification, the replacement, refurbishment, retirement, and cost associated with new facilities for complying with Order 636 are not accounted for in projecting total gross plant in service in year t. Total gross plant in service for a network arc is forecast as follows:

$$GPIS_{a,t} = GPIS\_E_{a,t} + GPIS\_N_{a,t} \tag{178}$$

where,

$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$GPIS\_E_{a,t}$ = gross plant in service in the last historical year (2006)
$GPIS\_N_{a,t}$ = capital cost of new plant in service in dollars
a = arc
t = forecast year

In the above equation, the capital cost of existing plant in service (GPIS_Ea,t) reflects the amount of gross plant in service in the last historical year (2006). The capital cost of new plant in service (GPIS_Na,t) in year t is computed as the accumulated new capacity expansion expenditures from 2007 to year t and is determined by the following equation:

$$GPIS\_N_{a,t} = \sum_{s=2004}^{t} NCAE_{a,s} \tag{179}$$

where,

$GPIS\_N_{a,t}$ = gross plant in service for new capacity expansion in dollars
$NCAE_{a,s}$ = new capacity expansion expenditures occurring in year s after 2006 (in dollars) [equation 176]
s = the year new expansion occurred
a = arc
t = forecast year

Next, net plant in service in year t is determined as the difference between total capital cost of plant in service (gross plant in service) in year t and previous year's accumulated depreciation, depletion, and amortization.

$$NPIS_{a,t} = GPIS_{a,t} - ADDA_{a,t-1} \tag{180}$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$GPIS_{a,t}$ = total capital cost of plant in service (gross plant in service) in dollars
$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for the combined existing and new capacity in year t is determined by the following equation:

$$ADDA_{a,t} = ADDA\_E_{a,t} + ADDA\_N_{a,t} \tag{181}$$

where,

$ADDA_{a,t}$ = accumulated depreciation, depletion, and amortization in dollars
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
a = arc
t = forecast year

With this and the relationship between the capital costs of existing and new plants in service from equation 178, total net plant in service (NPISa,t) is set equal to the sum of net plant in service for existing pipelines and new capacity expansions, as follows:

$$NPIS_{a,t} = NPIS\_E_{a,t} + NPIS\_N_{a,t} \tag{182}$$

$$NPIS\_E_{a,t} = GPIS\_E_{a,t} - ADDA\_E_{a,t-1} \tag{183}$$

$$NPIS\_N_{a,t} = GPIS\_N_{a,t} - ADDA\_N_{a,t-1} \tag{184}$$

where,

$NPIS_{a,t}$ = total net plant in service in dollars
$NPIS\_E_{a,t}$ = net plant in service for existing capacity in dollars
$NPIS\_N_{a,t}$ = net plant in service for new capacity in dollars
$GPIS\_E_{a,t}$ = gross plant in service in the last historical year (2006)
$ADDA\_E_{a,t}$ = accumulated depreciation, depletion, and amortization for existing capacity in dollars
$ADDA\_N_{a,t}$ = accumulated depreciation, depletion, and amortization for new capacity in dollars
GPIS_N = gross plant in service for new capacity in dollars
a = arc
t = forecast year

Accumulated depreciation, depletion, and amortization for a network arc in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization.

$$ADDA_{a,t} = ADDA_{a,t-1} + DDA_{a,t} \tag{185}$$

where,

$ADDA_{a,t}$	=	accumulated depreciation, depletion, and amortization in dollars
$DDA_{a,t}$	=	annual depreciation, depletion, and amortization costs in dollars
a	=	arc
t	=	forecast year

Annual depreciation, depletion, and amortization for a network arc in year t equal the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc.

$$DDA_{a,t} = DDA\_E_{a,t} + DDA\_N_{a,t} \tag{186}$$

where,

$DDAa_{,t}$	=	annual depreciation, depletion, and amortization in dollars
$DDA\_E_{a,t}$	=	depreciation, depletion, and amortization costs for existing capacity in dollars
$DDA\_N_{a,t}$	=	depreciation, depletion, and amortization costs for new capacity in dollars
a	=	arc
t	=	forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an arc, while an accounting algorithm is used for new capacity. For existing capacity, this expense is forecast as follows:

$$DDA\_E_{a,t} = \beta_{0,a} + \beta_1 * NPIS\_E_{a,t-1} + \beta_2 * NEWCAP\_E_{a,t} \tag{187}$$

where,

$DDA\_E_{a,t}$	=	annual depreciation, depletion, and amortization costs for existing capacity in nominal dollars
$\beta0_{,a}$	=	DDA_Ca, constant term estimated by arc (Appendix F, Table F3.3, β0,a = B_ARCxx_yy)
β_1	=	DDA_NPIS, estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3.3)
β_2	=	DDA_NEWCAP, estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3.3)
$NPIS\_E_{a,t}$	=	net plant in service for existing capacity (dollars)
$NEWCAP\_E_{a,t}$	=	change in gross plant in service for existing capacity between t and t-1 (dollars)

a = arc
t = forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$DDA\_N_{a,t} = GPIS\_N_{a,t} / 30 \tag{188}$$

where,

$DDA\_N_{a,t}$ = annual depreciation, depletion, and amortization for new capacity in dollars
$GPIS\_N_{a,t}$ = gross plant in service for new capacity in dollars [equation 179]
30 = 30 years of plant life
a = arc
t = forecast year

Next, total cash working capital ($CWC_{a,t}$) for the combined existing and new capacity by arc in the adjusted rate base equation consists of cash working capital, material and supplies, and other components that vary by company. Total cash working capital for pipeline transmission for existing and new capacity at the arc level is deflated using the chain-weighted GDP price index with 2005 as a base. This level of cash working capital ($R\_CWC_{a,t}$) is determined using a log-linear specification with correction for serial correlation given the economies in cash management in gas transmission. The estimated equation used for R_CWC (Appendix F, Table F3) is determined as a function of total operation and maintenance expenses, as defined below:

$$R\_CWC_{a,t} = CWC\_K * e^{(\beta_{0,a}*(1-\rho)+CWC\_TOM*\log(R\_TOM_{a,t})+\rho*\log(R\_CWC_{a,t-1})-\rho*CWC\_TOM*\log(R\_TOM_{a,t-1}))} \tag{189}$$

where,

$R\_CWC_{a,t}$ = total pipeline transmission cash working capital for existing and new capacity (2005 dollars)
$\beta_{0,a}$ = CWC_C_a, estimated arc-specific constant for gas transported from node to node (Appendix F, Table F3.2, $\beta_{0,a} = B\_ARC_{xx\_yy}$)
CWC_TOM = estimated R_TOM coefficient (Appendix F, Table F3.2)
$R\_TOM_{a,t}$ = total operation and maintenance expenses in 2005 dollars
CWC_K = correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3.2 CWC_RHO)
a = arc
t = forecast year

Last, the level of accumulated deferred income taxes for the combined existing and new capacity on a network arc in year t in the adjusted rate base equation depends on income tax regulations in effect, differences in tax and book depreciation, and the time vintage of past construction. The level of accumulated deferred income taxes for the combined existing and new capacity is derived as follows:

$$ADIT_{a,t} = \beta_{0,a} + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t} + ADIT_{a,t-1} \quad (190)$$

where,

$ADIT_{a,t}$ = accumulated deferred income taxes in dollars
$\beta_{0,a}$ = ADIT_Ca, constant term estimated by arc (Appendix F, Table F3.5, $\beta^{0,a}$ = $B\_ARC_{xx\_yy}$)
β_1 = BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003/2004 because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.
$NEWCAP_{a,t}$ = change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
a = arc
t = forecast year

Cost of capital. The capital-related components of the revenue requirement at the arc level depend upon the size of the adjusted rate base and the cost of capital to the pipeline companies associated with that arc. In turn, the company-level costs of capital depend upon the rates of return on debt, preferred stock and common equity, and the amounts of debt and equity in the overall capitalization. Cost of capital for a company is the weighted average after-tax rate of return (WAROR) which is a function of long-term debt, preferred stock, and common equity. The rate of return variables for preferred stock, common equity, and debt are related to forecast macroeconomic variables. For the combined existing and new capacity at the arc level, it is assumed that these rates will vary as a function of the yield on AA utility bonds (provided by the Macroeconomic Activity Module as a percent) in year t adjusted by a historical average deviation constant, as follows:

$$PFER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_PFER_a \quad (191)$$

$$CMER_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_CMER_a \quad (192)$$

$$LTDR_{a,t} = MC\_RMPUAANS_t / 100.0 + ADJ\_LTDR_a \quad (193)$$

where,

$PFER_{a,t}$ = rate of return for preferred stock
$CMER_{a,t}$ = common equity rate of return
$LTDR_{a,t}$ = long-term debt rate

$MC\_RMPUAANS_t$ = AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
ADJ_PFER_a = historical average deviation constant (fraction) for rate of return for preferred stock (1994-2003, over 28 major gas pipeline companies) (D_PFER/100., Appendix E)
ADJ_CMER_a = historical average deviation constant (fraction) for rate of return for common equity (1994-2003, over 28 major gas pipeline companies) (D_CMER/100., Appendix E)
ADJ_LTDR_a = historical average deviation constant (fraction) for long-term debt rate (1994-2003, over 28 major gas pipeline companies) (D_LTDR/100., Appendix E)
a = arc
t = forecast year

The weighted average cost of capital in the forecast year is computed as the sum of the capital-weighted rates of return for preferred stock, common equity, and debt, as follows:

$$WAROR_{a,t} = \frac{(PFER_{a,t} * PFES_{a,t}) + (CMER_{a,t} * CMES_{a,t}) + (LTDR_{a,t} * LTDS_{a,t})}{TOTCAP_{a,t}} \quad (194)$$

$$TOTCAP_{a,t} = (PFES_{a,t} + CMES_{a,t} + LTDS_{a,t}) \quad (195)$$

where,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = rate of return for preferred stock (fraction)
$PFES_{a,t}$ = value of preferred stock (dollars)
$CMER_{a,t}$ = common equity rate of return (fraction)
$CMES_{a,t}$ = value of common stock (dollars)
$LTDR_{a,t}$ = long-term debt rate (fraction)
$LTDS_{a,t}$ = value of long-term debt (dollars)
$TOTCAP_{a,t}$ = sum of the value of long-term debt, preferred stock, and common stock equity (dollars)
a = arc
t = forecast year

The above equation can be written as a function of the rates of return and capital structure ratios: as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_{a,t}) + (CMER_{a,t} * GCMESTR_{a,t}) + (LTDR_{a,t} * GLTDSTR_{a,t}) \quad (196)$$

where,

$$GPFESTR_{a,t} = PFES_{a,t} / TOTCAP_{a,t} \quad (197)$$

$$GCMESTR_{a,t} = CMES_{a,t} / TOTCAP_{a,t} \quad (198)$$

$$GLTDSTR_{a,t} = LTDS_{a,t} / TOTCAP_{a,t} \quad (199)$$

and,

$WAROR_{a,t}$	=	weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$	=	coupon rate for preferred stock (fraction)
$CMER_{a,t}$	=	common equity rate of return (fraction)
$LTDR_{a,t}$	=	long-term debt rate (fraction)
$GPFESTR_{a}$	=	ratio of preferred stock to estimated capital for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_{a}$	=	ratio of common stock to estimated capital for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_{a}$	=	ratio of long-term debt to estimated capital for existing and new capacity (fraction)[referred to as capital structure for long-term debt]
$PFES_{a,t}$	=	value of preferred stock (dollars)
$CMES_{a,t}$	=	value of common stock (dollars)
$LTDS_{a,t}$	=	value of long-term debt (dollars)
$TOTCAP_{a,t}$	=	estimated capital equal to the sum of the value of preferred stock, common stock equity, and long-term debt (dollars)
a	=	arc
t	=	forecast year

In the financial database, the estimated capital for each interstate pipeline is by definition equal to its adjusted rate base. Hence, the estimated capital ($TOTCAP_{a,t}$) defined in equation 195 is equal to the adjusted rate base ($APRB_{a,t}$) defined in equation 177:

$$TOTCAP_{a,t} = APRB_{a,t} \quad (200)$$

where,

$TOTCAP_{a,t}$	=	estimated capital in dollars
$APRB_{a,t}$	=	adjusted rate base in dollars
a	=	arc
t	=	forecast year

Substituting the adjusted rate base variable $APRB_{a,t}$ for the estimated capital $TOTCAP_{a,t}$ in equations 197 to 199, the values of preferred stock, common stock, and long-term debt by arc can be derived as functions of the capital structure ratios and the adjusted rate base. Capital structure is the percent of total capitalization (adjusted rate base) represented by each of the three capital components: preferred equity, common equity, and long-term debt. The percentages of total capitalization due to common stock, preferred stock, and long-term debt are considered fixed throughout the forecast. Assuming that the total capitalization fractions remain the same over the forecast horizon, the values of preferred stock, common stock, and long-term debt can be derived as follows:

$$\begin{aligned} PFES_{a,t} &= GPFESTR_a * APRB_{a,t} \\ CMES_{a,t} &= GCMESTR_a * APRB_{a,t} \\ LTDS_{a,t} &= GLTDSTR_a * APRB_{a,t} \end{aligned} \quad (201)$$

where,

$PFES_{a,t}$	=	value of preferred stock in nominal dollars
$CMES_{a,t}$	=	value of common equity in nominal dollars
$LTDS_{a,t}$	=	long-term debt in nominal dollars
$GPFESTR_a$	=	ratio of preferred stock to adjusted rate base for existing and new capacity (fraction) [referred to as capital structure for preferred stock]
$GCMESTR_a$	=	ratio of common stock to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for common stock]
$GLTDSTR_a$	=	ratio of long-term debt to adjusted rate base for existing and new capacity (fraction)[referred to as capital structure for long-term debt]
$APRB_{a,t}$	=	adjusted pipeline rate base (dollars)
a	=	arc
t	=	forecast year

In the forecast year update phase, the capital structures ($GPFESTR_a$, $GCMESTR_a$, and $GLTDSTR_a$) at the arc level in the above equations are held constant over the forecast period. They are defined below as the average adjusted rate base weighted capital structures over all pipelines associated with an arc and over the historical time period (1997-2006).

$$GPFESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GPFESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (202)$$

$$GCMESTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GCMESTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (203)$$

$$GLTDSTR_a = \frac{\sum_{t=1997}^{2006} \sum_{p} (GLTDSTR_{a,p,t} * APRB_{a,p,t})}{\sum_{t=1997}^{2006} \sum_{p} APRB_{a,p,t}} \quad (204)$$

where,

$GPFESTR_a$	=	historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period

$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_a$ = historical average capital structure for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$GPFESTR_{a,p,t}$ = capital structure for preferred stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_PFES)
$GCMESTR_{a,p,t}$ = capital structure for common stock (fraction) by pipeline company in the historical years (1997-2006) (Appendix E, D_CMES)
$GLTDSTR_{a,p,t}$ = capital structure for long-term debt (fraction) by pipeline company in the historical years (1997-2006) (Appendix E,D_LTDS)
$APRB_{a,p,t}$ = adjusted rate base (capitalization) by pipeline company in the historical years (1997-2006) (Appendix E, D_APRB)
P = pipeline company
a = arc
t = historical year

The weighted average cost of capital in the forecast year in equation 196 is forecast as follows:

$$WAROR_{a,t} = (PFER_{a,t} * GPFESTR_a) + (CMER_{a,t} * GCMESTR_a) + (LTDR_{a,t} * GLTDSTR_a) \tag{205}$$

where,

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital (fraction)
$PFER_{a,t}$ = coupon rate for preferred stock (fraction), function of AA utility bond rate [equation 191]
$CMER_{a,t}$ = common equity rate of return (fraction), function of AA utility bond rate [equation 192]
$LTDR_{a,t}$ = long-term debt rate (fraction), function of AA utility bond rate [equation 193]
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$GLTDSTR_a$ = historical average capital structure for long-term debt for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

The weighted-average after-tax rate of return on capital (WARORa,t) is applied to the adjusted rate base (APRBa,t) to project the total return on rate base (after taxes), also known as the after-tax operating income, which is a major component of the revenue requirement.

Projection of revenue requirement components

The approach to the projection of revenue requirement components is summarized in **Table 6-5**. Given the rate base, rates of return, and capitalization structure projections discussed above, the revenue requirement components are relatively straightforward to project. The capital-related components include total return on rate base (after taxes); federal and state income taxes; deferred income taxes; other taxes; and depreciation, depletion, and amortization costs. Other components include total operating and maintenance expenses, and regulatory amortization, which is small and thus assumed to be negligible in the forecast period. The total operating and maintenance expense variable includes expenses for transmission of gas for others; administrative and general expenses; and sales, customer accounts and other expenses. The total cost of service (revenue requirement) at the arc level for a forecast year is determined as follows:

$$TCOS_{a,t} = TRRB_{a,t} + DDA_{a,t} + TOTAX_{a,t} + TOM_{a,t} \tag{206}$$

where,

$TCOSa_{,t}$ = total cost-of-service or revenue requirement for existing and new capacity (dollars)
$TRRB_{a,t}$ = total return on rate base for existing and new capacity after taxes (dollars)
$DDA_{a,t}$ = depreciation, depletion, and amortization for existing and new capacity (dollars)
$TOTAX_{a,t}$ = total federal and state income tax liability for existing and new capacity (dollars)
$TOM_{a,t}$ = total operating and maintenance expenses for existing and new capacity (dollars)
a = arc
t = forecast year

Table 6-5. Approach to projection of revenue requirements

Projection Component	Approach
1. Capital-Related Costs	
a. Total return on rate base	Direct calculation from projected rate base and rates of return
b. Federal/State income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation
4. Other Taxes	Previous year's other taxes adjusted to inflation rate and growth in capacity

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$TRRB_{a,t} = WAROR_{a,t} * APRB_{a,t} \tag{207}$$

where,

$TRRB_{a,t}$ = total return on rate base (after taxes) for existing and new capacity in dollars

$WAROR_{a,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity in dollars
a = arc
t = forecast year

The return on rate base for existing and new capacity on an arc can be broken out into the three components:

$$PFEN_{a,t} = GPFESTR_a * PFER_{a,t} * APRB_{a,t} \tag{208}$$

$$CMEN_{a,t} = GCMESTR_a * CMER_{a,t} * APRB_{a,t} \tag{209}$$

$$LTDN_{a,t} = GLTDSTR_a * LTDR_{a,t} * APRB_{a,t} \tag{210}$$

where,

$PFEN_{a,t}$ = total return on preferred stock for existing and new capacity (dollars)
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$PFER_{a,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$APRB_{a,t}$ = adjusted rate base for existing and new capacity (dollars)
$CMEN_{a,t}$ = total return on common stock equity for existing and new capacity (dollars)
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$ = common equity rate of return for existing and new capacity (fraction)
$LTDN_{a,t}$ = total return on long-term debt for existing and new capacity (dollars)
$GLTDSTR_a$ = historical average capital structure ratio for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$LTDR_{a,t}$ = long-term debt rate for existing and new capacity (fraction)
a = arc
t = forecast year

Next, annual depreciation, depletion, and amortization $DDA_{a,t}$ for a network arc in year t is calculated as the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with the arc. $DDA_{a,t}$ is defined earlier in equation 186.

Next, total taxes consist of federal income taxes, state income taxes, deferred income taxes, and other taxes. Federal income taxes and state income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$TOTAX_{a,t} = FSIT_{a,t} + DIT_{a,t} + OTTAX_{a,t} \tag{211}$$

$$FSIT_{a,t} = FIT_{a,t} + SIT_{a,t} \tag{212}$$

where,

$TOTAX_{a,t}$ = total federal and state income tax liability for existing and new capacity (dollars)
$FSIT_{a,t}$ = federal and state income tax for existing and new capacity (dollars)
$FIT_{a,t}$ = federal income tax for existing and new capacity (dollars)
$SIT_{a,t}$ = state income tax for existing and new capacity (dollars)
$DIT_{a,t}$ = deferred income taxes for existing and new capacity (dollars)
$OTTAX_{a,t}$ = all other federal, state, or local taxes for existing and new capacity (dollars)
a = arc
t = forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the federal tax rate. The after-tax profit is determined as follows:

$$ATP_{a,t} = APRB_{a,t} * (PFER_{a,t} * GPFESTR_a + CMER_{a,t} * GCMESTR_a) \tag{213}$$

where,

$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
$APRB_{a,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$PFER_{a,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$GPFESTR_a$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$CMER_{a,t}$ = common equity rate of return for existing and new capacity (fraction)
$GCMESTR_a$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
a = arc
t = forecast year

and the federal income taxes are:

$$FIT_{a,t} = (FRATE * ATP_{a,t} / 1. - FRATE) \tag{214}$$

where,

$FIT_{a,t}$ = federal income tax for existing and new capacity (dollars)
FRATE = federal income tax rate (fraction, Appendix E)
$ATP_{a,t}$ = after-tax profit for existing and new capacity (dollars)
a = arc
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated federal income tax by a weighted-average state tax rate associated with each pipeline company. The weighted-average state tax rate is based on peak service volumes in each state served by the pipeline company. State income taxes are computed as follows:

$$SIT_{a,t} = SRATE * (FIT_{a,t} + ATP_{a,t}) \tag{215}$$

where,

$SIT_{a,t}$	=	state income tax for existing and new capacity (dollars)
SRATE	=	average state income tax rate (fraction, Appendix E)
$FIT_{a,t}$	=	federal income tax for existing and new capacity (dollars)
$ATP_{a,t}$	=	after-tax profits for existing and new capacity (dollars)
a	=	arc
t	=	forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$DIT_{a,t} = ADIT_{a,t} - ADIT_{a,t-1} \tag{216}$$

where,

$DIT_{a,t}$	=	deferred income taxes for existing and new capacity (dollars)
$ADIT_{a,t}$	=	accumulated deferred income taxes for existing and new capacity (dollars)
a	=	arc
t	=	forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation and capacity expansion.

$$OTTAX_{a,t} = OTTAX_{a,t-1} * EXPFAC_{a,t} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{217}$$

where,

$OTTAX_{a,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes for existing and new capacity (dollars)
$EXPFAC_{a,t}$	=	capacity expansion factor (see below)
MC_PCWGDP_t	=	GDP chain-type price deflator (Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

The capacity expansion factor is expressed as follows:

$$EXPFAC_{a,t} = PTCURPCAP_{a,t} / PTCURPCAP_{a,t-1} \tag{218}$$

where,

$EXPFAC_{a,t}$	=	capacity expansion factor (growth in capacity)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf) for existing and new capacity
a	=	arc
t	=	forecast year

Last, the total operating and maintenance costs for existing and new capacity by arc ($R\_TOM_{a,t}$) are determined using a log-linear form, given the economies of scale inherent in gas transmission. The estimated equation used for R_TOM (Appendix F, Table F3) is determined as a function of gross plant in service, $GPIS_a$, a level of accumulated depreciation relative to gross plant in service, $DEPSHR_a$, and a time trend, TECHYEAR, that proxies the state of technology, as defined below:

$$R\_TOM_{a,t} = TOM\_K * e^{(\beta_{0,a} * (1-\rho) + G2 + G3 + G4 + G5 + G6 - \rho * (G7 + G8 + G4 + G9))} \quad (219)$$

where,

$R\_TOM_{a,t}$	=	total operating and maintenance cost for existing and new capacity (2005 dollars)
TOM_K	=	correction factor estimated in stage 2 of the regression equation estimation process (Appendix F, Table F3)
$\beta_{0,a}$	=	TOM_C, constant term estimated by arc (Appendix F, Table F3.6, $\beta_{0,a}$ = $B\_ARC_{xx\_yy}$)
G_2	=	$\beta_1 * \log(GPIS_{a,t-1})$
G_3	=	$\beta_2 * DEPSHR_{a,t-1}$
G_4	=	$\beta_3 * 2006.0$
G_5	=	$\beta_4 * (TECHYEAR-2006.0)$
G_6	=	ρ * log(R_TOMa,t-1)
G_7	=	β1 * log(GPISa,t-2)
G_8	=	β2 * DEPSHRa,t-2
G_9	=	β4 * (TECHYEAR - 1.0- 2006.0)
log	=	natural logarithm operator
ρ	=	estimated autocorrelation coefficient (Appendix F, Table F3.6 -- TOM_RHO)
β_1	=	TOM_GPIS1, estimated coefficient on the change in gross plant in service (Appendix F, Table F3.6)
β_2	=	TOM_DEPSHR, estimated coefficient for the accumulated depreciation of the plant relative to the GPIS (Appendix F, Table F3.6)
β_3	=	TOM_BYEAR, estimated coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
β_4	=	TOM_BYEAR_EIA = TOM_BYEAR, estimated future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this coefficient is the same as the coefficient for the time trend variable TECHYEAR (Appendix F, Table F3.6)
$DEPSHR_{a,t}$	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
$GPIS_{a,t}$	=	capital cost of plant in service for existing and new capacity in dollars (not deflated)
TECHYEAR	=	MODYEAR (time trend in 4-digit Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For consistency, the total operating and maintenance costs are converted to nominal dollars:

$$TOM_{a,t} = R\_TOM_{a,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{2000}} \tag{220}$$

where,

$TOM_{a,t}$	=	total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_TOM_{a,t}$	=	total operating and maintenance costs for existing and new capacity (2005 dollars)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
a	=	arc
t	=	forecast year

Once all four components ($TRRB_{a,t}$, $DDA_{a,t}$, $TOTAX_{a,t}$, $TOM_{a,t}$) of the cost-of-service $TCOST_{a,t}$ of equation 206 are computed by arc in year t, each of them will be disaggregated into fixed and variable costs, which in turn will be disaggregated further into reservation and usage costs using the allocation factors for a straight fixed variable (SFV) rate design summarized in **Table 6-6**.[90] Note that the return on rate base ($TRRB_{a,t}$) has three components ($PFEN_{a,t}$, $CMEN_{a,t}$, and $LTDN_{a,t}$ [equations 208, 209, and 210]).

Disaggregation of cost-of-service components into fixed and variable costs

Let Item i,a,t be a cost-of-service component (i=cost component index, a=arc, and t=forecast year). Using the first group of rate design allocation factors ξi (**Table 6-6**), all the components of cost-of-service computed in the above section can be split into fixed and variable costs, and then summed over the cost categories to determine fixed and variable costs-of-service as follows:

$$FC_{a,t} = \sum_i (\xi_i * Item_{i,a,t}) \tag{221}$$

$$VC_{a,t} = \sum_i [(1.0 - \xi_i) * Item_{i,a,t}] \tag{222}$$

$$TCOS_{a,t} = FC_{a,t} + VC_{a,t} \tag{223}$$

where,

$TCOS_{a,t}$	=	total cost-of-service for existing and new capacity (dollars)
$FC_{a,t}$	=	fixed cost for existing and new capacity (dollars)
$VC_{a,t}$	=	variable cost for existing and new capacity (dollars)
$Item_{i,a,t}$		cost-of-service component index at the arc level

[90] The allocation factors of SFV rate design are given in percent in this table for illustration purposes. They are converted into ratios immediately after they are read in from the input file by dividing by 100.

ξ_i = first group of allocation factors (ratios) to disaggregate the cost-of-service components into fixed and variable costs
i = subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a = arc
t = forecast year

Table 6-6. Percentage allocation factors for a straight fixed variable (SFV) rate design

Cost-of-service Items (percentage) [$Item_{i,a,t}$, i=cost component index, a=arc, t=year]	**Break up cost-of-service items into fixed and variable costs**		**Break up fixed cost items into reservation and usage costs**		**Break up variable cost items into reservation and usage costs**	
$Item_{i,a,t}$	**$FC_{i,a,t}$**	**$VC_{i,a,t}$**	**$RFC_{i,a,t}$**	**$UFC_{i,a,t}$**	**$RVC_{i,a,t}$**	**$UVC_{i,a,t}$**
Cost Allocation Factors	ξ_i	100 - ξ_i	λ_i	100 - λ_i	μ_i	100-μ_i
After-tax Operating Income						
Return on Preferred Stocks	100	0	100	0	0	100
Return on Common Stocks	100	0	100	0	0	100
Return on Long-Term Debt	100	0	100	0	0	100
Normal Operating Expenses						
Depreciation	100	0	100	0	0	100
Income Taxes	100	0	100	0	0	100
Deferred Income Taxes	100	0	100	0	0	100
Other Taxes	100	0	100	0	0	100
Total O&M	60	40	100	0	0	100

Disaggregation of fixed and variable costs into reservation and usage costs

Each type of cost-of-service component (fixed or variable) in the above equations can be further disaggregated into reservation and usage costs using the second and third groups of rate design allocation factors λi and μi (**Table 6-6**), as follows:

$$RFC_{a,t} = \sum_i (\lambda_i * \xi_i * Item_{i,a,t}) \tag{224}$$

$$UFC_{a,t} = \sum_i [(1.0 - \lambda_i) * \xi_i * Item_{i,a,t}] \tag{225}$$

$$RVC_{a,t} = \sum_i [\mu_i * (1.0 - \xi_i) * Item_{i,a,t}] \tag{226}$$

$$UVC_{a,t} = \sum_i [(1.0 - \mu_i) * (1.0 - \xi_i) * Item_{i,a,t}] \tag{227}$$

$$TCOS_{a,t} = RFC_{a,t} + UFC_{a,t} + RVC_{a,t} + UVC_{a,t} \tag{228}$$

where,

$TCOS_{a,t}$	=	total cost-of-service for existing and new capacity (dollars)
$RFC_{a,t}$	=	fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$	=	fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$	=	variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$	=	variable usage cost for existing and new capacity (dollars)
$Item_{i,a,t}$	=	cost-of-service component index at the arc level
ξ_i	=	first group of allocation factors to disaggregate cost-of-service components into fixed and variable costs
λ_i	=	second group of allocation factors to disaggregate fixed costs into reservation and usage costs
μ_i	=	third group of allocation factors to disaggregate variable costsinto reservation and usage costs
i	=	subscript to designate a cost-of-service component (i=1 for PFEN, i=2 for CMEN, i=3 for LTDN, i=4 for DDA, i=5 for FSIT, i=6 for DIT, i=7 for OTTAX, and i=8 for TOM)
a	=	arc
t	=	forecast year

The summation of fixed and variable reservation costs (RFC and RVC) yields the total reservation cost (RCOST). This can be disaggregated further into peak and off-peak reservation costs, which are used to develop variable tariffs for peak and off-peak time periods. The summation of fixed and variable usage costs (UFC and UVC), which yields the total usage cost (UCOST), is used to compute the annual average fixed usage fees. Both types of rates are developed in the next section. The equations for the reservation and usage costs can be expressed as follows:

$$RCOST_{a,t} = (RFC_{a,t} + RVC_{a,t}) \tag{229}$$

$$UCOST_{a,t} = (UFC_{a,t} + UVC_{a,t}) \tag{230}$$

where,

$RCOST_{a,t}$	=	reservation cost for existing and new capacity (dollars)
$UCOST_{a,t}$	=	annual usage cost for existing and new capacity (dollars)
$RFC_{a,t}$	=	fixed reservation cost for existing and new capacity (dollars)
$UFC_{a,t}$	=	fixed usage cost for existing and new capacity (dollars)
$RVC_{a,t}$	=	variable reservation cost for existing and new capacity (dollars)
$UVC_{a,t}$	=	variable usage cost for existing and new capacity (dollars)
a	=	arc
t	=	forecast period

As **Table 6-6** indicates, all the fixed costs are included in the reservation costs and all the variable costs are included in the usage costs.

Computation of rates for forecast years

The reservation and usage costs-of-service RCOST and UCOST determined above are used separately to develop two types of rates at the arc level: variable tariffs and annual fixed usage fees. The determination of both rates is described below.

Variable tariff curves

Variable tariffs are proportional to reservation charges and are broken up into peak and off-peak time periods. Variable tariffs are derived directly from variable tariff curves which are developed based on reservation costs, utilization rates, annual flows, and other curve parameters.

In the PTS code, these variable curves are defined by a FUNCTION (NGPIPE_VARTAR) which is called by the ITS to compute the variable tariffs for peak and off-peak by arc and by forecast year. In this pipeline function, the tariff curves are segmented such that tariffs associated with current capacity and capacity expansion are represented by separate but similar equations. A uniform functional form is used to define these tariff curves for both the current capacity and capacity expansion segments of the tariff curves. It is defined as a function of a base point [price and quantity (PNOD, QNOD)] using different process-specific parameters, peak or off-peak flow, and a price elasticity. This functional form is presented below:

current capacity segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA\_PIPE} \qquad (231)$$

capacity expansion segment:

$$NGPIPE\_VARTAR_{a,t} = PNOD_{a,t} * (Q_{a,t} / QNOD_{a,t})^{ALPHA2\_PIPE} \qquad (232)$$

such that,

for peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * PKSHR\_YR}{(QNOD_{a,t} * MC\_PCWGDP_{t})} \qquad (233)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \qquad (234)$$

for off-peak transmission tariffs:

$$PNOD_{a,t} = \frac{RCOST_{a,t} * (1.0 - PKSHR\_YR)}{(QNOD_{a,t} * MC\_PCWGDP_{t})} \qquad (235)$$

$$QNOD_{a,t} = PTNETFLOW_{a,t} \qquad (236)$$

where,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (1987$/Mcf)
$PNOD_{a,t}$	=	base point, price (1987$/Mcf)

$QNOD_{a,t}$ = base point, quantity (Bcf)
$Q_{a,t}$ = flow along pipeline arc (Bcf)
ALPHA_PIPE = price elasticity for pipeline tariff curve for current capacity (Appendix E)
ALPHA2_PIPE = price elasticity for pipeline tariff curve for capacity expansion segment (Appendix E)
$RCOST_{a,t}$ = reservation cost-of-service (million dollars)
$PTNETFLOW_{a,t}$ = natural gas network flow (throughput, Bcf)
PKSHR_YR = portion of the year represented by the peak season (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

Annual fixed usage fees

The annual fixed usage fees (volumetric charges) are derived directly from the usage costs, peak and off-peak utilization rates, and annual arc capacity. These fees are computed as the average fees over each forecast year, as follows:

$$FIXTAR_{a,t} = UCOST_{a,t} / [(PKSHR\_YR * PTPKUTZ_{a,t} * PTCURPCAP_{a,t} + (1 - PKSHR\_YR) * PTOPUTZ_{a,t} * PTCURPCAP_{a,t}) * MC\_PCWGDP_t \quad (237)$$

where,

$FIXTAR_{a,t}$ = annual fixed usage fees for existing and new capacity (1987$/Mcf)
$UCOST_{a,t}$ = annual usage cost for existing and new capacity (million dollars)
PKSHR_YR = portion of the year represented by the peak season (fraction)
$PTCURPCAP_{a,t}$ = current pipeline capacity (Bcf)
$PTPKUTZ_{a,t}$ = peak pipeline utilization (fraction)
$PTOPUTZ_{a,t}$ = off-peak pipeline utilization (fraction)
MC_PCWGDP_t = GDP chain-type price deflator (from the Macroeconomic Activity Module)
a = arc
t = forecast year

As can be seen from the allocation factors in Table 6-6, usage costs (UCOST) are less than 10 percent of reservation costs (RCOST). Therefore, annual fixed usage fees which are proportional to usage costs are expected to be less than 10 percent of the variable tariffs. In general, these fixed fees are within the range of 5 percent of the variable tariffs which are charged to firm customers.

Canadian fixed and variable tariffs

Fixed and variable tariffs along Canadian import arcs are defined using input data. Fixed tariffs are obtained directly from the data (Appendix E, $ARC\_FIXTAR_{n,a,t}$), while variable tariffs are calculated in the FUNCTION subroutine (NGPIPE_VARTAR) and are based on pipeline utilization and a maximum expected tariff, CNMAXTAR. If the pipeline utilization along a Canadian arc for any time period (peak or off-peak) is less than 50 percent, then the pipeline tariff is set to a low level (70 percent of CNMAXTAR). If the Canadian pipeline utilization is between 50 and 90 percent, then the pipeline tariff is set to a level between 70 and 80 percent of CNMAXTAR. The sliding scale is determined using the corresponding utilization factor, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - 0.9) * 2.0] - [CNMAXTAR * (0.9 - CANUTIL_{a,t}) * 0.25] \quad (238)$$

If the Canadian pipeline utilization is greater than 90 percent, then the pipeline tariff is set to between 80 and 100 percent of CNMAXTAR. This is accomplished again using Canadian pipeline utilization, as follows:

$$NGPIPE\_VARTAR_{a,t} = CNMAXTAR - [CNMAXTAR * (1.0 - CANUTIL_{a,t}) * 2.0] \quad (239)$$

where,

$$CANUTIL_{a,t} = \frac{Q_{a,t}}{QNOD_{a,t}} \quad (240)$$

for peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * PKSHR\_YR * PTPKUTZ_{a,t} \quad (241)$$

for off-peak period:

$$QNOD_{a,t} = PTCURPCAP_{a,t} * (1.0 - PKSHR\_YR) * PTOPUTZ_{a,t} \quad (242)$$

and,

$NGPIPE\_VARTAR_{a,t}$	=	function to define pipeline tariffs (1987$/Mcf)
CNMAXTAR	=	maximum effective tariff (1987$/Mcf, ARC_VARTAR, Appendix E)
$CANUTIL_{a,t}$	=	pipeline utilization (fraction)
$QNOD_{a,t}$	=	base point, quantity (Bcf)
$Q_{a,t}$	=	flow along pipeline arc (Bcf)
PKSHR_YR	=	portion of the year represented by the peak season (fraction)
$PTPKUTZ_{a,t}$	=	peak pipeline utilization (fraction)
$PTCURPCAP_{a,t}$	=	current pipeline capacity (Bcf)
$PTOPUTZ_{a,t}$	=	off-peak pipeline utilization (fraction)
a	=	arc
t	=	forecast year

For the eastern and western Canadian storage regions, the “variable” tariff is set to zero and only the assumed “fixed” tariff (Appendix E, ARC_FIXTAR) is applied.

Storage tariff routine methodology

Background

This section describes the methodology used to assign a storage tariff for each of the 12 NGTDM regions. All variables and equations presented below are used for the forecast time period (1999-2030). If the time period t is less than 1999, the associated variables are set to the initial values read in from the input file (Foster's storage financial database[91] by region and year, 1990-1998).

This section starts with the presentation of the natural gas storage cost-of-service equation by region. The equation sums four components to be forecast: after-tax[92] total return on rate base (operating income); total taxes; depreciation, depletion, and amortization; and total operating and maintenance expenses. Once these four components are computed, the regional storage cost of service is projected and, with the associated effective storage capacity provided by the ITS, a storage tariff curve can be established (as described at the end of this section).

Cost-of-service by storage region

The cost-of-service (or revenue requirement) for existing and new storage capacity in an NGTDM region can be written as follows:

$$STCOS_{r,t} = STBTOI_{r,t} + STDDA_{r,t} + STTOTAX_{r,t} + STTOM_{r,t} \tag{243}$$

where,

$STCOS_{r,t}$	=	total cost-of-service or revenue requirement for existing and new capacity (dollars)
$STBTOI_{r,t}$	=	total return on rate base for existing and new capacity (after-tax operating income) (dollars)
$STDDA_{r,t}$	=	depreciation, depletion, and amortization for existing and new capacity (dollars)
$STTOTAX_{r,t}$	=	total federal and state income tax liability for existing and new capacity (dollars)
$STTOM_{r,t}$	=	total operating and maintenance expenses for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

The storage cost-of-service by region is first computed in nominal dollars and subsequently converted to 1987 dollars for use in the computation of a base for regional storage tariff, PNOD (1987$/Mcf). PNOD is used in the development of a regional storage tariff curve. An approach is developed to project the storage cost-of-service in nominal dollars by NGTDM region in year t and is provided in **Table 6-7**.

[91] Natural Gas Storage Financial Data, compiled by Foster Associates, Inc., Bethesda, Maryland for EIA under purchase order #01-99EI36663 in December of 1999. This data set includes financial information on 33 major storage companies. The primary source of the data is FERC Form 2 (or Form 2A for the smaller pipelines). These data can be purchased from Foster Associates.

[92] 'After-tax' in this section refers to 'after taxes have been taken out.'

Table 6-7. Approach to projection of storage cost-of-service

Projection Component	Approach
1. Capital-Related Costs	
a. Total return in rate base	Direct calculation from projected rate base and rates of return
b. Federal/state income taxes	Accounting algorithms based on tax rates
c. Deferred income taxes	Difference in the accumulated deferred income taxes between years t and t-1
2. Depreciation, Depletion, and Amortization	Estimated equation and accounting algorithm
3. Total Operating and Maintenance Expenses	Estimated equation

Computation of total return on rate base (after-tax operating income), STBTOIr,t

The total return on rate base for existing and new capacity is computed from the projected weighted cost of capital and estimated rate base, as follows:

$$STBTOI_{r,t} = STWAROR_{r,t} * STAPRB_{r,t} \tag{244}$$

where,

$STBTOI_{r,t}$ = total return on rate base (after-tax operating income) for existing and new capacity in dollars
$STWAROR_{r,t}$ = weighted-average after-tax rate of return on capital for existing and new capacity (fraction)
$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity in dollars
r = NGTDM region
t = forecast year

The return on rate base for existing and new storage capacity in an NGTDM region can be broken out into three components as shown below.

$$STPFEN_{r,t} = STGPFESTR_{r} * STPFER_{r,t} * STAPRB_{r,t} \tag{245}$$

$$STCMEN_{r,t} = STGCMESTR_{r} * STCMER_{r,t} * STAPRB_{r,t} \tag{246}$$

$$STLTDN_{r,t} = STGLTDSTR_{r} * STLTDR_{r,t} * STAPRB_{r,t} \tag{247}$$

where,

$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)
$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_{r}$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STAPRB_{r,t}$ = adjusted rate base for existing and new capacity (dollars)
$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)

$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)
$STLTDN_{r,t}$ = total return on long-term debt for existing and new capacity (dollars)
$STGLTDSTR_r$ = historical average capital structure ratio for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$STLTDR_{r,t}$ = long-term debt rate for existing and new capacity (fraction)
r = NGTDM region
t = forecast year

Note that the total return on rate base is the sum of the above equations and can be expressed as:

$$STBTOI_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t} + STLTDN_{r,t}) \quad (248)$$

It can be seen from the above equations that the weighted average rate of return on capital for existing and new storage capacity, STWARORr,t, can be determined as follows:

$$STWAROR_{r,t} = STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r + STLTDR_{r,t} * STGLTDSTR_r \quad (249)$$

The historical average capital structure ratios STGPFESTRr, STGCMESTRr, and STGLTDSTRr in the above equation are computed as follows:

$$STGPFESTR_r = \frac{\sum_{t=1990}^{1998} STPFES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (250)$$

$$STGCMESTR_r = \frac{\sum_{t=1990}^{1998} STCMES_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (251)$$

$$STGLTDSTR_r = \frac{\sum_{t=1990}^{1998} STLTDS_{r,t}}{\sum_{t=1990}^{1998} STAPRB_{r,t}} \quad (252)$$

where,

$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period

$STGLTDSTR_{r}$	=	historical average capital structure ratio for long-term debt for existing and new capacity (fraction), held constant over the forecast period
$STPFES_{r,t}$	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_{r,t}$	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_{r,t}$	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$STAPRB_{r,t}$	=	adjusted rate base for existing capacity (dollars) [read in as D_APRB]
r	=	NGTDM region
t	=	forecast year

In the STWAROR equation, the rate of return variables for preferred stock, common equity, and debt ($STPFER_{r,t}$, $STCMER_{r,t}$, and $STLTDR_{r,t}$) are related to forecast macroeconomic variables. These rates of return can be determined as a function of nominal AA utility bond index rate (provided by the Macroeconomic Module) and a regional historical average constant deviation as follows:

$$STPFER_{r,t} = MC\_RMPUAANS_{t} / 100.0 + ADJ\_STPFER_{r} \quad (253)$$

$$STCMER_{r,t} = MC\_RMPUAANS_{t} / 100.0 + ADJ\_STCMER_{r} \quad (254)$$

$$STLTDR_{r,t} = MC\_RMPUAANS_{t} / 100.0 + ADJ\_STLTDR_{r} \quad (255)$$

where,

$STPFER_{r,t}$	=	rate of return for preferred stock
$STCMER_{r,t}$	=	common equity rate of return
$STLTDR_{r,t}$	=	long-term debt rate
$MC\_RMPUAANS_{t}$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPUAA, percentage)
ADJ_STPFER_{r}	=	historical weighted average deviation constant (fraction) for preferred stock rate of return (1990-1998)
ADJ_STCMER_{r}	=	historical weighted average deviation constant (fraction) for ommon equity rate of return (1990-1998)
ADJ_STLTDR_{r}	=	historical weighted average deviation constant (fraction) for long-term debt rate (1990-1998)
r	=	NGTDM region
t	=	forecast year

The historical weighted average deviation constants by NGTDM region are computed as follows:

$$ADJ\_STLTDR_{r} = \frac{\sum_{t=1990}^{1998} \left(\frac{STLTDN_{r,t}}{STLTDS_{r,t}} - MC\_RMPUAANS_{t} / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (256)$$

$$ADJ\_STPFER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STPFEN_{r,t}}{STPFES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (257)$$

$$ADJ\_STCMER_r = \frac{\sum_{t=1990}^{1998} \left(\frac{STCMEN_{r,t}}{STCMES_{r,t}} - MC\_RMPUAANS_t / 100.\right) * STGPIS_{r,t}}{\sum_{t=1990}^{1998} STGPIS_{r,t}} \quad (258)$$

where,

ADJ_STLTDR_r	=	historical weighted average deviation constant (fraction) for long-term debt rate
ADJ_STCMER_r	=	historical weighted average deviation constant (fraction) for common equity rate of return
ADJ_STPFER_r	=	historical weighted average deviation constant (fraction) for preferred stock rate of return
$STPFEN_{r,t}$	=	total return on preferred stock for existing capacity (dollars) [read in as D_PFEN]
$STCMEN_{r,t}$	=	total return on common stock equity for existing capacity (dollars) [read in as D_CMEN]
$STLTDN_{r,t}$	=	total return on long-term debt for existing capacity (dollars) read in as D_LTDN]
$STPFES_{r,t}$	=	value of preferred stock for existing capacity (dollars) [read in as D_PFES]
$STCMES_r$	=	value of common stock equity for existing capacity (dollars) [read in as D_CMES]
$STLTDS_r$	=	value of long-term debt for existing capacity (dollars) [read in as D_LTDS]
$MC\_RMPUAANS_t$	=	AA utility bond index rate provided by the Macroeconomic Activity Module (MC_RMCORPPUAA, percentage)
$STGPIS_{r,t}$	=	original capital cost of plant in service (dollars) [read in as D_GPIS]
r	=	NGTDM region
t	=	forecast year

Computation of adjusted rate base, $STAPRB_{r,t}$ [93]

The adjusted rate base for existing and new storage facilities in an NGTDM region has three components and can be written as follows:

$$STAPRB_{r,t} = STNPIS_{r,t} + STCWC_{r,t} - STADIT_{r,t} \quad (259)$$

[93] In this section, any variable ending with "_E" will signify that the variable is for the existing storage capacity as of the end of 1998, and any variable ending with "_N" will mean that the variable is for the new storage capacity added from 1999 to 2025.

where,

$STAPRB_{r,t}$ = adjusted storage rate base for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STCWC_{r,t}$ = total cash working capital for existing and new capacity (dollars)
$STADIT_{r,t}$ = accumulated deferred income taxes for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The net plant in service is the level of gross plant in service minus the accumulated depreciation, depletion, and amortization. It is given by the following equation:

$$STNPIS_{r,t} = STGPIS_{r,t} - STADDA_{r,t-1} \tag{260}$$

where,

$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

The gross and net plant-in-service variables can be written as the sum of their respective existing and new gross and net plants in service as follows:

$$STGPIS_{r,t} = STGPIS\_E_{r,t} + STGPIS\_N_{r,t} \tag{261}$$

$$STNPIS_{r,t} = STNPIS\_E_{r,t} + STNPIS\_N_{r,t} \tag{262}$$

where,

$STGPIS_{r,t}$ = gross plant in service for existing and new capacity (dollars)
$STNPIS_{r,t}$ = net plant in service for existing and new capacity (dollars)
$STGPIS\_E_{r,t}$ = gross plant in service for existing capacity (dollars)
$STGPIS\_N_{r,t}$ = gross plant in service for new capacity (dollars)
$STNPIS\_E_{r,t}$ = net plant in service for existing capacity (dollars)
$STNPIS\_N_{r,t}$ = net plant in service for new capacity (dollars)
r = NGTDM region
t = forecast year

For the same reason as above, the accumulated depreciation, depletion, and amortization for t-1 can be split into its existing and new accumulated depreciation:

$$STADDA_{r,t-1} = STADDA\_E_{r,t-1} + STADDA\_N_{r,t-1} \tag{263}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity (dollars)
$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

The accumulated depreciation for the current year t is expressed as last year's accumulated depreciation plus this year's depreciation. For the separate existing and new storage capacity, their accumulated depreciation, depletion, and amortization can be expressed separately as follows:

$$STADDA\_E_{r,t} = STADDA\_E_{r,t-1} + STDDA\_E_{r,t} \tag{264}$$

$$STADDA\_N_{r,t} = STADDA\_N_{r,t-1} + STDDA\_N_{r,t} \tag{265}$$

where,

$STADDA\_E_{r,t}$ = accumulated depreciation, depletion, and amortization for existing capacity (dollars)
$STADDA\_N_{r,t}$ = accumulated depreciation, depletion, and amortization for new capacity (dollars)
$STDDA\_E_{r,t}$ = depreciation, depletion, and amortization for existing capacity (dollars)
$STDDA\_N_{r,t}$ = depreciation, depletion, and amortization for new capacity (dollars)
r = NGTDM region
t = forecast year

Total accumulated depreciation, depletion, and amortization for the combined existing and new capacity by storage region in year t is determined as the sum of previous year's accumulated depreciation, depletion, and amortization and current year's depreciation, depletion, and amortization for that total capacity.

$$STADDA_{r,t} = STADDA_{r,t-1} + STDDA_{r,t} \tag{266}$$

where,

$STADDA_{r,t}$ = accumulated depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA_{r,t}$ = annual depreciation, depletion, and amortization for existing and new capacity in dollars
r = NGTDM region
t = forecast year

Computation of annual depreciation, depletion, and amortization, $STDDA_{r,t}$

Annual depreciation, depletion, and amortization for a storage region in year t is the sum of depreciation, depletion, and amortization for the combined existing and new capacity associated with that region.

$$STDDA_{r,t} = STDDA\_E_{r,t} + STDDA\_N_{r,t} \tag{267}$$

where,

$STDDA_{r,t}$	=	annual depreciation, depletion, and amortization for existing and new capacity in dollars
$STDDA\_E_{r,t}$	=	depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_N_{r,t}$	=	depreciation, depletion, and amortization costs for new capacity in dollars
r	=	NGTDM region
t	=	forecast year

A regression equation is used to determine the annual depreciation, depletion, and amortization for existing capacity associated with an NGTDM region, while an accounting algorithm is used for new storage capacity. For existing capacity, this depreciation expense by NGTDM region is forecast as follows:

$$\begin{aligned} STDDA\_E_{r,t} = {} & STDDA\_CREG_{r} + STDDA\_NPIS * STNPIS\_E_{r,t-1} \\ & + STDDA\_NEWCAP * STNEWCAP_{r,t} \end{aligned} \tag{268}$$

where,

$STDDA\_E_{r,t}$	=	annual depreciation, depletion, and amortization costs for existing capacity in dollars
$STDDA\_CREG_{r}$	=	constant term estimated by region (Appendix F, Table F3)
STDDA_NPIS	=	estimated coefficient for net plant in service for existing capacity (Appendix F, Table F3)
STDDA_NEWCAP	=	estimated coefficient for the change in gross plant in service for existing capacity (Appendix F, Table F3)
$STNPIS\_E_{r,t}$	=	net plant in service for existing capacity (dollars)
$STNEWCAP_{r,t}$	=	change in gross plant in service for existing capacity (dollars)
r	=	NGTDM region
t	=	forecast year

The accounting algorithm used to define the annual depreciation, depletion, and amortization for new capacity assumes straight-line depreciation over a 30-year life, as follows:

$$STDDA\_N_{r,t} = STGPIS\_N_{r,t} / 30 \tag{269}$$

where,

$STDDA\_N_{r,t}$	=	annual depreciation, depletion, and amortization for new capacity in dollars
$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity in dollars
30	=	30 years of plant life
r	=	NGTDM region
t	=	forecast year

In the above equation, the capital cost of new plant in service (STGPIS_Nr,t) in year t is computed as the accumulated new capacity expansion expenditures from 1999 to year t and is determined by the following equation:

$$STGPIS\_N_{r,t} = \sum_{s=1999}^{t} STNCAE_{r,s} \tag{270}$$

where,

$STGPIS\_N_{r,t}$	=	gross plant in service for new capacity expansion in dollars
$STNCAE_{r,s}$	=	new capacity expansion expenditures occurring in year s after 1998 (in dollars)
s	=	the year new expansion occurred
r	=	NGTDM region
t	=	forecast year

The new capacity expansion expenditures allowed in the rate base within a forecast year are derived for each NGTDM region from the amount of incremental capacity additions determined by the ITS:

$$STNCAE_{r,t} = STCCOST_{r,t} * STCAPADD_{r,t} * 1{,}000{,}000. \tag{271}$$

where,

$STNCAE_{r,t}$	=	total capital cost to expand capacity for an NGTDM region (dollars)
$STCCOST_{r,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
$STCAPADD_{r,t}$	=	storage capacity additions as determined in the ITS (Bcf/yr)
r	=	NGTDM region
t	=	forecast year

The capital cost per unit of natural gas storage expansion in an NGTDM region (STCCOSTr,t) is computed as its 1998 unit capital cost times a function of a capacity expansion factor relative to the 1998 storage capacity. This expansion factor represents a relative change in capacity since 1998. Whenever the ITS forecasts storage capacity additions in year t in an NGTDM region, the increased capacity is computed for that region from 1998 and the unit capital cost is computed. Hence, the capital cost to expand capacity in an NGTDM region can be estimated from any amount of capacity additions in year t provided by the ITS and the associated unit capital cost. This capital cost represents the investment cost for generic storage companies associated with that region. The unit capital cost (STCCOSTr,t) is computed by the following equations:

$$STCCOST_{r,t} = STCCOST\_CREG_r * e^{(BETAREG_r * STEXPFAC98_r)} * (1.0 + STCSTFAC) \tag{272}$$

where,

$STCCOSTr_{,t}$	=	capital cost per unit of natural gas storage expansion (dollars per Mcf)
STCCOST_CREG	=	1998 capital cost per unit of natural gas storage expansion (1998 dollars per Mcf)
$BETAREG_r$	=	expansion factor parameter (set to STCCOST_BETAREG, Appendix E)

$STEXPFAC98_r$ = relative change in storage capacity since 1998
STCSTFAC = factor to set a particular storage region's expansion cost, based on an average [Appendix E]
r = NGTDM region
t = forecast year

The relative change in storage capacity is computed as follows:

$$STEXPFAC98_r = \frac{PTCURPSTR_{r,t}}{PTCURPSTR_{r,1998}} - 1.0 \tag{273}$$

where,

$PTCURPSTR_{r,t}$ = current storage capacity (Bcf)
$PTCURPSTR_{r,1998}$ = 1998 storage capacity (Bcf)
r = NGTDM region
t = forecast year

Computation of total cash working capital, $STCWC_{r,t}$

The total cash working capital represents the level of working capital at the beginning of year t deflated using the chain-weighted GDP price index with 1996 as a base year. This cash working capital variable is expressed as a non-linear function of total gas storage capacity (base gas capacity plus working gas capacity) as follows:

$$\begin{aligned} R\_STCWC_{r,t} = {} & e^{(STCWC\_CREG_r * (1-\rho))} * DSTTCAP_{r,t-1}^{STCWC\_TOTCAP} * \\ & R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * STCWC\_TOTCAP} \end{aligned} \tag{274}$$

where,

$R\_STCWC_{r,t}$ = total cash working capital at the beginning of year t for existing and new capacity (1996 dollars)
$STCWC\_CREG_r$ = constant term, estimated by region (Appendix F, Table F3)
ρ = autocorrelation coefficient from estimation (Appendix F, Table F3 − STCWC_RHO)
$STTCAP_{r,t}$ = total gas storage capacity (Bcf)
STCWC_TOTCAP = estimated DSTTCAP coefficient (Appendix F, Table F3)
r = NGTDM region
t = forecast year

This total cash working capital in 1996 dollars is converted to nominal dollars to be consistent with the convention used in this submodule.

$$STCWC_{r,t} = R\_STCWC_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \tag{275}$$

where,

$STCWC_{r,t}$	=	total cash working capital at the beginning of year t for existing and new capacity (nominal dollars)
$R\_STCWC_{r,t}$	=	total cash working capital at the beginning of year t for existing and new capacity (1996 dollars)
MC_PCWGDP_{t}	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
r	=	NGTDM region
t	=	forecast year

Computation of accumulated deferred income taxes, $STADIT_{r,t}$

The level of accumulated deferred income taxes for the combined existing and new capacity in year t in the adjusted rate base equation is a stock (not a flow) and depends on income tax regulations in effect, differences in tax, and book depreciation. It can be expressed as a linear function of its own lagged variable and the change in the level of gross plant in service between time t and t-1. The forecasting equation can be written as follows:

$$STADIT_{r,t} = STADIT\_C + (STADIT\_ADIT * STADIT_{r,t-1}) + (STADIT\_NEWCAP * NEWCAP_{r,t}) \quad (276)$$

where,

$STADIT_{r,t}$	=	accumulated deferred income taxes in dollars
STADIT_C	=	constant term from estimation (Appendix F, Table F3)
STADIT_ADIT	=	estimated coefficient for lagged accumulated deferred income taxes (Appendix F, Table F3)
STADIT_NEWCAP	=	estimated coefficient for change in gross plant in service (Appendix F, Table F3)
$NEWCAP_{r,t}$	=	change in gross plant in service for the combined existing and new capacity between years t and t-1 (in dollars)
r	=	NGTDM region
t	=	forecast year

Computation of total taxes, $STTOTAX_{r,t}$

Total taxes consist of Federal income taxes, State income taxes, deferred income taxes, and other taxes. Federal income taxes and State income taxes are calculated using average tax rates. The equation for total taxes is as follows:

$$STTOTAX_{r,t} = STFSIT_{r,t} + STDIT_{r,t} + STOTTAX_{r,t} \quad (277)$$

$$STFSIT_{r,t} = STFIT_{r,t} + STSIT_{r,t} \quad (278)$$

where,

$STTOTAX_{r,t}$	=	total federal and state income tax liability for existing and new capacity (dollars)
$STFSIT_{r,t}$	=	federal and state income tax for existing and new capacity (dollars)
$STFIT_{r,t}$	=	federal income tax for existing and new capacity (dollars)

$STSIT_{r,t}$ = state income tax for existing and new capacity (dollars)
$STDIT_{r,t}$ = deferred income taxes for existing and new capacity (dollars)
STOTTAX = all other taxes assessed by federal, state, or local governmentsfor existing and new capacity (dollars)
r = NGTDM region
t = forecast year

Federal income taxes are derived from returns to common stock equity and preferred stock (after-tax profit) and the federal tax rate. The after-tax profit is the operating income excluding the total long-term debt, which is determined as follows:

$$STATP_{r,t} = STAPRB_{r,t} * (STPFER_{r,t} * STGPFESTR_r + STCMER_{r,t} * STGCMESTR_r) \quad (279)$$

$$STATP_{r,t} = (STPFEN_{r,t} + STCMEN_{r,t}) \quad (280)$$

where,

$STATP_{r,t}$ = after-tax profit for existing and new capacity (dollars)
$STAPRB_{r,t}$ = adjusted pipeline rate base for existing and new capacity (dollars)
$STPFER_{r,t}$ = coupon rate for preferred stock for existing and new capacity (fraction)
$STGPFESTR_r$ = historical average capital structure for preferred stock for existing and new capacity (fraction), held constant over the forecast period
$STCMER_{r,t}$ = common equity rate of return for existing and new capacity (fraction)
$STGCMESTR_r$ = historical average capital structure for common stock for existing and new capacity (fraction), held constant over the forecast period
$STPFEN_{r,t}$ = total return on preferred stock for existing and new capacity (dollars)
$STCMEN_{r,t}$ = total return on common stock equity for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

and the federal income taxes are

$$STFIT_{r,t} = (FRATE * STATP_{r,t}) / (1. - FRATE) \quad (281)$$

where,

$STFIT_{r,t}$ = federal income tax for existing and new capacity (dollars)
FRATE = federal income tax rate (fraction, Appendix E)
$STATP_{r,t}$ = after-tax profit for existing and new capacity (dollars)
r = NGTDM region
t = forecast year

State income taxes are computed by multiplying the sum of taxable profit and the associated federal income tax by a weighted-average state tax rate associated with each NGTDM region. State income taxes are computed as follows:

$$STSIT_{r,t} = SRATE * (STFIT_{r,t} + STATP_{r,t}) \tag{282}$$

where,

$STSIT_{r,t}$	=	state income tax for existing and new capacity (dollars)
SRATE	=	average state income tax rate (fraction, Appendix E)
$STFIT_{r,t}$	=	federal income tax for existing and new capacity (dollars)
$STATP_{r,t}$	=	after-tax profits for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Deferred income taxes for existing and new capacity at the arc level are the differences in the accumulated deferred income taxes between year t and year t-1.

$$STDIT_{r,t} = STADIT_{r,t} - STADIT_{r,t-1} \tag{283}$$

where,

$STDIT_{r,t}$	=	deferred income taxes for existing and new capacity (dollars)
$STADIT_{r,t}$	=	accumulated deferred income taxes for existing and new capacity (dollars)
r	=	NGTDM region
t	=	forecast year

Other taxes consist of a combination of ad valorem taxes (which grow with company revenue), property taxes (which grow in proportion to gross plant), and all other taxes (assumed constant in real terms). Other taxes in year t are determined as the previous year's other taxes adjusted for inflation.

$$STOTTAX_{r,t} = STOTTAX_{r,t-1} * (MC\_PCWGDP_t / MC\_PCWGDP_{t-1}) \tag{284}$$

where,

$STOTTAX_{r,t}$	=	all other taxes assessed by federal, state, or local governments except income taxes for existing and new capacity (dollars) [read in asD_OTTAXr,t , t=1990-1998]
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
r	=	NGTDM region
t	=	forecast year

Computation of total operating and maintenance expenses, $STTOM_{r,t}$

The total operating and maintenance costs (including administrative costs) for existing and new capacity in an NGTDM region are determined in 1996 real dollars using a log-linear form with correction for serial correlation. The estimated equation is determined as a function of working gas storage capacity for region r at the beginning of period t. In developing the estimations, the impact of regulatory change and the differences between producing and consuming regions were analyzed.[94] Because their impacts were not supported by the data, they were not accounted for in the estimations. The final estimating equation is:

$$R\_STTOM_{r,t} = e^{(STTOM\_C*(1-\rho))} * DSTWCAP_{r,t-1}^{STTOM\_WORKCAP} * \\ R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*STTOM\_WORKCAP} \tag{285}$$

where,

$R\_STTOM_{r,t}$	=	total operating and maintenance cost for existing and new capacity (1996 dollars)
STTOM_C	=	constant term from estimation (Appendix F, Table F3)
ρ	=	autocorrelation coefficient from estimation (Appendix F, Table F3 -- STTOM_RHO)
$DSTWCAP_{r,t}$	=	level of gas working capacity for region r during year t
STTOM_WORKCAP	=	estimated DSTWCAP coefficient (Appendix F, Table F3)
r	=	NGTDM region
t	=	forecast year

Finally, the total operating and maintenance costs are converted to nominal dollars to be consistent with the convention used in this submodule.

$$STTOM_{r,t} = R\_STTOM_{r,t} * \frac{MC\_PCWGDP_t}{MC\_PCWGDP_{1996}} \tag{286}$$

where,

$STTOM_{r,t}$	=	total operating and maintenance costs for existing and new capacity (nominal dollars)
$R\_STTOM_{r,t}$	=	total operating and maintenance costs for existing and new capacity (1996 dollars)
MC_PCWGDP_t	=	GDP chain-type price deflator (from the Macroeconomic Activity Module)
r	=	NGTDM region
t	=	forecast year

Computation of storage tariff

The regional storage tariff depends on the storage cost of service, current working gas capacity, utilization rate, natural gas storage activity, and other factors. The functional form is similar to the pipeline tariff curve, in that it will be built from a regional base point [price and quantity (PNOD,QNOD)]. The base regional storage tariff ($PNOD_{r,t}$) is determined as a function of the cost of service ($STCOS_{r,t}$ (equation 243)) and other factors discussed below. $QNOD_{r,t}$ is set to an effective working gas storage capacity by region, which is defined as a regional working gas capacity times its utilization rate. Hence,

[94] The gas storage industry changed substantially when in 1994 FERC Order 636 required jurisdictional pipeline companies to operate their storage facilities on an open-access basis. The primary customers and use of storage in producing regions are significantly different from consuming regions.

once the storage cost of service is computed by region, the base point can be established. Minor adjustments to the storage tariff routine will be necessary in order to obtain the desired results.

In the model, the storage cost of service used represents only a portion of the total storage cost of service, the revenue collected from the customers for withdrawing during the peak period the quantity of natural gas stored during the off-peak period. This portion is defined as a user-set percentage (STRATIO, Appendix E) representing the portion (ratio) of revenue requirement obtained by storage companies for storing gas during the off-peak and withdrawing it for the customers during the peak period. This would include charges for injections, withdrawals, and reserving capacity.

The cost of service $STCOS_{r,t}$ is computed using the Foster storage financial database which represents only the storage facilities owned by the interstate natural gas pipelines in the United States which have filed a Form 2 financial report with the FERC. Therefore, an adjustment to this cost of service to account for all the storage companies by region is needed. For example, at the national level, the Foster database shows the underground storage working gas capacity at 2.3 Tcf in 1998 and the EIA storage gas capacity data show much higher working gas capacity at 3.8 Tcf. Thus, the average adjustment factor to obtain the “actual” cost of service across all regions in the U.S. is 165 percent. This adjustment factor, STCAP_ADJr,t, varies from region to region.

To complete the design of the storage tariff computation, two more factors need to be incorporated: the regional storage tariff curve adjustment factor and the regional efficiency factor for storage operations, which makes the storage tariff more competitive in the long run.

Hence, the regional average storage tariff charged to customers for moving natural gas stored during the off-peak period and withdrawn during the peak period can be computed as follows:

$$PNOD_{r,t} = \frac{STCOS_{r,t}}{(MC\_PCWGDP_t * QNOD_{r,t} * 1{,}000{,}000.)} * STRATIO_{r,t} * STCAP\_ADJ_{r,t} * ADJ\_STR * (1.0 - STR\_EFF/100.)^t \quad (287)$$

where,

$$STCAP\_ADJ_{r,t} = \frac{PTCURPSTR_{r,t}}{FS\_PTCURPSTR_{r,t}} \quad (288)$$

$$QNOD_{r,t} = PTCURPSTR_{r,t} * PTSTUTZ_{r,t} \quad (289)$$

and,

$PNOD_{r,t}$	=	base point, price (1987$/Mcf)
$STCOS_{r,t}$	=	storage cost of service for existing and new capacity (dollars)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
MC_PCWGDP_t	=	GDP chain-type price deflator (from Macroeconomic Activity Module)

$STRATIO_{r,t}$	=	portion of revenue requirement obtained by moving gas from the off-peak to the peak period (fraction, Appendix E)
$STCAP\_ADJ_{r,t}$	=	adjustment factor for the cost of service to total U.S. (ratio)
ADJ_STR	=	storage tariff curve adjustment factor (fraction, Appendix E)
STR_EFF	=	efficiency factor (percent) for storage operations (Appendix E)
$PTSTUTZ_{r,t}$	=	storage utilization (fraction)
$PTCURPSTR_{r,t}$	=	current storage capacity (Bcf)
$FS\_PTCURPSTR_{r,t}$	=	Foster storage working gas capacity (Bcf) [read in as D_WCAP]
r	=	NGTDM region
t	=	forecast year

Finally, the storage tariff curve by region can be expressed as a function of a base point [price and quantity (PNOD, QNOD)], storage flow, and a price elasticity, as follows:

current capacity segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA\_STR} \quad (290)$$

capacity expansion segment:

$$X1NGSTR\_VARTAR_{r,t} = PNOD_{r,t} * (Q_{r,t} / QNOD_{r,t})^{ALPHA2\_STR} \quad (291)$$

where,

$X1NGSTR\_VARTAR_{r,t}$	=	function to define storage tariffs (1987$/Mcf)
$PNOD_{r,t}$	=	base point, price (1987$/Mcf)
$QNOD_{r,t}$	=	base point, quantity (Bcf)
$Q_{r,t}$	=	regional storage flow (Bcf)
ALPHA_STR	=	price elasticity for storage tariff curve for current capacity (Appendix E)
ALPHA2_STR	=	price elasticity for storage tariff curve for capacity expansion segment (Appendix E)
r	=	NGTDM region
t	=	forecast year

Alaska and Mackenzie delta pipeline tariff routine

A single routine (FUNCTION NGFRPIPE_TAR) estimates the potential per-unit pipeline tariff for moving natural gas from either the North Slope of Alaska or the Mackenzie Delta to the market hub in Alberta, Canada for the years beyond the specified in-service date. The tariff estimates are based on a simple cost-of-service rate base methodology, given the infrastructure's initial capital cost at the beginning of the construction period (FR_CAPITL0 in billion dollars, Appendix E), the assumed number of years for the project to be completed (FRPCNSYR, Appendix E), the associated discount rate for the project (FR_DISCRT, Appendix E), the initial capacity (a function of delivered volume FR_PVOL, Appendix E), and the number of years over which the final cost of capitalization is assumed completely amortized (INVEST_YR=15). The input values vary depending on whether the tariff being calculated is associated with a pipeline for Alaska or for Mackenzie Delta gas. The cost of service consists of the following four components: depreciation, depletion, and amortization; after-tax operating income (known as the return on rate base); total operating and maintenance expenses; and total income taxes. The computation of each of the four components in nominal dollars per Mcf is described below:

Depreciation, depletion, and amortization, FR_DDA_t

The depreciation is computed as the final cost of capitalization at the start of operations divided by the amortization period. The depreciation equation is provided below:

$$FR\_DDA_t = FR\_CAPITL1 / INVEST\_YR \tag{292}$$

where,

FR_DDA_t	=	depreciation, depletion, and amortization costs (thousand nominal dollars)
FR_CAPITL1	=	final cost of capitalization at the start of operations (thousand nominal dollars)
INVEST_YR	=	investment period allowing recovery (parameter, INVEST_YR=15)
t	=	forecast year

The structure of the final cost of capitalization, FR_CAPITL1, is computed as follows:

$$FR\_CAPITL1 = FR\_CAPIT0 / FR\_PCNSYR * [(1+r) + (1+r)^2 + ... + (1+r)^{FR\_PCNSYR}] \tag{293}$$

where,

FR_CAPITL1	=	final cost of capitalization at the start of operations (thousand nominal dollars)
FR_CAPITL0	=	initial capitalization (thousand FR_CAPYR dollars), where FR_CAPYR is the year dollars associated with this assumed capital cost (Appendix E)
FR_PCNSYR	=	number of construction years (Appendix E)
r	=	cost of debt, fraction, which is equal to the nominal 10-year Treasury bill (MC_RMTCM10Y or TNOTE, in percent) plus a debt premium in percent (debt premium set to FR_DISCRT, Appendix E)

The net plant in service is tied to the depreciation by the following formulas:

$$\begin{aligned} FR\_NPIS_t &= FR\_GPIS_t - FR\_ADDA_t \\ FR\_ADDA_t &= FR\_ADDA_{t-1} + FR\_DDA_t \end{aligned} \tag{294}$$

where,

FR_GPIS_t	=	original capital cost of plant in service (gross plant in service) in thousand nominal dollars, set to FR_CAPITL1.
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
FR_ADDA_t	=	accumulated depreciation, depletion, and amortization in thousand nominal dollars
t	=	forecast year

After-tax operating income (return on rate base), FR_TRRB_t

This after-tax operating income, also known as the return on rate base, is computed as the net plant in service times an annual rate of return (FR_ROR, Appendix E). The net plant in service, FR_NPIS_t, is updated each year and is equal to the initial gross plant in service minus accumulated depreciation. Net plant in service becomes the adjusted rate base when other capital-related costs such as materials and supplies, cash working capital, and accumulated deferred income taxes are equal to zero.

The return on rate base is computed as follows:

$$FR\_TRRB_t = WACC_t * FR\_NPIS_t \quad (295)$$

where,

$$\begin{aligned} WACC_t = {} & FR\_DEBTRATIO * COST\_OF\_DEBT_t + \\ & (1.0 - FR\_DEBTRATIO) * COST\_OF\_EQUITY_t \end{aligned} \quad (296)$$

and

$$COST\_OF\_DEBT_t = (TNOTE_t + FR\_DISCRT) / 100. \quad (297)$$

$$COST\_OF\_EQUITY_t = (TNOTE_t \; / 100. \quad (298)$$

where,

FR_TRRB_t	=	after-tax operating income or return on rate base (thousand nominal dollars)
$WACC_t$	=	weighted average cost of capital (fraction), nominal
FR_NPIS_t	=	net plant in service (thousand nominal dollars)
$COST\_OF\_DEBT_t$	=	cost of debt (fraction)
$COST\_OF\_EQUITY_t$	=	cost of equity (fraction)
$TNOTE_t$	=	nominal 10-year Treasury bill rate, (MC_RMTCM10Yt, percent) provided by the Macroeconomic Activity Module
FR_DISCRT	=	user-set debt premium, percent (Appendix E)
FR_ROR_PREM	=	user-set risk premium, percent (Appendix E)
t	=	forecast year

Total taxes, FR_TAXES_t

Total taxes consist of federal and state income taxes and taxes other than income taxes. Each tax category is computed based on a percentage times net profit. These percentages are drawn from the Foster financial report's 28 major interstate natural gas pipeline companies. The percentage for income taxes (FR_TXR) is computed as the average over five years (1992-1996) of tax-to-net-operating-income ratio from the Foster report. Likewise, the percentage (FR_OTXR) for taxes other than income taxes is computed as the average over five years (1992-1996) of taxes-other-than-income-taxes-to-net-operating-income ratio from the same report. Total taxes are computed as follows:

$$FR\_TAXES_t = (FR\_TXR + FR\_OTXR) * FR\_NETPFT_t \quad (299)$$

where,

FR_TAXES_t = total taxes (thousand nominal dollars)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TXR = 5-year average Lower 48 pipeline income tax rate, as a proxy (Appendix E)
FR_OTXR = 5-year average Lower 48 pipeline other income tax rate, as a proxy (Appendix E)
t = forecast year

Net profit, FR_NETPFT, is computed as the return on rate base (FR_TRRB_t) minus the long-term debt (FR_LTDt), which is calculated as the return on rate base times long-term debt rate times the debt to capital structure ratio. The net profit and long-term debt equations are provided below:

$$FR\_NETPFT_t = (FR\_TRRB_t - FR\_LTD_t) \tag{300}$$

$$FR\_LTD_t = FR\_DEBTRATIO * (TNOTE_t + FR\_DISCRT) / 100.0 * FR\_NPIS_t \tag{301}$$

where,

FR_LTD_t = long-term debt (thousand nominal dollars)
FR_NPIS_t = net plant in service (thousand nominal dollars)
FR_DEBTRATIO = 5-year average Lower 48 pipeline debt structure ratio (Appendix E)
FR_NETPFT_t = net profit (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
$TNOTE_t$ = nominal 10-year Treasury bill, (MC_RMTCM10Y, percent) provided by the Macroeconomic Activity Module
FR_DISCRT = user-set debt premium, percent (Appendix E)
t = forecast year

In the above equations, the long-term debt rate is assumed equal to the 10-year Treasury bill plus a debt premium, which represents a risk premium generally charged by financial institutions. When 10-year Treasury bill rates are needed for years beyond the last forecast year (LASTYR), the variable $TNOTE_t$ becomes the average over a number of years (FR_ESTNYR, Appendix E) of the 10-year Treasury bill rates for the last forecast years.

Cost of service, FR_COS_t

The cost of service is the sum of four cost-of-service components computed above, as follows:

$$FR\_COS_t = (FR\_TRRB_t + FR\_DDA_t + FR\_TAXES_t + FR\_TOM_{FR\_CAPYR} * (MC\_PCWGDP_t / MC\_PCWGDP_{FR\_CAPYR}) * FR\_PVOL * 1.1484 * 1000.0) \tag{302}$$

where,

FR_COS_t = cost of service (thousand nominal dollars)
FR_TRRB_t = return on rate base (thousand nominal dollars)
FR_DDA_t = depreciation (thousand nominal dollars)

FR_TAXES_t = total taxes (thousand nominal dollars)
FR_TOMFR_CAPYR = total operating and maintenance expenses (in nominal dollars per Mcf, set constant in real terms) (Appendix E)
MC_PCWGDP_t = GDP price deflator (from Macroeconomic Activity Module)
FR_PVOL = maximum volume delivered to Alberta in dry terms (Bcf/year)
1.1484 = factor to convert delivered dry volume to wet gas volume entering the pipeline as a proxy for the pipeline capacity
t = forecast year

Hence, the annual pipeline tariff in nominal dollars is computed by dividing the above cost of service by total pipeline capacity, as follows:

$$COS_t = FR\_COS_t / (FR\_PVOL * 1.1484 * 1000.0) \tag{303}$$

where,

COS_t = per-unit cost of service or annual pipeline tariff (nominal dollars/Mcf)
t = forecast year

To convert this nominal tariff to 1987 dollars per Mcf, the GDP implicit price deflator variable provided by the Macroeconomic Activity Module is needed. The real tariff equation is written as follows:

$$COSR_t = COS_t / MC\_PCWGDP_t \tag{304}$$

where,

$COSR_t$ = annual real pipeline tariff (1987$/Mcf)
MC_PCWGDP_t = GDP price deflator (from Macroeconomic Activity Module)
t = forecast year

Last, the annual average tariff is computed as the average over a number of years (FR_AVGTARYR, Appendix E) of the first successive annual cost of services.

7. Model Assumptions, Inputs, and Outputs

This last chapter summarizes the model and data assumptions used by the Natural Gas Transmission and Distribution Module (NGTDM), and lists the primary data inputs to and outputs from the NGTDM.

Assumptions

This section presents a brief summary of the assumptions used within the NGTDM. Generally, there are two types of data assumptions that affect the NGTDM solution values. The first type can be derived based on historical data (past events), and the second type is based on experience and/or events that are likely to occur (expert or analyst judgment). A discussion of the rationale behind assumed values based on analyst judgment is beyond the scope of this report. Most of the FORTRAN variables related to model input assumptions, both those derived from known sources and those derived through analyst judgment, are identified in this chapter, with background information and actual values referenced in Appendix E.

The assumptions summarized in this section are mentioned in Chapters 2 through 6. They are used in NGTDM equations as starting values, coefficients, factors, shares, bounds, or user-specified parameters. Six general categories of data assumptions have been defined: classification of market services; demand, transmission and distribution service pricing; pipeline tariffs and associated regulation; pipeline capacity and utilization; and supply (including imports). These assumptions, along with their variable names, are summarized below.

Market service classification

Non-electric sector natural gas customers are classified as either core or noncore customers, with core customers defined as the type of customer that is expected to generally transport their gas under firm (or near-firm) transportation agreements and noncore customers expected to generally transport their gas under non-firm (interruptible or short-term capacity release) transportation agreements. The residential, commercial, and transportation (natural gas vehicles) sectors are assumed to be core customers. The transportation sector is further subdivided into fleet and personal vehicle customers with LNG and CNG vehicles. Industrial and electric generator end users fall into both categories, with energy-intensive industries and refineries assumed to be noncore and all other industrial users assumed to be core, and gas steam units or gas combined-cycle units assumed to be core and all other electric generators assumed to be noncore. Currently the core/noncore distinction for electric generators is not being used in the model.

Demand

The peak period is defined (*using PKOPMON*) to run from December through March, with the off-peak period filling up the remainder of the year.

The Alaskan natural gas consumption levels for residential and commercial sectors are primarily defined as a function of the number of customers (*AK_RN, AK_CM, Tables F1, F2*), which in turn are set based on an exogenous projection of the population in Alaska (*AK_POP*). Alaskan gas consumption is disaggregated into North and South Alaska in order to separately compute the natural gas production forecasts in these regions. Lease, plant, and pipeline fuel related to an Alaska pipeline to Alberta or to a new LNG export facility is set at an assumed percentage of their associated gas volumes (*AK_PCTPLT, AK_PCTPIP, AK_PCTLSE*).

The remaining lease and plant fuel is assumed to be consumed in the North and set based on historical trends. The amount of gas consumed by other sectors in North Alaska is small enough to assume as zero and to allow for the setting of South Alaska volumes equal to the totals for the State. Industrial consumption in South Alaska is set to the exogenously specified sum of the level of gas consumed at the Agrium fertilizer plant and at the liquefied natural gas plant (*AK_QIND_S*). Pipeline fuel in the South is set as a percentage (*AK_PCTPIP*) of consumption and exports. Production in the south is set to total consumption levels in the region. In the North, production equals the flow along an Alaska pipeline to Alberta or to a new LNG export facility, associated lease, plant, and pipeline fuel for either of these two projects, and the other calculated lease and plant fuel. The forecast for reporting discrepancy in Alaska (*AK_DISCR*) is set to an average historical value. To compute natural gas prices by end-use sector for Alaska, fixed markups derived from historical data (*AK_RM, AK_CM, AK_IN, AK_EM*) are added to the average Alaskan natural gas wellhead price over the North and South regions. The wellhead price is set using a simple estimated equation (*AK_F*). Historically based percentages and markups are held constant throughout the forecast period.

The shares (NG_CENSHR) for disaggregating non-electric Census Division demands to NGTDM regions are held constant throughout the forecast period and are based on average historical relationships (SQRS, SQCM, SQIN, SQTR). Similarly, the shares for disaggregating end-use consumption levels to peak and off-peak periods are held constant throughout the forecast, and are directly (*United States -- PKSHR_DMD, PKSHR_UDMD_F, PKSHR_UDMD_I*) or partially (*Canada -- PKSHR_CDMD*) historically based.

Canadian consumption levels are set exogenously (*CN_DMD*) based on another published forecast, and adjusted if the associated world oil price changes. Consumption, base-level production, and domestically consumed LNG imports into Mexico are set exogenously (*PEMEX_GFAC, IND_GFAC, ELE_GFAC, RC_GFAC, PRD_GFAC, MEXLNG*). After the base-level production is adjusted based on the average U.S. spot price, exports to Mexico are set to balance supply and consumption. Historically based shares (*PKSHR_ECAN, PKSHR_EMEX, PKSHR_ICAN, PKSHR_IMEX, PKSHR_ILNG, PKSHR_ELNG*) are applied to projected/historical values for natural gas exports and imports (*SEXP, SIMP, CANEXP, Q23TO3, FLO_THRU_IN,OGQNGEXP*). These historically based shares are generated from monthly historical data (*MON_QEXP, MON_QIMP*). LNG exports of domestically produced natural gas (*OGQNGEXP*) are set endogenously based on assumptions driving the price of natural gas in Europe and Asia relative to domestic prices. Reexported LNG volues (*REEXP*), are set exogenously.

Lease and plant fuel consumption in each NGTDM region is computed as an historically derived percentage (*using SQLP*) of dry gas production (*PCTLP*) in each NGTDM/OGSM region. These percentages are held constant throughout the forecast period. Natural gas used in the process of liquefying natural gas for export or for use in vehicles is added to this base-level lease and plant fuel projection and set as a percentage (PERLIQFUEL) of the associated LNG volumes. Pipeline fuel use is derived using historically (*SQPF*) based factors (*PFUEL_FAC*) relating pipeline fuel use to the quantity of natural gas exiting a regional node. Values for the most recent historical year are derived from monthly-published figures (*QLP_LHIS, NQPF_TOT*).

Projections of LNG exports of domestically produced gas depend on estimates of natural gas prices in Europe and Asia, set as a function of projections flexibly priced LNG in the market (*FLEXLNG*), for natural gas consumption in OECD Europe, Japan, and South Korea, and production and consumption in China

(*QOECD_EUR, QJAP, QSKOR, QCHINA, PCHINA*), as well as world oil prices. Domestic prices plus LNG related costs for liquefaction, shipping, and regasification (*CST_LIQ, CST_SHP, CST_RGAS, CST_RISK, BONUS, LOSSTO, PERFUELCST, DCF_RATE, BONUS*) are compared against these world natural gas price estimates to determine the economic viability over the next 20 years for building a generic liquefaction facility and ultimately the level of LNG exports. Each generic project consists of two trains of standard size (*EVOL_INCR*), with a limit of one train allowed to come online in each calendar year. The siting of a new project depends on relative expected profitability and assumed regional limitations (*FYREXP, MAXEXP*).

Pricing of Distribution Services

End-use prices for residential, commercial, industrial, transportation, and electric generation customers are derived by adding markups to the regional hub price of natural gas. Each regional end-use markup consists of an intraregional tariff (*INTRAREG_TAR*), an intrastate tariff (*INTRAST_TAR*), a distribution tariff (*endogenously defined*), and a city gate benchmark factor [endogenously defined based on historical seasonal city gate prices (*HCGPR*)]. Historical distributor tariffs are derived for all sectors as the difference between historical city gate and end-use prices (*SPRS, SPCM, SPIN, SPEU, SPTR, PRS, PCM PIN, PEU*).[95] Historical industrial end-use prices for core (non-energy-intensive) and noncore (energy-intensive) customers are derived in the module using econometrically estimated equations (Table F5). The residential, commercial, and industrial distributor tariffs are also based on econometrically estimated equations (Tables F4, F6, and F7). The electric generator distributor markup is assumed to change in response to the market share of electric generator natural gas consumption relative to that of the other sectors. The distributor tariffs for the personal (PV) and fleet vehicle (FV) customers of LNG and CNG vehicle fuels are set using using historical data on natural gas delivery charges, electric generator markups (as a proxy), a decline rate (*TRN_DECL*), state and federal taxes (*STAX, FTAX*), and assumed dispensing costs/charges (*RETAIL_COST*) which include relevant costs for LNG liquefaction/distribution.

Prices for exports (and fixed volume imports) are based on historical differences between border prices (SPIM, SPEX, MON_PIMP, MON_PEXP) and their closest market hub price (as determined in the module when executed during the historical years).

Pipeline and storage tariffs and regulation

Peak and off-peak 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. Peak and off-peak market transmission service rates are based on a cost-of-service/rate-of-return calculation for current pipeline capacity times an assumed utilization rate (*PKUTZ, OPUTZ*). To reflect recent regulatory changes related to alternative ratemaking and capacity release developments, these tariffs are discounted (based on an assumed price elasticity) as pipeline utilization rates decline.

In the computation of natural gas pipeline transportation and storage rates, the Pipeline Tariff Submodule uses a set of data assumptions based on historical data or expert judgment. These include the following:

[95] All historical prices are converted from nominal to real 1987 dollars using a price deflator (GDP_B87).

- Factors (*AFX, AFR, AVR*) to allocate each company's line-item costs into the fixed and variable cost components of the reservation and usage fees
- Capacity reservation shares used to allocate cost-of-service components to portions of the pipeline network
- Average pipeline capital cost (2005 dollars) per unit of expanded capacity by arc (*AVGCOST*) used to derive total capital costs to expand pipeline capacity
- Storage capacity expansion cost parameters (*STCCOST_CREG, STCCOST_BETAREG, STCSTFAC*) used to derive total capital costs to expand regional storage capacity
- Input coefficients (*ALPHA_PIPE, ALPH2_PIPE, ALPHA_STR, ALPHA2_STR, ADJ_STR, STR_EFF*) for transportation and storage rates
- Pipeline tariff curve parameters by arc (*PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE*)
- Storage tariff curve parameters by region (*STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR*)

In order to determine when a pipeline from either Alaska or the Mackenzie Delta to Alberta could be economic, the model estimates the tariff that would be charged on both pipelines should they be built, based on a number of assumed values. A simple cost-of-service/rate-of-return calculation is used, incorporating the following: initial capitalization (*FR_CAPITLO*); return on debt (*FR_DISCRT*) and return on equity (*FR_ROR_PREM*) (both specified as a premium added to the 10-year Treasury bill rate); total debt as a fraction of total capital (*FR_DEBTRATIO*); operation and maintenance expenses (*FR_TOM0*); federal income tax rate (*FR_TXR*); other tax rate (*FR_OTXR*); levelized cost period (*FR_AVGTARYR*); and depreciation period (*INVEST_YR*). In order to establish the ultimate charge for the gas in the lower 48 States, assumptions were made for the minimum spot price (FR_PMINWPC) including production, treatment, and fuel costs, as well as the average differential between Alberta and the lower 48 (*ALB_TO_L48*) and a risk premium (*FR_PRISK*) to reflect cost and market uncertainties. The market price in the lower 48 states must be maintained over a planning horizon (*FR_PPLNYR*) before construction would begin. Construction is assumed to take a set number of years (*FR_PCNSYR*) and result in a given initial capacity based on initial delivered volumes (*FR_PVOL*). An additional expansion is assumed on the condition of an increase in the market price (*FR_PADDTAR, FR_PEXPFAC*).

Pipeline and storage capacity and utilization

Historical and planned interregional, intraregional, and Canadian pipeline capacities are assigned in the module for the historical years and the first few years (*NOBLDYR*) into the forecast (*ACTPCAP, PTACTPCAP, PLANPCAP, SPLANPCAP, PER_YROPEN, CNPER_YROPEN*). The flow of natural gas along these pipeline corridors in the peak and off-peak periods of the historical years is set, starting with historical shares (*HPKSHR_FLOW*), to be consistent with the annual flows (*HAFLOW, SAFLOW*) and other known seasonal network volumes (e.g., consumption, production).

A similar assignment is used for storage capacities (*PLANPCAP, ADDYR*). The module only represents net storage withdrawals in the peak period and net storage injections in the off-peak period, which are known historically (*HNETWTH, HNETINJ, SNETWTH, NWTH_TOT, NINJ_TOT*).

For the forecast years, the use of both pipeline and storage capacity in each seasonal period is limited by exogenously set maximum utilization rates (*PKUTZ, OPUTZ, SUTZ*), not currently active for pipelines. They were intended to reflect an expected variant in the load throughout a season, but now adjustments are made within the module during the flow-sharing algorithm to reflect the seasonal load variation.

The decision concerning the share of gas that will come from each incoming source into a region for the purpose of satisfying the region's consumption levels (and some of the consumption upstream) is based on the relative costs of the incoming sources and assumed parameters (*GAMMAFAC, MUFAC*). During the process of deciding the flow of gas through the network, an iterative process is used that requires a set of assumed parameters for assessing and responding to nonconvergence (*PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, MAXCYCLE*).

Supply

The supply curves for domestic lower 48 nonassociated dry gas production and for tight and other gas production from the WCSB are based on an expected production level, the former of which is set in the OGSM. Expected production from the WCSB is set in the NGTDM using a series of three econometric equations for new successful wells drilled, quantity proved per well drilled, and expected quantity produced per current level proved, and is dependent on resource assumptions (*RESBASE, RESTECH*). A set of parameters (*PARM_SUPCRV3, PARM_SUPCRV5, SUPCRV, PARM_SUPELAS*) defines the price change from a base or expected price as production deviates from this expected level. These supply curves are limited by minimum and maximum levels, calculated as a factor (*PARM_MINPR, MAXPRRFAC, MAXPRRCAN*) times the expected production levels. Domestic associated-dissolved gas production is provided by the Oil and Gas Supply Module. Eastern Canadian production from other than the WCSB is set exogenously (*CN_FIXSUP*). Natural gas production in Canada from both coal beds and shale is based on assumed production withdrawal profiles from their perspective resource base totals (*ULTRES, ULTSHL*) at an assumed exogenously specified price path and is adjusted relative to how much the actual western Canadian price differs from the assumed. Production from the frontier areas in Canada (i.e., the Mackenzie Delta) is set based on the assumed size of the pipeline to transport the gas to Alberta, should the pipeline be built. Production from Alaska is a function of the consumption in Alaska and the potential capacity of a pipeline from Alaska to Alberta or to an LNG export facility.

Imports from Mexico and Canada at each border crossing point are represented as follows: (1) Mexican imports are set exogenously (*EXP_FRMEX*) with the exception of LNG imported into Baja for U.S. markets; (2) Canadian imports are set endogenously (except for the imports into the East North Central region, (*Q23TO3*) and limited to Canadian pipeline capacities (*ACTPCAP, CNPER_YROPEN*), which are set in the module, and expand largely in response to the introduction of Alaskan gas into the Alberta system. Total gas imports from Canada exclude the amount of gas that travels into the United States and then back into Canada (*FLO_THRU_IN*).

Liquefied natural gas imports are represented with an east and west supply curves to North America generated based on output results from EIA's International Natural Gas Model and shared to representative regional terminals based on regasification capacity, last year's imports, and relative prices. Regasification capacity is set based on known facilities, either already constructed or highly likely to be (*LNGCAP*).

The three supplemental production categories (synthetic production of natural gas from coal and liquids and other supplemental fuels) are represented as constant supplies within the Interstate Transmission Submodule, with the exception of any production from potential new coal-to-gas plants. Synthetic production from the existing coal plant is set exogenously (*SNGCOAL*). Forecast values for the other two categories are held constant throughout the forecast and are set to historical values (*SNGLIQ, SUPPLM*) within the module. The algorithm for determining the potential construction of new coal-to-gas plants uses an extensive set of detailed cost figures to estimate the total investment and operating costs of a plant (including accounting for emissions costs, electricity credits, and lower costs over time due to learning) for use within a discounted cash flow calculation. If positive cash flow is estimated to occur the number of generic plants built is based on a Mansfield-Blackman market penetration algorithm. Throughout the forecast, the annual synthetic gas production levels are split into seasonal periods using an historically (*NSUPLM_TOT*) based share (*PKSHR_SUPLM*).

The supply component uses an assortment of input values in defining historical production levels and prices (or revenues) by the regions and categories required by the module (*QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, lA_OFFD , ADW, NAW, TGD, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, HQSUP, HPSUP, WHP_LHIS, SPWH*). A set of seasonal shares (*PKSHR_PROD*) have been defined based on historical values (*MONMKT_PRD*) to split production levels of supply sources that are nonvariant with price (*CN_FIXSUP* and others) into peak and off-peak categories.

Discrepancies that exist between historical supply and disposition level data are modeled at historical levels (*SBAL_ITM*) in the NGTDM and kept constant throughout the forecast years at average historical levels (*DISCR, CN_DISCR*).

Model inputs

The NGTDM inputs are grouped into six categories: mapping and control variables, annual historical values, monthly historical values, Alaskan and Canadian demand/supply variables, supply inputs, pipeline and storage financial and regulatory inputs, pipeline and storage capacity and utilization-related inputs, end-use pricing inputs, and miscellaneous inputs. Short input data descriptions and identification of variable names that provide more detail (via Appendix E) on the sources and transformation of the input data are provided below.

Mapping and control variables

- Variables for mapping from states to regions (*SNUM_ID, SCH_ID, SCEN_DIV, SITM_REG, SNG_EM, SNG_OG, SIM_EX, MAP_PRDST*)
- Variables for mapping import/export borders to states and to nodes (*CAN_XMAPUS, CAN_XMAPCN, MEX_XMAP, CAN_XMAP*)
- Variables for handling and mapping arcs and nodes (*PROC_ORD,ARC_2NODE, NODE_2ARC, ARC_LOOP, SARC_2NODE, SNODE_2ARC, NODE_ANGTS, CAN_XMAPUS*)
- Variables for mapping supply regions (*NODE_SNGCOAL, MAPLNG_NG, OCSMAP, PMMMAP_NG, SUPSUB_NG, SUPSUB_OG*)
- Variables for mapping demand regions (*EMMSUB_NG, EMMSUB_EL, NGCENMAP*)

Annual historical values

- Offshore natural gas production and revenue data (*QOF_ALST, QOF_ALFD, QOF_LAST, QOF_LAFD, QOF_CA, ROF_CA, QOF_LA, ROF_LA, QOF_TX, ROF_TX, QOF_AL, ROF_AL, QOF_MS, ROF_MS, QOF_GM, ROF_GM, PRICE_CA, PRICE_LA, PRICE_AL, PRICE_TX, GOF_LA, GOF_AL, GOF_TX, GOF_CA, AL_ONSH, AL_OFST, AL_OFFD, LA_ONSH, LA_OFST, LA_OFFD, AL_ONSH2, AL_OFST2, AL_ADJ*)
- State-level supply prices (*SPIM, SPWH*)
- State/sub-state-level natural gas production and other supply/storage data (*ADW, NAW, TGD, TGW, MISC_ST, MISC_GAS, MISC_OIL, SMKT_PRD, SDRY_PRD, SIMP, SNET_WTH, SUPPLM*)
- State-level consumption levels (*SBAL_ITM, SEXP, SQPF, SQLP, SQRS, SQCM, SQIN, SQEU, SQTR*)
- State-level end-use prices (*SPEX, SPRS, SPCM, SPIN, SPEU, SPTR*)
- Miscellaneous (GDP_B87, OGHHPRNG)

Monthly historical values

- State-level natural gas production data (*MONMKT_PRD*)
- Import/export volumes and prices by source (*MON_QIMP, MON_PIMP, MON_QEXP, MON_PEXP, HQIMP*)
- Storage data (*NWTH_TOT, NINJ_TOT, HNETWTH, HNETINJ*)
- State-level consumption and prices (*CON & PRC -- QRS, QCM, QIN, QEU, PRS, PCM, PIN, PEU*)
- Electric power gas consumption and prices (*CON_ELCD, PRC_EPMCD, CON_EPMGR, PRC_EPMGR*)
- Miscellaneous monthly/seasonal data (*NQPF_TOT, NSUPLM_TOT, WHP_LHIS, QLP_LHIS, HCGPR*)

Alaskan, Canadian, & Mexican demand/supply variables

- Alaskan lease, plant, and pipeline fuel parameters (*AK_PCTPLT, AK_PCTPIP, AK_PCTLSE*)
- Alaskan consumption parameters (*AK_QIND_S, AK_RN, AK_CM, AK_POP, AK_HDD, HI_RN*)
- Alaskan pricing parameters (*AK_RM, AK_CM, AK_IN, AK_EM*)
- Canadian production and end-use consumption (*CN_FIXSUP, CN_DMD, PKSHR_PROD, PKSHR_CDMD*)
- Exogenously specified Canadian import/export related volumes (*CANEXP, Q23TO3, FLO_THRU_IN*)
- Historical western Canadian production and wellhead prices (*HQSUP, HPSUP*)
- Shale/coalbed western Canadian production parameters (*ULTRES, ULTSHL, RESBASE, PKIYR, LSTYR0, PERRES, RESTECH, TECHGRW*)
- Mexican production, LNG imports, and end-use consumption (*PEMEX_GFAC, IND_GFAC,ELE_GFAC,RC_GFAC, PRD_GFAC, MEXLNG*)

Supply inputs

- Liquefied natural gas supply curves and pricing (*LNGCAP, PARM_LNGCRV3, PARM_LNGCRV5,PARM_LNGELAS, LNGPPT, LNGQPT, LNGMIN,PERQ, BETA,LNGTAR*)
- Supply curve parameters (*SUPCRV, PARM_MINPR, PARM_SUPCRV3, PARM_SUPCRV5, PARM_SUPELAS, MAXPRRFAC, MAXPRRNG, PARM_MINPR*)
- Synthetic natural gas projection (*SNGCOAL, SNGLIQ, NRCI_INV, NRCI_LABOR_NRCI_OPER,INFL_RT, FEDTAX_RT, STTAX_RT, INS_FAC, TAX_FAC, MAINT_FAC, OTH_FAC,BEQ_OPRAVG, BEQ_OPRHRSK, EMRP_OPRAVG, EMRP_OPRHRSK, EQUITY_OPRAVG, EQUITY_OPRHRSK, BEQ_BLDAVG, BEQ_BLDHRSK, EMRP_BLDAVG, EMRP_BLDHRSK, EQUITY_BLDAVG, EQUITY_BLDHRSK, BA_PREM, PCLADJ, CTG_CAPYR$, PRJSDECOM, CTG_BLDYRS, CTG_PRJLIFE, CTG_OSBLFAC, CTG_PCTENV, CTG_PCTCNTG, CTG_PCTLND, CTG_PCTSPECL, CTG_PCTWC, CTG_STAFF_LCFAC, CTG_OH_LCFAC, CTG_FSIYR, CTG_INCBLD, CTG_DCLCAPCST, CTG_DCLOPRCST, CTG_BASHHV, CTG_BASCOL, CTG_BCLTON, CTG_BASSIZ, CTG_BASCGS, CTG_BASCGSCO2,*

CTG_BASCGG, CTG_BASCGGCO2,CTG_NCL, CTG_NAM, CTG_CO2,LABORLOC, CTG_PUCAP, XBM_ISBL, XBM_LABOR, CTG_BLDX, CTG_IINDX, CTG_SINVST)

Pipeline and storage financial and regulatory inputs

- Rate design specification (*AFX_PFEN, AFR_PFEN, AVR_PFEN, AFX_CMEN, AFR_CMEN, AVR_CMEN, AFX_LTDN, AFR_LTDN, AVR_LTDN, AFX_DDA, AFR_DDA, AVR_DDA, AFX_FSIT, AFR_FSIT, AVR_FSIT, AFX_DIT, AFR_DIT, AVR_DIT, AFX_OTTAX, AFR_OTTAX, AVR_OTTAX, AFX_TOM, AFR_TOM, AVR_TOM*)
- Pipeline rate base parameters (*D_TOM, D_DDA, D_OTTAX, D_DIT, D_GPIS, D_ADDA, D_NPIS, D_CWC, D_ADIT, D_APRB, D_GPFES, D_GCMES, D_GLTDS, D_PFER, D_CMER, D_LTDR)*
- *Storage rate base parameters (D_TOM, D_DDA, D_ADDA, D_OTTAX, D_FSIT, D_DIT, D_LTDN, D_PFEN, D_CMEN, D_GPIS, D_NPIS, D_CWC, D_ADIT, D_APRB, D_LTDS, D_PFES, D_CMES, D_TCAP D_WCAP*)
- Pipeline and storage revenue requirement forecasting equation parameters (Table F3)
- Rate of return set for generic pipeline companies (*MC_RMPUAANS, ADJ_PFER, ADJ_CMER, ADJ_LTDR*)
- Rate of return set for existing and new storage capacity (*MC_RMPUAANS, ADJ_STPFER, ADJ_STCMER, ADJ_STLTDR*)
- Federal and state income tax rates (*FRATE, SRATE*)
- Depreciation schedule (30-year life)
- Pipeline capacity expansion cost parameter for capital cost equations (*AVGCOST*)
- Pipeline capacity replacement cost parameter (*PCNT_R*)
- Storage capacity expansion cost parameters for capital cost equations (*STCCOST_CREG, STCCOST_BETAREG, STCSTFAC*)
- Parameters for interstate pipeline transportation rates (*PKSHR_YR, PTPKUTZ, PTOPUTZ, ALPHA_PIPE, ALPHA2_PIPE*)
- Canadian pipeline and storage tariff parameters (*ARC_FIXTAR, ARC_VARTAR, CN_FIXSHR*)
- Parameters for storage rates (*STRATIO, STCAP_ADJ, PTSTUTZ, ADJ_STR, STR_EFF, ALPHA_STR, ALPHA2_STR*)
- Parameters for Alaska-to-Alberta and Mackenzie Delta-to-Alberta pipelines (*FR_CAPITL0, FR_CAPYR, FR_PCNSYR, FR_DISCRT, FR_PVOL, INVEST_YR,FR_ROR_PREM, FR_TOM0, FR_DEBTRATIO, FR_TXR, FR_OTXR, FR_ESTNYR, FR_AVGTARYR*)

Pipeline and storage capacity and utilization related inputs

- Canadian natural gas pipeline capacity and planned capacity additions (*ACTPCAP, PTACTPCAP, PLANPCAP, CNPER_YROPEN*)
- Maximum peak and off-peak primary and secondary pipeline utilizations (*PKUTZ, OPUTZ, SUTZ, MAXUTZ, XBLD*)
- Interregional planned pipeline capacity additions along primary and secondary arcs (*PLANPCAP, SPLANPCAP, PER_YROPEN*)
- Maximum storage utilization (*PKUTZ*)
- Existing storage capacity and planned additions (*PLANPCAP, ADDYR*)
- Net storage withdrawals (peak) and injections (off-peak) in Canada (*HNETWTH, HNETINJ*)
- Historical flow data (*HPKSHR_FLOW, HAFLOW, SAFLOW*)
- Alaska-to-Alberta and Mackenzie Delta-to-Alberta pipeline (*FR_PMINYR, FR_PVOL, FR_PCNSYR, FR_PPLNYR, FR_PEXPFAC, FR_PADDTAR, FR_PMINWPR, FR_PRISK, FR_PDRPFAC, FR_PTREAT, FR_PFUEL*)

End-use pricing inputs

- Residential, commercial, industrial, and electric generator distributor tariffs (*OPTIND, OPTCOM, OPTRES, OPTELP, OPTELO, RECS_ALIGN, NUM_REGSHR, HHDD*)
- Intrastate and intraregional tariffs (*INTRAST_TAR, INTRAREG_TAR*)
- Historical city gate prices (*HCGPR*)
- State and federal taxes, costs to dispense, and other compressed natural gas pricing and infrastructure development parameters (*STAX, FTAX, RETAIL_COST, NSTAT, TRN_DECL, MAX_CNG_BUILD, CNG_HRZ, CNG_WACC, CNG_BUILDCOST*)

Miscellaneous

- Network processing control variables (*MAXCYCLE, NOBLDYR,ALPHAFAC, GAMMAFAC, PSUP_DELTA, QSUP_DELTA, QSUP_SMALL, QSUP_WT, PCT_FLO, SHR_OPT, PCTADJSHR*)
- Miscellaneous control variables (PKOPMON, NGDBGRPT, SHR_OPT, NOBLDYR)
- World volume and price indicators driving U.S. LNG exports (*FLEXLNG, OECD_EUR, QJAP, QSKOR, QCHINA, PCHINA, NGP87, JAP87*)
- Costs related to exporting LNG and associated modeling parameters (*FYREXP, MAXEXP, CST_LIQ, CST_SHP, CST_RGAS, CST_RISK, PREFUELCCST, PKSHR_ELNG, LOSSTO, BONUS, EVOL_INCR, PERTOFLEX, DCF_RATE*)
- STEO input data (*STEOYRS, STQGPTR, STQLPIN, STOGWPRNG, STPNGRS, STPNGIN, STPNGCM, STPNGEL, STOGPRSUP, NNETWITH, STDISCR, STENDCON, STSCAL_CAN, STINPUT_SCAL, STSCAL_PFUEL, STSCAL_LPLT, STSCAL_WPR, STSCAL_DISCR, STSCAL_SUPLM, STSCAL_NETSTR, STSCAL_FPR, STSCAL_IPR, STPHAS_YR, STLNGIMP*)

Model outputs

Once a set of solution values are determined within the NGTDM, those values required by other modules of NEMS are passed accordingly. In addition, the NGTDM module results are presented in a series of internal and external reports, as outlined below.

Outputs to NEMS modules

The NGTDM passes its solution values to different NEMS modules as follows:

- Pipeline fuel consumption and lease and plant fuel consumption by Census Division (to NEMS PROPER and REPORTS)
- Natural gas spot prices by Oil and Gas Supply Module region (to NEMS REPORTS, Oil and Gas Supply Module, and Liquid Fuels Market Module)
- Core and noncore natural gas prices by sector and Census Division (to NEMS PROPER and REPORTS, and NEMS demand modules)
- Fraction of retail fueling stations that sell compressed natural gas (to Transportation Module)
- Dry natural gas production and supplemental gas supplies by Oil and Gas Supply Module region (NEMS REPORTS and Oil and Gas Supply Module)
- Peak/off-peak, core/noncore natural gas prices to electric generators by NGTDM/Electricity Market Module region (to NEMS PROPER and REPORTS and Electricity Market Module)
- Coal consumed, electricity generated, and CO_2 produced in the process of converting coal into pipeline-quality synthetic gas in newly constructed plants (to Coal Market Module, Electricity Market Module, and NEMS PROPER)
- Dry natural gas production by PADD region (to Liquid Fuels Market Module)

- Nonassociated dry natural gas production by NGTDM/Oil and Gas Supply Module region (to NEMS REPORTS and Oil and Gas Supply Module)
- Natural gas imports, exports, and associated prices by border crossing (to NEMS REPORTS)

Internal reports

The NGTDM produces reports designed to assist in the analysis of NGTDM model results. These reports are controlled with a user-defined variable (NGDBGRPT), include the following information, and are written to the indicated output file:

- Primary peak and off-peak flows, shares, and maximum constraints going into each node (NGOBAL)
- Historical and forecast values historically based factors applied in the module (NGOBENCH)
- Intermediate results from the Distributor Tariff Submodule (NGODTM)
- Intermediate results from the Pipeline Tariff Submodule (NGOPTM)
- Convergence tracking and error message report (NGOERR)
- Aggregate/average historical values for most model elements (NGOHIST)
- Node and arc level prices and quantities along the network by cycle (NGOTREE)

External reports

In addition to the reports described above, the NGTDM produces external reports to support recurring publications. These reports contain the following information:

- Natural gas end-use prices and consumption levels by end-use sector, type of service (core and noncore), and Census Division (and for the United States)
- Natural gas spot prices and production levels by NGTDM region (and the average for the lower 48 States), including a price for the Henry Hub
- Natural gas end-use and city gate prices and margins
- Natural gas import and export volumes and import prices by source or destination
- Pipeline fuel consumption by NGTDM region (and for the United States)
- Natural gas pipeline capacity (entering and exiting a region) by NGTDM region and by Census Division
- Natural gas flows (entering and exiting a region) by NGTDM region and Census Division
- Natural gas pipeline capacity between NGTDM regions
- Natural gas flows between NGTDM regions
- Natural gas underground storage and pipeline capacity by NGTDM region
- Unaccounted-for natural gas[96]

[96] Unaccounted-for natural gas is a balancing item between the amount of natural gas consumed and the amount supplied. It includes reporting discrepancies, net storage withdrawals (in historical years), and differences due to convergence tolerance levels.

Appendix A. NGTDM Model Abstract

Model Name: Natural Gas Transmission and Distribution Module

Acronym: NGTDM

Title: Natural Gas Transmission and Distribution Module

Purpose: The NGTDM is the component of the National Energy Modeling System (NEMS) that represents the mid-term natural gas market. The purpose of the NGTDM is to derive natural gas supply and end-use prices and flow patterns for movements of natural gas through the regional interstate network. The prices and flow patterns are derived by obtaining a 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.

Status: ACTIVE

Use: BASIC

Sponsor: Office of Energy Analysis
Office of Petroleum, Natural Gas, and Biofuels Analysis, EI-33
Model Contact: Joe Benneche
Telephone: (202) 586-6132

Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, September 2012).

Previous Documentation: Energy Information Administration, *Model Documentation of the Natural Gas Transmission and Distribution Module (NGTDM) of the National Energy Modeling System (NEMS)*, DOE/EIA-M062 (Washington, DC, February 2012).

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Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Natural Gas Annual Flow Module (AFM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, August 25, 1992.

Paul R. Carpenter, PhD, Incentives Research, Inc. "Review of the *Component Design Report Capacity Expansion Module (CEM) for the Natural Gas Transmission and Distribution Model (NGTDM) of the National Energy Modeling System (NEMS)*." Boston, MA, April 30, 1993.

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Paul R. Carpenter, PhD, Incentives Research, Inc. "Final Review of the National Energy Modeling System (NEMS) Natural Gas Transmission and Distribution Model (NGTDM)." Boston, MA, January 4, 1995.

Archival: The NGTDM is archived as a component of NEMS on compact disc storage compatible with the PC multiprocessor computing platform upon completion of the NEMS production runs to generate the *Annual Energy Outlook 2012*, DOE/EIA-0383(2011). The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo.

Energy System: The NGTDM models the U.S. natural gas transmission and distribution network that links the suppliers (including importers) and consumers of natural gas, and in so doing determines the regional market clearing natural gas end-use and supply (including border) prices.

Coverage: Geographic: Demand regions are the 12 NGTDM regions, which are based on the nine Census Divisions with Census Division 5 split further into South Atlantic and Florida, Census Division 8 split further into Mountain and Arizona/New Mexico, and Census Division 9 split further into California and Pacific with Alaska and Hawaii handled separately. Production is represented in the lower 48 at 17 onshore and 3 offshore regions. Import/export border crossings include three at the Mexican border, seven at the Canadian border, and 12 liquefied natural gas import terminals. In a separate component, potential liquefied natural gas production and liquefaction for U.S. import is represented for 14 international ports. A simplified Canadian representation is subdivided into an eastern and western region, with potential LNG import facilities on both shores. Consumption, production, and LNG imports to serve the Mexico gas market are largely assumption-based and serve to set the level of exports to Mexico from the United States.

Time Unit/Frequency: Annually through 2040, including a peak (December through March) and off-peak forecast.

Product(s): Natural gas

Economic Sector(s): Residential, commercial, industrial, electric generators and transportation

Data Input Sources: (Non-DOE)

- The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU), Section 1113.
  - — Federal vehicle natural gas (VNG) taxes
- Canadian Association of Petroleum Producers Statistical Handbook
  - — Historical Canadian supply and consumption data

- Office of Natural Resources Revenue
  — Revenues and volumes for offshore production in Texas, California, and Louisiana
- Foster Pipeline and Storage Financial Cost Data
  — pipeline and storage financial data
- Data Resources Inc., U.S. Quarterly Model
  — Various macroeconomic data
- *Oil and Gas Journal*, "Pipeline Economics"
  — Pipeline annual capitalization and operating revenues
- Board of Governors of the Federal Reserve System Statistical Release, "Selected Interest Rates and Bond Prices"
  — Real average yield on 10-year U.S. government bonds
- International Fuel Tax Association, Inc.
  — compressed natural gas and liquefied natural gas vehicle taxes by state
- National Oceanic and Atmospheric Administration
  — State-level heating degree days
- U.S. Census
  — State-level population data for heating degree day weights
- Natural Gas Week
  — Canada storage withdrawal and capacity data
- PEMEX
  — Historical Mexico raw gas production by region
- Informes y Publicaciones, Anuario Estadísticas, Estadísticas Operativas, Producción de gas natural
  — Historical Mexico raw gas production by region
- Sener Prospectiva del Mercado de gas natural 2006-2015
  — Mexico LNG import projections
- Natural Gas Intelligence
  — Historical spot prices
- PFC Energy
  — Historical world flexibly priced LNG volumes

Data Input Sources

(DOE) Forms and/or Publications:

- *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216
  — Annual estimate of gas production for associated-dissolved and nonassociated categories by State/sub-state.
- *Natural Gas Annual*, DOE/EIA-0131
  — By state -- natural gas consumption by sector, dry production, imports, exports, storage injections and withdrawals, balancing item, state transfers, number of residential customers, fraction of industrial

market represented by historical prices, and city gate and end-use prices.
    - Supplemental supplies

- *Natural Gas Monthly*, DOE/EIA-0130
    - By month and state – natural gas consumption by sector, marketed production, net storage withdrawals, end-use prices by sector, city gate prices
    - By month – quantity and price of imports and exports by country, lease and plant consumption, pipeline consumption, supplemental supplies
- State Energy Data System (SEDS)
    - State-level annual delivered natural gas prices when not available in the Natural Gas Annual.
- *Electric Power Monthly*, DOE/EIA-0226
    - Monthly volume and price paid for natural gas by electric generators
- *Annual Energy Review*, DOE/EIA-0384
    - Gross domestic product and implicit price deflator
- EIA-846, "Manufacturing Energy Consumption Survey"
    - Base year average annual core industrial end-use prices
- *Short-Term Energy Outlook*, DOE/EIA-0131
    - National natural gas projections for first two years beyond history
    - Historical natural gas prices at the Henry Hub
- Department of Energy, *Natural Gas Imports and Exports*, Office of Fossil Energy
    - Import and export volumes and prices by border location
- Department of Energy, Alternative Fuels & Advanced Vehicles Data Center, including *Alternative Fuel Price Report*, Office of Energy Efficiency and Renewable Energy
    - Sample of retail prices paid for compressed natural gas for vehicles
    - State motor fuel taxes
- EIA-191, "Underground Gas Storage Report"
    - Used in part to develop working gas storage capacity data
- EIA-457, "Residential Energy Consumption Survey"
    - Number of residential natural gas customers
- *International Energy Outlook*, DOE/EIA-0484
    - Projection of natural gas consumption in Canada and Mexico
- *International Energy Annual*, DOE/EIA-0484
    - Historical natural gas data on Canada and Mexico

Models and other:
- National Energy Modeling System (NEMS)
    - Domestic supply and demand representations are provided interactively as inputs to the NGTDM from other NEMS models

- International Natural Gas Model (INGM)
  - — Provides information for setting LNG supply curves exogenously in the NGTDM

General Output Descriptions:

- Average natural gas end-use prices levels by sector and region
- Average natural gas production volumes and prices by region
- Average natural gas import and export volumes and prices by region and type
- Pipeline fuel consumption by region
- Lease and plant fuel consumption by region
- Flow of gas between regions by peak and off-peak period
- Pipeline capacity additions and utilization levels by arc
- Storage capacity additions by region

Related Models: NEMS (part of)

Model Features:

- Model Structure: Modular; three major components: the Interstate Transmission Submodule (ITS), the Pipeline Tariff Submodule (PTS), and the Distributor Tariff Submodule (DTS).
  - — ITS Integrating submodule of the NGTDM. Simulates the natural gas price determination process by bringing together all major economic and technological factors that influence regional natural gas trade in the United States. Determines natural gas production and imports, flows and prices, pipeline capacity expansion and utilization, storage capacity expansion and utilization for a simplified network representing the interstate natural gas pipeline system
  - — PTS Develops parameters for setting tariffs in the ITM for transportation and storage services provided by interstate pipeline companies
  - — DTS Develops markups for distribution services provided by LDCs and intrastate pipeline companies.

- Modeling Technique:
  - — ITS Heuristic algorithm, operates iteratively until supply/demand convergence is realized across the network
  - — PTS Econometric estimation and accounting algorithm
  - — DTS Econometric estimation
  - — Canada and Mexico supplies based on a combination of estimated equations and basic assumptions.

Model Interfaces: NEMS

Computing Environment:

- Hardware Used: Personal Computer
- Operating System: UNIX simulation
- Language/Software Used: FORTRAN
- Storage Requirement: 2,700K bytes for input data storage; 1,100K bytes for source code storage; and 17,500K bytes for compiled code storage
- Estimated Run Time: Varies from NEMS iteration and from computer processor, but rarely exceeds a quarter of a second per iteration and generally is less than 5 hundredths of a second.

Status of Evaluation Efforts:

Model developer's report entitled "Natural Gas Transmission and Distribution Model, Model Developer's Report for the National Energy Modeling System," dated November 14, 1994.

Date of Last Update: February 2012.

Appendix B. References

Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report*, November 2009.

Carpenter, Paul R., "Review of the Gas Analysis Modeling System (GAMS), Final Report of Findings and Recommendations" (Boston: Incentives Research, Inc., August 1991).

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Energy Information Administration, "Analytical Framework for a Natural Gas Transmission and Distribution Forecasting System," prepared by SAIC for the Analysis and Forecasting Branch within the Reserves and Natural Gas Division of the Office of Oil and Gas (Washington, DC, March 1991).

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Forbes, Kevin, Science Applications International Corporation, "Efficiency in the Natural Gas Industry," Task 93-095 Deliverable under Contract No. DE-AC01-92-EI21944 for Natural Gas Analysis Branch of the Energy Information Administration, January 31, 1995.

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Oil and Gas Journal, "Pipeline Economics," published annually in various editions.

Woolridge, Jeffrey M., Introductory Econometrics: A Modern Approach, South-Western College Publishing, 2000.

Appendix C. NEMS Model Documentation Reports

The National Energy Modeling System is documented in a series of 15 model documentation reports, most of which are updated on an annual basis. Copies of these reports are available by contacting the National Energy Information Center, 202/586-8800.

Energy Information Administration, *Integrating Module of the National Energy Modeling System: Model Documentation 2012*, DOE/EIA-M057.

Energy Information Administration, *Model Documentation Report: Macroeconomic Activity Module (MAM) of the National Energy Modeling System*.

Energy Information Administration, *International Energy Module of the National Energy Modeling System: Model Documentation 2011*.

Energy Information Administration, *Model Documentation Report: Residential Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Commercial Demand Module of the National Energy Modeling System: Model Documentation 2011*.

Energy Information Administration, *Model Documentation Report: Industrial Demand Module of the National Energy Modeling System*.

Energy Information Administration, *Transportation Sector Module of the National Energy Modeling System: Model Documentation 2011*.

Energy Information Administration, *The Electricity Market Module of the National Energy Modeling System*.

Energy Information Administration, *Documentation of the Oil and Gas Supply Module*.

Energy Information Administration, *Liquid Fuels Market Model of the National Energy Modeling System*.

Energy Information Administration, *Coal Market Module of the National Energy Modeling System, Model Documentation 2011*.

Energy Information Administration, *Model Documentation, Renewable Fuels Module of the National Energy Modeling System*.

Appendix D. Model Equations

This appendix presents the mapping of each equation (by equation number) in the documentation with the subroutine in the NGTDM code where the equation is used or referenced.

Equation number in documentation	SUBROUTINE (or FUNCTION*) in code
Chapter 2 Equations	
1	NGDMD_CRVF* (core), NGDMD_CRVI* (noncore)
2-19	NGSUP_PR*
20-25	NGOUT_CAN
26-39	NGCAN_FXADJ
40	NGOUT_MEX
41	NGSETLNG_INGM
42-44	NGDOMEXP
45-56	NGTDM_DMDALK
Chapter 4 Equations	
55,608	NGSET_NODEDMD, NGDOWN_TREE
e	NGSET_NODECDMD
59, 62	NGSET_YEARCDMD
63, 64	NGDOWN_TREE
65	NGSET_INTRAFLO
66	NGSET_INTRAFLO
67	NGSHR_CALC
68	NGDOWN_TREE
69	NGSET_MAXFLO*
70-73	NGSET_MAXPCAP
74-78	NGSET_MAXFLO*
79-81	NGSET_ACTPCAP
82-83	NGSHR_MTHCHK
84-87	NGSET_SUPPR
88-90	NGSTEO_BENCHWPR
91-92	NGSET_ARCFEE
93-96	NGUP_TREE
97	NGSET_STORPR
98-99	NGUP_TREE
100	NGCHK_CONVNG
101	NGSET_SECPR
102	NGSET_BENCH, HNGSET_CGPR
103-108	NGSET_SECPR
Chapter 5 Equations	
109-113	NGDTM_FORECAST_DTARF

Equation number in documentation	SUBROUTINE (or FUNCTION*) in code
114-115	NGHIST_IPR
116-121	NGDTM_FORECAST_DTARF
122-125	NGDTM_FORECAST_TRNF
Chapter 6 Equations	
126-131, 135-153, 202-204	NGPREAD
132-134, 154-155	NGPIPREAD
175-193, 205, 207-220	NGPSET_PLCOS_COMPONENTS
156-165, 171, 206, 221-230, 237	NGPSET_PLINE_COSTS
166-170, 231-236, 237-242	NGPIPE_VARTAR*
250-252	NGSTREAD
243-249, 253-255, 259-286	NGPSET_STCOS_COMPONENTS
256-258	NGPST_DEVCONST
172-174, 287-291	X1NGSTR_VARTAR*
194-201	(accounting relationships, not part of code)
292-304	NGFRPIPE_TAR*

Appendix E. Model Input Variables Mapped to Data Input Files

This appendix provides a list of the FORTRAN variables, and their associated input files, that are assigned values through FORTRAN READ statements in the source code of the NGTDM. Information about all of these variables and their assigned values (including sources, derivations, units, and definitions) are provided in the indicated input files of the NGTDM. The data file names and versions used for *AEO2013* are identified below. These files are located on the EIA NEMS-F8 NT server. Electronic copies of these input files are available as part of the NEMS2013 archive package. The archive package can be downloaded from ftp://ftp.eia.doe.gov/pub/forecasts/aeo. In addition, the files are available upon request from Joe Benneche at (202) 586-6132 or Joseph.Benneche@eia.doe.gov.

ngcan.txt	V1.85	nghismn.txt	V1.37	ngptar.txt	V1.29
ngcap.txt	V1.37	nglngdat.txt	V1.104	nguser.txt	V1.183
ngdtar.txt	V1.45	ngmap.txt	V1.9		
nghisan.txt	V1.44	ngmisc.txt	V1.178		

File	Variable
NGCAP	ACTPCAP
NGCAP	ADDYR
NGPTAR	ADIT_C
NGPTAR	ADJ_PIP
NGPTAR	ADJ_STR
NGHISAN	ADW
NGPTAR	AFR_CMEN
NGPTAR	AFR_DDA
NGPTAR	AFR_DIT
NGPTAR	AFR_FSIT
NGPTAR	AFR_LTDN
NGPTAR	AFR_OTTAX
NGPTAR	AFR_PFEN
NGPTAR	AFR_TOM
NGPTAR	AFX_CMEN
NGPTAR	AFX_DDA
NGPTAR	AFX_DIT
NGPTAR	AFX_FSIT
NGPTAR	AFX_LTDN
NGPTAR	AFX_OTTAX
NGPTAR	AFX_PFEN
NGPTAR	AFX_TOM
NGMISC	AK_C
NGMISC	AK_CM
NGMISC	AK_CN
NGMISC	AK_D
NGMISC	AK_E
NGMISC	AK_EM
NGMISC	AK_ENDCONS_N
NGMISC	AK_F
NGMISC	AK_G
NGMISC	AK_HDD
NGMISC	AK_IN
NGMISC	AK_PCTLSE
NGMISC	AK_PCTPIP
NGMISC	AK_PCTPLT
NGMISC	AK_POP
NGMISC	AK_QIND_S
NGMISC	AK_RM
NGMISC	AK_RN
NGMISC	AKPIP1
NGMISC	AKPIP2
NGHISAN	AL_ADJ
NGHISAN	AL_OFFD
NGHISAN	AL_OFST
NGHISAN	AL_OFST2
NGHISAN	AL_ONSH
NGHISAN	AL_ONSH2
NGMISC	ALB_TO_L48
NGLNGDAT	ALNGA
NGLNGDAT	ALNGB
NGLNGDAT	ALP
NGPTAR	ALPHA_PIPE
NGPTAR	ALPHA_STR
NGPTAR	ALPHA2_PIPE
NGPTAR	ALPHA2_STR
NGUSER	ALPHAFAC
NGMAP	AMAP
NGMAP	ANUM
NGCAN	ARC_FIXTAR
NGCAN	ARC_VARTAR
NGPTAR	AVG_CAPCOST
NGPTAR	AVR_CMEN
NGPTAR	AVR_DDA
NGPTAR	AVR_DIT
NGPTAR	AVR_FSIT
NGPTAR	AVR_LTDN
NGPTAR	AVR_OTTAX
NGPTAR	AVR_PFEN
NGPTAR	AVR_TOM
NGMISC	BA_PREM
NGMISC	BAJA_CAP
NGMISC	BAJA_FIX
NGMISC	BAJA_LAG
NGMISC	BAJA_MAX
NGMISC	BAJA_PRC
NGMISC	BAJA_STAGE
NGMISC	BAJA_STEP
NGMISC	BEQ_BLDAVG
NGMISC	BEQ_BLDHRSK
NGMISC	BEQ_OPRAVG
NGMISC	BEQ_OPRHRSK
NGLNGDAT	BET
NGPTAR	BNEWCAP_2003_2004
NGPTAR	BNEWCAP_POST2004
NGPTAR	BNEWCAP_PRE2003

File	Variable	File	Variable
NGLNGDAT	BONUS	NGMISC	CTG_DCLOPRCST
NGLNGDAT	BUILT	NGMISC	CTG_FSTYR
NGMAP	CAN_XMAPCN	NGMISC	CTG_IINDX
NGMAP	CAN_XMAPUS	NGMISC	CTG_INCBLD
NGCAN	CANEXP	NGMISC	CTG_NAM
NGDTAR	CM_ADJ	NGMISC	CTG_NCL
NGDTAR	CM_ALP	NGMISC	CTG_OH_LCFAC
NGDTAR	CM_LNQ	NGMISC	CTG_OSBLFAC
NGDTAR	CM_PKALP	NGMISC	CTG_PCTCNTG
NGDTAR	CM_RHO	NGMISC	CTG_PCTENV
NGCAN	CN_DMD	NGMISC	CTG_PCTLND
NGCAN	CN_FIXSHR	NGMISC	CTG_PCTSPECL
NGCAN	CN_OILSND	NGMISC	CTG_PCTWC
NGCAN	CN_UNPRC	NGMISC	CTG_PRJLIFE
NGCAN	CN_WOP	NGMISC	CTG_PUCAP
NGUSER	CNCAPSW	NGMISC	CTG_SINVST
NGDTAR	CNG_BUILDCOST	NGMISC	CTG_STAFF_LCFAC
NGDTAR	CNG_HRZ	NGPTAR	CWC_C
NGDTAR	CNG_MARKUP	NGPTAR	CWC_DISC
NGDTAR	CNG_RETAIL_MARKUP	NGPTAR	CWC_K
NGDTAR	CNG_WACC	NGPTAR	CWC_RHO
NGCAP	CNPER_YROPEN	NGPTAR	CWC_TOM
NGCAN	CNPLANYR	NGPTAR	D_CMER
NGHISMN	CON	NGPTAR	D_FLO
NGHISMN	CON_ELCD	NGPTAR	D_GCMES
NGHISMN	CON_EPMGR	NGPTAR	D_GLTDS
NGCAN	CONNOL_ELAS	NGPTAR	D_GPFES
NGLNGDAT	CST_LIQ	NGPTAR	D_LTDR
NGLNGDAT	CST_RGAS	NGPTAR	D_MXPKFLO
NGLNGDAT	CST_RISK	NGPTAR	D_PFER
NGLNGDAT	CST_SHP	NGLNGDAT	DCF_RATE
NGMISC	CTG_BASCGG	NGPTAR	DDA_C
NGMISC	CTG_BASCGGCO2	NGPTAR	DDA_NEWCAP
NGMISC	CTG_BASCGS	NGPTAR	DDA_NPIS
NGMISC	CTG_BASCGSCO2	NGCAN	DECL_GASREQ
NGMISC	CTG_BASCOL	NGMISC	DEXP_FRMEX
NGMISC	CTG_BASHHV	NGMISC	DFAC_TOMEX
NGMISC	CTG_BASSIZ	NGLNGDAT	DOMEXP
NGMISC	CTG_BCLTON	NGDTAR	EL_ALP
NGMISC	CTG_BLDX	NGDTAR	EL_CNST
NGMISC	CTG_BLDYRS	NGDTAR	EL_PARM
NGMISC	CTG_CAPYR$	NGDTAR	EL_RESID
NGMISC	CTG_DCLCAPCST	NGDTAR	EL_RHO

File	Variable
NGMISC	ELE_GFAC
NGMAP	EMMSUB_EL
NGMAP	EMMSUB_NG
NGMISC	EMRP_BLDAVG
NGMISC	EMRP_BLDHRSK
NGMISC	EMRP_OPRAVG
NGMISC	EMRP_OPRHRSK
NGMISC	EQUITY_BLDAVG
NGMISC	EQUITY_BLDHRSK
NGMISC	EQUITY_OPRAVG
NGMISC	EQUITY_OPRHRSK
NGLNGDAT	EVOL_INCR
NGPTAR	EXP_A
NGPTAR	EXP_B
NGPTAR	EXP_C
NGMISC	EXP_FRMEX
NGHISMN	FDGOM
NGDTAR	FDIFF
NGMISC	FE_CCOST
NGMISC	FE_EXPFAC
NGMISC	FE_FR_TOM
NGMISC	FE_PFUEL_FAC
NGMISC	FE_R_STTOM
NGMISC	FE_R_TOM
NGMISC	FE_STCCOST
NGMISC	FE_STEXPFAC
NGMISC	FEDTAX_RT
NGLNGDAT	FLEXLNG
NGCAN	FLO_THRU_IN
NGMISC	FR_AVGTARYR
NGMISC	FR_BETA
NGMISC	FR_CAPITL0
NGMISC	FR_CAPYR
NGMISC	FR_DEBTRATIO
NGMISC	FR_DISCRT
NGMISC	FR_ESTNYR
NGMISC	FR_OTXR
NGMISC	FR_PADDTAR
NGMISC	FR_PCNSYR
NGMISC	FR_PDRPFAC
NGMISC	FR_PEXPFAC
NGMISC	FR_PFUEL
NGMISC	FR_PMINWPR
NGMISC	FR_PMINYR
NGMISC	FR_PPLNYR
NGMISC	FR_PRISK
NGMISC	FR_PTREAT
NGMISC	FR_PVOL
NGMISC	FR_ROR_PREM
NGMISC	FR_TOM0
NGMISC	FR_TXR
NGPTAR	FRATE
NGDTAR	FREE_YRS
NGCAN	FRMETH
NGMAP	FSRGN
NGMISC	FUTWTS
NGLNGDAT	FYREXP
NGUSER	GAMMAFAC
NGMISC	GDP_B87
NGHISAN	GOF_AL
NGHISAN	GOF_CA
NGHISAN	GOF_LA
NGHISAN	GOF_TX
NGPTAR	HADDA
NGPTAR	HADIT
NGMISC	HAFLOW
NGPTAR	HAPRB
NGDTAR	HCG_BENCH
NGHISAN	HCGPR
NGCAN	HCUMSUCWEL
NGPTAR	HCWC
NGPTAR	HDDA
NGPTAR	HDIT
NGDTAR	HDYWHTLAG
NGMISC	HELE_SHR
NGPTAR	HFAC_GPIS
NGPTAR	HFAC_REV
NGPTAR	HGPIS
NGDTAR	HHDD
NGMISC	HI_RN
NGMISC	HIND_SHR
NGCAN	HISTRESCAN
NGCAN	HISTWELCAN
NGCAN	HNETINJ
NGHISMN	HNETINJ
NGCAN	HNETWTH

File	Variable
NGHISMN	HNETWTH
NGPTAR	HNPIS
NGCAP	HOPUTZ
NGPTAR	HOTTAX
NGMISC	HPEMEX_SHR
NGHISAN	HPIMP
NGMISC	HPKSHR_FLOW
NGCAP	HPKUTZ
NGHISMN	HPRC
NGHISAN	HPSPOT
NGCAN	HPSUP
NGHISAN	HQIMP
NGCAN	HQSUP
NGHISMN	HQTY
NGMISC	HRC_SHR
NGPTAR	HSTADDA
NGPTAR	HSTADIT
NGPTAR	HSTAPRB
NGPTAR	HSTCMEN
NGPTAR	HSTCMES
NGPTAR	HSTCWC
NGPTAR	HSTDDA
NGPTAR	HSTDIT
NGPTAR	HSTFSIT
NGPTAR	HSTGPIS
NGPTAR	HSTLTDN
NGPTAR	HSTLTDS
NGPTAR	HSTNPIS
NGPTAR	HSTOTTAX
NGPTAR	HSTPFEN
NGPTAR	HSTPFES
NGPTAR	HSTTCAP
NGPTAR	HSTTOM
NGPTAR	HSTWCAP
NGPTAR	HTOM
NGDTAR	HW_ADJ
NGDTAR	HW_BETA0
NGDTAR	HW_BETA1
NGDTAR	HW_RHO
NGCAN	ICNBYR
NGMISC	IEA_CON
NGMISC	IEA_PRD
NGMISC	IMP_TOMEX
NGDTAR	IN_ALP
NGDTAR	IN_CNST
NGDTAR	IN_DIST
NGDTAR	IN_LNQ
NGDTAR	IN_PKALP
NGDTAR	IN_RHO
NGMISC	IND_GFAC
NGMISC	INFL_RT
NGCAN	INIT_GASREQ
NGMISC	INS_FAC
NGDTAR	INTRAREG_TAR
NGDTAR	INTRAST_TAR
NGLNGDAT	JAP87
NGHISMN	JNETWTH
NGHISAN	LA_OFFD
NGHISAN	LA_OFST
NGHISAN	LA_ONSH
NGPTAR	LEVELYRS
NGMAP	LNG_XMAP
NGLNGDAT	LNGA
NGLNGDAT	LNGB
NGLNGDAT	LNGCAP
NGLNGDAT	LNGCRVOPT
NGMISC	LNGDATA
NGLNGDAT	LNGDIF_GULF
NGMISC	LNGDIFF
NGLNGDAT	LNGFIX
NGLNGDAT	LNGFXEX
NGLNGDAT	LNGHYR
NGLNGDAT	LNGMIN
NGLNGDAT	LNGPPT
NGLNGDAT	LNGPS
NGLNGDAT	LNGQPT
NGLNGDAT	LNGQS
NGLNGDAT	LNGTAR
NGDTAR	LNGV_LOSS
NGLNGDAT	LOSSTO
NGLNGDAT	LOSSTO
NGMISC	MAINT_FAC
NGMAP	MAP_NG
NGDTAR	MAP_NRG_CRG
NGMAP	MAP_OG
NGLNGDAT	MAP_OG_NG_LNG

File	Variable	File	Variable
NGHISMN	MAP_PRDST	NGUSER	NNETWITH
NGMAP	MAPLNG_NEW	NGUSER	NOBLDYR
NGMAP	MAPLNG_NG	NGMAP	NODE_ANGTS
NGLNGDAT	MAPLNGE_W	NGMAP	NODE_SNGCOAL
NGDTAR	MAX_CNG_BUILD	NGDTAR	NONU_ELAS_F
NGUSER	MAXCYCLE	NGDTAR	NONU_ELAS_I
NGLNGDAT	MAXEXP	NGMISC	NPEMEX_SHR
NGLNGDAT	MAXPLNG	NGMAP	NPROC
NGMISC	MAXPRRFAC	NGHISMN	NQPF_TOT
NGMISC	MAXPRRNG	NGMISC	NRC_SHR
NGCAP	MAXUTZ	NGMISC	NRCI_INV
NGMISC	MBAJA	NGMISC	NRCI_LABOR
NGMISC	MDPIP1	NGMISC	NRCI_OPER
NGMISC	MDPIP2	NGMAP	NSRGN
NGMAP	MEX_XMAP	NGDTAR	NSTAT
NGMISC	MEXEXP_SHR	NGHISMN	NSUPLM_TOT
NGLNGDAT	MEXFXEX	NGDTAR	NUM_REGSHR
NGMISC	MEXIMP_SHR	NGDTAR	NUMRS
NGMISC	MEXLNG	NGHISMN	NWTH_TOT
NGLNGDAT	MEXLNGMIN	NGMAP	OCSMAP
NGPTAR	MILES	NGDTAR	oEL_MRKUP_BETA
NGHISAN	MISC_GAS	NGMISC	oEQGCELGR
NGHISAN	MISC_OIL	NGMISC	oEQGFELGR
NGHISAN	MISC_ST	NGMISC	oEQGIELGR
NGHISMN	MON_PEXP	NGMISC	oOGHHPRNG
NGHISMN	MON_PIMP	NGLNGDAT	oOGQNGEXP
NGHISMN	MON_QEXP	NGMISC	oOGQNGEXP
NGHISMN	MON_QIMP	NGDTAR	OPTCOM
NGHISMN	MONMKT_PRD	NGDTAR	OPTELO
NGUSER	MUFAC	NGDTAR	OPTELP
NGHISAN	NAW	NGDTAR	OPTIND
NGLNGDAT	NBP87	NGDTAR	OPTRES
NGLNGDAT	NCASE	NGMISC	oQGCELGR
NGCAN	NCNMX	NGMISC	oQGFEL
NGMISC	NELE_SHR	NGMISC	oQGFELGR
NGMAP	NG_CENMAP	NGMISC	oQGIEL
NGHISMN	NGCFEL	NGMISC	oQGIELGR
NGUSER	NGDBGCNTL	NGMISC	oQNGEL
NGUSER	NGDBGRPT	NGMISC	oSQGFELGR
NGMISC	NIND_SHR	NGMISC	oSQGIELGR
NGHISMN	NINJ_TOT	NGMISC	OTH_FAC
NGLNGDAT	NLNGA	NGLNGDAT	PARM_LNGCRV3
NGLNGDAT	NLNGB	NGLNGDAT	PARM_LNGCRV5

File	Variable	File	Variable
NGLNGDAT	PARM_LNGELAS	NGUSER	PSUP_DELTA
NGUSER	PARM_MINPR	NGCAP	PTCURPCAP
NGUSER	PARM_SUPCRV3	NGCAN	PTMAXPCAP
NGUSER	PARM_SUPCRV5	NGPTAR	PTMBYR
NGUSER	PARM_SUPELAS	NGPTAR	PTMSTBYR
NGLNGDAT	PCHINA	NGHISAN	PUTL_POW
NGMISC	PCLADJ	NGCAN	Q23TO3
NGPTAR	PCNT_R	NGMISC	QAK_ALB
NGHISAN	PCT_AL	NGLNGDAT	QCHINA
NGHISAN	PCT_LA	NGLNGDAT	QJAP
NGHISAN	PCT_MS	NGHISMN	QLP_LHIS
NGHISAN	PCT_TX	NGMISC	QMD_ALB
NGUSER	PCTADJSHR	NGLNGDAT	QNGIMP
NGUSER	PCTFLO	NGLNGDAT	QOECD_EUR
NGMISC	PEMEX_GFAC	NGHISAN	QOF_AL
NGMISC	PEMEX_PRD	NGHISAN	QOF_ALFD
NGCAP	PER_YROPEN	NGHISAN	QOF_ALST
NGHISAN	PERFDTX	NGHISAN	QOF_CA
NGLNGDAT	PERFUELCST	NGHISAN	QOF_GM
NGLNGDAT	PERLIQFUEL	NGHISAN	QOF_LA
NGDTAR	PERMG	NGHISAN	QOF_LAFD
NGLNGDAT	PERTOFLEX	NGHISAN	QOF_LAST
NGPTAR	PIPE_FACTOR	NGHISAN	QOF_MS
NGMISC	PKOPMON	NGHISAN	QOF_TX
NGCAN	PKSHR_CDMD	NGLNGDAT	QSKOR
NGLNGDAT	PKSHR_ELNG	NGUSER	QSUP_DELTA
NGCAN	PKSHR_PROD	NGUSER	QSUP_SMALL
NGCAP	PLANPCAP	NGUSER	QSUP_WT
NGMAP	PMMMAP_NG	NGMISC	RD_GFAC
NGLNGDAT	PNGIMP	NGDTAR	RECS_ALIGN
NGHISMN	PRC_EPMCD	NGCAN	RESBASE
NGHISMN	PRC_EPMGR	NGCAN	RESBASYR
NGMISC	PRCWTS	NGCAN	RESTECH
NGMISC	PRCWTS2	NGDTAR	RETAIL_COST
NGMISC	PRD_GFAC	NGDTAR	RETAIL_COSTL
NGHISMN	PRD_MLHIS	NGHISMN	REV
NGHISAN	PRICE_AL	NGHISAN	ROF_AL
NGHISAN	PRICE_CA	NGHISAN	ROF_CA
NGHISAN	PRICE_LA	NGHISAN	ROF_GM
NGHISAN	PRICE_TX	NGHISAN	ROF_LA
NGMISC	PRJSDECOM	NGHISAN	ROF_MS
NGCAN	PRMETH	NGHISAN	ROF_TX
NGMAP	PROC_ORD	NGDTAR	RS_ADJ

File	Variable	File	Variable
NGDTAR	RS_ALP	NGHISAN	SQTR
NGDTAR	RS_COST	NGPTAR	SRATE
NGDTAR	RS_LNQ	NGMISC	SRC_SHR
NGDTAR	RS_PARM	NGHISAN	SSUPLM
NGDTAR	RS_PKALP	NGPTAR	STADIT_ADIT
NGDTAR	RS_RHO	NGPTAR	STADIT_C
NGMISC	SAFLOW	NGPTAR	STADIT_NEWCAP
NGMAP	SARC_2NODE	NGDTAR	STAX
NGHISAN	SBAL_ITM	NGDTAR	STAXL
NGHISAN	SDRY_PRD	NGPTAR	STCCOST_BETAREG
NGMISC	SELE_SHR	NGPTAR	STCCOST_CREG
NGHISAN	SEXP	NGPTAR	STCSTFAC
NGUSER	SHR_OPT	NGPTAR	STCWC_RHO
NGHISAN	SIMP	NGPTAR	STCWC_TOTCAP
NGMISC	SIND_SHR	NGPTAR	STDDA_CREG
NGHISAN	SMKT_PRD	NGPTAR	STDDA_CREG
NGHISAN	SNET_WTH	NGPTAR	STDDA_NEWCAP
NGMISC	SNGCOAL	NGPTAR	STDDA_NPIS
NGHISAN	SNGCOAL	NGUSER	STDISCR
NGHISAN	SNGLIQ	NGUSER	STENDCON
NGHISAN	SNGOTH	NGUSER	STEOYRS
NGMAP	SNODE_2ARC	NGUSER	STLNGIMP
NGHISAN	SPCM	NGUSER	STLNGRG
NGPTAR	SPCNEWFAC	NGUSER	STLNGRGN
NGPTAR	SPCNODID	NGUSER	STLNGYR
NGPTAR	SPCNODID	NGUSER	STLNGYRN
NGPTAR	SPCNODN	NGUSER	STOGPRSUP
NGPTAR	SPCPNODBAS	NGUSER	STOGWPRNG
NGMISC	SPEMEX_SHR	NGUSER	STPHAS_YR
NGHISAN	SPEU	NGUSER	STPIN_FLG
NGHISAN	SPEX	NGUSER	STPNGCM
NGHISAN	SPIM	NGUSER	STPNGEL
NGHISAN	SPIN	NGUSER	STPNGIN
NGHISAN	SPIN_PER	NGUSER	STPNGRS
NGCAP	SPLANPCAP	NGUSER	STQGPTR
NGHISAN	SPRS	NGUSER	STQLPIN
NGHISAN	SPTR	NGMAP	STR_2NODE
NGHISAN	SQCM	NGPTAR	STR_EFF
NGHISAN	SQEU	NGPTAR	STR_FACTOR
NGHISAN	SQIN	NGPTAR	STRATIO
NGHISAN	SQLP	NGUSER	STSCAL_CAN
NGHISAN	SQPF	NGUSER	STSCAL_DISCR
NGHISAN	SQRS	NGUSER	STSCAL_FPR

File	Variable	File	Variable
NGUSER	STSCAL_IPR	NGDTAR	TFDYRL
NGUSER	STSCAL_LPLT	NGPTAR	TOM_BYEAR
NGUSER	STSCAL_NETSTR	NGPTAR	TOM_BYEAR_EIA
NGUSER	STSCAL_PFUEL	NGPTAR	TOM_C
NGUSER	STSCAL_SUPLM	NGPTAR	TOM_DEPSHR
NGUSER	STSCAL_WPR	NGPTAR	TOM_GPIS1
NGHISMN	STSTATE	NGPTAR	TOM_K
NGMISC	STTAX_RT	NGPTAR	TOM_RHO
NGPTAR	STTOM_C	NGPTAR	TOM_YR
NGPTAR	STTOM_RHO	NGDTAR	TRN_DECL
NGPTAR	STTOM_WORKCAP	NGDTAR	UTIL_ELAS_F
NGPTAR	STTOM_YR	NGDTAR	UTIL_ELAS_I
NGMAP	SUPARRAY	NGHISMN	WHP_LHIS
NGUSER	SUPCRV	NGCAN	WLMETH
NGMAP	SUPREG	NGUSER	WPR4CAST_FLG
NGMAP	SUPSUB_NG	NGCAP	XBLD
NGMAP	SUPSUB_OG	NGMISC	XBM_ISBL
NGMAP	SUPTYPE	NGMISC	XBM_LABOR
NGCAP	SUTZ	NGMAP	XDMAP
NGMISC	TAX_FAC	NGMAP	XDNUM
NGDTAR	TFD	NGCAN	YDCL_GASREQ
NGDTAR	TFDL	NGMISC	YR1$4
NGDTAR	TFDYR		

Appendix F. Derived Data

Table F1

Data: Parameter estimates for the Alaskan natural gas consumption equations for the residential and commercial sectors and the Alaskan natural gas wellhead price.

Author: John Zyren, EIA, 2012; Margaret Leddy, EIA, 2009

Source: Consumption, number of customers, wellhead price – Natural Gas Annual, DOE/EIA-0131; Alaska population – U.S. Census Bureau, Population Division; Unemployment rate – NEMS Macroeconomic Activity Module; Heating degree days – National Oceanic and Atmospheric Administration (Anchorage International Airport); Oil price – Petroluem Marketing Annual, DOE/EIA-0487.

Residential Natural Gas Consumption

The estimated equation for residential natural gas consumption is shown below:

$$CONS\_R_t = \beta_0 + (\beta_1 * CUST\_R_t) + (\beta_2 * HDD\_DVN_t)$$

where,

$CONS\_R_t$ = Alaska residential natural gas consumption in MMcf (AKQTY_F(1) in code)
$CUST\_R_t$ = thousands of Alaska residential gas customers (AK_RN in code). See the forecast equation for Alaska residential gas customers in Table F2.
HDD_DVN_t = the deviation from the normal heating degree day first lag (0 in forecast).
t = year

Regression diagnostics and parameters estimates:

Dependent Variable: CONS_R
Method: Least Squares
Date: 09/06/12 Time: 13:08
Sample: 1984 2011
Included observations: 28

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4129.965	502.6366	8.216603	0.0000
CUST_R	133.6638	5.508943	24.26305	0.0000
HDD_DVN	1.154430	0.207722	5.557574	0.0000
R-squared	0.961437		Mean dependent var	16010.38
Adjusted R-squared	0.958352		S.D. dependent var	2755.974
S.E. of regression	562.4381		Akaike info criterion	15.60340
Sum squared resid	7908416.		Schwarz criterion	15.74613
Log likelihood	-215.4475		Hannan-Quinn criter.	15.64703
F-statistic	311.6415		Durbin-Watson stat	0.723680
Prob(F-statistic)	0.000000			

Commercial Natural Gas Consumption

A visual display of the data for commercial natural gas consumption shows clear discontinuities in the series. The particular reasons were not identified, but dummy variables were used in the estimation to account for the shifts. The estimated equation follows:

$$CONS\_C_t = \beta_0 + (\beta_1 * CUST\_C_t) + (\beta_2 * HDD\_DVN_t) + (\beta_3 * UNEMP_t) + (\beta_4 * L1995\_00) + (\beta_5 * L1982\_4) + (\beta_6 * 1985\_94)$$

where,

$CONS\_C_t$ = Alaska commercial natural gas consumption in MMcf (AKQTY_F(2) in code)
$CUST\_C_t$ = thousands of Alaska commercial gas customers (AK_CN in code). See the forecast equation in Table F2.
$UNEMP_t$ = U.S. civilian unemployment rate as a percent (MC_RUC in code, set by NEMS Macroeconomic Activity Module)

e

HDD_DVN_t = deviation of heating degree days from normal (10137.5)
L1995_00 = dummy variable with value of 1 from 1995 through 2000, 0 elsewhere
L1982_4 = dummy variable with value of 1 from 1982 through 1984, 0 elsewhere
L1985_94 = dummy variable with value of 1 from 1985 through 1994, 0 elsewhere
t = year

Regression diagnostics and parameters estimates:

Dependent Variable: CONS_C
Method: Least Squares
Date: 09/10/12 Time: 10:30
Sample: 1977 2011
Included observations: 35

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	17251.45	966.5315	17.84882	0.0000
CUST_C	124.4554	47.10005	2.642361	0.0133
HDD_DVN	0.704712	0.224793	3.134944	0.0040
UNEMP	-285.1327	100.7858	-2.829095	0.0085
L1995_00	9134.813	389.9092	23.42805	0.0000
L1982_4	8688.231	511.1704	16.99674	0.0000
L1985_94	3942.051	290.8965	13.55138	0.0000
R-squared	0.975410		Mean dependent var	20228.66
Adjusted R-squared	0.970141		S.D. dependent var	4037.064
S.E. of regression	697.5924		Akaike info criterion	16.11000
Sum squared resid	13625786		Schwarz criterion	16.42107
Log likelihood	-274.9251		Hannan-Quinn criter.	16.21738
F-statistic	185.1155		Durbin-Watson stat	1.707457
Prob(F-statistic)	0.000000			

So, the equation in the code for the Alaska commercial natural gas consumption is:

$$AKQTY\_F(2)_t = (17251.45 + (124.4554 * AK\_CN_t) + (-285.1327 * MC\_RUC_t))/1000$$

Natural Gas Wellhead Price

The forecast equation for the natural gas wellhead price in South Alaska is estimated as follows, using AR(1) to correct for first-order serial correlation:

$LNWELLHEAD\_PRICE_t = \beta_1 * LN\_IRAC87$

where,

$LN\_WELLHEAD\_PRICE_t$ = average natural gas wellhead price in Alaska (1987$/Mcf) (AK_WPRC in code)

$IRAC87_t$ = World oil price (Imported Refinery Acquisition Cost) (1987$/barrel) (IT_WOP(1) in the code, which has been redefined as the Brent price and is set centrally in NEMS)

t = year

Regression diagnostics and parameters estimates:

Dependent Variable: LN_WELLHEAD_PRICE

Method: Least Squares

Date: 07/22/09 Time: 13:25

Sample (adjusted): 1974 2008

Included observations: 35 after adjustments

Convergence achieved after 6 iterations

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
LN_IRAC87	0.280760	0.101743	2.759499	0.0094	β_1
AR(1)	0.934077	0.040455	23.08940	0.0000	β_{-1}
R-squared	0.881227		Mean dependent var	0.135244	
Adjusted R-squared	0.877628		S.D. dependent var	0.540629	
S.E. of regression	0.189122		Akaike info criterion	-0.437408	
Sum squared resid	1.180310		Schwarz criterion	-0.348531	
Log likelihood	9.654637		Hannan-Quinn criter.	-0.406727	
Durbin-Watson stat	2.121742				
Inverted AR Roots		.93			

The forecast equation becomes:

$$AK\_WPRC_t = AK\_WPRC_{t-1}^{0.934077} * oIT\_WOP_{y,1}^{(0.280760*(1-0.934077))}$$

Data used in estimating parameters in Tables F1 and F2

	CONS_R	CONS_C	CUST_R	CUST_C	AK_POP	UNEMP	HDD_DVN	AK_WPRC	IT_WOP
	mmcf	mmcf	thousand	thousand	thousand	percent		87$/Mcf	87$/bbl
1977	11282	14564	30.00	5.00	397.220	7.10	-869.1	0.68	24.88
1978	12166	15208	33.00	5.00	402.051	6.10	-1078.4	0.83	23.31
1979	7313	15862	36.00	6.00	403.367	5.80	-807.8	0.77	32.01
1980	7917	16513	37.00	6.00	405.315	7.10	415.0	0.99	45.90
1981	7904	16149	40.00	6.00	418.488	7.60	-667.5	0.77	45.87
1982	10554	24232	48.00	7.00	449.611	9.70	1050.3	0.74	39.15
1983	10434	24693	55.00	8.00	488.417	9.60	-69.6	0.82	32.89
1984	11833	24654	63.00	10.00	513.703	7.50	-569.0	0.79	31.25
1985	13256	20344	65.00	10.00	532.492	7.20	406.6	0.78	28.34
1986	12091	20874	66.00	11.00	544.269	7.00	-375.3	0.51	14.38
1987	12256	20224	67.65	11.48	539.310	6.20	-419.8	0.94	18.13
1988	12529	20842	68.61	11.65	541.982	5.50	-180.7	1.23	14.08
1989	13589	21738	69.54	11.81	547.153	5.30	398.2	1.27	16.85
1990	14165	21622	70.81	11.92	553.120	5.62	712.4	1.24	19.52
1991	13562	20897	72.57	12.07	569.273	6.85	79.5	1.28	16.21
1992	14350	21299	74.27	12.20	587.073	7.49	532.3	1.19	15.42
1993	13858	20003	75.84	12.36	596.993	6.91	-811.6	1.18	13.37
1994	14895	20698	77.67	12.48	600.624	6.10	147.2	1.03	12.58
1995	15231	24979	79.47	12.58	601.345	5.59	-135.5	1.30	13.62
1996	16179	27315	81.35	12.73	604.918	5.41	839.7	1.26	16.10
1997	15146	26908	83.60	12.95	608.846	4.94	-419.9	1.40	14.22
1998	15617	27079	86.24	13.18	615.205	4.50	-86.0	1.00	9.14
1999	17634	27667	88.92	13.41	619.500	4.22	870.2	1.02	12.91
2000	15987	26485	91.30	13.71	626.932	3.97	-358.8	1.29	20.28
2001	16818	15849	93.90	14.00	632.716	4.74	-87.9	1.42	15.73
2002	16191	15691	97.08	14.34	641.729	5.78	-770.2	1.50	16.66
2003	16853	17270	100.40	14.50	649.466	5.99	-736.5	1.66	19.06
2004	18200	18373	104.36	14.00	659.653	5.54	-538.0	2.29	24.01
2005	18029	16903	108.40	14.12	667.146	5.08	-829.4	3.08	31.65
2006	20616	18544	112.27	14.38	674.583	4.61	396.5	3.64	37.06
2007	19843	18756	115.50	13.41	680.169	4.62	60.8	3.44	41.01
2008	21439	17025	119.04	12.76	686.818	5.80	864.2	3.88	55.44
2009	19978	16620	120.12	13.22	697.828	9.28	193.5	--	--
2010	18714	15920	121.17	13.00	710.231	9.63	-140.0	--	--
2011	19432	16203	122.21	12.78	716.575	9.07	80.8	--	--

Table F2

Data: Equations for the number of residential and commercial customers in Alaska

Author: John Zyren, EIA, 2012

Source: Number of customers – *Natural Gas Annual*, DOE/EIA-0131; Alaska population – U.S. Census Bureau, Population Division; Unemployment rate – NEMS Macroeconomic Activity Module; Heating degree days – National Oceanic and Atmospheric Administration (Anchorage International Airport).

a. Residential customers

The number of residential customers was estimated as a function of the population in Alaska as well as the U.S. unemployment rate. Visual analysis of the available data shows a definite disconnect in the percent change data beginning in the year 1986. Since stability tests indicate a significant regime shift after 1985, only data for subsequent years (1986 to 2011) were used in the current analysis. The estimating method was Ordinary Least Squares (OLS) using EViews Version 7 with lagged dependent variables used to correct for first-order serial correlation. The forecast equation follows:

$$CUST\_R_t = \beta_0 + \beta_1 * POP\_AK_t + \beta_2 * UNEMP_t + \beta_3 * CUST\_R_{t-1} + \beta_4 * CUST\_R_{t-2}$$

where,

$CUST\_R_e$ = thousands of Alaska residential gas customers (AK_RN in code)

POP_AK_t = Alaska population in thousands (AK_POP in code, Appendix E)

$UNEMP_t$ = U.S. civilian unemployment rate as a percent (MC_RUC in code, set by NEMS Macroeconomic Activity Module)

Regression diagnostics and parameters estimates:

Dependent Variable: CUST_R
Method: Least Squares
Date: 09/05/12 Time: 16:07
Sample (adjusted): 1986 2011
Included observations: 26 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-4.690027	3.624917	-1.293830	0.2098
POP_AK	0.017224	0.009672	1.780721	0.0894
UNEMP	-0.310546	0.091090	-3.409216	0.0026
CUST_R(-1)	1.464274	0.158065	9.263773	0.0000
CUST_R(-2)	-0.498923	0.161537	-3.088594	0.0056
R-squared	0.999411		Mean dependent var	91.08808
Adjusted R-squared	0.999299		S.D. dependent var	19.03747
S.E. of regression	0.504127		Akaike info criterion	1.639064
Sum squared resid	5.337026		Schwarz criterion	1.881006
Log likelihood	-16.30784		Hannan-Quinn criter.	1.708735
F-statistic	8907.635		Durbin-Watson stat	1.876857
Prob(F-statistic)	0.000000			

e**b. Commercial customers**

The number of commercial consumers was estimated as a function of the population in Alaska, the deviation from normal heating degree days, and the U.S. civilian unemployment rate. Visual analysis of the data from 1973 through 2011 shows a definite disconnect in the percent change data beginning in the year 1988, so only data for subsequent years were used in the current analysis. There is some indication that another change may have occurred in 2003, hence the dummy variable (L2006) in the selected equation. The forecast equation was estimated using OLS and EViews Version 7, with data from 1987 to 2011 as follows:

$$CUST\_C_t = \beta 0 + (\beta_1 *POP\_AK_t) + (\beta_2 *HDD\_DVN_t) + (\beta_3 *UNEMP_t) + (\beta_4 *UNEMP_{t-1}) + (\beta_5 *L2006)$$

where,

$CUST\_C_t$ = number of Alaska commercial gas customers, in thousands (AK_CM in the code)
POP_AK_t = Alaska population in thousands (AK_POP in code, Appendix E)
HDD_DVN_t = the deviation from normal heating degree days in Alaska (10137.5)
$UNEMP_t$ = U.S. civilian unemployment rate as a percent (MC_RUC in code, set by NEMS Macroeconomic Activity Module)
L2006 = dummy variable equal to 0 from 1987 through 2003 and 1 from 2004 forward.
t = year

Regression diagnostics and parameters estimates:

Dependent Variable: CUST_C
Method: Least Squares
Date: 09/05/12 Time: 16:19
Sample (adjusted): 1987 2011
Included observations: 25 after adjustments

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	4.053311	1.676962	2.417056	0.0259
POP_AK	0.017833	0.002733	6.524092	0.0000
HDD_DVN	-0.000497	0.000159	-3.136025	0.0054
UNEMP	-0.157808	0.094370	-1.672229	0.1109
UNEMP(-1)	-0.182030	0.100340	-1.814137	0.0855
L2006	-0.625477	0.298387	-2.096195	0.0497
R-squared	0.851056		Mean dependent var	13.00160
Adjusted R-squared	0.811860		S.D. dependent var	0.898692
S.E. of regression	0.389809		Akaike info criterion	1.159242
Sum squared resid	2.887065		Schwarz criterion	1.451772
Log likelihood	-8.490520		Hannan-Quinn criter.	1.240377
F-statistic	21.71291		Durbin-Watson stat	1.716340
Prob(F-statistic)	0.000000			

Table F3

Data: Coefficients for the following Pipeline Tariff Submodule forecasting equations for pipeline and storage: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity.

Author: Science Applications International Corporation (SAIC)

Source: Foster Pipeline Financial Data, 1997-2006
Foster Storage Financial Data, 1990-1998

Variables:

For Transportation:

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 dollars)
DDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
NPIS_E	=	net plant in service for existing capacity in dollars (nominal dollars)
NEWCAP_E	=	change in existing gross plant in service (nominal dollars) between t and t-1 (set to zero during the forecast year phase since $GPIS\_E_{a,t} = GPIS\_E_{a,t+1}$ for year t >= 2007)
ADIT	=	accumulated deferred income taxes (nominal dollars)
NEWCAP	=	change in gross plant in service between t and t-1 (nominal dollars)
R_TOM	=	total operating and maintenance cost for existing and new capacity (2005 dollars)
GPIS	=	capital cost of plant in service for existing and new capacity (nominal dollars)
DEPSHR	=	level of the accumulated depreciation of the plant relative to the gross plant in service for existing and new capacity at the beginning of year t. This variable is a proxy for the age of the capital stock.
TECHYEAR	=	MODYEAR (time trend in Julian units, the minimum value of this variable in the sample being 1997, otherwise TECHYEAR=0 if less than 1997)
a	=	arc
t	=	forecast year

For Storage:

R_STCWC	=	total cash working capital at the beginning of year t for existing and new capacity (1996 dollars)
DSTTCAP	=	total gas storage capacity (Bcf)
STDDA_E	=	annual depreciation, depletion, and amortization costs for existing capacity (nominal dollars)
STNPIS_E	=	net plant in service for existing capacity (nominal dollars)

STNEWCAP	=	change in gross plant in service for existing capacity (nominal dollars)
STADIT	=	accumulated deferred income taxes (nominal dollars)
NEWCAP	=	change in gross plant in service for the combined existing and new capacity between years t and t-1 (nominal dollars)
R_STTOM	=	total operating and maintenance cost for existing and new capacity (1996 dollars)
DSTWCAP	=	level of gas working capacity for region r during year t (Bcf)
r	=	NGTDM region
t	=	forecast year

References: For transportation: “Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM,” by SAIC, June 23-July 22, 2008.

For storage: “Memorandum describing the estimated and forecast equations for TOM, DDA, CWC, and ADIT for the new PTM,” by SAIC, May 31, 2000.

Derivation: Estimations were done by using an accounting algorithm in combination with estimation software. Projections are based on a series of econometric equations which have been estimated using the Time Series Package (TSP) software. Equations were estimated by arc for pipelines and by NGTDM region for storage, as follows: total cash working capital for the combined existing and new capacity; depreciation, depletion, and amortization expenses for existing capacity; accumulated deferred income taxes for the combined existing and new capacity; and total operating and maintenance expense for the combined existing and new capacity. These equations are defined as follows:

(1) Total Cash Working Capital for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model.

Because of economies in cash management, a log-linear specification between total operating and maintenance expenses, R_TOM_a, and the level of cash working capital, R_CWC_a was assumed. To control for arc-specific effects, a binary variable was created for each of the arcs. The associated coefficient represents the arc-specific constant term.

The underlying notion of this equation is that working capital represents funds to maintain the capital stock and is therefore driven by changes in R_TOM.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned} Ln(R\_CWC_{a,t}) = {} & CWC\_C_a * (1-\rho) + CWC\_TOM * Ln(R\_TOM_{a,t}) + \\ & \rho * Ln(R\_CWC_{a,t-1}) - \rho * CWC\_TOM * Ln(R\_TOM_{a,t-1}) \end{aligned}$$

Stage 2:

$$R\_CWC_{a,t} = CWC\_K * \exp(Ln(R\_CWC_{a,t}))$$

where,

R_CWC	=	total pipeline transmission cash working capital for existing and new capacity (2005 dollars)
CWC_C_a	=	estimated arc-specific constant for gas transported from node to node (see Table F3.2)
CWC_TOM	=	estimated R_TOM coefficient (see Table F3.2)
R_TOM	=	total operation and maintenance expenses in 2005 dollars
CWC_K	=	correction factor estimated in stage 2 of the regression equation estimation process
ρ	=	autocorrelation coefficient from estimation (see Table F3.2 -- CWC_RHO)

Ln is a natural logarithm operator and CWC_K is the correction factor estimated in equation two.

The results of this regression are reported below:

Dependent variable: R_CWC
Number of observations: 396

Mean of dep. var.	= 18503.0	LM het. Test	= 135.638 [.000]
Std. dev. of dep. var.	= 283454.4	Durbin-Watson	= 2.29318 [<1.00]
Sum of squared residuals	= .116124E+11	Jarque-Bera test	= 6902.15 [.000]
Variance of residuals	= .293986E+08	Ramsey's RESET2	= .849453 [.357]
Std. error of regression	= 5422.05	Schwarz B.I.C.	= 3969.29
R-squared	= .963435	Log likelihood	= -3966.30
Adjusted R-squared	= .963435		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
CWC_K	1.01813	8.31E-03	122.551	[.000]

For Storage:

$$\begin{aligned} R\_STCWC_{r,t} = {} & e^{(\beta_{0,r} * (1-\rho))} * DSTTCAP_{r,t-1}^{\beta_1} * \\ & R\_STCWC_{r,t-1}^{\rho} * DSTTCAP_{r,t-2}^{-\rho * \beta_1} \end{aligned}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.1, $\beta_{0,r}$ = REG_r)
	=	STCWC_CREG (Appendix E)
β_1	=	1.07386
	=	STCWC_TOTCAP (Appendix E), t-statistic (2.8)
ρ	=	0.668332
	=	STCWC_RHO (Appendix E), t-statistic (6.8)
DW	=	1.53
R-Squared	=	0.99

(2) Total Depreciation, Depletion, and Amortization for Existing Capacity

(a) existing capacity (up to 2000 for pipeline and up to 1998 for storage)

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. A linear specification was chosen given that DDA_E is generally believed to be proportional to the level of net plant. The forecasting equation was estimated with a correction for first order serial correlation.

$$\begin{aligned}DDA\_E_{a,t} = {} & DDA\_C_a * ARC_a + DDA\_NPIS * NPIS_{a,t-1} + \\ & DDA\_NEWCAP * NEWCAP\_E_{a,t}\end{aligned}$$

where,

DDA_C_a	=	constant term estimated by arc for the binary variable ARC_a (see Table F3.3, DDA_C_a = $B\_ARC_{xx\_yy}$)
ARC_a	=	binary variable created for each arc to control for arc specific effects
DDA_NPIS	=	estimated coefficient (see Table F3.3)
DDA_NEWCAP	=	estimated coefficient (see Table F3.3)

The standard errors in Table F3.3 are computed from heteroscedastic-consistent matrix (Robust-White).

The results of this regression are reported below:

Dependent variable: DDA_E
Number of observations: 446

Mean of dep. var.	= 25154.4	R-squared	= .995361
Std. dev. of dep. var.	= 33518.3	Adjusted R-squared	= .994761
Sum of squared residuals	= .231907E+10	LM het. Test	= 30.7086 [.000]
Variance of residuals	= .588597E+07	Durbin-Watson = 2.06651 [<1.00]	
Std. error of regression	= 2426.10		

For Storage:

$$STDDA\_E_{r,t} = \beta_{0,r} + \beta_1 * STNPIS\_E_{r,t-1} + \beta_2 * STNEWCAP_{r,t}$$

where,

$\beta_{0,a}$	=	constant term estimated by region (see Table F3.4, $\beta_{0,r}$ = REG_r)
	=	STDDA_CREG (Appendix E)
β_1, β_2	=	(0.032004, 0.028197)
	=	STDDA_NPIS, STDDA_NEWCAP (Appendix E)
t-statistic	=	(10.3) (16.9)
DW	=	1.62
R-Squared	=	0.97

(b) new capacity (generic pipelines and storage)

A regression equation is not used for the new capacity; instead, an accounting algorithm is used (presented in Chapter 6).

(3) Accumulated Deferred Income Taxes for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc-specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc-specific constant term.

Because the level of deferred income taxes is a stock (and not a flow) it was hypothesized that a formulation that focused on the change in the level of accumulated deferred income taxes from the previous year, $deltaADIT_{a,t}$, would be appropriate. Specifically, a linear relationship between the change in ADIT and the change in the level of gross plant in service, $NEWCAP_{a,t}$, and the change in tax policy, POLICY_CHG, was assumed. The form of the estimating equation is:

$$delta\,ADIT_{a,t} = ADIT\_C_a * ARC_a + \beta_1 * NEWCAP_{a,t} + \beta_2 * NEWCAP_{a,t} + \beta_3 * NEWCAP_{a,t}$$

where,

$ADIT\_C_a$	=	constant term estimated by arc for the binary variable ARC_a (see Table F3.5, $ADIT\_C_a = B\_ARC_{xx\_yy}$)
β_1	=	BNEWCAP_PRE2003, estimated coefficient on the change in gross plant in service in the pre-2003 period because of changes in tax policy in 2003 and 2004 (Appendix F, Table F3.5). It is zero otherwise.

β_2 = BNEWCAP_2003_2004, estimated coefficient on the change in gross plant in service for the years 2003 and 2004 because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

β_3 = BNEWCAP_POST2004, estimated coefficient on the change in gross plant in service in the post-2004 period because of changes in tax policy (Appendix F, Table F3.5). It is zero otherwise.

The estimation results are:

Dependent variable: DELTAADIT
Number of observations: 396

Mean of dep. var.	= 6493.50	R-squared	= .464802
Std. dev. of dep. var.	= 17140.8	Adjusted R-squared	= .383664
Sum of squared residuals	= .621120E+11	LM het. test	= 4.03824 [.044]
Variance of residuals	= .181084E+09	Durbin-Watson	= 2.44866 [<1.00]
Std. error of regression	= 13456.8		

For Storage:

$$\mathrm{STADIT}_{r,t} = \beta_0 + \beta_1 * \mathrm{STADIT}_{r,t-1} + \beta_2 * \mathrm{NEWCAP}_{r,t}$$

where,

β_0 = -212.535
= STADIT_C (Appendix E)
β_1, β_2 = (0.921962, 0.212610)
= STADIT_ADIT, STADIT_NEWCAP (Appendix E)
t-statistic = (58.8) (8.4)
DW = 1.69
R-Squared = 0.98

(4) Total Operating and Maintenance Expense for the Combined Existing and New Capacity

For Transportation:

The equation was estimated using FERC Form 2 data over the period 1997 through 2006. In this analysis, the data were aggregated to the ARC level so that the results would be more consistent with the previous model. To control for arc-specific effects, a binary variable ARC_a was created for each of the arcs. The associated coefficient represents the arc-specific constant term.

The forecasting equation is presented in two stages.

Stage 1:

$$\begin{aligned}\text{Ln}(\text{R\_TOM}_{a,t}) = {} & \text{TOM\_C}_a * \text{ARC}_a * (1-\rho) + \text{TOM\_GPIS1} * \text{Ln}(\text{GPIS}_{a,t-1}) \\ & + \text{TOM\_DEPSHR} * \text{DEPSHR}_{a,\,t-1} + \text{TOM\_BYEAR} * 2006 \\ & + \text{TOM\_BYEAR\_EIA} * (\text{TECHYEAR} - 2006.0) + \rho * \text{Ln}(\text{R\_TOM}_{a,t-1}) \\ & - \rho * (\text{TOM\_GPIS1} * \text{Ln}(\text{GPIS}_{a,t-2}) + \text{TOM\_DESHR} * \text{DEPSHR}_{a,\,t-2} \\ & + \text{TOM\_BYEAR} * 2006 + \text{TOM\_BYEAR\_EIA} * (\text{TECHYEAR} - 1 - 2006.0))\end{aligned}$$

Stage 2:

$$\text{R\_TOM}_{a,t} = \text{TOM\_K} * \exp(\text{Ln}(\text{R\_TOM}_{a,t}))$$

where Ln is a natural logarithm operator and TOM_K is the correction factor estimated in equation two, and where,

TOM_C_a	=	constant term estimated by arc for the binary variable ARCa (see Table F3.6, TOM_Ca = B_ARCxx_yy)
ARC_a	=	binary variable created for each arc to control for arc specific effects
TOM_GPIS1	=	estimated coefficient (see Table F3.6)
TOM_DEPSHR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR	=	estimated coefficient (see Table F3.6)
TOM_BYEAR_EIA	=	future rate of decline in R_TOM due to technology improvements and efficiency gains. EIA assumes that this rate is the same as TOM_BYEAR (see Table F3.6)
ρ	=	first-order autocorrelation, TOM_RHO (see Table F3.6)

The results of this regression are reported below:

Dependent variable: R_TOM
Number of observations: 396

Mean of dep. var.	= 52822.9	LM het. test	= 28.7074 [.000]
Std. dev. of dep. var.	= 76354.9	Durbin-Watson	= 2.01148 [<1.00]
Sum of squared residuals	= .668483E+11	Jarque-Bera test	= 13559.1 [.000]
Variance of residuals	= .169236E+09	Ramsey's RESET2	= 4.03086 [.045]
Std. error of regression	= 13009.1	Schwarz B.I.C.	= 4215.86
R-squared	= .971019	Log likelihood	= -4312.87
Adjusted R-squared	= .971019		

Variable	Estimated Coefficient	Standard Error	t-statistic	P-value
TOM_K	0.940181	6.691E-03	140.504	[.000]

For Storage:

$$R\_STTOM_{r,t} = e^{(\beta_0 * (1-\rho))} * DSTWCAP_{r,t-1}^{\beta_1} * R\_STTOM_{r,t-1}^{\rho} * DSTWCAP_{r,t-2}^{-\rho*\beta_1}$$

where,

β_0 = -6.7702
= STTOM_C (Appendix E)
β_1 = 1.44442
= STTOM_WORCAP (Appendix E), t-statistic (33.6)
ρ = 0.761238
= STTOM_RHO (Appendix E), t-statistic (10.2)
DW = 1.39
R-Squared = 0.99

Table F3.1. Summary statistics for storage total cash working capital equation

Variable	Coefficient	Standard Error	t-statistic
REG2	-2.30334	5.25413	-.438386
REG3	-1.51115	5.33882	-.283049
REG4	-2.11195	5.19899	-.406224
REG5	-2.07950	5.06766	-.410346
REG6	-1.24091	4.97239	-.249559
REG7	-1.63716	5.27950	-.310097
REG8	-2.48339	4.68793	-.529740
REG9	-3.23625	4.09158	-.790954
REG11	-2.15877	4.33364	-.498143

Table F3. 2. Summary statistics for pipeline total cash working capital equation

Variable	**Coefficient**	**Standard-Error**	**t-statistic**	**P-value**
CWC_TOM	0.381679	.062976	6.06073	[.000]
B_ARC01_01	4.83845	.644360	7.50892	[.000]
B_ARC02_01	5.19554	.644074	8.06668	[.000]
B_ARC02_02	6.37816	.781655	8.15982	[.000]
B_ARC02_03	4.38403	.594344	7.37625	[.000]
B_ARC02_05	5.02364	.684640	7.33764	[.000]
B_ARC03_02	5.51162	.651682	8.45754	[.000]
B_ARC03_03	6.10201	.772378	7.90028	[.000]
B_ARC03_04	4.10475	.572836	7.16566	[.000]
B_ARC03_05	4.69978	.665214	7.06507	[.000]
B_ARC03_15	4.99465	.600910	8.31180	[.000]
B_ARC04_03	5.56047	.718330	7.74083	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC04_04	6.15095	.783539	7.85021	[.000]
B_ARC04_07	4.26747	.590736	7.22400	[.000]
B_ARC04_08	4.12216	.611516	6.74089	[.000]
B_ARC05_02	5.50272	.732227	7.51505	[.000]
B_ARC05_03	4.93360	.667589	7.39018	[.000]
B_ARC05_05	6.03791	.774677	7.79409	[.000]
B_ARC05_06	3.27334	.516303	6.33995	[.000]
B_ARC06_03	5.80098	.714338	8.12078	[.000]
B_ARC06_05	5.76939	.741907	7.77644	[.000]
B_ARC06_06	6.73455	.807246	8.34262	[.000]
B_ARC06_07	3.52000	.555549	6.33606	[.000]
B_ARC06_10	4.64811	.665947	6.97970	[.000]
B_ARC07_04	5.60946	.732039	7.66279	[.000]
B_ARC07_06	6.35683	.778573	8.16471	[.000]
B_ARC07_07	6.81298	.828208	8.22616	[.000]
B_ARC07_08	3.60827	.543296	6.64144	[.000]
B_ARC07_11	5.89640	.708385	8.32373	[.000]
B_ARC07_21	4.85140	.621031	7.81185	[.000]
B_ARC08_04	4.94307	.678799	7.28208	[.000]
B_ARC08_07	3.97367	.579267	6.85982	[.000]
B_ARC08_08	5.58162	.723678	7.71286	[.000]
B_ARC08_09	5.19274	.635784	8.16746	[.000]
B_ARC08_11	5.12277	.637835	8.03148	[.000]
B_ARC08_12	4.29097	.593945	7.22452	[.000]
B_ARC09_08	4.10222	.576694	7.11333	[.000]
B_ARC09_09	5.44178	.684020	7.95558	[.000]
B_ARC09_12	4.96229	.600227	8.26735	[.000]
B_ARC09_20	2.63716	.448339	5.88207	[.000]
B_ARC11_07	5.58226	.687702	8.11726	[.000]
B_ARC11_08	4.36952	.548152	7.97137	[.000]
B_ARC11_11	6.13044	.728452	8.41571	[.000]
B_ARC11_12	5.93253	.710336	8.35173	[.000]
B_ARC11_22	4.33062	.545420	7.93998	[.000]
B_ARC15_02	5.09861	.583090	8.74412	[.000]
B_ARC16_04	5.03673	.592859	8.49567	[.000]
B_ARC17_04	4.17798	.576943	7.24158	[.000]
B_ARC19_09	5.14500	.618100	8.32389	[.000]
B_ARC20_09	4.58498	.624006	7.34766	[.000]
B_ARC21_07	4.26846	.563536	7.57441	[.000]
CWC_RHO	0.527389	.048379	10.9011	[.000]

Table F3.3. Summary statistics for pipeline depreciation, depletion, and amortization equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
DDA_NEWCAP	.725948E-02	.200846E-02	3.61446	[.000]
DDA_NPIS	.023390	.103991E-02	22.4923	[.000]
B_ARC01_01	4699.58	862.825	5.44674	[.000]
B_ARC02_01	5081.37	853.478	5.95372	[.000]
B_ARC02_02	43769.1	1954.50	22.3940	[.000]
B_ARC02_03	2050.29	814.056	2.51861	[.012]
B_ARC02_05	7876.12	880.047	8.94965	[.000]
B_ARC03_02	5973.21	842.863	7.08681	[.000]
B_ARC03_03	33063.3	1489.77	22.1936	[.000]
B_ARC03_04	1032.74	809.439	1.27588	[.202]
B_ARC03_05	2386.89	845.864	2.82184	[.005]
B_ARC03_15	7652.92	864.810	8.84924	[.000]
B_ARC04_03	19729.5	1118.66	17.6368	[.000]
B_ARC04_04	35522.7	2267.45	15.6663	[.000]
B_ARC04_07	1919.97	811.222	2.36677	[.018]
B_ARC04_08	747.069	822.607	.908172	[.364]
B_ARC05_02	15678.2	1114.41	14.0686	[.000]
B_ARC05_03	6452.49	855.092	7.54596	[.000]
B_ARC05_05	45000.5	1771.82	25.3979	[.000]
B_ARC05_06	446.742	809.035	.552191	[.581]
B_ARC06_03	11967.8	942.879	12.6928	[.000]
B_ARC06_05	22576.3	1243.19	18.1599	[.000]
B_ARC06_06	67252.9	2892.23	23.2530	[.000]
B_ARC06_07	1134.14	809.115	1.40170	[.161]
B_ARC06_10	15821.4	989.531	15.9888	[.000]
B_ARC07_04	15041.4	984.735	15.2746	[.000]
B_ARC07_06	48087.6	1908.12	25.2015	[.000]
B_ARC07_07	80361.2	3384.54	23.7436	[.000]
B_ARC07_08	833.829	809.565	1.02997	[.303]
B_ARC07_11	4732.17	928.814	5.09486	[.000]
B_ARC07_21	1452.16	922.486	1.57418	[.115]
B_ARC08_04	4920.06	1022.86	4.81008	[.000]
B_ARC08_07	1425.79	811.348	1.75731	[.079]
B_ARC08_08	34661.3	1694.49	20.4553	[.000]
B_ARC08_09	5962.90	873.649	6.82528	[.000]
B_ARC08_11	1088.95	824.202	1.32122	[.186]
B_ARC08_12	7610.79	899.215	8.46382	[.000]
B_ARC09_08	2857.54	814.127	3.50994	[.000]
B_ARC09_09	15070.9	1021.78	14.7496	[.000]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC09_12	3120.00	833.569	3.74295	[.000]
B_ARC09_20	279.322	917.025	.304595	[.761]
B_ARC11_07	4022.68	871.680	4.61485	[.000]
B_ARC11_08	325.210	809.288	.401846	[.688]
B_ARC11_11	5616.89	1025.31	5.47822	[.000]
B_ARC11_12	4041.93	940.189	4.29906	[.000]
B_ARC11_22	259.293	809.060	.320487	[.749]
B_ARC15_02	2125.53	812.198	2.61701	[.009]
B_ARC16_04	8017.53	871.030	9.20465	[.000]
B_ARC17_04	3316.38	860.323	3.85481	[.000]
B_ARC19_09	4216.02	853.774	4.93810	[.000]
B_ARC20_09	6238.31	834.249	7.47776	[.000]
B_ARC21_07	666.813	810.034	.823192	[.410]

Table F3.4. Summary statistics for storage depreciation, depletion, and amortization equation

Variable	Coefficient	Standard-Error	t-statistic
REG2	4485.56	1204.28	3.72467
REG3	6267.52	1806.17	3.47006
REG4	3552.55	728.230	4.87833
REG5	2075.31	646.561	3.20976
REG6	1560.07	383.150	4.07169
REG7	4522.42	1268.87	3.56412
REG8	1102.49	622.420	1.77129
REG9	65.2731	10.1903	6.40542
REG11	134.692	494.392	.272439

Table F3.5. Summary statistics for pipeline accumulated deferred income tax equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
BNEWCAP_PRE2003	.067242	.023235	2.89405	[.004]
BNEWCAP_2003_2004	.132014	.013088	10.0865	[.000]
BNEWCAP_POST2004	.109336	.028196	3.87766	[.000]
B_ARC01_01	3529.80	4775.58	.739134	[.460]
B_ARC02_01	2793.71	4766.40	.586125	[.558]
B_ARC02_02	15255.3	5318.30	2.86844	[.004]
B_ARC02_03	767.648	4758.23	.161331	[.872]
B_ARC02_05	2479.86	4768.91	.520005	[.603]
B_ARC03_02	1663.09	4761.98	.349243	[.727]
B_ARC03_03	6184.51	4966.65	1.24521	[.213]
B_ARC03_04	-14.6495	4757.75	-.307908E-02	[.998]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC03_05	3183.89	4761.49	.668676	[.504]
B_ARC03_15	2531.19	4759.07	.531866	[.595]
B_ARC04_03	3660.65	4780.00	.765826	[.444]
B_ARC04_04	6076.87	4900.20	1.24013	[.215]
B_ARC04_07	-391.339	4757.90	-.082250	[.934]
B_ARC04_08	1798.04	4758.19	.377884	[.706]
B_ARC05_02	6654.17	4801.91	1.38573	[.166]
B_ARC05_03	1842.90	4762.25	.386982	[.699]
B_ARC05_05	6344.87	5220.98	1.21526	[.224]
B_ARC05_06	148.421	4757.73	.031196	[.975]
B_ARC06_03	2475.65	4775.18	.518441	[.604]
B_ARC06_05	5193.49	4996.38	1.03945	[.299]
B_ARC06_06	24991.1	5803.11	4.30650	[.000]
B_ARC06_07	-259.276	4757.72	-.054496	[.957]
B_ARC06_10	13015.7	4862.80	2.67659	[.007]
B_ARC07_04	189.221	4776.34	.039616	[.968]
B_ARC07_06	14166.3	5012.13	2.82640	[.005]
B_ARC07_07	16102.7	5680.52	2.83472	[.005]
B_ARC07_08	118.047	4758.11	.024810	[.980]
B_ARC07_11	-434.842	4808.84	-.090426	[.928]
B_ARC07_21	495.934	5498.36	.090197	[.928]
B_ARC08_04	4679.95	4780.56	.978955	[.328]
B_ARC08_07	365.793	4762.84	.076801	[.939]
B_ARC08_08	5133.64	5235.92	.980466	[.327]
B_ARC08_09	-3672.71	4770.23	-.769923	[.441]
B_ARC08_11	-1856.45	4762.76	-.389784	[.697]
B_ARC08_12	795.831	4808.51	.165505	[.869]
B_ARC09_08	537.433	4759.95	.112907	[.910]
B_ARC09_09	-1812.27	4829.76	-.375230	[.707]
B_ARC09_12	-2803.40	4761.86	-.588719	[.556]
B_ARC09_20	55.5366	5493.73	.010109	[.992]
B_ARC11_07	-1137.92	4772.21	-.238448	[.812]
B_ARC11_08	276.612	4757.86	.058138	[.954]
B_ARC11_11	7.99239	4874.89	.163950E-02	[.999]
B_ARC11_12	-1079.76	4825.77	-.223750	[.823]
B_ARC11_22	337.987	4759.18	.071018	[.943]
B_ARC15_02	429.875	4758.19	.090344	[.928]
B_ARC16_04	2744.23	4759.07	.576631	[.564]
B_ARC17_04	935.795	4757.97	.196680	[.844]
B_ARC19_09	-3806.27	4762.95	-.799141	[.424]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC20_09	1173.22	4768.48	.246037	[.806]
B_ARC21_07	586.673	4759.84	.123255	[.902]

Table F3.6. Summary statistics for pipeline total operating and maintenance expense equation

Variable	Coefficient	Standard-Error	t-statistic	P-value
TOM_GPIS1	.256869	.114518	2.24304	[.025]
TOM_DEPSHR	1.69807	.429440	3.95415	[.000]
TOM_BYEAR	-.019974	.718590E-02	-2.77955	[.005]
B_ARC01_01	45.8116	13.5505	3.38081	[.001]
B_ARC02_01	45.7428	13.5502	3.37580	[.001]
B_ARC02_02	47.4313	13.4380	3.52963	[.000]
B_ARC02_03	45.3570	13.6230	3.32944	[.001]
B_ARC02_05	46.3936	13.5393	3.42658	[.001]
B_ARC03_02	45.8277	13.5539	3.38115	[.001]
B_ARC03_03	47.1662	13.4461	3.50779	[.000]
B_ARC03_04	44.5365	13.6401	3.26512	[.001]
B_ARC03_05	45.9318	13.5464	3.39071	[.001]
B_ARC03_15	45.1262	13.5508	3.33015	[.001]
B_ARC04_03	46.5137	13.4799	3.45060	[.001]
B_ARC04_04	47.4725	13.4290	3.53508	[.000]
B_ARC04_07	45.0325	13.6249	3.30516	[.001]
B_ARC04_08	45.6096	13.5965	3.35451	[.001]
B_ARC05_02	46.8361	13.4859	3.47298	[.001]
B_ARC05_03	46.2316	13.5556	3.41052	[.001]
B_ARC05_05	47.2881	13.4422	3.51788	[.000]
B_ARC05_06	44.2555	13.6969	3.23105	[.001]
B_ARC06_03	46.4249	13.4976	3.43948	[.001]
B_ARC06_05	46.9210	13.4730	3.48260	[.000]
B_ARC06_06	47.6072	13.4045	3.55157	[.000]
B_ARC06_07	44.5090	13.6696	3.25606	[.001]
B_ARC06_10	46.0547	13.5171	3.40715	[.001]
B_ARC07_04	46.6884	13.4905	3.46084	[.001]
B_ARC07_06	47.2664	13.4316	3.51904	[.000]
B_ARC07_07	47.8651	13.3928	3.57395	[.000]
B_ARC07_08	44.7096	13.6750	3.26944	[.001]
B_ARC07_11	46.7847	13.5263	3.45880	[.001]
B_ARC07_21	45.4067	13.6138	3.33535	[.001]
B_ARC08_04	46.3290	13.5124	3.42864	[.001]
B_ARC08_07	45.1349	13.6437	3.30810	[.001]

Variable	Coefficient	Standard-Error	t-statistic	P-value
B_ARC08_08	46.8373	13.4658	3.47825	[.001]
B_ARC08_09	45.7056	13.5495	3.37323	[.001]
B_ARC08_11	45.9766	13.5925	3.38250	[.001]
B_ARC08_12	45.1596	13.5537	3.33190	[.001]
B_ARC09_08	44.9927	13.6211	3.30317	[.001]
B_ARC09_09	46.2997	13.5103	3.42699	[.001]
B_ARC09_12	45.2655	13.5793	3.33342	[.001]
B_ARC09_20	43.2644	13.7686	3.14226	[.002]
B_ARC11_07	46.4472	13.5409	3.43015	[.001]
B_ARC11_08	44.9105	13.6898	3.28058	[.001]
B_ARC11_11	47.0985	13.5107	3.48603	[.000]
B_ARC11_12	46.8744	13.5270	3.46526	[.001]
B_ARC11_22	44.8071	13.7118	3.26778	[.001]
B_ARC15_02	44.8267	13.6116	3.29327	[.001]
B_ARC16_04	45.0068	13.5491	3.32175	[.001]
B_ARC17_04	44.8832	13.5582	3.31042	[.001]
B_ARC19_09	45.4861	13.5613	3.35412	[.001]
B_ARC20_09	45.5729	13.5745	3.35725	[.001]
B_ARC21_07	44.6298	13.6465	3.27041	[.001]
TOM_RHO	.297716	.052442	5.67707	[.000]

Table F4

Data: Equations for industrial distribution tariffs

Author: Joe Benneche, EIA, 2012.

Source: Annual historical industrial prices for the core and noncore categories are generated as described in Table F5. Seasonal prices are generated from these annual prices based on the derived seasonal price differentials shown from the industrial prices published in the Natural Gas Monthly, DOE/EIA-0130. This same source is used to derive seasonal shares for breaking out noncore industrial consumption into peak and off-peak figures. The noncore consumption values were taken from the National Energy Modeling System and set within its Industrial Demand Module. State-level city gate prices by month were averaged using quantity weights to arrive at seasonal (peak and off-peak), regional-level (12 NGTDM regions) prices. The quantity weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical distributor tariffs are set by subtracting these city gate prices from the delivered industrial prices.

Variables:

$TINDI_{r,n,t}$	=	noncore industrial distributor tariff in region r, network n (1987$/Mcf) [$DTAR_SI_{3,n,r}$]
$TINDF_{r,n,t}$	=	core industrial distributor tariff in region r, network n (1987$/Mcf) [$DTAR_SF_{3,n,r}$]
$REGION_r$	=	1, if observation is in region r, =0 otherwise
$QINDI_{r,n,t}$	=	noncore industrial gas consumption in region r, in season n (Bcf) [$BASQTY\_SI_{3,r}$]
n	=	period or season
r	=	NGTDM region
t	=	year
α_r, $\alpha_{r,n}$	=	estimated parameters for noncore regional constants [$PINREG19I_r$, $PINREGPK19I_{r,n}$]
δ_r, $\delta_{r,n}$	=	estimated parameters for core regional constants [$PINREG19F_r$, $PINREGPK19F_{r,n}$]
β_1	=	estimated parameter for noncore consumption (QINDI)
β_2	=	estimated parameter for noncore distributor tariff (TINDI)
ρ_1, ρ_2	=	autocorrelation coefficient for noncore (1) and core (2) equation

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The industrial distributor tariff equations were estimated using backcasted data for the 12 NGTDM regions over the 1990 to 2010 time period. The equations were estimated in linear form with corrections for cross-sectional heteroscedasticity and first order serial correlation using Eviews. The forms of the estimating equations follow:

$$TINDI_{r,n,t} = \sum_{r}(\alpha_r + \alpha_{r,pk}) * REGION_r + \beta_1 * QINDI_{r,n,t} + \rho_1 * TINDI_{r,n,t\ \ 1}$$

$$\rho_1 * (\sum_{r}(\alpha_r + \alpha_{r,pk}) * REGION_r + \beta_1 * QINDI_{r,n,t\ \ 1})$$

$$TINDF_{r,n,t} = \sum_{r}(\delta_r + \delta_{r,pk}) * REGION_r + \beta_2 * TINDI_{r,n,t} + \rho_2 * TINDF_{r,n,t\ \ 1}$$

$$\rho_2 * (\sum_{r}(\delta_r + \delta_{r,pk}) * REGION_r + \beta_2 * TINDI_{r,n,t\ \ 1})$$

Regression diagnostics and parameter estimates:

Dependent Variable: TINDI
Method: Least Squares
Date: 08/31/12 Time: 08:41
Sample (adjusted): 2 528
Included observations: 527 after adjustments
Convergence achieved after 5 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
REGION3	0.344421	0.088710	3.882560	0.0001
REGION9	0.396508	0.084572	4.688415	0.0000
REGION10	0.510307	0.084641	6.029082	0.0000
REGION11	0.583418	0.084894	6.872320	0.0000
REGION12	0.948548	0.087723	10.81295	0.0000
REGION1PK	1.178899	0.127891	9.217992	0.0000
REGION2PK	0.743417	0.119956	6.197433	0.0000
REGION7PK	-0.396888	0.131651	-3.014689	0.0027
QINDI	-0.000651	0.000116	-5.591997	0.0000
AR(1)	0.434485	0.039870	10.89760	0.0000
e	0.666366		Mean dependent var	0.203239
Adjusted R-squared	0.660558		S.D. dependent var	0.575396
S.E. of regression	0.335235		Akaike info criterion	0.670824
Sum squared resid	58.10183		Schwarz criterion	0.751796
Log likelihood	-166.7622		Hannan-Quinn criter.	0.702526
Durbin-Watson stat	2.153064			
Inverted AR Roots		.43		

Dependent Variable: TINDF
Method: Least Squares
Date: 08/31/12 Time: 08:40
Sample (adjusted): 2 528
Included observations: 527 after adjustments
Convergence achieved after 6 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
REGION1	0.400924	0.043226	9.275039	0.0000
REGION2	0.315417	0.041171	7.661055	0.0000
REGION3	0.284744	0.040598	7.013804	0.0000
REGION4	0.309361	0.040660	7.608395	0.0000
REGION5	0.242834	0.040551	5.988354	0.0000
REGION6	0.280499	0.040492	6.927322	0.0000
REGION7	0.191963	0.042020	4.568344	0.0000
REGION8	0.389896	0.040483	9.630995	0.0000
REGION9	0.378518	0.041065	9.217440	0.0000
REGION10	0.353700	0.041426	8.538151	0.0000
REGION11	0.412150	0.041581	9.911945	0.0000
REGION12	0.354604	0.043591	8.134719	0.0000
TINDI	1.017384	0.017454	58.28946	0.0000
AR(1)	0.533751	0.037522	14.22489	0.0000
R-squared	0.956133		Mean dependent var	0.532939
Adjusted R-squared	0.955021		S.D. dependent var	0.647040
S.E. of regression	0.137226		Akaike info criterion	-1.108167
Sum squared resid	9.660308		Schwarz criterion	-0.994807
Log likelihood	306.0020		Hannan-Quinn criter.	-1.063785
Durbin-Watson stat	2.183486			
Inverted AR Roots		.53		

Data used for estimation

			1	2	3	4	5	6	7	8	9	10	11	12
Year	Vari-able	Season	New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
1990	tindi	peak	1.319	0.932	0.365	0.024	0.425	0.049	-0.735	0.097	0.613	0.471	0.544	0.887
1990	tindi	off-peak	0.402	0.525	0.376	-0.137	0.082	-0.09	-0.915	-0.542	0.411	0.575	0.659	0.608
1991	tindi	peak	1.233	0.914	0.281	-0.06	0.244	-0.028	-0.864	-0.276	0.554	0.241	0.597	1.022
1991	tindi	off-peak	0.268	0.272	0.166	-0.29	-0.21	-0.214	-0.837	-0.776	0.487	0.329	0.464	0.622
1992	tindi	peak	1.451	0.83	0.258	0.06	0.303	0.034	-0.789	-0.211	0.583	0.365	1.598	1.106
1992	tindi	off-peak	0.01	-0.049	-0.028	-0.204	-0.244	-0.269	-0.754	-1.03	0.625	0.283	1.343	0.294
1993	tindi	peak	1.5	0.662	0.276	0.035	0.318	0.106	-0.702	-0.274	0.555	0.534	0.963	0.146
1993	tindi	off-peak	-0.234	-0.023	0.13	-0.289	-0.304	-0.191	-0.622	-0.663	0.477	0.674	0.848	-0.318
1994	tindi	peak	1.535	0.855	0.533	0.175	0.272	0.288	-0.654	-0.543	0.466	0.132	1.163	0.603
1994	tindi	off-peak	-0.5	0.198	0.35	-0.33	-0.359	-0.108	-0.531	-0.785	0.232	0.294	0.651	0.319
1995	tindi	peak	1.136	0.582	0.116	0.047	0.293	0.234	-0.784	-0.154	0.35	-0.035	1.29	1.539
1995	tindi	off-peak	-0.569	0.187	-0.107	-0.405	-0.186	-0.206	-0.716	-0.148	0.33	0.104	1.038	0.897
1996	tindi	peak	1.599	0.74	0.181	0.349	0.367	-0.021	-0.257	0.084	0.442	0.156	1.005	1.071
1996	tindi	off-peak	-0.207	0.125	0.206	-0.303	-0.004	0.045	-0.311	0.11	0.151	0.376	0.943	0.817
1997	tindi	peak	1.447	0.824	0.462	0.126	0.368	0.218	-0.55	0.05	0.621	-0.095	0.506	1.373
1997	tindi	off-peak	-0.011	-0.741	0.103	-0.514	-0.152	-0.005	-0.275	0.214	0.179	0.288	0.38	0.689
1998	tindi	peak	1.074	0.082	0.393	0.135	0.15	0.209	-0.287	-0.025	0.275	0.146	0.692	1.375
1998	tindi	off-peak	-0.561	-0.464	0.308	-0.354	-0.408	-0.168	-0.197	0.178	0.173	0.133	0.308	0.67
1999	tindi	peak	0.568	0.107	0.339	0.049	-0.141	0.158	-0.488	0.568	0.151	0.687	0.489	0.636
1999	tindi	off-peak	-0.64	-0.793	-0.045	-0.404	-0.584	-0.174	-0.303	0.226	0.032	-0.092	0.059	0.218
2000	tindi	peak	0.7	0.442	0.19	-0.072	-0.095	-0.031	-0.474	0.364	0.479	0.152	0.021	0.796
2000	tindi	off-peak	-0.378	-0.448	0.132	-0.501	-0.499	-0.221	-0.302	0.327	-0.138	0.493	0.043	0.664
2001	tindi	peak	0.359	0.772	0.321	-0.276	-0.189	-0.14	-0.814	0.259	-0.36	-0.146	-0.025	-0.661
2001	tindi	off-peak	0.214	0.378	0.469	-0.412	-0.518	0.003	-0.462	0.846	0.302	1.07	0.768	0.668
2002	tindi	peak	0.786	0.488	-0.188	-0.192	-0.226	0.183	-0.685	0.961	0.836	0.832	1.389	1.078
2002	tindi	off-peak	-0.728	0.179	-0.487	-0.342	-0.616	-0.008	-0.563	1	0.003	0.417	0.811	0.718
2003	tindi	peak	1.186	1.499	0.269	-0.276	-0.07	0.309	-0.31	0.583	0.221	-0.39	0.419	1.153
2003	tindi	off-peak	0.552	1.044	0.426	-0.47	-0.552	-0.394	-0.292	0.653	0.105	0.672	0.725	0.97
2004	tindi	peak	1.857	1.123	0.475	-0.166	0.065	0.123	-0.527	0.306	0.417	0.479	0.495	1.3
2004	tindi	off-peak	0.693	0.427	0.046	-0.577	-0.477	-0.182	-0.267	0.292	0.043	0.73	0.541	0.567
2005	tindi	peak	1.791	1.213	0.439	0.225	0.324	0.474	-0.49	0.561	0.626	0.363	0.558	1.653
2005	tindi	off-peak	0.4	0.417	-0.063	-0.713	-0.501	-0.002	-0.234	0.333	0.099	-0.249	0.647	0.568
2006	tindi	peak	1.271	0.604	-0.035	0.056	-0.327	-0.003	-0.919	0.362	0.42	0.872	0.428	1.255
2006	tindi	off-peak	0.484	-0.13	0.043	-0.671	-0.553	-0.47	-0.622	0.189	0.278	1.44	1.114	0.959
2007	tindi	peak	1.755	0.359	0.071	0.002	-0.077	-0.252	-0.925	0.036	0.742	0.849	0.765	0.95
2007	tindi	off-peak	0.599	-0.064	0.197	-0.364	-0.444	-0.42	-0.84	0.298	0.608	1.027	0.938	0.939
2008	tindi	peak	1.43	0.823	0.28	0.208	0.293	0.017	-0.633	0.238	0.943	0.666	0.619	1.271

			1	2	3	4	5	6	7	8	9	10	11	12
Year	Vari-able	Season	New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
2008	tindi	off-peak	1.159	0.651	0.876	0.132	0.22	0.034	-0.587	0.241	-0.007	0.967	1.292	1.471
2009	tindi	peak	0.697	0.023	0.29	-0.154	-0.859	-0.576	-1.469	-0.169	0.51	0.314	-0.231	0.857
2009	tindi	off-peak	0.094	-0.073	-0.121	-0.631	-0.868	-0.56	-1.189	0.151	0.975	1.456	0.387	0.71
2010	tindi	peak	0.918	0.27	-0.181	-0.096	-0.047	0.016	-0.876	-0.015	-0.006	0.677	0.052	0.567
2010	tindi	off-peak	0.067	-0.029	0.169	-0.434	-0.683	-0.376	-1.175	-0.021	0.179	1.06	0.236	0.872
2011	tindi	peak	0.936	0.641	0.146	-0.077	-0.295	-0.4	-1.145	-0.019	0.53	0.747	-0.021	0.948
2011	tindi	off-peak	0.025	0.57	0.17	-0.562	-0.65	-0.584	-1.255	-0.198	0.207	0.917	0.035	0.713
1990	tindf	peak	1.786	1.434	0.71	0.551	0.666	0.438	-0.36	0.67	1.115	0.909	1.129	1.363
1990	tindf	off-peak	0.736	0.959	0.687	0.313	0.292	0.247	-0.622	-0.034	0.851	0.979	1.276	1.044
1991	tindf	peak	1.639	1.389	0.632	0.445	0.491	0.367	-0.557	0.239	1.068	0.537	1.253	1.488
1991	tindf	off-peak	0.553	0.668	0.48	0.162	-0.009	0.134	-0.57	-0.296	0.965	0.61	1.111	1.016
1992	tindf	peak	1.915	1.283	0.64	0.552	0.559	0.423	-0.516	0.295	1.106	0.668	2.369	1.585
1992	tindf	off-peak	0.342	0.341	0.332	0.289	-0.004	0.115	-0.457	-0.566	1.155	0.579	2.088	0.669
1993	tindf	peak	2.178	1.084	0.705	0.503	0.543	0.511	-0.43	0.099	1.018	0.996	1.57	0.456
1993	tindf	off-peak	0.273	0.369	0.563	0.147	-0.094	0.205	-0.335	-0.311	0.962	1.158	1.458	-0.054
1994	tindf	peak	2.21	1.333	1.075	0.677	0.667	0.77	-0.343	-0.084	0.949	0.824	1.87	1.283
1994	tindf	off-peak	-0.029	0.582	0.844	0.125	-0.024	0.328	-0.258	-0.35	0.687	0.94	1.197	0.864
1995	tindf	peak	1.682	0.989	0.613	0.51	0.724	0.762	-0.501	0.481	0.954	0.554	2.024	2.196
1995	tindf	off-peak	-0.179	0.543	0.357	0.007	0.194	0.253	-0.454	0.476	0.911	0.735	1.707	1.444
1996	tindf	peak	2.201	1.161	0.447	0.821	0.848	0.466	-0.016	0.586	0.995	0.616	1.554	1.734
1996	tindf	off-peak	0.212	0.469	0.474	0.105	0.422	0.477	-0.104	0.624	0.686	0.817	1.477	1.393
1997	tindf	peak	2.079	1.278	0.919	0.563	0.841	0.722	-0.24	0.524	1.178	0.503	0.93	2.019
1997	tindf	off-peak	0.438	-0.409	0.511	-0.151	0.252	0.423	-0.006	0.689	0.655	0.88	0.794	1.187
1998	tindf	peak	1.67	0.423	0.897	0.56	0.536	0.723	0.012	0.429	0.732	0.723	1.17	1.934
1998	tindf	off-peak	-0.11	-0.176	0.802	0.038	-0.066	0.311	0.079	0.619	0.628	0.69	0.736	1.1
1999	tindf	peak	1.084	0.422	0.759	0.402	0.244	0.544	-0.25	1.02	0.504	1.241	0.872	1.012
1999	tindf	off-peak	-0.164	-0.5	0.39	-0.043	-0.178	0.21	-0.019	0.63	0.404	0.342	0.437	0.587
2000	tindf	peak	1.08	0.649	0.348	0.095	0.215	0.141	-0.377	0.576	0.612	0.395	0.208	0.764
2000	tindf	off-peak	-0.015	-0.243	0.302	-0.324	-0.171	-0.041	-0.193	0.543	-0.024	0.784	0.242	0.631
2001	tindf	peak	0.875	1.143	0.75	0.07	0.119	0.284	-0.566	0.654	-0.217	0.334	0.347	-0.672
2001	tindf	off-peak	0.653	0.642	0.821	-0.178	-0.31	0.308	-0.307	1.223	0.432	1.483	1.117	0.66
2002	tindf	peak	1.269	0.848	0.059	0.104	0.023	0.525	-0.513	1.604	1.332	1.203	1.934	1.473
2002	tindf	off-peak	-0.32	0.509	-0.235	-0.03	-0.348	0.316	-0.37	1.597	0.449	0.768	1.298	1.095
2003	tindf	peak	1.642	1.759	0.433	-0.152	0.166	0.464	-0.242	0.803	0.402	-0.251	0.627	1.428
2003	tindf	off-peak	0.91	1.273	0.595	-0.356	-0.339	-0.262	-0.234	0.874	0.296	0.841	0.937	1.23
2004	tindf	peak	2.364	1.288	0.655	-0.041	0.174	0.267	-0.459	0.478	0.61	0.674	0.689	1.578
2004	tindf	off-peak	1.165	0.571	0.221	-0.457	-0.372	-0.046	-0.196	0.457	0.231	0.932	0.739	0.815
2005	tindf	peak	2.028	1.144	0.414	0.201	0.268	0.361	-0.596	0.58	0.697	0.224	0.602	1.765

			1	2	3	4	5	6	7	8	9	10	11	12
Year	Vari-able	Season	New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZ/NM	WA/OR	Florida	AZ/NM	CA/HI
2005	tindf	off-peak	0.638	0.349	-0.09	-0.737	-0.563	-0.122	-0.362	0.352	0.169	-0.391	0.695	0.677
2006	tindf	peak	1.626	0.823	0.211	0.203	-0.178	0.181	-0.868	0.712	0.687	1.197	0.769	1.576
2006	tindf	off-peak	0.77	0.036	0.249	-0.56	-0.435	-0.33	-0.58	0.498	0.527	1.738	1.448	1.201
2007	tindf	peak	2.105	0.518	0.234	0.117	0.029	-0.171	-0.896	0.426	0.963	1.043	1.095	1.173
2007	tindf	off-peak	0.914	0.081	0.357	-0.264	-0.343	-0.345	-0.81	0.655	0.82	1.211	1.265	1.151
2008	tindf	peak	1.484	0.877	0.309	0.219	0.281	0.012	-0.621	0.369	0.988	0.721	0.832	1.424
2008	tindf	off-peak	1.22	0.709	0.909	0.144	0.205	0.028	-0.572	0.382	0.038	1.031	1.524	1.651
2009	tindf	peak	1.161	0.531	0.819	0.227	-0.489	-0.178	-1.252	0.386	1.171	0.9	0.303	1.314
2009	tindf	off-peak	0.457	0.323	0.282	-0.363	-0.588	-0.272	-1.016	0.639	1.665	2.036	0.888	1.075
2010	tindf	peak	1.46	0.594	0.171	0.178	0.185	0.316	-0.693	0.342	0.425	1.121	0.461	0.957
2010	tindf	off-peak	0.534	0.27	0.501	-0.203	-0.489	-0.128	-1.027	0.31	0.613	1.486	0.597	1.217
2011	tindf	peak	1.432	1.075	0.504	0.194	-0.061	-0.162	-0.995	0.325	0.973	1.199	0.342	1.326
2011	tindf	off-peak	0.484	1.004	0.522	-0.309	-0.42	-0.354	-1.097	0.149	0.649	1.375	0.4	1.081
1990	qindi	peak	10.6	71.3	177.5	53.8	81.1	74.6	489.0	32.4	29.4	13.2	7.5	112.7
1990	qindi	off-peak	23.5	123.7	285.7	93.5	153.8	133.5	1024.6	53.7	51.7	24.0	14.0	247.0
1991	qindi	peak	18.7	85.2	190.5	58.2	74.5	77.2	504.6	38.1	29.4	13.2	8.2	125.4
1991	qindi	off-peak	39.2	142.4	288.4	98.9	143.9	140.3	1032.4	62.7	54.4	23.1	13.9	249.6
1992	qindi	peak	30.7	120.3	191.9	58.6	83.0	83.1	542.6	42.3	31.3	13.4	7.8	136.6
1992	qindi	off-peak	61.7	209.1	299.5	99.2	158.4	152.2	1034.8	73.3	55.7	24.6	13.1	237.4
1993	qindi	peak	24.7	132.9	190.8	61.9	83.5	88.0	536.2	45.0	32.6	15.4	7.1	129.0
1993	qindi	off-peak	49.2	217.5	283.5	105.0	161.2	152.5	1081.8	79.9	59.3	29.7	13.5	267.4
1994	qindi	peak	29.4	133.9	203.1	72.9	85.7	87.5	571.7	55.4	40.5	20.1	8.3	146.7
1994	qindi	off-peak	53.9	218.8	292.2	122.4	178.3	154.1	1086.6	91.1	78.3	39.4	18.8	311.9
1995	qindi	peak	30.1	152.9	208.4	67.0	93.1	93.9	575.5	55.6	43.0	23.3	11.1	147.3
1995	qindi	off-peak	52.2	257.4	311.2	116.0	192.0	167.9	1159.8	92.8	79.1	39.5	18.3	321.9
1996	qindi	peak	25.2	149.2	207.7	63.1	91.0	91.9	630.7	56.3	47.1	21.6	10.8	163.7
1996	qindi	off-peak	52.4	251.7	314.3	107.4	181.2	166.6	1228.7	101.3	95.6	42.6	19.2	326.3
1997	qindi	peak	28.6	143.6	206.1	69.5	101.3	96.2	643.0	53.4	52.1	19.9	12.6	171.6
1997	qindi	off-peak	50.9	246.6	318.1	112.2	189.1	173.1	1246.9	93.1	96.6	39.5	24.2	359.4
1998	qindi	peak	16.4	83.5	175.7	58.9	70.3	75.4	512.8	37.8	38.4	14.3	7.2	107.3
1998	qindi	off-peak	29.9	138.5	267.3	106.0	129.8	132.7	980.7	61.7	70.5	28.5	14.1	237.2
1999	qindi	peak	17.8	75.0	182.2	57.9	79.1	81.3	456.7	32.1	37.8	15.7	7.7	94.3
1999	qindi	off-peak	32.5	126.1	280.1	98.8	121.9	148.4	907.1	60.8	69.8	32.3	14.2	242.1
2000	qindi	peak	18.0	58.9	189.7	59.3	69.9	81.7	482.2	35.6	25.0	12.6	7.0	95.5
2000	qindi	off-peak	28.4	101.1	277.2	103.9	131.0	141.7	995.0	56.8	45.0	25.0	13.8	244.4
2001	qindi	peak	17.3	55.8	170.8	55.6	55.5	68.3	464.8	41.6	23.2	11.0	7.6	96.3
2001	qindi	off-peak	29.8	91.6	248.3	95.6	108.6	121.3	872.6	66.7	42.8	22.9	14.1	207.9
2002	qindi	peak	23.3	78.3	169.1	59.5	57.7	66.7	452.6	33.8	25.4	9.6	5.3	119.0

			1	2	3	4	5	6	7	8	9	10	11	12
	Vari-		New		E.N.	W.N.		E.S.	W.S.	Mtn-	WA/			
Year	able	Season	Engl	Mid Atl	Cntrl	Cntrl	S.Atl-FL	Cntrl	Cntrl	AZ/NM	OR	Florida	AZ/NM	CA/HI
2002	qindi	off-peak	38.3	127.2	272.8	108.3	109.4	115.2	897.3	62.4	42.8	18.3	9.6	246.4
2003	qindi	peak	16.7	66.7	166.3	62.0	56.0	65.3	420.2	32.3	21.5	8.1	5.0	115.2
2003	qindi	off-peak	19.4	102.9	234.5	101.8	95.1	106.2	815.2	52.6	39.4	15.3	9.3	240.5
2004	qindi	peak	15.5	66.1	166.4	64.2	53.2	60.6	425.9	33.0	21.7	7.1	5.8	118.4
2004	qindi	off-peak	19.1	103.8	233.1	109.1	92.2	105.7	833.9	53.0	39.2	12.1	9.6	246.4
2005	qindi	peak	18.8	71.9	184.4	73.9	54.2	61.5	380.6	37.6	23.4	7.2	5.6	129.4
2005	qindi	off-peak	21.4	109.2	262.4	121.9	91.5	103.3	724.7	64.1	42.6	12.6	11.1	248.5
2006	qindi	peak	10.3	47.4	167.7	79.2	62.2	68.2	410.5	34.7	21.9	9.4	4.9	105.8
2006	qindi	off-peak	14.2	79.0	263.1	143.8	117.8	126.6	820.1	54.0	39.0	17.5	8.2	211.2
2007	qindi	peak	12.8	45.7	184.2	102.6	64.1	71.7	417.5	34.7	22.5	9.3	4.9	109.3
2007	qindi	off-peak	17.0	72.5	265.3	179.6	116.4	123.9	797.3	55.7	40.1	16.7	8.3	215.9
2008	qindi	peak	14.3	51.8	203.3	133.6	64.7	76.0	432.2	38.0	25.6	10.0	5.2	111.9
2008	qindi	off-peak	19.3	76.4	290.0	221.4	116.4	130.6	832.1	58.4	41.5	17.9	9.2	223.0
2009	qindi	peak	15.3	52.3	206.5	150.6	65.5	71.5	424.0	38.8	23.4	10.3	5.0	115.9
2009	qindi	off-peak	22.3	76.5	285.2	245.9	119.1	130.5	834.8	59.8	40.7	19.2	8.9	236.3
2010	qindi	peak	16.5	53.1	221.8	167.7	71.0	79.3	455.1	37.8	22.3	12.7	5.4	114.0
2010	qindi	off-peak	22.2	78.4	330.3	282.7	125.5	136.3	866.9	58.8	40.8	22.1	9.2	235.5
2011	qindi	peak	19.1	60.5	233.9	175.3	72.5	81.9	469.0	36.4	24.2	13.9	6.5	111.8
2011	qindi	off-peak	26.5	88.6	355.5	308.0	132.1	143.9	902.6	58.2	41.6	25.6	10.9	238.0

Table F5

Data: Historical industrial sector natural gas prices by type of service, NGTDM region.

Author: Joe Benneche, EIA, 2012.

Source: The source for core and noncore industrial prices is EIA's Manufacturing Energy Consumption Survey. The industrial prices as purchased from a local distribution company come from the Natural Gas Monthly, DOE/EIA-0130. Prices for imports and production, and their associated weights, largely come from EIA data, with production prices set at a regional spot price minus an assumed gathering charge.

Variables:

$mecs87_{type}$ = core and noncore industrial prices across Census Division and year (1987$/Mcf), used to estimate PIN_FNG (core) and PIN_ING (noncore) prices by NGTDM region

ngap87 = natural gas price to industrial customers who purchase gas from a local distributor across Census Division and year (1987$/Mcf)

supplyp87 = quantity-weighted average supply (import and production) price across Census Division and year

α_{type} = estimated constant term for core and noncore

$\beta_{1,type}$, $\beta_{2,type}$ = estimated coefficients for core and noncore

Derivation: Historically the price paid for natural gas by energy-intensive industries is notably lower than the price paid by non-energy-intensive industries based on data from EIA's Manufacturing Energy Consumption Survey (MECS). Therefore, within the industrial module of NEMS the lower noncore price generated by the NGTDM is assigned to energy-intensive industries and the core price is assigned to non-energy-intensive industries. Since the MECS data are only available every four years by the four Census Divisions, two equations were estimated to derive core and noncore prices for the 12 NGTDM regions in all historical years (HPGFINGR, HPGIINGR). MECS data for the years 1994, 1998, 2002, and 2006 were used to estimate a core and noncore price equation for the regional MECS price as a function of the regional Natural Gas Annual (NGA) industrial price and the regional supply price (quantity-weighted average of the gas wellhead price and import price). The resulting regional prices are scaled to insure that the resulting quantity-average regional price equals the price published in the NGA. The general form of the estimated equation follows:

$$mecs87_{type} = \alpha_{type} + (\beta_{1,type} * supplyp87) + (\beta_{2,type} * ngap87)$$

The equations were estimated using a basic ordinary least squares approach applied to the data provided below.

Regression diagnostics and parameter estimates:

Dependent Variable: MECS87 (Core)
Method: Least Squares
Date: 08/30/12 Time: 17:58
Sample: 1 16
Included observations: 16

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.657744	0.248773	2.643956	0.0202
SUPPLYP87	0.398046	0.219644	1.812228	0.0931
NGAP87	0.530439	0.160211	3.310884	0.0056
R-squared	0.927584	Mean dependent var		3.552521
Adjusted R-squared	0.916443	S.D. dependent var		1.281307
S.E. of regression	0.370378	Akaike info criterion		1.018773
Sum squared resid	1.783334	Schwarz criterion		1.163634
Log likelihood	-5.150185	Hannan-Quinn criter.		1.026191
F-statistic	83.25902	Durbin-Watson stat		1.868392
Prob(F-statistic)	0.000000			

Dependent Variable: MECS87 (noncore)
Method: Least Squares
Date: 08/30/12 Time: 17:59
Sample: 17 32
Included observations: 16

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.220117	0.145436	1.513495	0.1541
SUPPLYP87	0.602180	0.128408	4.689603	0.0004
NGAP87	0.421469	0.093662	4.499908	0.0006
R-squared	0.976230	Mean dependent var		3.197442
Adjusted R-squared	0.972573	S.D. dependent var		1.307442
S.E. of regression	0.216528	Akaike info criterion		-0.054829
Sum squared resid	0.609499	Schwarz criterion		0.090031
Log likelihood	3.438634	Hannan-Quinn criter.		-0.047411
F-statistic	266.9491	Durbin-Watson stat		2.528349
Prob(F-statistic)	0.000000			

Data used for estimation

obs	year	Census Division	type	mecs87	ngap87	supplyp87
1	1994	Northeast	Core	3.670585	3.408	2.005362
2	1998	Northeast	Core	3.1393	2.775	1.956774
3	2002	Northeast	Core	3.600087	4.099	2.520687
4	2006	Northeast	Core	6.468766	7.495	4.699691
5	1994	Midwest	Core	2.721138	3.072	1.473176
6	1998	Midwest	Core	2.603661	2.804	1.571211
7	2002	Midwest	Core	2.90596	3.004	2.211106
8	2006	Midwest	Core	5.194191	5.716	4.107197
9	1994	South	Core	2.846393	2.156	1.515677
10	1998	South	Core	1.995999	2.244	1.551466
11	2002	South	Core	2.578564	2.657	2.307403
12	2006	South	Core	4.988157	4.66	4.046488
	1994	West	Core	3.134492	2.56	1.244672
14	1998	West	Core	2.700268	2.612	1.341248
15	2002	West	Core	2.787593	3.692	1.737192
16	2006	West	Core	5.505184	5.923	3.610242
17	1994	Northeast	Noncore	2.756907	3.408	2.005362
18	1998	Northeast	Noncore	2.699863	2.775	1.956774
19	2002	Northeast	Noncore	3.375998	4.099	2.520687
20	2006	Northeast	Noncore	6.220472	7.495	4.699691
21	1994	Midwest	Noncore	2.259632	3.072	1.473176
22	1998	Midwest	Noncore	2.205087	2.804	1.571211
23	2002	Midwest	Noncore	2.986226	3.004	2.211106
24	2006	Midwest	Noncore	4.807767	5.716	4.107197
25	1994	South	Noncore	2.205068	2.156	1.515677
26	1998	South	Noncore	1.816138	2.244	1.551466
27	2002	South	Noncore	2.52904	2.657	2.307403

obs	year	Census Division	type	mecs87	ngap87	supplyp87
28	2006	South	Noncore	4.937482	4.66	4.046488
29	1994	West	Noncore	2.209961	2.56	1.244672
30	1998	West	Noncore	2.059031	2.612	1.341248
31	2002	West	Noncore	3.193424	3.692	1.737192
32	2006	West	Noncore	4.896972	5.923	3.610242

Table F6

Data: Equations for residential distribution tariffs

Author: Ernest Zampelli, SAIC, reestimated by Katherine Teller, EIA, 2011.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State-level city gate and residential prices by month were averaged using quantity weights to arrive at seasonal (peak and off-peak), regional-level (12 NGTDM regions) prices. The quantity weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. The source for the number of residential customers was the Natural Gas Annual, DOE/EIA-0131.

Variables:

$TRS_{r,n,t}$	=	residential distributor tariff in the period n for region r (1987$/Mcf) [DTAR_SF$_1$]
REG_r	=	1, if observation is in region r, =0 otherwise
$QRS\_NUMR_{r,n,t}$	=	residential gas consumption per customer in the period for region r in year t (Bcf per thousand customers) [(BASQTY_SF$_1$+BASQTY_SI$_1$)/NUMRS]
$NUMRS_{r,t}$	=	number of residential customers (thousands)
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PRSREGPK19]
$\beta_{1,n}$, $\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Residential distributor tariff equations were estimated using panel data for the 12 NGTDM regions and two periods over the 1990 to 2010 time period. The equations were estimated in log-linear form with corrections for cross-sectional heteroscedasticity and first-order serial correlation using EViews. The general form for the estimating equation follows:

$$\ln TRS_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t} + \beta_{2,n} * \ln NUMRS_{r,t} +$$
$$\rho_n * \ln TRS_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QRS\_NUMR_{r,n,t-1} + \beta_{2,n} * \ln NUMRS_{r,t-1})$$

Regression diagnostics and parameter estimates:

Dependent Variable: LNTRS87

Method: Least Squares

Date: 10/24/11   Time: 17:34

Sample (adjusted): 2 504

Included observations: 503 after adjustments

Convergence achieved after 6 iterations

HAC standard errors & covariance (Bartlett kernel, Newey-West fixed
bandwidth = 6.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQRS_NUMR	-0.722013	0.065100	-11.09074	0.0000
LN_NUMR_ANN	0.237781	0.068210	3.486027	0.0005
PK_OP_CODE=0,REGION=1	-9.446609	0.882254	-10.70735	0.0000
PK_OP_CODE=0,REGION=2	-9.800428	0.958346	-10.22640	0.0000
PK_OP_CODE=0,REGION=3	-10.31084	0.969735	-10.63264	0.0000
PK_OP_CODE=0,REGION=4	-10.15845	0.922695	-11.00954	0.0000
PK_OP_CODE=0,REGION=5	-9.845712	0.928149	-10.60790	0.0000
PK_OP_CODE=0,REGION=6	-10.00934	0.903550	-11.07779	0.0000
PK_OP_CODE=0,REGION=7	-10.16296	0.937902	-10.83585	0.0000
PK_OP_CODE=0,REGION=8	-10.19248	0.910076	-11.19959	0.0000
PK_OP_CODE=0,REGION=9	-9.601351	0.852554	-11.26187	0.0000
PK_OP_CODE=0,REGION=10	-9.293436	0.839097	-11.07551	0.0000
PK_OP_CODE=0,REGION=11	-9.686159	0.865821	-11.18725	0.0000
PK_OP_CODE=0,REGION=12	-10.35764	0.964097	-10.74336	0.0000
PK_OP_CODE=1,REGION=1	-9.167668	0.876011	-10.46524	0.0000
PK_OP_CODE=1,REGION=2	-9.739686	0.955348	-10.19491	0.0000
PK_OP_CODE=1,REGION=3	-10.35329	0.972490	-10.64617	0.0000
PK_OP_CODE=1,REGION=4	-10.13165	0.919069	-11.02383	0.0000
PK_OP_CODE=1,REGION=5	-9.761448	0.920822	-10.60080	0.0000
PK_OP_CODE=1,REGION=6	-9.920335	0.893652	-11.10090	0.0000
PK_OP_CODE=1,REGION=7	-10.38420	0.935958	-11.09473	0.0000
PK_OP_CODE=1,REGION=8	-10.24749	0.890453	-11.50819	0.0000
PK_OP_CODE=1,REGION=9	-9.507696	0.851202	-11.16973	0.0000
PK_OP_CODE=1,REGION=10	-9.544786	0.835036	-11.43039	0.0000
PK_OP_CODE=1,REGION=11	-9.768462	0.863116	-11.31767	0.0000
PK_OP_CODE=1,REGION=12	-10.37381	0.962529	-10.77766	0.0000
AR(1)	0.275330	0.047452	5.802310	0.0000

R-squared	0.925094	Mean dependent var	1.112296
Adjusted R-squared	0.921002	S.D. dependent var	0.413691
S.E. of regression	0.116274	Akaike info criterion	-1.413546
Sum squared resid	6.435385	Schwarz criterion	-1.186993
Log likelihood	382.5067	Hannan-Quinn criter.	-1.324669
Durbin-Watson stat	2.018560		
Inverted AR Roots		.28	

Peak period data used for estimation in log form

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.30	1.07	0.40	0.40	1.02	0.61	0.61	0.40	1.01	1.45	1.01	0.95
1990	NUMRS	14.42	15.92	16.22	15.25	15.24	14.66	15.51	14.55	13.57	13.03	13.77	15.96
1990	QRS_NUMR	-9.81	-9.83	-9.55	-9.68	-9.97	-9.98	-10.11	-9.84	-9.93	-11.09	-10.14	-10.29
1991	TRS87	1.35	1.12	0.44	0.41	0.99	0.72	0.65	0.42	0.88	1.56	1.02	1.07
1991	NUMRS	14.43	15.99	16.24	15.27	15.26	14.68	15.53	14.58	13.67	13.05	13.84	15.97
1991	QRS_NUMR	-9.85	-9.87	-9.49	-9.59	-9.94	-9.93	-10.05	-9.76	-9.93	-11.16	-10.20	-10.40
1992	TRS87	1.38	1.17	0.42	0.48	1.06	0.74	0.64	0.45	0.95	1.53	0.98	1.02
1992	NUMRS	14.44	16.00	16.25	15.28	15.31	14.71	15.53	14.61	13.69	13.06	13.81	15.98
1992	QRS_NUMR	-9.75	-9.80	-9.50	-9.70	-9.90	-9.92	-10.10	-9.83	-9.99	-11.01	-10.15	-10.41
1993	TRS87	1.38	1.15	0.47	0.42	1.03	0.67	0.59	0.43	0.94	1.64	0.99	1.02
1993	NUMRS	14.45	15.95	16.26	15.31	15.32	14.74	15.55	14.64	13.75	13.09	13.82	15.99
1993	QRS_NUMR	-9.72	-9.70	-9.43	-9.57	-9.80	-9.87	-10.03	-9.74	-9.82	-11.14	-10.19	-10.37
1994	TRS87	1.46	1.21	0.56	0.54	1.04	0.78	0.62	0.32	1.00	1.57	1.10	1.06
1994	NUMRS	14.47	15.95	16.28	15.32	15.36	14.77	15.55	14.69	13.81	13.12	13.86	15.99
1994	QRS_NUMR	-9.68	-9.63	-9.42	-9.58	-9.82	-9.86	-10.07	-9.85	-9.92	-11.10	-10.24	-10.40
1995	TRS87	1.48	1.24	0.42	0.54	1.04	0.77	0.67	0.49	1.06	1.55	1.16	1.25
1995	NUMRS	14.47	15.96	16.30	15.33	15.38	14.79	15.57	14.73	13.86	13.15	13.90	16.00
1995	QRS_NUMR	-9.81	-9.72	-9.45	-9.63	-9.83	-9.89	-10.14	-9.96	-10.02	-11.06	-10.41	-10.52
1996	TRS87	1.35	1.08	0.18	0.51	0.83	0.39	0.53	0.33	0.95	1.48	0.80	1.04
1996	NUMRS	14.48	15.97	16.31	15.35	15.41	14.82	15.58	14.78	13.92	13.16	13.93	16.01
1996	QRS_NUMR	-9.75	-9.66	-9.39	-9.52	-9.75	-9.81	-10.02	-9.85	-9.88	-10.96	-10.30	-10.53
1997	TRS87	1.42	1.26	0.52	0.52	1.07	0.78	0.54	0.27	0.87	1.59	0.82	0.96
1997	NUMRS	14.49	15.98	16.32	15.36	15.43	14.84	15.59	14.81	13.96	13.19	13.97	16.02
1997	QRS_NUMR	-9.82	-9.75	-9.50	-9.65	-9.92	-9.95	-10.06	-9.81	-9.98	-11.27	-10.16	-10.48
1998	TRS87	1.43	1.29	0.49	0.62	1.00	0.86	0.80	0.56	1.00	1.61	0.95	1.22
1998	NUMRS	14.50	16.00	16.34	15.40	15.47	14.86	15.61	14.86	14.01	13.20	14.01	16.04
1998	QRS_NUMR	-9.92	-9.89	-9.65	-9.79	-10.00	-10.03	-10.17	-9.87	-9.93	-11.21	-10.16	-10.37
1999	TRS87	1.51	1.27	0.47	0.60	0.77	0.85	0.71	0.72	0.92	1.64	1.07	1.16
1999	NUMRS	14.51	16.00	16.35	15.39	15.51	14.87	15.61	14.89	14.06	13.23	14.06	16.05

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/ OR	Florida	AZ/NM	CA/HI
1999	QRS_NUMR	-9.93	-9.76	-9.55	-9.74	-10.01	-10.04	-10.31	-9.95	-9.91	-11.30	-10.33	-10.35
2000	TRS87	1.24	0.96	0.28	0.57	1.04	0.66	0.49	0.46	0.88	1.58	0.84	1.02
2000	NUMRS	14.55	16.02	16.37	15.41	15.52	14.90	15.62	14.94	14.11	13.26	14.10	16.06
2000	QRS_NUMR	-9.80	-9.71	-9.52	-9.71	-9.82	-9.94	-10.21	-9.93	-9.93	-11.15	-10.36	-10.48
2001	TRS87	1.17	0.84	0.42	0.51	0.99	0.74	0.62	0.51	0.92	1.70	0.80	0.76
2001	NUMRS	14.55	16.04	16.38	15.42	15.55	14.91	15.63	14.97	14.14	13.29	14.13	16.08
2001	QRS_NUMR	-9.85	-9.78	-9.59	-9.70	-9.97	-9.96	-10.13	-9.88	-9.90	-11.13	-10.27	-10.44
2002	TRS87	1.33	1.01	0.18	0.55	1.17	0.91	0.79	0.60	1.35	1.77	1.28	1.01
2002	NUMRS	14.56	16.04	16.39	15.43	15.56	14.92	15.64	15.00	14.17	13.31	14.17	16.09
2002	QRS_NUMR	-9.90	-9.84	-9.63	-9.95	-9.95	-9.98	-10.15	-9.89	-10.00	-11.20	-10.35	-10.50
2003	TRS87	1.06	0.97	0.23	0.31	0.95	0.73	0.49	0.25	0.88	1.70	0.97	0.97
2003	NUMRS	14.58	16.05	16.40	15.44	15.58	14.93	15.65	15.04	14.24	13.33	14.19	16.10
2003	QRS_NUMR	-9.73	-9.68	-9.51	-9.70	-9.83	-9.93	-10.13	-9.99	-10.11	-11.14	-10.43	-10.58
2004	TRS87	1.45	1.11	0.46	0.59	1.15	0.94	0.74	0.48	1.00	1.83	1.05	0.99
2004	NUMRS	14.58	16.05	16.41	15.45	15.59	14.93	15.66	15.07	14.24	13.37	14.22	16.12
2004	QRS_NUMR	-9.80	-9.73	-9.57	-9.76	-9.87	-10.02	-10.26	-9.99	-10.04	-11.20	-10.36	-10.51
2005	TRS87	1.34	1.01	0.52	0.60	1.20	1.11	0.83	0.65	1.10	1.85	1.08	1.06
2005	NUMRS	14.58	16.05	16.44	15.46	15.62	14.94	15.66	15.11	14.28	13.39	14.27	16.13
2005	QRS_NUMR	-9.75	-9.71	-9.60	-9.79	-9.92	-10.07	-10.30	-10.01	-10.07	-11.27	-10.50	-10.61
2006	TRS87	1.44	1.07	0.59	0.78	1.30	1.16	0.92	0.67	1.19	1.96	1.24	1.05
2006	NUMRS	14.60	16.07	16.42	15.47	15.62	14.94	15.67	15.14	14.31	13.42	14.30	16.15
2006	QRS_NUMR	-9.96	-9.91	-9.79	-9.96	-10.13	-10.22	-10.46	-10.05	-10.08	-11.30	-10.57	-10.61
2007	TRS87	1.48	1.09	0.44	0.67	1.30	0.97	0.62	0.33	1.31	1.84	1.26	0.94
2007	NUMRS	14.61	16.08	16.43	15.47	15.64	14.94	15.69	15.16	14.34	13.43	14.33	16.16
2007	QRS_NUMR	-9.84	-9.77	-9.64	-9.81	-10.05	-10.17	-10.27	-9.97	-10.05	-11.43	-10.45	-10.58
2008	TRS87	1.36	1.12	0.48	0.52	1.26	0.96	0.70	0.29	1.15	1.76	1.15	0.95
2008	NUMRS	14.54	16.07	16.43	15.48	15.65	14.94	15.70	15.18	14.36	13.43	14.34	16.17
2008	QRS_NUMR	-9.73	-9.79	-9.59	-9.72	-10.05	-10.08	-10.28	-9.95	-10.05	-11.35	-10.47	-10.56
2009	TRS87	1.47	1.25	0.73	0.71	1.22	1.11	0.92	0.57	1.30	1.95	1.28	1.05
2009	NUMRS	14.62	16.08	16.42	15.48	15.65	14.93	15.71	15.19	14.37	13.42	14.34	16.17
2009	QRS_NUMR	-9.76	-9.75	-9.65	-9.78	-9.96	-10.12	-10.34	-10.04	-10.00	-11.32	-10.61	-10.62
2010	TRS87	1.34	1.13	0.42	0.59	1.22	0.92	0.74	0.47	1.15	1.78	1.13	0.93
2010	NUMRS	14.60	16.08	16.44	15.50	15.69	14.97	15.70	15.17	14.31	13.47	14.33	16.16
2010	QRS_NUMR	-9.88	-9.73	-9.63	-9.73	-9.83	-9.92	-10.08	-9.99	-10.14	-11.02	-10.46	-10.63

Off-peak data used for estimation in log form

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TRS87	1.46	1.36	0.77	0.71	1.28	1.02	1.16	0.52	1.22	1.81	1.41	0.95
1990	NUMRS	14.42	15.92	16.22	15.25	15.24	14.66	15.51	14.55	13.57	13.03	13.77	15.96
1990	QRS_NUMR	-10.17	-10.20	-9.93	-10.15	-10.43	-10.47	-10.53	-10.20	-10.33	-11.25	-10.74	-10.54
1991	TRS87	1.47	1.37	0.76	0.76	1.26	1.08	1.15	0.52	1.14	1.87	1.39	1.13
1991	NUMRS	14.43	15.99	16.24	15.27	15.26	14.68	15.53	14.58	13.67	13.05	13.84	15.97
1991	QRS_NUMR	-10.21	-10.28	-9.94	-10.15	-10.43	-10.52	-10.53	-10.16	-10.26	-11.22	-10.70	-10.47
1992	TRS87	1.30	1.29	0.68	0.74	1.12	0.95	1.13	0.37	1.19	1.87	1.37	1.01
1992	NUMRS	14.44	16.00	16.25	15.28	15.31	14.71	15.53	14.61	13.69	13.06	13.81	15.98
1992	QRS_NUMR	-10.03	-10.15	-9.86	-10.13	-10.33	-10.46	-10.54	-10.29	-10.44	-11.18	-10.77	-10.59
1993	TRS87	1.24	1.33	0.80	0.78	1.20	0.94	1.03	0.51	1.08	1.93	1.35	1.05
1993	NUMRS	14.45	15.95	16.26	15.31	15.32	14.74	15.55	14.64	13.75	13.09	13.82	15.99
1993	QRS_NUMR	-10.08	-10.15	-9.89	-10.08	-10.37	-10.42	-10.44	-10.16	-10.29	-11.16	-10.72	-10.56
1994	TRS87	1.40	1.52	0.90	0.75	1.31	1.17	1.25	0.54	1.14	1.94	1.39	1.17
1994	NUMRS	14.47	15.95	16.28	15.32	15.36	14.77	15.55	14.69	13.81	13.12	13.86	15.99
1994	QRS_NUMR	-10.23	-10.21	-10.03	-10.28	-10.52	-10.65	-10.63	-10.22	-10.32	-11.27	-10.71	-10.46
1995	TRS87	1.37	1.50	0.64	0.80	1.25	1.04	1.21	0.70	1.22	1.92	1.43	1.27
1995	NUMRS	14.47	15.96	16.30	15.33	15.38	14.79	15.57	14.73	13.86	13.15	13.90	16.00
1995	QRS_NUMR	-10.25	-10.20	-9.90	-10.13	-10.45	-10.57	-10.63	-10.12	-10.34	-11.28	-10.76	-10.53
1996	TRS87	1.22	1.41	0.73	0.80	1.29	1.04	1.15	0.59	1.05	1.91	1.24	1.16
1996	NUMRS	14.48	15.97	16.31	15.35	15.41	14.82	15.58	14.78	13.92	13.16	13.93	16.01
1996	QRS_NUMR	-10.18	-10.10	-9.86	-10.10	-10.37	-10.47	-10.59	-10.18	-10.24	-11.18	-10.76	-10.56
1997	TRS87	1.37	1.30	0.69	0.70	1.30	1.16	1.16	0.73	0.96	1.98	1.50	1.18
1997	NUMRS	14.49	15.98	16.32	15.36	15.43	14.84	15.59	14.81	13.96	13.19	13.97	16.02
1997	QRS_NUMR	-10.18	-10.14	-9.91	-10.19	-10.38	-10.55	-10.60	-10.22	-10.26	-11.34	-10.85	-10.61
1998	TRS87	1.35	1.48	0.89	0.95	1.44	1.21	1.32	0.98	1.08	1.94	1.61	1.26
1998	NUMRS	14.50	16.00	16.34	15.40	15.47	14.86	15.61	14.86	14.01	13.20	14.01	16.04
1998	QRS_NUMR	-10.31	-10.28	-10.15	-10.39	-10.62	-10.73	-10.80	-10.26	-10.39	-11.30	-10.81	-10.47
1999	TRS87	1.09	1.37	0.77	0.92	1.39	1.18	1.27	0.90	1.04	1.95	1.41	1.08
1999	NUMRS	14.51	16.00	16.35	15.39	15.51	14.87	15.61	14.89	14.06	13.23	14.06	16.05
1999	QRS_NUMR	-10.22	-10.26	-10.16	-10.38	-10.66	-10.75	-10.83	-10.24	-10.22	-11.30	-10.76	-10.46
2000	TRS87	1.20	1.16	0.76	0.94	1.28	1.21	1.24	0.77	1.03	1.95	1.05	1.14
2000	NUMRS	14.55	16.02	16.37	15.41	15.52	14.90	15.62	14.94	14.11	13.26	14.10	16.06
2000	QRS_NUMR	-10.29	-10.20	-10.09	-10.35	-10.48	-10.71	-10.77	-10.30	-10.30	-11.33	-10.75	-10.52
2001	TRS87	1.60	1.53	0.89	1.15	1.49	1.45	1.35	1.28	1.43	2.19	1.55	1.12
2001	NUMRS	14.55	16.04	16.38	15.42	15.55	14.91	15.63	14.97	14.14	13.29	14.13	16.08
2001	QRS_NUMR	-10.36	-10.32	-10.23	-10.42	-10.64	-10.80	-10.88	-10.38	-10.17	-11.36	-10.97	-10.63
2002	TRS87	1.18	1.32	0.49	0.91	1.43	1.33	1.24	0.98	1.31	2.09	1.64	1.03

Year		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
2002	NUMRS	14.56	16.04	16.39	15.43	15.56	14.92	15.64	15.00	14.17	13.31	14.17	16.09
2002	QRS_NUMR	-10.29	-10.25	-10.04	-10.42	-10.56	-10.78	-10.82	-10.30	-10.31	-11.38	-11.01	-10.60
2003	TRS87	1.62	1.51	0.91	1.07	1.60	1.44	1.51	0.97	1.03	2.21	1.62	1.05
2003	NUMRS	14.58	16.05	16.40	15.44	15.58	14.93	15.65	15.04	14.24	13.33	14.19	16.10
2003	QRS_NUMR	-10.25	-10.25	-10.14	-10.41	-10.60	-10.89	-10.96	-10.36	-10.40	-11.40	-11.00	-10.58
2004	TRS87	1.47	1.46	0.88	1.12	1.64	1.49	1.53	0.96	1.17	2.19	1.64	0.91
2004	NUMRS	14.58	16.05	16.41	15.45	15.59	14.93	15.66	15.07	14.24	13.37	14.22	16.12
2004	QRS_NUMR	-10.34	-10.30	-10.24	-10.51	-10.67	-10.95	-10.98	-10.38	-10.47	-11.40	-11.01	-10.64
2005	TRS87	1.26	1.31	0.88	1.06	1.53	1.41	1.51	0.98	1.15	2.09	1.50	0.93
2005	NUMRS	14.58	16.05	16.44	15.46	15.62	14.94	15.66	15.11	14.28	13.39	14.27	16.13
2005	QRS_NUMR	-10.33	-10.31	-10.29	-10.53	-10.65	-10.85	-11.00	-10.42	-10.45	-11.35	-11.03	-10.68
2006	TRS87	1.58	1.46	0.94	1.16	1.75	1.51	1.64	0.89	1.42	2.21	1.84	1.14
2006	NUMRS	14.60	16.07	16.42	15.47	15.62	14.94	15.67	15.14	14.31	13.42	14.30	16.15
2006	QRS_NUMR	-10.41	-10.41	-10.25	-10.52	-10.69	-10.91	-11.05	-10.45	-10.46	-11.42	-11.09	-10.69
2007	TRS87	1.56	1.47	1.09	1.33	1.78	1.49	1.55	0.96	1.49	2.19	1.80	1.19
2007	NUMRS	14.61	16.08	16.43	15.47	15.64	14.94	15.69	15.16	14.34	13.43	14.33	16.16
2007	QRS_NUMR	-10.37	-10.34	-10.31	-10.58	-10.70	-11.00	-11.04	-10.49	-10.42	-11.40	-11.16	-10.74
2008	TRS87	1.49	1.46	1.21	1.22	1.61	1.47	1.47	0.76	0.99	2.07	1.81	1.24
2008	NUMRS	14.54	16.07	16.43	15.48	15.65	14.94	15.70	15.18	14.36	13.43	14.34	16.17
2008	QRS_NUMR	-10.14	-10.34	-10.26	-10.48	-10.62	-10.90	-11.03	-10.43	-10.35	-11.40	-11.14	-10.79
2009	TRS87	1.59	1.61	1.14	1.25	1.87	1.62	1.62	0.99	1.59	2.28	1.82	1.17
2009	NUMRS	14.62	16.08	16.42	15.48	15.65	14.93	15.71	15.19	14.37	13.42	14.34	16.17
2009	QRS_NUMR	-10.28	-10.38	-10.31	-10.49	-10.75	-10.95	-11.00	-10.40	-10.45	-11.47	-11.11	-10.76
2010	TRS87	1.53	1.55	1.33	1.35	1.90	1.65	1.65	0.87	1.35	2.22	1.74	1.23
2010	NUMRS	14.60	16.08	16.44	15.50	15.69	14.97	15.70	15.17	14.31	13.47	14.33	16.16
2010	QRS_NUMR	-10.28	-10.41	-10.40	-10.58	-10.83	-11.07	-11.03	-10.33	-10.25	-11.36	-11.05	-10.63

Table F7

Data: Equation for commercial distribution tariffs

Author: Ernest Zampelli, SAIC, reestimated by Katherine Teller, EIA, 2011.

Source: The source for the peak and off-peak data used in this estimation was the *Natural Gas Monthly*, DOE/EIA-0130. State-level city gate and commercial prices by month were averaged using quantity weights to arrive at seasonal (peak and off-peak), regional-level (12 NGTDM regions) prices. The quantity weights for the city gate prices consisted of residential consumption plus commercial consumption that is represented by on-system sales plus industrial consumption that is represented by on-system sales. Historical commercial floorspace data by census division were extracted from the NEMS model and allocated to NGTDM region using Census population figures.

Variables:

$TCM_{r,n,t}$	=	commercial distributor tariff in region r, network n (1987$/Mcf) [DTAR_SF$_2$]
REG_r	=	1, if observation is in region r, =0 otherwise
$QCM\_FLRr_{r,n,t}$	=	commercial gas consumption per floorspace for region r in year t (Bcf) [(BASQTY_SF$_2$+BASQTY_SI$_2$)/FLRSPC12]
$FLR_{r,t}$	=	commercial floorspace for region r in year t (estimated in thousand square feet) [FLRSPC12]
r	=	NGTDM region
n	=	network (1=peak, 2=off-peak)
t	=	year
$\alpha_{r,n}$	=	estimated parameters for regional dummy variables [PCMREGPK15]
$\beta_{1,n}$,$\beta_{2,n}$	=	estimated parameters
ρ_n	=	autocorrelation coefficient

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The commercial distributor tariff equation was estimated using panel data for the 12 NGTDM regions over the 1990 to 2010 time period. The equation was estimated in log-linear form with corrections for cross-sectional heteroscedasticity and first-order serial correlation using EViews. The form of the estimated equation follows:

$$\ln TCM_{r,n,t} = \sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM\_FLR_{r,n,t} + \beta_{2,n} * \ln FLR_{r,t} +$$
$$\rho_n * \ln TCM_{r,n,t-1} - \rho_n * (\sum_r (\alpha_{r,n} * REG_r) + \beta_{1,n} * \ln QCM\_FLR_{r,n,t-1} + \beta_{2,n} * \ln FLR_{r,t-1})$$

Regression diagnostics and parameter estimates for the peak period

Dependent Variable: LNTCM87

Method: Least Squares

Date: 10/24/11 Time: 17:27

Sample (adjusted): 2 252

Included observations: 251 after adjustments

Convergence achieved after 8 iterations

HAC standard errors & covariance (Bartlett kernel, Newey-West fixed bandwidth = 5.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.218276	0.124401	-1.754624	0.0806
LNFLRSPC	0.150704	0.102502	1.470259	0.1428
REGION=1	-3.526089	1.313936	-2.683607	0.0078
REGION=2	-3.798187	1.351682	-2.809970	0.0054
REGION=3	-4.415061	1.374032	-3.213214	0.0015
REGION=4	-4.243611	1.316003	-3.224620	0.0014
REGION=5	-4.000282	1.372574	-2.914438	0.0039
REGION=6	-3.978679	1.323626	-3.005894	0.0029
REGION=7	-4.470323	1.370945	-3.260761	0.0013
REGION=8	-4.271251	1.278048	-3.342010	0.0010
REGION=9	-3.833011	1.301843	-2.944296	0.0036
REGION=10	-4.034227	1.406916	-2.867426	0.0045
REGION=11	-3.958974	1.292165	-3.063831	0.0024
REGION=12	-3.779088	1.384304	-2.729956	0.0068
AR(1)	0.277930	0.082560	3.366409	0.0009
R-squared	0.807713		Mean dependent var	0.593633
Adjusted R-squared	0.796306		S.D. dependent var	0.344073
S.E. of regression	0.155289		Akaike info criterion	-0.829163
Sum squared resid	5.691031		Schwarz criterion	-0.618478
Log likelihood	119.0599		Hannan-Quinn criter.	-0.744378
Durbin-Watson stat	1.984327			
Inverted AR Roots		.28		

Regression diagnostics and parameter estimates for the off-peak period

Dependent Variable: LNTCM87
Method: Least Squares
Date: 10/24/11 Time: 17:27
Sample: 253 504
Included observations: 252
Convergence achieved after 6 iterations
HAC standard errors & covariance (Bartlett kernel, Newey-West fixed
bandwidth = 5.0000)

Variable	Coefficient	Std. Error	t-Statistic	Prob.
LNQCM_FLRSPC	-0.608792	0.199819	-3.046710	0.0026
LNFLRSPC	0.503207	0.196918	2.555417	0.0112
REGION=1	-13.41218	1.726226	-7.769654	0.0000
REGION=2	-13.64636	1.887462	-7.230005	0.0000
REGION=3	-13.99379	1.915516	-7.305496	0.0000
REGION=4	-13.81613	1.790232	-7.717508	0.0000
REGION=5	-13.89771	1.848034	-7.520267	0.0000
REGION=6	-13.51703	1.745063	-7.745868	0.0000
REGION=7	-14.01982	1.841615	-7.612785	0.0000
REGION=8	-13.35967	1.750222	-7.633130	0.0000
REGION=9	-13.26152	1.678338	-7.901580	0.0000
REGION=10	-13.82132	1.742950	-7.929842	0.0000
REGION=11	-13.07115	1.649462	-7.924492	0.0000
REGION=12	-13.57916	1.847466	-7.350151	0.0000
AR(1)	0.176525	0.087901	2.008234	0.0458
R-squared	0.611030		Mean dependent var	0.586260
Adjusted R-squared	0.588053		S.D. dependent var	0.331838
S.E. of regression	0.212984		Akaike info criterion	-0.197524
Sum squared resid	10.75081		Schwarz criterion	0.012561
Log likelihood	39.88797		Hannan-Quinn criter.	-0.112990
Durbin-Watson stat	1.998969			
Inverted AR Roots		.18		

Data used for peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	1.03	0.78	0.14	0.04	0.69	0.43	0.21	0.03	0.68	0.73	0.54	0.91
1990	QCM_FLR	-10.81	-10.28	-10.03	-10.01	-10.87	-10.66	-10.69	-10.05	-10.89	-12.20	-10.65	-10.66
1990	FLR	14.73	15.69	15.92	15.08	15.52	14.83	15.51	14.31	14.34	14.86	13.95	15.48
1991	TCM87	1.01	0.80	0.20	0.09	0.64	0.52	0.22	0.06	0.62	0.76	0.58	1.06
1991	QCM_FLR	-10.78	-10.22	-9.97	-9.93	-10.77	-10.61	-10.61	-9.99	-10.87	-12.15	-10.67	-10.81
1991	FLR	14.74	15.70	15.94	15.09	15.55	14.84	15.52	14.33	14.37	14.89	13.97	15.51
1992	TCM87	1.07	0.86	0.19	0.17	0.71	0.56	0.32	0.08	0.66	0.71	0.55	1.07
1992	QCM_FLR	-10.67	-10.16	-9.98	-10.02	-10.70	-10.61	-10.66	-10.05	-10.96	-12.10	-10.67	-10.77
1992	FLR	14.75	15.71	15.95	15.10	15.57	14.85	15.53	14.35	14.39	14.91	13.99	15.53
1993	TCM87	1.02	0.82	0.26	0.13	0.68	0.52	0.29	0.13	0.63	0.92	0.58	1.14
1993	QCM_FLR	-10.61	-10.14	-9.93	-9.90	-10.65	-10.55	-10.69	-9.95	-10.77	-12.16	-10.72	-10.85
1993	FLR	14.75	15.72	15.96	15.11	15.59	14.87	15.54	14.37	14.40	14.92	14.00	15.54
1994	TCM87	1.18	0.95	0.38	0.31	0.71	0.65	0.26	-0.04	0.72	0.73	0.70	1.44
1994	QCM_FLR	-10.36	-10.10	-9.89	-9.91	-10.66	-10.52	-10.67	-10.02	-10.86	-12.17	-10.78	-10.89
1994	FLR	14.76	15.72	15.97	15.12	15.60	14.88	15.55	14.39	14.42	14.94	14.03	15.56
1995	TCM87	1.13	0.95	0.23	0.25	0.71	0.63	0.28	0.19	0.78	0.73	0.78	1.38
1995	QCM_FLR	-10.43	-10.10	-9.91	-9.94	-10.64	-10.53	-10.63	-10.11	-10.91	-12.16	-10.88	-10.89
1995	FLR	14.76	15.73	15.99	15.14	15.62	14.90	15.57	14.42	14.43	14.96	14.05	15.57
1996	TCM87	0.98	0.87	-0.05	0.27	0.55	0.14	0.14	-0.02	0.65	0.64	0.32	1.11
1996	QCM_FLR	-10.34	-9.98	-9.84	-9.85	-10.63	-10.45	-10.66	-10.01	-10.77	-12.15	-10.81	-11.04
1996	FLR	14.77	15.73	16.00	15.15	15.64	14.92	15.58	14.44	14.44	14.98	14.08	15.58
1997	TCM87	1.11	0.93	0.33	0.22	0.74	0.56	0.19	-0.14	0.47	0.66	0.36	1.09
1997	QCM_FLR	-10.31	-10.00	-9.95	-9.99	-10.69	-10.55	-10.59	-10.00	-10.86	-12.31	-10.72	-10.95
1997	FLR	14.78	15.74	16.01	15.17	15.67	14.94	15.60	14.48	14.45	15.01	14.11	15.59
1998	TCM87	1.06	0.69	0.30	0.28	0.72	0.67	0.45	0.27	0.62	0.82	0.61	1.23
1998	QCM_FLR	-10.40	-9.99	-10.10	-10.06	-10.72	-10.66	-10.75	-10.10	-10.81	-12.33	-10.74	-10.97
1998	FLR	14.79	15.75	16.03	15.18	15.70	14.97	15.62	14.51	14.47	15.03	14.14	15.61
1999	TCM87	1.02	0.60	0.29	0.29	0.56	0.64	0.28	0.46	0.58	0.82	0.68	1.09
1999	QCM_FLR	-10.60	-9.93	-10.01	-10.07	-10.72	-10.67	-10.77	-10.20	-10.75	-12.35	-10.84	-10.96
1999	FLR	14.81	15.76	16.05	15.20	15.73	14.99	15.65	14.55	14.49	15.06	14.19	15.63
2000	TCM87	0.81	1.01	0.00	0.24	0.69	0.40	-0.12	0.11	0.59	0.69	0.14	0.97
2000	QCM_FLR	-10.52	-9.98	-9.98	-10.05	-10.67	-10.61	-10.72	-10.17	-10.79	-12.16	-10.87	-11.04
2000	FLR	14.82	15.77	16.07	15.22	15.76	15.02	15.68	14.59	14.52	15.10	14.23	15.66
2001	TCM87	0.74	0.91	0.13	0.19	0.77	0.57	-0.07	0.24	0.54	1.13	0.22	0.73
2001	QCM_FLR	-10.57	-10.07	-10.04	-10.05	-10.79	-10.65	-10.75	-10.13	-10.77	-12.16	-10.87	-11.06
2001	FLR	14.84	15.78	16.09	15.24	15.80	15.05	15.71	14.63	14.54	15.13	14.26	15.68
2002	TCM87	1.00	0.44	0.14	0.21	0.76	0.73	0.35	0.36	1.06	1.12	0.91	0.89

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
2002	QCM_FLR	-10.63	-10.05	-10.13	-10.28	-10.78	-10.70	-10.66	-10.15	-10.90	-12.08	-10.91	-11.14
2002	FLR	14.86	15.80	16.11	15.26	15.83	15.07	15.73	14.66	14.57	15.17	14.30	15.71
2003	TCM87	0.74	0.82	-0.05	-0.01	0.52	0.51	0.02	-0.15	0.52	1.03	0.44	0.79
2003	QCM_FLR	-10.60	-9.93	-9.98	-10.07	-10.73	-10.63	-10.68	-10.26	-10.94	-12.13	-11.00	-11.08
2003	FLR	14.88	15.81	16.12	15.28	15.86	15.09	15.76	14.69	14.59	15.19	14.33	15.73
2004	TCM87	1.16	0.91	0.18	0.28	0.75	0.67	0.35	0.10	0.84	1.17	0.52	0.80
2004	QCM_FLR	-10.66	-9.93	-10.05	-10.11	-10.73	-10.71	-10.80	-10.25	-10.90	-12.11	-10.93	-11.14
2004	FLR	14.89	15.82	16.14	15.30	15.88	15.11	15.78	14.72	14.61	15.22	14.35	15.74
2005	TCM87	1.07	0.76	0.20	0.32	0.73	0.94	0.48	0.37	0.74	1.01	0.56	0.91
2005	QCM_FLR	-10.65	-10.04	-10.07	-10.17	-10.75	-10.78	-10.93	-10.28	-10.91	-12.12	-11.04	-11.20
2005	FLR	14.90	15.83	16.15	15.32	15.91	15.13	15.80	14.74	14.62	15.24	14.38	15.76
2006	TCM87	1.11	0.78	0.36	0.51	0.84	0.92	0.49	0.42	0.95	1.31	0.77	0.95
2006	QCM_FLR	-10.80	-10.20	-10.26	-10.32	-10.92	-10.89	-11.07	-10.31	-10.90	-12.29	-11.06	-11.19
2006	FLR	14.92	15.84	16.17	15.33	15.93	15.15	15.82	14.77	14.64	15.27	14.41	15.78
2007	TCM87	1.20	0.60	0.20	0.40	0.90	0.70	0.10	0.04	1.04	1.03	0.78	0.73
2007	QCM_FLR	-10.64	-10.08	-10.15	-10.21	-10.86	-10.87	-10.95	-10.26	-10.88	-12.32	-11.02	-11.13
2007	FLR	14.93	15.85	16.19	15.35	15.96	15.17	15.85	14.81	14.66	15.30	14.44	15.80
2008	TCM87	1.02	0.58	0.08	0.24	0.81	0.68	0.14	-0.05	0.82	0.99	0.56	0.80
2008	QCM_FLR	-10.56	-10.08	-10.08	-10.11	-10.89	-10.82	-10.97	-10.25	-10.86	-12.33	-11.06	-11.14
2008	FLR	14.95	15.87	16.20	15.36	15.99	15.19	15.87	14.84	14.67	15.32	14.47	15.81
2009	TCM87	1.13	0.60	0.47	0.44	0.81	0.93	0.46	0.24	0.99	1.06	0.73	0.82
2009	QCM_FLR	-10.53	-10.07	-10.13	-10.16	-10.83	-10.89	-11.00	-10.28	-10.84	-12.36	-11.17	-11.19
2009	FLR	14.95	15.88	16.22	15.37	16.01	15.21	15.90	14.87	14.69	15.35	14.51	15.83
2010	TCM87	0.84	0.64	0.06	0.31	0.80	0.65	0.27	0.26	0.77	1.03	0.51	0.80
2010	QCM_FLR	-10.54	-10.08	-10.13	-10.14	-10.73	-10.69	-10.88	-10.30	-11.03	-12.19	-11.11	-11.20
2010	FLR	14.96	15.88	16.22	15.38	16.03	15.23	15.92	14.89	14.70	15.36	14.52	15.84

Data used for off-peak period estimation in log form

Year	Variable	1	2	3	4	5	6	7	8	9	10	11	12
		New Engl	Mid Atl	E.N. Cntrl	W.N. Cntrl	S.Atl-FL	E.S. Cntrl	W.S. Cntrl	Mtn-AZNM	WA/OR	Florida	AZ/NM	CA/HI
1990	TCM87	0.82	0.71	0.38	-0.17	0.63	0.53	0.19	-0.18	0.74	0.74	0.56	0.53
1990	QCM_FLR	-10.90	-10.34	-10.31	-10.18	-10.97	-10.86	-10.59	-10.29	-11.03	-11.77	-10.73	-10.39
1990	FLR	14.73	15.69	15.92	15.08	15.52	14.83	15.51	14.31	14.34	14.86	13.95	15.48
1991	TCM87	0.82	0.70	0.41	-0.08	0.58	0.56	0.22	-0.18	0.70	0.73	0.67	0.73
1991	QCM_FLR	-10.94	-10.38	-10.38	-10.15	-10.90	-10.89	-10.60	-10.25	-10.94	-11.71	-10.73	-10.32
1991	FLR	14.74	15.70	15.94	15.09	15.55	14.84	15.52	14.33	14.37	14.89	13.97	15.51
1992	TCM87	0.51	0.70	0.26	-0.12	0.43	0.43	0.08	-0.55	0.78	0.69	0.49	0.44
1992	QCM_FLR	-10.74	-10.30	-10.29	-10.19	-10.83	-10.84	-10.56	-10.36	-11.11	-11.68	-10.68	-10.38
1992	FLR	14.75	15.71	15.95	15.10	15.57	14.85	15.53	14.35	14.39	14.91	13.99	15.53
1993	TCM87	0.15	0.67	0.44	0.06	0.50	0.44	0.13	-0.12	0.68	0.95	0.57	0.85
1993	QCM_FLR	-10.77	-10.33	-10.31	-10.21	-10.85	-10.80	-10.58	-10.22	-11.01	-11.69	-10.64	-10.58
1993	FLR	14.75	15.72	15.96	15.11	15.59	14.87	15.54	14.37	14.40	14.92	14.00	15.54
1994	TCM87	0.36	0.91	0.55	-0.15	0.56	0.62	0.37	-0.02	0.70	0.85	0.73	1.21
1994	QCM_FLR	-10.58	-10.34	-10.39	-10.28	-10.88	-10.89	-10.63	-10.23	-10.99	-11.77	-10.68	-10.49
1994	FLR	14.76	15.72	15.97	15.12	15.60	14.88	15.55	14.39	14.42	14.94	14.03	15.56
1995	TCM87	0.44	0.88	0.27	0.05	0.56	0.53	0.17	0.29	0.81	0.73	0.76	1.09
1995	QCM_FLR	-10.55	-10.26	-10.27	-10.18	-10.84	-10.86	-10.48	-10.15	-10.98	-11.78	-10.71	-10.41
1995	FLR	14.76	15.73	15.99	15.14	15.62	14.90	15.57	14.42	14.43	14.96	14.05	15.57
1996	TCM87	0.25	0.75	0.36	0.07	0.60	0.65	0.16	0.02	0.59	0.83	0.41	0.91
1996	QCM_FLR	-10.43	-10.23	-10.24	-10.16	-10.80	-10.77	-10.62	-10.19	-10.90	-11.77	-10.71	-10.62
1996	FLR	14.77	15.73	16.00	15.15	15.64	14.92	15.58	14.44	14.44	14.98	14.08	15.58
1997	TCM87	0.53	0.01	0.33	-0.20	0.70	0.69	0.36	0.18	0.48	0.87	0.52	0.91
1997	QCM_FLR	-10.32	-9.96	-10.25	-10.29	-10.79	-10.73	-10.49	-10.22	-10.87	-11.92	-10.79	-10.57
1997	FLR	14.78	15.74	16.01	15.17	15.67	14.94	15.60	14.48	14.45	15.01	14.11	15.59
1998	TCM87	0.39	0.41	0.52	0.17	0.74	0.60	0.51	0.57	0.62	0.81	0.83	1.05
1998	QCM_FLR	-10.47	-10.05	-10.42	-10.48	-10.83	-10.90	-10.71	-10.26	-10.99	-11.91	-10.78	-10.42
1998	FLR	14.79	15.75	16.03	15.18	15.70	14.97	15.62	14.51	14.47	15.03	14.14	15.61
1999	TCM87	0.36	-0.33	0.38	0.04	0.64	0.60	0.42	0.50	0.57	0.82	0.60	0.94
1999	QCM_FLR	-10.57	-9.96	-10.44	-10.48	-10.91	-10.89	-10.76	-10.31	-10.89	-12.01	-10.78	-10.70
1999	FLR	14.81	15.76	16.05	15.20	15.73	14.99	15.65	14.55	14.49	15.06	14.19	15.63
2000	TCM87	-0.21	-0.50	0.37	0.17	0.58	0.62	0.23	0.24	0.32	0.66	0.16	0.85
2000	QCM_FLR	-10.65	-9.93	-10.38	-10.46	-10.88	-10.97	-10.67	-10.32	-10.90	-11.73	-10.81	-10.66
2000	FLR	14.82	15.77	16.07	15.22	15.76	15.02	15.68	14.59	14.52	15.10	14.23	15.66
2001	TCM87	0.73	0.95	0.58	0.49	0.91	0.96	0.45	1.00	1.09	1.36	0.74	0.82
2001	QCM_FLR	-10.75	-10.04	-10.51	-10.55	-10.93	-11.03	-10.86	-10.45	-10.82	-11.74	-10.91	-10.70
2001	FLR	14.84	15.78	16.09	15.24	15.80	15.05	15.71	14.63	14.54	15.13	14.26	15.68
2002	TCM87	0.27	0.29	0.26	0.30	0.66	0.82	0.31	0.54	0.84	1.10	0.85	0.60

Year	Variable	1 New Engl	2 Mid Atl	3 E.N. Cntrl	4 W.N. Cntrl	5 S.Atl-FL	6 E.S. Cntrl	7 W.S. Cntrl	8 Mtn-AZNM	9 WA/OR	10 Florida	11 AZ/NM	12 CA/HI
2002	QCM_FLR	-10.70	-9.99	-10.35	-10.52	-10.96	-11.04	-10.63	-10.39	-11.02	-11.64	-10.98	-10.74
2002	FLR	14.86	15.80	16.11	15.26	15.83	15.07	15.73	14.66	14.57	15.17	14.30	15.71
2003	TCM87	1.13	0.78	0.51	0.41	0.80	0.77	0.69	0.54	0.47	1.20	0.73	0.72
2003	QCM_FLR	-10.82	-10.13	-10.46	-10.54	-10.94	-11.06	-10.73	-10.43	-11.01	-11.70	-10.99	-10.85
2003	FLR	14.88	15.81	16.12	15.28	15.86	15.09	15.76	14.69	14.59	15.19	14.33	15.73
2004	TCM87	0.83	0.74	0.39	0.36	0.71	0.82	0.65	0.49	0.79	1.18	0.76	0.39
2004	QCM_FLR	-10.95	-10.09	-10.52	-10.58	-10.97	-11.05	-10.85	-10.48	-11.08	-11.70	-11.02	-10.85
2004	FLR	14.89	15.82	16.14	15.30	15.88	15.11	15.78	14.72	14.61	15.22	14.35	15.74
2005	TCM87	0.59	0.53	0.24	0.18	0.47	0.79	0.54	0.45	0.52	0.94	0.45	0.43
2005	QCM_FLR	-10.98	-10.26	-10.56	-10.64	-10.99	-11.04	-10.97	-10.46	-11.03	-11.69	-11.05	-10.82
2005	FLR	14.90	15.83	16.15	15.32	15.91	15.13	15.80	14.74	14.62	15.24	14.38	15.76
2006	TCM87	0.99	0.35	0.40	0.41	0.94	0.92	0.79	0.46	1.06	1.18	1.14	0.80
2006	QCM_FLR	-11.03	-10.28	-10.52	-10.61	-11.00	-11.11	-11.04	-10.50	-11.03	-11.84	-11.08	-10.78
2006	FLR	14.92	15.84	16.17	15.33	15.93	15.15	15.82	14.77	14.64	15.27	14.41	15.78
2007	TCM87	0.94	0.40	0.55	0.58	0.84	0.85	0.61	0.59	1.11	1.18	1.04	0.79
2007	QCM_FLR	-10.95	-10.22	-10.58	-10.66	-11.03	-11.15	-11.02	-10.57	-11.00	-11.85	-11.14	-10.81
2007	FLR	14.93	15.85	16.19	15.35	15.96	15.17	15.85	14.81	14.66	15.30	14.44	15.80
2008	TCM87	0.91	0.54	0.77	0.49	0.62	0.91	0.31	0.24	0.28	1.07	1.04	0.92
2008	QCM_FLR	-10.87	-10.24	-10.54	-10.57	-10.99	-11.14	-10.99	-10.52	-10.95	-11.89	-11.17	-10.84
2008	FLR	14.95	15.87	16.20	15.36	15.99	15.19	15.87	14.84	14.67	15.32	14.47	15.81
2009	TCM87	1.01	0.52	0.52	0.44	1.11	1.07	0.84	0.64	1.20	1.18	1.11	0.75
2009	QCM_FLR	-10.91	-10.27	-10.59	-10.61	-11.07	-11.20	-10.99	-10.49	-11.05	-11.93	-11.15	-10.85
2009	FLR	14.95	15.88	16.22	15.37	16.01	15.21	15.90	14.87	14.69	15.35	14.51	15.83
2010	TCM87	0.69	0.37	0.67	0.58	0.92	0.96	0.74	0.47	0.90	1.13	0.91	0.80
2010	QCM_FLR	-10.91	-10.23	-10.64	-10.64	-11.08	-11.22	-11.03	-10.48	-10.94	-11.87	-11.18	-10.82
2010	FLR	14.96	15.88	16.22	15.38	16.03	15.23	15.92	14.89	14.70	15.36	14.52	15.84

Table F8

Data: Equation for natural gas price at the Henry Hub

Author: Joe Benneche, EIA, 2012.

Source: Data for the years 1994 through 2011 from Natural Gas Intelligence, converted to 1987 dollars per Mcf using EIA GDP deflator and Btu content data.

Variables:

OGHHPRNG = Henry Hub spot natural gas price (1987$/MMBtu)
$PSUP_9$ = NGTDM/OGSM region 9 average spot price (1987$/Mcf)
intercept = constant term
coefficient variable 1 = estimated parameter for $PSUP_9$ (i.e., variable 1)

Derivation: Using Excel's regression feature and annual price data from 1994 through 2011, the equation was estimated using ordinary least squares.

$$OGHHPRNG = intercept + (coefficient\ variable\ 1 * PSUP_9)$$

Regression diagnostics and parameter estimates

SUMMARY OUTPUT	
Regression Statistics	
Multiple R	0.999785692
R Square	0.999571429
Adjusted R Square	0.999542858
Standard Error	0.02948968
Observations	17

ANOVA

	df	SS	MS	F	Significance F
Regression	1	30.4244266	30.424427	34985.032	1.11408E-26
Residual	15	0.01304462	0.0008696		
Total	16	30.4374712			

	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%	Lower 95.0%	Upper 95.0%
Intercept	-0.03693	0.01801061	-2.0251713	0.0610268	-0.074863258	0.0019141	-0.074863258	0.001914134
X Variable 1	1.022	0.00546491	187.04286	1.114E-26	1.010523968	1.0338203	1.010523968	1.033820322

Data used for estimation:

Year	Henry Hub Spot Natural Gas Price ($/Mcf, in 1987 dollars)	Average NGTDM/OGSM Region 9 Natural Gas Spot Price ($/Mcf, in 1987 dollars)
1994	1.58	1.57
1995	1.40	1.38
1996	2.24	2.18
1997	1.94	1.94
1998	1.62	1.62
1999	1.73	1.73
2000	3.23	3.22
2001	2.90	2.91
2002	2.42	2.42
2003	3.87	3.85
2004	4.02	4.00
2005	5.92	5.76
2006	4.34	4.29
2007	4.35	5.34
2008	5.41	2.33
2009	2.37	2.33
2010	2.61	2.60
2011	2.33	2.32

Table F9

Data: Lease and plant fuel consumption in Alaska

Author: Margaret Leddy, EIA summer intern, 2009.

Source: EIA's Petroleum Supply Annual and Natural Gas Annual.

Variables:

LSE_PLT = Lease and plant fuel consumption in Alaska [QALK_LAP_N]
OIL_PROD = Oil production in Alaska (thousand barrels) [OGPRCOAK]
[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using EViews and annual price data from 1981 through 2007, the following equation was estimated using ordinary least squares without a constant term:

$$LSE\_PLT_t = \beta_{-1} * LSE\_PLT_{t-1} + \beta_1 * OIL\_PROD_t$$

The intent was to find an equation that demonstrated similar characteristics to the projection by the Alaska Department of Natural Resources in their "Alaska Oil and Gas Report."

Regression diagnostics and parameter estimates

Dependent Variable: LSE_PLT
Method: Least Squares
Date: 07/24/09 Time: 17:34
Sample (adjusted): 1981 2007
Included observations: 27 after adjustments

	Coefficient	Std. Error	t-Statistic	Prob.	Symbol
OIL_PROD	0.038873	0.015357	2.531280	0.0180	β_1
LSE_PLT_PREV	0.943884	0.037324	25.28876	0.0000	β_{-1}
R-squared	0.911327		Mean dependent var	210731.2	
Adjusted R-squared	0.907780		S.D. dependent var	86703.97	
S.E. of regression	26329.98		Akaike info criterion	23.26599	
Sum squared resid	1.73E+10		Schwarz criterion	23.36198	
Log likelihood	-312.0909		Hannan-Quinn criter.	23.29453	
Durbin-Watson stat	2.407017				

Data used for estimation:

Year	oil_prod	lse_plt	Year	oil_prod	lse_plt	Year	oil_prod	lse_plt
1981	587337	15249	1990	647309	193875	1999	383199	265504.375
1982	618910	94232	1991	656349	223194.366	2000	355199	269177.988
1983	625527	97828	1992	627322	234716.225	2001	351411	271448.841
1984	630401	111069	1993	577495	237701.556	2002	359335	285476.659
1985	666233	64148	1994	568951	238156.064	2003	355582	300463.487
1986	681310	72686	1995	541654	292810.594	2004	332465	281546.298
1987	715955	116682	1996	509999	295833.863	2005	315420	303215.128
1988	738143	153670	1997	472949	271284.345	2006	270486	257091.267
1989	683979	192239	1998	428850	281871.556	2007	263595	268571.098

Table F10

Data: Western Canada successful tight/other gas wells

Author: Joe Benneche, EIA, 2012

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource based on estimates from National Energy Board of Canada.

Variables:

GWELLS	=	Number of successful new natural gas wells drilled in western Canada [SUCWELL]
PRICE87	=	Average natural gas wellhead price in Alberta (1987 U.S. dollars per Mcf) [OGCNPPRD]
BOYREMAIN	=	Remaining natural gas undiscovered resources in western Canada (Bcf) [URRCAN]
PR_LAG	=	Production-to-reserves ratio last forecast year [CURPRRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: Using EViews Version 7.1 and annual price data from 1963 through 2011, the following equation was estimated after taking natural logs of all of the variables and correcting for first-order serial correlation:

$$\ln GWELLS = \beta_0 + \beta_1 * \ln PRICE87 + \beta_2 * \ln BOYREMAIN + \beta_3 * \ln PR\_LAG + \beta_4 * AR(1)$$

Regression diagnostics and parameter estimates

Dependent Variable: LNGWELLS

Method: Least Squares

Date: 09/05/12 Time: 16:51

Sample (adjusted): 4 48

Included observations: 45 after adjustments

Convergence achieved after 6 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-21.64607	8.263672	-2.619426	0.0124
LNPRICE87	0.688283	0.107709	6.390209	0.0000
LNBOYREMAIN	2.933252	0.738300	3.972984	0.0003
LNPR_LAG	2.328811	0.338786	6.873989	0.0000
AR(1)	0.327292	0.152246	2.149759	0.0377
R-squared	0.926531		Mean dependent var	7.933813
Adjusted R-squared	0.919184		S.D. dependent var	0.975170
S.E. of regression	0.277223		Akaike info criterion	0.376448
Sum squared resid	3.074096		Schwarz criterion	0.577188
Log likelihood	-3.470075		Hannan-Quinn criter.	0.451282
F-statistic	126.1120		Durbin-Watson stat	1.971083
Prob(F-statistic)	0.000000			
Inverted AR Roots		.33		

where LNGWELLS is the natural log of the number of successful gas wells drilled, C is the constant term, LNPRICE87 is the natural log of the natural gas wellhead price in 1997$ per Mcf, LNBOYREMAIN is the natural log of remaining natural gas resources, and PR_LAG is the one-year lag of the natural gas production-to-reserves ratio.

Data used for estimation:

OBS	Year	GWELLS	PRICE87	BOYREMAIN	PRLAG
1	1963	338	0.4175	--	--
2	1964	308	0.4276	322860	--
3	1965	320	0.4161	313783	0.02666
4	1966	342	0.4225	311682	0.027586
5	1967	372	0.4123	307794	0.024289
6	1968	478	0.3943	304726	0.02649
7	1969	524	0.371	299932	0.028469
8	1970	731	0.3801	294988	0.032332
9	1971	838	0.3714	290387	0.034601
10	1972	1164	0.3774	286648	0.035936
11	1973	1656	0.3909	285752	0.038741

OBS	Year	GWELLS	PRICE87	BOYREMAIN	PRLAG
12	1974	1902	0.5806	282996	0.040456
13	1975	2080	1.0352	282572	0.041023
14	1976	3304	1.6416	279077	0.041365
15	1977	3192	1.9065	276838	0.043445
16	1978	3319	1.9265	272038	0.044406
17	1979	3450	1.9875	266747	0.043292
18	1980	4241	2.4808	261002	0.044527
19	1981	3206	2.3618	258004	0.039249
20	1982	2555	2.3558	253019	0.03702
21	1983	1374	2.4083	250500	0.03766
22	1984	1866	2.2944	247453	0.034472
23	1985	2528	2.0411	239350	0.037508
24	1986	1298	1.5413	238328	0.041115
25	1987	1599	1.251	237271	0.034458
26	1988	2300	1.1747	236291	0.038425
27	1989	2313	1.1983	234542	0.045529
28	1990	2226	1.183	229410	0.049948
29	1991	1645	1.0339	226061	0.051562
30	1992	908	0.952	222686	0.054682
31	1993	3327	1.0613	219818	0.060246
32	1994	5333	1.1109	216250	0.067537
33	1995	3325	0.8009	212248	0.074416
34	1996	3664	0.9187	205761	0.078992
35	1997	4820	1.0727	203288	0.083958
36	1998	4955	0.9794	201243	0.083931
37	1999	7005	1.2439	197568	0.090201
38	2000	9004	2.2934	192765	0.098453
39	2001	10654	2.5728	187856	0.103091
40	2002	8980	1.7394	181157	0.106168
41	2003	12846	3.0894	175937	0.108154
42	2004	14918	3.301	171531	0.104207
43	2005	15475	4.5213	166436	0.106679
44	2006	13228	3.7188	160065	0.109426
45	2007	8906	3.7686	155734	0.109859
46	2008	7479	4.4699	150196	0.106006
47	2009	3059	2.0825	142203	0.104027
48	2010	3050	2.1956	138638	0.096591
49	2011	2354	2.0552	127000	0.087879

Table F11

Data: Western Canada tight/other natural gas finding rate

Author: Joe Benneche, EIA, 2012

Source: Canadian Association of Petroleum Producers, Statistical Handbook. Undiscovered remaining resource based on estimates from National Energy Board of Canada.

Variables:

FR = Natural gas proved reserves added per successful natural gas well in western Canada (Bcf/well) [FRCAN]

BOYREMAIN = Beginning-of-year remaining natural gas undiscovered resources in western Canada (Bcf) [URRCAN]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation to project the average natural gas finding rate in western Canada was estimated for the time period 1963-2011 using EViews version 7 and aggregated reserves and production data for the provinces in western Canada. Natural logs were taken of all data before the estimation was performed. The following equation was estimated with correction for first-order serial correlation:

$$\ln FR_t = \beta_0 + \beta_1 * \ln BOYREMAIN_t + \beta_2 * AR(1)$$

Regression diagnostics and parameter estimates

Dependent Variable: LNFR
Method: Least Squares
Date: 09/05/12 Time: 16:26
Sample: 3 48
Included observations: 46
Convergence achieved after 5 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-18.84688	13.33437	-1.413407	0.1647
LNBOYREMAIN	1.546983	1.082563	1.429001	0.1602
AR(1)	0.530872	0.129599	4.096268	0.0002
R-squared	0.474146		Mean dependent var	0.259958
Adjusted R-squared	0.449688		S.D. dependent var	1.013822
S.E. of regression	0.752084		Akaike info criterion	2.331056
Sum squared resid	24.32211		Schwarz criterion	2.450315
Log likelihood	-50.61429		Hannan-Quinn criter.	2.375731
F-statistic	19.38589		Durbin-Watson stat	2.276043
Prob(F-statistic)	0.000001			
Inverted AR Roots		.53		

Data used for estimation:

OBS	Year	fr	remain
1	1963	9.289941	--
2	1964	29.47078	322860
3	1965	6.565625	313783
4	1966	11.36842	311682
5	1967	8.247312	307794
6	1968	10.02929	304726
7	1969	9.435115	299932
8	1970	6.294118	294988
9	1971	4.461814	290387
10	1972	0.7689	286648
11	1973	1.664251	285752
12	1974	0.222923	282996
13	1975	1.680288	282572
14	1976	0.677663	279077
15	1977	1.503759	276838
16	1978	1.594155	272038
17	1979	1.665217	266747
18	1980	0.706909	261002
19	1981	1.554585	258004
20	1982	0.986301	253019
21	1983	2.217613	250500
22	1984	4.34298	247453
23	1985	0.403877	239350
24	1986	0.81433	238328
25	1987	0.612883	237271
26	1988	0.760435	236291
27	1989	2.218764	234542
28	1990	1.504492	229410
29	1991	2.051672	226061
30	1992	3.15859	222686
31	1993	1.072438	219818
32	1994	0.750422	216250
33	1995	1.950977	212248
34	1996	0.674672	205761
35	1997	0.424274	203288
36	1998	0.741675	201243
37	1999	0.685653	197568
38	2000	0.545313	192765
39	2001	0.628778	187856

OBS	Year	fr	remain
40	2002	0.581292	181157
41	2003	0.342986	175937
42	2004	0.341534	171531
43	2005	0.411696	166436
44	2006	0.327412	160065
45	2007	0.621828	155734
46	2008	1.068726	150196
47	2009	1.165414	142203
48	2010	3.815738	138638
49	2011	--	127000

Table F12

Data: Western Canada production-to-reserves ratio

Author: Joe Benneche, EIA, 2012

Source: Canadian Association of Petroleum Producers, Statistical Handbook.

Variables:

PR = Natural gas production-to-reserve ratio in western Canada [PRRATCAN]
PRRAT = PR / (1-PR)
GWELLS = Number of successful new natural gas wells drilled in western Canada [SUCWELL}
FR = Proved natural gas reserves added per successful natural gas well in western Canada (Bcf/well) [FRCAN]
YEAR = Calendar year [RLYR]

[Note: Variables in brackets correspond to comparable variables used in the main body of the documentation and in the model code.]

Derivation: The equation was estimated using EViews version 7 for the period from 1978 to 2007 using aggregated data in natural log form (with the exception of YEAR) for the provinces of western Canada. Because the PR ratio is bounded between zero and one, the dependent variable was measured in logistic form, as follows:

$$\ln \frac{PR_t}{1-PR_t} = \beta_0 + \beta_1 * \ln GWELLS_t + \beta_2 * \ln FR_t + \beta_3 * YEAR$$

$$+ \rho * \ln \frac{PR_{t-1}}{1-PR_{t-1}}$$

$$- \rho * (\beta_0 + \beta_1 * \ln GWELLS_{t-1} + \beta_2 * \ln FR_{t-1} + \beta_3 * (YEAR - 1))$$

Regression diagnostics and parameter estimates

Dependent Variable: LNPRRAT
Method: Least Squares
Date: 09/05/12 Time: 20:57
Sample: 16 48
Included observations: 33
Convergence achieved after 17 iterations

Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	-72.31364	43.79561	-1.651162	0.1099
LNGWELLS	0.123062	0.034680	3.548541	0.0014
LNFR	0.032055	0.018747	1.709857	0.0984
YEAR	0.034333	0.021844	1.571750	0.1272
AR(1)	0.940628	0.087021	10.80920	0.0000
R-squared	0.984323		Mean dependent var	-2.640746
Adjusted R-squared	0.982084		S.D. dependent var	0.476106
S.E. of regression	0.063728		Akaike info criterion	-2.529661
Sum squared resid	0.113715		Schwarz criterion	-2.302918
Log likelihood	46.73941		Hannan-Quinn criter.	-2.453369
F-statistic	439.5165		Durbin-Watson stat	1.163558
Prob(F-statistic)	0.000000			
Inverted AR Roots		.94		

Data used for estimation:

OBS	Year	PR	GWELLS	FR
1	1963	0.023777	338	9.289941
2	1964	0.024992	308	29.47078
3	1965	0.022606	320	6.565625
4	1966	0.023722	342	11.36842
5	1967	0.024982	372	8.247312
6	1968	0.027438	478	10.02929
7	1969	0.030308	524	9.435115
8	1970	0.032619	731	6.294118
9	1971	0.034313	838	4.461814
10	1972	0.037697	1164	0.7689
11	1973	0.041419	1656	1.664251
12	1974	0.040855	1902	0.222923
13	1975	0.042815	2080	1.680288
14	1976	0.042731	3304	0.677663
15	1977	0.044639	3192	1.503759
16	1978	0.041781	3319	1.594155
17	1979	0.042642	3450	1.665217
18	1980	0.037496	4241	0.706909
19	1981	0.03676	3206	1.554585

OBS	Year	PR	GWELLS	FR
20	1982	0.036323	2555	0.986301
21	1983	0.034488	1374	2.217613
22	1984	0.037176	1866	4.34298
23	1985	0.038167	2528	0.403877
24	1986	0.035334	1298	0.81433
25	1987	0.039254	1599	0.612883
26	1988	0.046734	2300	0.760435
27	1989	0.051076	2313	2.218764
28	1990	0.050408	2226	1.504492
29	1991	0.054859	1645	2.051672
30	1992	0.06068	908	3.15859
31	1993	0.068904	3327	1.072438
32	1994	0.075709	5333	0.750422
33	1995	0.080323	3325	1.950977
34	1996	0.082542	3664	0.674672
35	1997	0.08798	4820	0.424274
36	1998	0.095583	4955	0.741675
37	1999	0.102053	7005	0.685653
38	2000	0.105234	9004	0.545313
39	2001	0.108333	10654	0.628778
40	2002	0.107047	8980	0.581292
41	2003	0.105848	12846	0.342986
42	2004	0.109682	14918	0.341534
43	2005	0.111248	15475	0.411696
44	2006	0.109054	13228	0.327412
45	2007	0.109173	8906	0.621828
46	2008	0.104421	7479	1.068726
47	2009	0.092141	3059	1.165414
48	2010	0.090333	3050	3.815738
49	2011	0.077777	2354	--

Appendix G. Variable Cross-Reference Table

With the exception of the Pipeline Tariff Submodule (PTS), all of the equations in this model documentation report are the same as those used in the model FORTRAN code. Table G-1 presents cross-references between model equation variables defined in this document and in the FORTRAN code for the PTS.

Table G-1. Cross-reference of PTM variables between documentation and code

Documentation	Code Variable	Equation #
$R_{i,f}$	Not represented	156
$R_{i,v}$	Not represented	157
ALL_f	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	158
ALL_v	AVA_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	157
R_i	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	156, 157
FC_a	Not represented	158
VC_a	Not represented	159
$R_{i,f,r}$	RFC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	160
$R_{i,f,u}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$R_{i,v,r}$	RVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$R_{i,v,u}$	UVC_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
$ALL_{f,r}$	AFR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	160
$ALL_{f,u}$	AFU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	161
$ALL_{v,r}$	AVR_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	162
$ALL_{v,u}$	AVU_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	163
ξ_i	AFX_ i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	221, 222, 224-227
$Item_{i,a,t}$	PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	221, 222, 224-227
$FC_{a,t}$	Not represented	221
$VC_{a,t}$	Not represented	222
$TCOS_{a,t}$	Not represented	223, 228
$RFC_{a,t}$	RFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	224
$UFC_{a,t}$	UFC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	224
$RVC_{a,t}$	RVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	226
$UVC_{a,t}$	UVC_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	227
λ_i	AFR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	224, 225
μ_i	AVR_i, where i = PFEN, CMEN, LTDN, DDA, FSIT, DIT, OTTAX, TOM	226, 227

a - arc, t - year, i - cost-of-service component index

Appendix H. Coal-to-Gas Submodule

A Coal-to-Gas (CTG) algorithm has been incorporated into the NGTDM to project potential new CTG plants at the Census Division level and the associated pipeline-quality gas production. The Coal-to-Gas process with no carbon sequestration is adopted as the generic facility for the CTG. The CTG_INVEST subroutine calculates the annualized capital costs, operating costs, and other variable costs for a generic coal-to-gas plant producing 100 MMcf/day (Appendix E, CTG_PUCAP) of pipeline-quality synthetic gas from coal. The capital costs are converted into a per-unit basis by dividing by the plant's assumed output of gas. Capital and operating costs are assumed to decline over the forecast due to technological improvements. To determine whether it is profitable to build a CTG plant, the per-unit capital and operating costs plus the coal costs are compared to the average market price of natural gas and electricity. If a CTG plant is profitable, the actual number of plants to be built is set using the Mansfield-Blackman market penetration algorithm. Any new generic plant is assumed to be built in the regions with the greatest level of profitability and to produce pipeline-quality natural gas and cogenerated electricity (cogen) for sale to the grid.

Electricity generated by a CTG facility is partially consumed in the facility, while the remainder is assumed to be sold to the grid at wholesale market prices (EWSPRCN, 1987$/MWh, from the EMM). Cogeneration for each use is set for a generic facility using assumed ratios of electricity produced to coal consumed (Appendix E, own—CTG_BASECGS, grid—CTG_BASCGG). The revenue from cogen sales is treated as a credit (CGNCRED) by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTG syngas. The annualized transmission cost (CGNTRNS) for cogen sent to the grid is accounted for in the operating cost of the CTG facility.

The primary inputs to the CTG model include a mine-mouth coal price (PCLGAS, 1987$/MMBtu, from the Coal Market Module (CMM)) and a regional wholesale equivalent natural gas price (NODE_ENDPR, 1987$/Mcf). A carbon tax (JCLIN, 1987$/MMBtu from the Integration Module) is added to the coal price as well as a penalty for SO_2 and HG. If the CTG plant is deemed to be economic, the final quantity of coal demanded (QCLGAS, Quad Btu/yr) is sent back to the CMM for feedback. The final outputs from the model are coal consumed, gas produced, electricity consumed, and electricity sold to the grid.

Investment decisions for building new CTG facilities are based on the total investment cost of a CTG plant (CTG_INVCST). Actual cash flows associated with the operation of the individual plants are considered, as well as cash flows associated with capital for the construction of new plants. Terms for capital-related financial charges (CAPREC) and fixed operating costs (FXOC) are included.

$$CTG\_INVCST = CAPREC + FXOC \qquad (305)$$

Once a build decision is made, a Mansfield-Blackman algorithm for market penetration is used to determine the limit on the number of plants allowed to build in a given year. The investment costs are further adjusted to account for learning and for resource competition. The methodologies used to calculate the capital-related financial charges and the fixed operating costs, the Mansfield-Blackman model, and investment cost adjustments are presented in detail below.

Capital-related financial charges for coal-to-gas

A discounted cash flow calculation is used to determine the annual capital charge for a CTG plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital, which includes the cost of equity (CTGCOE) and interest payments on any loans or other debt instruments used as part of capital project financing (CTGCOD) with an assumed interest rate of the Industrial BAA bond rate (MC_RMCORPBAA, from MACRO) plus an additional risk premium (Appendix E, BA_PREM). Together, this translates into the capital recovery factor (CTG_RECRAT) which is calculated on an after-tax basis.

Some of the steps associated with the capital-related financial charge estimates are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant capital-related cost estimation algorithm are:

0) Estimation of the inside battery limit field cost (ISBL)

1) Year-dollar and location adjustments for ISBL Field Costs

2) Estimation of outside battery limit field cost (OSBL) and Total Field Cost

3) Estimation of Total Project Cost

4) Calculate Annual Capital Recovery

5) Convert capital-related financial costs to a “per-unit” basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 - Estimation of ISBL Field Cost

The inside battery limits (CTG_ISBL) field costs include direct costs such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs such as distributables. The ISBL investment and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 - Year-Dollar and Location Adjustments to ISBL Field Costs

Before utilizing the ISBL investment cost information, the raw data must be converted according to the following steps:

a) Adjust the ISBL field and labor costs from 2004 dollars, first to the year-dollar reported by NEMS, using the Nelson-Farrar refining industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by NEMS.

b) Convert the ISBL field costs in 1987 dollars from a PADD III basis (Appendix E, XBM_ISBL) to costs in the NGTDM demand regions using location multipliers (Appendix E, CTG_INVLOC). The location multipliers represent differences in material costs between the various regions.

$$CTG\_ISBL = CTG\_INVLOC * BM\_ISBL / 1000 \tag{306}$$

Step 2 - Estimation of OSBL and Total Field Cost

The outside battery-limit (OSBL) costs for CTG are included in the inside battery-limit costs.

The total field cost (CTG_TFCST) is the sum of ISBL and OSBL

$$CTG\_TFCST = (1 - CTG\_OSBLFAC) * CTG\_ISBL \tag{307}$$

The OSBL field cost is estimated as a fraction (Appendix E, CTG_OSBLFAC) of the ISBL costs.

Step 3 - Estimation of Total Project Cost

The total project investment (CTG_TPI) is the sum of the total field cost (Eq. 3) and other one-time costs (CTG_OTC).

$$CTG\_TPI = CTG\_TFCST + CTG\_OTC \tag{308}$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital. The other one-time costs are estimated as a function of total field costs using cost factors (OTCFAC):

$$CTG\_OTC = OTCFAC * CTG\_TFCST \tag{309}$$

where,

$$\begin{aligned} OTCFAC = {} & CTG\_PCTENV + CTG\_PCTCNTG + CTG\_PCTLND + \\ & CTG\_PCTSPECL + CTG\_PCTWC \end{aligned} \tag{310}$$

and,

CTG_PCTENV	=	Home, office, contractor fee
CTG_CNTG	=	Contractor & owner contingency
CTG_PCTLND	=	Land
CTG_PCTSPECL	=	Prepaid royalties, license, start-up costs
CTG_PCTWC	=	Working capital

The total project investment given above represents the total project cost for 'overnight construction.' The total project investment at project completion and startup will be discussed below.

Closely related to the total project investment are the fixed capital investment (CTG_FCI) and total depreciable investment (CTG_TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs.

$$WRKCAP = CTG\_PCTWC * CTG\_TFCST \tag{311}$$

Thus,

$$CTG\_FCI = CTG\_TPI - WKRCAP \tag{312}$$

For the CTG plant, the total depreciable investment (CTG_TDI) is assumed to be equal to the total project investment.

Step 4 - Annual Capital Recovery

The annual capital recovery (ACAPRCV) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated previously is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$\begin{aligned} TPI\_START = {} & FVI\_CONSTR * LAND + FV\_CONSTR * \\ & (CTG\_FCI - LAND) + WRKCAP \end{aligned} \tag{313}$$

where,

FVI_CONSTR	=	Future-value compounding factor for an instantaneous payment made n years before the startup year
FV_CONSTR	=	Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup, and the compounding rate used is the cost of capital (CTG_RECRAT).

The recoverable investment (RCI_START) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (PRJSDECOM) of the used equipment:

$$RCI\_START = PV\_PRJ * (LAND + WKRCAP + PRJSDECOM) \tag{314}$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI\_START = TPI\_START - RCI\_START \tag{315}$$

Thus, the annual capital recovery (ACAPRCV) is given by:

$$ACAPRCV = LC\_LIFE * PVI\_START \tag{316}$$

where,

LC_LIFE = uniform-value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$ADEPREC = CTG\_TDI / CTG\_PRJLIFE \tag{317}$$

$$ADEPTAXC = ADEPREC * FEDST\_TAX \tag{318}$$

$$ACAPCHRGAT = ACAPRCV - ADEPTAXC \tag{319}$$

$$DCAPCHRGAT = ACAPCHRGAT / 365 \tag{320}$$

where,

ADEPREC = annual levelized depreciation
ADEPTAXC = levelized depreciation tax credit, after federal and state taxes
ACAPCHRGAT = annual capital charge, after tax credit
DCAPCHRGAT = daily capital charge, after tax credit

Step 5 - Convert Capital Costs to a 'per-day,' 'per-capacity' Basis

The annualized capital-related financial charge is converted to a daily charge, and then converted to a "per-capacity" basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operating cost on a per-Mcf basis (CAPREC).

CTG plant fixed operating costs

Fixed operating costs (FXOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other overhead costs. These components can be factored from either the operating labor requirement or the capital cost.

Like capital cost estimations, operating cost estimations involve a number of distinct steps. Some of the steps associated with the FXOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

0) Estimation of the annual cost of direct operating labor

1) Year-dollar and location adjustment for operating labor costs (OLC)

2) Estimation of total labor-related operating costs (LRC)

3) Estimation of capital-related operating costs (CRC)

4) Convert fixed operating costs to a “per-unit” basis

Step 0 involves several adjustments which must be made prior to input into the NGTDM; steps 1-4 are performed within the NGTDM.

Step 0 – Estimation of Direct Labor Costs

Direct labor costs are reported based on a given processing unit size. Operation and labor costs were provided for plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in 2004 dollars.

Step 1 – Year-Dollar and Location Adjustment for Operating Labor Costs

Before the labor cost data can be utilized, it must be converted via the following steps:

a) Adjust the labor costs from 2004 dollars, first to the year-dollar reported by NEMS using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by NEMS (Appendix E, XBM_LABOR).

b) Convert the 1987 operating labor costs from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional location factors. The location multiplier (Appendix E, LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$CTG\_LABOR = LABORLOC * BM\_LABOR \tag{321}$$

Location multipliers are translated to the NGTDM demand regions.

Step 2 - Estimation of Labor-Related Fixed Operating Costs

Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the plant, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (FXOC_LABOR) can be factored from the direct operating labor cost. This relationship is expressed by:

$$FXOC\_STAFF = CTG\_LABOR * CTG\_STAFF\_LCFAC \tag{322}$$

$$\begin{aligned} FXOC\_OH = {} & (CTG\_LABOR + FXOC\_STAFF) \\ & * CTG\_OH\_LCFAC \end{aligned} \tag{323}$$

$$FXOC\_LABOR = CTG\_LABOR + FXOC\_STAFF + FXOC\_OH \quad (324)$$

where,

FXOC_STAFF = Supervisory and staff salary costs
FXOC_OH = Benefits and overhead

Step 3 - Estimation of Capital-Related Fixed Operating Costs

Capital-related fixed operating costs (FXOC_CAP) include insurance, local taxes, maintenance, supplies, non-labor-related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (CTG_FCI). This relationship is expressed by:

$$FXOC\_INS = CTG\_FCI * INS\_FAC \quad (325)$$

$$FXOC\_TAX = CTG\_FCI * TAX\_FAC \quad (326)$$

$$FXOC\_MAINT = CTG\_FCI * MAINT\_FAC \quad (327)$$

$$FXOC\_OTH = CTG\_FCI * OTH\_FAC \quad (328)$$

$$\begin{aligned} FXOC\_CAP = {} & FXOC\_INS + FXOC\_TAX + \\ & FXOC\_MAINT + FXOC\_OTH \end{aligned} \quad (329)$$

where,

INS_FAC = Yearly Insurance
TAX_FAC = Local Tax Rate
MAINT_FAC = Yearly Maintenance
OTH_FAC = Yearly Supplies, Overhead, Etc.

Step 4 - Convert Fixed Operating Costs to a "per-capacity" Basis

On a "per-capacity" basis, the FXOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

Mansfield-blackman model for market penetration

The Mansfield-Blackman model for market penetration has been incorporated to limit excessive growth of CTG (on a national level) once it becomes economically feasible.[97] The indices associated with this modeling algorithm are user inputs that define the characteristics of the CTG process. They include an innovation index of the industry (Appendix E, CTG_IINDX), the relative profitability of the investment within the industry (Appendix E, CTG_PINDX), the relative size of the investment (per plant) as a

[97] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765.
A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

percentage of total company value (Appendix E, CTG_SINVST), and a maximum penetration level (total number of units, Appendix E, CTG_BLDX).[98]

$$KFAC = -LOG((CTG\_BLDX / NCTGBLT) - 1) \tag{330}$$

$$PHI = -0.3165 + (0.23221 * CTG\_IINDX) + (0.533 * CTG\_PINDX) - (0.027 * CTG\_SINVST) \tag{331}$$

$$SHRBLD = 1/(1 + EXP(-KFAC - (YR * PHI))) \tag{332}$$

$$CTGBND = CTG\_BLDX * SHRBLD \tag{333}$$

where,

CTG_BLDX	=	maximum number of plants allowed
NCTGBLT	=	number of plants already built
SHRBLD	=	the share of the maximum number of plants that can be built in a given year
CTGBND	=	the upper bound on the number of plants to build

Investment cost adjustments

To represent cost improvements over time (due to learning), a decline rate (CTG_DCLCAPCST) is applied to the original CTG capital costs after builds begin.

$$CTG\_INVADJ = CTG\_INVBAS * (1 - CTG\_DCLCAPCST)^{(YR - CTG\_BASYR)} \tag{334}$$

where,

CTG_INVBAS	=	the initial CTG investment cost
CTG_BASYR	=	the first year CTG plants are allowed to build
CTG_INVADJ	=	the adjusted CTG investment cost

However, once the capacity builds exceed 1.1 bcf/day, a supplemental algorithm is applied to increase costs in response to impending resource depletions (such as competition for water).[99]

$$CTG\_CSTADD = 15 * TANH(0.4 * (MAX(0, (CTGPRODC / 1127308) - 1))) \tag{335}$$

where,

CTGPRODC	=	current CTG production
CTG_CSTADD	=	the additional cost

[98] These have been defined in a memorandum from Andy Kydes (EIA) to Han-Lin Lee (EIA), entitled "Development of a model for optimistic growth rates for the coal-to-liquids (CTG) technology in NEMS," dated March 23, 2002.
[99] The basic algorithm is defined in a memorandum from Andy Kydes (EIA) to William Brown (EIA), entitled “CTL run-- add to total CTLCST in ADJCTLCST sub,” dated September 29, 2006.